BC Oil & Gas COMMISSION

FLARING AND VENTING REDUCTION GUIDELINE

October l 2011

Version 4.2

Summary of Revisions

The Flaring and Venting Reduction Guideline has been revised. Structural changes by section are highlighted below.

Applications received on or after the effective date will be required to meet the revised application standards.

Effective Date	Section	Description/Rationale
1-Feb-2011	General	Updated manual formatting and hyperlinks.
1-March-2011	General	Updated manual formatting.
1-June-2011	General	Updated email addresses from "gov.bc.ca" to "bcogc.ca".
1-Sep-2011	General	Updated all hyperlinks and email addresses to BCOGC.
1-Oct-2011	Section 4.2	Corrected references to Section 10 to Section 11.

1 Preface

1.1 Purpose

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 measuring 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). This guideline is effective October 4, 2010.

1.2 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.

1.3 How to Use This Guideline

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”.

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” indicates a best practice that should be used by the applicable party but does not carry an enforcement consequence.

Major changes to the flaring regulatory program include the following:

- Mandatory inline testing of wells near pipelines and populated areas;
- Approval is required for all well test and cleanup flaring[1];
- Implementation of a new flaring reporting system for wells;
- Facility design guidance to eliminate or reduce flaring;
- Requirements for flare meters at new gas plants and large compressor stations;
- Elimination of non-routine flaring approvals for pipelines and facilities and
- Requirements to consider the use of incineration when flaring near populated areas.

The updates to this Guideline are intended to continue progress toward achieving the Energy Plan goals, reduce the nuisance impacts associated with flaring in or near populated areas and improve 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 and the province of British Columbia’s goal as stated

[1] Transitional provisions will authorize some flaring during the initial completion of a well approved prior to implementation of the *Oil and Gas Activities Act*.

in the Energy Plan to "eliminate all routine flaring[2] at oil and gas producing wells and production facilities by 2016, with an interim goal to reduce routine flaring by 50 per cent by 2011".

2 Routine flaring is defined as the continuous flaring of gas that is not required for safety or environmental purposes and is economical to conserve.

1.4 Additional Guidance

The glossary page on the Commission website provides a comprehensive list of terms.

Other navigational and illustrative elements used in the guideline include:

Hyperlinks: Hyperlinked items appear as blue, underlined text. Clicking on a hyperlink takes the user directly to a document or location on a webpage.

Sidebars: Sidebars highlight important information such as a change from the old procedure, new information, or reminders and tips.

Figures: Figures illustrate a function or process to give the user a visual representation of a large or complex item.

Tables: Tables organize information into columns and rows for quick comparison.

1.4.1 Feedback

The Commission is committed to continuous improvement by collecting information on the effectiveness of guidelines and manuals. Clients and stakeholders wishing to comment on Commission guidelines and manuals may send constructive comments to OGC.Systems@bcogc.ca Reduction.

1.4.2 Frequently Asked Questions

A Frequently Asked Questions (FAQ) link is available on the Commission OGAA page. 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.

1.5 Flaring Reduction Reporting

The Commission reports annually on the current state of flaring, incinerating and venting in the province of British Columbia and progress made towards reduction goals.

The 2009 Flaring, Incinerating and Venting Reduction Annual Report was published in September 2010.

1.6 Flaring and Venting Management Hierarchy and Framework

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

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

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).

Click on the diagram to expand the view.

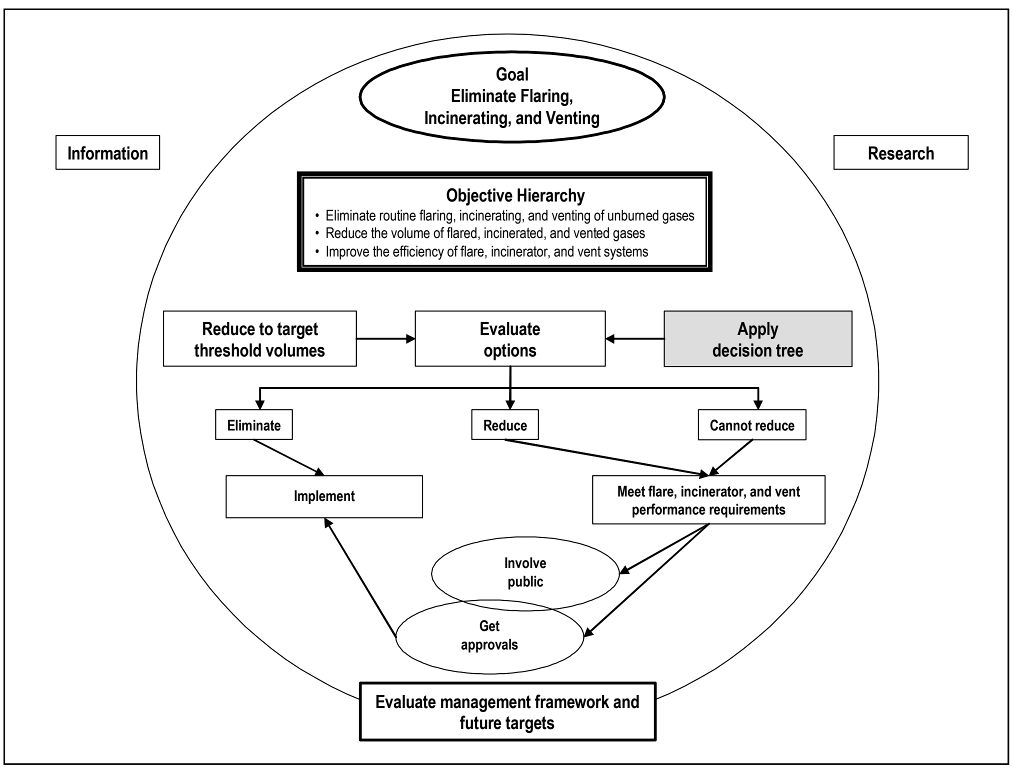

Figure 1.1: Gas Flaring/Venting Management Framework (adapted from CASA)

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?

New requirements have been incorporated into this guideline to reduce the impacts associated with flaring and venting near populated areas.

2 Solution Gas Management - Crude Oil Battery 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 solution gas for sale, for use as fuel for production facilities, for other useful purposes (e.g. power generation) or for beneficial injection into an oil or gas pool (e.g., pressure maintenance, enhanced oil recovery). Conservation opportunities are evaluated as economic or uneconomic based on the criteria listed in Section 2.9.

2.1 Solution Gas Flaring Reduction Targets

Since 1996, a significant reduction in flaring has been accomplished by the upstream petroleum industry, based on flaring data reported to the Commission and other provincial agencies. The BC Energy Plan[3] set a goal of 50 per cent reduction in routine associated gas flaring by 2011 with complete elimination by 2016. Consistent with this plan, this guideline incorporates requirements to move towards this goal.

2.2 Solution Gas Venting Reduction

The Commission does not consider venting as an acceptable alternative to flaring. If gas volumes are sufficient to sustain stable combustions, the gas must be burned or conserved (see Section 8.1). If venting is the only feasible alternative, it must meet the requirements set out in Section 8.

[3] The BC Energy Plan can be found at http://energyplan.gov.bc.ca. Look under Oil & Gas for the flaring goals.

2.3 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 2.1), as recommended by CASA. Permit holders must apply the decision tree to all flares and vents greater than 900m^3/day and be able to demonstrate how each element of the decision tree was considered and, where appropriate, implemented.

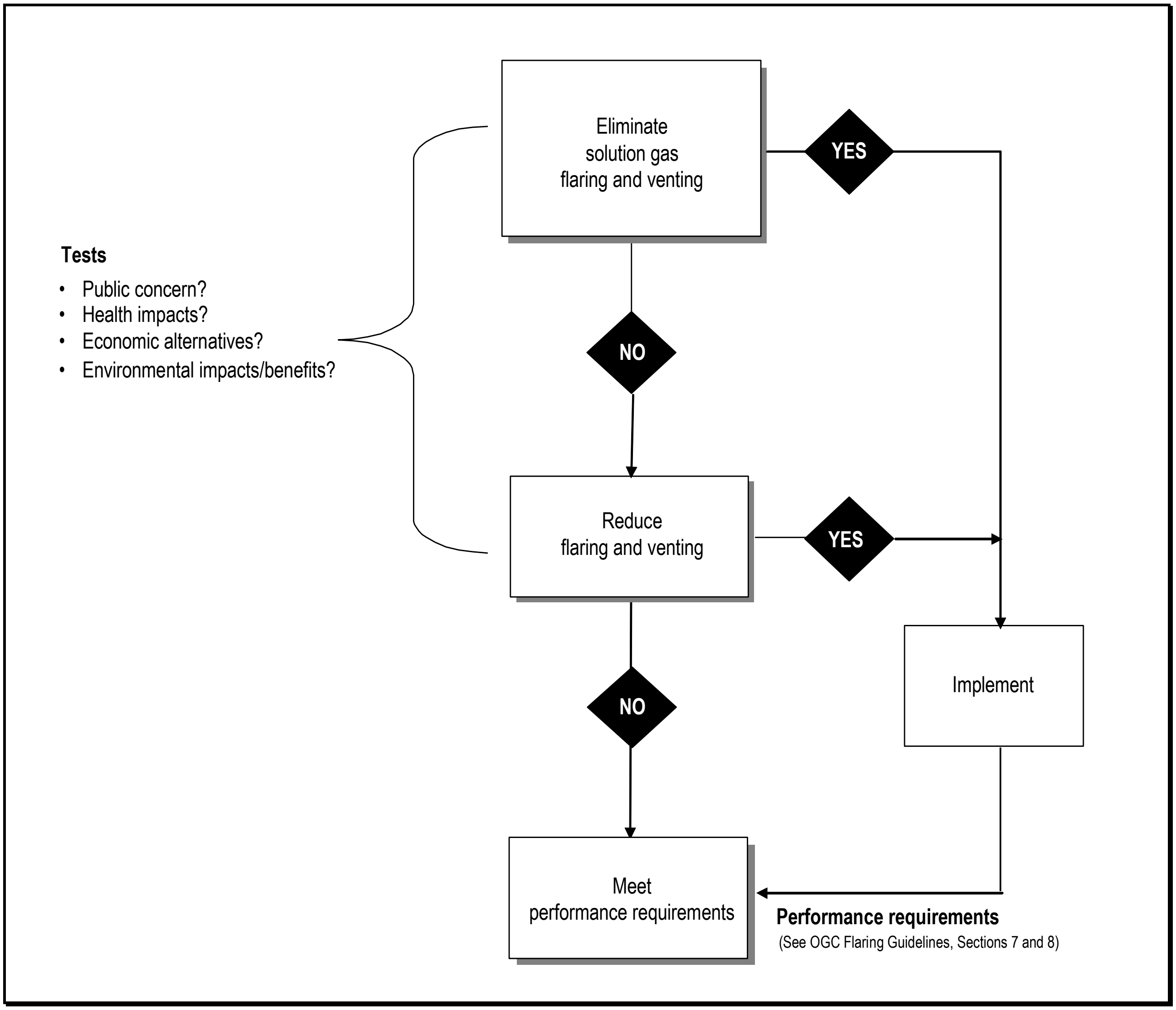

Figure 2.1: Solution Gas Flaring/Venting Decision Tree (adapted from CASA)

2.4 Conservation at New Oil Batteries

In general for new oil sites[4], 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 Section 3.3 for further details and extensions to time limits).

The Commission expects that conservation will be implemented at all new oil batteries, however, sites where conservation is not economic (as evaluated in accordance with Section 2.9) or practical may be approved by the Commission on a site by site basis.

If gas is not conserved at a new oil battery and the flare is expected to be visible from a populated area, the use of incineration must be considered during the facility application process (see Section 10).

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

2.5 Conservation of Existing Oil Batteries

These requirements apply to all existing oil batteries unless otherwise specified.

1) Permit holders must conserve solution gas at all sites where:
    a. Combined flaring and venting volumes are greater than 900 m^3/day per site[5] and the decision tree process and economic evaluation (section 2.9) result in a net present value (NPV) of greater than -C$50,000
    b. The gas to oil ratio (GOR) is greater than 3000 m^3/m^3. All wells producing with a GOR greater than 3000 m^3/m^3 at any time during the life of the well must be shut-in until the gas is conserved or
    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 metres of an existing solution gas flare after the effective date of this guideline, permit holders should provide information about the flaring operation to the new residents
2) For any sites flaring or venting combined volumes greater than 900 m^3/day and not conserving, a review of conservation economics must be done at least once every 12 months using the criteria in Section 2.9.
3) The Commission may still require economic evaluations for sites flaring or venting combined volumes less that 900 m^3/day and not conserving on a case-by-case basis if it is believed that conservation may be feasible.
4) Conserving facilities must be designed for 95 per cent conservation with a minimum operating level of 90 per cent.

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

5) Permit holders may apply to discontinue conservation if annual operating expenses exceed annual revenue. See Section 2.5(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 residents within 500 metres of the facility and the Commission Pipelines and Facilities Department of their intentions to discontinue conservation and initiate flaring or venting at a site and
    d. Comply with Table 2.1 in the event conservation facilities are not operational until Commission approval to discontinue conservation is granted

2.6 Clustering

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 (section 2.9) are enhanced if conservation is incorporated into the initial planning of larger multi-well projects.

1) Permit holders of production facilities within 3 kilometres (km) of each other or other appropriate oil and gas facilities (including pipelines) must 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 must assess conservation on a project or development area basis regardless of distance. Evaluations must address all potential gas vent and flare sources associated with the multi-well development.

   a. Permit holders must 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 must include a summary of the gas conservation evaluation and a description of the permit holder's related project plans

2.7 Power Generation

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

Approval of electrical power plants by the B.C. Ministry of Environment (MoE) is required under the Environmental Management Act for power plants greater than 5MW.

2.8 Consultation and Notification

Public consultation and notification requirements for flaring activities are done prior to the submission of well or facility permit applications. The Consultation and Notification Manual describes the consultation and notification process for permit applications.

2.9 Economic Evaluation of Gas Conservation

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

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

2.9.1 Economic Evaluation Criteria

Economic evaluations of gas conservation must use the criteria listed below. The permit holder must consider the most economically feasible option in providing detailed economics. Specific Commission economic evaluation submission requirements are listed in Section 2.9.2.

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

1) Evaluations must be completed on a before-tax basis.
2) Price forecasts used in the evaluation of gas conservation projects (gas gathered, processed, and sold to market) must use the most recent Sproule Associates Limited *Natural Gas Price Forecasts*, *Various Trading Points* table. Natural gas prices must be obtained from the “BC West Coast – Station 2” column ($Cdn/MMBtu). Condensate prices must be obtained from the *Natural Gas Liquids Price Forecasts and Inflation and Exchange Rates* table in the “Edmonton Pentanes Plus” column ($Cdn/bbl).

3) Price forecasts for power generation projects must reflect the price offered in the most recent BC Hydro energy call. The power price must 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 must have information to support the remaining reserves calculation and the production forecast (including planned drilling programs and pressure maintenance schemes).
5) Permit holders must have a detailed breakdown of capital costs showing equipment, material, installation, and engineering costs. Capital costs must be approved-for-expenditure quality numbers and must be based on selection of appropriate technology. Any capital costs incurred prior to the initiation of the project (sunk costs) must 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 must be considered in the conservation economic evaluation and subtracted from the overall cost of the conservation infrastructure in evaluating the economics of solution gas tie-in
    b. Salvage value of gas conservation infrastructure must be included as project revenue in the year the value would be realized (e.g., transfer of a gas compressor from one conservation project at the end of that project's life to another conservation project). The salvage value must be a reasonable market value estimate of the equipment and not a depreciated value from a taxation perspective
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 (H_2S) 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 must 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 must 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 must 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. If this evaluation results in an NPV equal to or greater than C$50,000 the permit holder must proceed with the conservation project.

11) A gas conservation project is considered economic, and the gas must be conserved, if the economics of gas conservation generates an NPV before-tax greater than C$50,000.

   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 Section 2.5(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 C$50,000 and is therefore considered uneconomic on its initial evaluation, the project economics must be re-evaluated annually using updated prices, costs and forecasts.

2.9.2 Economic Evaluation Audit Requirements

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

- Detailed capital and operating cost schedule as set out in Sections 2.9.1(5) and 2.9.1(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

2.10 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.

2.10.1 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 2.1, below.
2) Table 2.1 does not apply to non-associated gas (the percentage cutbacks listed in Table 2.1 apply to solution gas only). All non-associated gas must be shut-in during facility outages.
3) Permit holders must notify as required in Section 6.
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 GOR 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.
    a. 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 2.1.

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 Section 8.
Planned	< 4 hours	Permit holders must make all reasonable efforts[1] 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: • Solution gas must not be flared from wells that have an H_2S 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 Section 6.
Emergency[2] or	< 4 hours	No reduction in plant inlet is required.
Plant upset	> 4 hours	Permit holders must reduce battery or solution gas plant inlet gas volumes by 75% of average daily solution gas production over the preceding 30-day period and must meet the following requirements: • Solution gas must not be flared from wells that have an 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 Section 6.
Repeat non-routine flaring[3]		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.

1 Notwithstanding solution gas reduction requirements listed in Table 2.1, if a sour or acid gas flare or incinerator stack is not designed to meet the one-hour BC *Air Quality Objectives and Standards* for sulphur dioxide (SO_2) under high flow rate conditions, action must be taken immediately to reduce gas to a rate compliant with BC's *Air Quality Objectives and Standards* (see Section 7).

2 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.

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

Table 2.1: Requirements for non-routine flaring and venting during solution gas conserving facility outage

2.10.2 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 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

2.10.3 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 be done only if the permit holder can demonstrate that shutting in a well or group of wells may cause damage to well equipment or permanent reduction in productivity or if shutting in is impractical due to the remoteness of facilities. In these special cases, the permit holder must consult with the Commission about alternatives to shut-in for a particular gas plant or battery.

Permit holders must plan for outages. If an alternative to Table 2.1 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 must submit the written request to the Commission a minimum of 30 days prior to a planned shutdown.

2.11 Solution Gas Reporting Requirements and Data Access

2.11.1 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 Section 11. Permit holders must report all new oil well production, including the test period, and obtain a battery code for any new oil wells before production, including flaring, can be reported.

2.11.2 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.

2.11.3 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 Section 2.6).

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.

3 Well Flaring

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

See Section 8 for temporary venting requirements. 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 Section 8.

3.1 Temporary Flaring Decision Tree

Permit holders must use the Temporary Flaring Decision Tree Process (Figure 3.1) to evaluate all opportunities to eliminate or reduce flaring, regardless of volume.

Click on the diagram to expand the view.

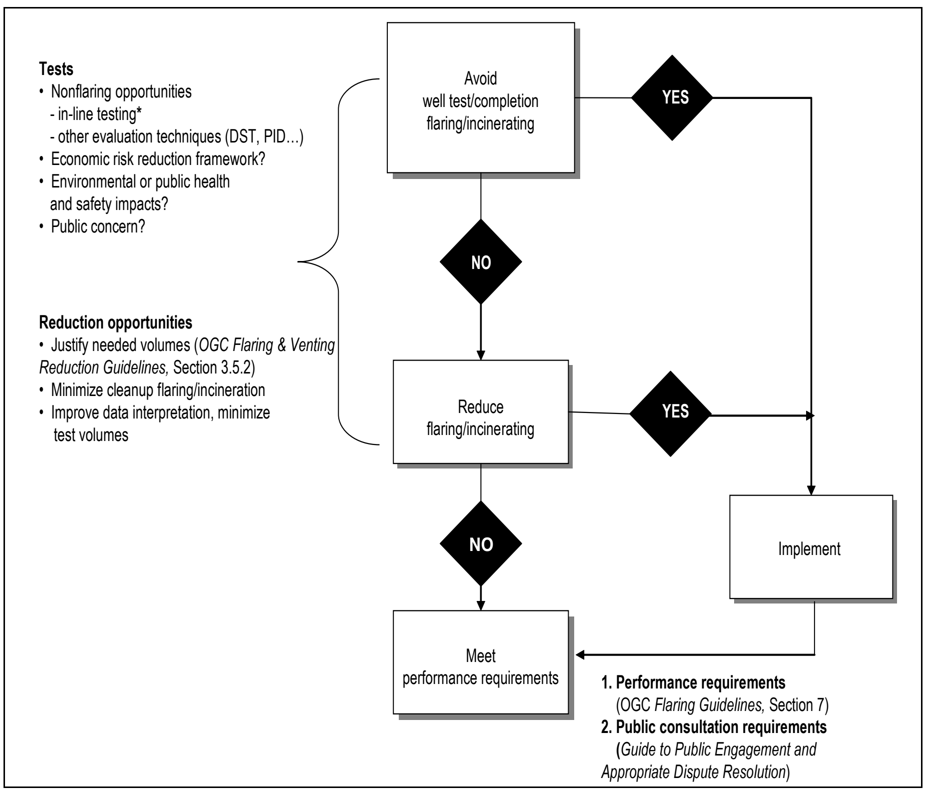

Figure 3.1: Temporary Flaring Decision Tree (adapted from CASA)

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 three 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 Resource Conservation Department, 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.

3.2 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 Section 10) 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.

3.3 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/sites[6]: 72 hours
b. gas (non-coalbed methane): 72 hours
c. dry coalbed methane development wells (producing less than 1 m^3 of water per operating day): 120 hours
d. dry coalbed methane non-development wells (producing less than 1 m^3 of water per operating day): 336 hours
e. wet coalbed methane wells (producing more than 1 m^3 of water per operating day): see Section 3.3(5) below
f. shale gas development wells: 120 hours
g. shale gas non-development wells: 336 hours

2) Extensions to the time limits listed in 1 (a), (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 (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 (a), (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 m^3 of water per operating day), flaring or venting must cease (gas must be conserved) within 6 months of gas production for an individual well exceeding a cumulative total of 100

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

10^3 m^3 for any consecutive 3-month period (about 1100 m^3/day). Shorter tie-in periods must be pursued whenever possible.

a. Permit holders must notify the Commission as soon as the cumulative total gas production exceeds 100 103 m3 for any consecutive 3-month period as at a wet coalbed methane well that is flaring or venting.

b. For wet coalbed methane wells that do not trigger the requirement above (100 103 m3 in 3 months), flaring and venting are limited to a total period of 18 months, including the time to tie in the well.

3.4 Temporary Flaring Approval

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

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

Approval to flare may be requested at the time of well permit application or by amending a well permit. Refer to the Well Permit Application Manual for the permit application and amendment processes.

As a transitional measure, flaring for the purposes of cleanup and testing during initial completion of a well is authorized wells approved prior to October 4, 2010 as follows:

- The maximum volume of flared gas for development wells is 400 10^3 m^3
- The maximum volume of flared gas for exploratory wells is 600 10^3 m^3
- Approval to flare in excess of the above thresholds may be granted by amendment of the well permit

3.4.1 Guidelines for Flaring Requests

Information requirements apply to all requests to flare.

1) Permit holders must provide specific engineering, economic, and operational information to justify reasons for the requested flared volume if the requested flared volume exceeds the following thresholds:
    a. 600 103m3 for wells that have not been tied in and have an exploratory classification.
    b. 400 10^3m^3 for wells that have not been tied in and have a development classification.
    c. 200 10^3m^3 for wells that have been tied into facilities appropriately designed to handle production from the well.
    d. 200 10^3m^3 for each additional segregated zone in the well.
2) In general, the following circumstances are not justification for the approval of extended flaring volumes:
    a. Multiple well tests for wells at the same location that are completed n the same zone. Multiple tests may be justifiable during the early stages of a new play or for experimental reasons.
    b. Flaring due to delay of a tie-in unless the well is required to enable start-up of a facility.
3) Requests relating to tests to determine if sufficient gas supply exists to justify related investments must include information on the scope of development required to produce the well and necessary threshold reserves. See Appendix 3.

Note: Conventional well evaluation techniques may not be relevant for the testing of unconventional wells (i.e. shale gas). For example, attempts to reach a stabilized flow rate.

1) Requests relating to tests to determine the relationship between absolute open flow (AOF) and deliverability of the well must include justification of the volume being requested as it pertains to obtaining an accurate deliverability relationship, in accordance with the Commission well testing requirements.
2) Requests relating to tests to establish the stabilized flow rate of the well must include justification of the flare volume

request as it pertains to obtaining a stabilized flow rate, including the identification of any analogous well(s) being used for comparison purposes.

3) If relevant, equipment to be used during the flaring operation (flare stack or incinerator and stack height).

3.4.2 Commission Review of Approval Requests

Requested volumes, rates, and/or conditions may not be granted by the Commission. 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 before a decision is rendered.

3.5 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 H_2S. See Section 7.5.3 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 H_2S and < 5 mole percent H_2S, 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 H_2S, permit holders must submit the dispersion modelling to the Commission in accordance with section 6(1)(d) of the Oil and Gas Waste Regulation.
5) 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.

3.6 Site-Specific Requirements Related to Well Flaring

1) Flares and incinerators must comply with design and operation requirements defined in Section 7.
2) Flares and incinerators must not be operated outside design operating ranges as specified by a professional engineer registered with APEGBC.
3) Permit holders must determine the H_2S content of flared or incinerated gas using Tutweiller or gas chromatography methods as soon as practical after commencement of operation if gas analysis has not been obtained within the preceding 12 months.
4) If the H_2S content in the gas is found to exceed 5 mole percent H_2S and dispersion modelling was not submitted with flaring application, or if the H_2S content of the gas exceeds the maximum value listed in the related permit conditions, operations must be suspended until the Commission has approved the resumption of operations.
5) Both high and low-pressure gas-liquid separation stages must be used for sour gas to minimize vapour released from produced hydrocarbon liquid and sour water storage.
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 4-2000/02: 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 Pipelines and Facilities Manual.
8) For compliance purposes, flaring commences when there is burnable gas at surface. The total flared volume does not include completion fluid (i.e. CO_2) that is flowed back from the well or fuel gas that is added to improve the heating value of the flared gas.

3.7 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 both the pipeline and facility permit application manuals for application requirements.

Applications for conservation projects will be given priority treatment by the Commission.

3.8 Notification Requirements

Prior to flaring, permit holders must notify the Commission and all residents and administrators of incorporated centres in accordance with Section 6.

3.9 Reported Flared Volumes

Flared volumes must be reported to the Commission online drilling reporting system within 60 days of the completion of flaring.

Well test results must be submitted in accordance with the requirements of Section 60(2) 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 Resource Conservation Department.

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 by phone: 1-800-667-1182.

4 Natural Gas Facility Flaring and Venting

This section addresses flaring and venting at natural gas facilities (includes processing plants, compressor stations and dehydrator facilities).

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

Permit holders must use the decision tree analysis shown in Figure 4.1 to evaluate all new and existing facility flaring and venting regardless of volume except for intermittent small sources (less than 100 m^3 per month), such as pig trap depressuring. Subject to safety and environmental considerations, permit holders must conserve all gas that is economic to conserve (the net present value of conservation is positive).

Click on the diagram to expand the view.

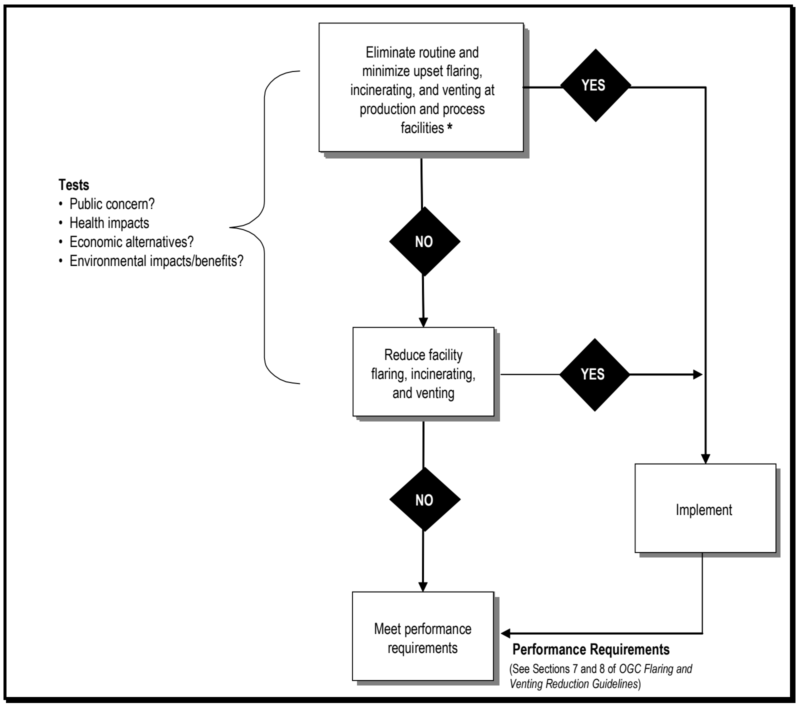

Figure 4.1: Facility flaring and venting decision tree (adapted from CASA)

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 Sections 7 and 8, 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 Section 10).

4.2 Measurement

1) Flare measurement and estimation at existing facilities must be in accordance with Section 11 of this guide.
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 Section 11, a flare meter is required at all new gas processing plants and gas compressor stations that have an inlet capacity ≥ 300 10^3 m^3/day.

The Commission may require flare meter installation at existing facilities that are undergoing significant modification. The Commission may consider alternatives to flare meter installation at the time of permit application.

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.

4.3 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 Section 6.

4.4 Reporting

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.

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.

Gas burned in an incinerator must be reported as flared. Fuel gas burned in an incinerator must be reported as fuel gas.

Gas flared or vented at gas facilities must be reported at the location where the flaring or venting took place.

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 – identified in Section 7.1.1

4.5 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 must 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 4.1.

Approved inlet capacity	Major flaring event definition*
>500 10^3 m^3/d	100 10^3 m^3 or more
150 – 500 10^3 m^3/d	20% of design daily inlet or more
< 150 10^3 m^3/d	30 10^3 m^3 or more
*The definition of a flaring event includes situations where: 1) volumes greater than or equal to those specified in the table are flared in any single day; each day that specified flared volumes are exceeded is considered to be a separate, individual event; or 2) volumes greater than or equal to those specified in the table are flared in one contiguous period spanning more than one day (for example, flaring for four days at a continuous rate of 25 10^3 m^3/d is considered one event).	

Table 4.1: Major Flaring Event Definition

Permit holders must log and monitor non-routine flaring events, as required in Section 11.4.

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 a written exceedence report to the Commission Pipelines and Facilities Department within 30 days of the occurrence of the sixth flaring event.

Written Exceedence 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 exceedence of the 6-in-6 criterion occurs within 24 month

5 Pipeline Flaring and Venting

This section 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 depressuring for maintenance, process upsets or emergency depressuring for safety reasons.

5.1 Pipeline Systems Flaring and Venting Decision Tree

Permit holders should use the decision tree analysis shown in Figure 5.1 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 depressuring of pipeline systems.

Flaring or incinerating of gas from sweet natural gas transmission pipeline depressuring may not be practical when impacts on system customers and producers are considered. In such situations, the Commission Pipeline and Facilities Department may allow venting of gas to reduce the duration of system outages and related impacts.

Click on the diagram to expand the view.

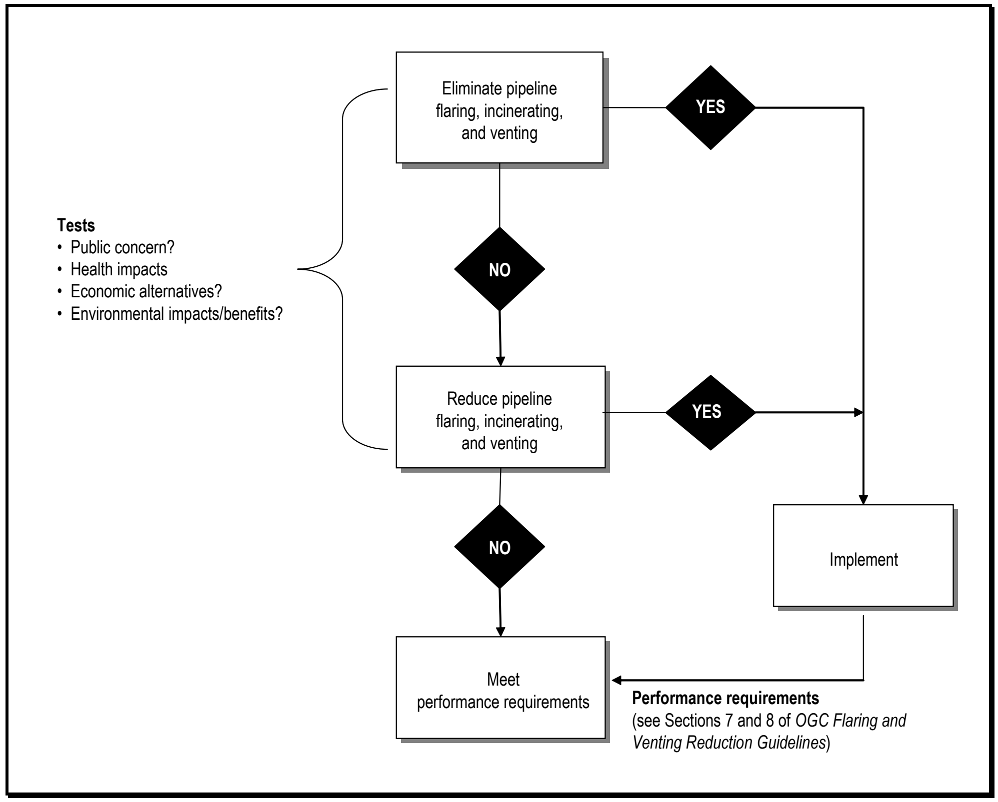

Figure 5.1: Pipeline Flaring and Venting Decision Tree (adapted from CASA)

5.2 Notification and Reporting

All monthly flared 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.

Notification requirements described in Section 6 apply.

6 Notification Requirements

Permit holders must notify the Commission and all residents and administrators of incorporated centres located within the notification radius that flaring, incinerating or venting will occur (Table 6.1).

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

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

Table 6.1: Notification Requirements

6.1 Notification of Residents and Administrators of Incorporated Areas

1) Notification must be given a minimum of 24 hours prior to commencement of planned flaring events and within 24 hours of unplanned flaring events.
2) Permit holders should consult with residents and administrators of incorporated centres to develop and implement a notification process that is mutually acceptable.
3) If a mutually acceptable notification process has not been implemented, notification must be in writing and include the following minimum information:
    a. Company name, contact persons and telephone numbers;
    b. Location of the flaring;
    c. Duration of the event;
    d. Expected volume and rate;

e. Information on the type of well (oil or gas) and information on H_2S content; and,

f. 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.

6.2 Notification of the Commission

Notification must be given a minimum of 24 hours prior to commencement of planned 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 online drilling reporting system.

For flaring at Pipelines and Facilities, permit holders must notify the Commission Pipelines and Facilities Department by email.

7 Performance Requirements

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, but is not intended as a comprehensive design manual.

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 section, some requirements are specific to the type of equipment used and this is specified in each requirement.

1) Permit holders must ensure that a professional engineer registered with APEGBC 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 registered with APEGBC. If this equipment is used for emergency shutdowns, this must be considered in the design.

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

   a. Field testing of newly designed equipment is not allowed unless there are acceptable and redundant combustion systems to ensure that any sweet, sour, or acid gas can be properly combusted if the new equipment fails to perform as predicted or the ability exits to shut-in if problems arise.

4) The Drilling and Production Regulation, API-RP-521: Guide for Pressure-Relieving and Depressuring Systems, Section 4: Selection of Disposal 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 comply with the noise limits established in the British Columbia Noise Control Best Practices Guideline. Temporary flare stacks and incinerators should comply with the intent of the Guideline.

7.1 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, or
   b. 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.

7.1.1 Heating Value and Exit Velocity for Flares

If a flare is subject to a permit under the Environmental Management Act or the Oil and Gas Activities Act and a minimum heating value has been assigned in the permit, the minimum heating value specified within the permit shall continue to apply.

1) The combined net or lower heating value of gas, including make-up fuel gas, directed to a flare must not be less than 20 megajoules per cubic meter (MJ/m^3), except as noted below:
    a. If existing stacks have an established history of stable operation and compliance with the BC *Air Quality Objectives and Standards*, (permit holders are expected to support claims that existing stacks have operated satisfactorily over time), permit holders are allowed to maintain the current heating value provide that it is not less than 12 MJ/m^3.
    b. If flare stacks have a history of flame failure, odour complaints, and/or of exceeding the BC *Air Quality Objectives and Standards*, permit holders must operate with a combined flare gas heating value of not less than 20 MJ/m^3.
2) If fuel make-up is required, it must be specified for flare stacks by a professional engineer registered with APEGBC.
    a. Equipment controls must be installed and operating procedures must 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.

7.2 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

7.3 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

Under Section 47 of the Drilling and Production Regulation, a permit holder must ensure that flares, incinerators, and enclosed gas burners are located at least 80 m from any public road, public utility, building, installation, works place of public concourse or any reservation for national defence;

Refer to the Well Completions Manual and the Pipelines and Facilities manual for more information on spacing requirements.

7.4 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 exceedence of the BC *Air Quality Objectives and Standards*.
- Gas containing more than 1 mole percent H_2S must not be flared in pits.

- Permit holders must conduct evaluations of solution gas flares for flare pits as described in Section 2 and implement the resulting decision.
- Access restrictions and procedures must be in place in areas around flare pits where ground-level radiant heat intensity at maximum flare rates will exceed 4.73 kW/m^2.

7.5 Dispersion Modelling Requirements

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

- Permit holders must demonstrate that SO_2 and H_2S emissions from burning of sour and acid gas will not result in unacceptable air quality impacts using the dispersion modelling methods outlined in this section if the gas contains ≥ 1 mole percent H_2S.
- Permit holders combusting gas below the above concentrations are encouraged to consider dispersion modelling as part of environmental considerations. Facilities requiring approval from the Commission may require more detailed evaluation. Permit holders should consult the Commission directly in these circumstances.

7.5.1 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.

7.5.2 Facility Modelling

These requirements apply to the combustion of gas containing ≥ 1 mole percent H_2S in low pressure flares or incinerators located at production facilities.

For the purposes of screening, modelling Alberta's *EUBflare.xls and EUBincin.xls* may be used. Based on the results of screening modelling, more detailed modelling may be required. Contact the Commission Waste Management and Reclamation Department for details. Results of modelling must be made available on request.

7.5.3 Well Test Modelling

Initial modeling may be conducted using the screening assessment provided in the EUBflare.xls and EUBincin.xls spreadsheets when evaluating well test flares with sour gas content greater than or equal to 1 mole percent H_2S, but less than 5 mole percent H_2S.

Well test flares with sour gas content greater than or equal to 5 mole percent H_2S must be modeled in accordance with the Ministry of Environment Guidelines for Air Quality Dispersion Modelling in British Columbia.

If any post-test remodelling, monitoring or assessment reports are required, they must be submitted to the Commission Drilling and Production Department.

8 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.

8.1 General Requirements

- All continuous and temporary venting must be evaluated using the decision tree in the appropriate sections of this guideline.
- 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.

8.2 Limitations of Venting Gas Containing H_2S or Other Odorous Compounds

The Commission recommends that permit holders eliminate the venting of gas containing hydrogen sulphide. Wells drilled and facilities constructed after September 1, 2010 must not use gas containing hydrogen sulphide for instrumentation or to provide motive force for pumps unless exempted by the Commission.

The Commission recommends any pressure safety valves (PSVs) or blowdown systems be connected to a flare system where such systems are installed.

8.3 Limitations of Venting Gas Containing Benzene

In order to reduce and manage benzene emissions from glycol dehydrators in British Columbia, permit holders must comply with the following requirements, effective June 30, 2007:

1) When evaluating dehydration requirements in order to achieve the lowest possible benzene emission levels, permit holders must use the decision tree process in Appendix A of the Best Management Practices for Control

of Benzene Emissions from Glycol Dehydrators, June 2006 (Benzene Control BMP), and retain appropriate analysis documentation for review by the Commission.

2) The permit holder must follow the public consultation process outlined in the Benzene Control BMP.

3) Permit holders must ensure that all dehydrators meet the following benzene emissions limits:

    a. If more than one dehydrator is located at a facility or lease site, the cumulative benzene emissions for all dehydrators must not exceed the limit of the oldest dehydrator on site. Modifications may be required to existing units to meet the site limit.

    b. Any new or relocated dehydrators added to an existing site with dehydrators must operate at a maximum benzene emission limit of 1 tonne/yr or less. The cumulative benzene emissions must not exceed the limit of the oldest dehydrator on site.

    c. For dehydrators that are only in operation for a portion of the year, the benzene emission rate must be prorated.

4) Permit holders must complete a DEOS (Dehydrator Engineering and Operations Sheet), located in Appendix B of the Benzene Control BMP, to determine the benzene emissions from each dehydrator. The sheet must be posted at the dehydrator for use by operations staff and inspected by the Commission. The DEOS must be revised once each calendar year or upon change in operation status of a dehydrator.

5) Permit holders must complete and submit an annual Dehydrator Benzene Inventory List by email in accordance with Section 12 of the Benzene Control BMP.

Date of Installation or Relocation	Benzene Emissions Limit
Prior to January 1, 1999	
a) Greater than 750 m to the nearest permanent resident or public facility	5 tonnes/yr
b) Less than 750 m to the nearest permanent resident or public facility	3 tonnes/yr
January 1, 1999 to June 30, 2007	3 tonnes/yr
After June 30, 2007	1 tonne/yr

Table 8.1: Date of Installation or Relocation

8.4 Venting of Non-combustible Gas Mixtures

Release of inert gases such as nitrogen and carbon dioxide (CO_2) from upstream petroleum industry equipment or produced from wells may not have sufficient heating value to support combustion. These gases can be vented to atmosphere subject to the following requirement:

Non-combustible gas mixtures containing odorous compounds including H_2S must not be vented to the atmosphere if off-lease odours may result. Alternatives to venting such gas include flaring or incinerating with sufficient fuel gas to ensure destruction of odorous compounds or underground disposal.

8.5 Surface Casing Vents

Refer to the Well Completion Maintenance and Abandonment Guideline.

8.6 Fugitive Emissions Management

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

These programs must meet or exceed the CAPP Best Management Practice for Fugitive Emissions Management.

Permit holders must use pressurized tank trucks or trucks with suitable and functional emission controls when transporting sour fluids from upstream petroleum industry facilities.

9 Sulphur Recovery Requirements

Some facilities may have significant sulphur emissions originating from combustion of sour solution 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.

10 Incineration Evaluation

Where incinerator evaluation is required, decisions to use an incinerator or a flare stack must 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

11 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 Requirements for Upstream Oil and Gas Operations Manual
- Ministry of Finance Oil and Gas Royalty Handbook
- Drilling and Production Regulation

1) Permit holders of oil and natural gas production and processing facilities must report volumes of gas greater than or equal to 0.1 10^3 m^3/month (adjusted to 101.325 kPa(a) and 15ºC) 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. This does not include fuel gas added to flare or incinerator streams in order to meet minimum heating value requirements.
3) Fugitive emissions are NOT to be reported as flared or vented gas as they are considered part of shrinkage.
4) Permit holders must be able to demonstrate that volumes of gas are determined in an accurate and reliable manner. Permit holders must have written documentation detailing the methodology used to determine flared, incinerated and vented volumes for each of their well, pipelines and facilities and that documentation must be readily available for review by an official.
5) 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 10^3 m^3/d on an annual average.

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

11.1 Metering Requirements and Guidelines

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

continuous or non-routine flare and vent sources at all oil and gas production and processing facilities where annual average total flared, incinerated and vented volumes per facility exceed 0.5 10^3 m^3/day (excluding dilution gas);

if all solution gas is flared or vented from production facilities, the measured produced gas (less any fuel gas use) may be used to report volumes flared or vented; in such situations, specific flare or vent gas meters are not required;

acid gas flared, either continuously or in emergencies, from gas sweetening systems regardless of volume; and

any fuel gas added to acid gas to meet minimum heating value requirements or ground level ambient air concentrations where the annual average flow rate exceeds 0.5 10^3 m^3/d.

Chapter 2 of the Measurement Requirements for Upstream Oil and Gas Operations Manual provides details regarding calibration and proving of measurement devices. Measurement uncertainty of the measured volumes must meet the criteria in Table 11.1 below (extracted from the Measurement Requirements for upstream Oil and Gas Operations Manual).

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	10%	10%

Table 11.1: 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.

11.2 Estimating Requirements

The Commission will accept estimates of flared, incinerated, and vented gas if measurement is not stated as a requirement in Section 11.1 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 10^3 m^3/month) during routine, emergency and maintenance operations, including depressurizing of vessels, compressors and pipelines.

    b. Volume estimates must be based on engineering calculations and be shown to meet the uncertainty requirements specified in Table 11.1.

   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 Section 11.4), for review by the Commission upon request.

   a. 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.

3) 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.

11.3 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 a gas plant
- BC-S2 form – flaring from all other facilities, compressors, pipelines, and gas gathering systems
- When well test flaring is in excess of 50 mol/kmol H_2S (5%), permit holders must complete a Data Confirmation for Flaring Approval Registration and file the report with the Director at the Ministry of Environment in Fort St. John within 30 days of the last day of flaring at the site.

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.

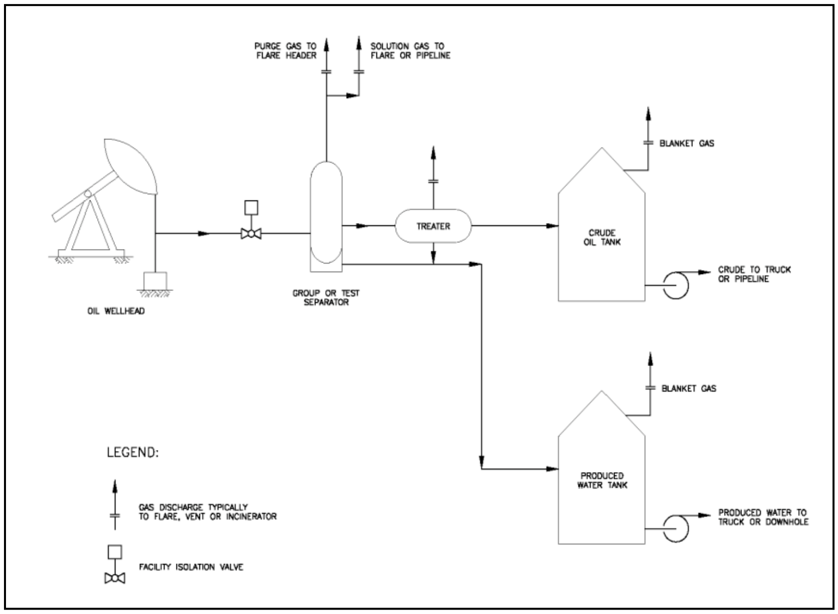

Figure 11.1: Reportable Flaring Streams – Upstream Oil Battery

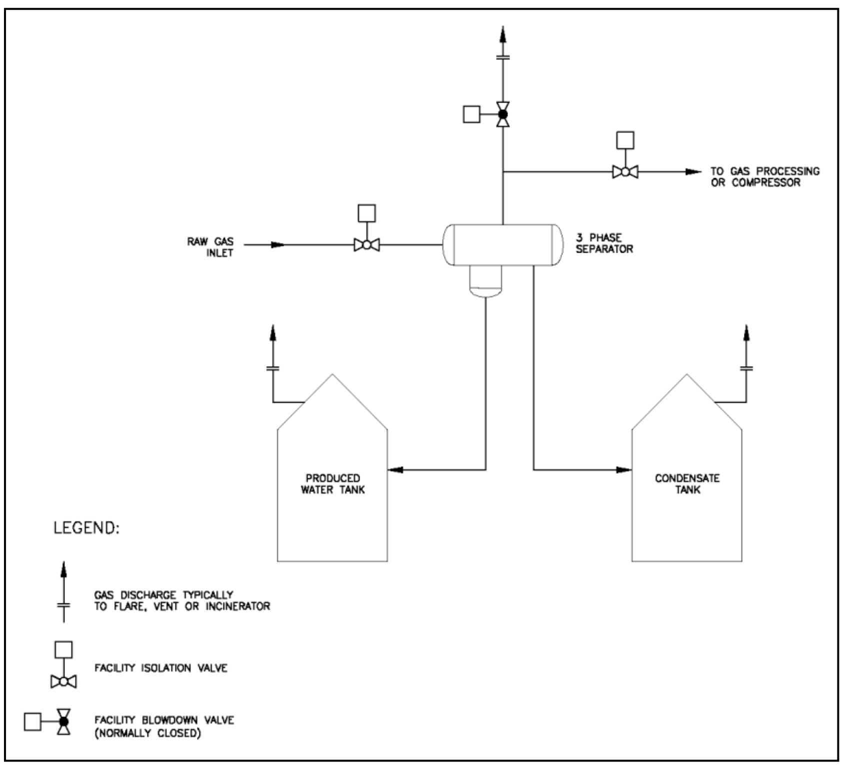

Figure 11.2: Reportable Flaring Streams – Inlet Separation Facility

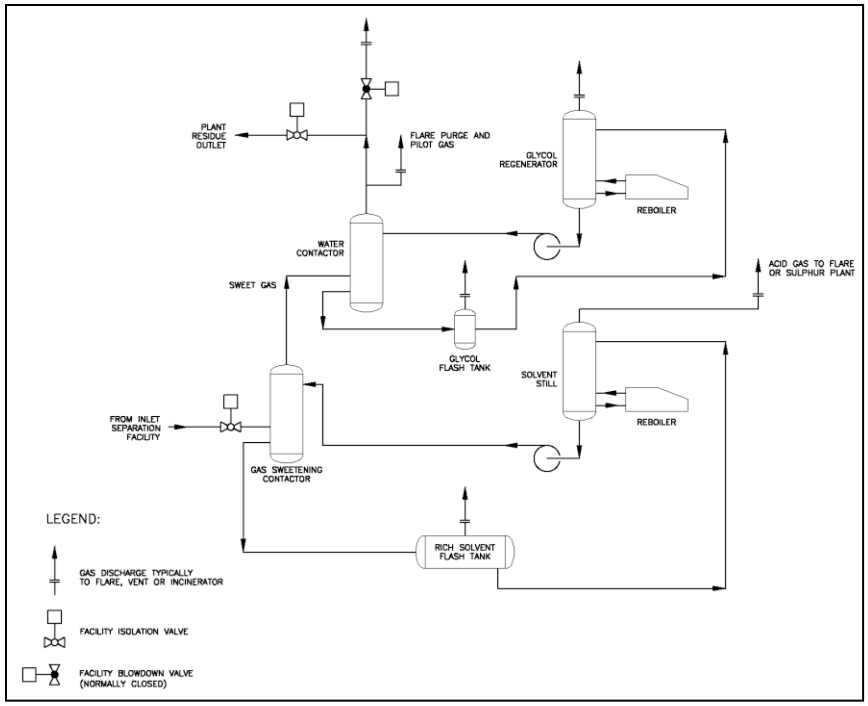

Figure 11.3: Reportable Flaring Streams – Gas Processing Plant

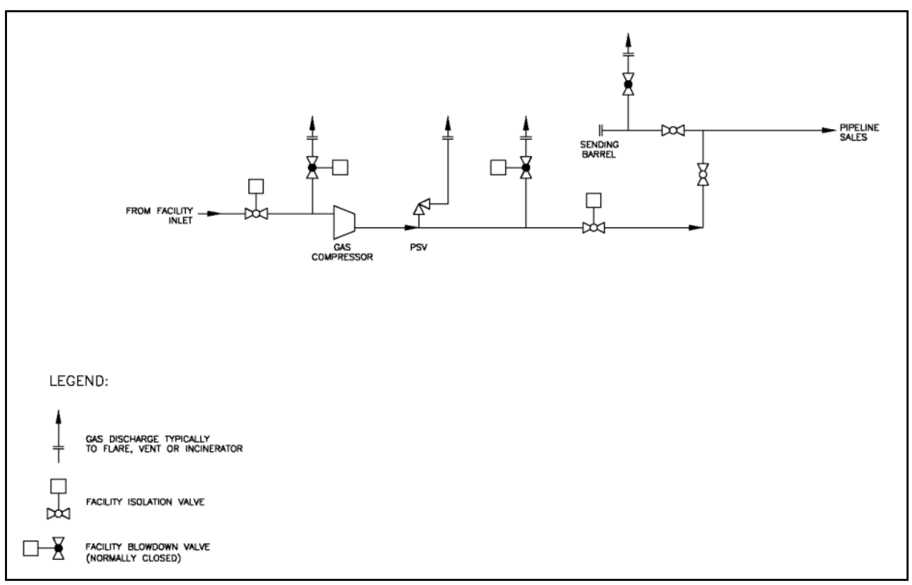

Figure 11.4: Reportable Flaring Streams – Gas Compression Facility

11.4 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.

Appendix 1: Definitions of Terms as Used in the Guideline

TERM	DEFINITION
Acid gas	Gas that is separated in the treating of natural gas that contains hydrogen sulphide (H_2S), total reduced sulphur compounds, and/or carbon dioxide (CO_2).
Associated gas	Gas that is produced from an oil reservoir. This may apply to gas produced from a gas cap or in conjunction with oil.
Clustering	Clustering is defined as the practice of gathering the solution gas from several flares or vents at a common point for conservation.
Combustion Efficiency (CE)	The CE quantifies the effectiveness of a device to fully oxidize a fuel. Products of complete combustion (i.e., CO_2, H_2O and sulphur dioxide [SO_2]) result in all of the chemical energy released as heat. Products of incomplete combustion (e.g., CO, unburned hydrocarbons, other partially oxidized carbon compounds, H_2S, and other reduced and partially oxidized sulphur compounds) reduce the amount of energy released. For the purposes of this guideline, CE is reported as the percentage of the net heating value that is released as heat through combustion.
Conservation	The recovery of solution gas for use as fuel for production facilities, other useful purposes (e.g., power generation), sale, or beneficial injection into an oil or gas pool.
Conservation efficiency	Conservation efficiency (%) = (Solution gas production – Flared - Vented) / (Solution gas production) x 100
Conserving facility	Any potential tie-in point that is conserving gas, such as batteries, plants, compressor stations, pipelines, and pump stations.
Fugitive emissions	Unintentional releases of gas resulting from production, processing, transmission, storage, and delivery.
Gas production facility	A system or arrangement of tanks and other surface equipment (including interconnecting piping) that

TERM	DEFINITION
	receives the effluent from one or more wells that might provide measurement and separation, compression, dehydration, dew point control, H_2S scavenging, line heating, or other gas handling functions prior to delivery to market or other disposition.
Gas processing plant	A system or arrangement of equipment used for the extraction of H_2S, helium, ethane, natural gas liquids or other substances from raw gas.
Must	Indicates a requirement that an operator is legally required to meet.
Non-associated gas	Gas produced from a gas pool (i.e., not associated with oil or bitumen reservoirs with production).
Non-routine flaring, venting or incinerating	Intermittent and infrequent events such as well testing, planned maintenance, process upsets, and emergencies that result in flaring, venting or incinerating.
Oil battery	A system or arrangement of tanks or other surface equipment or devices receiving the effluent of one or more wells for the purpose of separation and measurement prior to the delivery to market or other disposition.
Recommended or recommends	Indicates that the procedure or practice described is a guideline that can be used by the applicable party but is not a regulatory requirement.
Refined assessment	This is a more complex and data-intensive level of dispersion modeling. Refined assessments more closely estimate actual air quality impacts by using site-specific meteorological data.
Required	The specified action or item is a minimum regulatory requirement.
Routine flaring, venting, incinerating	Continuous flaring, venting, and incinerating.
Screening assessment	This is the quickest and simplest dispersion modelling approach. Screening assessments usually provide a conservative (worst-case) estimate of downwind concentrations.
Solution gas	All gas that is separated from oil production (for the purposes

TERM	DEFINITION
	of this guideline).
Sour gas	Gas containing H_2S. Depending on H_2S concentrations, sour gas may pose a public safety hazard if released or may result in unacceptable off-lease odours if vented into the atmosphere.
Source	All gas flared, incinerated, or vented from a single operating site, such as an oil battery or multiple-well pad.
Sulphur emissions	For the purposes of this guideline, this includes all air emissions of sulphur-containing compounds, including SO_2, H_2S, and total reduced sulphur compounds (e.g., mercaptans). Sulphur emissions from flare stacks are expected to be primarily in the form of SO_2, with minor amounts of other compounds.
Venting	The release of uncombusted gas.

Appendix 2: Abbreviations

Abbreviation	Definition
$10^6 m^3$	Million cubic metres
$10^3 m^3$	Thousand cubic metres
AOF	Absolute open flow
APEGBC	Association of Professional Engineers and Geoscientists of BC
CAPP	Canadian Association of Petroleum Producers
CASA	Clean Air Strategic Alliance
CO_2	Carbon dioxide
CSA	Canadian Standards Association
D&PR	Drilling and Production Regulation
EMA	Environmental Management Act
ESDV	Emergency shutdown valve
GOR	Gas-to-oil ratio (gas:oil)
H_2S	Hydrogen sulphide
HLSD	High-level shutdown
km	Kilometre
kPa	Kilopascal
mol/kmol	Mole per kilomole
MJ	Megajoule
MJ/m^3	Megajoule per cubic metre
MW	Megawatt
NPV	Net present value
OGWR	Oil and Gas Waste Regulation
ppm	Parts per million
OGAA	Oil and gas Activities Act
PSV	Pressure safety valve
SO_2	Sulphur dioxide

Appendix 3: Information for Flaring Approval Requests

For well tests that are expected to exceed the volume allowance threshold, the request must include the following information:

- A brief description of the development required to bring the well onto production. For example, length and size of pipeline to tie in well, well site facilities, compression, gas processing facilities
- The minimum recoverable reserves required for the well to be economic (minimum economic reserves)
- Details of the analysis used to determine the minimum economic reserves (operators may use simplified “netback” economics showing the current operating profit [revenues minus operating costs] to estimate the recoverable reserves required to pay out facility investment costs. Alternatively, permit holders may choose to present a more detailed economic analysis involving features such as discounted gas flow projections);
- the estimated recovery factor and surface loss for the pool;
- the estimated initial reservoir pressure;
- the amount of reservoir depletion being targeted by the test (the operator must provide a brief description justifying this depletion in relation to the minimum economic reserve) – the recommended maximum pressure depletion guidelines **for conventional gas wells only** are:
    - 1per cent of the first 5000 kPa of reservoir pressure
    - 0.5 per cent of the reservoir pressure above 5000 kPa; (for example, a maximum depletion guideline of 100 kPa is targeted for a reservoir with an initial pressure of 15,000 kPa)
    - Justification for pre-test cleanup and servicing flaring or incinerating if related volumes exceed 200 103 m3

Note: an incremental volume of up to 200 10^3 m^3 may be added to the permit request in order to provide for pre-test cleanup and servicing operations if these are needed to establish the minimum economic reserve without additional justification.