Flaring And Venting Reduction Guideline

VERSION 5.4: December 2023

About the Regulator

The BC Energy Regulator (Regulator) is the single-window regulatory agency with responsibilities for regulating oil and gas activities in British Columbia, including exploration, development, pipeline transportation and reclamation.

The Regulator's core roles include reviewing and assessing applications for industry activity, consulting with First Nations, ensuring industry complies with provincial legislation and cooperating with partner agencies. The public interest is protected by ensuring public safety, protecting the environment, conserving petroleum resources and ensuring equitable participation in production.

Vision, Mission and Values

Vision

A resilient energy future where B.C.'s energy resource activities are safe, environmentally leading and socially responsible.

Mission

We regulate the life cycle of energy resource activities in B.C., from site planning to restoration, ensuring activities are undertaken in a manner that:

- Protects public safety and the environment
- Supports reconciliation with Indigenous peoples and the transition to low-carbon energy
- Conserves energy resources
- Fosters a sound economy and social well-being

Values

Respect is our commitment to listen, accept and value diverse perspectives.

Integrity is our commitment to the principles of fairness, trust and accountability.

Transparency is our commitment to be open and provide clear information on decisions, operations and actions.

Innovation is our commitment to learn, adapt, act and grow.

Responsiveness is our commitment to listening and timely and meaningful action.

Additional Guidance

As with all Regulator documents, this document does not take the place of applicable legislation. Readers are encouraged to become familiar with the acts and regulations and seek direction from Regulator staff for clarification.

The Regulator publishes both application and operations manuals and guides. The application manual provides guidance to applicants in preparing and applying for permits and the regulatory requirements in the planning and application stages. The operation manual details the reporting, compliance and regulatory obligations of the permit holder. Regulator manuals focus on requirements and processes associated with the Regulator's legislative authorities. Some activities may require additional requirements and approvals from other regulators or create obligations under other statutes. It is the applicant and permit holder's responsibility to know and uphold all legal obligations and responsibilities. For example, Federal Fisheries Act, Transportation Act, Highway Act, Workers Compensation Act and Wildlife Act.

Throughout the document there are references to guides, forms, tables and definitions to assist in creating and submitting all required information. Additional resources include:

- Glossary and acronym listing on the Regulator's website.
- Documentation and guidelines on the Regulator's website.
- Frequently asked questions on the Regulator's website.
- Advisories, bulletins, reports and directives on the Regulator's website.
- Regulations and Acts listed on the Regulator's website.

In addition, this document may reference some application types and forms to be submitted outside of the Application Management System but made available on the Regulator's website. Application types and forms include:

- Heritage Conservation Act, Section 12
- Road use permits
- Water licences
- Master licence to cut
- Certificate of restoration
- Waste discharge permit
- Experimental scheme application
- Permit extension application

Table of Contents

Manual Revisions

The Regulator is committed to the continuous improvement of its documentation. Revisions to the documentation are highlighted in this section and are posted to the Documentation Section of the Regulator's website.

Stakeholders are invited to provide input or feedback on Regulator documentation to servicedesk@bc-er.ca.

Version Number	Posted Date	Effective Date	Chapter Section	Summary of Revision(s)
5.0	April 9, 2018	May 1, 2018	Various	Various edits have been made to this document. Users are encouraged to review the document in its entirety.
5.1	May 7, 2018	June 1, 2018	Various	Updated "pipelines.facilities@bcogc.ca" to "OGCPipelines.Facilities@bcogc.ca".
5.2	May 27, 2021	June 1, 2021	Various	Various edits have been made to this document. Users are encouraged to review the document in its entirety.
5.3	Sept 2, 2022	Sept 2, 2022	Wording, CH10, pg 74	Changed from "before" to "after" in "Natural gas powered pneumatic pumps at facilities that began operations after January 1, 2021"
5.4	Dec 18, 2023	Dec 18, 2023	Various	Replace BCOGC with BCER; OGAA with ERAA; new logos, references and associations

Preface

The Flaring and Venting Reduction Guideline (the Guideline) provides regulatory requirements and guidance for flaring, incinerating and venting in British Columbia, as well as procedural information for flare approval requests, dispersion modelling and the measurement and reporting of flared, incinerated and vented gas. The Guideline applies to the flaring, incineration and venting of natural gas at wellsites, facilities and pipelines regulated under the Energy Resource Activities Act (ERAA).

Scope

This guideline focuses exclusively on requirements and processes associated with the BC Energy Regulator's (the Regulator) legislative authorities and does not provide information on legal responsibilities that the Regulator does not regulate. It is the responsibility of the applicant or permit holder to know and uphold its other legal responsibilities.

How to Use This Guideline

Regulator requirements and recommended practices are numbered sequentially within each section and subsection throughout the Guideline. "Must" indicates a requirement for which compliance is expected and may be subject to Regulator enforcement, while "recommends" or "should" indicates a best practice that should be used by the applicable party.

Throughout this Guideline, the term "flaring" refers to the combustion of gas in a flare stack or an incinerator unless otherwise specified. Gas combusted in an incinerator is considered to be "flared".

The updates to this Guideline are intended to continue progress towards achieving the BC Energy Plan's goals, reducing upstream oil and gas flaring within the province, eliminating economical routine solution gas flaring, reducing the nuisance impacts associated with flaring and improvement of flaring reporting.

The Regulator recognizes that evolving technologies and practices may not be addressed by these guidelines. The Regulator is willing to consider innovative ideas, solutions, practices and technologies that meet the goals set out in this guideline.

Additional Guidance

Frequently Asked Questions

A Frequently Asked Questions (FAQ) link is available on the Regulator webpage. The information provided is categorized into topics which reflect the manuals for easy reference. Please consult the FAQ page before contacting the Regulator to help keep response times short.

Flaring Reduction Reporting

The Regulator has produced a series of flaring reports, and beginning in the 2014 reporting year, Air Summary Reports. These are available for download from the Reports section of the Regulator's website.

Flaring and Venting Management Hierarchy and Framework

Flaring and venting are associated with a wide range of energy development activities and operations associated with:

- Oil and gas well drilling, completion and testing;
- Oil production (solution gas);
- Gas production;
- Planned non-routine depressurization of processing equipment and gas pipelines for maintenance;
- Un-planned non-routine depressurization of process equipment and gas pipelines due to process upsets or emergency and;
- Waste management facilities

The Regulator adopted the Clean Air Strategic Alliance's (CASA) objective hierarchy and framework for management of all sources of gas flaring and venting (Figure 1.1).

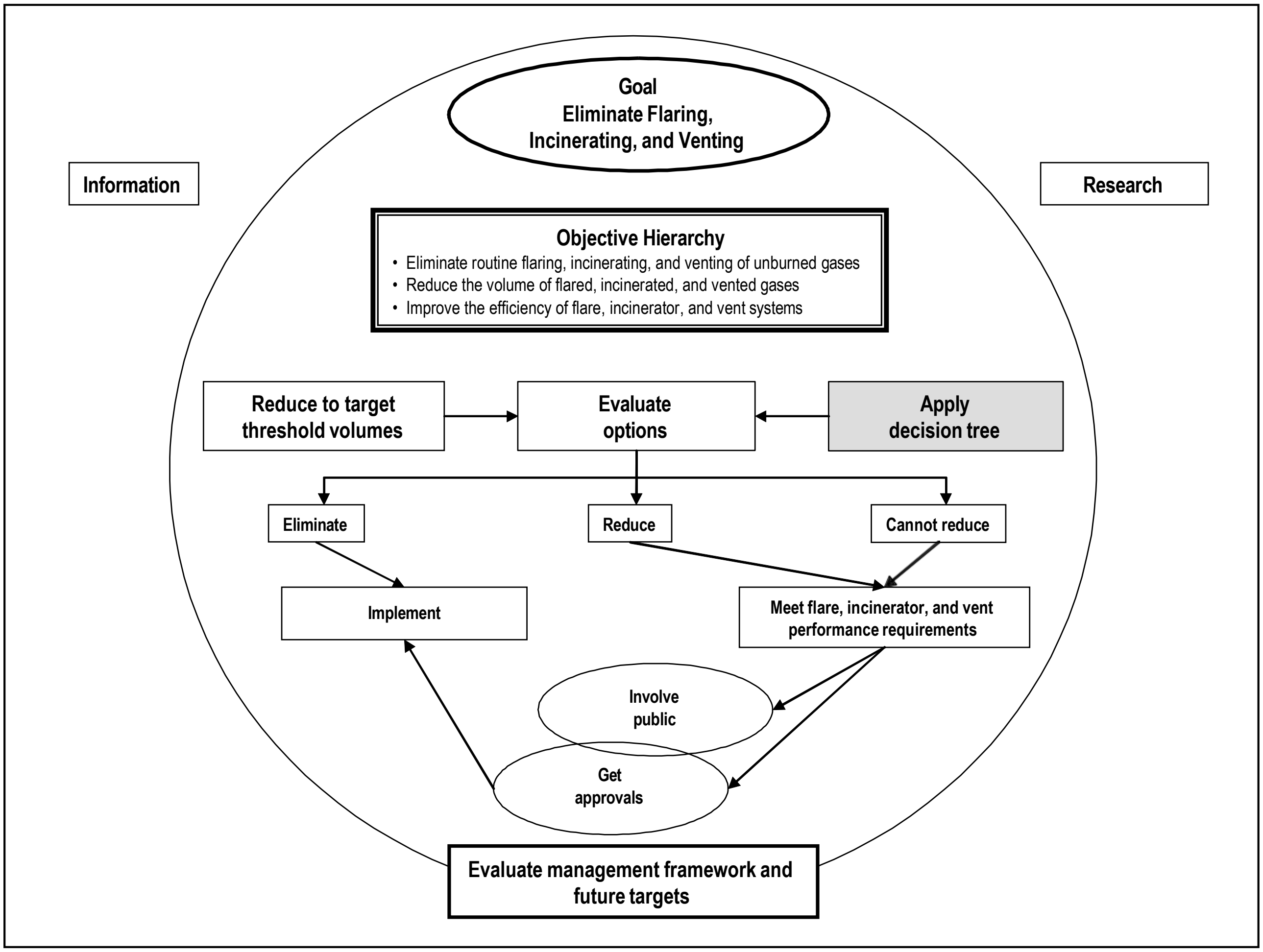

Figure 1.1: Gas Flaring/Venting Management Framework (adapted from CASA)

In accordance with the objective hierarchy, operators must evaluate the following three options:

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

Chapter 1: Solution Gas Management - Oil Facility Flaring and Venting

The Regulator's goal is to have the upstream petroleum industry reduce the volume of solution gas that is flared or vented. The Regulator, in consultation with stakeholders, will monitor progress to determine the need for additional requirements to facilitate solution gas conservation.

Conservation is defined as the recovery of gas that would otherwise be vented or flared at an oil or gas facility, and using it as a fuel for production facilities, other useful purpose (e.g. power generation), sales, or beneficial injection into an oil or gas pool. Conservation opportunities are evaluated as economic or uneconomic based on the criteria listed in Chapter 1.8.

1.1 Solution Gas Venting Reduction

The Regulator does not consider venting as an acceptable alternative to flaring. If gas volumes are sufficient to sustain stable combustion, the gas must be burned or conserved (see Chapter 7.1). If venting is the only feasible alternative, it must meet the requirements set out in Chapter 7 of this guideline.

1.2 Solution Gas Flaring and Venting Decision Tree

The Regulator adopted the Gas Flaring/Venting Management Framework (Figure 1.1) and endorses the Solution Gas Flaring/Venting Decision Tree Process (Figure 1.2), as recommended by CASA. Permit holders must apply the decision tree to all flares and vents greater than 900m³/day and be able to demonstrate how each element of the decision tree was considered and, where appropriate, implemented.

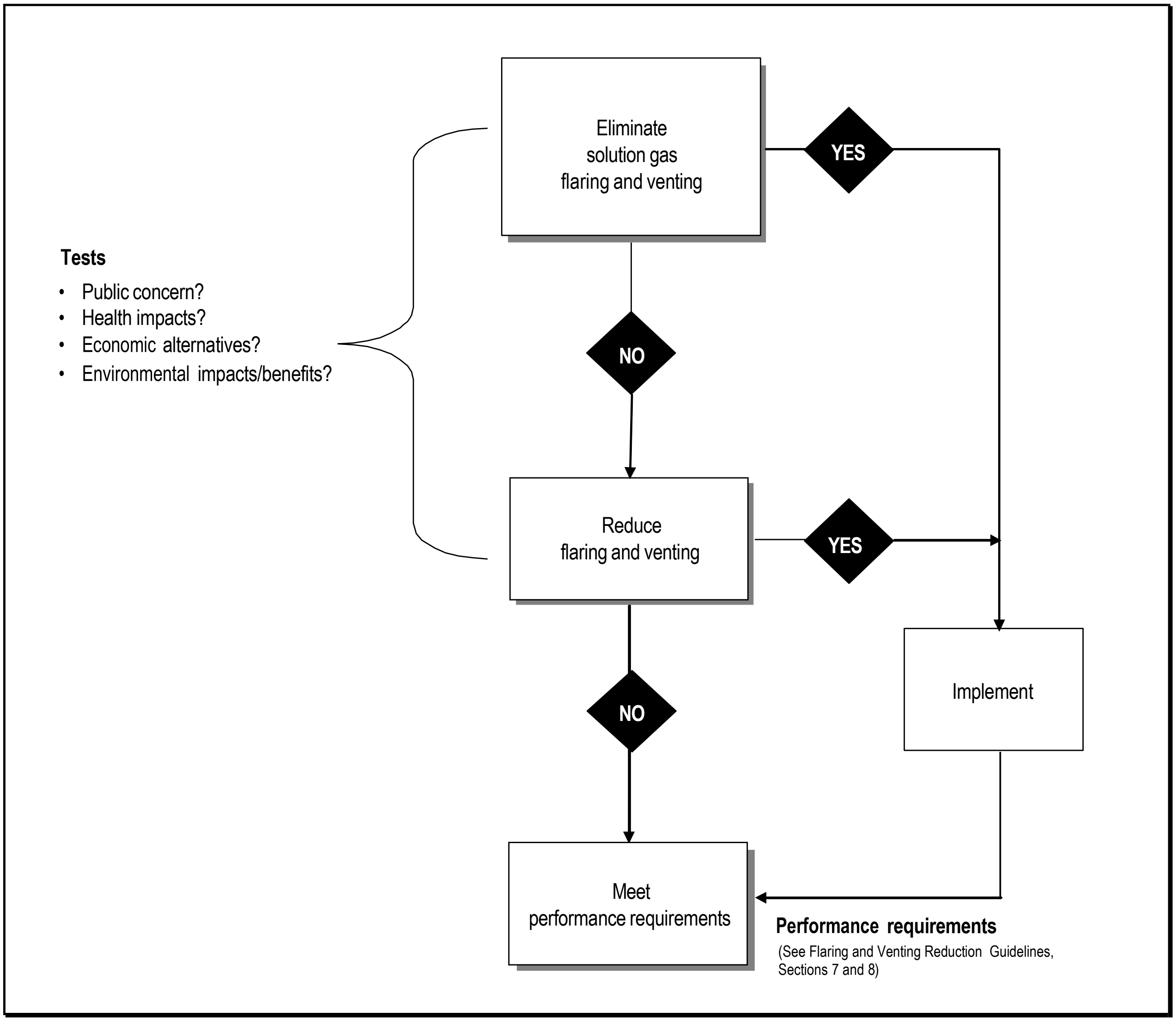

Figure 1.2: Solution Gas Flaring/Venting Decision Tree (adapted from CASA)

1.3 Conservation at New Oil Facilities

In general, for new oil sites[1], solution gas flaring cannot be extended beyond the period required to produce the test period allowable set out in Section 56 of the Drilling and Production Regulation.

It is expected that the actual flaring duration will 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 a total of 72 hours (see Chapter 2.3 for further details and extensions to time limits).

The Regulator expects that conservation will be implemented at all new oil facilities. However, sites where conservation is not economic (as evaluated in accordance with Chapter 1.8) or practical may be approved by the Regulator on a site by site basis. Refer to Figure 1.3 for a New Oil Facility Gas Conservation Decision Tree.

If the Net Present Value (NPV) of the gas conservation project is greater than -$50,000CAD, the wells should be shut in until conservation is implemented.

If gas is not conserved at a new oil facility and the flare is expected to be visible from a populated area, the use of incineration should be considered during the facility application process (see Chapter 9).

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

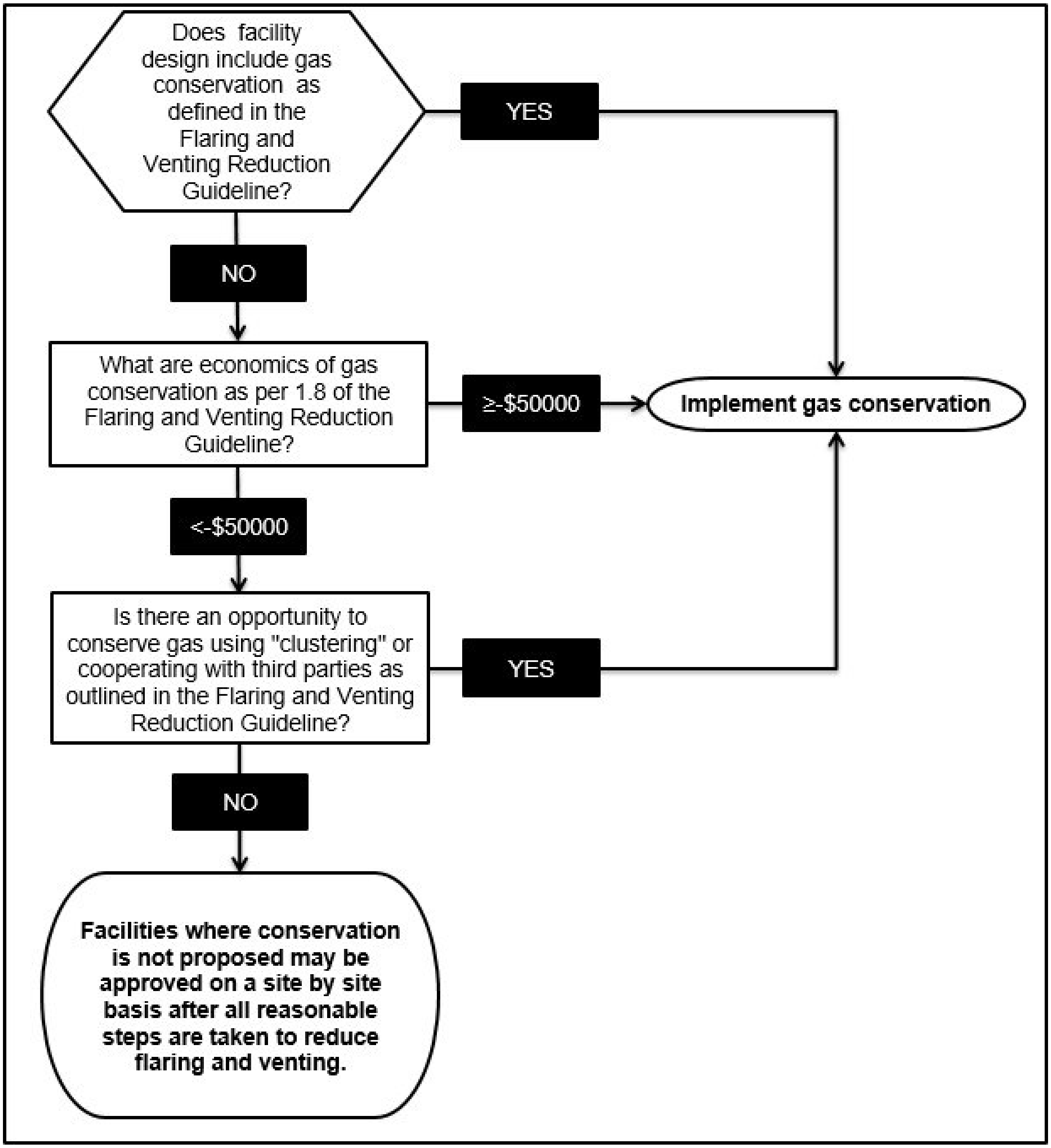

Figure 1.3: New Oil Facility Gas Conservation Decision Tree

1.4 Conservation at Existing Oil Facilities

These requirements apply to all existing oil facilities unless otherwise specified. Refer to Figure 1.4 for an Existing Oil Facility Gas Conservation Decision Tree.

1) Permit holders should conserve solution gas at all sites where:
   a. Combined flaring and venting volumes are greater than 900 m^3/day per site[2] and the decision tree process and economic evaluation (Chapter 1.8) result in a NPV of greater than -$50,000CAD.
   b. The gas to oil ratio (GOR) is greater than 3000 m^3/m^3. All wells producing with a GOR greater than 3000 m^3/m^3 at any time during the life of the well should be shut-in until the gas is conserved.
   c. Flared volumes are greater than 900 m^3/day per site and the flare is within 500 metres of an existing residence, regardless of economics.
      i. If a new residence is constructed or relocated within 500 metres of an existing solution gas flare after the effective date of this guideline, permit holders should provide information about the flaring operation to the new residents.
2) For any sites flaring or venting combined volumes greater than 900 m^3/day and not conserving, a review of conservation economics should be done at least once every 12 months using the criteria in Chapter 1.8.
3) The Regulator may still require economic evaluations for sites flaring or venting combined volumes less than 900 m^3/day and not conserving on a case-by-case basis if it is believed that conservation may be feasible.
4) Conserving facilities should be designed for 95 per cent conservation with a minimum operating level of 95 per cent.
5) Permit holders may apply to discontinue conservation if annual operating expenses exceed annual revenue. See Chapter 1.4(6).

[2] Volumes are calculated based on a 3-month rolling average.

6) Permit holders must obtain approval from the Regulator to discontinue conservation implemented at any facility and:

   a. Complete a decision tree to evaluate alternatives to discontinuing conservation.
   b. Provide information on annual operating expenses and revenues.
   c. Notify as required by Chapter 5 of this Guideline. The consultation and notification requirements found in Chapter 6.1 of the Oil and Gas Activity Application Manual may also apply.
   d. Submit a facility amendment application, and
   e. Comply with Table 1.1 in the event conservation facilities are not operational until Regulator approval to discontinue conservation is granted.

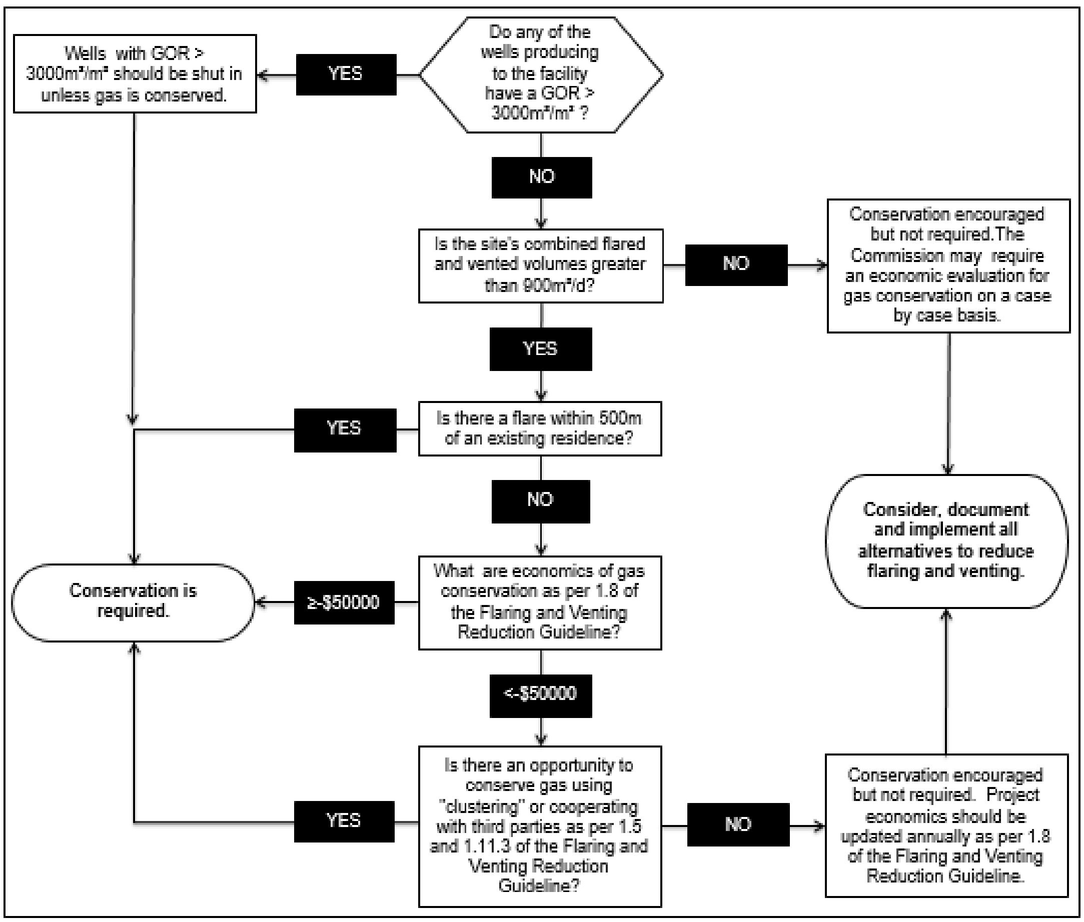

Figure 1.4: Existing Oil Facility Gas Conservation Decision Tree

1.5 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 may be economic to conserve in some areas if permit holders coordinate their efforts in an efficient, cooperative process to take advantage of combined gas volumes and economies of scale. Furthermore, solution gas conservation economics (Chapter 1.8) are enhanced if conservation is incorporated into the initial planning of larger multi-well projects.

1) Permit holders of production facilities within 3 kilometers of each other or other appropriate oil and gas facilities (including pipelines) should jointly consider "clustering" when evaluating solution gas conservation economics. The Regulator may suspend production in the area under consideration until the economic assessment is complete.

The Regulator recommends that:

   a. Permit holders exchange production data and jointly consider clustering of solution gas production or regional gas conservation systems; and,
   b. The permit holder with the largest flare and vent volumes take the lead in coordinating the evaluation of conservation economics for the area.

2) Permit holders of multi-well oil developments should assess conservation on a project or development area basis regardless of distance. Evaluations should address all potential gas vent and flare sources associated with the multi-well development.
   a. Permit holders should incorporate provisions for conservation at all stages of project development to optimize the opportunity for economic conservation of solution gas.
   b. Applications for multi-well oil developments may require a summary of the gas conservation evaluation and a description of the permit holder's related project plans.

1.6 Power Generation

Power generation, using otherwise flared or vented gas, is an alternative for conserving solution gas.

1.7 Consultation and Notification

Public consultation and notification requirements for routine flaring activities are done prior to the submission of well or facility permit applications. Chapter 6.1 of the Oil and Gas Activity Application Manual describes the consultation and notification process for permit applications.

1.8 Economic Evaluation of Gas Conservation

Methods of conservation include pipeline to sales, lease fuel, power generation, pressure maintenance, or any other alternative method that may become available.

For any sites flaring or venting combined volumes greater than 900 m^3/day and not conserving, conservation economics should be updated every 12 months.

1.8.1 Economic Evaluation Criteria

Economic evaluations of gas conservation should use the criteria listed below. The permit holder should consider the most economically feasible option in providing detailed economics. Specific Regulator economic evaluation submission requirements are listed in Chapter 1.8.2.

1) Evaluations should be completed on a before-tax basis, and should exclude contingency and overhead costs.
2) Price forecasts used in the evaluation of gas conservation projects (gas gathered, processed, and sold to market) should use the most recent Sproule Associates Limited Natural Gas Price Forecasts, Various Trading Points table. Natural gas prices should be obtained from the “BC West Coast – Station 2” column ($Cdn/MMBtu). Condensate prices should be obtained from the Natural Gas Liquids Price Forecasts and Inflation and Exchange Rates table in the “Edmonton Pentanes Plus” column ($Cdn/bbl).
3) Price forecasts for power generation projects should reflect the price offered in the most recent BC Hydro energy call. The power price should be escalated at the long-term inflation rate (see item 8). Alternatively, the cost of the power displaced at the site may be used.
4) Permit holders should have information to support the remaining reserves calculation and the production forecast (including planned drilling programs and pressure maintenance schemes).

5) Permit holders should have a detailed breakdown of capital costs showing equipment, material, installation, and engineering costs. Capital costs should be approved-for-expenditure quality numbers and should be based on selection of appropriate technology. Any capital costs incurred prior to the initiation of the project (sunk costs) should not be included in the analysis; only future capital costs related to conservation may be included.
    a. For new flares, if there are capital cost savings resulting from implementing gas conservation, such as any equipment that would otherwise be required, they should 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 should 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 should be a reasonable market value estimate of the equipment and not a depreciated value from a taxation perspective.
6) 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 1 mole per cent hydrogen sulphide (H_2S) or more, the incremental annual operating costs for the project are assumed to be up to 20 per cent of the capital cost to install the conservation facilities.
    a. The economic evaluation should account for any cost savings, such as carbon tax, reduced trucking, equipment rental, and permit holder costs resulting from the conservation project.
7) 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.
8) The inflation rate should be set to the Bank of Canada long-term inflation rate target of 2 per cent unless the permit holder can justify the use of a different inflation rate.
9) The discount rate should be equal to the prime lending rate of the Bank of Canada on loans payable in Canadian dollars plus 3 per cent, based on the month preceding the month during which the evaluation is conducted. This rate may be revised if the cost of capital for the oil and gas industry changes significantly.
10) The conservation economics should be evaluated on a royalties-in-basis (paying royalties) for incremental gas and gas by-products that would otherwise be flared or vented.

11) A gas conservation project is considered economic, and the gas should be conserved, if the economics of gas conservation generates an NPV before-tax greater than -$50,000CAD.
    a. The NPV is defined as a 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 Chapter 1.4(6) provides a process whereby operators may apply to discontinue conservation if annual expenses exceed annual revenue.
12) If a gas conservation project has an NPV less than -$50,000CAD and is therefore considered uneconomic on its initial evaluation, the project economics should be re-evaluated annually using updated prices, costs and forecasts.

1.8.2 Economic Evaluation Audit Requirements

Economic evaluation packages must be submitted to the Regulator upon request and should contain the following information in International System of Units (SI):

- Detailed capital and operating cost schedule as set out in Chapters 1.8.1(5) and 1.8.1(6).
- Oil and gas reserves calculations and supporting information (including a discussion of planned drilling programs and pressure maintenance schemes).
- A production forecast for both the oil and gas streams and the economic limit (date and production rates) of the project (including planned drilling programs and pressure maintenance schemes).
- A copy of the gas analysis from the project or a representative analog complete with gas heating value and gas liquid yields.
- Documentation of alternatives that were considered in order to eliminate or reduce flaring or venting, how they were evaluated, and the outcome of the evaluation.

1.9 Non-routine Flaring and Venting at Solution Gas Conserving Facilities

Permit holders must minimize non-routine flaring and venting during upsets and outages of solution gas conserving facilities.

1.9.1 Limitations on Non-Routine Flaring and Venting During Solution Gas Conserving Facility Outages

1) Production operations must be managed to control non-routine flaring and venting of normally conserved solution gas in accordance with Table 1.1.
2) Table 1.1 does not apply to non-associated gas (the percentage cutbacks listed in Table 1.1 apply to solution gas only). All non-associated gas must be shut-in during facility outages.
3) Permit holders must notify as required in Chapter 5.
4) If there is a restriction to plant inlet, solution gas must be processed on a priority basis in relation to non-associated gas in order to minimize unnecessary flaring of solution gas.
5) The Regulator recommends that wells with the highest GORs be shut-in first during facility outages and cutbacks.
6) 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.
7) When multiple permit holders are involved, they may determine how best to implement the overall required production reductions. If agreement cannot be reached, each permit holder must implement production reductions as specified in Table 1.1 below.

Table 1.1: Requirements for non-routine flaring and venting during solution gas conserving facility outage

Shutdown Category	Duration	Operational Requirements
Partial equipment outages	< 5 days	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 10^3 m^3/day, subject to limitations on venting, as defined in Chapter 7.
Planned	< 4 hours	Permit holders must make all reasonable efforts to reduce battery or solution gas plant inlet gas volumes by 50% of average daily solution gas production over the preceding 30-day period.
Planned	> 4 hours	Permit holders must reduce battery or solution gas plant inlet gas volumes by 75% of average daily solution gas production over the preceding 30-day period and meet the following requirements: • Solution gas must not be flared from wells that have an H_2S content greater than 5 mole per cent; • Production may be sustained at rates to provide sufficient throughput to keep equipment operating safely and within minimum design turndown range; • The Regulator also recommends that operators notify individuals that have identified themselves to the permit holder as being sensitive or interested regarding emissions from the facility; and, • Residents and the Regulator must be notified 24 hours prior to the planned event in accordance with Chapter 5.
Emergency or	< 4 hours	No reduction in plant inlet is required.
Plant upset	> 4 hours	Permit holders must reduce battery or solution gas plant inlet gas volumes by 75% of average daily solution gas production over the preceding 30-day period and must meet the following requirements: • Solution gas must not be flared from wells that have an H_2S content greater than 5 mole per cent; • Production may be sustained at rates to provide sufficient throughput to keep equipment operating safely and within minimum design turndown range; • The Regulator also recommends that permit holders notify individuals that have identified themselves to the permit holder as being sensitive or interested regarding emissions from the facility; and, • Residents and the Regulator must be notified within 24 hours of the unplanned flaring event in accordance with Chapter 5.
Repeat non-routine flaring		Permit holders must investigate the causes of repeat non-routine flaring or venting and take steps necessary to eliminate or reduce the frequency of such incidents.
Notwithstanding solution gas reduction requirements listed in Table 1.1, if a sour or acid gas flare or incinerator stack is not designed to meet the one-hour BC Air Quality Objectives and Standards for sulphur dioxide (SO_2) under high flow rate conditions, action must be taken immediately to reduce gas to a rate compliant with BC's Air Quality Objectives and Standards (see Chapter 6).Emergency shutdowns or plant upsets are unplanned events at the battery site or at facilities downstream of the battery that cause non-routine flaring at the battery. Repeat non-routine flares are defined as recurring events of similar cause at a conserving facility during a 30-day period.		

1.9.2 Planned Shutdown (Turnaround) Considerations

Permit holders must evaluate and implement appropriate measures to reduce solution gas flaring and venting during a gas plant turnaround or planned shutdown. Alternatives that minimize impacts of planned shutdowns include:

- Delivering solution gas to a nearby gas plant that is not on turnaround;
- Scheduling maintenance at related oil facilities to coincide with the gas plant turnaround;
- Injecting solution gas into the gas cap of an oil pool or into a gas reservoir (requires prior approval) and producing it back when the gas plant is back on stream; and,
- Communicating with well, battery and gas plant permit holders to ensure that non-routine solution gas flaring and venting are minimized.

1.9.3 Alternatives to Solution Gas Shut-in Requirements

The Regulator will consider alternatives to the shut-in requirements listed in this Guideline for solution gas. This will only be done if the permit holder can provide appropriate rational for why shutting in is impractical. In these special cases, the permit holder must consult with the Regulator about alternatives prior to implementation. .

Permit holders must plan for outages. If an alternative to Table 1.1 is justified, permit holders must submit a written request to the Regulator explaining the alternative requested and giving supporting reasons for the request. Contact with the Regulator must not be deferred until an actual outage occurs. Permit holders should submit the written request to the Regulator a minimum of 30 days prior to a planned shutdown.

1.10 Approvals and Notifications for Non-Conserving Facilities

Specific approval is not required for non-routine flaring at facilities including maintenance and emergencies, however, limitations on non-routine flaring may be specified in the facility permit. Flaring for other purposes must be approved in the facility permit. Permit holders must notify residents and the Regulator of non-routine flaring at facilities as described in Chapter 5.

1.11 Solution Gas Reporting Requirements and Data Access

1.11.1 Solution Gas Reporting Requirements

Flared, incinerated and vented solution gas must be reported in Petrinex. as described in Chapter 10. Permit holders must report all new oil well production, including the test period. If necessary, permit holders must obtain a battery code for any new oil wells before production, including flaring, can be reported.

1.11.2 Data Access

The Regulator makes available production data related to the disposition of oil, and gas for all crude oil batteries, with the exception of information associated with wells that are part of an approved Special Project for experimental purposes. Confidential information is respected using existing confidentiality protocols.

The production data for all crude oil wells is available on a monthly basis as a data download from the Regulator's website. Log on to the secure site, click on Data Downloads and download files.

Disposition of the flared gas volumes is currently only available through special requests. The Regulator contemplates having this included as a regular report in the future.

1.11.3 Cooperating with Third Parties

The Regulator recommends that permit holders cooperate with qualified third parties attempting to conserve solution gas through open market or clustering efforts by providing non-confidential information, such as gas analyses, flared and vented volumes, pressures, and other relevant data, on a timely basis (also see Chapter 1.5).

In cases where conservation is determined by the permit holder to be uneconomic, but a third party is able to conserve the gas, the Regulator recommends that permit holders 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 organization must not have an impact on the upstream operations.

Any third party making data requests to operators must be technically qualified and have a reasonable expectation of proceeding with the gas conservation project. Third parties must also comply with all relevant Regulator requirements.

Chapter 2: Well Flaring

This chapter applies to temporary flaring activities at wells. These activities include well testing, well cleanup and well maintenance/servicing.

The Regulator does not consider venting as an acceptable alternative to flaring. If gas is not conserved and gas volumes are sufficient to sustain stable combustion, the gas must be burned. If venting is the only feasible alternative, it must meet the requirements in Chapter 7.

2.1 Temporary Flaring Decision Tree

Permit holders should use the Temporary Flaring Decision Tree Process (Figure 2.1) to evaluate all opportunities to eliminate or reduce flaring, regardless of volume.

1) Permit holders must evaluate opportunities to use existing gas gathering systems prior to commencing temporary maintenance, well cleanup, or testing operations; that is, in-line testing.
2) In-line testing is mandatory for all wells on private land and wells on Crown land within 1.25 km of a residence and 3.0 km of a suitable pipeline, unless exempted by the Regulator (see Directive 2010-03).
3) If in-line testing is not possible, permit holders must design completions and well testing programs to minimize emissions, while ensuring a technically sound well completion and acquisition of sufficient reservoir and productivity information for future development decisions. The Regulator's Well Testing and Reporting Requirements Guide should be consulted for details on the minimum pressure and deliverability requirements for well testing and the recommended practices to ensure that appropriate information is obtained for conservation and pool management purposes, in addition to the requirements of this guideline.

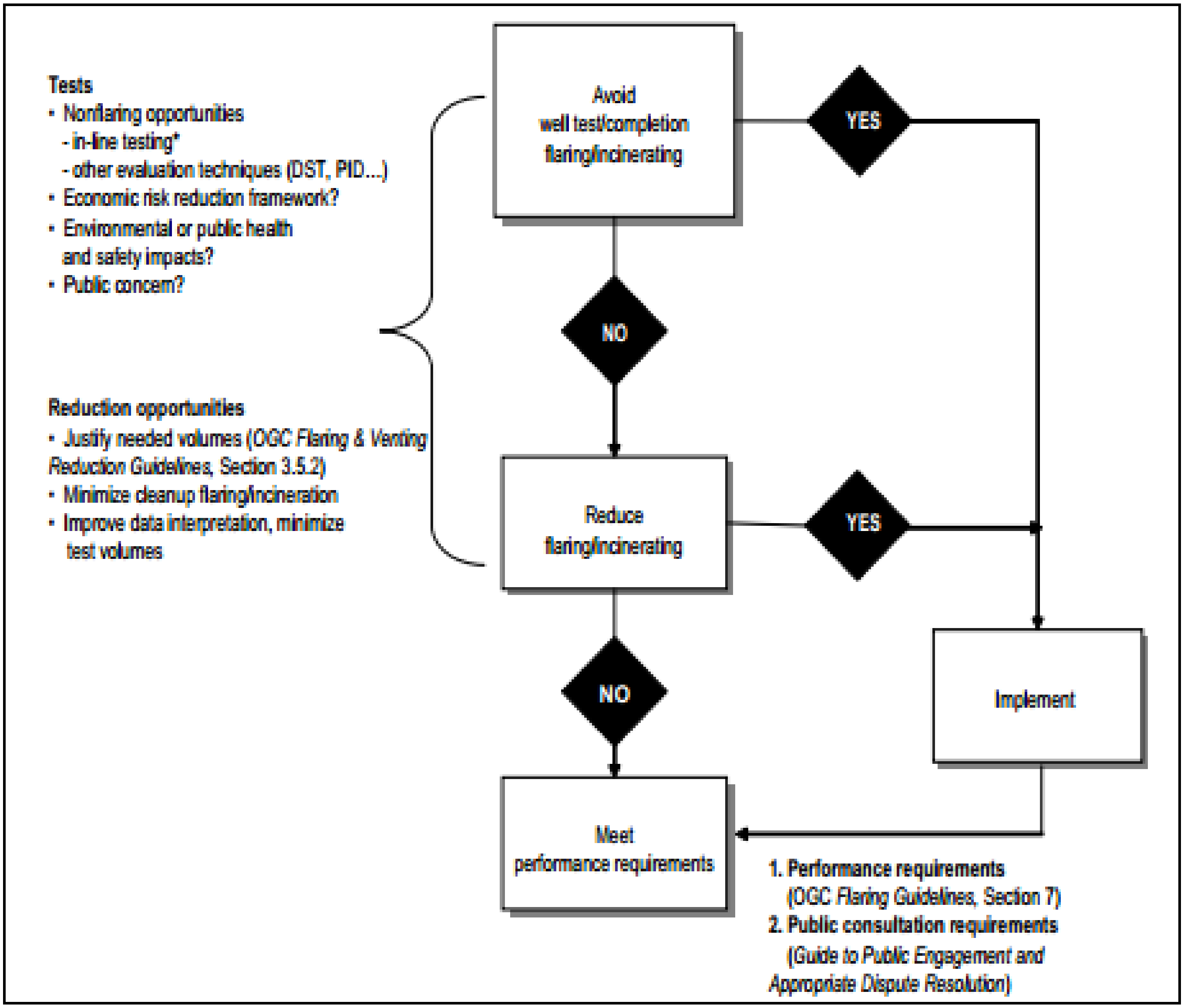

Figure 2.1: Temporary Flaring Decision Tree (adapted from CASA)

2.2 Flaring Impact Reduction

Permit holders must make reasonable efforts to reduce the impacts of temporary flaring near populated areas. Consideration should be given to:

- Reducing noise,
- Flaring during daylight hours and,
- The use of incineration (see Chapter 9) where appropriate.

Subject to safety and air quality considerations, the Regulator may require the use of incineration as a well permit condition based on the outcome of public consultation.

2.3 Temporary Flaring Approval for Well Testing

The Drilling and Production Regulation authorizes flaring at wells under the following circumstances:

- If the flaring is related to drilling operations;
- If the flaring is necessary for emergency purposes;
- If the flaring is for well workover or maintenance operations, and the cumulative quantity of flared gas does not exceed 50 000 m^3 in one year; or,
- If it is in accordance with the well permit.

Flaring for purposes of well testing requires approval in the pertinent well permit. Approval to flare may be requested at the time of well permit application or by amending the well permit. Refer to the Chapter 4.1 of the Oil and Gas Activity Application Manual for the permit application and amendment processes and requirements.

Requested volumes, rates, and/or conditions may not be granted by the Regulator. Before a decision is rendered, consideration will be given to the technical justification for the flaring request, total volumes, potential to exceed the BC Air Quality Objectives and Standards, total sulphur emissions, proximity of residences, and results of consultation.

2.4 Ambient Air Quality Evaluation

1) Permit holders must evaluate impacts of gas flaring on ambient air quality if it is proposed to burn gas containing ≥ 1 mole per cent H_2S or one tonne per day of sulphur emission rate during the event. See Chapter

6.10 for more information.

2) Modelling does not need to be submitted at the time of well permit application, however, modelling must be completed prior to flaring.

3) For gas flaring ≥ 1 mole per cent H_2S and < 5 mole per cent H_2S, permit holders must retain, for one year after the flaring event, information on dispersion assessments. This information must be provided to the Regulator upon request.

4) For gas flaring ≥ 5 mole per cent H_2S, permit holders must submit the dispersion modelling to the Regulator in accordance with Section 6(1)(d) of the Oil and Gas Waste Regulation.

   Depending on the results of dispersion modelling, the Regulator may impose conditions. These conditions may include, but are not limited to, air quality monitoring, meteorological monitoring with shutdown criteria and stack height, flow rate, and gas composition requirements.

2.5 Oil and Gas Well Test Flaring and Venting Duration Limits

1) These time limits are per zone and non-consecutive and they do not include shut-in time. These time periods include cleanup, completion, and testing operations:
   a. crude oil wells: 72 hours.
   b. gas (non-coalbed methane) wells: 72 hours.
   c. dry coalbed methane development wells (producing less than 1 m³ of water per operating day): 120 hours.
   d. dry coalbed methane non-development wells (producing less than 1 m³ of water per operating day): 336 hours.
   e. wet coalbed methane wells (producing more than 1 m³ of water per operating day): see Chapter 2.3(5) below.
   f. unconventional gas development wells: 120 hours.
   g. unconventional gas non-development wells: 336 hours.
2) Extensions to the time limits listed in 1 (b), (c) and (d) are allowed if:
   a. cleanup of the wellbore is not complete;
   b. stabilized flow has not been reached; or,
   c. there have been mechanical problems with the well.
3) Extensions to the time limits listed in 1 (a), (f) and (g) are allowed if:
   a. cleanup of the wellbore is not complete; or,

b. there have been mechanical problems with the well.

4) The permit holder must document these reasons for extension and keep the information on file for audit by the Regulator when requested. The permit holder is not required to obtain permission to extend the flaring/venting beyond the specified time limit listed in 1 (b), (c) or (d) if the reason matches those listed in #2 (a) or (b), but must provide advance notification to the Regulator as soon as the permit holder recognizes that the time limit will be exceeded.

5) For wet coalbed methane wells (producing more than 1 m^3 of water per operating day), flaring or venting must cease (gas must be conserved) within 6 months of gas production for an individual well exceeding a cumulative total of 100 10^3m^3 for any consecutive 3-month period (about 1100 m^3/day). Shorter tie-in periods must be pursued whenever possible.
   a. Permit holders must notify the Regulator as soon as the cumulative total gas production exceeds 100 10^3m^3 for any consecutive 3-month period at a wet coalbed methane well that is flaring or venting.
   b. For wet coalbed methane wells that do not trigger the requirement above (100 10^3m^3 in 3 months), flaring and venting are limited to a total period of 18 months, including the time to tie in the well.

2.6 Site-Specific Requirements Related to Well Flaring

1) Flares and incinerators must comply with design and operation requirements defined in Chapter 6.
2) Flares and incinerators must not be operated outside design operating ranges as specified by a professional engineer licensed or registered under the Engineers and Geoscientists Regulation.
3) Permit holders must determine the H_2S content of flared or incinerated gas using Tutweiller or gas chromatography methods as soon as practical after commencement of operation if gas analysis has not been obtained within the preceding 12 months.
4) If the H_2S content in the gas is found to exceed 5 mole per cent H_2S and dispersion modelling was not submitted with flaring application, or if the H_2S content of the gas exceeds the maximum value listed in the related permit conditions, operations must be suspended until the Regulator has approved the resumption of operations.
5) Both high and low-pressure gas-liquid separation stages should be used for sour gas to minimize vapour released from produced hydrocarbon liquid and sour water storage.
6) Liquid storage must be designed to prevent the escape of sour gas to the environment. (For additional detail see ENFORM, Industry Recommended Practice (IRP) Volume 4: Well Testing and Fluid Handling.)
7) Tanks and equipment used for temporary flaring operations must be provided with secondary containment,

when required, as specified in the Oil and Gas Activity Application Manual.

8) For compliance purposes, flaring commences when there is burnable gas at surface. The total flared volume does not include completion fluid (i.e. CO_2) that is flowed back from the well or fuel gas that is added to improve the heating value of the flared gas.

2.7 Temporary Pipelines and Facilities for In-Line Tests

To facilitate conservation, the permit holder may install temporary equipment such as a compressor or a temporary surface pipeline. Refer to Chapters 4.2 (pipelines) and 4.3 (facilities) of the Oil and Gas Activity Application Manual for application requirements.

2.8 Notification Requirements

Prior to flaring, permit holders must notify the Regulator and all residents and administrators of incorporated centers in accordance with Chapter 5.

Notification to Regulator must be done through eSubmission, via a Notice of Flare.

2.9 Reported Flared Volumes

- Well test results must be submitted in accordance with the requirements of the Drilling and Production Regulation via eSubmission.
- All well deliverability tests must be submitted within 60 days of completing the fieldwork. This information must include the volume of gas produced to flare, vent or pipeline. All analyses from samples gathered at the wellhead must also be submitted via eSubmission.
- The volumes of all fluids recovered during well cleanup and well testing must be reported in the monthly volumetric submission in Petrinex. This includes all flared gas and any condensate and water produced.
- All flared volumes, from both workover operations and testing, must be reported in Petrinex.
- Any gas produced or flared during underbalanced drilling must be reported in Petrinex. Permit holders must contact the Regulator through the Online Service Support Form to have a well event created.
- Questions regarding volumetric reporting in Petrinex should be directed to the BC Ministry of Finance.

Chapter 3: Natural Gas Facility Flaring and Venting

This Chapter addresses flaring and venting at natural gas facilities (such as processing plants, compressor stations and dehydrator facilities).

3.1 Gas Production Facility and Gas Processing Plant Flaring and Venting Decision Tree

Permit holders should use the decision tree analysis shown in Figure 3.1 to evaluate all new and existing facility flaring and venting regardless of volume except for intermittent small sources (less than 100 m^3 per month), such as pig trap depressurization. Subject to safety and environmental considerations, permit holders must conserve all gas that is economic to conserve (the net present value of conservation is greater than $0 using the economic evaluation criteria in Chapter 1.8 of this Guideline).

Permit holders must document alternatives that were considered in order to eliminate or reduce flaring and/or venting, how they were evaluated, and the outcome of the evaluation.

- Permit holders should refer to the CAPP Facility Flare Reduction BMP for methods to document, evaluate and reduce sources of flaring.
- Permit holders must make reasonable efforts to address concerns or objections of residents related to facility flaring.
- Flare, incinerator, and vent systems must be designed and operated in compliance with Chapters 6 and 7, good engineering practice and relevant safety codes and regulations.
- For new facilities, the use of incineration must be considered during the facility permit application process for continuous flares (other than purge and pilot gas) if the flare is expected to be visible from a populated area (see Chapter 9).

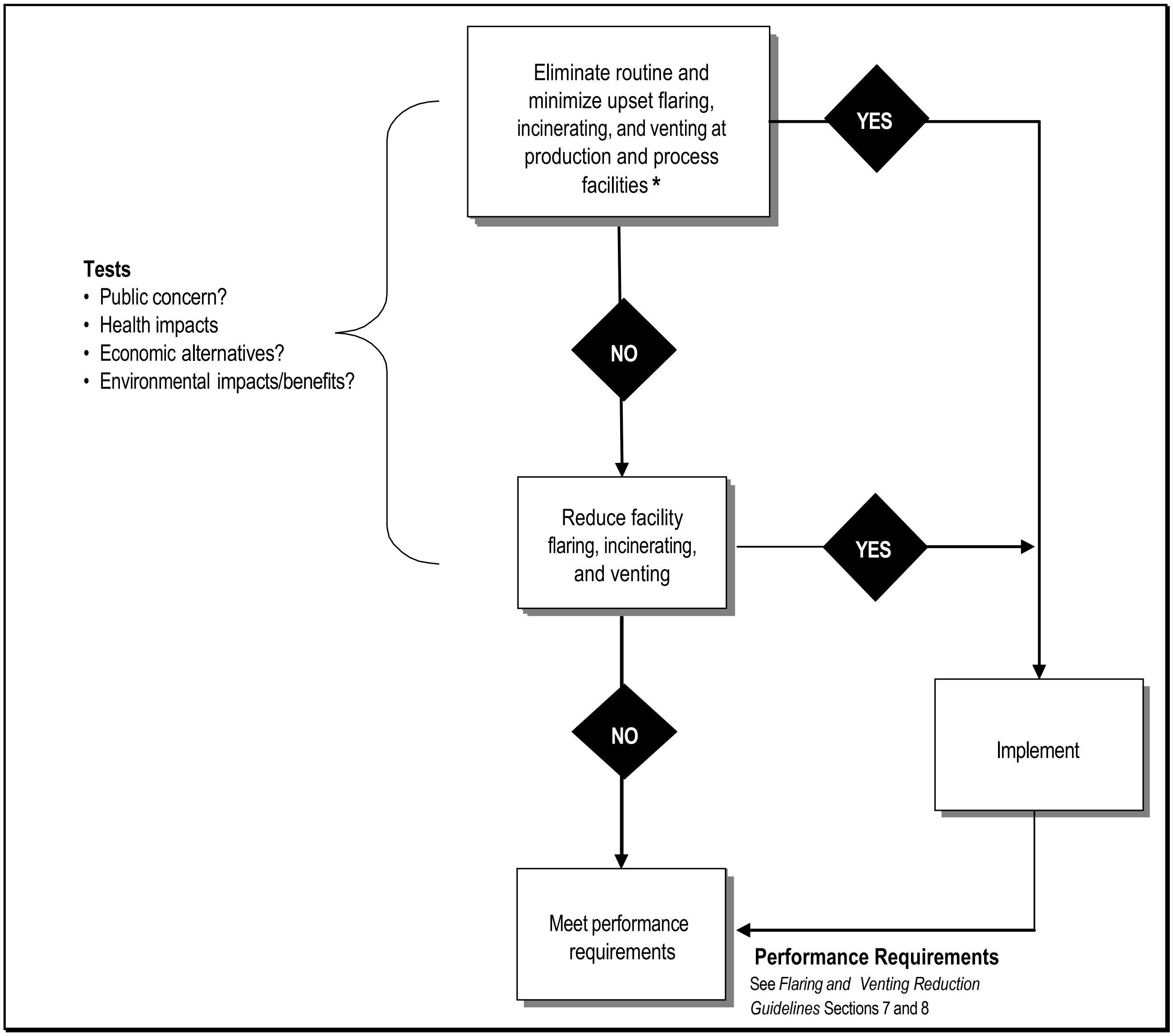

Figure 3.1: Facility flaring and venting decision tree (adapted from CASA)

3.2 Conservation at Gas Facilities

These requirements apply to all new and existing natural gas facilities. Flaring and incineration volumes in this section do not include fuel gas used for pilots or flare system purge.

1) Permit holders should conserve gas at natural gas facilities where:
    a. Conservation economics produce a NPV greater than $0 (using the economic evaluation criteria in Chapter 1.8 of this Guideline).
    b. Flared volumes are greater than 4000 m³/day per site and the flare is within 1000 m of an existing residence.
        i. If a new residence is constructed or relocated within 1000 m of an existing facility gas flare, permit holders should provide information about the flaring operation to the new residents.
2) For any sites flaring or venting combined volumes greater than 4000 m³/day and not conserving, a review of conservation economics should be done at least once every 12 months using the criteria in Chapter 1.8.
3) New sites flaring or venting combined volumes greater than 6000 m³/day should implement gas conservation. However, sites where conservation is not economic (as evaluated in accordance with Chapter 1.8) or practical may be approved by the Regulator on a site by site basis.
4) The Regulator may require additional conservation evaluations at non-conserving facilities when necessary.
5) Conservation is subject to safety and environmental concerns.
6) The Regulator may consider conservation alternatives for temporary, remote or exceptional natural gas facilities.
7) Conserving facilities should be designed for 95 per cent conservation with a minimum operating level of 95 per cent.
8) Permit holders must obtain approval from the Regulator to discontinue conservation implemented at any facility and:
    a. Complete a decision tree to evaluate alternatives to discontinuing conservation.
    b. Provide information on annual operating expenses and revenues.
    c. Notify as required by Chapter 5 of this Guideline. The consultation and notification requirements of Chapter 6.1 of the Oil and Gas Activity Application Manual may also apply, and;
    d. Submit a facility amendment application.

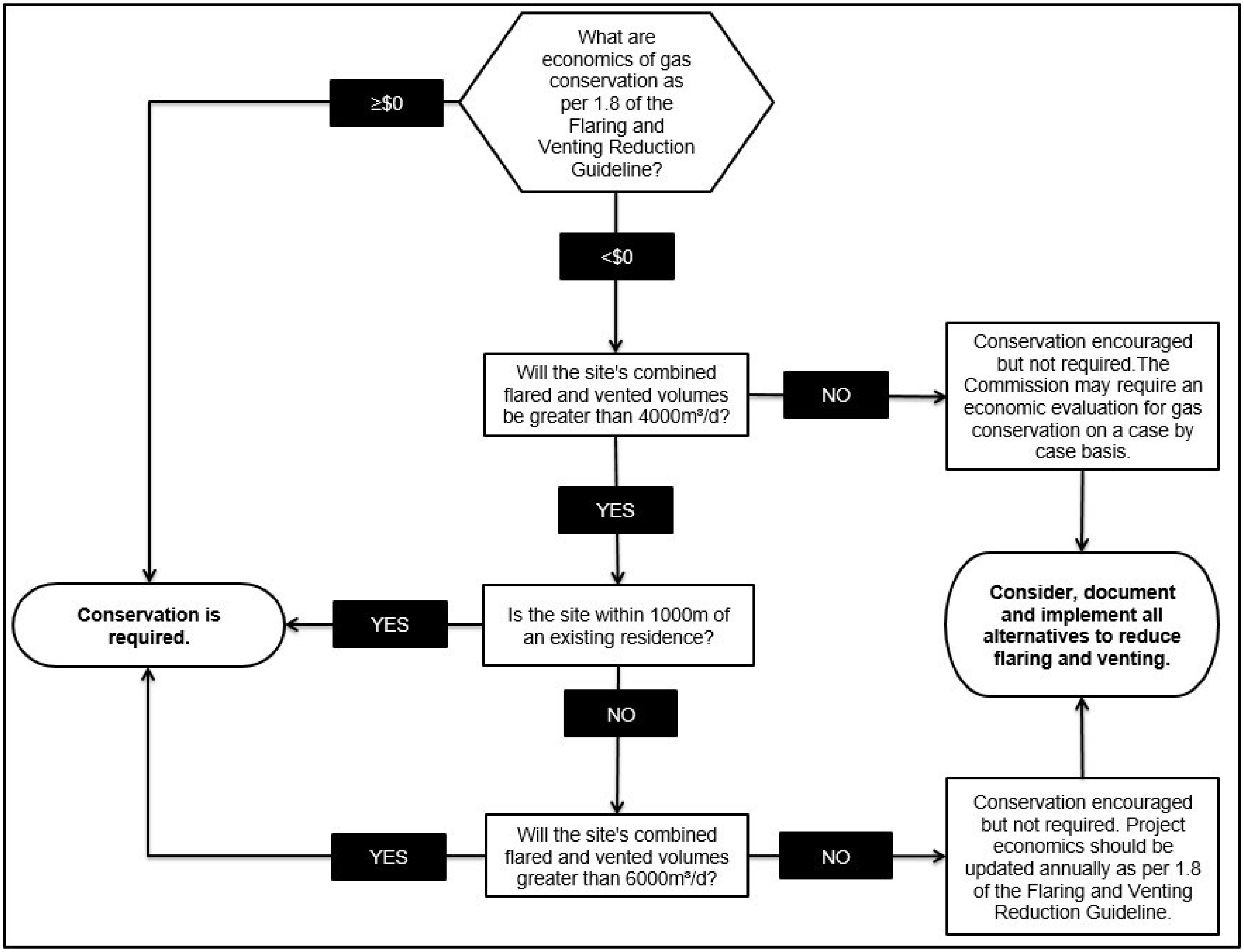

Figure 3.2: Gas Facility Conservation Decision Tree

3.3 Measurement

1) Flare measurement and estimation at existing facilities must be in accordance with Chapter 10 of this guideline.
2) If significant deficiencies in the documentation and reporting of flared volumes at a facility are identified, the Regulator may order the installation of a flare meter.
3) In addition to the requirements in Chapter 10, a flare meter must be considered at all new gas processing plants and gas compressor stations that have an inlet capacity ≥ 300 10^3 m^3/day.
4) The Regulator may require flare meter installation at existing facilities that are undergoing significant modification.
5) Flare meters must be capable of providing reliable and accurate measurement under the range of flow conditions and gas compositions expected within the gas stream. Refer to the Global Gas Flaring Reduction Partnership Guidelines) on Flare and Vent Measurement for more information regarding the selection of a suitable flare meter.

3.4 Approvals and Notification

1) Specific approval is not required for non-routine flaring at facilities including maintenance and emergencies. Limitations on non-routine flaring may be specified in the facility permit.
2) Flaring for purposes other than those specified in 1) must be approved in the facility permit.
3) Permit holders must notify residents and the Regulator of non-routine flaring at facilities as described in Chapter 5.

3.5 Reporting

1) For all facilities, including gas processing plants, all monthly flared, incinerated and vented volumes must reported via Petrinex.
2) Refer to Chapter 10 of this Guideline for more details.
3) Gas burned in an incinerator must be reported as flare gas. Fuel gas burned in an incinerator must be reported as flare gas.
4) Gas flared or vented at gas facilities must be reported at the location where the flaring or venting took place.
5) Questions regarding volumetric reporting in Petrinex should be directed to the BC Ministry of Finance.

3.6 Frequent Non-Routine Flaring/Venting

- Permit holders must make reasonable efforts to investigate and correct causes of repeat non-routine flaring, incinerating, and venting.
- Gas processing plants should not exceed six major non-routine flaring events in any consecutive (rolling) six-month period (6-in-6).
- Major flaring events are defined in Table 3.1.

Approved 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% of 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: 1) 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 2) Volumes greater than or equal to those specified in the table are flared in one contiguous period spanning more than one day (for example, flaring for four days at a continuous rate of 25 10^3 m^3/d is considered one event).	

Table 3.1: Major Flaring Event Definition

- Permit holders must log and monitor non-routine flaring events, as required in Chapter 10.4.
- Major flaring events must be flagged. Should a sixth major flaring event occur within any consecutive (rolling) six-month period, permit holders must submit (via email to Pipelines.Facilities@bc-er.ca) a Written Exceedance Report within 30 days of the occurrence of the sixth flaring event.

3.6.1 Written Exceedance Report

- The report must provide data on all flaring events (volume and duration) for the consecutive (rolling) six-month period in question and their possible causes.
- The report must also propose a plan and corresponding timeline for implementing corrective actions to ensure that frequent major non-routine flaring does not recur.
- Permit holders must expedite schedules for implementing the corrective actions.
- After the plan implementation date, the Regulator may take enforcement action if another exceedance of the 6-in-6 criterion occurs within 24 months.

3.7 Gas Facility Outage Flaring/Venting

- Permit holders must comply with the solution gas reduction limitations found in Chapter 1.9 of this Guideline during facility outages.
- All non-associated gas must be shut in during facility outages.
- If multiple flare stacks are available, permit holders should use the flare stack that is most efficient and capable of providing the best dispersion.
- The Regulator recommends that solution gas be processed on a priority basis in relation to non-associated gas.

Chapter 4: Pipeline Flaring and Venting

This chapter addresses disposal of gases from gas gathering and transmission lines by flaring and venting. Sources of natural gas flaring or venting include non-routine flaring and venting for pipeline depressurization for maintenance, process upsets or emergency depressurization for safety reasons.

4.1 Pipeline Systems Flaring and Venting Decision Tree

- Permit holders should use the decision tree analysis shown in Figure 4.1 to evaluate all new and existing pipeline systems, including compression station flares, incinerators and vents. These evaluations should be updated prior to any planned flaring or venting events.
- Permit holders should document alternatives considered in order to eliminate or reduce flaring and venting, how they were evaluated, and the outcome of the evaluation.
- Permit holders should assess opportunities to eliminate or reduce flaring and venting of gas due to frequent maintenance or facility outages.
- Permit holders should investigate and correct repeat events at gas pipelines and related facilities (e.g. compressor stations).
- Permit holders should address public complaints and concerns related to pipeline facility flaring or venting.
- Permit holders should investigate and implement feasible measures to conserve gas from the depressurization of pipeline systems.
- Permit holders must ensure that flares, incinerators and vents are designed and operated in compliance with Chapters 6 and 7 of this Guideline, good engineering practices, and all relevant safety codes and regulations.
- The economic evaluation in Chapter 1.8 is not applicable for evaluating conservation of gas from non-routine pipeline depressurization. However, permit holders should evaluate the conservation of gas from planned non-routine pipeline depressurization having regard for the value of gas, costs of conserving the gas, and economic impacts of extending outages on downstream customers and upstream producers.
- Flaring or incinerating of gas from sweet natural gas transmission pipeline depressurization may not be practical when impacts on system customers and producers are considered. In such situations, the Regulator may allow venting of gas to reduce the duration of system outages and related impacts.

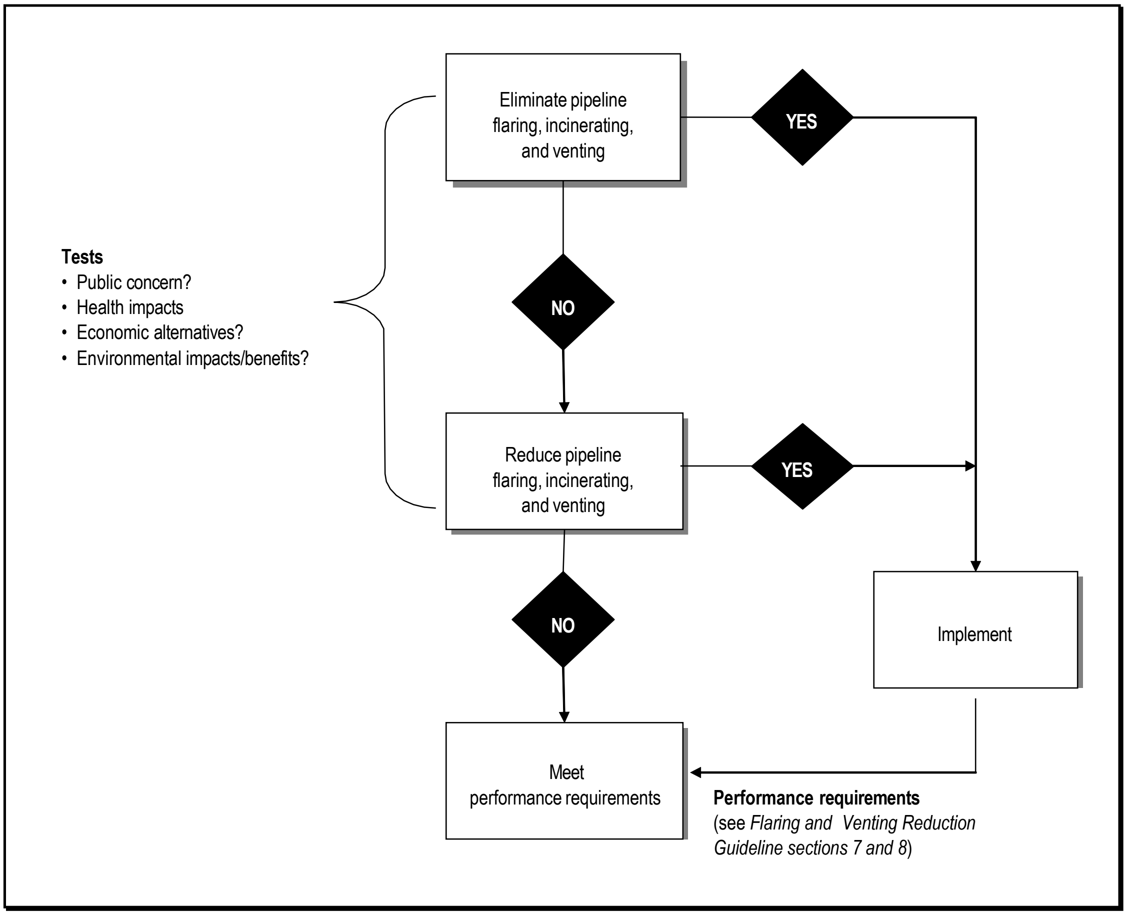

Figure 4.1: Pipeline Flaring and Venting Decision Tree (adapted from CASA)

4.2 Notification and Reporting

1) Specific approval is not required for non-routine flaring at pipelines, including maintenance and emergencies.
2) Permit holders must notify residents and the Regulator of non-routine flaring of pipelines as described in Chapter 5.
3) All monthly flared, incinerated, and vented volumes must be reported via Petrinex.

Chapter 5: Notification Requirements

Permit holders must notify the Regulator and all residents and administrators of incorporated centers located within the notification radius that non-routine flaring, incinerating or venting will occur (Table 5.1).

The Regulator does not require permit holders to obtain the consent of the residents within the notification radius.

H_2S Content	Flaring Event Duration or Volume	Notification Radius
Any	<4 hrs and < 10 e^3m^3	None
<1%	>4 hrs or > 10 e^3m^3	1.0 km
$1\% \leq H_2S < 5\%$		1.5 km
≥5%		3.0 km

Table 5.1: Notification Requirements

5.1 Notification of Residents and Administrators of Incorporated Areas

1) Notification must be given a minimum of 24 hours prior to commencement of planned non-routine flaring events and within 24 hours of unplanned flaring events.
2) Permit holders should consult with residents and administrators of incorporated centers to develop and implement a notification process that is mutually acceptable.
3) If a mutually acceptable notification process has not been implemented, notification must be in writing and include the following minimum information:
    a. Company name, contact persons and telephone numbers;
    b. Location of the flaring;
    c. Duration of the event;
    d. Expected volume and rate;
    e. Information on the type of well (oil or gas) and information on H_2S content; and,
    f. Regulator contact number.
4) The Regulator recommends that permit holders consider placing signage on public roads in the vicinity of

temporary flaring operations indicating the operation type and contact number for inquiries.

5.2 Notification to the Regulator

- Notification must be given a minimum of 24 hours prior to commencement of planned non-routine flaring events and within 24 hours of unplanned flaring events.
- For flaring at wells, including underbalanced drilling, well cleanup, testing and maintenance operations, permit holders must notify the Regulator through eSubmission.
- For flaring at Pipelines and Facilities, permit holders must notify the Regulator Pipelines and Facilities Department by email (Pipelines.Facilities@bc-er.ca)

Chapter 6: Performance Requirements

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

For the purposes of this Guideline, the term flaring is used to refer to flaring and incineration. In this chapter, some requirements are specific to the type of equipment used and this is specified in each requirement.

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

1) Permit holders must ensure that a professional engineer licensed or registered under the Engineers and Geoscientists Regulation is responsible for the design or review of flare and the incinerator systems, including separation, related piping, and controls, and for the specification of safe operating procedures. Equipment and controls design information must be provided to the Regulator upon request.

2) Permit holders 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 Regulator upon request.
   b. Flare and incinerator systems must be operated within operational ranges and type of service specified by a professional engineer licensed or registered under the Engineers and Geoscientists Regulation . If this equipment is used for emergency shutdowns it must be considered in the design.

3) If a permit holder is using a flare or incinerator in a field service that has not previously been field tested, the permit holder must be able to provide actual monitoring data to show that performance specifications can 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 the ability exits to shut-in if problems arise.

4) The Drilling and Production Regulation, API STD 537 Flare Details for Petroleum, Petrochemical, and Natural Gas Industries, API STD 521: Guide for 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) Permit holders must comply with BC safety regulations with respect to the design of pressure vessels and piping systems and the design of equipment and operating procedures.

6) Permanent flare stacks and incinerators should be operated in accordance with the noise limits established in the British Columbia Noise Control Best Practices Guideline, and the Light Control Best Practices Guideline.

6.1 Conversion Efficiency

1) Flares, 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 odours.
   b. exceed the BC Air Quality Objectives and Standards, or
   c. result in adverse impacts to public health and safety or injury to vegetation.
2) Permit holders must modify or replace existing flares or incinerators if operations result in off-lease odours, odour complaints, or visible emissions (e.g. black smoke).
3) If operations at a site cause, or are suspected to cause, unacceptable air quality impacts, the Regulator may require the permit holder to:
   a. Conduct an environmental impact assessment. The assessment may include, but is not limited to, dispersion modelling, air quality monitoring and vegetation assessment,
   b. Take whatever actions the Regulator deems necessary to mitigate or eliminate the air quality impacts.

6.1.1 Black Smoke

Black Smoke is to be avoided such that flares, incinerators and other combustion equipment is designed and operated with no visible emissions, except for periods not to exceed a total of five (5) minutes during any two (2) consecutive hours. Inspection to determine if black smoke is present or not is to be performed using United States Method 22 – Visual Determination of Fugitive Emissions. https://www.epa.gov/emc/method-22-visual-determination-fugitive-emissions.

In the event that there is a public complaint regarding black smoke, the permit holder is to:

1) As soon as practical perform a Method 22 inspection, and
2) Prepare a log entry according to 10.4 of this guideline with the additions:

a. Duration (in hours and minutes), and
b. Completed Method 22 inspection form (Fugitive or Smoke Emission Inspection Outdoor Location).

6.1.2 Heating Value and Exit Velocity for Flares

If a flare is subject to a permit under the Environmental Management Act and the Energy Resource Activities Act and a minimum heating value has been assigned in the permits, the more stringent minimum heating value will apply.

1) The combined net or lower heating value of gas, including make-up fuel gas, directed to a flare should not be less than 20 megajoules per cubic metre (MJ/m^3), except as noted below:

   a. If existing stacks have an established history of stable operation and compliance with the BC Air Quality Objectives and Standards, (permit holders are expected to support claims that existing stacks have operated satisfactorily over time), permit holders are allowed to maintain the current heating value provide that it is not less than 12 MJ/m^3.
   b. If flare stacks have a history of flame failure, odour complaints, and/or of exceeding the BC Air Quality Objectives and Standards, permit holders should operate with a combined flare gas heating value of not less than 20 MJ/m^3.

2) If fuel make-up is required, it must be specified for flare stacks by a professional engineer licensed or registered under the Engineers and Geoscientists Regulation.

   a. Equipment controls should be installed and operating procedures should be documented to ensure minimum fuel gas make-up during routine and non-routine operating conditions.
   b. Facilities must be operated in compliance with specified minimum fuel gas make-up requirements.

3) The flare tip diameter must be properly sized for the anticipated flaring rates.
4) Equipment and controls design information must be provided to the Regulator upon request.
5) Operating limits and procedures must be provided to the Regulator upon request.

6.1.3 Design and Operating Parameters for Enclosed Combustors

All requirements 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 below.

Enclosed combustors must be designed and operated as follows:

- Combustion process must be totally enclosed, except for the combustion air intake and the exhaust discharge.
- There must be no visible flame.
- All surfaces exposed to the atmosphere must:
    - operate below the temperature that would ignite a flammable substance present in the surrounding area, or
    - be shielded or blanketed in such a way to prevent a flammable substance present in the surrounding area from contacting the surface.

- Exhaust gases must be below auto-ignition temperature of a flammable substance present in the surrounding area.
- All intakes must be equipped with a flame arresting device.

6.2 Non-routine Sour and Acid Gas Flaring Procedures

If operating procedures and controls are used to limit the magnitude and/or the duration of the event, they must be documented and the facility operated in accordance with these procedures:

- Automated shutdowns must be installed in facilities that are not staffed 24 hours/day (semi-attended).
- Staff responsible for operations must be aware of the current operating procedures and trained in following those procedures.
- Operating procedures and related dispersion evaluations must be provided to the Regulator on request.

6.3 Flare and Incinerator Spacing Requirements

Permit holders must follow good engineering and safety practices in the layout of facilities. Notwithstanding liquid separation requirements, unexpected liquid carryover to flares and incinerators can happen. Flares and incinerators must be located an adequate distance from areas frequented by workers and from flammable liquids and sources of ignitable vapours. Permit holders must consult fire protection codes and guidelines as part of facility design.

Recommended minimum spacing distances for flares and incinerators are:

- 50 m from oil or gas wells.
- 50 m from crude oil and condensate tanks.
- 25 m from separators, produced water tanks and other sources of ignitable vapours.

Spacing must meet the requirements of Section 47 of the Drilling and Production Regulation.

Refer to Chapter 9 (Well Activity: Completions, Maintenance and Abandonment) of the Oil and Gas Activity Operations Manual for more information on spacing.

6.4 Stack Design

Flare stacks must meet the design requirements found in Section 44 of the Drilling and Production Regulation.
The Regulator recommends that:

- Flare and incinerator stacks be designed so that the maximum heat intensity at ground level will not exceed 4.73 kW/m², or that an equivalent level of safety can be ensured.
- The blackened area beneath a flare stack is at least 1.5 times the stack height to a minimum of 10 meters in cultivated areas, and 30 meters in forested areas, unless conditions support lesser distance.
- Flares and incinerators located within a distance of 5 times the height of any neighbouring building have a height of at least 2.5 times the height of the highest building.
- Flares and incinerators are designed and operated to minimize fuel consumption.
- Interconnecting lines to the flare or incinerator are adequately secured.

The Regulator recognizes that lesser distances may be justified depending on the circumstances, provided that the requirements of Section 47 of the Drilling and Production Regulation (See Chapter 6.3) are being met. It is ultimately the responsibility of the permit holder to maintain a sufficient area, given the location and the conditions under which flaring will or may occur.

Flare blackened areas must not extend off of an approved lease.

6.5 Flare Pits

The Regulator recommends that operators phase out existing flare pits used for routine gas flaring. New flare pits will no longer be approved.

The use of existing flare pits may continue provided that the following requirements are met:

- Produced liquids must not enter the pit.
- Flaring of gas must not result in exceedance of the BC Air Quality Objectives and Standards.
- Gas containing more than 1 mole per cent H_2S should not be flared in pits.
- Permit holders should conduct evaluations of solution gas flares for flare pits as described in this Guideline and implement the resulting decision.
- Access restrictions and procedures should be in place in areas around flare pits where ground-level radiant heat intensity at maximum flare rates will exceed 4.73 kW/m^2.

6.6 Ignition

Flares and incinerators must have reliable systems to ensure continuous ignition of any gas that may discharge to the device.

- As required by section 44 of the Drilling and Production Regulation, unsupervised flare stacks where intermittent flaring may occur must be equipped with an adequate auto-ignition system.
- As required by Section 44 of the Drilling and Production Regulation, unsupervised flare stacks where continuous flaring will occur and the H_2S content of the gas to be flared exceeds 1 mole per cent must be equipped with a flame-out detection device with operation shut down capability that provides an immediate alarm to the permit holder.
- If repeat failures have occurred or off-lease odours or other impacts have resulted from failure to ensure ignition of flared gas, the Regulator may require the installation of pilots, automatic ignition and/or flame out detection and alarms.

- Manual flare and incinerator ignition subject to good fire safety practices may be accepted for non-routine purposes where no continuous gas flow exists and no automatic relieving systems are connected to the stack.

In situations where gas it not continuously or routinely flared and the potential exists to safely conserve gas by avoiding continuous pilots and/or purge gas, the Regulator may consider a satisfactory system of controls to minimize and ensure safe venting rather than maintaining a continuous flare.

6.7 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. Adequate gas-liquid separation equipment to protect the gas combustion system must be used.

- Liquid separation equipment should be used in both temporary and permanent flare and incinerator systems.
- Flare and incinerator separators should be designed in accordance with good engineering practice to remove droplets of 300 to 600 micron diameter and be designed based on the lowest density hydrocarbon liquid that could be released to the flare or incinerator system.
- Flare and incinerator separators should be designed to have sufficient holding capacity for all liquids that may accumulate as a result of upstream operations, such as hydrocarbon carryover, liquid slugs and line condensation.
- Knockout drums should be equipped with high-level alarms and liquid level indication. High-level shutdowns should be considered where facilities have a history of liquid carryover or black smoke emissions, and where liquid streams are directed to the knockout drum for storage. Facility permit holders must monitor and remove accumulated liquids in the knockout drums as necessary.
- High level alarms and liquid level indication may not be required where only manually operated and continuously attended flaring will occur.

6.8 Backflash Control

Improperly designed flare or incinerator systems may have sufficient 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.

- The permit holder must take precaution to prevent backflash using appropriate engineering and operating practices, such as installing flame/detonation arrestors between the point of combustion and the flare or knockout drum or provision of sufficient flare header sweep gas velocities (i.e. purge or blanket gas) to prevent oxygen intrusion into the flare or incinerator system.
- Check valves are not an acceptable form of backflash control.
- Safe work procedures must be in place to ensure complete purging of oxygen from flare or incinerator system prior to ignition.
- The permit holder must provide information of backflash control to the Regulator on request.

The Regulator will consider approving temporary or maintenance flare stacks without flame/detonation arrestors or purge if all of the following are met:

- The flare stack is manually lit and continuously supervised,
- Has no intermittent venting connections (ie. PSVs), and
- Is not connected to any production or storage tanks.

6.9 Flare Maintenance

- The permit holder should develop a maintenance program for the flare stack and flare knock out taking into consideration the type of service fluids, operating conditions, operating history, design characteristics and other pertinent factors to ensure the equipment functions as designed.

6.10 Dispersion Modelling Requirements

The requirements applying to the combustion of sour gas in process equipment, flares and incinerators are as follows:

- Permit holders must demonstrate that SO_2 and H_2S emissions from the burning of sour and acid gas will not result in unacceptable air quality impacts using the dispersion modelling methods outlined in this section. Modelling is required for routine and non-routine flaring/incineration events ≥ 1 mole per cent H_2S or ≥ one tonne per day of sulphur emissions, unless the event is ≤ 15 minutes and ≤ one tonne per day sulphur.

- Permit holders combusting gas below one mole per cent H_2S are encouraged to consider dispersion modelling as part of environmental considerations. Permit holders may be asked to make these environmental assessments based on applications submitted to the Regulator, ensuring that ambient air quality objectives can be maintained throughout resource development. Facilities requiring an Environmental Management Act approval from the Regulator may require more detailed evaluation. Permit holders should consult with the Regulator's Environmental Stewardship Group directly in these circumstances.
- Dispersion modelling must be completed by qualified personnel using acceptable models and methodology.

6.11 Modelling Approach

An appropriate model must be selected and this choice must be defensible. The permit holder must be able to demonstrate that the modelling follows accepted methodologies and standards.

The permit holder must use representative input parameters (e.g. flow rate, gas composition) within the model and be prepared to justify that those parameters are representative.

Screening and refined modelling for individual sources such as a permanent or temporary flare or incinerator, may be conducted by using the protocol outlined within the B.C Modelling Guideline or by using the AERflare-incin & ABflare tools and associated modelling protocol. Modelling should address a full range of expected flow rate conditions and may include the low, average, and maximum flow rate.

Refined modelling may be required if results of the screening model are unacceptable. This is a more complex and data-intensive level of dispersion modelling. Refined assessments more closely estimate actual air quality impacts by using site-specific meteorological data.

Routine sour flaring decisions are to be compared to the Canadian Council of the Ministers of the Environment (CCME) new Canadian National Objective for sulphur dioxide as defined within the B.C Ambient Air Quality Objectives. Sour non-routine flaring decisions may compare to the former provincial sulphur dioxide objectives until otherwise defined by the province.

The source design must not result in ground-level SO_2 concentration predictions higher than those outlined in the applicable ambient air quality objectives. If it is not practical to design flares or incinerators of sufficient height for adequate dispersion, the permit holder may wish to consider using an air quality management plan, develop operating procedures and process controls which prevent emission rates and durations which are predicted to exceed ambient air quality objectives, or the permit holder may consider the addition of fuel gas to increase heat release and plume rise.

The Alberta Risk Based Criteria (RBC), as defined in the CAPP Sour Non-Routine Flaring Framework and accessed through the applicable modelling tools, may be applied to sour non-routine flaring scenarios. Although modelled predictions up to the RBC will be accepted, actual exceedances of the ambient air quality objectives are not permitted.

As per the B.C Modelling Guideline well test flares must evaluate for foliar injury and human health impacts based on ground level concentration predictions defined within the Guideline.

Well test flares ≥ 5 mole per cent H_2S must be authorized under the Oil and Gas Waste Regulation. To discharge air contaminants pursuant to Section 6(1)(d) of the Oil and Gas Waste Regulation, the permit holder must, at least 15 days prior to commencement of well test flare or incineration of sour gas containing ≥ 5 mole per cent H_2S and in accordance with Section 8 of that regulation, submit dispersion modelling and details of the well test to the satisfaction of the Regulator. Submissions may be made to Waste.Management@bc-er.ca.

Please contact the Environmental Stewardship Group for questions concerning dispersion modelling.

Chapter 7: Venting and Fugitive Emissions Management Requirements

Venting is not an acceptable alternative to conservation or flaring. Venting is the least preferred option and gas should be flared under all except the most exceptional circumstances.

7.1 General Requirements

- All continuous and temporary venting must be evaluated using the decision tree in the appropriate sections of this guideline. Vent sources at facilities must be evaluated using the Vent Evaluation Decision Tree (Figure 7.1).
- Permit holders must burn all non-conserved volumes of gas if volumes and flow rates are sufficient to support stable combustion.
- Vented gas must not constitute a safety hazard.
- Venting must not result in off-site odours.
- The quantity and duration of vented gas must be minimized.
- Guidance for the management of fugitive emissions are detailed in Fugitive Emissions Management Guideline. Additional regulatory requirements and guidance specific to venting associated with storage tanks, compressor seals, pneumatic devices, pneumatic pumps, and some measurement equipment is provided in Appendix A.

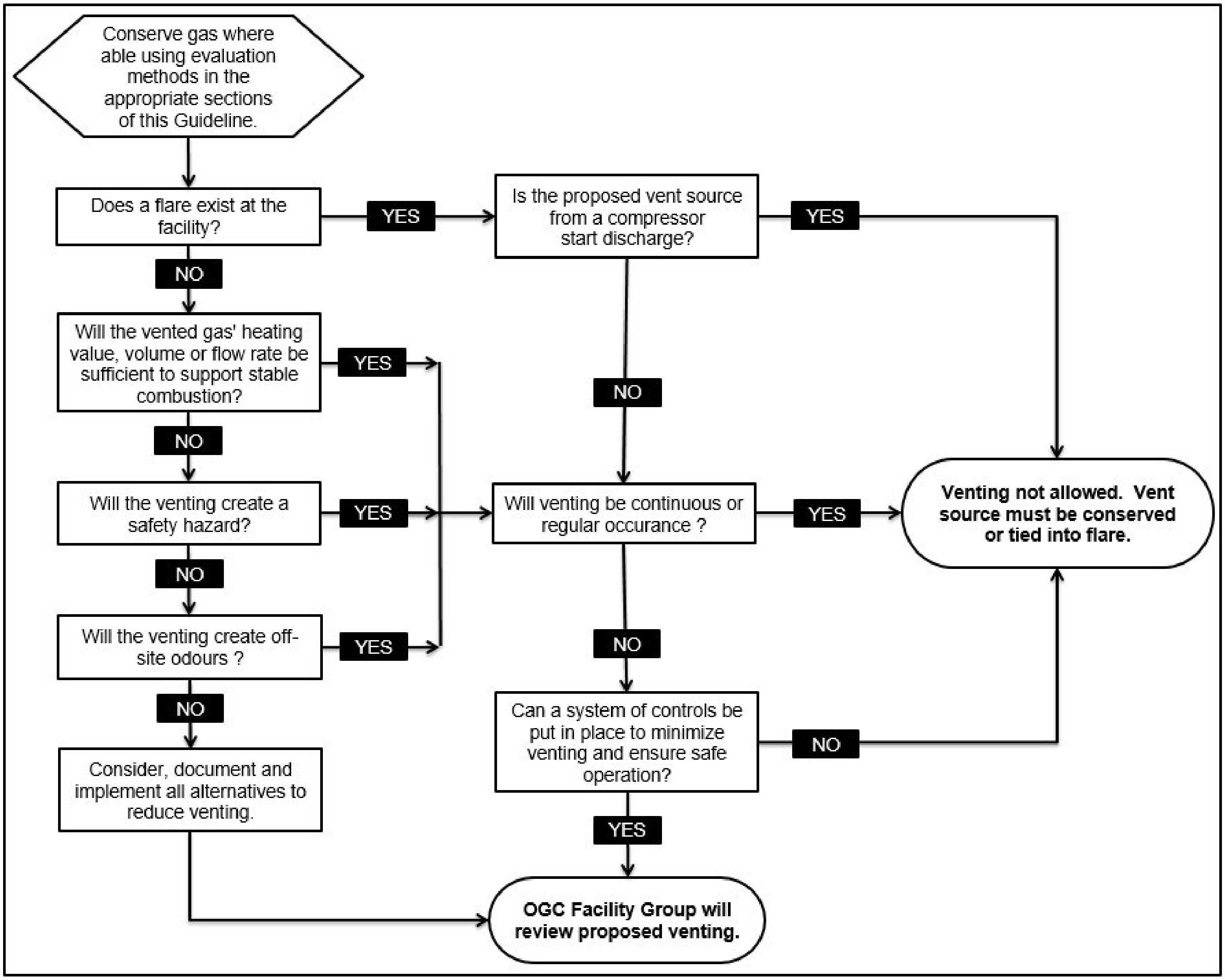

Figure 7.1: Vent Evaluation

7.2 Limitations of Venting Gas Containing H2S or Other Odorous Compounds

- The Regulator recommends that permit holders eliminate the venting of gas containing hydrogen sulphide. As per Section 41(6) of the Drilling and Production Regulation, wells and facilities must not use gas containing more than 20ppm hydrogen sulphide for instrumentation or to provide motive force for pumps.
- The Regulator recommends any pressure safety valves (PSVs) or blowdown systems be connected to a flare system where such systems are installed.
- Where it is not practical to install a flare system to flare PSV venting, the Regulator will consider a satisfactory system of controls to minimize and ensure safe PSV discharge events.

7.3 Limitations of Venting Gas Containing Benzene

Permit holders shall comply with the benzene emission requirements outlined in Appendix J of the Oil and Gas Activity Operations Manual.

7.4 Venting of Non-combustible Gas Mixtures

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

- Non-combustible gas mixtures containing odorous compounds including H_2S must not be vented to the atmosphere if off-lease odours may result. Alternatives to venting such gas include flaring or incinerating with sufficient fuel gas to ensure destruction of odorous compounds, or underground disposal.
- The permit holder has taken precaution to protect human health, public safety, property and the environment.
- The permit holder has taken precautions in fire prevention, explosion prevention and other impacts such as reducing visibility.
- Venting of these substances do not result in unacceptable air quality impacts. Refer to BC Air Quality for additional information.
- The Regulator may require the permit holder to demonstrate that non-combustible gas mixtures do not result in unacceptable air quality impacts using an acceptable dispersion modelling technique.

7.5 Surface Casing Vents

Refer to Chapter 9 of the Oil and Gas Activity Operations Manual for surface casing vent requirements.

7.6 Fugitive Emissions Management

- Permit holders must develop and implement a program to detect and repair leaks.

Guidance for the management of fugitive emissions are detailed in the Fugitive Emissions Management Guideline.

7.7 Compressor Start Gas Discharge

- For new facility applications where natural gas is being utilized as the motive force to start compressors, the starter discharge vents must be connected to a flare system or the gas conserved through an expansion vessel and a vapour recovery system if one is proposed at the facility unless there is acceptable rationale provided in the application for venting in accordance with Section 41 of the Drilling and Production Regulation.
- For existing compressor facility installations where natural gas is being utilized as the motive force to start compressors and the gas is being vented directly to atmosphere, the Regulator requires the permit holder to conduct and submit a documented review of the current venting practice in relation to the requirements set out in Section 41 of the Drilling and Production Regulation. The Regulator will require compressor start gas to be conserved or flared unless acceptable rationale is provided.
- Reviews must be submitted as a separate document to the Regulator's Facility Engineering Group upon request.
- Permit holders of existing compressors where start gas discharge is venting may be subject to compliance actions if these reviews have not been completed or rational has not been accepted by the Regulator's Facility Engineering Group.
- Refer to Industry Bulletin 2011-29 for additional information.
- Permit holders and applicants can follow the Compressor Start Gas Discharge Decision Tree (Figure 7.3) to assist in reviewing compressor start gas discharge.

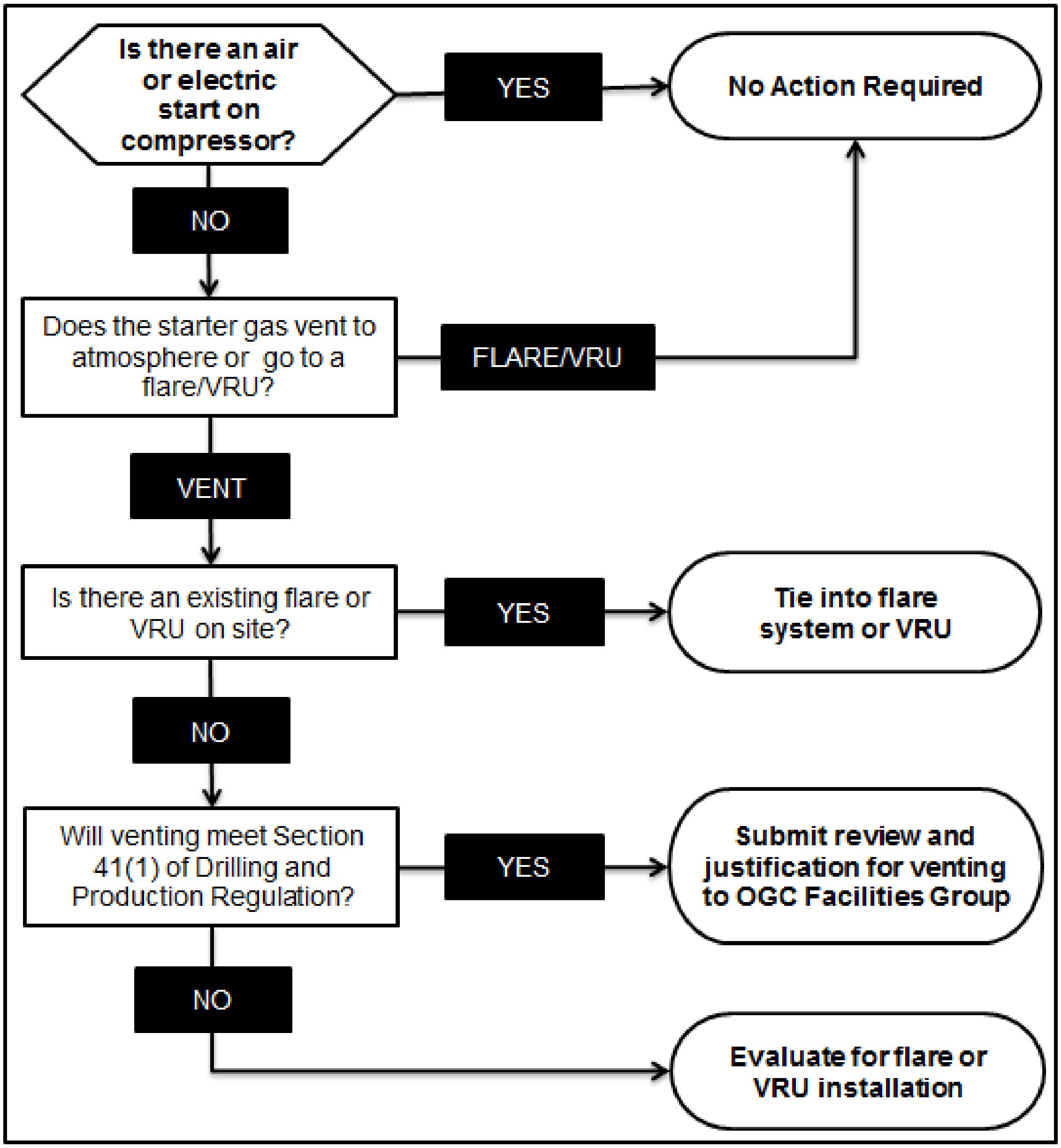

Figure 7.3 Compressor Start Gas Discharge Decision Tree

Chapter 8: Sulphur Recovery Requirements

Some facilities may have significant sulphur emissions originating from combustion of sour gas (by flaring, incinerating or use as fuel gas), low-pressure produced water flash-gas, and flaring of glycol dehydrator vent gas. Appropriate pollution prevention measures must be implemented in such situations to minimize sulphur emissions associated with combustion of sour or acid gas.

The Oil and Gas Waste Regulation applies to compressor stations with less than 3000 kW of compression and other small upstream petroleum facilities, such as oil production batteries, wellsite facilities, and pipeline facilities.

Gas plants processing or discharging into the environment more than two tonnes per day of sulphur may be required to implement sulphur recovery. Sulphur recovery requirements will be specified in the plant's Environmental Management Act air discharge permit.

Chapter 9: Incineration Evaluation

Where incinerator evaluation is required, decisions to use an incinerator or a flare stack should consider the following:

- Air quality including the potential to exceed air quality objectives for sulphur dioxide and the potential for black smoke emissions.
- Results of consultation with the landowner and residents within the consultation radius.
- History of flaring concerns and activity levels in the area.
- Quantity and duration of flaring.
- Visibility of flare to area residents, communities and major highways.
- Noise; noise considerations should be based on best available technology operating within manufacturers recommended flow rates. Flares and incinerators should comply with the noise limits established in the British Columbia Noise Control Best Practices Guideline.
- Any other relevant factors.

9.1 Minimum Residence Time and Exit Temperatures

Any requirements regarding minimum residence time or exit temperature contained in the permit approval will take precedence over the following recommendations:

1) Incinerators should provide a minimum residence time (calculated between the top of the final burner and the stack exit) of 0.5 seconds at maximum flow rate or greater as required for complete combustion of heavier gases.
   a. Incinerators must be operated without an exposed flame.
   b. If the gas contains less than 1 mole per cent H_2S and the unsupplemented heating value of the gas is 20 MJ/m^3 or greater, no minimum residence time is required.
2) Incinerators should operate with a minimum exit temperature of (measured within one stack diameter of the exit) of 600°C.
   a. For combustion of gases with greater than 1 mole per cent H_2S, the facility should be designed to automatically shut down if the exit temperature of the incinerator drops below 600°C.
   b. For combustion of gases with greater than 5 mole per cent H_2S, the incinerator should also be equipped with process temperature control and recording.
      i. Equipment and controls design information must be provided to the Regulator upon request.
3) Operating limits and procedures must be provided to the Regulator upon request.
4) Any permit holder using incinerators must be able to provide details about the conversion efficiency of the equipment.

5) 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.

Chapter 10: Measurement and Reporting

The following requirements for measuring and reporting volumes of gas flared, incinerated or vented are in addition to requirements specified in the:

- BC Measurement Guideline
- Ministry of Finance Oil and Gas Royalty Handbook
- Drilling and Production Regulation

1) Permit holders of oil and natural gas production and processing facilities must report volumes of gas greater than or equal to 0.1 10^3m^3/month (adjusted to 101.325 kPa(a) and 15°C) that are flared, incinerated or vented.
    a. These volumes are to be reported in Petrinex, and are to include all flaring, incinerating and venting from routine operations, emergency conditions and the depressurizing of pipeline, compression and processing systems.
2) All flared and vented gas must be reported as described in the most recent British Columbia Oil and Gas Royalty Handbook:
    a. Incinerated gas must be reported as "flared" gas..
    b. Acid gas streams at a gas plant that are incinerated or flared as part of normal operations are to be reported as flared gas.
    c. For the purposes of measurement and reporting, the following definitions for fuel gas, flare gas, and vent gas can be used:

Fuel gas - 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:

- engines,
- catalytic heaters and other building heaters,
- process vessel burners,
- sulphur recovery unit reaction furnaces,
- line heaters, and
- thermoelectric generators

Flare gas - 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:

- waste gas;
- pilot gas;
- dilution and makeup gas added to a flare gas stream before flaring or incineration;
- acid gas (routine and non routine);
- blanket gas, purge gas, and sweep gas;
- gas used to operate pneumatic devices (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.

Vent gas - Uncombusted gas that is released to the atmosphere at upstream oil and gas operations, but does not include fugitive emissions.

Types of gas, if released to the atmosphere uncombusted, include the following:

- 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

3) Fugitive emissions are considered a part of shrinkage.

Note: Fugitive emissions are NOT to be reported as flared or vented gas.

4) Permit holders must be able to demonstrate that volumes of gas are determined in an accurate and reliable manner. Permit holders must have written documentation detailing the methodology used to determine flared, incinerated and vented volumes for all of their wells, pipelines and facilities, and that documentation must be readily available for review by an official.

5) The Regulator recommends that permit holders meter total flare streams in larger oil batteries and gas facilities, pipeline facilities, and gas processing plants where there could be multiple connections to the flare system from sources such as process equipment, storage tank vents, pressure-relieving valves, manual blowdowns, and emergency vent valves, even when the volume is less than 0.5 $10^3m^3/d$ on an annual average.

6) For gas well gas tied into an oil battery, or solution gas tied into a gas facility, the permit holder must report all flared, incinerated or vented gas on a single production statement for the battery/facility.

10.1 Metering Requirements and Guidelines

Meters designed for expected flow conditions and range must be used to measure the following flare and vent streams:

- continuous or non-routine flare and vent sources at all oil and gas production and processing facilities where annual average total flared, incinerated and vented volumes per facility exceed 0.5 10^3m^3/day (excluding dilution gas). Vent sources such as compressor distance piece vents, pumps, valve controllers, and some flared sources such as pilots can be estimated rather than metered.
- if all solution gas is flared or vented from production facilities, the measured produced gas (less any fuel gas use) may be used to report volumes flared or vented; in such situations, specific flare or vent gas meters are not required.
- acid gas flared, either continuously or in emergencies, from gas sweetening systems regardless of volume; and
- any fuel gas added to acid gas to meet minimum heating value requirements or ground level ambient air concentrations where the annual average flow rate exceeds 0.5 10^3m^3/d.

Chapter 2 of the BC Measurement Guideline provides details regarding calibration and proving of measurement devices.

Measurement uncertainty of the measured volumes must meet the criteria in Table 10.1 below (extracted from the BC Measurement Guideline).

Stream	Max Uncertainty of Monthly Volume*	Single Point Measurement Uncertainty
Fuel gas > 500 m^3/d	5%	3%
Fuel gas < 500 m^3/d	20%	10%
Flare, incinerator or vent gas	20%	5%
Acid gas before compression		10%
Acid gas after compression		3%

Table 10.1: Measurement Uncertainty Requirements

* This uncertainty is applicable when the reported monthly volume is not determined solely from metered volumes. If a monthly volume is determined solely from a metered volume(s), then the Single Point Measurement Uncertainty requirement applies to that monthly volume.

10.2 Estimating Requirements

The Regulator will accept estimates of flared, incinerated, and vented gas if measurement is not stated as a requirement in Chapter 10.1 and the following conditions are met:

1) Permit holders must be able to demonstrate that reliable and consistent flared, incinerated and vented gas estimating and reporting systems are in use. The Regulator recognizes CAPP's Guide for Estimation of Flaring and Venting Volumes from Upstream Oil and Gas Facilities, 2002 as containing acceptable practices for estimating.
   a. Estimating systems must account for all gas released through flaring, incinerating and venting activities at the facility (expressed to the nearest 0.1 10^3m^3/month) during routine, emergency and maintenance operations, including depressurizing of vessels, compressors and pipelines.
   b. Volume estimates must be based on engineering calculations and be shown to meet the uncertainty requirements specified in Table 10.1.

c. If volumes are not measured by meters, a formal system for consistently estimating and reporting these volumes must be in place.

2) Permit holders must produce documentation describing flared (including fuel and pilot gas) and vented gas estimating and reporting procedures, as well as related operating logs (see Chapter 10.4), for review by the Regulator upon request.

3) Documentation should include simplifying assumptions, mathematical formulae, estimation methodology, details on the means used to obtain and update input data, the data handling process and other such documents as required.

4) The Regulator may require that meters be installed where there are failures to demonstrate adequate flare or vent gas estimating and reporting systems, or if accuracy standards cannot be met.

10.3 Flared and Vented Gas Reporting

Flared and vented gas must be reported as follows:

- Flaring associated with well drilling, completions and maintenance must be reported through the Regulator online drilling reporting system. A Well Deliverability Test Report must be submitted for deliverability type flow tests, clean-up flows and underbalanced drilling operations.
- Flared and vented gas at all facilities, including gas processing plants must be reported in Petrinex.
- When well test flaring is in excess of 50 mol/kmol H_2S (5%), permit holders must complete volume reporting requirements as outlined in the well test approval.
- For flaring and incineration resulting from under-balanced drilling operations, gas volumes should be reported as net volumes (i.e. gas produced minus gas injected). Similarly, flared gas rates should be representative of net gas obtained near the end of drilling operations.
- Incinerated gas must be reported as flared gas. This also applies to acid gas streams at a gas plant that are flared or incinerated as part of normal operations; in these cases, the flared or incinerated acid gas would be reported as flared gas.
- The permit holder must report all flared or vented gas at the associated reporting facility.
- It is recommended operators produce a Quality Assurance and Control Manual that includes policies, procedures and an execution plan to ensure measurement data is properly generated, collected and reported to the necessary parties.

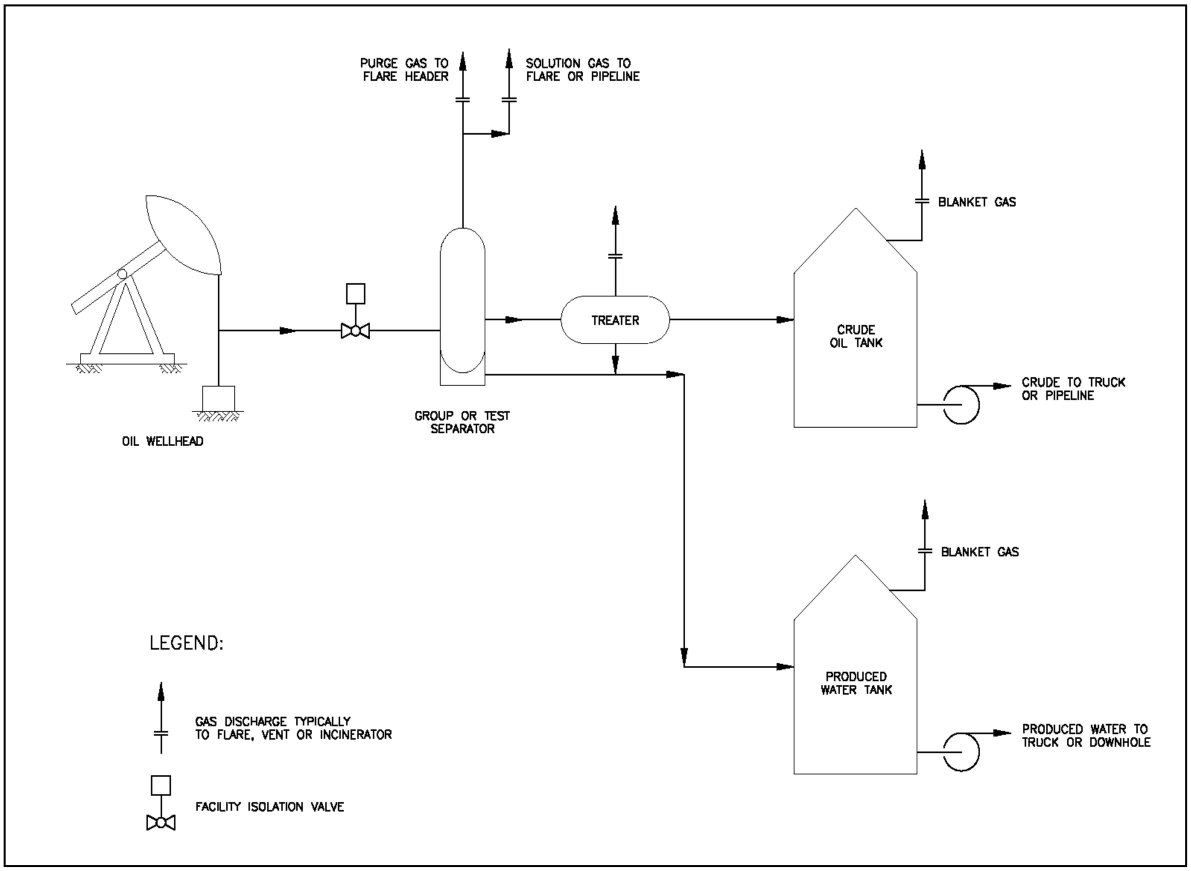

Figure 10.1: Reportable Flaring Streams – Upstream Oil Battery

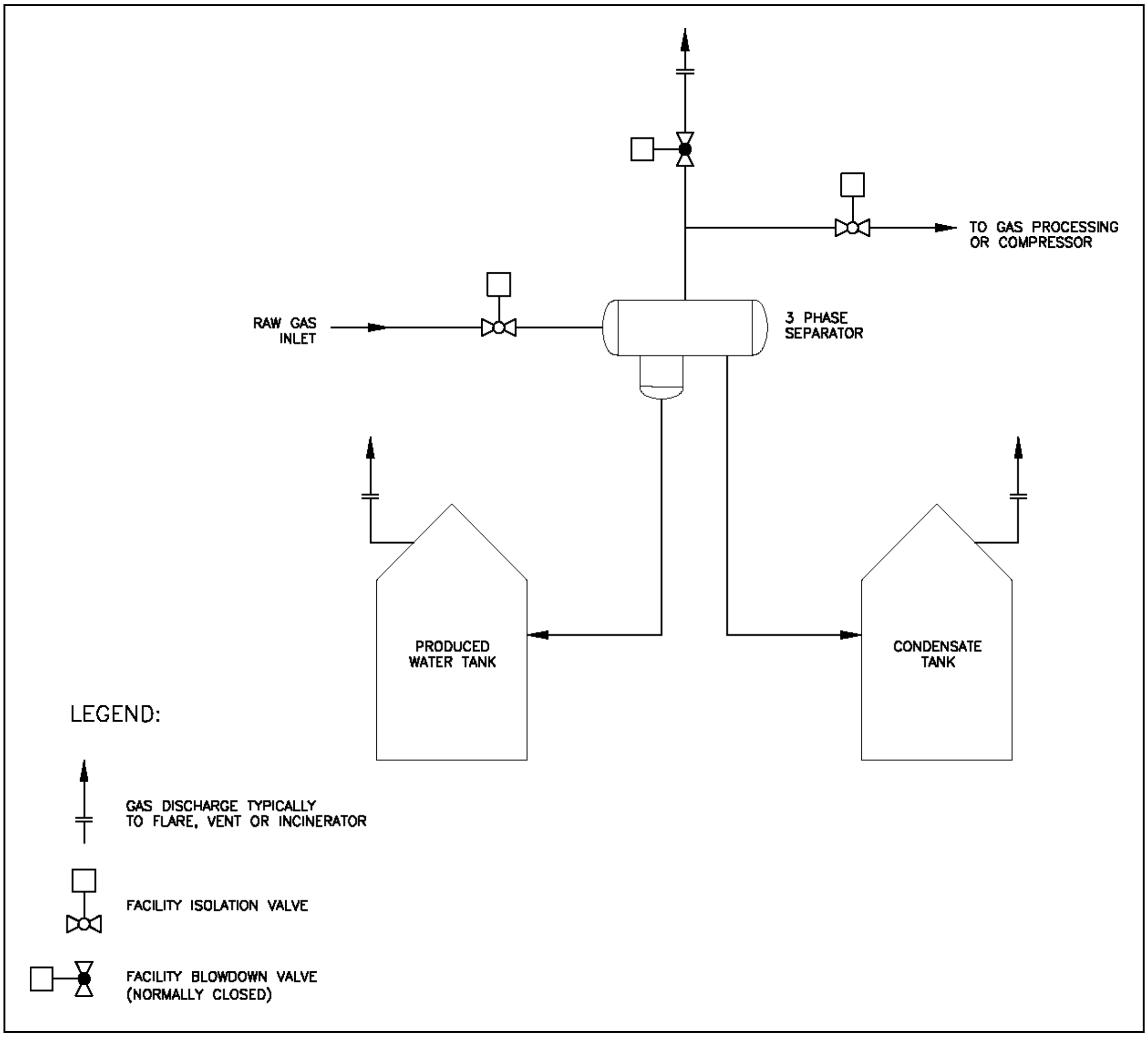

Figure 10.2: Reportable Flaring Streams – Inlet Separation Facility

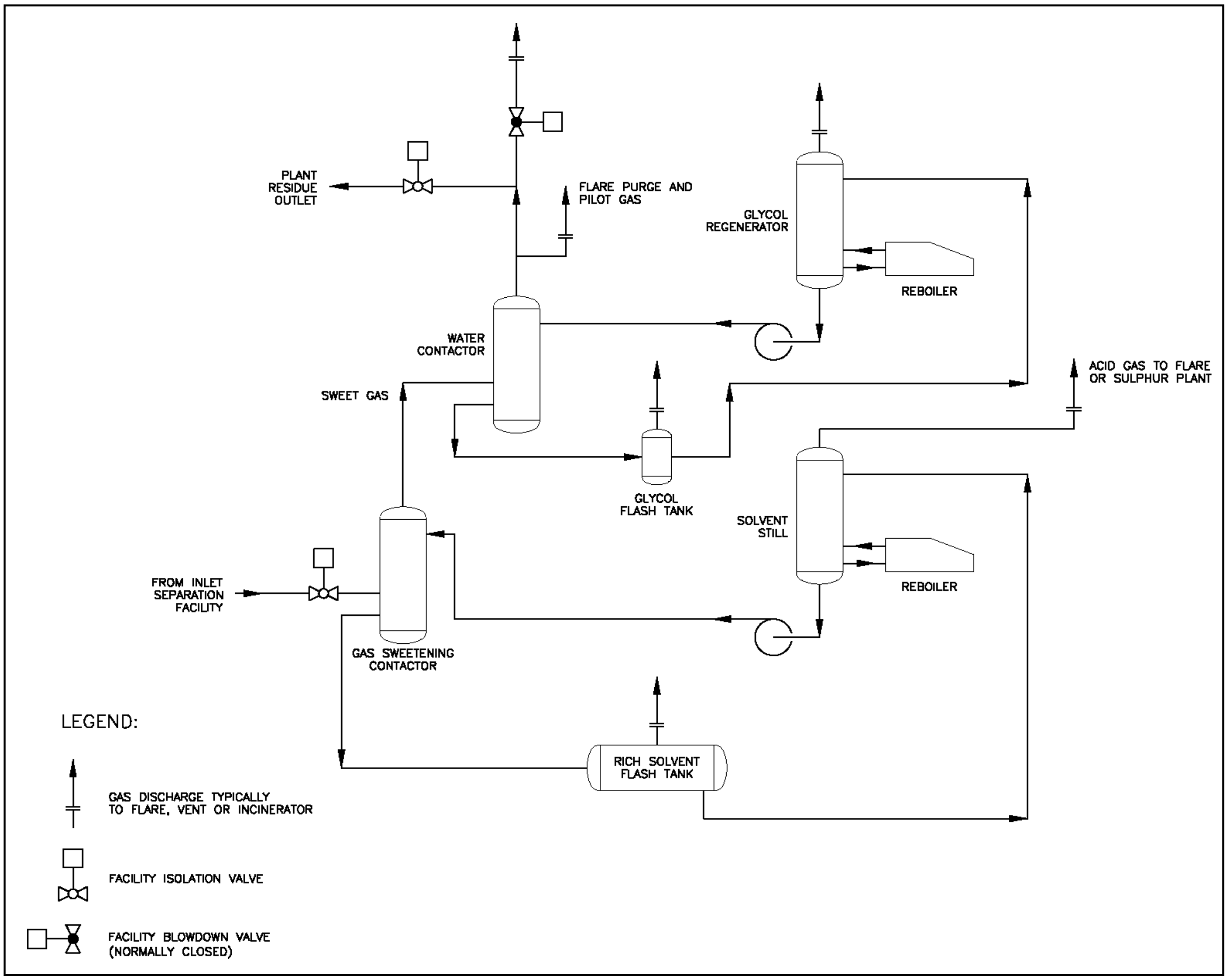

Figure 10.3: Reportable Flaring Streams – Gas Processing Plant

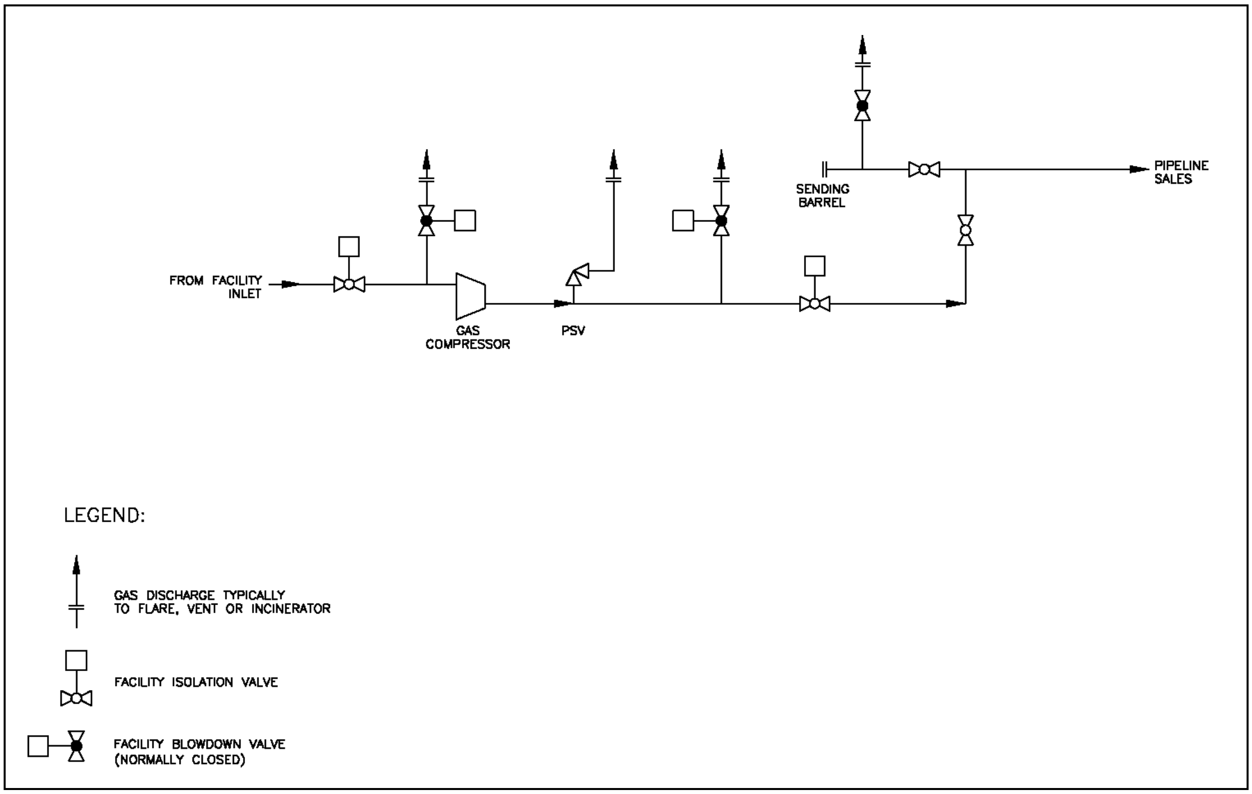

Figure 10.4: Reportable Flaring Streams – Gas Compression Facility

10.4 Flaring and Venting Records (Logs)

Permit holders must maintain a log of flaring and venting events and respond to public complaints.

Logs must include information on complaints related to flaring and venting events and how these complaints were investigated and addressed. In addition to the information required below, they must at a minimum include:

- Complainant name and contact information.
- company representative assigned to investigate.
- Regulator representative contacted.
- If the complaint was resolved.

Logs must record the following:

- Each non-routine flaring and venting incident.
- The reason it occurred.
- Any changes implemented to prevent future non-routine events of a similar nature from occurring.

Logs must include:

- Date and time.
- Duration (in hours).
- Gas source or type (e.g. sour inlet gas, acid gas).
- Volume for each incident and how the volume information was derived (estimated or metered).

Logs must be signed and the name printed legibly by the facility permit holder's representative and kept for a minimum of 12 months.

Flaring and venting records (logs) must be made available to an official upon request for each pipeline and facility where flaring and venting occur.

Permit holders may retain logs for remote or semi-attended facilities at a central location (e.g. the operator regional office) where public complaints related to the facility in question would normally be received.

Appendix A: Venting Management Guideline Related to Specific Sources

The contents of this appendix pertain to the following sections of the Drilling and Production Regulation (DPR):

1) 52.03 Storage tanks
2) 52.04 Compressor seals
3) 52.05 Pneumatic devices
4) 52.06 Pneumatic pumps
5) 52.12 Measurement equipment

The requirements of the DPR sections referenced above come into effect from 2021 to 2023. Guidance is being provided to help permit holders transition to the coming requirements.

On January 1, 2021, new requirements came into effect for the following sources of methane emissions:

- new pneumatic pump installations;
- pneumatic devices at new facility installations;
- new centrifugal compressor installations; and,
- new reciprocating compressors installations.

On January 1, 2022, new requirements come into effect for the following sources of methane emissions:

- pneumatic devices at gas plants that began operations before January 1, 2021;
- pneumatic devices at compressor stations at which the total power of all compressors is 3 MW or greater that began operations before January 1, 2021;
- pneumatic devices at facilities that began operations before January 1, 2021;
- centrifugal compressors installed before January 1, 2021;
- reciprocating compressors installed before January 1, 2021; and,
- storage tanks at new facility installations.

On January 1, 2023 new requirements come into effect for the following sources of methane emissions:

- storage tanks at facilities that began operations before January 1, 2022.

Vent Gas Sources

Storage Tanks

Atmospheric storage tanks (storage tanks), used in the upstream oil and gas industry to store liquids such as oil, condensate, and produced water may have emissions that are either captured and combusted or vented to atmosphere.

Storage tanks can be a substantial source of emissions and several factors influence the volume, including:

1) whether or not the tank emissions are captured and combusted or vented to atmosphere;
2) operating pressure and temperature in the separator(s) upstream of the storage tank;
3) inefficient separation (e.g., inadequate residence time);
4) piping anomalies;
5) leakage of process gas or volatile product past valve seats;
6) tank throughput; and,
7) material stored.

These factors must be evaluated on a case-by-case basis with the goal of minimizing emissions (DPR Section 41).
It is recommended practice that vent gas be captured for beneficial use (e.g., fuel). Where this is not practical, it is recommended that the gas be captured and flared or incinerated.

Storage tanks are subject to the following vent limits:

- All new facilities (those that began operations on or after January 1, 2022) must ensure that the vented emissions from all storage tanks combined do not exceed 1,250 m^3/calendar month (41.7 m^3/day). (DPR Section 52.03(1)).
- Starting on January 1, 2023: All existing facilities (those that began operations before January 1, 2022) must ensure that the vented emissions from all storage tanks combined do not exceed 9,000 m^3/calendar month (300 m^3/day). (DPR Section 52.03(2)).

These vent limits do not include fugitive emissions (eg., unintentional leak from a connection or seal). Fugitive emissions are managed through the Fugitive Emissions Management Guideline and leaks must be repaired within 30 days of detection. (DPR Section 41.1 (5)(a)). However, unintentional gas carry-through to storage tanks is included in the vent limit. This includes sources such as leakage of process gas or volatile product past valve seats, level controller malfunction, inefficient separation, and emissions resulting from piping anomalies.

There is no exemption to the regulations intended for storage tanks based on their capacity or size.

Pneumatic Devices

Pneumatic devices are instruments that require a supply of pneumatic gas to work. They include but are not limited to:

- actuators;
- controllers;
- positioners;
- regulators;
- switches; and,
- transducers.

They specifically exclude:

- compressor starters;
- pneumatic pumps; and,
- online gas analyzers.

Pneumatic or pneumatic equivalent devices may have motive force supplied by natural gas, propane, instrument air, or electric power (from solar, generated by thermal electric generator (TEG) or power generator on site, fuel cell, or grid power). The vent limits detailed within this guideline pertain only to natural gas powered pneumatic devices that are designed to vent natural gas as part of normal operation.

Devices that operate using propane gas as supplying the motive force are excluded from the regulation. (DPR Section 52.01) The use of propane, however, is not recommended as a replacement for natural gas. It is recommended that devices be powered by instrument air or electric power (from solar, generated by thermal electric generator (TEG) or power generator on site, fuel cell, or grid power etc.).

Some pneumatic devices emit continuously and others emit intermittently. Still, others emit a small flow continuously and a larger flow intermittently. All of these devices are subject to the Drilling and Production Regulation venting limits. The venting limits include both static and dynamic emissions.
There is no exemption to the regulation intended for emergency or low use pneumatic devices.

Natural gas powered pneumatic devices are subject to the following vent limits:

- A facility permit holder who operates a facility that began operations on or after January 1, 2021 must not use at the facility a pneumatic device that emits natural gas. (DPR Section 52.05(2)).
- Beginning on January 1, 2022, a facility permit holder who operates a gas processing plant or a compressor station with 3MW or greater of compression (large compressor station) must not use at the facility a pneumatic device that emits natural gas.
- Beginning on January 1, 2022, a facility permit holder who operates a facility that began operations after January 1, 2021, other than a gas processing plant or a large compressor station, must not use at the facility a pneumatic device that emits natural gas unless:

    - the emissions of natural gas from each device does not exceed 0.17 m^3 per hour (including all components of the device); or,
    - the facility permit holder has a signed statement, from a professional engineer licensed or registered under the Engineers and Geoscientists Regulation , that:
    - the device cannot be operated so as to meet the emission limit of 0.17 m^3 per hour without compromising the safe operation of the facility;
    - it is not practical to replace the device with a device that can be operated so as to meet those requirements;
    - the emissions of natural gas from the device are minimized to the extent consistent with efficient operation of the device and safe operation of the facility; and,
    - the device is marked with a weatherproof and readily visible tag.

Natural gas vented from pneumatic devices that is collected and combusted or conserved is excluded from the venting limit.

Not all emissions from pneumatic devices are intentional. Where unintentional releases occur, such as due to improper installation, the emissions over and above the design rate are considered to be fugitive emissions and they are managed through the Fugitive Emissions Management Guideline. Fugitive emissions must be repaired within 30 days of detection. (DPR Section 41.1 (5)(a)).

Pneumatic Pumps

Pneumatic pumps are pumps that require a supply of pneumatic gas to work. They include but are not limited to:

- diaphragm; and
- piston.

The type of chemical pumped may include but is not limited to:

- biocide;
- clarifier;
- corrosion inhibitor;
- demulsifier;
- hydrate inhibitor;
- hydrogen sulphide scavenger;
- oxygen scavenger;
- paraffin control;
- scale inhibitor; and,
- surfactant.

They specifically exclude:

- energy exchange pump used to pump glycol (glycol dehydration unit);
- engine coolant pump;
- engine lube oil pump; and,
- pump used for heat medium circulation.

Pneumatic or pneumatic equivalent pumps may be powered by natural gas, propane, instrument air, or electric power (from solar, generated by TEG or power generator on site, fuel cell, or grid power etc.). The vent limits detailed within this guideline pertain only to natural gas powered pneumatic pumps that are designed to vent natural gas as part of normal operation.

Pumps that operate using propane gas are excluded from the regulation. (DPR Section 52.01) It is recommended practice that pumps powered by instrument air or electric power be used in all new installations and retrofits.

Natural gas powered pneumatic pumps at facilities that began operations before January 1, 2021, must not vent natural gas unless the pump is operated for 750 hours or less per year. Natural gas vented from pneumatic pumps that is collected and combusted or conserved is excluded from the venting restriction.

Reciprocating Compressor Seals

Each cylinder on a reciprocating compressor has a packing case seal to prevent the leakage of large volumes of natural gas but packing systems intentionally vent some natural gas either into the distance piece or through a vent line connected to the packing case, or both. The amount of seal gas venting depends on the cylinder pressure, the packing installation, and the amount of wear on the packing rings and compressor rod shaft. Over time, the seal gas venting increases as wear progresses.

It is recommended practice that seal vent gas be captured for beneficial use (e.g., fuel). Where this is not practical, it is recommended that the gas be captured and combusted.

The vent limits described in the Drilling and Production Regulation (Section 52.04) pertain to natural gas that is vented to atmosphere.

The seal vent limits are as follows:

- A reciprocating compressor installed on or after January 1, 2021 that has 4 or more throws must not vent seal gas to atmosphere if its engine is rated at 75 kW or more or if it operates for more than 450 hours per year. (DPR Section 52.04 (2));
- Starting on January 1, 2022, the permit holder fleet average of reciprocating compressors must be less than or equal to 0.83 m^3/hr/throw. (DPR Section 52.04 (6)). A fleet is comprised of the following:Compressors installed before January 1, 2021 with engines rated at or over 75 kW that are pressurized for at least 450 hours per year are included in the fleet;
- Compressors with fewer than 4 throws are included in the fleet regardless of their installation date;
- Only compressors that vent seal gas to atmosphere are included in the fleet. Compressors with seal gas that is combusted or conserved are not included in the fleet;
- No compressor in the fleet may vent more than 5 m^3/hr/throw; and,
- The fleet includes all compressors that meet the above criteria that are operated by the same permit holder.

Compressor blowdown volumes are not included in the seal vent gas limits.

Centrifugal Compressor Seals

Seals on rotating shafts prevent the leakage of large volumes of high-pressure natural gas from centrifugal compressor casings. These seals can be either “wet” or “dry”.

In wet seals, oil is circulated under high pressure between rings and around the compressor shaft to form a barrier that prevents the leakage of natural gas to atmosphere. Natural gas is entrained in the seal oil that exits the unit. It is flashed off in a flash tank and the degassed oil is recirculated back into the compressor system.

A dry seal is a mechanical seal.

It is recommended practice that seal vent gas be captured for beneficial use (e.g., fuel). Where this is not practical, it is recommended that the gas be captured and flared or incinerated.

The seal gas limits are as follows:

- Centrifugal compressors installed on or after January 1, 2021 must not vent more than 3.40 m^3/hr/compressor body (0.057 m^3/minute/compressor) of seal gas to the atmosphere. (DPR Section 52.04 (5)); and,
- Starting on January 1, 2022, centrifugal compressors installed before January 1, 2021 must not vent more than 10.2 m^3/hr/compressor body (0.17 m^3minute/compressor) of seal gas to the atmosphere. (DPR Section 52.04 (4)).

When two or more compressor bodies are driven by a single driver each compressor body is considered separately for compliance with the vent limit. A single engine driving two stages of compression is considered to have two compressor bodies.

Compressor blowdown gas is not included in the seal vent gas limits.

The regulation does not include different vent limits for different sizes of centrifugal compressors.

The limits apply to compressors that:

- operate for 450 or more hours per year; or
- have engines that are rated for 75 kW or more.

Vent Gas Quantification

Storage Tanks

The measurement of storage tank vents is not a requirement of the Drilling and Production Regulation. Storage tank venting must be quantified using a methodology that is in accordance with the Greenhouse Gas Emission Reporting Regulation where methodologies exist.

Pneumatic Devices

The measurement of pneumatic device vents is not a requirement of the Drilling and Production Regulation. Pneumatic device venting must be quantified using a methodology that is in accordance with the Greenhouse Gas Emission Reporting Regulation.

Pneumatic Pumps

The measurement of pneumatic pump vents is not a requirement of the Drilling and Production Regulation. Pneumatic pump venting must be quantified using a methodology that is in accordance with the Greenhouse Gas Emission Reporting Regulation.

Reciprocating Compressor Seals

The annual measurement of compressor vented seal gas is a requirement of the Drilling and Production Regulation. The annual test must occur at conditions that are representative of the normal operation of the compressor and take place over a minimum of a 15 minute period. (DPR Section 52.04(7)(c)) Longer tests may be needed in some cases to achieve a representative measurement. Seal gas that is conserved or flared does not require measurement for methane reporting purposes. The measurement equipment and methods used must achieve a measurement uncertainty of plus or minus 10 per cent. (DPR Section 52.12).

The presence of seal gas venting may be detected using an optical gas imaging camera, Method 21, tuneable diode-infrared laser absorption spectroscopy (TDLAS), or cavity ring-down laser absorption spectroscopy (CRLAS) to ensure that all seal gas is being metered, the integrity of meter connections and that leaks do not develop during the measurement due to back pressure. If the seal gas cannot be detected using an optical gas imaging camera or organic vapour analyzer that meets the requirements of Section 41.1(1) of the Drilling and Production Regulation or by TDLAS or by CRLAS (with a similar or lower minimum detection limit) it does not need to be measured and a flow rate of zero may be recorded.

When seal gas is detected, it may be measured using the following technologies:

- full flow meter;
- high flow sampler;
- hotwire anemometer; and,
- vane anemometer.

The measurement system must be selected based on worker safety, the flow rate encountered, be in good operating condition, and be set up and used in accordance with the manufacturer's specifications. The use of a measurement device that includes a data logger and totalizer is preferred, however, the use of measurement technologies that take spot readings (e.g., high flow sampler) is acceptable (within the measurement limits of the device). When using spot readings take a minimum of one reading every 5 minutes for 15 minutes (four readings – initial, 5 minutes, 10 minutes, 15 minutes) after the initial flow rate has stabilized and average the results to provide an overall measured value.

The following may be sources of seal vent gas:

- piston rod packing vents and drains;
- distance piece vents and drains; and,
- compressor crankcase vents (considered to be a fugitive emission in reciprocating compressors that conserve or combust seal gas and is managed through the Fugitive Emissions Management Guideline).

Clearance pocket stem seal leakage is considered to be a fugitive emission. The management of which is detailed in the Fugitive Emissions Management Guideline.

Reciprocating compressors with piston-rod-packing vents and drains and distance piece vents and drains (including purge-system vents) that are not vented to atmosphere do not have to be tested annually. In these cases, gas emitted out of the compressor crankcase is a fugitive emission. The management of which is detailed in the Fugitive Emissions Management Guideline.

Care must be taken to ensure that all seal gas is measured if there are multiple vent points within a compressor unit that are not tied into a common manifold.

Multiple compressors that are tied into a common vent manifold may be measured together or separately as long as a representative value can be obtained for each compressor.

The testing point for each compressor seal that emits natural gas should be accessible at ground level and clearly identified.

The testing is to 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.

If a compressor piston-rod packing is replaced on one or more throws of a reciprocating compressor seal after it is tested, it should be retested to verify compliance. If it is not retested, a value of 0.16 m^3 vent gas per hour per throw can be used until the next test is completed for the purposes of calculating fleet average . If a compressor seal has been replaced since the last test, it does not need to be retested until the next annual test.

For the period of time before the first test is completed, emission rates can be estimated by using an average emission rate of 1.28 m³ vent gas per hour per throw can be used until the first test is completed. This same average emission rate may also be used when a facility changes operatorship and a test value is not available from the previous operator.

The fleet average natural gas vent rate 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 (m^3)
t	=	the number of hours per calendar year that the reciprocating compressor is pressurized
c	=	number of pressurized throws for the reciprocating compressor

Centrifugal Compressor Seals

The annual measurement of centrifugal compressor vented seal gas is a requirement of the Drilling and Production Regulation. The annual test must occur at conditions that are representative of the normal operation of the compressor and take place over a minimum of a 15 minute period. (DPR Section 52.04(7)(c)) Longer tests may be needed in some cases to achieve a representative measurement. Seal gas that is conserved or flared does not require measurement. The measurement equipment and methods must achieve a measurement uncertainty of plus or minus 10 per cent. (DPR Section 52.12).

The presence of seal gas venting may be detected using an optical gas imaging camera, Method 21, tuneable diode-infrared laser absorption spectroscopy (TDLAS), or cavity ring-down laser absorption spectroscopy (CRLAS) to ensure that all seal gas is being metered, the integrity of meter connections and that leaks do not develop during the measurement due to back pressure. If the seal gas cannot be detected using an optical gas imaging camera or organic vapour analyzer that meets the requirements of Section 41.1(1) of the Drilling and Production Regulation or by TDLAS or by CRLAS (with a similar or lower minimum detection limit) it does not need to be measured and a flow rate of zero may be recorded.

When seal gas is detected, it may be measured using the following technologies:

- full flow meter;
- hotwire anemometer; and,
- vane anemometer.

The measurement system must be selected based on worker safety, the flow rate encountered, be in good operating condition, and be set up and used in accordance with the manufacturer's specifications. The use of a measurement device that includes a totalizer is preferred however, the use of measurement technologies that take spot readings is acceptable. When using spot readings take a minimum of one reading every 5 minutes for 15 minutes (four readings – initial, 5 minutes, 10 minutes, 15 minutes) after the initial flow rate has stabilized and average the results to provide an overall measured value.

All potential venting paths from the unit must be included in the vent gas rate determination.

Care must be taken to ensure that all seal gas is measured if there are multiple vent points within a compressor unit that are not tied into a common manifold.

Multiple compressors that are tied into a common vent manifold must be measured separately unless the vent gas can be prorated back to each unit from which it originated and a representative value can be obtained for each compressor.

The testing point for each compressor seal that emits natural gas should be accessible at ground level and clearly identified.

If a centrifugal compressor seal is replaced after a test is completed it should be retested. If it is not and for the period of time before the first test is completed, emission rates can be estimated by using an average emission rate of 1.27 m^3 vent gas per hour per unit can be used until the first test is completed.

When air or inert buffer (non-hydrocarbon) gas or purge gas is used as part of the sealing system its volume may be discounted from the measured vent rate for the purposes of comparison with the Drilling and Production Regulation.

Compressor Seal Vent Detection and Measurement

The following technologies may be used to determine whether there is a detectable vent flowrate present to measure prior to attempting to take a measurement. If there is no detectable flowrate present no measurement is needed and a quantity of zero may be reported.

Optical Gas Imaging

See description in Fugitive Emission Management Guideline.

Organic Vapour Analyzer

See description in Fugitive Emission Management Guideline.

Tunable Diode-infrared Laser Absorption Spectroscopy

A tunable diode-infrared laser tuned to absorb methane can be used to detect vented methane. The detector works by comparing the laser beam reflected back to the device with the laser beam that was sent out. If the laser passes through a plume containing methane, the methane will absorb some of the light causing an imbalance.

Cavity Ring-Down Laser Absorption Spectroscopy (CRLAS)

A beam from a laser diode enters a mirror cavity, filling it with light. When the beam is turned off the light intensity within the cavity decays to zero. The decay is also known as “ring down”. The time needed to decay to zero is measured by a photodetector. A gas species introduced into the cavity changes the ring down time and the change in time is used to determine gas concentration.

Technologies that can be used to measure vent gas flowrate are listed below. Note that the list does not replace the need for case-by-case selection of a suitable measurement system.

High Flow Sampler

See description in Fugitive Emission Management Guideline.

Full- Flow Meter

See description in Fugitive Emission Management Guideline.

Vane Anemometer

A vane anemometer measures vent gas velocity using a vane wheel. The anemometer is placed at the centre of a vent pipe opening or into the centre of a vent pipe through a port and the number of revolutions per unit time are recorded and converted to velocity. Velocity is then converted to flow rate using the cross sectional area of the vent pipe.

When measuring emissions using a vane anemometer manufacturer specifications are to be followed.

Hotwire Anemometer

A hotwire anemometer consists of an exposed hot wire that, when, inserted into a stream of flowing gas, measures velocity by correlating it with heat lost to convection. As with a vane anemometer, velocity is converted to flow rate using the cross sectional area of the vent pipe.

When measuring emissions using a hotwire anemometer manufacturer specifications are to be followed.

Equipment Calibration and Maintenance

Keep records of the methods of calibrating and practices for maintaining the detection and measurement equipment. This must include how frequently any maintenance or calibration activities are conducted and any procedures or tracking systems used to ensure that these activities are carried out (DPR Section 52.12).

Documentation to demonstrate that equipment is being maintained and calibrated to the manufacturer's specifications must be maintained. This includes, but is not limited to the calibration of the meter to the composition of the gas measured.

Training and Competency

Keep records of internal and external vent gas detection and measurement training programs measurement technicians undertake, including the topics covered and the duration of training, and relevant certifications. Keep records of the specific training for the types of equipment being used.

Technicians should have experience detecting, measuring recording, and reporting vented emissions. If they do not, such as in the case of a person that is being trained, the trainee should work under the direct supervision of a trained individual.

Additionally, it is expected that all technicians will have applicable site safety training and certificates.

Repairs or Replacements

Any vent rate above the permitted limit for its source must be repaired or the device/packing must be replaced, whichever is appropriate.

Repairs/replacements/retrofits should be made quickly after discovery, unless parts are unavailable, the equipment requires shutdown to complete repair, or other good cause exists and must be made within 30 days of detection in the case of reciprocating compressor packings/seals. Action must be taken within 90 days where required to reduce seal gas vent rates on centrifugal compressors.

Data Management

Data management systems allow permit holders to track, manage, and analyze vented emissions data. These systems should:

- track completed measurements and repairs (including work orders);
- track scheduled measurements and upcoming repairs/replacements;
- track performance data over time;
- enable data analysis to identify trends; and
- generate data summaries for use in regulatory reports.

Record Keeping

Data must be submitted electronically to the Regulator through eSubmission by May 31 of each year for data collected during the previous calendar year. If May 31 occurs on a Saturday or a Sunday, the data are due on the following Monday (DPR Section 41.1 (7)). The first report must be submitted by May 31, 2023.

Records related to vent identification, quantification, and repair/replacement must be retained for a period of not less than 7 years after the date the vent identification, quantification, or repair/replacement was complete to meet the requirements of the Greenhouse Gas Emission Reporting Regulation.

The Regulator may request records pertaining to regulated sources outside of the eSubmission process. The Regulator requests that it receive the records within 10 working days of the request, unless otherwise noted.