ALBERTA TECHNOLOGY INNOVATION & EMISSIONS REDUCTION (TIER) REGULATION

AGGREGATE FACILITIES OVERVIEW

NORTH SHORE Environmental Consultants

JUNE 2020

Presented by: Anthony Pham, P.Eng

TIER Regulation Overview

- TIER effective January 1, 2020
- Applies to a facility emitting > 100,000 t CO_2e per year
- Requires the facility to reduce emissions based on either
  - a facility-specific benchmark approach, or
  - high performance benchmark approach, whichever is the least stringent
- Opt in options for facilities:
  - Competing against a regulated facility
  - Belongs to a trade exposed sector, with emissions > 10,000 t CO2e
  - **Opting in an aggregate facility**

Opt-in – Aggregate Facility

- **Aggregate Facility:** two or more small facilities that meet the conventional oil and gas definition that are treated as a single facility under the Regulation
- Regulated Emission Sources: stationary combustion emissions only
- Emission intensity reduction requirement of 10% , FSB of 90% historical emissions 2020
- Emissions intensity is not subject an annual tightening rate
- HPB may be applicable in the near future, subject to least stringent approach

Federal Fuel Charge

- Government of Canada will apply the federal fuel charge in Alberta beginning January 1, 2020 under the Greenhouse Gas Pollution Pricing Act (GGPPA).

Year	Fuel Charge (tonne CO_2e)	Natural Gas (marketable)	Natural Gas (non-market)	Gasoline	Diesel (Light Fuel Oil)
2020	$30	5.87 ¢/m^3	7.76 ¢/m^3	6.63 ¢/L	8.05 ¢/L
2021	$40	7.83 ¢/m^3	10.35 ¢/m^3	8.84 ¢/L	10.73 ¢/L
2022	$50	13.04 ¢/m^3	17.24 ¢/m^3	14.73 ¢/L	17.89 ¢/L

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2022	\$50	13.04 ¢/m^3	17.24 ¢/m^3	14.73 ¢/L	17.89 ¢/L

- Facilities under TIER meet the federal exemption. TIER protects regulated facilities from the full cost of complying with the GGPPA

Aggregate Facility – Reference Years

- FSB for aggregate facility are set according to reference years:

Compliance Year	Reference Years	Benchmark
2020	2020	90% of emissions intensity in 2020
2021	2020 – 2021	90% of 2-year average emissions intensity: 2020 – 2021
2022	2020 – 2022	90% of 3-year average emissions intensity: 2020 – 2022
2023+	2020 – 2022	90% of 3-year average emissions intensity: 2020 – 2022

- Optional 2019 Reference Year:

Example – Opt-in Aggregate Facility

Example – Opt-in Aggregate Facility

Compliance Year	# Facilities	Fuel Gas (e^3m^3)	Federal Fuel Charge	Total
2020	79	187,206	$0.0587/m^3	**$10,988,969**

Example – Opt-in Aggregate Facility

Compliance Year	# Facilities	Fuel Gas (e^3m^3)	Federal Fuel Charge	Total
2020	79	187,206	$0.0587/$m^3$	**$10,988,969**

Year	Gas Equivalency (e^3m^3)
2020	2,384,686

Example – Opt-in Aggregate Facility

Compliance Year	# Facilities	Fuel Gas (e^3m^3)	Federal Fuel Charge	Total
2020	79	187,206	$0.0587/m³	**$10,988,969**

Year	Gas Equivalency (e^3m^3)	Stationary Combustion Emissions (tonnes CO_2e)
2020	2,384,686	483,990

Example – Opt-in Aggregate Facility

Compliance Year	# Facilities	Fuel Gas (e^3m^3)	Federal Fuel Charge	Total
2020	79	187,206	$0.0587/m^3	**$10,988,969**

Year	Gas Equivalency (e^3m^3)	Stationary Combustion Emissions (tonnes CO_2e)	Emissions Intensity (t CO_2e/e^3m^3)
2020	2,384,686	483,990	0.20296

Example – Opt-in Aggregate Facility

Compliance Year	# Facilities	Fuel Gas (e^3m^3)	Federal Fuel Charge	Total
2020	79	187,206	\$0.0587/m^3	**\$10,988,969**

Year	Gas Equivalency (e^3m^3)	Stationary Combustion Emissions (tonnes CO_2e)	Emissions Intensity (t CO_2e/e^3m^3)
2020	2,384,686	483,990	0.20296

2020 Facility Specific Reference Year (Aggregate Facility)

Example – Opt-in Aggregate Facility

Compliance Year	# Facilities	Fuel Gas (e^3m^3)	Federal Fuel Charge	Total
2020	79	187,206	$0.0587/m³	**$10,988,969**

Year	Gas Equivalency (e^3m^3)	Stationary Combustion Emissions (tonnes CO_2e)	Emissions Intensity (t CO_2e/e^3m^3)	Reduction Target FSB @ 90%
2020	2,384,686	483,990	0.20296	0.18266

Example – Opt-in Aggregate Facility

Compliance Year	# Facilities	Fuel Gas (e^3m^3)	Federal Fuel Charge	Total
2020	79	187,206	$0.0587/m³	**$10,988,969**

Year	Gas Equivalency (e^3m^3)	Stationary Combustion Emissions (tonnes CO_2e)	Emissions Intensity (t CO_2e/e^3m^3)	Reduction Target FSB @ 90%	Obligated Reduction (tonnes CO_2e)
2020	2,384,686	483,990	0.20296	0.18266	48,399

Example – Opt-in Aggregate Facility

Compliance Year	# Facilities	Fuel Gas (e^3m^3)	Federal Fuel Charge	Total
2020	79	187,206	$0.0587/$m^3$	**$10,988,969**

Year	Gas Equivalency (e^3m^3)	Stationary Combustion Emissions (tonnes CO_2e)	Emissions Intensity (t CO_2e/e^3m^3)	Reduction Target FSB @ 90%	Obligated Reduction (tonnes CO_2e)	Obligated Compliance ($30/tonne)
2020	2,384,686	483,990	0.20296	0.18266	48,399	$**1,451,970**

Example – Opt-in Aggregate Facility

Compliance Year	Compliance Option	Total
2020	Federal Fuel Charge (GGPPA)	**$10,988,969**
2020	Opt-in Aggregate Facility (TIER)	**$ 1,451,970**

Example – Opt-in Aggregate Facility

Compliance Year	Compliance Option	Total
2020	Federal Fuel Charge (GGPPA)	**$10,988,969**
2020	Opt-in Aggregate Facility (TIER)	**$ 1,451,970**
	Difference	**$ 9,562,680**

Weighing the Pros and Cons

Opt-in Aggregate Facility:

- Ideal for companies with a large number of facilities
  - Simplification: reporting, verification, and compliance processes, administrative costs ↓
  - Reduces financial burden – "GGPPA fuel tax vs TIER compliance cost" previous example

Considerations:

- May not be ideal for companies with small number facilities or facilities with low fuel
  - Costs of compliance, verification and reporting > cost difference from previous example

Alberta Greenhouse Gas Quantification Methodologies

Chapter 15 Aggregate Facilities

Technology Innovation and Emissions Reduction Regulation

April 2020

Alberta

Alberta Greenhouse Gas Quantification Methodologies
Chapter 15 Aggregate Facilities

Technology Innovation and Emissions Reduction Regulation

Draft Quantification Methodology Comment Form:

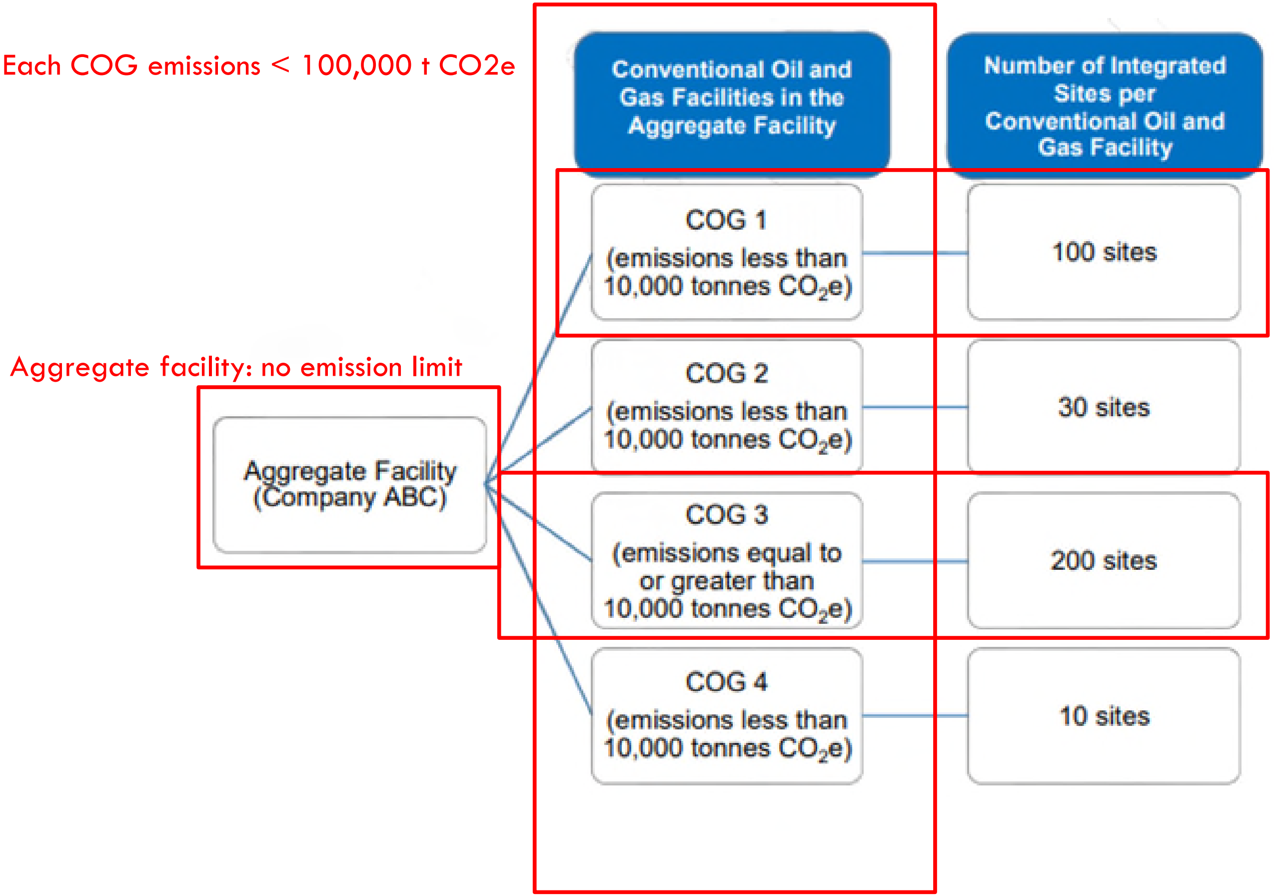
- https://www.alberta.ca/assets/documents/aep-aggregate-facilities-comment-submission-form.docx
- 40 Day Commenting Period Starting from May 29, 2020 until July 04, 2020

Aggregate Facilities

Chapter 15 of AEP's Greenhouse Gas Quantification Methodology prescribes methodologies for aggregate facilities

- An aggregated facility consists of 2 or more conventional oil and gas facilities (COG)
- Regulated emissions only include stationary fuel combustion and is compared to the total production volumes for benchmarking and compliance reporting
- Multiple sites may be integrated in operation and be identified as a single COG within an aggregate facility, provided the integrated site emits < 100,000 tonnes of carbon dioxide equivalent (t CO_2e)

Figure 15-1: Example of an aggregate facility



Identify these 100 sites as COG 1 facility to facilitate emissions estimation

Example:

- 1 Gas Plant (AB GP 0000000)
- 1 Battery (AB BT 0000000)
- 1 Gas Gathering (AB GS 0000000)
- 97 Wells (ABWI00000000000W500)

Identify these 200 sites as COG 2 facility to facilitate a different emissions approach than COG 1

Quantification Methodologies

The quantification methodology document provides estimation methods for the following parameters:

- Fuel Consumption Volumes: Methods 1 to 3
- Carbon Dioxide (CO_2) Emissions: Methods 4 to 7
- Methane (CH_4) & Nitrous Oxide Emissions (N_2O): Methods 8 to 10
- Petrinex Production Volumes: Method 11

Figure 15-2 Quantification Methodology Level Classification

Level[1]	Methods	Conventional Oil and Gas Facility	
		Less than 10,000 tonnes CO_2e	Equal to or greater than 10,000 tonnes CO_2e
Fuel Consumption			
0	Method 1 – Single gas stream approach	✓	✕
1	Method 2 – Multiple gas stream approach	✓	✓
	Method 3 – Third party supplied fuels	✓	✓
Carbon Dioxide Emissions			
0	Method 4 – Single default CO_2 emission factor	✓	✕
1	Method 5 – Default CO_2 emissions factors for non-variable fuels	✓	✓
	Method 6 – Higher heating value correlation	✓	✓
	Method 7 – Gas compositional analysis	✓	✓
Methane and Nitrous Oxide Emissions			
0, 1	Method 8 – Default emission factors for non-variable fuels (Table 15-5)	✓	✓
0, 1	Method 9 – Variable fuel sector-based emission factors (Table 15-6)	✓	✓
0, 1	Method 10 – Variable fuel technology-based emission factors (Table 15-7)	✓	✓
Production			
0, 1	Method 11 – Petrinex production volumes	✓	✓

[1]This is the minimum level prescribed to a corresponding method. A COG is permitted to use a method that is prescribed at a higher level.

Fuel Consumption and Composition

- Method 1: Single fuel gas stream approach:
  - For individual COG facilities with emissions < 10,000 tCO_2e
  - Reported fuel gas in Petrinex assumed to be the same composition
  - Applies default CO_2 emission factor, based on a rich gas composition, to calculate emissions

Fuel Consumption and Composition

- Method 2: Multiple fuel gas stream approach
  - All COGs may use this method
  - Requirement COG facility with annual emissions >= 10,000 tCO_2e
  - Required to maintain consumption totals for each type of fuel gas consumed
  - Fuel gas quantities reported in Petrinex are not differentiated by gas compositions. The facility must demonstrate the separation of fuel gas streams based on metered volumes and representative gas analyses
  - Average gas composition of the reporting period and/or higher heating value (HHV) must be calculated using a weighted-average approach
    - ECCC GHGRP Quantification Requirements:
      - > 2 semi-annual analyses for marketable gas
      - Weekly for non-marketable gas

Fuel Consumption and Composition

- Method 3: Fuel consumption based on internal facility metering, or third party metering/invoices
  - Fuels not reported in Petrinex
  - Examples: Consumption of Diesel, Propane, Gasoline based on direct metering or third party invoices.

Stationary Fuel Combustion Emissions

Stationary fuel combustion sources combust solid, liquid or gaseous fuel for the purpose of providing use heat or energy for industrial, commercial or institutional use. Examples include boilers, turbines, engines, generators, portable equipment, heaters and furnaces.

This source category does not include flare or waste incineration sources, except for the fuel used as pilot gas or fuel to the incineration process.

The quantification methodology document provides the following CO_2 estimation methods:

- Method 4: CO_2 emissions based on default fuel gas emission factor;
- Method 5: CO_2 emissions based on default emission factors for non-variable fuels;
- Method 6: CO_2 emissions based on high heating value correlation; and,
- Method 7: CO_2 emissions based on fuel gas carbon content.

Stationary Fuel Combustion Emissions

- Method 4: CO_2 emissions based on default fuel gas emission factor
  - For individual COG facilities with emissions < 10,000 tCO_2e
  - Used for fuel gas volumes calculated using Method 1 (fuel reported in Petrinex)
  - CO_2 emissions calculated using a single fuel gas stream and default emission factor (tCO_2/m^3) shown in Table 15-3 and using Equation 15-4

$$CO_{2,p} = v_{fuel,p} \times EF_{vol} \qquad \text{Equation 15-4}$$

  - Must apply this methodology for both benchmarking & compliance reporting

Stationary Fuel Combustion Emissions

Table 15-3 Default Fuel Gas and Carbon Dioxide Emission Factor

Parameter		Default Values
For Benchmarking and Compliance Reporting[1]:		
Default Carbon Dioxide Emission Factor		
	Volume Basis (tCO_2/m^3)	0.00233
Default Rich Gas Composition (vol%)		
	Methane (CH_4)	80
	Ethane (C_2H_6)	15
	Propane (C_3H_8)	5
Default Higher Heating Value (GJ/m^3)		0.04477

Stationary Fuel Combustion Emissions

- The COG facility may apply to use a default sales gas emission factor for the benchmarking period, if the facility would like to:
  - apply gas compositions or HHV to calculate CO_2 emissions but does not have the required gas compositions or HHV for the benchmark period required, or
  - change methodologies from the default CO_2 emission factor to using gas composition or HHV to calculate CO_2 emissions for compliance reporting and does not have the required gas compositions or HHV for the benchmark period

Stationary Fuel Combustion Emissions

Parameter		Default Values
For Benchmarking only[2]:		
Default Carbon Dioxide Emission Factor		
	Volume Basis (tCO_2/m^3)	0.00190
Default Sales Gas Composition (vol%)		
	Methane (CH_4)	98
	Ethane (C_2H_6)	1
	Propane (C_3H_8)	0.3
	Butane (C_4H_{10})	0.1
	Carbon Dioxide (CO_2)	0.3
	Nitrogen (N_2)	0.3
Default High Heating Value (GJ/m^3)		0.03825

Stationary Fuel Combustion Emissions

- Method 5: CO_2 emissions based on default emission factors for non-variable fuels not reported in Petrinex
  - Fuel volumes calculated using Method 3 (fuel not listed in Petrinex)
  - On-site transportation emissions are not included as stationary combustion
  - CO_2 emissions calculated using:
    - measured or supplied HHV using Equation 15-5
    - Fuel-specific default CO_2 emission factor from Table 15-4 using Equation15-5a

$$CO_{2,p} = v_{fuel,p} \times HHV \times EF_{ene} \qquad \text{Equation 15-5}$$

$$CO_{2,p} = v_{fuel,p} \times EF_{vol} \text{ or } ENE_{fuel,p} \times EF_{ene} \qquad \text{Equation 15-5a}$$

Stationary Fuel Combustion Emissions

Table 15-4

Non-Variable Fuels	CO_2 Emission Factor[2]	
	tonne/kl	tonne/GJ
Diesel	2.681	0.0699
Diesel in Alberta[1]	2.610	0.06953
Gasoline	2.307	0.069
Gasoline in Alberta[1]	2.174	0.06540
Butane	1.747	0.0614
Ethane	0.986	0.0573
Propane	1.515	0.0599

Stationary Fuel Combustion Emissions

- Method 6: CO_2 emissions based on high heating value correlation
  - Consistent with ECCC GHGRP, intended to be used for fuel considered to be marketable natural gas
  - For use with fuel volume calculations and compositions using Method 2 (multiple fuel gas streams) and CO_2 emissions are calculated using Equation 15-6 and is based on measured HHV

$$CO_{2,p} = v_{fuel,i,p} \times (60.554 \times HHV_p - 404.15) \times 10^{-6} \qquad \text{Equation 15-6}$$

  - Ideal for companies where the fuel and HHV is supplied on an volumetric and energy basis and is available by the third party supplier

Stationary Fuel Combustion Emissions

- Method 7: CO_2 emissions based on fuel gas carbon content
  - Based on mass balance approach using the fuel carbon content and is for fuel consumed as calculated by Method 2 (multiple fuel gas stream) or Method 3 (fuels not listed in Petrinex)
  - Carbon content can be measured by the facility or provided by the supplier
  - For gaseous fuels where consumption is measured by volume (m^3) basis use Equation 15-7a:

$$CO_{2,p} = v_{fuel\,(gas),i,p} \times CC_{gas,p} \times 3.664 \times 0.001 \qquad \text{Equation 15-7a}$$

  - For gaseous fuels where consumption is measured by energy (GJ) basis use Equation 15-7b:

$$CO_{2,p} = \frac{ENE_{fuel\,(gas),i,p} \times CC_{gas,p} \times 3.664 \times 0.001}{HHV} \qquad \text{Equation 15-7b}$$

Methane and Nitrous Oxide Emissions

Applicable to all COG facilities, there are three types of default emission factors CH_4 and N_2O:

- Method 8: EF for non-variable fuel (propane, diesel, gasoline, others)
- Method 9: EF for sector-based variable fuel
- Method 10: EF technology-based variable fuel

Methane and Nitrous Oxide Emissions

- Method 8: Non-variable fuel emission factors

Table 15-5 Default emission factors for non-variable fuel types (Method 8)

Non-Variable Fuels	HHV (GJ/kl)	CH_4 Emission Factor[3]		N_2O Emission Factor[3]	
		tonne/kl	tonne/GJ	tonne/kl	tonne/GJ
Diesel[1]	38.35	-	-	-	-
All Industry - Stationary Combustion (not technology specific)	-	7.8E-05	2E-06	2E-05	5.8E-07
<19kW	-	7.3E-05	1.9E-06	2.0E-05	5.8E-07
>=19kW, Tier 1-3	-	7.3E-05	1.9E-06	2.0E-05	5.8E-07
>=19kW, Tier 4[6]	-	7.3E-05	1.9E-06	2.3E-04	5.9E-06
Diesel in Alberta[2]	37.83	see note 4			
Biodiesel	35.16	see note 4			
Gasoline	33.43	-	-	-	-

Where an equipment inventory is not available for diesel or gasoline combustion equipment, must use the emissions factors specified for ">=19kW, Tier 4" for diesel combustion equipment and "4-stroke" for gasoline combustion equipment.

Methane and Nitrous Oxide Emissions

- Method 8: Non-variable fuel emission factors

Gasoline	33.43	-	-	-	-
All Industry - Stationary Combustion (not technology specific)	-	1E-04	3.0E-06	2E-05	6E-07
2-stroke	-	1.1E-02	3.0E-04	1.3E-05	3.6E-07
4-stroke[6]	-	5.1E-03	1.5E-04	6.4E-05	1.8E-06

Where an equipment inventory is not available for diesel or gasoline combustion equipment, must use the emissions factors specified for “>=19kW, Tier 4” for diesel combustion equipment and “4-stroke” for gasoline combustion equipment.

Methane and Nitrous Oxide Emissions

- Method 9: Variable fuel sector-based emission factors

Table 15-6 Sector based CH_4 and N_2O emission factors for various fuel gas types (Method 9)

Sectors	CH_4 Emission Factor[2]		N_2O Emission Factor[2]	
	tonne/m³	tonne/GJ	tonne/m³	tonne/GJ
Oil and Gas Sector and Producer Consumption (Non-marketable)[1]	6.4E-06	1.4E-04	6.0E-08	1.3E-06

Methane and Nitrous Oxide Emissions

- Method 10: Variable fuel technology-based emission factors

Table 15-7 Technology based CH_4 and N_2O emission factors for various fuel gas types (Method 10)

Technology Types	CH_4 Emission Factor		N_2O Emission Factor		Reference[1]
	tonne/m³	tonne/GJ	tonne/m³	tonne/GJ	
Boilers/Furnaces/Heaters:					
NOx Controlled	3.7E-08	9.7E-07	1.0E-08	2.7E-07	AP-42 Table 1.4-2
NOx Uncontrolled	3.7E-08	9.7E-07	3.5E-08	9.3E-07	AP-42 Table 1.4-2
Internal Combustion Engine[3]:					
Turbine	1.4E-07	3.7E-06	4.9E-08	1.3E-06	AP-42 Table 3.1-2a
2 stroke lean	2.37E-05	6.23E-04	-	-	AP-42 Table 3.2-1
NOx 90-105% Load	-	-	7.77E-07	2.04E-05	AP-42 Table 3.2-1
NOx < 90% Load	-	-	4.75E-07	1.25E-05	AP-42 Table 3.2-1
4 stroke lean	2.04E-05	5.37E-04	-	-	AP-42 Table 3.2-2
NOx 90-105% Load	-	-	1.00E-06	2.63E-05	AP-42 Table 3.2-2
NOx < 90% Load	-	-	2.07E-07	5.46E-06	AP-42 Table 3.2-2
4 stroke rich	3.76E-06	9.89E-05	-	-	AP-42 Table 3.2-3
NOx 90-105% Load	-	-	5.41E-07	1.43E-05	AP-42 Table 3.2-3
NOx < 90% Load	-	-	5.56E-07	1.46E-05	AP-42 Table 3.2-3

Methane and Nitrous Oxide Emissions

- Selection Criteria for Methods 9 & 10
  - COG facility must apply either Method 9 (sector-based) or 10 (technology-based) to equipment within a COG facility
  - Must consistently use one method for both benchmarking and compliance reporting
  - For Method 10 (technology-based), required to use the same EF for both benchmarking and compliance reporting, unless different equipment is present
    - Example: Uncontrolled NO_x boiler present during the benchmarking period and Controlled NO_x boiler present during the compliance period

Aggregate Facility Production Quantification

- Method 11 Petrinex Production Volumes
  - Aggregate facilities' production volumes quantified and reported under TIER will be the volumes reported in Petrinex for each COG

Aggregate Facility Production Quantification

- Method 11 Petrinex Production Volumes

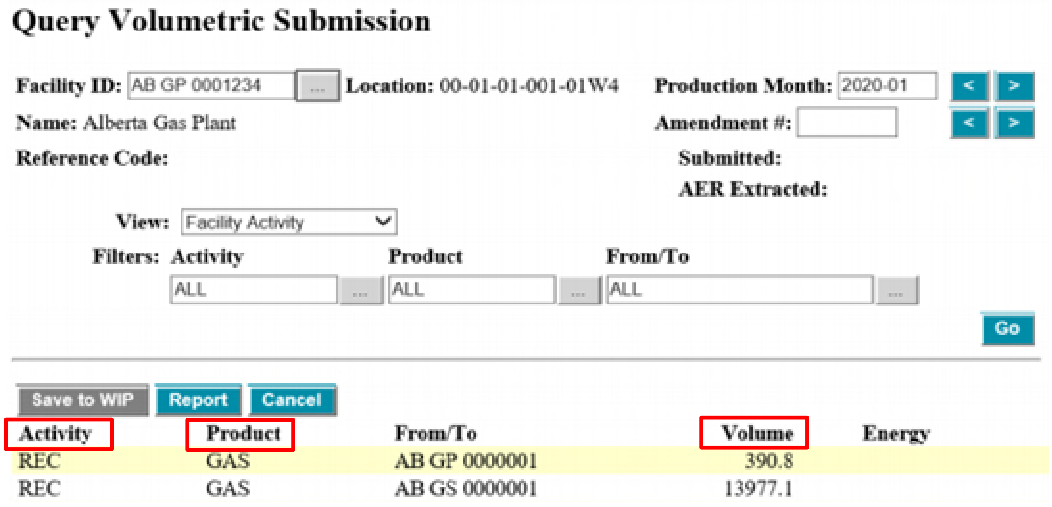


Figure 15-1 An example of the facility activity page for a typical COG facility

Aggregate Facility Benchmark Unit

The person responsible for an aggregate facility may request a benchmark unit for the aggregate facility by using the following:

- Option 1: Request to use one of the following benchmark units for specified energy products (m^3 oil equivalent):
  - Production;
  - Dispositions; or,
  - Receipts.
- Option 2: propose to use an alternative benchmark unit if Option 1 is not applicable to the aggregate facility. The alternative must be derived from correlation coefficients of emission to production.

Aggregate Facility Benchmark Unit

Once a benchmark unit has been selected (*production, disposition, or receipts*), the volumes associated with the benchmark unit are determined in using Equation 15-9 and 15-9a

$$P_k = \sum_i^n v_{Product_i} \times Conversion\ Factor_i \qquad \text{Equation 15-9}$$

$$P_{Agg} = \sum_{k=1}^r P_k \qquad \text{Equation 15-9a}$$

Table 15-9 – Oil Equivalent (OE) Conversion Factors

Product Code	Product Name	Units	Conversion Factors to m^3 OE
OIL	Crude Oil, Crude Bitumen	m^3	1.00
GAS	Gas	e^3m^3	0.971
C1-MX	Methane Mix	m^3	0.000971
LITEMX	Lite Mix	m^3	0.000971
C2-SP	Ethane Spec	m^3	0.48
C2-MX	Ethane Mix	m^3	0.48
C3-SP	Propane Spec	m^3	0.66
C3-MX	Propane Mix	m^3	0.66
IC4-MX	Iso-Butane Mix	m^3	0.72
IC4-SP	Iso-Butane Spec	m^3	0.72
C4-SP	Butane Spec	m^3	0.75
C4-MX	Butane Mix	m^3	0.75

Assessment of requested benchmark unit from Method 11

A benchmark unit requested from Method 11 will be evaluated by the director as part of the facility specific benchmark assignment process based on the following criteria:

- Achieves a strong month-to-month correlation between the requested benchmark unit and aggregate emissions;
- Minimizes variability of month-to-month emissions intensities over the course of a year; and,
- Represents the composition and operation of the aggregate facility

Aggregate Facility Timeline Example

(Aggregate Facilities)

2020

~~September 1, 2020~~ **Delayed to 2021**
~~Baseline Applications~~
~~FSB 2019 year)~~ **Changed to 2020 year**

2021

BENCHMARK REPORTING /
1st COMPLIANCE REPORT (2020 Reporting)
Reporting & Verification Due Date **TBD**
FSB @ **90%** (**2020** Reference Year)

2022

2nd COMPLIANCE REPORT (2021 Reporting)
Compliance & Verification June 30
FSB @ 90% (**2020 & 2021** Reference Years)

2023

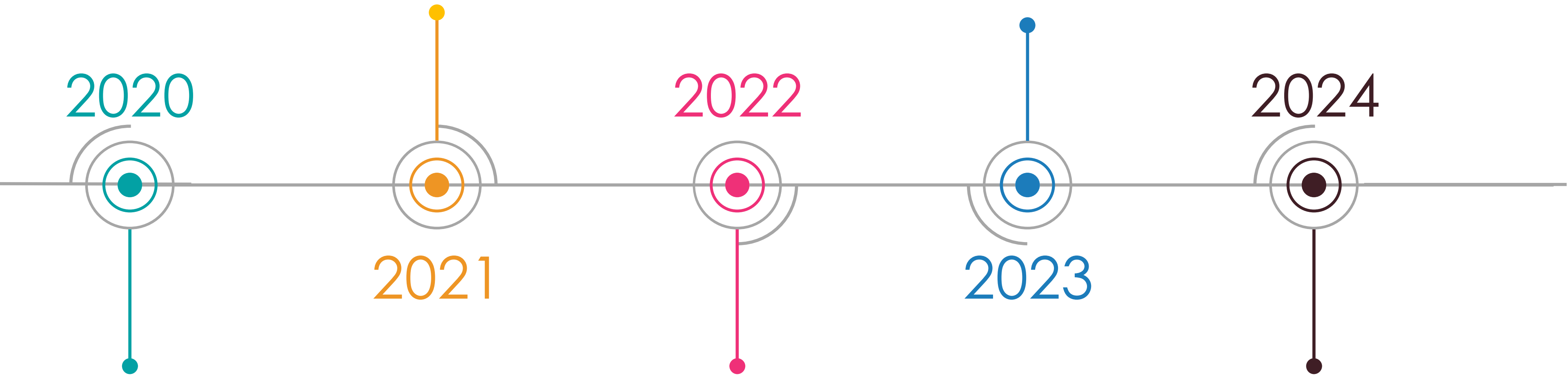
3rd COMPLIANCE Report (2022 Reporting)
Compliance & Verification June 30
FSB @ 90% (**2020 – 2022** Reference Years)

2024

4th COMPLIANCE REPORT (2023 Reporting)
Compliance & Verification June 30
FSB @ 90% (2020-2022 Reference Year)

Aggregate Facility Timeline Example

(Aggregate Facilities)



~~September 1, 2020~~ **Delayed to 2021**
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~~FSB 2019 year)~~ **Changed to 2020 year**

TIER Regulation Resources

- AEP TIER Overview:
  - https://www.alberta.ca/technology-innovation-and-emissions-reduction-regulation.aspx
- Alberta Greenhouse Gas Quantification Methodologies – Chapter 15 – Aggregate Facilities
  - https://www.alberta.ca/assets/documents/aep-alberta-greenhouse-gas-quantification-methodologies-chapter-15-aggregate-facilities-draft.pdf
- Draft Quantification Methodology Comment Form:
  - https://www.alberta.ca/assets/documents/aep-aggregate-facilities-comment-submission-form.docx
  - 40 Day Commenting Period Starting from May 25, 2020

Questions?

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NORTH SHORE
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REGINA

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