Standard for Completing Greenhouse Gas Compliance Reports

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Disclaimer:	Part 1 of this Standard is adopted by the Specified Gas Emitters Regulation (AR 139/2007), under the authority of section 61 of the *Climate Change and Emissions Management Act*. Pursuant to section 3.1 of the Specified Gas Emitters Regulation, Part 1 of this Standard is enforceable as law. Part 2 of this Standard sets out additional requirements for persons responsible. Part 2 is not intended to have binding legal effect, but includes statements of policy to inform the application of Part 1. Part 2 of this Standard is not a substitute for the legal requirements. In addition to Part 1 of this Standard, a person responsible for a facility must comply with the Specified Gas Emitters Regulation and all applicable legislation. In the event there is a difference between Part 2 of this Standard and any applicable legislation or Part 1 of this Standard, the applicable legislation or Part 1 of this Standard prevails.

Summary of Revisions

Version	Date	Summary of Revisions
1.0	October 2017	New standard replacing previous guidance document published in January 2014.

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Alberta Climate Change Office Related Publications

- *Climate Change and Emissions Management Act*
- Specified Gas Emitters Regulation
- Specified Gas Reporting Regulation
- Standard for Greenhouse Gas Emission Offset Project Developers
- Technical Guidance for Completing Baseline Emissions Intensity Applications
- Technical Guidance for Landfill Operators
- Technical Guidance for Greenhouse Gas Verification at Reasonable Level Assurance
- Guidance for the Quantification of Area Fugitive Emissions at Oil Sands Mines Specified Gas Emitters Regulation Consolidated Reporting Form
- Landfill With Partial Gas Collection Workbook

INTRODUCTION

Part 1 of the Standard for Completing Greenhouse Gas Compliance Reports is adopted by the Specified Gas Emitters Regulation (AR 139/2007) (the "Regulation"), under the authority of section 61 of the *Climate Change and Emissions Management Act* (the "Act").

Part 1 of the Standard is enforceable as law. Section 3.1(3) of the Regulation states "The person responsible for a facility shall comply with the rules and other requirements set out in Part 1 of the Standard for Completing Greenhouse Gas Compliance Reports in preparing and submitting a compliance report for the facility under section 11." The Regulation further provides that a person who contravenes section 3.1(3) is guilty of an offence. Additionally, administrative penalties for contravening section 3.1(3) of the Regulation are payable in accordance with the Schedule of the Administrative Penalty Regulation (AR 140/2007).

In addition to the legal requirements in Part 1 of this Standard, persons responsible must comply with all applicable requirements of the Act, the Regulation, and all other applicable laws.

Part 2 of the Standard for Completing Greenhouse Gas Compliance Reports sets out additional requirements for persons responsible. Part 2 is not intended to have binding legal effect, but includes statements of policy to inform the application of Part 1.

PART 1 – REGULATORY DETAILS

Division 1

Interpretation and Application

Definitions

1(1) Terms that are defined in the Act and Regulation are incorporated into and become part of Part 1 – Regulatory Details.

(2) In this standard,

(a) "Act" means the *Climate Change and Emissions Management Act*;

(b) "cogeneration compliance adjustment" means a cogeneration compliance adjustment described in section 5;

(c) "Introduction" means the portion of this standard identified by the subtitle "Introduction";

(d) "Part 1" means the portion of this standard identified by the subtitle "Part 1 – Regulatory Details";

(e) "Part 2" means the portion of this standard identified by the subtitle "Part 2 – Compliance Reporting Requirements for Persons Responsible";

(f) "Regulation" means the Specified Gas Emitters Regulation;

(g) "this standard" means the Standard for Completing Greenhouse Gas Compliance Reports and includes the Introduction, Part 1, and Part 2

(h) "verifier" means a third party auditor hired by the person responsible for a facility to verify the facility's compliance report.

Duty to comply

2 The person responsible for a facility shall comply with all requirements of Part 1.

Non-binding parts of this standard

3 For further certainty, and subject to any other express provisions in Part 1, the provisions of the following portions of this standard are not binding:

(a) The Introduction;

(b) Part 2.

In the event of a conflict

4 If there is any conflict between Part 1 and the Act or the Regulation, the Act or the Regulation prevails over Part 1.

5 **Cogeneration compliance adjustment** For the purposes of sections 6 and 9 of the Regulation, the cogeneration compliance adjustment (CCA) must be determined by the following formula:

CCA = E x EF

Where:

CCA is the cogeneration compliance adjustment expressed in tonnes of CO_2e;

E is the electricity produced from the cogeneration facility net of station services expressed in Megawatt hours;

EF is the electricity emissions factor which is

0.418 tonnes CO_2e/MWh ;

Compliance report

6(1) A compliance report under section 11 of the Regulation must be in the form and include the information prescribed in the Compliance Report Template provided by the department.

(2) The compliance report must

(a) be signed by the person responsible for the facility, and

(b) be completed before a verifier verifies it.

(3) If the person responsible for a facility modifies or changes the compliance report after it has been verified and before it is submitted for compliance, the compliance report must be re-verified.

Compliance report supporting documents

7 A compliance report submitted under section 11 of the Regulation by the person responsible for a facility must include the following:

(a) a process flow diagram that indicates in schematic detail

(i) the processes that produce direct emissions at the facility, and

(ii) each source of direct emissions that produces over 1,000 tonnes of carbon dioxide equivalent in the reporting period;

(b) a third party verification report including

(i) a Conflict-of-Interest checklist signed by the verifier;

(ii) a Statement of Qualification form signed by the verifier;

(iii) a Statement of Verification form signed by the verifier;

(c) a Statement of Certification signed by the person responsible

and

(d) a quantification methodology document;

Verification

8 The person responsible for the facility shall hire a verifier to

(a) verify the compliance report, and

(b) prepare a verification report

in accordance with the Technical Guidance for Greenhouse Gas Verification at Reasonable Level Assurance.

PART 2 – COMPLIANCE REPORTING REQUIREMENTS FOR PERSONS RESPONSIBLE

1.0 Purpose of this Document

The purpose of this document is to assist facilities regulated under the Specified Gas Emitters Regulation (the Regulation) in completing annual compliance reports and to provide information about the compliance options available to facilities that are unable to meet their emissions reduction targets through facility level improvements.

Compliance reporting is used to compare a facility's annual emissions intensity to its approved net emissions intensity limit. Facilities that are not able to meet their reduction obligation through direct facility improvements can use one or more of the available compliance options to meet their net emissions intensity limit. Facilities may submit emission offsets that are serialized on the Alberta Emissions Offset Registry, submit serialized emission performance credits (EPCs) generated at a regulated facility that has reduced its emissions intensity below its net emissions intensity limit, or purchase fund credits from the Climate Change and Emissions Management Fund.

2.0 Overview of the Specified Gas Emitters Program

In 2003, Alberta passed the *Climate Change and Emissions Management Act*, signalling its commitment to manage the impacts of climate change and greenhouse gas (GHG) emissions in the province. In 2004, Alberta passed the Specified Gas Reporting Regulation currently requiring all facilities emitting over 50,000 tonnes of carbon dioxide equivalent (CO_2e) annually to report their GHG emissions.

In 2007, Alberta passed the Regulation, reinforcing its commitment to regulate GHG emissions from large facilities. This regulation requires all facilities in Alberta having emitted over 100,000 tonnes of CO_2e per year to reduce their annual emissions intensity. New facilities are given a graduated reduction obligation, starting in their fourth year of commercial operation.

Emissions intensity is regulated on a facility-by-facility basis. Each facility is given a reduction target, and its performance over time is compared to its approved baseline emissions intensity. The Department supports and encourages consistency in reporting methodologies across individual sectors. Where appropriate, sectors are encouraged to develop sector-specific reporting methodologies that improve accuracy and consistency in reporting of GHG emissions for that sector.

The Regulation encourages facilities to improve emissions performance relative to production. This can be achieved through a number of initiatives, including, without limitation, incremental improvements in on-site energy use, development of emission offset projects, and supporting development and implementation of new emissions reduction technologies.

2.1 Thresholds

The threshold for determining if a facility is subject to the Regulation has been set at 100,000 tonnes of CO_2e per year of total direct emissions. A facility's total direct emissions must include all GHG emissions sources on site, including CO_2 emissions from the combustion and decomposition of biomass and industrial process emissions. Facilities that exceed the emissions threshold in any single calendar year on or after 2003 are considered regulated facilities. All regulated facilities are required to establish a baseline emissions intensity and submit annual compliance reports.

The Regulation currently captures facilities in the following sectors (though it applies to any facility emitting 100,000 tonnes of CO_2e per year of total direct emissions):

- Chemical Manufacturing
- Coal Mining
- Conventional Oil and Gas Extraction
- Electric Power Generation

- Fertilizer Manufacturing
- Food Processing
- Mineral Product Manufacturing
- Oil Sands In Situ Extraction
- Oil Sands Mining and Upgrading
- Petroleum and Coal Products
- Pipeline Transportation
- Primary Metal Manufacturing
- Waste Treatment and Disposal
- Wood Product Manufacturing

2.2 Reduction Obligations

The Regulation requires all regulated facilities to reduce their annual emissions intensity below their approved baseline emissions intensity as outlined in Table 1.

Table 1: New facility reduction obligation based on the number of years of commercial operation.

	Reduction Target and Baseline Period for New Facilities		
Year	*Description*	*Reduction Target (2017)*	*Baseline Emissions Intensity*
Start-up	Partial calendar year of initial operations	No target	No baseline
Year 1	First full calendar year of commercial operation	No target	No baseline
Year 2	Second year of commercial operation	No target	No baseline
Year 3	Third year of commercial operation. Baseline application as first reporting under the regulation.	No target	No baseline
Year 4	Baseline established. First year reduction obligation	3%	Year 3
Year 5	Second year reduction obligation	7%	Years 3 and 4
Year 6	Third year reduction obligation	10%	Years 3 to 5
Year 7	Fourth year reduction obligation	13%	Years 3 to 5
Year 8	Fifth year reduction obligation	17%	Years 3 to 5
Year 9	Considered an established facility	20%	Years 3 to 5

2.3 Compliance Options

Facilities that are not able to meet their reduction obligation through performance improvements (e.g., technology improvements, changes in maintenance and/or operations, etc.) may use one or more of the following compliance options:

(1) Emission Performance Credits (EPCs);
(2) Emission Offsets; or
(3) Climate Change Emissions Management Fund credits.

More information about these compliance options is available in Section 4.0.

Facilities must submit sufficient credits such that their net emissions intensity is equal to their net emissions intensity limit for each compliance period.

Facilities that reduce their annual emissions intensity below their net emissions intensity limit are eligible to request EPCs, which can be banked for future use at the same facility or traded/sold to other Alberta facilities that have not met their reduction targets. See Section 4.2 for more information about EPCs.

2.4 Greenhouse Gas Reporting Program

The GHG reporting program, operated in accordance with the Specified Gas Reporting Regulation, is a complementary program that requires all facilities emitting more than a certain threshold of CO_2e in a calendar year to report their annual GHG emissions. Facilities whose emissions do not exceed the threshold for the Specified Gas Reporting Regulation may voluntarily report their GHG emissions through the Specified Gas Reporting Program. More information regarding this program is available on the Department's GHG reporting website at:

- http://aep.alberta.ca/climate-change/guidelines-legislation/specified-gas-reporting-regulation/default.aspx

3.0 Compliance Information

All facilities regulated under the Regulation must submit annual compliance reports to the Department. Facilities that undergo decommissioning or significant changes to the operation such that they no longer fit the definition of "facility" prescribed in the Regulation may be removed from the Regulation upon receipt of written notice from the Director. Decommissioning is discussed in more detail in Section 3.5.5 and in the Technical Guidance for Completing Baseline Emissions Intensity Applications document.

3.1 Baseline Emissions Intensity Establishment

All regulated facilities must establish a baseline emissions intensity by submitting a baseline emissions intensity application to the Department for review and approval before submitting annual compliance reports. More information about the baseline emissions intensity application process can be found in the Technical Guidance for Completing Baseline Emissions Intensity Applications document.

3.2 Submission Deadline

The submission deadline for annual specified gas compliance reports is March 31 of the year following each emissions year.

If the due date lies on a weekend or statutory holiday, facilities will have until the following business day at 4:30 pm to submit their documents to the Department.

3.3 Signatures

Electronic signatures must be sufficient to identify the person signing and must be consistent with the purpose of the document or record being signed. The Department will accept electronic signatures for the purposes of compliance under the Regulation, but reserves the right to request signed originals where the electronic signature is ambiguous or cannot be verified.

3.4 Submission Process

Compliance reports may be submitted electronically to AEP.GHG@gov.ab.ca. For administrative purposes, separate e-mail submissions must be made for each facility.

An e-mail confirming receipt of each compliance report will be sent to the facility reporter once the submission has been received. The Department will conduct a review of each compliance report. In accordance with Section 12 of the Regulation, the Department may request additional information or materials to support the review.

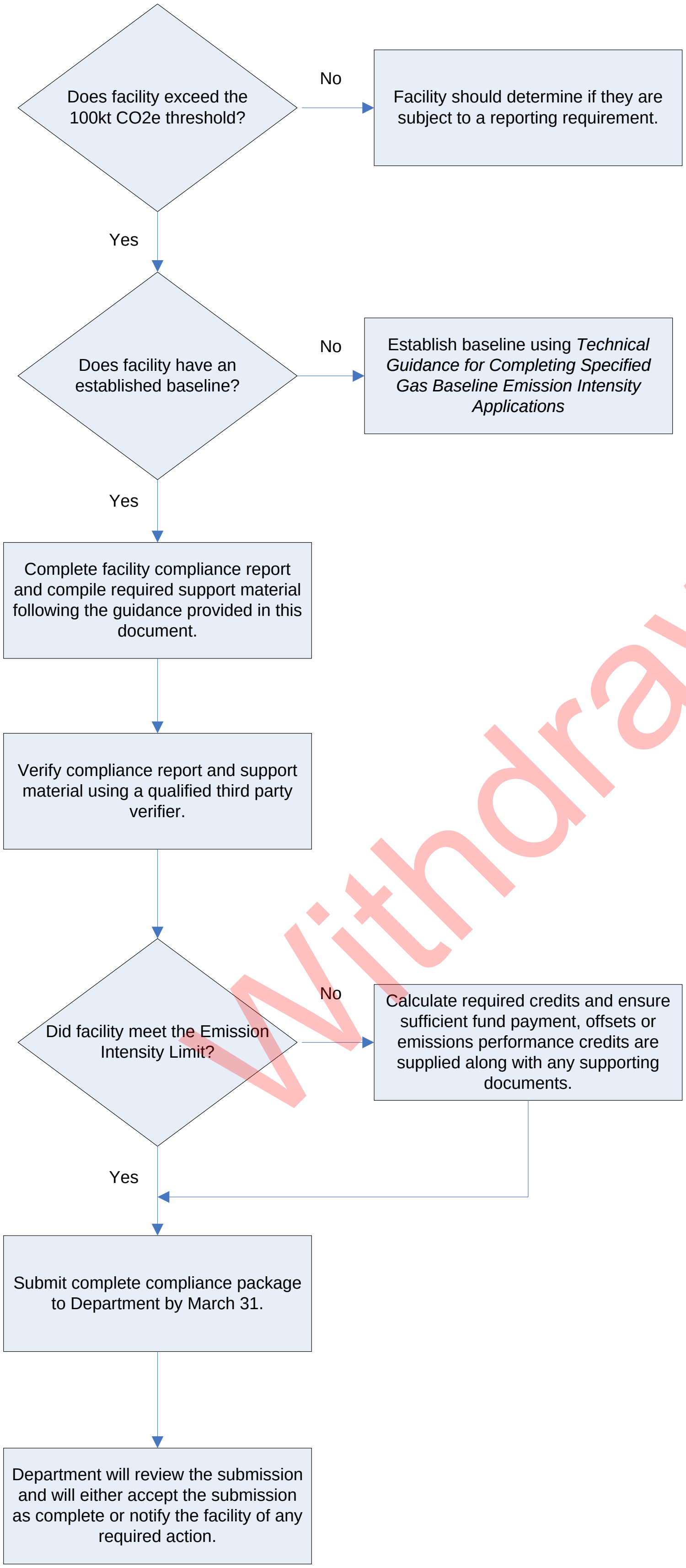
After the review has been completed, the Director will notify the facility in writing that either:

(1) the compliance report submission has been reviewed and accepted as administratively complete or

(2) corrective action is required for the facility to meet compliance reporting requirements.

A schematic overview of the compliance report submission process is provided in Figure 1.

Figure 1: Compliance report submission review and decision tree.



3.5 Special Circumstances

3.5.1 Methodology Unavailability

Situations may occur where the calculation methodology used in the baseline emissions intensity application is not available for use in an annual compliance report due to metering changes or data unavailability. In such cases, facilities should contact the Department to discuss the most appropriate path forward.

More information about emissions estimation methodologies is provided in Section 5.0 and in the Technical Guidance for Completing Baseline Emissions Intensity Applications document.

3.5.2 Major Modifications and Operational Changes

The Department must be notified whenever modifications or operational changes that affect production, emissions, or emissions intensity by more than 10 percent from previous reporting periods are made to a regulated facility. Major modifications include the installation of new equipment, replacement of old equipment, conversion of fuel-burning equipment to electricity, and other changes that affect facility operation. The Department will work with the facility to determine the most appropriate path forward, which may include, without limitation, restatement of the baseline emissions intensity.

Companies are encouraged to notify the Department of any planned future modifications in order to help avoid delays or resubmissions after the changes have been made.

Options available to the Director in the event of significant changes at the facility include, but are not limited to:

- baseline period change;
- same year baseline (use compliance period intensity as the baseline, i.e., a straight target on emissions);
- recalculated baseline that accounts for the change; and/or
- proxy baseline relative to similar facilities in the sub-sector.

Assessment of EPC requests are further explained in Section 4.2 .

In assessing the options for addressing major modifications or operational changes at facilities, the goals are to:

- ensure that facilities that are not new are subject to the Regulation;
- maintain a compliance requirement consistent with recognizing intentional improvements in emissions at the facility and the intent and stringency of the Regulation;
- ensure facilities have a baseline that is representative for assessing actual performance in the compliance year; and
- reduce large changes in compliance obligations due to changes resulting from external factors such as changes in market conditions.

3.5.3 Multi-Product or Multi-Inlet Facility

Emission intensities from multi-product and multi-inlet facilities have the potential to fluctuate annually due to a number of factors. Some of these contributing factors are not eligible to reduce compliance obligation or generate emissions performance credits. Examples of these include but are not limited to shutdown of product stream(s), adding new product streams and shifts in relative production levels.

Facilities producing multiple products must report the individual products in the compliance form and explicitly explain how these are combined into an intensity denominator. Facilities that import intermediate or alternative product feedstocks must report all imported feeds and disclose any impact this has had on emissions intensity. These can be reported in Section B4 or in the comments section.

If a facility's emissions intensity is fluctuating due to varying levels of the individual product or inlet streams, the Department will seek to establish product weightings with the facility that reflect the emissions intensity of each product or production process. These weightings will be assigned as a new facility baseline in order to make the compliance outcomes for the facility less sensitive to changes in the production mix. Emissions will be allocated appropriately where processes share heat or other energy or emissions intensive materials within the facility. For example if a central cogeneration unit supplies heat to multiple parts of the process the deemed heat emissions (Dh value) would be allocated accordingly.

Facilities using emissions-based product weightings will not have a single baseline emissions intensity. Instead the facility will enter a 1 in the baseline emissions intensity field in Section E1 of the reporting form and enter the Director-assigned baseline emissions weightings to each product or group of products in Section B6. These weightings will be entered in the production form.

3.5.4 Phased Expansion

Phased expansion occurs when a facility is built to accommodate a series of expansion operations, which are typically included in its approval conditions or amendments. These facilities often exhibit significant changes in emissions intensity over the course of expansion. For example, a facility may have a lower operating efficiency in early operation stages when the facility is overbuilt relative to production. In such cases, the emissions intensity typically improves as the phased expansions occur and the facility shifts to operations more consistent with the design capacity.

3.5.4.1 Phased Expansion Policy Principles

The following policy principles guide the consideration of policy adjustments for phased facility expansion, and are reflected in the expansion treatment policy for *in situ* oil sands extraction facilities described in Section 3.5.4.2:

- expanding facilities are still subject to the Regulation;
- a price signal is maintained on all facility emissions to encourage emissions intensity improvements;
- expansion alone cannot be a mechanism for meeting the net emissions intensity limit, generating credits or exempting emissions from the Regulation;
- each facility's baseline emissions intensity must be a relevant reference point for evaluating ongoing facility operation;
- adaptation to expansion should minimize administrative burden on both facilities and the Department;
- the policy must be sufficiently robust to deal with most expansions as consistently as possible, but the Department will retain flexibility to deal with special scenarios;
- the expansion policy must be consistent with the overall system;
- expansion should not result in excessive or punitive compliance burden;
- significant expansions occurring in the baseline period should be similarly dealt with to avoid dilution of the ongoing reduction target at the facility; and
- the policy should separate the impact of phased expansion and the impact of innovation and technology improvement where possible. It should apply the same logic applied across the overall system for dealing with technology improvements.

3.5.4.2 Phased Expansion Treatment for the In Situ Oil Sands Extraction Sector

During expansion start up in the *in situ* oil sands extraction sector, there is typically a period lasting up to one year where the expansion phase experiences significant emissions with little or no production, creating a high emissions intensity relative to ongoing operations. This occurs in all new wells, but the effect is typically diluted by numerous mature wells for facilities operating at constant steam capacity. However, when a large portion of new steam capacity is added to a facility, a large number of wells can experience this high intensity start-up phase simultaneously, causing a significant increase in the facility's aggregate emissions intensity relative to ongoing operation. The following policy treatment for expansions in the *in situ* expansion sector has been developed in consultation with the sector to address this situation.

There are two main types of facility expansions:

- Integrated expansions add steam generation and processing capacity to a central processing facility to augment the original facility and allow it to serve additional well pads, typically with a shared steam header.
- Satellite expansions have a new steam and or processing plant at a separate location from the original facility. These plants may still share some services such as water treatment or product processing and may have limited ability to share steam to some common or adjacent well pads, or they may be totally self-contained.

Where a facility grows through the satellite expansion model, it is necessary for the Director to make a decision on whether an additional plant adjacent to an existing facility is a phased expansion or a new facility.

Facilities that start up a new steam generation plant that is related through ownership or operation to an adjacent plant should contact the Department to confirm whether it will be considered a new facility prior to December 31 of the year in which steam production is commenced.

A new phase adjacent to an existing facility will typically be considered an expansion if:

- it has shared *Environmental and Enhancement Act* (EPEA) and *Water Act* approvals with the original facility;
- it has shared heat production, water treatment, product processing and shipping, or fuel supply systems with the original facility;
- growth and development of the plants are planned in an integrated fashion;
- there are limited technology advancements from the base facility;
- the sites are adjacent and there are future plans for integration;
- the sites are within a common Alberta Energy Regulator scheme boundary and have similar reservoir characteristics; and/or
- the sites have common royalty boundaries.

To be eligible to request expansion treatment, facilities must demonstrate:

(1) a significant step change in emissions (25 per cent increase) associated with the addition of physical steam generation and production infrastructure;
(2) the overall facility's emissions intensity has been affected by the expansion by more than 10 per cent compared to the baseline emissions intensity; and
(3) a clear and accurate method for separating both the emissions and production between the expansion phase and the existing facility (i.e., it must be able to pass verification to a reasonable level of assurance).

Where all of the criteria above are not satisfied, the whole facility, including expansion, must report against the existing baseline emissions intensity.

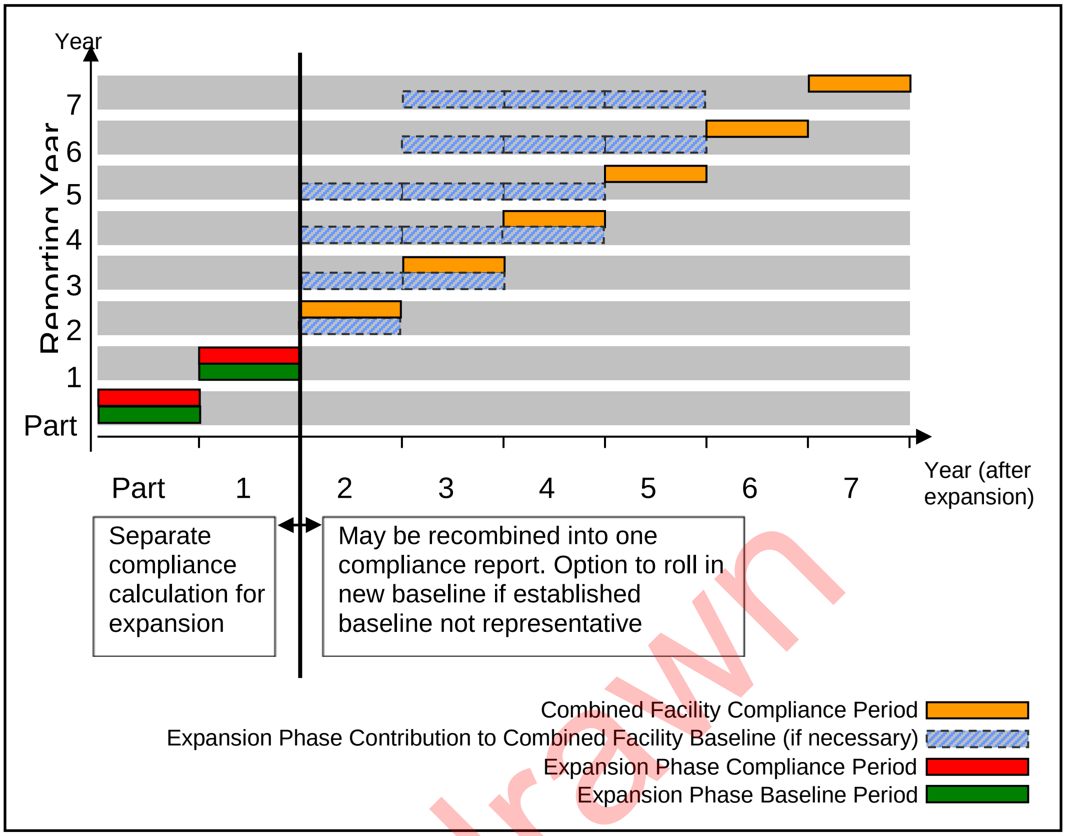
The emissions and production from the expansion portion of the facility associated with new equipment and new well pads or areas of the reservoir (areas not impacted by previous facility operation) are submitted separately for the first partial year and the first full year of expansion operation to isolate the impact of intensity changes due to initial steaming.

In the case of phased expansions that are integrated with the original facility, the apportioning of emissions and production can be done through allocation based on steam:

- expansion steam is the lesser of steam generated from new sources and steam used at new well pads on a monthly basis;
- in months where steam from new equipment is less than steam used at new well pads, the newest well pads will be considered to use expansion steam first;
- production from well pads using a portion of expansion steam will be allocated based on the ratio of expansion steam to total steam produced;
- stationary fuel combustion emissions will be allocated (per unit if possible starting with the newest unit) based on the ratio of expansion steam to total steam produced; and
- all other emissions will be allocated based on the ratio of expansion production to total production.

For these separate submissions, the expansion portion uses a baseline period that is the same as the compliance period, as depicted in Figure 2, and uses the reduction target applied to the original facility for that compliance year. This is achieved by entering four significant digits of the expansion emissions intensity as the facility baseline in the compliance form.

Figure 2: Policy for phased expansion of in situ oil sands facilities.



After the first full year of operation of the expansion:

- all of the facility's emissions and production are combined into one common compliance report, as illustrated in Figure 2, using the original facility's baseline emissions intensity, as long as this is deemed by the Department to be a valid reference for the whole facility (e.g., if the expansion uses similar technology); or
- separate compliance reports are submitted using separate baselines until year 5 of the expansion when a combined baseline that is representative of the entire facility can be created using production-weighted averaging. In this case, the expansion portion of the facility will be required to submit a separate compliance report for an additional four years so that the emissions and production from the expansion phase can be built into the new baseline emissions intensity. See the Technical Guidance for Completing Baseline Emissions Intensity Applications document for more detail.

If an expansion occurs during the baseline period for an original facility, the emissions and production associated with the expansion will be reported as part of the expansion and excluded from the original facility's baseline emissions intensity calculation.

Elements of the *in situ* expansion treatment may be applied to facilities in other sectors in cases where the same policy principles exist.

The Department maintains the authority to account for significant changes or anomalies in operation on a facility by facility basis, including the ability to update the baseline period for a facility if the approved baseline is not representative.

3.5.5 Decommissioning

The Department recognizes that production may decline more rapidly than emissions as some facilities reach the end of their operating life, causing a significant increase in emissions intensity. Regulated facilities with emissions below the threshold level, and where both production and total annual emissions are in decline, causing an increase in emissions intensity and compliance requirements, may apply for a special declining production baseline emissions intensity. These situations are handled on a case-by-case basis.

Facilities whose approval status under the EPEA has been amended to “decommissioned” must notify the Department in order to be released from the requirements of the Regulation.

Facilities that do not have an EPEA approval must demonstrate to the Department that no production or direct emissions are occurring or are planned to occur at the facility and that the facility is being decommissioned in order to be released from the requirements of the Regulation.

3.5.6 New Facility

New facility treatment recognizes that new facilities are typically built to higher design standards than older facilities. New facility treatment under the Regulation recognizes these improvements by assigning a graduated compliance target for new builds. This category only applies to newly built facilities, and does not apply to facilities undergoing major modifications described in Section 3.5.2.

More information about the establishment of baseline emissions intensities is provided in the Technical Guidance for Completing Baseline Emissions Intensity Applications.

3.6 Compliance Report Errors

3.6.1 Detection and Correction of Errors

When errors are detected in a facility’s annual compliance report or the associated baseline emissions intensity application, including discrepancies between a compliance report and the associated baseline emissions intensity application, the errors must be immediately disclosed to the Department. Errors may be detected by facilities, third party verifiers, the Department, or through the Department’s third party audit process.

When errors are identified, the Department will work with the affected facility to establish the most appropriate corrective action, and will determine whether or not reconciliation of past compliance obligations is required (i.e., adjustment of credits required or EPCs granted). The required corrective action will depend on the nature and the magnitude of the error. Typically, **immaterial** errors are corrected on a go-forward basis, and **material** errors require both retroactive and go-forward correction of the data. If a contravention of the *Climate Change Emissions Management Act* or SGER is suspected a formal investigation may be conducted.

Table 2: Materiality threshold levels for compliance report submissions.

Total Annual Emissions	Materiality Threshold
< 500 kt CO_2e	5 per cent
≥ 500 kt CO_2e	2 per cent

In cases where errors have a significant effect on a facility’s compliance obligation, retroactive reconciliation of the compliance obligation is typically required. Retroactive adjustment of compliance obligations may be made up to a maximum of three compliance periods preceding the most recent submission deadline. For example, after March 31, 2016, adjustment of previous compliance obligations will only be considered for the 2015, 2014, and 2013 compliance periods.

Where retroactive correction of errors is not required, facilities may propose voluntary data corrections. In such cases, the Department may require third party verification of the correction, depending on the extent of the changes.

Adjustment to past compliance obligations will not be made in situations where facilities update or move to improved calculation methodologies if consistent methodologies were used between the previously accepted baseline and compliance reports. More information about calculation methodologies can be found in Section 5.3.

The above error correction policies do not apply where corrections are required as the result of an investigation or offence under the *Climate Change and Emissions Management Act*. In such cases, the extent of the required correction, reconciliation or penalties will be determined based on the specific situation.

3.6.2 Compliance Adjustments

Reconciliation of past compliance obligations will be made through payment into the Climate Change and Emissions Management Fund at the fund price applicable to that compliance period.

In cases where adjustment of a facility's past compliance obligation results in over-compliance (i.e., the corrected net emissions intensity, with previously submitted true-up, is less than the facility's net emission intensity limit), reconciliation will occur as follows:

- If fund credits were purchased for the original true-up, they will be refunded at the value that was originally paid, up to a maximum of the number of fund credits submitted for the facility. At the discretion of the Department, the overpayment may be carried forward to the next compliance period.
- If emission offsets or EPCs were submitted for true-up, and an error correction was made during the facility's compliance review, the Department will only confirm retirement of the total tonnes of credits required to achieve compliance. Additional credits will remain active on the registry under that facility's name and will be available for use in future compliance periods.
- If emission offsets or EPCs were submitted for true-up, and error correction is made after the facility's compliance report was reviewed, accepted as complete and the credits were retired, the retired tonnes will be carried forward to the next compliance period in which credits are required. This carryover is non-transferable and must be used as the first compliance option at the facility.
- If EPCs were requested or generated by the facility, the number of EPCs will be adjusted to reflect the corrected compliance report. If the total number of EPCs increases, additional credits will be issued. If the total number of EPCs decreases and serial numbers have already been issued, some of the previously issued credits will be revoked, and will go through a similar correction process outlined for emission offsets in Section 4.3.2.

4.0 Compliance Options

4.1 Facility Improvements

Facilities are encouraged to implement operational improvements to reduce GHG emissions relative to production output. Decreases in annual emissions intensity will help facilities to meet their net emissions intensity limit. Facilities that reduce their annual emissions intensity below their net emission intensity limit are eligible to request EPCs. More information about EPCs is provided in Section 4.2.

Examples of facility improvements include:

Example 1: Technology Improvements

Technology improvements can include adapting new technologies that increase energy efficiency, retrofitting existing equipment, and adapting more efficient practices to improve a facility's performance. Improving energy efficiency will often improve emissions intensity, and can also improve competitiveness and productivity over the long-term.

Technology improvements can also be made to reduce the total quantity of GHG emissions that are released to the atmosphere.

Example 2: Maintenance

Maintenance procedures can be implemented to reduce GHG emissions. For example, fugitive emissions represent a significant portion of total facility emissions for some industrial operations. Regular maintenance, including leak detection and repair programs, and equipment replacement can often help reduce fugitive emissions without sacrificing production, improving emissions intensity. Note that quantification methods for fugitive emissions must be sufficiently defensible to support GHG emissions reduction claims.

Example 3: Fuel Switching

The type of fuel used in combustion activities at a facility has a significant effect on the amount of resulting GHG emissions. Switching to a fuel that releases a smaller quantity of emissions per unit of energy produced can help to reduce annual emissions intensity.

For example, displacing on-site coal combustion with natural gas combustion could potentially help to reduce emissions intensity.

Switching from on-site fuel usage to energy sources with significant indirect emissions (e.g., electricity, steam, or hydrogen) is not considered fuel switching. See Section 3.5.2 for more information.

4.2 EPCs

EPCs are issued for reductions of specified gases beyond the reduction requirement at regulated facilities. EPCs may be requested for each tonne of CO_2e that the total annual emissions quantity is less than the product of net emissions intensity limit and total production for the compliance year. The compliance cogeneration adjustment is also taken into account in calculating the emissions performance credits which may be requested.

The Department reviews requests for EPCs and, if approved, issues serial numbers for the credits generated. Once serialized, these credits may be banked for use in future compliance cycles, transferred to another regulated facility or sold.

4.2.1 Generating EPCs

EPCs must result from direct, demonstrable improvements to a regulated facility, and cannot be generated through changes in reporting methodology, shifting of emissions upstream or downstream of the facility (i.e., increases in indirect emissions), or short-term fluctuations in facility production. If a facility shifts emissions from on site to another location off site, as compared to their baseline condition, the portion of EPCs requested that relate to this change will not be granted. If such a change is permanent, a baseline adjustment may be required. In addition, EPCs can only be generated from reductions in emissions that are included in a facility's total annual emissions calculation.

Reductions of industrial process emissions, CO_2 emissions from combustion and decomposition of biomass, and indirect emissions do not affect annual emissions intensity, and are not eligible to generate EPCs.

Facilities that are eligible to request EPCs must include an EPC request form with their compliance report, and must describe the actions that were taken to improve emissions intensity. Facilities that request EPCs may be required to provide detailed information regarding the impact of individual actions on the overall facility performance. The Department reviews all emission performance requests, and may reject a request, in part or whole, if it is determined that the requested credits did not result from actual facility improvements, did not lead to reductions in Alberta, or fail to meet the requirements of the Regulation. EPCs may be revoked at any time if it is later determined that they do not meet these requirements.

Once it has been determined that EPCs meet the requirements described above and can be approved, facilities are notified in writing.

4.2.2 EPC Serialization and Tracking

EPCs are approved, serialized and tracked using the following process:

(1) Facilities that are eligible to request EPCs must submit an EPC request form to the Department with their compliance report submission.
(2) The Department reviews each EPC request as part of the compliance report review process.
(3) Once the compliance report review process is complete, the Department makes a decision regarding the approval of requested EPCs request and notifies the facility in writing.
(4) The Department creates and assigns serial numbers to approved EPCs on the EPC registry (http://www.csaregistries.ca/albertacarbonregistries/epc_user.cfm), and notification of serial numbers is provided to facilities.
(5) Credit transactions occur as bilateral agreements between buyers and sellers and are tracked on the registry. All documentation associated with the transaction of credits should be kept available.
(6) Facilities wishing to submit EPCs as a compliance mechanism must transfer the credits to the facility using them and place the units in pending retirement on the registry and should include the serial numbers in their compliance form.
(7) The Department retires the submitted EPCs after review of the submitting facility's compliance report.

The Department has developed a registry for serialization and tracking of EPCs, using a similar platform to the current offset registry.

In order to recover costs of providing the registry, fees are associated with certain transactions. Details of currently applicable transaction fees can be found here:

- http://www.csaregistries.ca/albertacarbonregistries/epc_user.cfm

The Department issues EPCs to the facility demonstrating the reductions, and does not track joint venture ownership or other contractual obligations that may affect ownership of credits. It is each facility's responsibility, once EPCs have been serialized, to transfer the ownership of credits to appropriate parties.

4.2.3 Submitting EPCs for Compliance

EPCs may only be used once for compliance purposes and must be serialized before use. All serialized EPCs remain valid until they are submitted for compliance, voluntarily retired, or revoked by the Department.

Ownership and use of EPCs must be negotiated through contractual agreements between the parties involved. EPCs must be owned by one of the companies with controlling interest of, and must be allocated to, the facility submitting them for compliance.

4.3 Emission Offsets

Emission offsets are generated through reductions of specified gases resulting from activities not covered by the Regulation or otherwise required by law. The aim of the Alberta offset system is to encourage voluntary emissions reductions that would not otherwise have occurred. Emission offsets cannot be generated from reductions that occur at regulated facilities as part of their emissions intensity calculation.

Detailed requirements for Alberta emission offsets can be found here:

- http://aep.alberta.ca/climate-change/guidelines-legislation/specified-gas-emitters-regulation/offset-credit-system-protocols.aspx.

4.3.1 Submitting Emission Offsets for Compliance

Companies submitting emission offsets for compliance with the Regulation must request retirement for the serial ranges being submitted. The registry will issue a confirmation of initiation of retirement letter to the company. The emission offsets submitted for compliance must be listed as pending retirement on the offset registry as of the compliance deadline. The Department will confirm final retirement of the emission offsets as part of the facility's compliance review.

The Alberta Emissions Offset Registry processes all requests for retirement in the order that they are received. Project developers and regulated facilities are encouraged to submit all project documentation, including requests for retirement, as early as possible to allow sufficient time to process the request. The registry will try to process all requests before the compliance deadline. Emission offsets that have not been serialized or have not been initiated for retirement will not be accepted for compliance.

4.3.2 Emission Offset Error Correction

The emission offset error correction process is outlined in Section 2.8 of the Standard for Greenhouse Gas Emission Offset Project Developers. If errors have been identified with an emission offset project and an error correction is applicable to a facility, the government will notify the facility in writing.

If the emission offsets that a facility submitted for compliance are revoked or removed from the registry, the facility will be required to pay into the Climate Change and Emissions Management Fund at the fund price applicable to the compliance year for which the emission offsets were submitted.

The process for removing or revoking emission offsets will be as follows:

- Revocation/removal will be attributed to the serial number range(s) in which the problem occurred. Emission offsets are revoked or removed proportionally across the vintage years , unless finer serial number division is available.
- Revocation/removal will first be attributed to emission offsets held by the project developer.
- If the project developer does not hold sufficient emission offsets to account for the entire revocation/removal, remaining revocation/removal will be attributed proportionally to each party holding emission offsets in the affected serial range(s).
- Revocation/removal from each party that holds offsets will first be attributed to emission offsets that have not yet been submitted for compliance (unretired).
- If the party does not hold sufficient unretired emission offsets to account for the entire revocation/removal, remaining revocation/removal will be attributed proportionally to each facility for each compliance year that the emission offsets were submitted.

Any corrective actions between the buyers and sellers of emission offsets to address invalid emission offsets are beyond the scope of the government regulatory system.

If the Department becomes aware of fraudulent behaviour, including but not limited to double counting or deliberate misrepresentation of GHG emissions reductions, appropriate action will be taken, and may include, without limitation, revoking all emission offsets associated with the project.

4.4 Climate Change and Emissions Management Fund Credits

Fund credits are purchased from the Government of Alberta, Finance and Administration Branch, Alberta Environment and Parks. Fund credit payments must be accompanied by a fund credit purchase form supplied as part of the facility compliance form. For each purchase, the dollar value stated on this form must match the dollar value paid to the Government of Alberta.

Facilities wishing to purchase fund credits should:

(1) calculate number of whole tonnes of CO_2e required to achieve compliance, and the portion that will be achieved through fund credits;

(2) calculate the total value of the fund credits being purchased at a cost of $30/tonne CO_2e for 2017 using the fund credit purchase form, available in the SGER consolidated compliance form; and

(3) submit a cheque payment made payable to “Government of Alberta” and the fund credit purchase form to:

Government of Alberta

Finance and Administration Branch

Alberta Environment and Parks

6th floor, South Petroleum Plaza

9915 108 Street NW

Edmonton, Alberta

T5K 2G8

Or, submit payment by electronic fund transfer using the following details, and provide the fund credit purchase form at least three business days in advance of the electronic funds transfer.

Account Name	Climate Change and Emissions Management
Bank Name	CIBC
Bank Address	10102 Jasper Avenue Edmonton
Institution Number	0010
Transit Number	00059
Account Number	92-74219
Ministry/Department	Alberta Environment and Parks, Finance and Administration Branch
Department Contact	Sandra Moore
E-mail	AEP.revenue@gov.ab.ca
Phone Number	780-427-9110

After payment has been submitted, the following will occur:

- the Finance and Administration Branch will stamp the fund credit purchase form with a receipt number when received; and
- the stamped fund credit purchase form will be sent to the facility as a purchase receipt within 10 working days. A copy of the purchase receipt will be forwarded to the Regulatory and Compliance Branch and added to the facility's compliance report.

Companies may purchase fund credits for one or more regulated facilities owned by the same company at the same time by submitting payment for the total number of CO_2e equivalent units required. One completed purchase form for the entire purchase must be included with the payment. This form must allocate all purchased fund credits to the facilities submitting them for compliance. The submitted fund credit purchase form will be stamped with a fund credit receipt number and will function as a purchase receipt for all facilities included in the payment.

5.0 Estimation and Reporting of Specified Gases

5.1 Emission Source Categories

Source categories have been established to provide additional information regarding GHG emissions in Alberta and to facilitate special treatment of certain types of emissions (e.g., exclusion of industrial process emissions from the annual emissions intensity calculation).

Emissions of CO_2, CH_4, and N_2O must be disaggregated and reported according to the following source categories:

- Stationary Fuel Combustion
- Industrial Process
- Venting
- Flaring
- Other /Fugitive
- On-site Transportation
- Waste and Wastewater
- Formation CO_2
- CO_2 from Combustion of Biomass
- CO_2 from Decomposition of Biomass

Emissions of hydrofluorocarbon (HFC), perfluorocarbon (PFC), and sulphur hexafluoride (SF_6) must be disaggregated and reported according to the following source categories:

- Industrial Process
- Industrial Product Use (release of emissions that do not qualify as Industrial Process)

Table 3 provides an overview of the GHG types that must be reported for each source category and whether the associated emissions are included in the total direct emissions and total annual emissions calculations.

Table 3: Summary of the Regulation reporting requirements by source category and specified gas.

Source Category	Specified Gas	Reported	Total Direct Emissions (TDE)	Total Annual Emissions (TAE)
Industrial Process	All	Y	Y	N
Industrial Product Use	HFC, PFC, SF_6	Y	Y	Y
Stationary Fuel Combustion	CO_2, CH_4, N_2O	Y	Y	Y
Venting	CO_2, CH_4, N_2O	Y	Y	Y
Flaring	CO_2, CH_4, N_2O	Y	Y	Y
Other / Fugitive	CO_2, CH_4, N_2O	Y	Y	Y
Waste and Wastewater	CO_2, CH_4, N_2O	Y	Y	Y
On-site Transportation	CO_2, CH_4, N_2O	Y	Y	Y
Formation CO_2	CO_2	Y	Y	Y

CO_2 from Combustion of Biomass	CO_2	Y	Y	N
CO_2 from Decomposition of Biomass	CO_2	Y	Y	N

5.1.1 Stationary Fuel Combustion

Stationary fuel combustion emissions are direct emissions resulting from non-vehicular combustion of fuel for the purpose of energy production (e.g., to generate electricity, heat or steam), and include emissions from waste combustion/incineration where waste materials are used directly as a fuel or converted to fuel for the purpose of energy production. Stationary fuel combustion is a common source of GHG emissions and is found in most industrial sectors.

Emissions of N_2O and CH_4 from combustion of biomass are included in the stationary fuel combustion category if the combustion is used for energy production.

CO_2 emissions from significant amounts of entrained CO_2 in flare or fuel gas may be classified as venting emissions or formation CO_2 emissions if the facility is of the opinion that this is more representative.

5.1.2 Industrial Process

Industrial process emissions are direct emissions of specified gases from an industrial process involving chemical or physical reactions other than combustion, and where the primary purpose of the industrial process is not energy production. Industrial process emissions are not found in all industrial sectors.

This source category applies to industrial processes that are integral to facility production where the only option for reducing the emissions is to scale back production. Where an industrial process involves multiple emissions sources that can be quantified separately, only the emissions meeting the definition of industrial process can be included in this category. If the product of an industrial process is combusted or vented (e.g., hydrogen being used as a fuel or flared or vented rather than as a process feed stock) the emissions associated with that product are not considered industrial process emissions, and must be reported under the most appropriate emissions category.

Industrial process emissions are included in the threshold emissions calculation, but are excluded from the total annual emissions calculation. The Department is reviewing the treatment of the industrial process source category and may introduce a reduction target on these emissions for future compliance.

Examples of industrial process emissions include:

- **Hydrogen production**: steam-methane reforming and shift reactions
  - Primary reforming: $CH_4 + H_2O \rightarrow CO + 3\ H_2$
  - Shift reaction: $CO + H_2O \rightarrow CO_2 + H_2$
- **Decomposition of carbonates:**
  - Calcination of limestone: $CaCO_3 \rightarrow CaO + CO_2$
  - Calcination of magnesium carbonate: $MgCO_3 \rightarrow MgO + CO_2$
  - Acid leaching of carbonate rock: $CaCO_3 + H_2SO_4 \rightarrow CaSO_4 + CO_2 + H_2O$
  - Demineralization of water: HCO_3- + acid $\rightarrow CO_2 + H_2O$
  - Use of limestone as flux: $CaCO_3 + FeS + 1.5\ O_2 \rightarrow Fe + CaSO_4 + CO_2$
- **Use of carbon as reductant for metal oxides:**

- Carbon as a reductant for steelmaking: $3\ C + 2\ Fe_2O_3 \rightarrow 4\ Fe + 3\ CO_2$

- **N_2O from nitric acid production**

Facilities that are unclear on whether an emissions source meets the definition of industrial process emissions should discuss with the Department before submitting their compliance report.

5.1.3 Venting

Venting emissions are direct emissions from intentional releases to the atmosphere of a waste gas or liquid stream. Examples include: casing gas emissions; treater, stabilizer, dehydrator off-gas; vented blanket gas; emissions from pneumatic devices that use natural gas as a driver; and compressor start-up venting. Formation CO_2 emissions are not included in this source category.

CO_2 emissions from significant amounts of entrained CO2 in flare or fuel gas may be classified as venting emissions or formation CO2 emissions (as applicable) if the facility is of the opinion that this is more representative.

5.1.4 Flaring

Flaring emissions are direct emissions from the controlled combustion of a gas or liquid stream produced on site, but not for the purpose of energy production, and include, without limitation, emissions from waste petroleum incineration, hazardous emissions prevention systems (in pilot or active mode), flare purge gas, well testing, natural gas gathering systems, processing plant operations, crude oil production, pipeline operations, petroleum refining, chemical fertilizer production and steel production. The flaring category does not include emissions from combustion of biomass or landfill gas.

CO_2 emissions from significant amounts of entrained CO_2 in flare or fuel gas may be classified as venting emissions or formation CO_2 emissions if the facility is of the opinion that this is more representative.

5.1.5 Other / Fugitive

Fugitive/other emissions are direct emissions that do not fit into the stationary fuel combustion, industrial process, venting, flaring, on-site transportation, waste and wastewater, formation CO_2, CO_2 from combustion of biomass, or CO_2 from decomposition of biomass categories, and include, without limitation, intentional or unintentional releases of gases arising from the production, processing, transmission, storage and use of solid, liquid or gaseous fuels.

In general, fugitive/other emissions result from the handling or processing of various types of fuel in the fossil fuel industry. Fugitive/other sources include leaks from natural gas transmission lines and processing plants, accidental releases from oil and gas wells, and releases from the mining and handling of coal or bitumen.

5.1.6 Formation Carbon Dioxide

Formation CO_2 emissions are direct emissions of CO_2 that are recovered or are recoverable from an underground reservoir and are gaseous at conditions under which its volume is measured or estimated. This source category includes CO_2 venting from gas sweetening.

CO_2 emissions from significant amounts of entrained CO_2 in flare or fuel gas may be classified as venting emissions or formation CO_2 emissions if the facility is of the opinion that this is more representative.

5.1.7 Waste and Wastewater

Waste and wastewater emissions are direct emissions from on-site waste disposal and waste/wastewater treatment, and include emissions from landfilling of solid waste, flaring of landfill gas, treatment of liquid waste, and waste incineration, but exclude emissions from waste-to-energy operations and CO_2 emissions from decomposition and combustion of biomass.

Emissions of CH_4 and N_2O from combustion or decomposition of biomass and landfill gas are to be reported in the Waste and Wastewater category if the combustion is not for energy production. Emissions of CH_4 and N_2O from the combustion of biomass for energy (including heat) are to be included in the stationary fuel combustion category.

Quantification methodologies should be chosen and clearly documented which are appropriate to the type of waste system (e.g., landfill, aerobic/anaerobic waste water treatment).

5.1.8 On-site Transportation

On-site transportation emissions are direct emissions resulting from fuel combustion in machinery used for the on-site transportation of products and materials integral to the production process. Examples of on-site transportation include:

- transportation of raw or intermediate products and materials within the production process such as equipment used at an oil sands operation to mine and/or move materials to subsequent on-site processing;
- equipment used at above or below ground mining operations to mine and/or move mined materials;
- equipment used to transport intermediate products or materials to different on-site production processes;
- equipment used to handle or load final product for transport, including movement or management of inventory prior to final shipment outside of facility boundaries; and
- transportation of by-products or wastes, such as mining overburden or tailings.

On-site vehicle emissions associated with emergency vehicles, staff transportation, and maintenance may optionally be excluded from the total direct emissions and total annual emissions calculations, but must be excluded or included consistently between the approved baseline emissions intensity application and associated compliance reports for each facility.

5.1.9 Carbon Dioxide from Combustion of Biomass

Carbon dioxide emissions from combustion of biomass are included in this category. Biomass includes wood and wood products, charcoal, agricultural residues, trees, crops, grasses, tree litter, roots, municipal and industrial wastes where the organic material is biological in origin, landfill gas, bio-alcohols, black liquor, sludge gas, and animal or plant-derived oils. Emissions from this source category are included in the total direct emissions calculations, but not in the total annual emissions calculation.

Emissions of CH_4 and N_2O from combustion of biomass are included in either the stationary fuel combustion category or the waste and wastewater category.

5.1.10 Carbon Dioxide from Decomposition of Biomass

Carbon dioxide emissions resulting from decomposition of biomass are included in the threshold determination and total direct emissions calculations, but not in the total annual emissions calculation.

Emissions of CH_4 and N_2O from waste decomposition are included in the waste and wastewater category.

5.2 Reporting of Hydrofluorocarbons, Perfluorocarbons and Sulphur Hexafluoride

Hydrofluorocarbon (HFCs), perfluorocarbon (PFCs), and sulphur hexafluoride (SF_6) emissions occur in small volumes relative to the principle specified gases—carbon dioxide (CO_2), methane (CH_4) and nitrous oxide (N_2O)—but have high global warming potentials. Consequently, the Department requires all emissions of HFCs, PFCs, and SF_6 associated with facility production to be calculated and reported according to the following source categories:

- **Industrial Process**: The same description of industrial process emissions in Section 5.1.2 applies for emissions of HFCs, PFCs, and SF_6. Industrial process emissions of HFCs, PFCs, and SF_6 are also not included in the total annual emissions calculation.
- **Industrial Product Use**: Industrial product use emissions are all emissions of HFCs, PFCs, and SF_6 associated with production that do not meet the definition of industrial process, and are included in the total annual emissions calculation.

Emissions of HFC, PFC, and SF_6 associated with emergency equipment and other sources not related to production are excluded from the threshold and emissions calculations. For example, emissions from air conditioning equipment are to be included if from mobile equipment used to haul product, but are exempt for the office refrigerators and office air conditioners. In cases where it is unclear which category emissions of HFC, PFC, and SF_6 belong to, the Department should be contacted to discuss the matter.

5.2.1 Hydrofluorocarbon

Hydrofluorocarbons are a family of synthetic gases that contain carbon, hydrogen and fluorine. Although emissions of hydrofluorocarbons are usually very small, species of HFC often have very large global warming potentials, ranging from 140 to 11,700 times that of carbon dioxide.

Examples of HFC sources from industrial product use include emissions from foam blowing and use of HFC as a cover gas in metal production.

5.2.2 Perfluorocarbon

Perfluorocarbons are a family of industrial gases. Although emissions of PFC are usually very small, species of PFC have significant global warming potentials ranging from 6,500 to 9,200 times that of carbon dioxide.

Examples of PFC sources from industrial product use include emissions from aluminum production and foam blowing.

5.2.3 Sulphur Hexafluoride

Sulphur hexafluoride is a synthetic gas that is relatively inert due to its specific chemical properties. Emissions of SF_6 are usually small, but have a significant global warming potential of 23,900 times that of carbon dioxide.

Examples of SF_6 emissions from industrial product use include emissions of SF_6 used as a cover gas in magnesium smelting and casting, as foundry products in the aluminum industry, and as an insulating gas in electrical equipment such as circuit breakers and on-site power stations.

5.3 Captured Carbon Dioxide

The Department is collecting CO_2 data for activities related to carbon capture. All captured CO_2 which leaves the boundary of a regulated facility must be reported as an emission. It should be reported in the appropriate source category, as if it had not been captured. However, CO_2 captured from a regulated facility, with permanent sequestration outside the facility boundary, may be eligible for generation of emission offsets using an approved quantification protocol.

In addition, the following specific quantities must be reported as part of each SGER compliance report:

- CO_2 geologically injected on site – carbon dioxide that has been injected into a geological formation from an injection point within the facility boundaries, including CO_2 injected for enhanced oil or gas recovery, acid gas disposal or CO_2 storage;
- CO_2 received on site – carbon dioxide that has been received at the facility from an off-site location, including CO_2 used as a process feedstock, but not including trace CO_2 in fuels, feedstock or products; and

- CO_2 sent off site – carbon dioxide that has not been emitted to the atmosphere and has been sent from the facility to an off-site location, including CO_2 sent off-site as waste, for storage or sold as a product. This does not include trace CO_2 in products.

The first two data fields above are not included in the calculation of total annual emissions, total production, or annual emissions intensity. However, all CO_2 that is released or sent off site must be reported in the appropriate emissions source category based on its origin, and is included in the total annual emissions calculation.

5.4 Indirect Emission Sources

Indirect emissions are those emissions associated with the use or purchase of a product. Large changes in the quantity of indirect emission sources (e.g., steam, electricity, hydrogen) can have a significant impact on a facility's emissions intensity. While indirect emissions are not accounted for in the total annual emissions, annual emissions intensity, or compliance obligation calculations, they are considered when determining if EPCs are issued, or if a baseline emissions intensity adjustment is requested or required.

5.5 Negligible Emissions

Negligible emissions are direct emissions from on-site sources that are very small in magnitude and are not expected to increase or vary significantly on an annual basis, such as start up of back up power generators for maintenance purposes. For inventory completeness, ongoing, expected and predictable activities such as kerosene consumption for building heat should be captured in the appropriate source category rather than negligible emissions. The negligibility threshold has been set at the lesser of 1,000 tonnes CO_2e or one per cent of a facility's total annual emissions, on an aggregate basis.

If the aggregate emissions total from all sources deemed to be negligible falls below the threshold, these emissions may be excluded from the total annual emissions calculation. Facilities should be aware of any changes to negligible sources that may increase emissions beyond the negligibility threshold and must notify the Department of any such changes. The Department may periodically request re-evaluation of a facility's negligible sources to ensure that they remain below the negligibility threshold.

If negligible emission sources exist at a facility, the following information must be provided:

In the baseline emissions intensity application:

- a conservative estimate of the magnitude and annual variation of each emission source to be treated as negligible. If this was not provided in the application for the approved baseline emissions intensity or in previous compliance reporting, it should be provided in the next annual compliance report.

In each annual compliance report:

- a list of on-site sources that existed in the compliance period that are deemed to be negligible and confirmation that these sources have not changed significantly; and
- a conservative estimate, as above, for any sources present in the compliance period that were not present in the baseline period.

5.6 Fuels Consumed

Reporting of fossils fuels consumption is required to support estimates of emissions and feedstock quantities. Classification of types of fuel should be further distinguished between fuel and feedstock. The fuel and feedstock values reported as part of the compliance submission will be subject to the same verification review as the rest of the submission.

5.7 Emissions Quantification Methodologies

There is a problem with the derivation of the CO_2 emissions factor for gas turbines and reciprocating engines in tables 3.1-2a, 3.2-1, 3.2-2 and 3.2-3 of EPA's AP 42 as well as emissions factors taken from this source including those in Table 1-6 of CAPP's 2003 Calculating GHG Emissions.

The Department expects the use of data and calculation methods of highest accuracy available, including the use of fuel gas analysis and mole balances instead of generic emissions factors where available. The AP 42 internal combustion factor is given as 110 lb/10^6 Btu which less than physically possible for natural gas (factor for pure methane would be approximately 115 lb/MMBtu). For reference the AP 42 table 1.4-2 value for external natural gas combustion is 120,000 lb/10^6 scf or 118 lb/10^6 Btu at a heating value of 1,020 Btu/scf. This issue has been identified to the EPA; they recognize the problem and are looking into it. In the meantime, for 2011 compliance and periods moving forward, we require the substitution of another recognized natural gas CO_2 emissions factor of the facilities choice.

If this EPA turbine or reciprocating engine emissions factor was used in establishing the facility baseline please contact the Department.

Facilities must use the same calculation methodologies for annual compliance reports that were used in the approved baseline emissions intensity application, including emission factors, energy equivalence factors, and unit conversions. Facilities are also responsible for ensuring that consistent methods have been used to calculate input data taken from other parts of the operation such as production accounting data.

If facilities wish to change or update calculation methodologies to produce a more accurate emissions and production inventory for future compliance report submissions, they should contact the Department as soon as possible to discuss the most appropriate path forward. In such cases, restatement of the baseline emissions intensity will likely be required before the new methodology can be used for completion of annual compliance reports.

In cases where previously used methodologies are unavailable or must be changed for completion of the annual compliance report (e.g., due to changes in metering, temporary data unavailability, etc.), the Department should be informed before submission of the affected compliance reports. Depending on the nature and the extent of the change, restatement of the baseline emissions intensity may be required. Emission factors within a source category should be from a consistent reference source for each species, wherever possible.

Facility and verifiers must clearly identify where there are missing records, such as invoices or data, and must document how these were accounted for. This should be included in the methodology document identifying all cases of missing records, as well as clearly indicated as annotations in the detailed calculations for each case when adjustment for missing records is undertaken.

More information regarding choice of calculation methodologies and relative accuracy can be found in the Technical Guidance for Completing Baseline Emissions Intensity Applications document.

5.8 Total Production

The production value is the total annual quantity of saleable output, except where an output is not produced (e.g., landfills). Each facility must determine an appropriate production metric during the establishment of its baseline emissions intensity. More information about the choice of production metrics is provided in the Technical Guidance for Completing Baseline Emissions Intensity Applications.

Facilities must use the same production metric for their annual compliance reports as was used in the approved baseline emissions intensity application. The Department may require the use of a different production metric if it is determined that the current metric does not align with the criteria described above.

Facilities that produce multiple distinct products must report all products separately in the units measured on site, and provide detailed, transparent calculations for how these products are converted into a single denominator for the facility’s emissions intensity. For example a facility whose product is diluted bitumen should report the quantity of diluent and bitumen included in the denominator and any conversion factor used to obtain common units. End products or by-products that are excluded from the intensity denominator (such as sulphur or petroleum coke at some facilities) must still be reported and explicitly given a zero weighting, with appropriate justification in the methodology document. Treatment of by-products should be discussed with the Department as part of the baseline setting process.

If a facility has an intensity weighted multiproduct treatment the conversion factor set by the Director should be entered in the weighting column of Section B6. These weightings take the place of a facility's baseline emissions intensity. These facilities will enter a 1 in the baseline emissions intensity field in Section E1.

The Department has accepted some facility compliance reports using alternate production metrics to calculate production. These include refinery activity index (RAI) and inlet gas. Use of these alternates is being reviewed to better understand their relevance, appropriateness, and applicability to reduction targets. Facilities using these alternate denominator metrics must also submit actual production data with their annual compliance reports.

5.9 Quantification Methodology Document

All facilities must provide a quantification methodology document containing the information outlined in Section 5.9.1 as part of their annual compliance report. This document provides an explanation of the facilities operations, processes, boundaries, and the methods and assumptions used to quantify the reported emissions intensity. The purpose of this document is to provide an accurate, transparent and complete overview of the facility's GHG emission sources and methodologies used to estimate the reported emissions intensity. The use of a standardized format will improve the efficiency of verification, review and audits. It is within the scope of verification to review accuracy and completeness of quantification methodology document.

As facilities are expected to use the same methodologies for compliance reporting as were used in establishing their baseline emissions intensity this document should be largely unchanged from year to year.

5.9.1 Format for Standardized Quantification Methodology Document

Facilities are required to use the following outline for the quantification methodology document. Additional sections may be included at the end of the document.

- **Facility overview:**
  - Facility name, as it appears in Section A1 of the compliance report.
  - Approved baseline emission intensity, including date of approval.
  - Facility boundary description – Include the EPEA approval number, Alberta Energy Regulator (formerly Energy Utility Board or Energy Resource Conservation Board) number, a description of which operations are included in the compliance report, justification for all excluded operations, and a description of any changes to the facility boundary that have occurred since the baseline period.
  - Description of site processes and a complete list of emission sources. The description may refer to process flow diagram described below.
  - Changes from baseline – Describe any changes to facility equipment, operations, or production that affect the reported emissions, production, or emissions intensity by 10 per cent or more. These changes must also be reported in Section A3 of the compliance report.
- **Simplified process flow diagram(s)** that provides an overview of the facility operations, shows the major material flows, major process elements, major energy and fuel flows, emission sources labelled by source category as well as identifying important measurement points feeding into the quantification including measurement of fuel consumption and composition.
- **Emission source categories** – For each fuel/energy source, provide:

    - A list of equipment units for major GHG emissions sources using that fuel, including the unit name and number that is used in the data management system.
    - An explanation of how the fuel/energy is received on site, where it is used and how the final use is determined (i.e., directly measured, allocated, invoiced). Provide supporting information such as:
        - A simplified fuel flow diagram showing fuel sources, applicable key meters, gauges, product analyzers, sampling points, and fuel/production receipt and disposition points. This diagram is useful to facilities, verifiers, and the Department, and facilities are encouraged to develop and include these diagrams.
        - The sampling procedure and frequency when fuel analysis is used for the quantification of fuel use emissions.
    - The emission calculation equations used, including a listing of activity data, emissions factors including an example calculation and a list of the approved reference sources for the calculation and factors.
    - Any assumptions used during the calculation (e.g., combustion efficiency, control efficiency, thermal efficiency, etc.), including an explanation.
- **Meter calibration procedure and schedule** – List key measurement device(s), provide documentation showing maximum uncertainty of key measurement devices. For each measurement device used for SGER reporting purposes, describe the operating procedures for:
    - Calibration and Proving –outline the frequency and method of calibration, checking, or proving. Calibration should be at a frequency equal to or greater than suggested by the meter manufacturer.
    - Gauging – Outline the method of gauging tanks/storage ponds/vessels and the frequency of calibrating applicable gauging devices, if applicable.
    - Trucking – Outline the method(s) of measuring, sampling, and recording production moved by truck to or from the sites associated with the facility, if applicable.
- **For non-combustion emissions categories describe the emission calculation equations used**, including a listing of activity data, frequency of any measurements, method of averaging or annual roll up, emissions factors including an example calculation and a list of the approved reference sources for the calculation and factors:
    - For industrial process emissions sources, provide a diagram showing where the inputs, outputs, recycle and measurement points including those of the hydrogen production process.
- **Description and justification for any methodology changes from the baseline period.**
- **Explain averaging method** where multiple raw data sources are rolled up prior to quantification of emissions. Weighted averages should be used based on the finest grained data available, highlight and explain any exceptions.
- **Data management system** – Include a brief explanation of how raw data moves through the system, into the compliance report, and what controls are used. Additionally, provide a brief description of how a fuel/energy source (purchased or produced) is tracked and allocated to the final emission source and rolled up to the source category (e.g., onsite transportation, stationary fuel combustion, etc.) and if these volumes are reconciled back or checked against the invoice and production meters. Facilities are encouraged to use a data flow diagram to display the logic of the data sources and how data flows from raw sources through calculation logic and quality assurance systems:

- Include important meter tag identification numbers, with a brief description on where they are used.
- Virtual tag expressions (list the formulas that are embedded within the Information Management System for automated calculations) are optional in the quantification methodology document, but will likely be required by the verifier and auditor.
- A description of data and information controls used by the organization, as well as quality assurance and quality control activities used in the preparation of the compliance report is recommended to assist verifiers.

- **Production** – List the facility's products and explain how they are quantified, and aggregated to calculate total production including a description of where production data (quantity and composition) is measured (e.g., oil equivalent factors). Also include any production accounting performed to account for changes in inventory.
- **Cogeneration** – If a cogeneration unit is present on site, provide an explanation of the system in place, its inputs and how the steam and power are used. Include a simple conceptual / logic diagram, a summary of the energy balance and an explanation of how heat calculations are done, including enthalpies. For each of the various thermal streams provide annualized flow averages, temperature averages, and pressure averages. If fuel factors were used to calculate the GHG emissions from integrated cogeneration, provide the factors used including references. If fuel analysis was used to calculate GHG emissions from cogeneration, provide a synopsis of the fuel analysis. Fuel compositions and a summary of the relevant data used in the emissions calculation can also be provided.
- **Negligible emission sources** – Include the calculation used to estimate the magnitude of each potentially negligible emission source, and justification for the omission of any sources. This should be carried forward from your baseline submission.
- **Conversions Page** – Show any repeated calculations or conversions that are used.
- **Other** – Any further information that assists in explaining the GHG calculations for the facility (e.g., a list of facility specific acronyms).

6.0 Cogeneration

The following section provides guidance to facilities submitting annual compliance reports with either integrated or stand-alone cogeneration.

Cogeneration is the combined production of heat for use in industrial facilities and the production of electricity as a by-product. Electricity not used within the plant may be offered to the competitive electricity market. Combined use of fuel to produce heat for production and to generate electricity improves the overall efficiency of the plant and can displace higher emissions grid electricity. Treatment of cogeneration under the Regulation recognizes the environmental benefits associated with the higher energy efficiencies generally afforded by cogeneration operations.

The cogeneration calculation methodology compares cogeneration to reference technologies where the heat was sourced from a conventional boiler operating at an efficiency of 80 per cent and the electricity was produced from a natural gas combined cycle electricity generation plant with a GHG intensity of 0.418 tonnes CO_2e/MWh. No reduction target is placed on the incremental emissions associated with electricity generation.

Cogeneration facilities often have insulated switchgear where SF_6 emissions may be present and these should be reported as described in Section 5.2.3.

6.1 Definitions

Standalone cogeneration facilities are those units that derive all their energy outputs from on-site fuel combustion. These units do not have any other external energy inputs. All the thermal and electrical output should be traced down to a single source. All emissions from a standalone facility should be from cogeneration related equipment.

Integrated cogeneration facilities are those units that, in addition to their own fuel source, also have other sources contributing to generating thermal or electrical output. This source could be combustion at the host site, any exothermic reaction, or, in some cases, import or export of steam from a second heat source depending upon demand.

6.2 Cogeneration Reporting Requirements

Reporting requirements for cogeneration facilities differ from reporting requirements for regular facilities. This is to recognize the environmental benefits of the combined generation of heat and electricity at a facility. Facilities that use deemed GHG emissions must provide the following information in their compliance report:

- total GHG emissions (G_T) in tonnes CO_2e from the cogeneration facility for January 1 to December 31;
- fuel used by the cogeneration facility for January 1 to December 31;
- if fuel factors are used to calculate the GHG emissions, provide the factors with references;
- if fuel analysis is used to calculate the GHG emissions, provide a synopsis of the fuel analysis;
- total net heat production (H) in GJ produced by the cogeneration facility for January 1 to December 31;
- mass/volume of fuel deemed used to produce heat for January 1 to December 31;
- total electricity generation (E) in MWh generated by the cogeneration facility (net of station loads) for January 1 to December 31; and
- deemed GHG emissions from electricity generation (D_E) in tonnes CO_2e for January 1 to December 31.

The reporter must also provide the following information as part of their methodology document:

- simple conceptual/logic diagram of the cogeneration layout including boundary, and control volume used for heat calculations;
- a description of the cogeneration unit boundary;
- explanation of how heat calculations were done, including how the enthalpies were averaged;
- a list of the various thermal streams entering or leaving the cogeneration boundary and annualized flow averages, temperature averages, and pressure averages for each stream; and

- hours of operation of the cogeneration facility for January 1 to December 31.

6.3 Greenhouse Gas Emissions from Cogeneration

Total annual GHG emissions for both integrated and stand-alone cogeneration facilities shall be calculated using the most accurate method available based on the fuel consumed in cogeneration. Carbon dioxide emissions from combustion of biomass should not be included in calculation of total emissions from cogeneration.

6.4 Deemed Greenhouse Gas Emissions for Electricity Generation

Deemed GHG emissions are calculated according to the methodology outlined below.

6.4.1 Measure the Total Electricity Generated by the Cogeneration Facility

Deemed emissions associated with electricity generation are calculated based on electrical generation. That is, the calculation should account for the net electricity that crosses the cogeneration boundary (exported to the host facility and the electricity grid). This calculation of electrical generation should be net of station loads (i.e., loads integral to the function of the cogeneration unit).

6.4.2 Calculate the Deemed Greenhouse Gas Emissions for Electricity Generation

Deemed GHG emissions for a cogeneration facility are based on a natural gas combined cycle turbine with a deemed GHG emissions intensity of 0.418 tonnes CO_2e/MWh and are calculated according to the following formula:

$$D_E = 0.418 * E$$

where:

D_E = Deemed GHG emissions from electricity [tonnes CO2e]

E = Electricity generation by the cogeneration facility during the year [MWh]

6.5 Emissions Intensities Calculation

The net emissions intensity calculations differ between integrated and stand-alone cogeneration facilities. Integrated cogeneration units may have multiple products depending on the nature of the facility.

Stand-alone cogeneration facilities produce heat and electricity; however, emissions associated with electricity generation are excluded from the emissions intensity calculation.

The net emissions intensity is computed by subtracting all credits used for true-up from the numerators of the following equations. This calculation is done automatically in sheet E5 of the compliance report form, when applicable.

6.5.1 Integrated Cogeneration Facility

The following formula is used to calculate the emissions intensity of an integrated cogeneration facility:

$$EI = (TAE – CCA) / P$$

where:

EI = Emissions intensity for the compliance year. [tonnes CO_2e / unit of product]

TAE = Total Annual Emissions from the entire facility for the compliance period. [tonnes CO_2e]

(Excluding: GHG emissions from industrial process, CO_2 emissions from combustion of biomass and CO_2 emissions from decomposition of biomass but including emissions from the cogeneration unit).

CCA = Deemed GHG emissions from electricity generation for the compliance period (De). [tonnes CO_2e]

P = Production for the compliance period. [appropriate units of production]

6.5.2 Stand-Alone Cogeneration Facility

The emissions intensity for stand-alone cogeneration facilities is calculated using the following formula:

$$EI = (G_T – CCA) / H$$

where:

EI = Emissions intensity for the compliance period. [tonnes CO_2e / GJ]

G_T = Total annual GHG emissions for the compliance period. [tonnes CO_2e]

CCA = Deemed GHG emissions attributed to electricity generation for the compliance period (De). [tonnes CO_2e]

H = Total net heat produced by the cogeneration facility during the compliance period. [GJ]

6.6 Significant Change in Cogeneration Unit Operation

If the operation of the cogeneration facility changes such that there is no material production of one of the energy products, all or part of the cogeneration adjustment may be removed from the baseline emissions intensity. This situation could arise if the host facility decreased its take of energy from the cogeneration plant such that one or more of the products was no longer used. These situations will be reviewed on a case-by-case basis.

7.0 Data Confidentiality and Access to Information

The regulation includes provisions for granting confidentiality as well as dealing with access to information contained in baseline applications and compliance reports. Be sure to familiarize yourself with these provisions.

8.0 Third Party Verification

All facility specified gas compliance reports must be verified before they are submitted to the Department. This requirement for third party verification is consistent with international standards requiring independent, third party verification for GHG assertions.

The Department has released detailed guidance for verifiers conducting GHG verifications in Alberta. This guidance is available on the Department's website in the Standard for Greenhouse Gas Verification. It is expected that facilities familiarize themselves with this standard.

The verifier is required to assess the facility's compliance report, including emissions and production data, against the facility's approved baseline emissions intensity and program criteria to ensure the GHG assertion is fairly presented at reasonable level of assurance. The GHG assertion refers to the emissions, production information, cogeneration data, and intensity value reported by the facility.

The verifier must flag discrepancies in reported data, identify areas where interpretation of data differs from guidance provided by the Department and flag unresolved discrepancies.

The facility must make every effort to resolve issues identified during verification prior to finalization of the verification and submission of the compliance report to the Department.

The final audience for the verification report is the Department. All verification reports must meet the requirements outlined in the Standard for Greenhouse Gas Verification. Verification reports that do not meet these requirements may be considered incomplete, and could result in the facility being deemed out of compliance with the Regulation.

9.0 Government Audit

The Department audits approximately 10 per cent of facility compliance reports annually to assess conformance with program criteria. Facilities selected for audit will receive written notification of the audit.

The Department also uses information collected during the audits to assess program performance and identify areas for improvement.

9.1 Audit Process

The Department's audit process uses a similar approach to third party verification with a few key differences. This process is outlined in Figure 3 and discussed below.

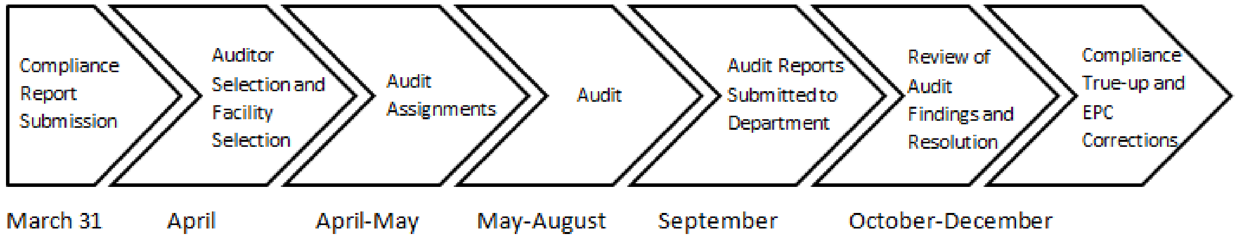
The Department issues a Request for Proposal to solicit bids from qualified audit teams. Auditors are hired based on whether they meet the requirements for a third party auditor under Section 18 of the Regulation, their audit experience and their sector specific expertise. Auditors hired by the Department must meet the same independence requirements as verifiers; an audit team will not be assigned to a facility if there is an actual or perceived conflict of interest unless sufficient action can be taken to ensure independence.

Auditors are required to perform a site visit. Facilities must enable the site visit. Failure to allow access may result in a qualified audit finding, and could result in a compliance investigation.

Auditors may schedule a close-out meeting with the facility to discuss key findings and preliminary results. Note, compliance reports selected for audit are considered final and cannot be changed during the course of the audit. If issues are identified during the audit, the facility may provide additional information to clarify how the assertion was developed, but cannot make changes to compliance report or GHG assertion.

The final audit report is submitted directly to the Department. The Department will review the audit findings and coordinate a follow-up meeting with the facility to review the audit findings and determine what, if any, follow-up action is required.

Figure 3: Department compliance report audit process.



9.2 Materiality for Department Audits

Government audits use the same materiality threshold for audits as verification. Auditors must assess both quantitative and qualitative errors associated with a compliance report to reach a reasonable level of assurance on the GHG assertion. Auditors are required to identify all material and immaterial errors discovered during the audit in the final audit report. The Department will work with the facility to determine appropriate, corrective actions.

9.3 Termination of an Audit

If the auditor identifies significant issues such as incomplete records, missing records, records in un-auditable formats, records that cannot be replicated such that the verifier cannot conduct the verification, or significant reluctance on the part of the facility to provide records or access during the site visit, the auditor, in consultation with the Department, may issue notice to the Department to terminate the audit.

Terminated audits are considered a failed audit. The facility will adhere to the error correction policy for material audit findings.

9.4 Error Correction

The procedures for correction of errors or discrepancies identified in the Department audits is the same as that for errors identified by the Department or the facility, and is described in Section 3.6.

9.5 Three Party Contracting for Re-audits

Facilities that are required to make corrections based on government audit that results in a re-audit will be required to use an audit team appointed by the Department and paid for by the facility. The audit team will, in most cases, be the same team that identified the initial errors. If an alternate audit team is needed, the Department will select the audit team consistent with its selection criteria.

The audit team and facility will be required to enter into a three party agreement with the facility to pay for the re-audit.

9.6 Confidentiality

Auditors are contracted by the Department. As an agent of the government, they are bound by Government of Alberta confidentiality requirements, and must comply with all appropriate confidentiality regulations. Information collected for audit purposes is subject to Section 16 of the Regulation. Further, government contracts explicitly reference confidentiality requirements under the *Freedom of Information and Protection of Privacy Act.*

Facilities wishing to request confidentiality on information collected during the audit must submit a written request to the Director that identifies the confidential material and provides justification for the request. More information about confidentiality can be found in Section 7.0.

9.7 Continuous Improvement

Additional information collected during the audit process is used to support program improvements and may be reflected in guidance changes, protocol reviews, or other changes as required and are part of a larger framework of on-going program reviews and improvements.

10.0 Glossary of Terms

Terms that are defined in the Act, Regulation or Part 1 are not included here.

Activity data is a quantitative measure of operations on site that result in GHG emissions, for example quantity of fuel consumed by specific equipment.

Biomass refers to material derived from living or recently dead organisms. Examples include, but are not limited to wood and wood products, charcoal, agricultural residue, landfill gas and bio-alcohols. A more complete list is available in Section 5.1.9.

Biomass emissions are direct emissions resulting from the decomposition and/or combustion of biomass from plant materials and animal waste.

Certifying official is the person designated by the facility with signing authority for that facility.

Compliance assertion is the total annual emissions, production quantities, emissions intensity value and cogeneration data including cogeneration emissions, deemed heat emissions and deemed electrical emissions.

Flaring emissions are direct emissions from the controlled combustion of a gas or liquid stream produced on site for purposes other than producing energy. This includes, but is not limited to the incineration of waste petroleum and other hazardous materials, safety flares, and test wells.

Formation CO_2 emissions are direct, gaseous emissions of carbon dioxide recovered or recoverable at a well from an underground reservoir including, but not limited to, CO_2 emissions vented from gas sweetening and formation gas.

GHGs are the atmospheric gases responsible for the GHG effect. The most common GHGs are carbon dioxide (CO_2), methane (CH_4) and nitrous oxide (N_2O). Less prevalent, but very powerful GHGs include hydrofluorocarbons (HFCs), perfluorocarbons (PFCs) and sulphur hexafluoride (SF6).

Global warming potential measures a GHG's relative warming effect on the Earth's atmosphere compared with carbon dioxide and is often expressed as a 100-year average. Department currently utilizes the global warming potential value published in the International Panel on Climate Change Fourth Assessment Report for the gases regulated under the Regulation.

HFC species are hydrofluorocarbon gases and include: CHF_3, CH_2F_2, CH_3F, $C_5H_2F_{10}$ (structure: $CF_3CHFCHFCF_2CF_3$), C_2HF_5, $C_2H_2F_4$ (structure: CHF_2CHF_2), $C_2H_2F_4$ (structure: CH_2FCF_3), $C_2H_3F_3$ (structure: CHF_2CH_2F), $C_2H_3F_3$ (structure: CF_3CH_3), $C_2H_4F_2$ (structure: CH_3CHF_2), C_3HF_7 (structure: CF_3CHFCF_3), $C_3H_2F_6$ (structure: $CF_3CH_2CF_3$) and $C_3H_3F_5$ (structure: $CH_2FCF_2CHF_2$). These gases are regulated under the Regulation.

Industrial product use emissions are all direct emissions from the use of HFCs, PFCs or SF_6 associated with production that do not meet the definition of Industrial Process Emissions. Examples include SF_6 and HFC use as a cover gas and SF_6 in on-site industrial electrical equipment.

Materiality refers to a measure of the magnitude of an error, omission, or misrepresentation that would affect the GHG assertion stated in the baseline emissions intensity application or compliance statement.

On-site transportation emissions are direct emissions resulting from fuel combustion in machinery used for the on-site transportation of products and material including raw, intermediate and end products, wastes or land clearing.

Other/fugitive emissions are direct emissions that do not fall under the other emissions categories and includes, without limitation, intentional or unintentional releases of gases arising from the production, processing, transmission, storage and use of solid, liquid or gaseous fuels.

PFC species are perfluorocarbon gases and include: CF_4, C_2F_6, C_3F_8, C_4F_{10}, c-C_4F_8, C_5F_{12}, and C_6F_{14}. These gases are subject to the Regulation.

Reporter is the person designated by the facility responsible for completing the facility's baseline emissions intensity application and compliance report form.

Stationary fuel combustion emissions are direct emissions from the combustion of fossil or biomass fuel for the purpose of producing energy, excluding CO_2 emissions from the combustion of biomass.

Unit of production is an appropriate, common production metric for all end products of a facility consistent with the industry accepted norms for the sector to which the facility belongs.

Venting emissions are direct emissions from the intentional release to the atmosphere of waste gas or liquid streams.

Waste and wastewater emissions means direct emissions from disposal or treatment of waste or wastewater, but does not include CO_2 emissions from decomposition of biomass waste.

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Any comments or questions regarding the content of this document may be directed to:

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