

# **Greenhouse Gas Emission Estimation Methodologies for the Oil Sands / Heavy Oil Upgrader Industry**

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## Executive Summary

This document has been prepared by the four operators of Oil Sands / Heavy Oil Upgrader (OS / HOU) facilities to document current or proposed methodologies for determining and reporting Greenhouse Gas (GHG) emissions to meet the requirements of:

1. Alberta Environmental Protection mandatory provincial GHG reporting commencing in 2004
2. Environment Canada (CEPA) mandatory federal GHG reporting commencing in 2005.

The participants include:

Suncor Energy Inc. (Suncor)  
Syncrude Canada Limited (Syncrude)  
Shell Canada Limited (Shell) acting on behalf of the Athabasca Oil Sands Project  
Husky Energy Inc.

Canadian Natural Resources Ltd. (CNRL) and Nexen have also reviewed this document.

This document is intended to:

- summarize the methodology for developing an inventory of GHG emissions from each of the OS / HOU participants;
- identify acceptable primary and alternate methodologies for estimating GHG emissions;
- reference the applicable industry standard(s) which provide the detailed methodology, or where no such industry standard exists, describe the industry specific methodology to be used by the OS / HOU sector;
- document common standards and conversion factors to be used by the OS / HOU participants or reference the applicable industry standard(s) utilized.

Due to differences in the technologies utilized by each company, OS / HOU specific emission factors cannot be provided. However, common methods for the derivation of emission factors and the calculation of emissions can be applied, depending on the type and quality of information available at each facility.

Detailed facility specific calculation methodologies will be prepared and maintained by each OS / HOU participant. The detailed methodologies will be consistent with the guidelines provided in this document, but will contain facility specific information required to carry out the GHG emission calculations, including, but not limited to the following:

- key measurement device identification
- sample points or information source for compositional data
- key assumptions
- frequency for updating information
- emission sources by category

These detailed methodologies will be updated by the facilities on an as required basis to reflect changes due to plant modifications or additions, or changes in technology.

A definition of the Business As Usual case and the establishment of GHG emission intensity targets are beyond the scope of this document. However, some of the factors that must be considered are summarized, and a recommendation has been made to establish “facility specific” targets rather than “sector specific” (i.e. mining/extraction and upgrading) targets. This recommendation recognizes the unique nature of each participant’s facilities, and provides the operator with the flexibility to implement emission reduction initiatives that will achieve the best overall reduction for the facility. Emissions from highly heat integrated facilities such as Suncor and Syncrude cannot be compared to cumulative emissions from stand-alone mine/extraction (Shell’s Albion facility) and upgrading (Husky) facilities. Similarly, a stand-alone upgrader facility (Husky) cannot be compared to an upgrader that is heat integrated with a refinery (Shell).

## Background

An OS / HOU sector group was formed through CAPP to recommend a common GHG emission calculation methodology for this sector to respond to the following initiatives:

1. the Federal Government's GHG emission reduction requirements under the Kyoto Protocol, and
2. the Alberta Government's mandatory GHG reporting under a new Climate Change & Emissions Management Act (Bill 37)

All of the parties involved in the development of this document have participated in the Voluntary Challenge and Registry (VCR) Program since its inception, and each party had developed their own methodologies for determining GHG emissions.

In the fall of 2003, the OS / HOU participants met to evaluate the alternate methods, and select a common methodology. Two alternate methods for determining GHG emissions were evaluated, the Carbon Balance method and the Point Source method. The Carbon Balance method measures the total carbon input from all feed streams, and total carbon output in all product streams (including losses or releases) from the facility. In this method, emissions are determined by difference. The Point Source method quantifies emissions by source, quantifying combustion emissions by fuel type and emission factors, and includes sources of fugitive releases that are not associated with combustion.

The Point Source method was selected for common use based on the following benefits:

- consistent with Upstream Oil and Gas reporting methodologies;
- allows identification and allocation of emission for each commodity and each source;
- reasonably accurate (use of custody transfer meters and fuel gas metering where available);
- enables deletion/addition of "line items" as required for Provincial and Federal GHG reporting; and
- enables allocation of emissions to each "owner" where commodity contracts exist.

## Common Guidelines

The primary references utilized include the following:

- CAPP Guide "CAPP Guide Calculating Greenhouse Gas Emissions April 2003" (<http://www.capp.ca/raw.asp?NOSTAT=YES&dt=PDF&dn=55904>)
  - API Guide "API Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry" Pilot Version April 2001, updated February 2004 (<http://api-ec.api.org/filelibrary/Compendium2004Word.zip>) (Note: links to most recent version)
  - Alberta Guide "Alberta Greenhouse Gas Reporting Program Guidance 1<sup>st</sup> Draft June 6, 2003";
  - US Environmental Protection Agency (EPA) AP-42 Compilation of Air Pollutant Emission Factors, Volume 1 – Stationary Point and Area Sources (<http://www.epa.gov/ttn/chief/ap42/>)
  - Environment Canada "Development of GHG Intensity Indicators for Canadian Industry Report prepared by CIEEDAC for Environment Canada and Canadian Industry Program for Energy Conservation, dated March 2001."
  - Environment Canada Canada's Greenhouse Gas Inventory 1990 - 1999, Emission and Removal Estimation Practices and Methods, April 2001" Greenhouse Gas Division, <http://www.ec.gc.ca/publications/index.cfm?lang=e&screen=publication> - Climate change publications
- World Business Council for Sustainable Development / World Resources Institute Climate Leaders Greenhouse Gas Protocol (<http://www.wbcsd.org/web/publications/ghg-protocol-revised.pdf>) (Note: links to most recent version)

## Deviations From Guidelines

It should be noted that where technically applicable, calculation methodologies outlined in the above documents have been utilized. However, some calculations must be modified due to:

1. Differences in the composition of some of the streams processed in OS / HOU facilities compared with conventional Oil and Gas streams. For example, CAPP Guide Equation 3 and Alberta Guide Equation 7 do not include olefins (ethylene, propylene, butylene, etc) or some of the heavier hydrocarbons and reduced sulphur compounds found in Upgrader fuel gas streams which are converted to carbon dioxide during combustion. Although these equations are referenced below, they will be modified by each of the OS/ HOU participants to reflect the actual composition of their process gas streams, using the implied stoichiometric combustion methodology cited in the references.
2. Differences in process technology. Although there are similarities in some of the processes utilized by the OS / HOU participants, feedstocks, processing technologies, material balances, and fuel options can vary significantly. For example:
  - a) Coking technology. Two coking technologies are utilized in the OS / HOU sector; delayed coking, and fluid coking. Delayed coking is a batch process which produces solid coke which is physically cut from a coke drum and collected. One company dewater, pulverizes, and utilizes a portion of this product as fuel in coke-fired boilers. Delayed coking furnaces utilize a gaseous fuel. In comparison, the fluid-coking process is a continuous process that utilizes a portion of the coke produced during the thermal cracking process to fuel the coker burner. Different methodologies are therefore required to accurately quantify the emissions associated with the combustion of coker coke.
  - b) Process gas composition and utilization. Each participant produces a process gas (amine contactor offgas) which is normally utilized as a fuel source for fired heaters. One participant has entered into a long term agreement with a third party to extract natural gas liquids (propane, butane, and condensate) and olefins (propylene and butylene) as liquid products, and return the remaining gas containing components lighter than propylene to the participant for use as fuel in its fired heaters, gas fired boilers, and a modified coke fired boiler. In this case, calculation methodologies are required which permit accurate estimations of emissions under various operating scenarios.
  - c) Hydrogen production and purification technologies and associated efficiencies. Emission calculations associated with the production of hydrogen by steam methane reforming need to take into consideration several factors, including:
    - The composition of the natural gas (e.g. ethane contribution:  $C_2H_6 + 4H_2O \Rightarrow H_2 + 2CO_2$ )
    - The efficiency of the conversion process. (i.e., the amount of unconverted methane or heavier hydrocarbons which slip through the hydrogen production process and are captured in the produced process gas stream utilized for fuel). An overstatement of emissions will occur if this is not addressed.
    - The hydrogen purification process downstream of the steam methane reformation process. Two processes are utilized: Catacarb absorption and regeneration, and pressure swing absorption (PSA). Catacarb units vent carbon dioxide directly to atmosphere. The product hydrogen stream which contains unconverted hydrocarbon gases and carbon monoxide is utilized in hydrotreating processes. These components end up in the process gas stream as fuel components along with light gases produced during the Upgrading process. In comparison, PSA units extract a very high purity hydrogen product. The remaining PSA offgases are utilized directly as fuel for the endothermic reforming process.
  - d) Diesel / Kerosene production capability. Two of the participants produce the diesel utilized as fuel in their mobile mining equipment. Some may also purchase “clear diesel” for fuel use. Emission factors are facility specific based on diesel composition.

3. Differences in facility specific measurement capabilities. This document identifies primary and alternate methodologies for calculating GHG emissions in recognition of the fact that OS / HOU participants have different measurement capabilities and purchasing practices. The method that provides the most technically accurate estimate of emissions has been identified as the primary method. Alternate methods are suggested for situations where measurement or compositional information is not available.
4. Guidelines do not provide an applicable methodology. The references cited do not provide methodologies for Oil Sands mine and pond surface methane emissions. Emissions from pond surfaces and mine surfaces will vary according to a number of factors, and therefore, no attempt has been made to develop standardized emission factors for pond and mine surface emissions for the OS / HOU sector.

## **Common Conversion Factors**

The use of common, consistent conversion factors to estimate GHG emissions for all sources is recommended:

- CAPP Guide Section 1.11 Conversion Factors
- API Guide Section 3.6 Units, Conversions, and Fuel Properties, Table 3-2 Conversion Factors
- Alberta Guide - Appendix 1 Conversion Factors
- US EPA (4/2000) AP-42 Supplement to Compilation of Air Pollutant Emission Factors, Volume 1 – Stationary Point and Area Sources. Table 3.1-2a. Emission Factors for Criteria Pollutants and GHGs from Stationary Combustion Turbines; and
- US EPA (7/1998) AP-42 Compilation of Air Pollutant Emission Factors, Volume 1 – Stationary Point and Area Sources. Table 1.4-2. Emission Factors for Criteria Pollutants and Greenhouse Gases from Natural Gas Combustion.

## Global Warming Potential Factors

The following table provides the GWP factors from key references.

Gas	Formula	100 year GWP CAPP Table 1-2	100 year GWP API Table 3-1	100 year GWP IPCC (*)
Carbon Dioxide	CO <sub>2</sub>	1	1	1
Methane	CH <sub>4</sub>	21	21	21
Nitrous Oxide	N <sub>2</sub> O	310	310	310
Sulphur Hexafluoride	SF <sub>6</sub>	23,900	23,900	23,900
Hydrofluorocarbons (HFCs):				
HFC-23	CHF <sub>3</sub>	11,700	11,700	11,700
HFC-32	CH <sub>2</sub> F <sub>2</sub>	-	-	650
HFC-41	CH <sub>3</sub> F	-	-	150
HFC-43-0mee	C <sub>5</sub> H <sub>2</sub> F <sub>10</sub>	-	1,300	1,300
HFC-125	C <sub>2</sub> HF <sub>5</sub>	2,800	2,800	2,800
HFC-134	C <sub>2</sub> H <sub>2</sub> F <sub>4</sub> (CHF <sub>2</sub> CHF <sub>2</sub> )	-	-	1,000
HFC-134a	C <sub>2</sub> H <sub>2</sub> F <sub>4</sub> (CH <sub>2</sub> FCF <sub>3</sub> )	1,300	1,300	1,300
HFC-143	C <sub>2</sub> H <sub>3</sub> F <sub>3</sub> (CHF <sub>2</sub> CH <sub>2</sub> F)	-	-	300
HFC-143a	C <sub>2</sub> H <sub>3</sub> F <sub>3</sub> (CF <sub>3</sub> CH <sub>3</sub> )	-	3,800	3,800
HFC-152a	C <sub>2</sub> H <sub>4</sub> F <sub>2</sub> (CH <sub>3</sub> CHF <sub>2</sub> )	140	140	140
HFC-227ea	C <sub>3</sub> HF <sub>7</sub>	-	2,900	2,900
HFC-236fa	C <sub>3</sub> H <sub>2</sub> F <sub>6</sub>	-	6,300	6,300
HFC-245CA	C <sub>3</sub> H <sub>3</sub> F <sub>5</sub>	-	-	560
Perfluorocarbons (PFCs):				
Perfluoromethane	CF <sub>4</sub>	6,500	6,500	6,500
Perfluoroethane	C <sub>2</sub> F <sub>6</sub>	9,200	9,200	9,200
Perfluoropropane	C <sub>3</sub> F <sub>8</sub>	-	-	7,000
Perfluorobutane	C <sub>4</sub> F <sub>10</sub>	-	7,000	7,000
Perfluorocyclobutane	c-C <sub>4</sub> F <sub>8</sub>	-	-	8,700
Perfluoropentane	C <sub>5</sub> F <sub>12</sub>	-	-	7,500
Perfluorohexane	C <sub>6</sub> F <sub>14</sub>	-	7,400	7,400

\* The values provided in the Alberta Guide and CAPP Guide are consistent with the values provided in "IPCC (1996a), 1995 Summary for Policy Makers – A Report of Working Group 1 of the Intergovernmental Panel on Climate Change".

Greenhouse gas emissions expressed in terms of CO<sub>2</sub> Equivalents will be calculated using the GWP factors provided above, using the following formula:

$$\begin{aligned}
 \text{Total Emissions} = & \sum_1^i (E_{CO_2} \times GWP_{CO_2})_i + (E_{CH_4} \times GWP_{CH_4})_i + \\
 & (E_{N_2O} \times GWP_{N_2O})_i + (E_{PFC} \times GWP_{PFC})_i + (E_{HFC} \times GWP_{HFC})_i + \\
 & (E_{SF_6} \times GWP_{SF_6})_i
 \end{aligned}$$

where:

E= Total emissions of a particular gas or gas species measured in tonnes

GWP = global warming potential of the same gas or gas species

Note: individual species of HFCs and PFCs are quantified separately and then multiplied by the corresponding GWP.

## Business as Usual / Emission Intensity

Several factors need to be considered in the establishment of Emission Intensity targets, including the following:

1. **Quality of Oil Products.** Although each of the OS / HOU sector members produces oil products, there are significant differences in the quality and variety of oil products produced, ranging from diluted bitumen blends to light hydrotreated naphthas, and liquified gases. The degree to which products are hydrotreated to remove sulphur and nitrogen varies between operators, and significantly influences the emission intensity.
2. **Definition of Production.** In addition to oil products, members of the OS / HOU sector also produce and market other non-oil products, including sulphur, coke, and gypsum. Additional products are envisioned. One facility will begin producing fertilizer in the near future.
3. **Heat Integration.** There are significant differences in the amount of heat integration between processing units for integrated facilities which have mining, extraction, and upgrading facilities in close proximity, (Suncor and Syncrude), compared to non-integrated facilities such as Shell's stand-alone mining / extraction facility located north of Fort McMurray and the Shell upgrading facility which is located adjacent to, and heat integrated with, the Shell Scotford refinery. The Husky stand-alone heavy oil upgrader is not heat integrated with any other facility. Effective heat integration reduces the amount of fuel required by the facility, and therefore reduces GHG emissions compared to a stand-alone facility. The Suncor and Syncrude upgraders reject heat in the form of low-pressure steam and hot water. In addition, low-grade heat is rejected by the power generation processes. This rejected heat can be productively utilized in an integrated Oil Sands extraction process, eliminating the need to combust fuels to provide heat. Integrated and non-integrated facilities cannot be compared for the purpose of setting "sector specific" emission intensity targets.
4. **Base Year Determination.** The base year will be determined through consultation with CAPP, stakeholders, and government agencies.
5. **Cogeneration.** The allocation of cogen emissions and inclusion or exclusion of GHG emissions from on-site cogeneration equipment will directly impact the establishment of emission intensity targets for oil sands and heavy oil upgrader facilities.

Due to the above factors, the OS / HOU sector representatives strongly recommend that the development of BAU emission intensities and targets for the OS / HOU section be "facility specific". Facility specific targets will permit each sector member to determine the best method for achieving GHG reductions for their facility.

## Inventory

Oil Sands / Heavy Oil Industry GHG inventories include Scope 1 and Scope 2 emissions as described in the Climate Leaders' GHG Emissions Inventory Protocol based on the World Resource Institute – World Business Council for Sustainable Development's Greenhouse Gas Protocol.

**Scope 1** direct GHG emissions come from sources that are owned or controlled by the reporting company. OS/HOU Scope 1 emissions are principally the result of the following activities:

- Production of electricity, heat, and steam
- Physical or chemical processing. (e.g. steam methane reforming for hydrogen production, flue gas desulphurization using  $\text{CaCO}_3$ )
- Transportation of materials, products, waste, and employees on the facility site utilizing fuel dispensed on site.
- Fugitive emissions

**Scope 2** accounts for indirect emissions that are attributable to the import of purchased electricity, heat, or steam

**Scope 3** includes "other" indirect emissions that are a consequence of the activities of the reporting company, but occur from sources owned or controlled by another company:

- Employee business travel
- Transportation of products, materials, and waste by other companies. (e.g. fuel utilized in the transportation of sulphur to market)
- Outsourced activities, contract manufacturing, and franchises
- Emissions from waste generated by the reporting company when the point of GHG emissions occurs at sources or sites that are owned or operated by another company, e.g., methane emissions from off site landfills.
- Emissions from the use and end-of-life phases of products produced by the reporting company
- Employees commuting to and from work in personal vehicles or on buses
- Production of imported materials (e.g. CaO for flue gas desulphurization)

For clarity:

- Scope 3 emissions are not included in the OS / HOU inventory.
- Emissions associated with the operation of company owned aircraft are not included in OS / HOU inventory, and may be reported at a corporate level.

## **Emission Source Categories**

Scope 1 direct emissions source categories are based on the Alberta Greenhouse Gas Reporting Program Guidance 1<sup>st</sup> Draft, and include the following:

1. Combustion Sources. Combustion of carbon based fuels resulting in the release of CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O to atmosphere from:
  - a) Stationary Devices: CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O emissions from the combustion of fuels in boilers, process heaters, and other stationary fired equipment. (Note: Cogeneration equipment is considered to be stationary combustion equipment. OS / HOU emissions associate with cogeneration equipment will be separately quantified in this category).
  - b) Mobile Internal Combustion Engines: CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O emissions from the combustion of fuels in mobile equipment, including mine mobile fleets, contractor vehicles and company operated light vehicle fleets fueled on-site.
  - c) Biomass combustion / incineration: As per provincial and federal reporting requirements, emissions from biomass combustion are required to be quantified, and reported in a separate notation. OS / HOU participants do not presently combust biomass; therefore, this category does not apply.
2. Process-Related: CO<sub>2</sub> emissions from the utilization of natural gas or fuel gas as feedstocks for process operations or from an industrial process involving chemical reactions other than combustion and not for the purpose of supplying energy such as:
  - a) Steam methane reformation in Upgrading
  - b) Sulphur plant thermal oxidizer unitsand, CO<sub>2</sub> emissions from processes which release CO<sub>2</sub> to atmosphere as a result of a chemical reaction:
  - c) Flue gas desulphurization using limestone (CaCO<sub>3</sub>)
3. Fugitive:
  - a) Flaring (Point Source) CO<sub>2</sub> and CH<sub>4</sub> emissions
  - b) Venting (Point Source) CH<sub>4</sub> emissions from tank vents, vapour recovery unit vents etc.
  - c) Mine Surface CH<sub>4</sub> emissions (Non-Point Source)
  - d) Pond Surface CH<sub>4</sub> and potentially CO<sub>2</sub> emissions (Non-Point Source)
  - e) Unintentional releases from pipeline, pumps, valves, flanges, etc. (Non-Point Source; equipment leaks)
  - f) Solid-waste disposal (Non-Point Source)

- g) Wastewater Treatment (Point Source) CH<sub>4</sub> emissions
- 4. Consumption of Halocarbons and SF<sub>6</sub>
  - a) Hydrofluorocarbons (HFCs) and Perfluorocarbons (PFCs): emissions from refrigeration and stationary air conditioning.
  - b) SF<sub>6</sub> emissions from gas-insulated substation leaks (electrical switch gear) and emissions resulting from use as tracer gas for fugitive emission measurement and geotechnical well diffusion studies.

Scope 2 indirect emissions represent purchased electrical power, (regardless of whether the power is purchased from the grid or from an on-site third party owned and operated cogeneration facility), heat, and steam.

It should be noted that the emission source categories for CEPA reporting differ slightly from the Alberta Guide. Emissions from on-site (i.e. at the facility) disposal of waste, waste water treatment, and emissions from transportation that is integral to the production process are classified as “Other” emissions.

## **Applicability of Methodology**

The following sections of this document provide a description of the methodologies utilized by the OS/HOU participants to calculate emissions for each of the emission source categories. Due to differences in technology, emission sources may not apply to each participant's facility. Measurement capabilities may also influence the method used to determine emissions.

The following legend is used for each category to compare facilities:

- indicates an emission source exists and is included in the GHG inventory
- indicates an emission source exists, but has not been included in the GHG inventory
- indicates no emission source
- P indicates the recommended primary method for achieving the most technically accurate result.
- (A1) indicates an alternate method
- (A2) indicates an alternate method

## **Combustion Emissions**

Combustion equipment represents the most significant source of GHG emissions from the OS / HOU sector.

### ***Key Assumptions***

- 100% combustion efficiency for most combustion equipment per CAPP Guide Equation 3, and API Guide Section 4.1.
- As per the Alberta Guide Section 8.1.4 Flaring is not treated as a combustion emission. “*Emissions from flaring of natural gas are considered combustion-related only if the heat generated during combustion is captured for use or sale. If the heat is not captured, flaring emissions are reported under fugitive emissions*”
- Scope 3 “other” indirect emissions are excluded:
  - Fuel utilized for business transportation of employees on company owned aircraft or other aircraft
  - Fuel utilized by busing companies which transport employees to work
- Natural gas utilized for hydrogen production or other non-fuel use (e.g. tank blanketing) is excluded from combustion category and tracked as a process-related emission or a fugitive emission.

### ***Stationary Devices***

Stationary combustion devices are devices which combust fuel directly in burners associated with the equipment, and include the following types of equipment:

- Fired process heaters / furnaces
- Boilers
- Incinerators
- Cokers
- Building Heaters
- Diesel fired pumps or generators
- Natural gas ring headers on flare tips
- Cogeneration Equipment
  - Note: the allocation of emissions from cogeneration facilities will follow the recommendations made by CAPP to CASA.

### ***Mobile Internal Combustion Engines***

Essential mobile sources include the following:

- Mine Equipment (mine diesel consumption by heavy haul trucks, dozers, graders, back hoes, hydraulic shovels etc.)
- Light Vehicle Fleet (gasoline purchased and consumed in company owned or leased light vehicles fueled at loading facilities located on site, and potentially on-site contractor vehicle consumption)

**Table 1. Combustion Emissions By Fuel Type**

<b>Fuel</b>	<b>Suncor</b>	<b>Syncrude</b>	<b>Shell</b>	<b>Husky</b>	<b>Calculation methodology/ factor</b>
Natural gas purchased and combusted as fuel in Stationary Devices	•	•	•	•	<p>Total purchased volume per:                      (P) invoice(s)                      (A1) per delivery meters                      (A2) per distribution meters</p> <p>CO<sub>2</sub> emission factor:                      (P) calculated from average delivered natural gas composition using amended CAPP Guide Equation 3, amended API Guide Section 4.1.1, or amended Alberta Guide Equation 7.                      (A1) industry emission factors (CAPP Guide Table 1-3 or Environment Canada)</p> <p>N<sub>2</sub>O emission factors per Environment Canada or US EPA AP42</p> <p>Specific utilization (e.g. boilers / GTG's / upgrading fuel) tracked where metering exists or other estimate available.</p> <p>Unmetered utilization included in emissions reporting to achieve reconciled gas balance closure.</p>
Process Gas (Upgrader produced fuel gases) utilized in Stationary Devices	•	•	•	•	<p>Volume per:                      (P) amine contactor offgas production flow meters                      (A1) Fuel gas distribution meters (adjusted for any natural gas blend)                      (A2) estimate based on material balance or heater duty.</p> <p>CO<sub>2</sub> emission factor:                      (P) calculated from average fuel gas composition (excluding natural gas make up) composition (amended CAPP Guide Equation 3, amended API Compendium Section 4.1.1, or amended Alberta Guide Equation 7.)                      (A1) industry emission factors (CAPP Guide Table 1-3 or Environment Canada)</p> <p>N<sub>2</sub>O emission factors per Environment Canada or US EPA EP42</p>
Diesel and/or Kerosene utilized	•	•	—	—	<p>Volume per:                      (P) flow measurement or tank inventory change</p>

<b>Fuel</b>	<b>Suncor</b>	<b>Syncrude</b>	<b>Shell</b>	<b>Husky</b>	<b>Calculation methodology/ factor</b>
in Stationary Devices (e.g. fire water pumps)					(A1) measurement by deliver truck meter (A2) material balance method  CO <sub>2</sub> emission factor: (P) Laboratory analysis for carbon content, heating value, and specific gravity. (A1) industry emission factor (CAPP Guide, API Compendium)  N <sub>2</sub> O emission factors per Environment Canada or US EPA AP42
Diesel and/or Kerosene utilized in Essential Mobile Sources	•	•	•	—	Volume per: (P) flow measurement or tank inventory change (A1) measurement by delivery truck meter (A2) material balance method  CO <sub>2</sub> emission factor: (P) Laboratory analysis for carbon content, heating value, and specific gravity. (A1) industry emission factor (CAPP Guide, API Compendium, or Environment Canada)  N <sub>2</sub> O emission factors per Environment Canada or US EPA AP42
Gas Oil utilized in Stationary Devices	•	—	—	—	Volume per: (P) flow measurement or tank inventory change  CO <sub>2</sub> emission factor: (P) Laboratory analysis for carbon content, heating value, and specific gravity. (A1) industry emission factor (CAPP Guide, API Compendium)  N <sub>2</sub> O emission factors per Environment Canada or US EPA AP42
Petroleum coke	•	•	—	—	Suncor and Syncrude utilize different coking technology, and combust coke in dissimilar equipment. Each company has developed a methodology for estimating the amount of CO <sub>2</sub> released through the combustion of coke.  Suncor: back calculated based on steam production, boiler efficiency, enthalpy of 790# steam and boiler feed water, heating value and carbon content of coke.

Fuel	Suncor	Syncrude	Shell	Husky	Calculation methodology/ factor
					Syncrude: Coke burnt in the Fluid Coker Burners is based on a correlation with coker air and historical/design stoichiometric relationships (conversion to CO and CO <sub>2</sub> ) and assumed 100% combustion of Coker Burner Overhead Gases in the CO Boilers.
Propane	•	•	•	•	<p>CO<sub>2</sub> = volume purchased X propane specific CO<sub>2</sub> emission factor.</p> <p>Total purchased volume per: (P) invoice(s) (A1) per delivery tickets</p> <p>CO<sub>2</sub> emission factor: (P) industry emission factor (API Guide Table 4-3 12,500 lb/1000 gal, or Environment Canada)</p> <p>N<sub>2</sub>O emission factors per Environment Canada or US EPA AP42 (mobile equipment only)</p>
Gasoline	•	•	•	—	<p>CO<sub>2</sub> = volume purchased X gasoline specific CO<sub>2</sub> emission factor X conversion factors</p> <p>Total purchased volume per: (P) invoice(s) (A1) per delivery tickets</p> <p>CO<sub>2</sub> emission factor: (P) industry emission factors (API Guide Table 3-5 Higher Heating Value = 5.46 X 10<sup>6</sup> BTU/bbl, Table 4-6 CO<sub>2</sub> emission factor 72.098 g CO<sub>2</sub>/10<sup>6</sup>J; (A1) 2.27 tonnes CO<sub>2</sub> / KL for purchased unleaded gasoline based on 85 wt% Carbon, and a specific gravity of 0.73 (Syncrude) or Environment Canada</p> <p>N<sub>2</sub>O emission factors per Environment Canada or US EPA AP42 (for mobile equipment only)</p>
Biomass	—	—	—	—	No current Biomass combustion or incineration

## Process Related Emissions

Process-related emissions include:

CO<sub>2</sub> emissions from the utilization of natural gas or fuel gas as feedstocks for process operations such as:

- a) Steam methane reformation in Upgrading for the production of hydrogen. The overall steam methane reaction is as follows:  $\text{CH}_4 + 2\text{H}_2\text{O} \Rightarrow 4\text{H}_2 + \text{CO}_2$
- b) Sulphur plant thermal oxidizer units.

CO<sub>2</sub> emissions from processes which release CO<sub>2</sub> to atmosphere as a result of a chemical reaction:

- c) Flue gas desulphurization using limestone wherein CO<sub>2</sub> is released as a product from the reaction between calcium carbonate (CaCO<sub>3</sub>) and sulphur dioxide (SO<sub>2</sub>).

### *Key Assumptions*

- Natural gas is supplied to OS/HOU facilities from different sources and therefore the composition of the gas varies. The gas composition must be considered in determining emissions, or alternately, a methane equivalent must be determined.
-

**Table 2. Process Related Emissions**

Source	Suncor	Syncrude	Shell	Husky	Calculation methodology/ factor
Steam Methane Reforming (Hydrogen Plant) CO <sub>2</sub> vents	•	•	•	•	<p><u>Catacarb Unit Purification:</u> Gas Volume X H<sub>2</sub> Conversion Efficiency X CO<sub>2</sub> Emission Factor</p> <p>Where: Volume per reformer natural gas feed meter,  Conversion efficiency per equipment design or plant test data</p> <p>CO<sub>2</sub> emission factor: (P) calculated from average delivered natural gas composition using amended CAPP Guide Equation 3, amended API Guide Section 4.1.1, or amended Alberta Guide Equation 7. (A1) industry emission factors (CAPP Guide Table 1-3)</p> <p><u>PSA Unit Purification:</u> Methane equivalent back calculated from H<sub>2</sub> production; PSA offgas treated as fuel for combustion emissions.</p>
Sulphur Plant Thermal Oxidizer	•	—	—	—	<p>Volume per: (P) flow meter (A) balance or estimate</p> <p>CO<sub>2</sub> emission factor: (P) calculated from average delivered natural gas composition using amended CAPP Guide Equation 3, amended API Guide Section 4.1.1, or amended Alberta Guide Equation 7. (A1) industry emission factors (CAPP Guide Table 1-3)</p>
Flue Gas Desulphurization Using CaCO <sub>3</sub> from Limestone	•	—	—	—	<p>Backcalculated based on: mass of limestone, limestone %CaCO<sub>3</sub>, and conversion factor for CO<sub>2</sub> equivalency</p>

## **Fugitive Emissions**

Fugitive emissions include emissions from the following sources:

1. Flaring (Point Source) CO<sub>2</sub> and CH<sub>4</sub> emissions
2. Venting (Point Source) CH<sub>4</sub> emissions from tank vents, vapour recovery unit vents etc.
3. Mine Surface CH<sub>4</sub> emissions (Non-Point Source)
4. Pond Surface CH<sub>4</sub> emissions (Non-Point Source)
5. Unintentional releases from pipeline, pumps, valves, flanges, etc. (Non-Point Source)
6. Solid-waste disposal (Non-Point Source)
7. Wastewater Treatment (Point Source) CH<sub>4</sub> emissions

## ***Key Assumptions***

### Flaring

A combustion efficiency of ninety eight percent (98%) is assumed for Upgrader flares. This assumption is a conservative assumption, erring on the side of overestimating emissions, as refinery flares are expected to have a higher combustion efficiency than production flares based on the following references:

- CAPP Guide Section 1.7.3 98% consistent with Alberta EUB, G60 Flaring Guideline.
- API Guide Section 4.1.3 *“General industry practice assumes 0.5% residual, unburned CH<sub>4</sub> remaining in the flared gas for well designed and operated flares, such as in refineries. For production flares, where greater operational variability exists, CH<sub>4</sub> emissions may be based on an assumed value of 2% noncombusted.”*
- Alberta Guide Section 8.1.4 *“Emissions from flaring of natural gas are considered combustion-related only if the heat generated during combustion is captured for use or sale. If the heat is not captured, flaring emissions are reported under fugitive emissions. Combustion efficiency of natural gas in flares (approximately 98%) is less than that from other combustion sources (>99.5%)*

### Venting

Facility specific methodologies, based on industry standards where available, will be used to quantify emissions from significant sources. Potential point sources include:

- Tank venting
- Natural gas overpressure pressure relief devices which vent to atmosphere (main supply lines)
- Vapour recovery unit vents to atmosphere

### Mine Surface Emissions

Oil Sands mine surfaces emit low levels of CH<sub>4</sub> to atmosphere. The emissions are dependent on a number of factors including the type of mine surface (exposed ore, overburden, etc.), the surface area, ore quality, the length of time the surface has been exposed, and the ambient temperature. Syncrude and Suncor have each determined site-specific emission factors using emission flux measurement.

New operators may elect to use Syncrude and Suncor historical data, or to establish their own facility-specific emission factors by conducting site flux emission measurement.

### Pond Surface Emissions

Pond surface emission factors vary depending on the age of a pond, the surface area of the pond, and the corresponding degree of microbial action. Syncrude and Suncor have each determined site-specific emission factors using emission flux measurement.

### Unintentional Releases

Unintentional releases include equipment leaks from pipelines, pumps, valves, flanges, etc. (Non-Point Source). The contribution of these emissions is considered de minimis in comparison to other site emission sources. Due to safety and environmental concerns, the detection and minimization of leaks is a high priority. Major releases, such as the rupture of a natural gas supply line, may be quantified should they occur.

### Solid Waste Disposal

As per the Alberta Guide:

“Annual CH<sub>4</sub> emissions arising from the anaerobic decomposition of organic matter should be calculated using Equation 20. This equation accounts for variations in annual amounts of landfilled waste, which is assumed to decompose to CH<sub>4</sub> following a first order decay model. Emissions from old landfills may be limited to 25 years as per IPCC.”

Landfills utilized by participants in the OS / HOU sector do not contain significant amounts of organic waste, and the contribution of landfills to the overall inventory is considered de minimis.

Syncrude has undertaken emission flux measurement testing, and the results of this testing indicate very low GHG emissions.

### Waste Water Treatment

As per the Alberta Guide:

“CH<sub>4</sub> emissions from anaerobic treatment of wastewater (not including oil sands tailings ponds) or sludge should be calculated using Equation 21 based on either chemical oxygen demand (COD) or biological oxygen demand (BOD).”

Waste Water Treatment is not a primary function in the OS / HOU sector, and the contribution of Waste Water Treatment to overall emissions is considered de minimis.

Syncrude has measured CH<sub>4</sub> emissions from the anaerobic sewage lagoon on-site.

**Table 3. Fugitive Emissions**

Source	Suncor	Syncrude	Shell	Husky	Calculation methodology/ factor
Process flare gas	•	•	•	•	<p>Volume per:                      (P) AEUB S23 reports                      (A1) Flare meters</p> <p>CO<sub>2</sub> emission factor:                      (P) calculated from average flare gas composition using amended CAPP Guide Equation 3, amended API Guide Section 4.1.1, or amended Alberta Guide Equation 7.                      (A1) calculated as above using average fuel gas compositions                      (A2) industry emission factors (CAPP Guide Table 1-3)</p> <p>CH<sub>4</sub> emission                      Combustion efficiency for flares assumed to be 98% (CAPP Guide reference: Alberta EUB, G60 Flaring Guideline. API Compendium reference: EPA, AP-42 Section 13.5.2, September 1991)</p>
Venting	•	•	•	•	<b>See Key Assumptions Above</b>
Mine Face Emissions	•	•	•	—	<b>See Key Assumptions Above</b>
Tailings Ponds	•	•	•	—	<b>See Key Assumptions Above</b>
Unintentional releases from pipeline, pumps, valves, flanges, etc. (Non-Point Source)	○	○	○	○	<b>See Key Assumptions Above</b>
Solid-waste disposal (Non-Point Source)	○	•	○	—	<b>See Key Assumptions Above</b> The Alberta Guide provides Equation 20
Waste Water Treatment Systems Process Affected Water	○	•	○	—	<b>See Key Assumptions Above</b> The Alberta Guide provides Equation 21

## **Consumption of Halocarbons (HFCs and PFCs) and SF<sub>6</sub>**

### ***Key Assumptions***

HFCs are utilized in refrigeration systems, air conditioning, and fire suppression systems, replacing CFCs and HCFC. Emissions for each species will be quantified separately.

PFCs emissions are associated with the aluminum smelting process, semiconductor manufacturing, and etching glass. The OS / HOU sector does not emit PFCs.

Sulphur hexafluoride (SF<sub>6</sub>) is a gas that is used in electrical equipment for the power transmission and distribution industry, as an insulating and arc interrupting gas. Applications include gas-insulated circuit breakers, gas-insulated transmission lines, gas-insulated transformers, and gas-insulated substations. SF<sub>6</sub> is also used in tracer gas studies for fugitive emission measurement programs and geotechnical well diffusion studies.

**Table 4. Emissions from the Consumption of Halocarbons and SF<sub>6</sub>**

Substance	Suncor	Syncrude	Shell	Husky	Calculation methodology/ factor
HFCs	•	•	○	•	Leakage cannot be measured directly.  P1 Annual Emission Inventory (A.E.I) calculated based on purchased volumes and the time between recent and last consumption (TBC) in years:  A.E.I. <sub>HFC</sub> = Purchased volume of replacement HFC / TBC  P2 Alberta Guide Equations 22 and 23
PFCs	—	—	—	—	
SF <sub>6</sub>	•	○	○	○	P1 A.E.I. <sub>SF6</sub> = Purchased volume of replacement SF <sub>6</sub> / TBC P2 Alberta Guide Equations 22 and 23

## **Indirect Emissions**

### ***Key Assumptions***

Indirect emissions associated with the operation of cogeneration facilities will follow the recommendations of CASA.

**Table 5. Indirect Emissions**

Source	Suncor	Syncrude	Shell	Husky	Calculation methodology/ factor
Electricity Purchases – from the grid	•	•	•	•	Imported Purchased Power ( MWH ) * CO2 Emission Factor (CAPP Guide – 2001 TransAlta 1.07 Tonnes/MWh)
Electricity Purchases – from on-site cogeneration facility owned by others	•	—	•	—	Imported Purchased Power ( MWH ) * CO2 Emission Factor