



Flaring And Venting Reduction Guideline

VERSION 5.1: May 2018

About the Commission

The BC Oil and Gas Commission (Commission) 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 Commission'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.

Mission

The Commission regulates oil and gas activities for the benefit of British Columbians by:

- Protecting public safety.
- Respecting those affected by oil and gas activities.
- Conserving the environment.
- Supporting resource development.

Through the active engagement of stakeholders and partners, the Commission provides fair and timely decisions within its regulatory framework. It supports opportunities for employee growth, recognizes individual and group contributions, demonstrates accountability at all levels, and instills pride and confidence in our organization.



Vision and Values

To provide oil and gas regulatory excellence for British Columbia's changing energy future.

- Respectful Accountable
- Effective Efficient
- Responsive Transparent

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Manual Revisions

The Commission 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 Commission’s website.

Stakeholders are invited to provide input or feedback on Commission documentation to OGC.Systems@bcogc.ca or submit feedback using the [feedback form](#).

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”.

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 Oil and Gas Activities Act (OGAA).

Scope

This guideline focuses exclusively on requirements and processes associated with the BC Oil and Gas Commission's (the Commission) legislative authorities and does not provide information on legal responsibilities that the Commission 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

Commission 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 Commission 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 Commission recognizes that evolving technologies and practices may not be addressed by these guidelines. The Commission 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 Commission webpage. The information provided is categorized into topics which reflect the manuals for easy reference. Please consult the FAQ page before contacting the Commission to help keep response times short.

Flaring Reduction Reporting

The Commission 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 Commission'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 Commission 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).

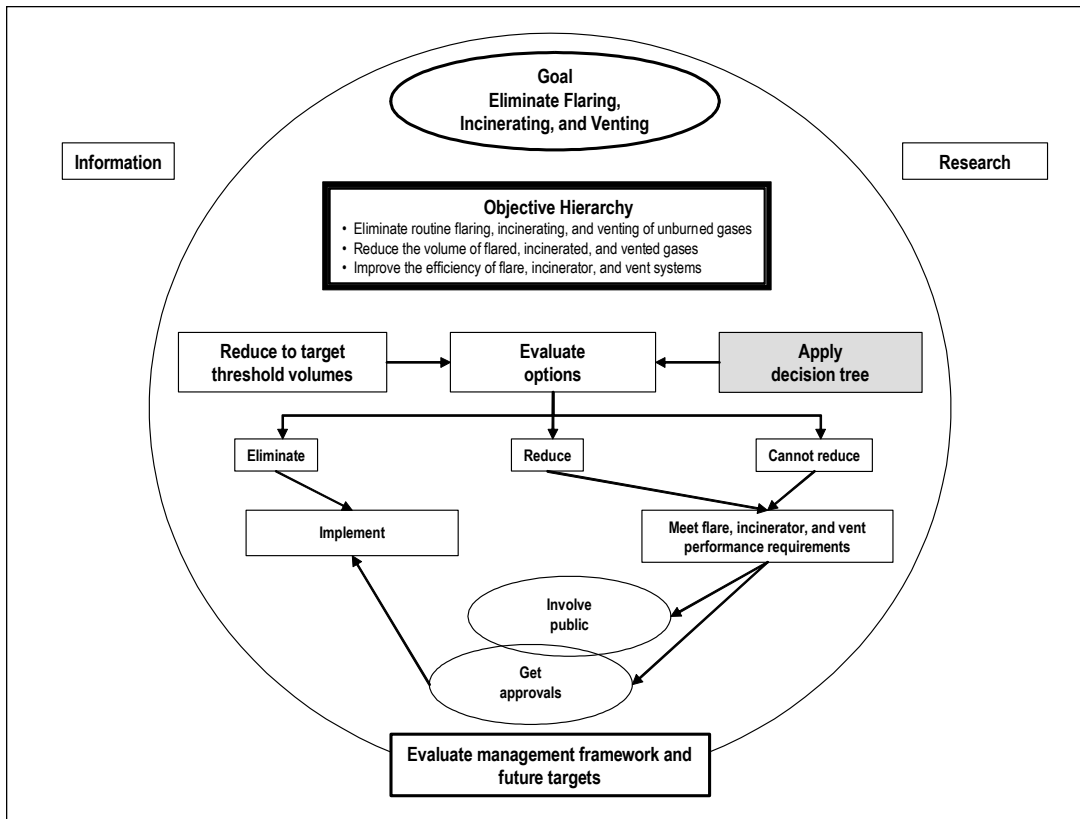


Figure 1.1: Gas Flaring/Venting Management Framework (adapted from CASA)

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 Commission's goal is to have the upstream petroleum industry reduce the volume of solution gas that is flared or vented. The Commission, 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 (eg. 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 Commission 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 Commission 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.

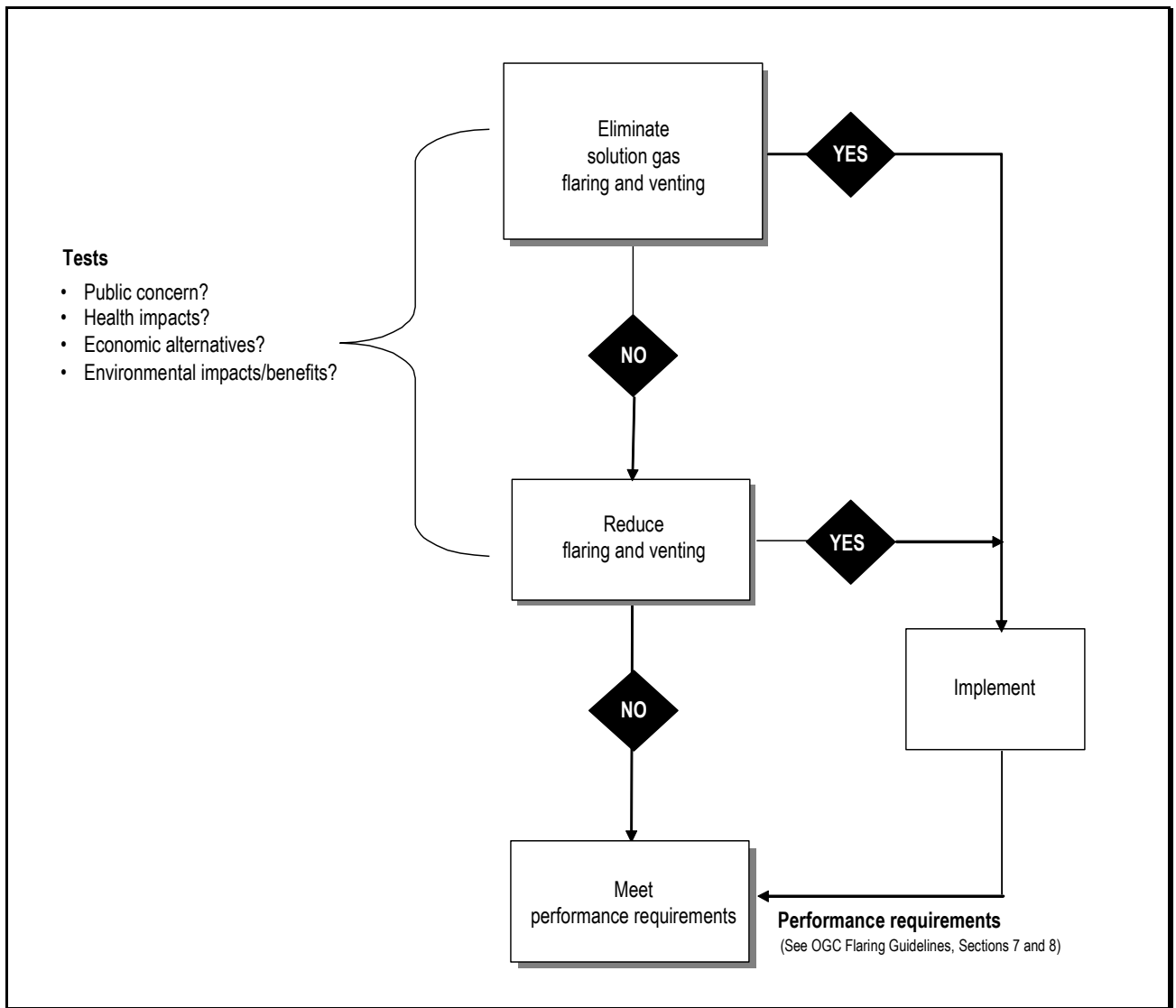


Figure 1.2: Solution Gas Flaring/Venting Decision Tree (adapted from CASA)

1.3 Conservation at New Oil Facilities

In general, for new oil sites¹, 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 Commission 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 Commission 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.

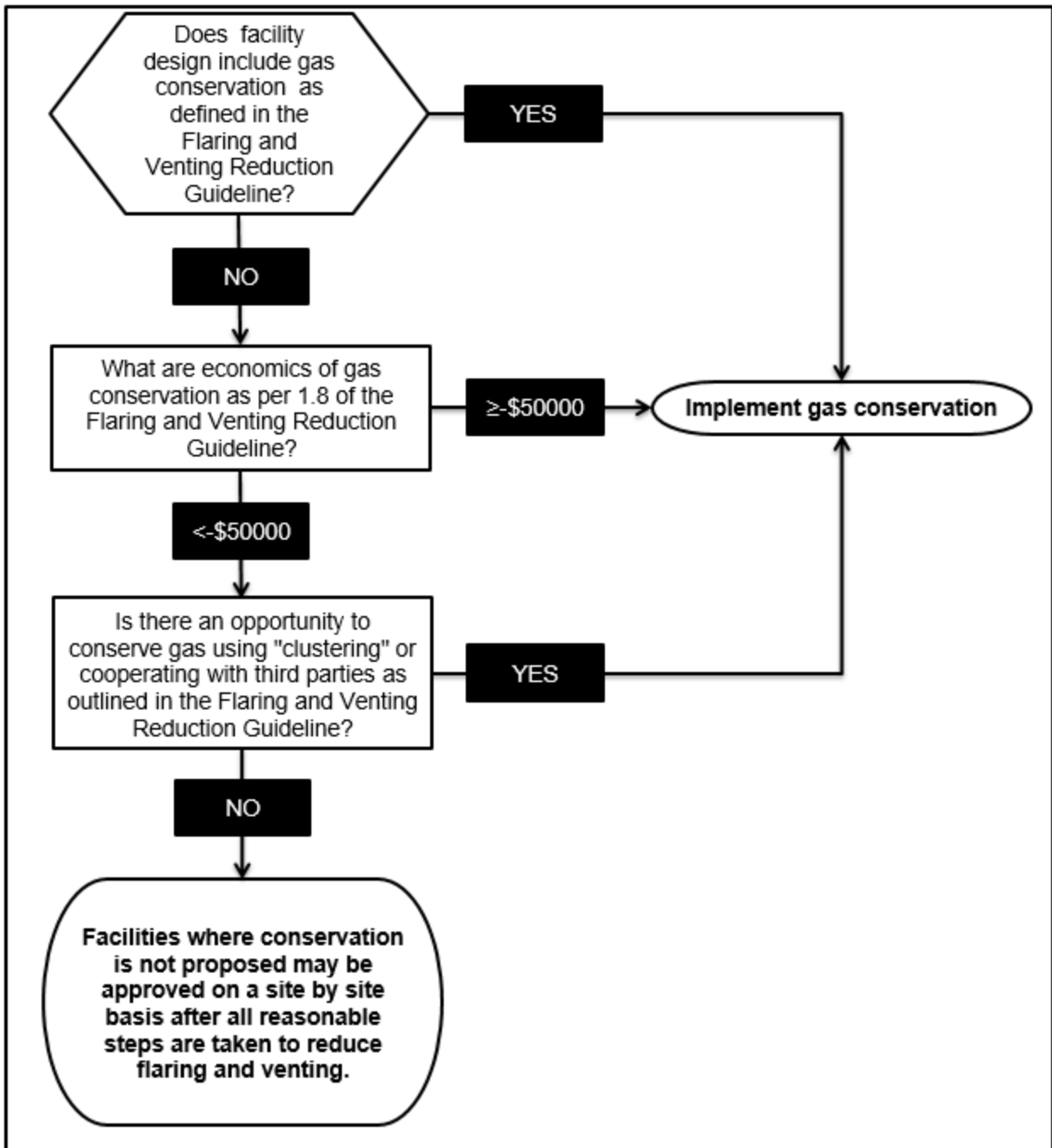


Figure 1.3: New Oil Facility Gas Conservation Decision Tree

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 m³/day per site² 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 m³/m³. All wells producing with a GOR greater than 3000 m³/m³ 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 m³/day per site and the flare is within 500 m of an existing residence, regardless of economics.
 - i. If a new residence is constructed or relocated within 500 meters 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 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) The Commission may still require economic evaluations for sites flaring or venting combined volumes less than 900 m³/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).
- 6) Permit holders must obtain approval from the Commission 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.

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

- d. Submit a facility amendment application, and
- e. Comply with Table 1.1 in the event conservation facilities are not operational until Commission approval to discontinue conservation is granted.

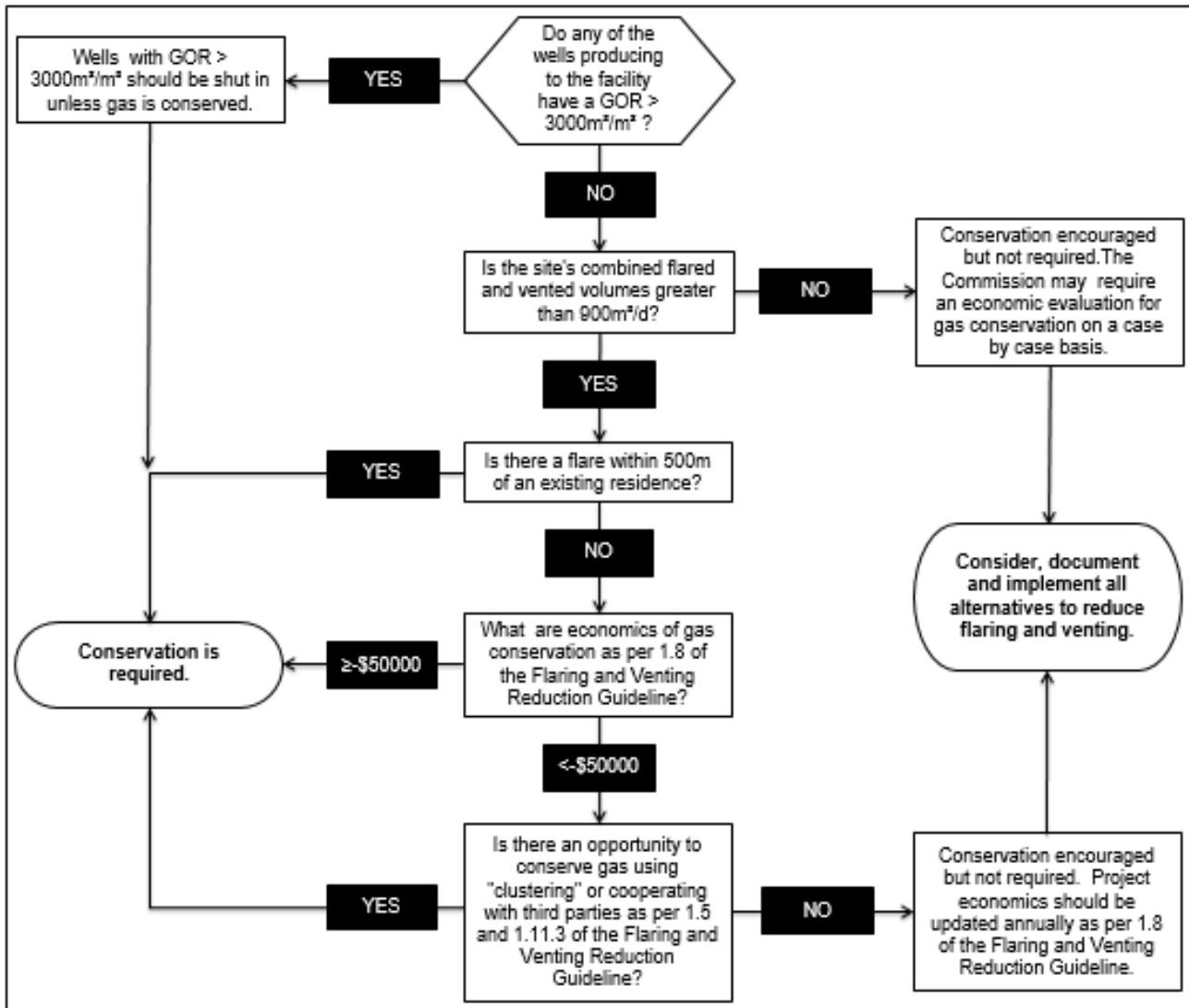


Figure 1.4: Existing Oil Facility Gas Conservation Decision Tree

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

The Commission 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 m³/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 Commission 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 percent of the initial capital cost of installing the conservation facilities. If the gas contains 1 mole percent hydrogen sulphide (H₂S) or more, the incremental annual operating costs for the project are assumed to be up to 20 percent 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 percent of the initial capital cost of installing the generation facilities. Standby fees may be calculated in addition to this 10 percent allowance.
- 8) The inflation rate should be set to the Bank of Canada long-term inflation rate target of 2 percent 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 percent, 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 Commission 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 Commission 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.

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.
	> 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: <ul style="list-style-type: none"> • Solution gas must not be flared from wells that have an H₂S content greater than 5 mole percent. • Production may be sustained at rates to provide sufficient throughput to keep equipment operating safely and within minimum design turndown range. • The Commission also recommends that operators notify individuals that have identified themselves to the permit holder as being sensitive or interested regarding emissions from the facility. • Residents and the Commission must be notified 24 hours prior to the planned event by 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: <ul style="list-style-type: none"> • Solution gas must not be flared from wells that have an H₂S content greater than 5 mole percent. • Production may be sustained at rates to provide sufficient throughput to keep equipment operating safely and within minimum design turndown range. • The Commission 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. • Residents and the Commission 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.
<p>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 <i>Air Quality Objectives and Standards</i> for sulphur dioxide (SO₂) under high flow rate conditions, action must be taken immediately to reduce gas to a rate compliant with BC's <i>Air Quality Objectives and Standards</i> (see Chapter 6).</p> <p>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.</p> <p>Repeat non-routine flares are defined as recurring events of similar cause at a conserving facility during a 30-day period.</p>		

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

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 Commission 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 rationale for why shutting in is impractical. In these special cases, the permit holder must consult with the Commission 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 Commission explaining the alternative requested and giving supporting reasons for the request. Contact with the Commission must not be deferred until an actual outage occurs. Permit holders should submit the written request to the Commission 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 Commission 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 monthly to the Ministry of Finance, Mineral, Oil and Gas Revenue Branch on a BC-S2 “Monthly Disposition Statement” form 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 Commission 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 Commission 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 Commission contemplates having this included as a regular report in the future.

1.11.3 Cooperating with Third Parties

The Commission 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 Commission 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 Commission 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 Commission 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 Commission (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 Commission's Well Testing Requirements document 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.

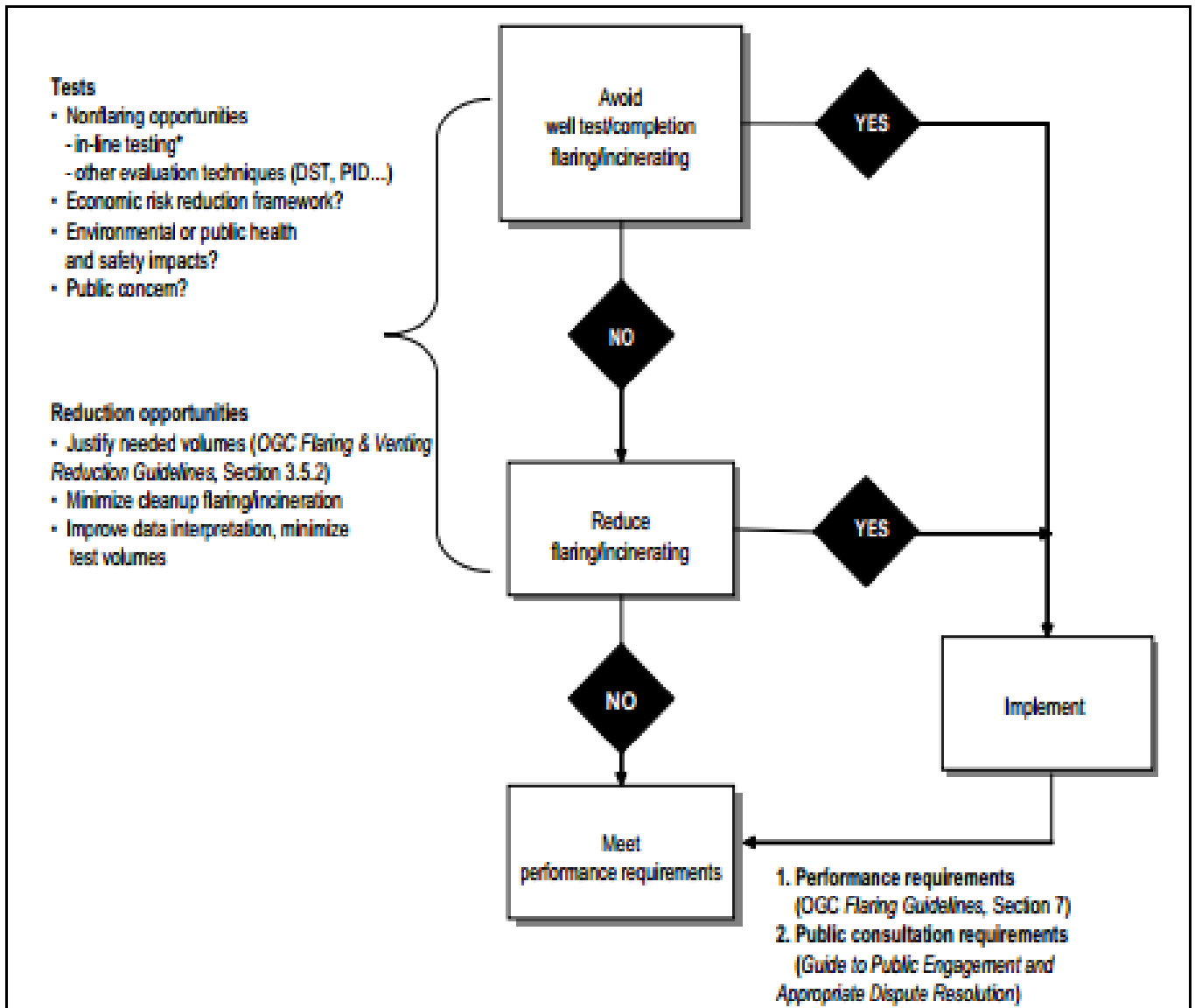


Figure 2.1: Temporary Flaring Decision Tree (adapted from CASA)

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 Commission may require the use of incineration as a well permit condition based on the outcome of public consultation.

2.3 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 Commission 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 Commission as soon as the permit holder recognizes that the time limit will be exceeded.
- 5) For wet coalbed methane wells (producing more than 1 m³ 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 10³m³ for any consecutive 3-month period (about 1100 m³/day). Shorter tie-in periods must be pursued whenever possible.
 - a. Permit holders must notify the Commission as soon as the cumulative total gas production exceeds 100 10³m³ 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 10³m³ in 3 months), flaring and venting are limited to a total period of 18 months, including the time to tie in the well.

2.4 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 m³ in one year.
- 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 Commission. 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.

2.5 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 percent H₂S 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 percent H₂S and < 5 mole percent H₂S, permit holders must retain, for one year after the flaring event, information on dispersion assessments. This information must be provided to the Commission upon request.
- 4) For gas flaring ≥ 5 mole percent H₂S, permit holders must submit the dispersion modelling to the Commission in accordance with Section 6(1)(d) of the Oil and Gas Waste Regulation. Depending on the results of dispersion modelling, the Commission 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.

2.6 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 Act](#).
- 3) Permit holders must determine the H₂S content of flared or incinerated gas using Tutweiler 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 H₂S content in the gas is found to exceed 5 mole percent H₂S and dispersion modelling was not submitted with flaring application, or if the H₂S content of the gas exceeds the maximum value listed in the related permit conditions, operations must be suspended until the Commission 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. CO₂) 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 Commission and all residents and administrators of incorporated centers in accordance with Chapter 5.

2.9 Reported Flared Volumes

- Flared volumes must be reported to the Commission eSubmission portal within 60 days of the completion of flaring.
- Well test results must be submitted in accordance with the requirements of the Drilling and Production Regulation on a Well Deliverability Test Report.
- All well deliverability test reports must be submitted within 60 days of completing the fieldwork. This information must include the volume of gas produced to flare, vent or pipeline, as well as all analyses from samples gathered at the wellhead, and must be submitted to the Commission eSubmission Portal.
- Flaring related to gas well cleanup and well testing should not be reported on BC-S1 and BC-S2 reports.
- For underbalanced drilling, operations that result in gas sales during the drilling process are issued test facility codes. Deliveries and receipts of gas between the test facility and the reporting facility must be reported on BC-S2 reports.

- Condensate obtained during gas well tests must be reported on the BC-08 Marketable Gas and By-Product Owner Allocation reports in the Field Condensate Volume and Field Condensate Value fields. If a well has not been connected to a reporting facility during the month, no plant or facility codes are required. Allocated raw gas volume should be reported as zero.
- Questions regarding the BC-S1, BC-S2 and BC-08 reports should be submitted to the B.C. 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 m³ 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).

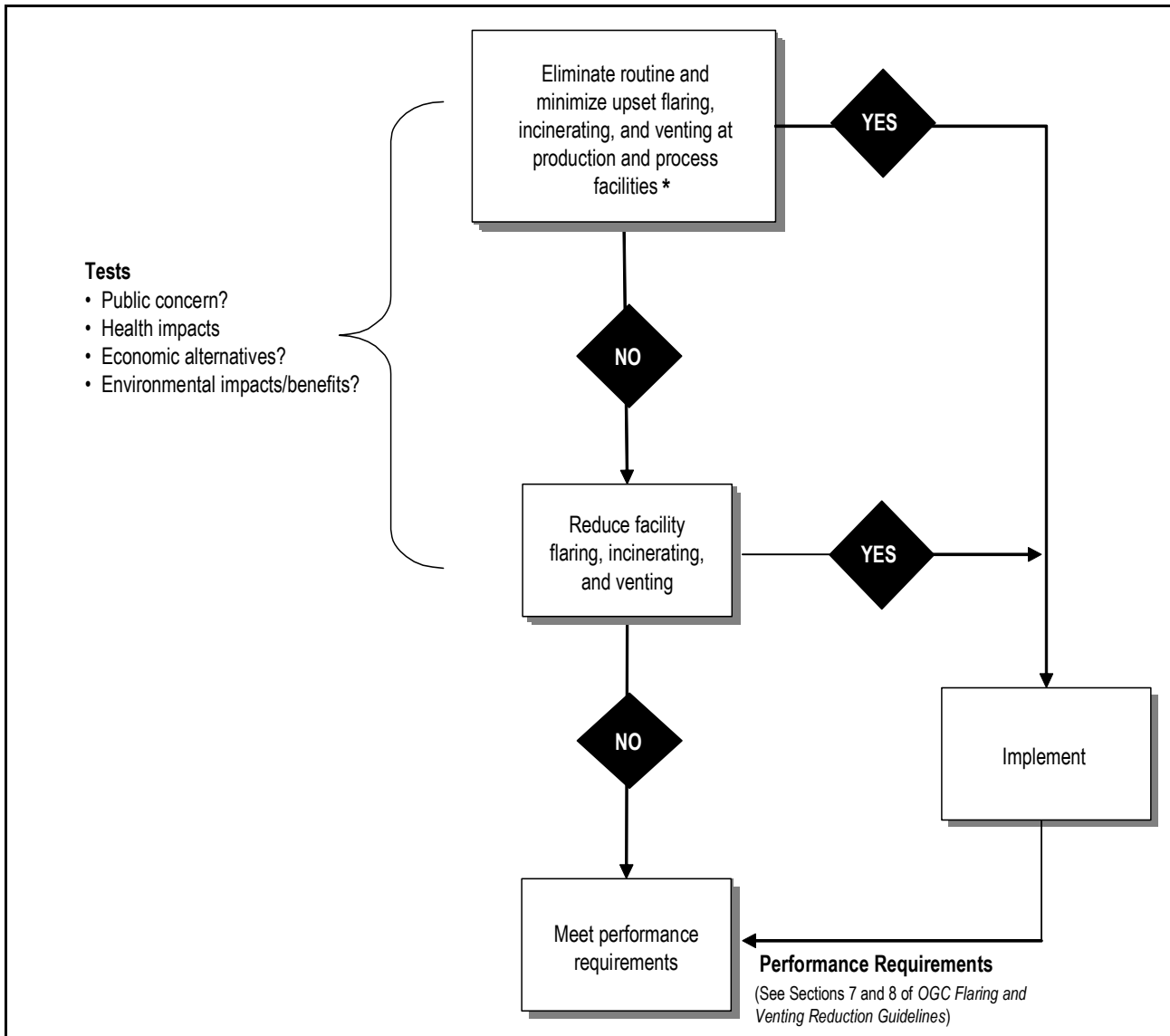


Figure 3.1: Facility flaring and venting decision tree (adapted from CASA)

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 Commission on a site by site basis.
- 4) The Commission may require additional conservation evaluations at non-conserving facilities when necessary.
- 5) Conservation is subject to safety and environmental concerns.
- 6) The Commission 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 Commission 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.

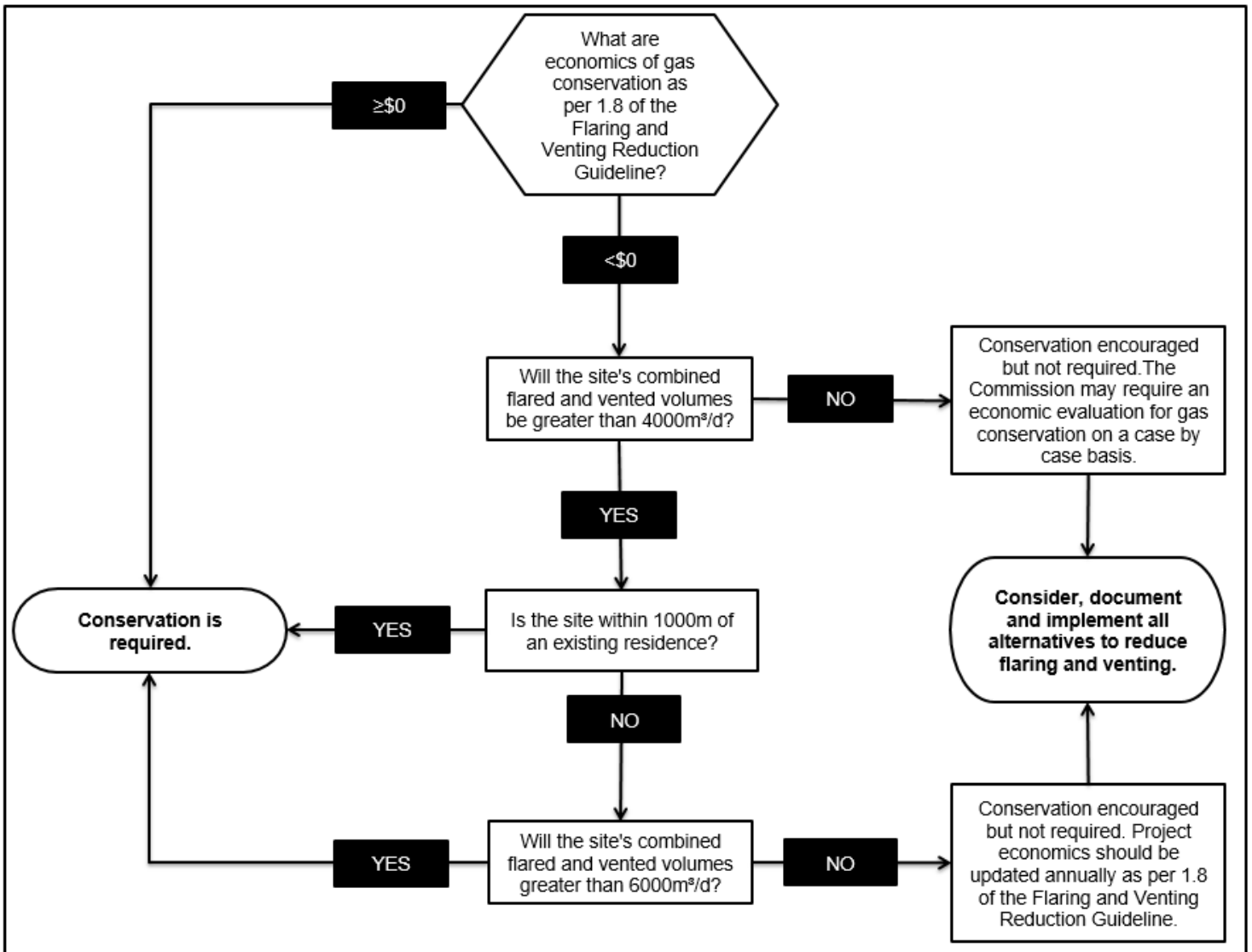


Figure 3.2: Gas Facility Conservation Decision Tree

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 Commission 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 $\geq 300 \times 10^3 \text{ m}^3/\text{day}$.
- 4) The Commission 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 Commission of non-routine flaring at facilities as described in Chapter 5.

3.5 Reporting

- 1) For facilities other than gas processing plants, all monthly flared, incinerated, and vented volumes must be reported separately on a Monthly Disposition BC-S2 form and be submitted to the Mineral, Oil and Gas Revenue Branch of the Ministry of Finance. Refer to Chapter 10 of this Guideline for more details.
- 2) For gas processing plants, all monthly flared, incinerated, and vented volumes must be reported separately on a Monthly Disposition BC-19 form and be submitted to the Mineral, Oil and Gas Revenue Branch of the Ministry of Finance.
- 3) Gas burned in an incinerator must be reported as flared. Fuel gas burned in an incinerator must be reported as fuel gas.

- 4) Gas flared or vented at gas facilities must be reported at the location where the flaring or venting took place.
- 5) Fuel gas that is flared or vented (e.g. flare pilot gas, purge gas, storage tank blanket gas) must be reported as either flared or vented gas, not fuel gas. This does not include fuel gas added to flare or incinerator streams in order to meet minimum heating value requirements.

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
<p>*The definition of a flaring event includes situations where:</p> <p>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</p> <p>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 25 10³ m³/d is considered one event).</p>	

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 OGCPipelines.Facilities@bcoqc.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 Commission 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 Commission 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 Commission may allow venting of gas to reduce the duration of system outages and related impacts.

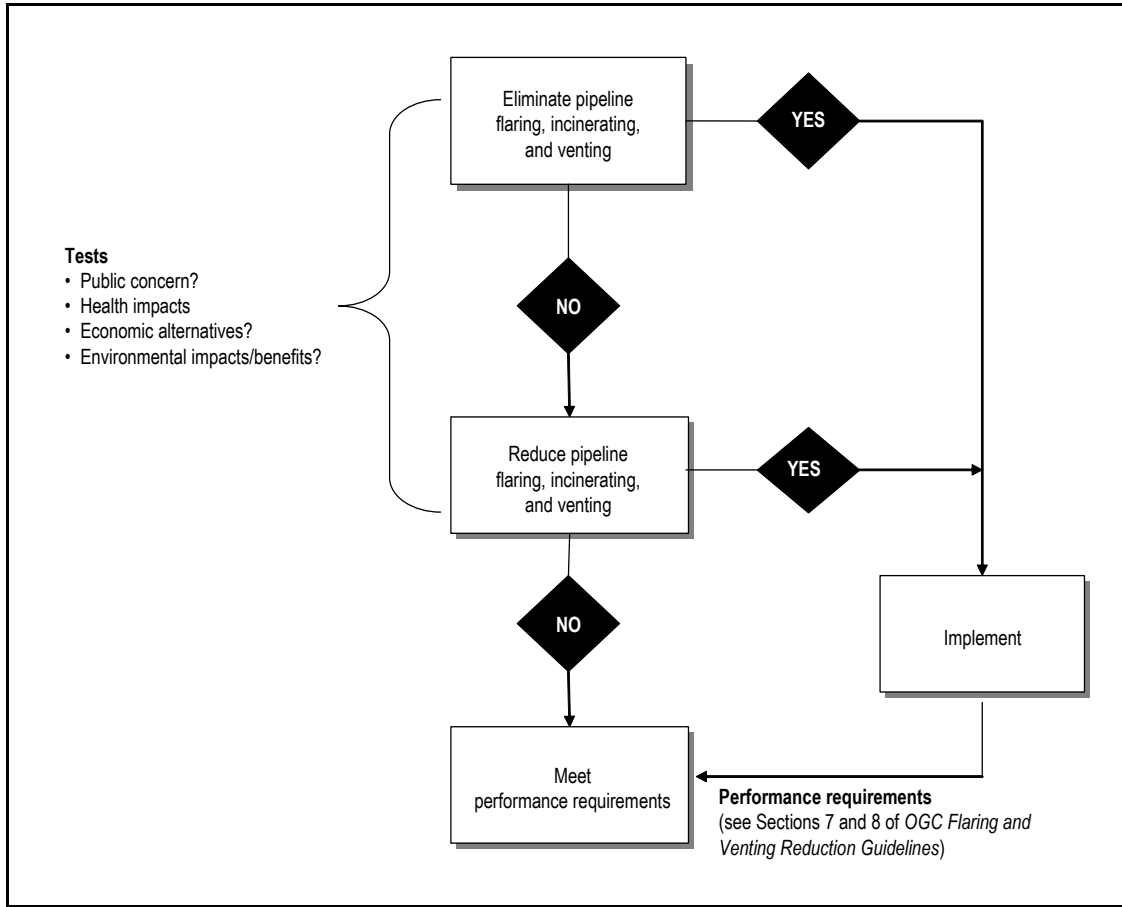


Figure 4.1: Pipeline Flaring and Venting Decision Tree (adapted from CASA)

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 Commission of non-routine flaring of pipelines as described in Chapter 5.
- 3) All monthly flared, incinerated, and vented volumes must be reported separately on a Monthly Disposition BC-S2 form and be submitted to the Mineral, Oil and Gas Revenue Branch of the Ministry of Finance. Refer to Chapter 10 of this Guideline for more details.

Chapter 5: Notification Requirements

Permit holders must notify the Commission 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 Commission does not require permit holders to obtain the consent of the residents within the notification radius.

H ₂ S Content	Flaring Event Duration or Volume	Notification Radius
Any	<4 hrs and < 10 e ³ m ³	None
<1%	>4 hrs or > 10 e ³ m ³	1.0 km
1%≤H ₂ S<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 H₂S content; and,
 - f. Commission contact number.
- 4) The Commission 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 Commission

- 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 Commission through the eSubmission portal.
- For flaring at Pipelines and Facilities, permit holders must notify the Commission Pipelines and Facilities Department by email (OGCPipelines.Facilities@bcogc.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 Commission 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 Act](#) 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 Commission 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 Commission 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 Act](#). 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 exists to shut-in if problems arise.

- 4) The Drilling and Production Regulation, API-RP-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.

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 Commission 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 Commission deems necessary to mitigate or eliminate the air quality impacts.

6.1.1 Heating Value and Exit Velocity for Flares

If a flare is subject to a permit under the Environmental Management Act and the Oil and Gas 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 meter (MJ/m³), 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/m³.

- 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/m³.
- 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 Act](#).
 - 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 Commission upon request.
 - 5) Operating limits and procedures must be provided to the Commission upon request.

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 Commission 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 Commission 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 a 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 Commission 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 Commission 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 percent H₂S 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/m².

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 H₂S content of the gas to be flared exceeds one mole percent 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 Commission 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 is not continuously or routinely flared and the potential exists to safely conserve gas by avoiding continuous pilots and/or purge gas, the Commission 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 Commission on request.

The Commission 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 SO₂ and H₂S 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 percent H₂S or \geq one tonne per day of sulphur emissions, unless the event is ≤ 15 minutes and \leq one tonne per day sulphur.
- Permit holders combusting gas below one mole percent H₂S 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 Commission, ensuring that ambient air quality objectives can be maintained throughout resource development. Facilities requiring an Environmental Management Act approval from the Commission may require more detailed evaluation. Permit holders should consult with the Commission's Environmental Stewardship Group directly in these circumstances.
- Dispersion modelling must be completed by qualified personnel using acceptable models and methodology.

6.10.1 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 SO₂ 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 percent 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 percent 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 Commission. Submissions may be made to OGCWaste.Management@bcogc.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.
- A facility permit holder must have an adequate fugitive emissions management program.

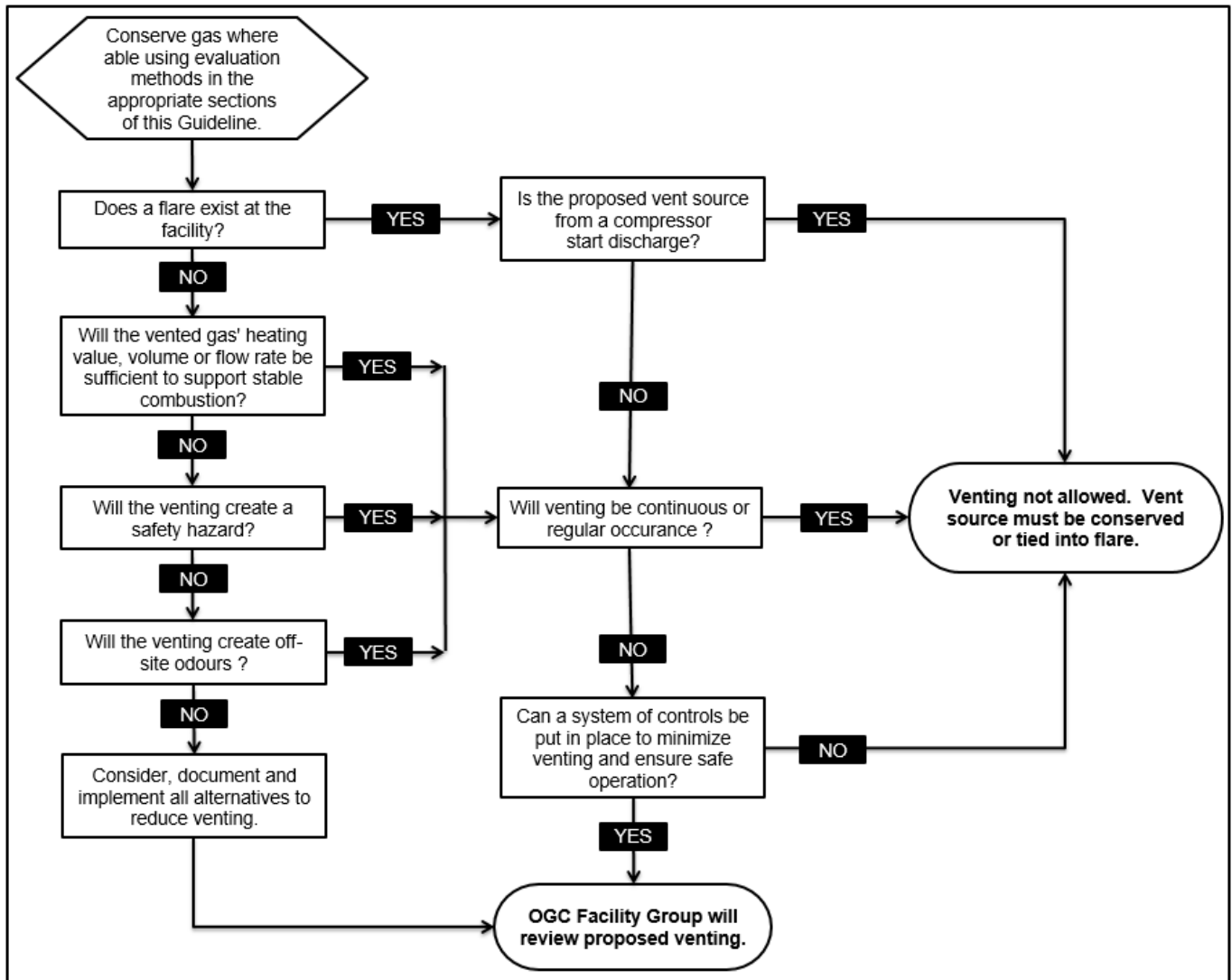


Figure 7.1: Vent Evaluation

7.2 Limitations of Venting Gas Containing H₂S or Other Odorous Compounds

- The Commission 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 Commission 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 Commission 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 H₂S must not be vented to the atmosphere if off-lease odours may result. Alternatives to venting such gas include flaring or incinerating with sufficient fuel gas to ensure destruction of odorous compounds, 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 Commission 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.
- These programs should meet or exceed the CAPP Best Management Practice for Fugitive Emissions Management.

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 Commission 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 Commission 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 Commission'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 rationale has not been accepted by the Commission'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.

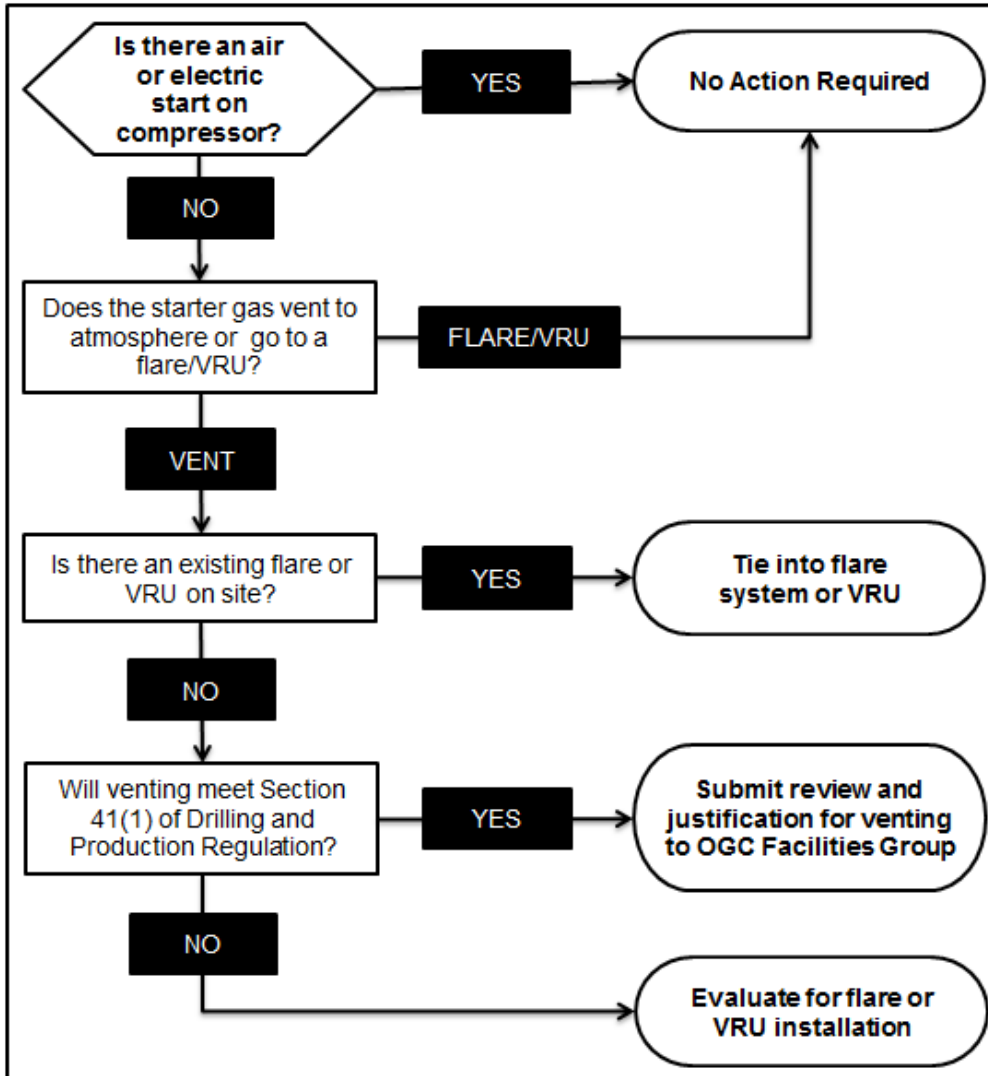


Figure 7.3 Compressor Start Gas Discharge Decision Tree

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 percent H₂S and the unsupplemented heating value of the gas is 20 MJ/m³ 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 percent H₂S, 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 percent H₂S, the incinerator should also be equipped with process temperature control and recording.
 - i. Equipment and controls design information must be provided to the Commission upon request.

- 3) Operating limits and procedures must be provided to the Commission 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 percent, 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:

- Measurement Guideline for Upstream Oil and Gas Operations
- 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 $0.1 \text{ } 10^3\text{m}^3\text{/month}$ (adjusted to 101.325 kPa(a) and 15°C) that are flared, incinerated or vented.
 - a. These volumes are to be reported on the Ministry of Finance BC-S2 and/or BC-19 forms and are to include all flaring, incinerating and venting from routine operations, emergency conditions and the depressurizing of pipeline, compression and processing systems.
- 2) Gas that is used for pilot, purge or blanket gas must be reported as either flared or vented. Process gas used to operate instrumentation or as power gas to drive chemical pumps must be included as vented gas. Dilution gas is to be reported as fuel gas.
- 3) 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 if an incinerator is used in place of a flare stack.
 - b. Acid gas streams at a gas plant that are incinerated or flared as part of normal operations are to be reported as shrinkage.
Note: NOT to be reported as flared gas.
 - c. Fuel gas used to operate a flare stack for pilot purposes is to be reported as flared gas.
Note: NOT to be reported as fuel gas.
 - d. Dilution gas (or gas used to maintain a minimum heating value of the flared or incinerated gas) is to be reported as fuel gas.

Note: The reported total flare volume MUST EXCLUDE any of these fuel volumes.

- 4) Fugitive emissions are considered a part of shrinkage.
Note: Fugitive emissions are NOT to be reported as flared or vented gas.
- 5) 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.
- 6) The Commission 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 $0.5 \times 10^3 \text{m}^3/\text{d}$ on an annual average.
- 7) 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 $0.5 \times 10^3 \text{m}^3/\text{day}$ (excluding dilution gas). Vent sources such as compressor distance piece vents, pumps, valve controllers, and some flared sources such as pilots and purge 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 $0.5 \times 10^3 \text{m}^3/\text{d}$.

Chapter 2 of the Measurement Guideline for Upstream Oil and Gas Operations 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 Measurement Guideline for Upstream Oil and Gas Operations).

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 Commission 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 Commission 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 10³m³/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 Commission 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 Commission 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 Commission online drilling reporting system. A Well Deliverability Test Report must be submitted for deliverability type flow tests, clean-up flows and underbalanced drilling operations.
- BC-19 form – all flaring and venting of gas at gas plants and associated gathering system.
- BC-S2 form – flaring and venting from all other facilities, compressors, pipelines, and gas gathering systems.
- When well test flaring is in excess of 50 mol/kmol H₂S (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 if an incinerator is used in place of a flare stack. This would not apply 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 acid gas shrinkage, not flared.
- 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.

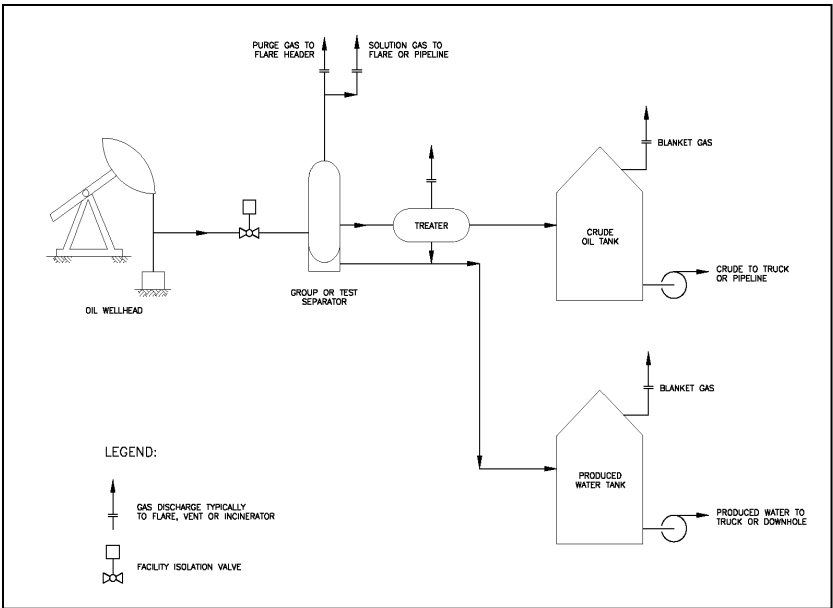


Figure 10.1: Reportable Flaring Streams – Upstream Oil Battery

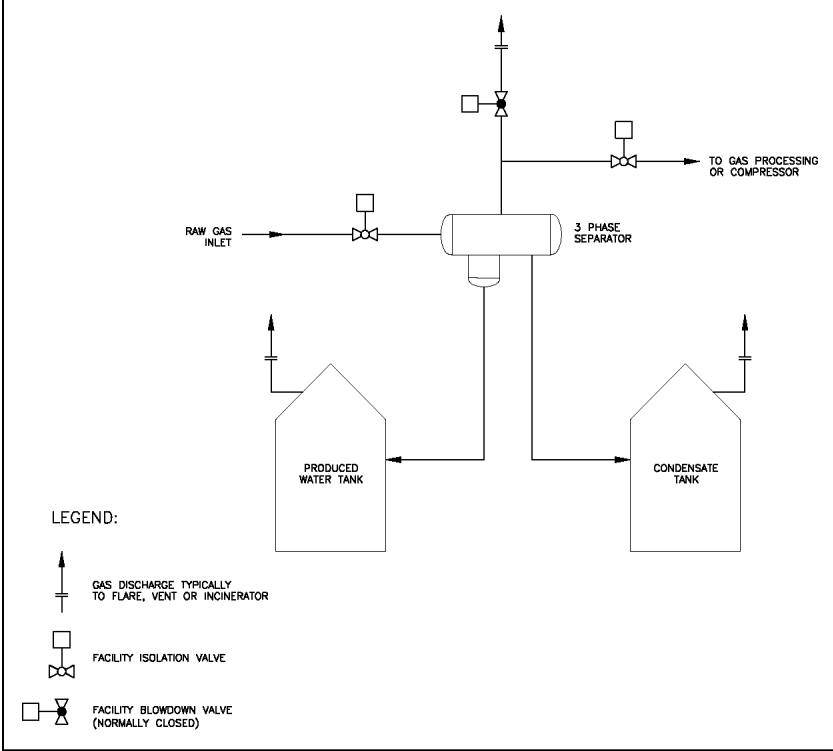


Figure 10.2: Reportable Flaring Streams – Inlet Separation Facility

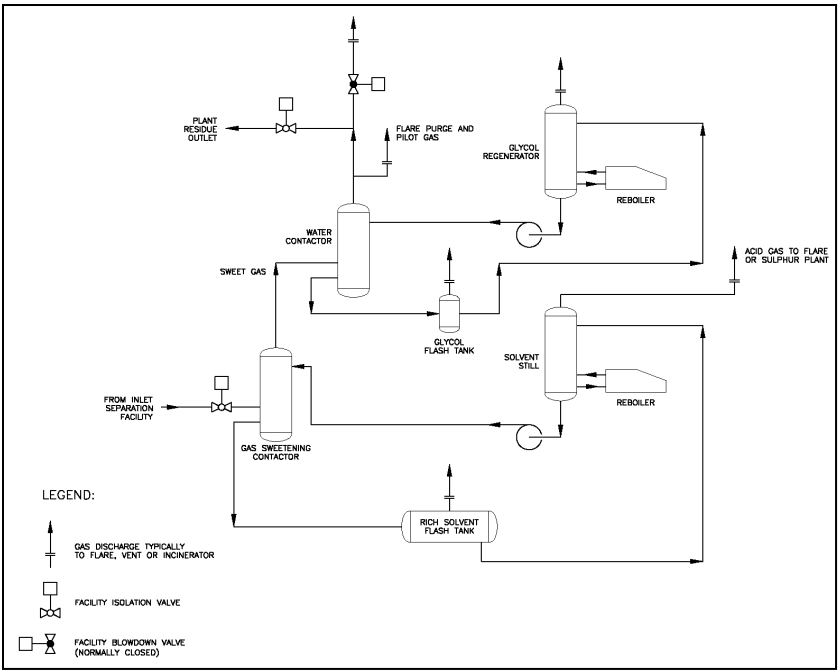


Figure 10.3: Reportable Flaring Streams – Gas Processing Plant

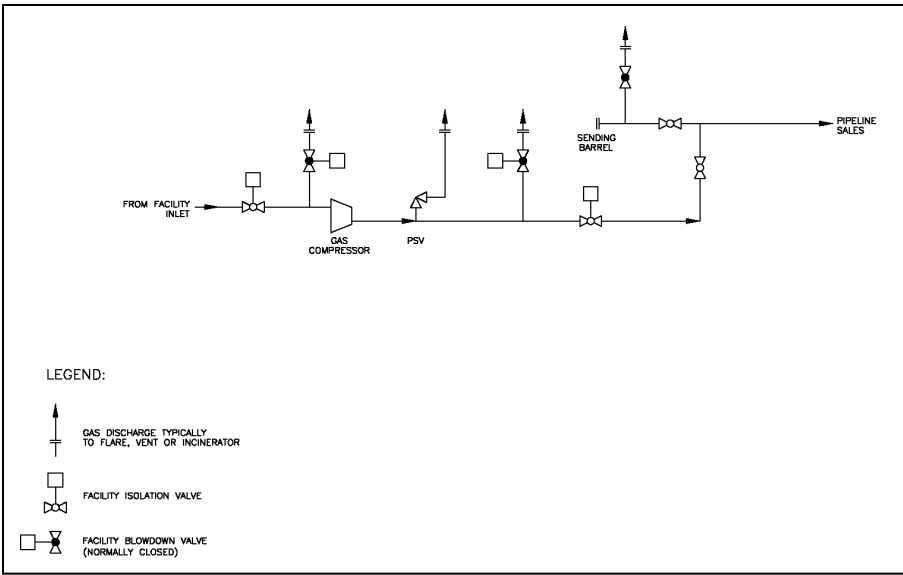


Figure 10.4: Reportable Flaring Streams – Gas Compression Facility

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.
- Commission 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.