Offset Project Report Form
AltaGas Turin Acid Gas Injection Project

Project Developer:
AltaGas Processing Partnership

Prepared by:
Bluesource Canada

Reporting Period:
January 1, 2017 – December 31, 2017

Date:
March 5, 2018

Greenhouse Gas Assertion

Project Developer:

AltaGas Processing Partnership

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Project Documents:

Offset Project Report Form: AltaGas Turin Acid Gas Injection Project

Greenhouse Gas Emissions Reduction Offset Project Plan: AltaGas Turin Acid Gas Injection Project, March 1, 2012, revised February 4, 2014.

Quantification Protocol for Acid Gas Injection, Version 1, AESRD 2008.

Project Identification:

Project Name: AltaGas Turin Acid Gas Injection Project (6878-6600)
Reporting period: January 1, 2017 – December 31, 2017

The Turin sour gas processing plant, operated by AltaGas Processing Partnership, is a sour gas processing facility with a licensed capacity of 44 mmscf/d. The plant consists of inlet separation, approximately 3,200 horsepower of inlet compression, a sweetening train and a refrigeration system. The emission reductions claimed under this report are relative to the back-end treatment and disposal of the acid gas stream generated as a result of the processing of the hydrocarbon feedstock at the facility.

LSD: 12-19-12-18 W4M (Turin Sour Gas Processing Plant); 03-25-012-19 W4 (Injection Well)

Emission Reduction Removal, Sequestration or Capture Assertion:

Vintage	Gas Type	Quantity (tCO_2e)
2017 (Jan 1 – Dec 31)	CO_2	44,355
	CH_4	4,573
	N_2O	705
	CO_2e	25,241
Total Quantity		74,874

Project Developer Signature:

I am a duly authorized corporate officer of the project developer mentioned above and have personally examined and am familiar with the information submitted in this greenhouse gas assertion, the accompanying project report on which it is based. Based upon reasonable investigation, including my inquiry of those individuals responsible for obtaining the information, I hereby warrant that the submitted information is true, accurate and complete to the best of my knowledge and belief, and that all matters affecting the validity of the emission reduction claim or the protocol(s) upon which it is based have been fully disclosed. I understand that any false statement made in the submitted information may result in de-registration of credits and may be punishable as a criminal offence in accordance with provincial or federal statutes.

The project developer has executed this offset project report as of the 30 day of March 2018.

BR
SP

Signature: ______________________

Name: James Shelford

Title: SVP Commercial Operations

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1.0 Contact Information

Table 1: Project Contact Information

Project Developer Contact Information	Additional Contact Information
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2.0 Project Scope and Site Description

Table 2: Project Information

Project title	AltaGas Turin Acid Gas Injection Project ('the Project')
Project purpose and objectives	The project was implemented to meet sulphur emissions reduction requirements, by implementing an acid gas injection (AGI) program. The AGI scheme allows for a net reduction in direct greenhouse gas (GHG) emissions due to the geological storage of carbon dioxide (CO_2) and acid gas and as a result of reduced fossil fuel usage to treat sulphur emissions.
Activity start date	November 30, 2004
Offset start date	The credit start date was January 1, 2005 as the data required to quantify emissions reductions from November 30, 2004 to December 31, 2004 was unavailable
Offset crediting period	The initial credit duration was from January 1, 2005 to December 31, 2012. Alberta Environment and Sustainable Resource Development (AESRD) granted the Project a 5-year Crediting Extension Period, from

	January 1, 2013 - December 31, 2017 as indicated in a letter dated April 23, 2013 (see OPP). This is the final crediting year of the project.
Reporting period covered by the project	January 1, 2017 to December 31, 2017
Actual emission reductions/capture/sequestration	Jan 1 – Dec 31, 2017: 74,874 tonnes of CO_2e Total emission reductions over project lifetime: 1,105,033 tonnes CO_2e
Unique site identifier	Latitude: 50.01327° (Plant); 50.020623° (Injection Well) Longitude: -112.458632° (Plant); -112.475712° (Injection Well) LSD: 12-19-12-18 W4M (Turin Sour Gas Processing Plant); 03-25-012-19 W4 (Injection Well) This is not an aggregated Project.
Project boundary	The Project boundary includes the Turin gas plant at 12-19-12-18 W4, which comprises the K-12 acid gas compressor, the electricity transformer, supporting pipeline network and equipment. The boundary also includes the injection well at 3-25-12-19 W4 where the acid gas is sequestered. The Turin gas plant is operated by AltaGas and the injection well was recompleted for the Project acid gas. The Project is located in Alberta, located at the AltaGas Processing Partnership Turin Sour Gas Processing Plant located near Turin, Alberta.
Ownership	AltaGas Processing Partnership (herein referred to as "the Proponent") owns 100% of the environmental attributes associated with the Project. AltaGas is able to sell or use the credits internally as they see fit.

2.1 Project Implementation

The Project was implemented according to the Acid Gas Injection Protocol (Version 1, May 2008) as the Plant flared acid gas prior to the regulatory requirement to reduce Sulphur emissions. After contemplating an AGI scheme or a three-bed Claus Sulphur recovery unit (SRU), the Plant chose to install an AGI scheme. Therefore, the assumed baseline condition is the Claus SRU that would have processed the acid gas on site to meet the Sulphur emissions regulation.

The offset project was implanted according to the Offset Project Plan, with the following variances and improvements made to the quantification methodology throughout the project lifetime.

The following variances were implemented in the current 2017 reporting period:

i) P9 Injection Unit Operation (2017 VY)

In 2017, electricity consumption at the injection well (3-25-12-19 W4) was identified and made available to Bluesource. Therefore, the kWh consumption was added to SS P9 Injection Unit Operation as a project electricity emissions source. The electricity is used to supply heat and lighting to the injection well building that would not otherwise be used by the Turin gas Plant in the absence of the AGI scheme. The total emissions from this variance are immaterial at 6.6 t CO_2e; however, the inclusion increases project accuracy.

ii) Fortis AGSR WSD Data

For this reporting period, electricity consumption data for the K-12 Acid Gas compressor and the injection well offsite were derived directly from the Fortis electricity consumption spreadsheet. In the previous reporting period, a summary sheet provided by AltaGas was used for monthly electricity values. To increase project accuracy and transparency, the Fortis data was used directly 2017 for all months.

Highlighted below are a number of key changes to the Project during the 2016 reporting period as compared to the Offset Project Plan:

i) SS P6 Acid Gas Dehydration and Compression (2016 VY)

In previous reporting periods, the power usage for the K-12 Acid Gas Compressor was determined using the kW rating for the compressor and runtime hours. This method assumed full compressor load was being utilized at all times. For this reporting period monthly power consumption (kWh) data for the compressor was obtained, as it is metered separately from the plant. Thus, the calculator includes the exact power consumption data for the compressor rather than an estimate based on runtime hour; adhering to the ISO 14064-2 principle of accuracy. Conversely, a meter specifically for fans and intercooler power consumption was not available. Therefore, the power consumption for these components is calculated using the previous method of runtime hours and kW ratings for the fan motors.

Using the directly metered power consumption data over the previous estimation method resulted in a 3% increase in credits created by the project (or 2,274 tonnes CO_2e).

ii) SS B6a Incineration (Fuel Gas) and B6b Incineration (Tail Gas)

In the previous reporting periods the SULSIM ratio was calculated using the molar flow of the tail gas stream and the molar flow of a wet acid gas stream. For this reporting period it was confirmed that the acid gas being injected has had water removed from the stream as a result of the compression processes before injection and, therefore, it was determined that using a dry acid gas stream in the calculation of the molar flow ratio is more accurate. This change in methodology was applied to determining the tail gas volumes for this reporting period in line with the ISO 14064-2 principle of accuracy. As a result, a higher SRU molar ratio (1.097) is calculated relative to the previous year's (1.051), thereby increasing the volume of tail gas that would have been produced by the SRU by 3.6%. In addition, the baseline volume of fuel gas required for incineration is increased by 3.8%. Therefore, the new method results in an increase of baseline emissions due to the increased volume of tail gas and fuel gas required for incineration, and a larger project emission reduction.

iii) SS B6b Incineration (Tail Gas) – Inclusion of N_2O emissions

For this reporting period, N_2O emissions created during the incineration of tail gas were added to SS B6 – Baseline Emissions from Incineration calculations. The formula is included in Section 6.0 below, under the SS B6 subsection.

iv) SS P12 – Fuel Extraction and Processing

In previous reporting periods, the volume of natural gas used in project condition calculations was the amount of fuel gas that would have been required to flare acid gas in the absence of the project. For this reporting period, the volume of fuel gas required for catadyne heaters in the compressor building and EFM in the acid gas injection scheme were also included in SS P12 calculations. The formulas for calculating fuel extraction and processing emissions with the combined volume of project condition fuel gas have been adjusted below in Section 6.0.

Highlighted below are a number of key changes to the Project during the 2015 reporting period as compared to the Offset Project Plan:

(i) SS P9 Injection Unit Operation

A number of small emission sources as part of the acid gas injection scheme have been identified for this reporting period. These include 17 fuel gas Catadyne heaters used to maintain optimal temperature in the winter time for a number of measurement devices, and three electric Ruffneck heaters used to heat the compressor building. Emissions from these sources were calculated and included as project emissions under "P9 Injection Unit Operation" for this reporting period. This is a variance from the offset project plan, which had excluded emissions from P9 Injection Unit Operation. Emissions were calculated for operating the heaters during five winter months resulting in a total of 40.4 tonnes of CO_2e and a 0.05% drop in emissions reductions achieved.

(ii) Change in Grid Emissions Intensity Factor

Alberta Environment & Parks (AEP) released the Carbon Offset Emission Factors Handbook Version 1.0 in March of 2015. This document contains updated emission factors for projects in the Alberta carbon offset system. The Project uses grid electricity for the operation of the acid gas compressor, electric heaters and other electric devices resulting in emissions in the project condition. Therefore, the grid emissions intensity factor was updated to 0.64 tonnes CO_2e per MWh for this reporting period. Using this updated emission factor is more accurate than the previous grid emissions factor.

Highlighted below are a number of key changes to the Project during the 2014 reporting period as compared to the Offset Project Plan:

(iii) SS B6b Incineration (Tail Gas)

Emissions from tail gas incineration were calculated by multiplying the percentage of CO_2 and other carbon components found in the *acid* gas by the volume of *acid* gas produced. This approach was updated so that the *tail* gas volumes generated and the *tail* gas composition based on the SULSIM produced by Sulphur Experts are used instead. Use of the simulated *tail* gas composition and the calculated *tail* gas volumes due to the molar flow change within the SRU are more accurate than using the acid gas composition and the acid gas volumes, which was previously done. This increased the accuracy of emissions from tail gas combustion in the baseline.

(iv) Change in Global Warming Potentials

The Alberta Environment and Sustainable Resource Development (AESRD) released a memorandum on January 23, 2014 entitled "*Notice of Change for Global Warming Potentials*". The memorandum stated that Alberta has adopted the 2007 global warming potentials as published by the International Panel on Climate Change (IPCC). These new global warming potentials (GWP's) apply to all vintage credits generated in 2014 onwards in the Alberta Offset program. As a result, the global warming potentials for methane (25, previously 21) and nitrous oxide (298, previously 310) have been updated for this project reporting period.

No additional changes to record keeping, data collection, monitoring, emissions factors, or quantification were made during this reporting period that were not otherwise already discussed.

This is the final crediting year for the Project; therefore, regulatory changes and modifications to the Alberta Offset System as a result of the carbon levy alignment process will not affect the Project in 2019.

2.2 Protocol

The Project is quantified under the now-withdrawn *Quantification Protocol for Acid Gas Injection*, Version 1, AESRD May 2008. As the Project was ongoing at the time the Protocol was terminated, the Project received grandfathering status and was able to fulfill its crediting period duration.

Only one protocol was used to develop and quantify this project. The protocol was applicable to the Project as the AGI scheme is located in Alberta and directly reduces GHG emissions through the permanent sequestration of acid gas and CO_2 that would have otherwise been released to atmosphere. A Claus SRU is used in the baseline condition as prescribed by the Protocol.

No deviation requests were required by the Project. The following flexibility mechanism was used by the Project in order to increase Project accuracy:

> *Site specific emission factors may be substituted for the generic emission factors indicated in this protocol document. The methodology for generation of these emission factors must be sufficiently robust as to ensure reasonable accuracy;*

The methodology for the calculation of the fuel gas emission factor was sourced from best practice guidance from the Canadian Association of Petroleum Producers (CAPP), Calculating Greenhouse Gas Emissions (CAPP and Altus Environmental Engineering Ltd, 2003) as shown below.

[(a+2b + 3c + 4d + 5e + f) × 44.01]/23.64 = kg CO2/m3 fuel burned

Where:

a to f = mole fractions of natural gas components (a=C1, b=C2, c=C3, etc.).

44.01 = molecular weight of CO_2

23.64 = volume in m^3 occupied by 1 kmole of gas at STP (15°C and 101.3 kPa)

2.3 Risks

There are no additional offset projects at the Project location at this time, nor additional risks beyond those included in the OPP. There are no other offset projects registered at 12-19-12-18 W4M or the injection well.

3.0 Project Quantification

Total Baseline emissions during the reporting period: 77,473 tonnes CO_2e

Total Project emissions during the reporting period: 2,599 tonnes CO_2e

Total emission reductions claimed in the reporting period: 74,874 tonnes CO_2e

3.1 Summary Table Non-Levied Emissions

Vintage	Gas Type	Baseline Emissions	Project Emissions	Total Reduction, Sequestration, or Capture
2017	CO_2	44,570	215	44,355
2017	CH_4	4,595	22	4,573
2017	N_2O	707	2.0	705
2017	CO_2e	27,601	2,360	25,241
Total 2017	**CO_2e**	***77,473 t CO_2e***	***2,599 tCO_2e***	***74,874 tCO_2e***
n/a	CO_2	n/a	n/a	n/a
n/a	CH_4	n/a	n/a	n/a
n/a	N_2O	n/a	n/a	n/a
n/a	Other	n/a	n/a	n/a
Total Year Y	**CO_2e**	n/a	n/a	n/a

Total for Reporting Period	**CO_2e**	***77,473 t CO_2e***	***2,599 tCO_2e***	***74,874 tCO_2e***

Table "3.1 Summary Table *Levied* Emissions and Biogenic CO_2" below has been excluded as this Project is not impacted by the Carbon levy for the 2017 vintage year and this is the final crediting year for the Project. Therefore, all emission reductions are eligible for the Project and considered 'non-levied' as indicated in the table above.

3.1 Summary Table Levied Emissions and Biogenic CO_2

Vintage[1]	Gas Type[2]	Baseline Emissions	Project Emissions	Total Reduction, Sequestration, or Capture
Year X	CO_2	n/a	n/a	n/a
Year X	CH_4	n/a	n/a	n/a
Year X	N_2O	n/a	n/a	n/a
Year X	Other *(specify)*	n/a	n/a	n/a
Year X	Biogenic	n/a	n/a	XX tCO_2
Total Year X	**CO_2e**	***XX tCO_2e***	***XX tCO_2e***	***XX tCO_2e***
Year Y	CO_2	n/a	n/a	n/a
Year Y	CH_4	n/a	n/a	n/a
Year Y	N_2O	n/a	n/a	n/a
Year Y	Other	n/a	n/a	n/a
Year Y	Biogenic	n/a	n/a	XX tCO_2
Total Year Y	**CO_2e**	***XX tCO_2e***	***XX tCO_2e***	**XX tCO_2e**
Total for Reporting Period	**CO_2e**	n/a	n/a	n/a

3.2 Calculations

GHG emission reductions were calculated following the *Quantification Protocol for Acid Gas Injection,* version 1.0 (AENV, 2008). The activities and procedures outlined in the Offset Project Plan provide a detailed description of the project's adherence to the requirements of the quantification protocol. The formulas used to quantify GHG offset by the project are listed below. A flexibility mechanism was utilized in the quantification procedures: a site-specific emission factor for CO_2 from natural gas combustion was substituted for the generic emission factor from Environment Canada (2016).

Emission Reduction = Emissions Baseline – Emissions Project

Emissions Baseline = sum of the emissions under the baseline condition.

(i) Emissions Fuel Extraction and Processing = emissions under SS (B9) Fuel Extraction/ Processing
(ii) Emissions Incineration = emissions under SS (B6) Incineration (fuel gas & tail gas)

Emissions Project = sum of the emissions under the project condition.

(i) Emissions Fuel Extraction and Processing = emissions under SS (P12) Fuel Extraction/ Processing
(ii) Emissions Gas Dehydration and Compression = emissions under SS (P6) Acid Gas Dehydration and Compression
(iii) Emissions Upset Flaring = emissions under SS (P8) Upset Flaring (fuel gas & tail gas)

a. SS B9 (Fuel Extraction and Processing)

$$\text{Emissions of } CO_2 = B_{Flaring} \times EF_{CO_2-XP}$$

$$\text{Emissions of } CH_4 = B_{Flaring} \times EF_{CH_4-XP} \times GWP_{CH4}$$

$$\text{Emissions of } N_2O = B_{Flaring} \times EF_{N_2O-XP} \times GWP_{N2O}$$

Where:

$EF_{CO2-XP}/EF_{CH4-XP}/EF_{N2O-XP}$ (tonnes/e^3m^3) = Emission factor for natural gas extraction and processing of CO_2, CH_4, and N_2O as per the Handbook (2015), see Table 4;

$B_{Flaring}$ (e^3m^3) = Fuel gas volume for baseline tail gas flaring, 20,423.9 e^3m^3;

$$= (AG_{Flare} + P_{Disposal}) \times FG{:}AG$$

$GWP_{CH4/N2O}$ = Global warming potential of CH_4 and N_2O according to the Handbook (2015).

And:

AG_{Flare} (e^3m^3) = Acid gas flared volumes (upset flaring), obtained from S30 Balance Reports, 162.03 e^3m^3;

$P_{Disposal}$ (e^3m^3) = Metered acid gas disposal volumes from meter 3B at the injection well, 15,111.33 e^3m^3;

FG:TG = Fuel gas to tail gas ratio;

$$= \frac{\mathrm{LHV_{Combined}} - \mathrm{LHV_{Tail\ Gas}}}{\mathrm{LHV_{Fuel}} - \mathrm{LHV_{Combined}}}$$

And:

$LHV_{Combined}$ = Combined net heating value of tail gas and make-up fuel gas; 20 MJ/m^3 as per AER Directive 060

$LHV_{Tail\ Gas}$ = Lower heating value of tail gas (composition of tail gas based on simulation provided by Sulphur Experts) 0.2273 MJ/m^3;

LHV_{FG} = Lower heating value of fuel gas, based on fuel gas composition and mole fraction, 36.23 MJ/m^3;

TG = tail gas produced by the Sulphur Recovery Unit, 16,753.5 e^{3}m^3;

$$= \left(\mathrm{AG_{Flare}} + \mathrm{P_{Disposal}}\right) \times \mathrm{TG:AG}$$

TG:AG = molar flow ratio of tail gas to acid gas as simulated by the SULSIM produced by Sulphur Experts, 1.097;

$$= \mathrm{TailGas_{INCT}} \div \mathrm{AG\ DryBasis_{2017}}$$

$$= 80.453 \div 73.345$$

$$=1.097$$

$TailGas_{INCT}$ = molar flow output (tail gas) of sulphur recovery unit as simulated by Sulphur Experts and reported in the SULSIM, 80.453 kg mole/h.

AG $DryBasis_{2017}$ = molar flow of acid gas streaming into the sulphur recovery unit as simulated by Sulphur Experts and presented in the SULSIM, 73.345 kg mole/h.

Therefore, emissions from SS B9:

$$\text{Emissions of } \mathrm{CO_2} = 20{,}423.9\ \mathrm{e^3m^3} \times 0.133\ \mathrm{t\ CO_2e/e^3m^3}$$

$$\text{Emissions of } \mathrm{CH_4} = 20{,}423.9\ \mathrm{e^3m^3} \times 0.003\ \mathrm{t\ CO_2e/e^3m^3} \times \mathrm{GWP_{25}}$$

$$\text{Emissions of } \mathrm{N_2O} = 20{,}423.9\ \mathrm{e^3m^3} \times 0.000007\ \mathrm{t\ CO_2e/e^3m^3} \times \mathrm{GWP_{298}}$$

$$= 4{,}086.5\ \text{tonnes } \mathrm{CO_2e}$$

b. SS B6a (Incineration of Fuel Gas)[1]

$$\text{Emissions of } \mathrm{CO_2}\ (\text{SS B6a}) = \mathrm{B_{Flaring}} \times \mathrm{EF_{CO_2-Turin}}$$

$$\text{Emissions of } \mathrm{CH_4}\ (\text{SS B6a}) = \mathrm{B_{Flaring}} \times \mathrm{EF_{CH_4-COM}} \times \mathrm{GWP_{CH4}}$$

$$\text{Emissions of } \mathrm{N_2O}\ (\text{SS B6a}) = \mathrm{B_{Flaring}} \times \mathrm{EF_{N_2O-COM}} \times \mathrm{GWP_{N2O}}$$

[1] Density of CO_2 and CH_4 from Alberta Environment 2008 AGI Protocol (pg 25, 26, and 31)

$EF_{CO2\text{-}Turin}$ (tonnes/e^3m^3) = Turin site-specific CO_2 emission factor for natural gas combustion at the Turin plant as developed by the flexibility mechanism discussed above, see Table 4;

$EF_{CH4\text{-}COM}$/$EF_{N2O\text{-}COM}$ (tonnes/e^3m^3) = Emission factor for natural gas combustion of CH_4 and N_2O as per the Handbook (2015), see Table 4;

Therefore, emissions from SS B6a:

$$\text{Emissions of } CO_2 \text{ (SS B6a)} = 20{,}423.9\ e^3m^3 \times 2.0493\ t\ CO_2e/e^3m^3$$

$$\text{Emissions of } CH_4 \text{ (SS B6a)} = 20{,}423.9\ e^3m^3 \times 0.0064\ t\ CO_2e/e^3m^3 \times GWP_{25}$$

$$\text{Emissions of } N_2O \text{ (SS B6a)} = 20{,}423.9\ e^3m^3 \times 0.00006\ t\ CO_2e/e^3m^3 \times GWP_{298}$$

$$= 45{,}487.3 \text{ tonnes } CO_2e$$

c. SS B6b (Incineration of Tail Gas)

The acid gas from Turin's combined stream (i.e. Enchant, Retlaw, and Turin) contains CO_2, N_2O, and residual hydrocarbons including CH_4, C_2H_6, C_3H_8, iC_4H_{10}, nC_4H_{10}, $neoC_5H_{12}$, iC_5H_{12}, nC_5H_{12}, and nC_6H_{14}. Below are the equations used to determine the tonnes of CO_2e of each hydrocarbon species and N_2O due to flaring of tail gas in the baseline condition (combustion).

$$\text{Emissions of } CO_2 \text{ (SS B6b)} = TG \times \%CO_{2,\ \text{Combined}} \times \rho CO_2$$

$$\text{Emissions of } CH_4 \text{ (SS B6b)} = TG \times \%CH_{4,\ \text{Combined}} \times \rho CH_4 \times \left[\frac{44\frac{g}{mole}CO_2}{16\frac{g}{mole}CH_4}\right]$$

$$\text{Emissions of } C_2H_6 \text{ (SS B6b)} = TG \times \%C_2H_{6,\ \text{Combined}} \times \rho C_2H_6 \text{ x } \left[2 \text{ x } \frac{44\frac{g}{mole}CO_2}{30\frac{g}{mole}C_2H_6}\right]$$

$$\text{Emissions of } C_3H_8 \text{ (SS B6b)} = TG \times \%C_3H_{8,\ \text{Combined}} \times \rho C_3H_8 \times \left[3 \text{ x } \frac{44\frac{g}{mole}CO_2}{44\frac{g}{mole}C_3H_8}\right]$$

$$\text{Emissions of } iC_4H_{10} \text{ (SS B6b)} = TG \times \%iC_4H_{10,\ \text{Combined}} \times \rho iC_4H_{10} \times \left[4 \text{ x } \frac{44\frac{g}{mole}CO_2}{58\frac{g}{mole}iC_4H_{10}}\right]$$

$$\text{Emissions of } nC_4H_{10} \text{ (SS B6b)} = TG \times \%nC_4H_{10,\ \text{Combined}} \times \rho nC_4H_{10} \times \left[4 \text{ x } \frac{44\frac{g}{mole}CO_2}{58\frac{g}{mole}nC_4H_{10}}\right]$$

$$\text{Emissions of } iC_5H_{12} \text{ (SS B6b)} = TG \times \%iC_5H_{12,\ \text{Combined}} \text{ x } \rho iC_5H_{12} \times \left[5 \text{ x } \frac{44\frac{g}{mole}CO_2}{72\frac{g}{mole}iC_5H_{12}}\right]$$

$$\text{Emissions of } nC_5H_{12} \text{ (SS B6b)} = TG \times \%nC_5H_{12,\ \text{Combined}} \times \rho nC_5H_{12} \times \left[5 \text{ x } \frac{44 \frac{g}{mole} CO_2}{72 \frac{g}{mole} nC_5H_{12}}\right]$$

$$\text{Emissions of } nC_6H_{14} \text{ (SS B6b)} = TG \times \%nC_6H_{14,\ \text{Combined}} \times \rho nC_6H_{14} \times \left[6 \text{ x } \frac{44 \frac{g}{mole} CO_2}{86 \frac{g}{mole} nC_6H_{14}}\right]$$

$$\text{Emissions of } nC_7H_{16} \text{ (SS B6b)} = TG \times \%nC_7H_{16,\ \text{Combined}} \times \rho nC_7H_{16} \times \left[7 \text{ x } \frac{44 \frac{g}{mole} CO_2}{100 \frac{g}{mole} nC_7H_{16}}\right]$$

$$\text{Emissions of } nC_8H_{18} \text{ (SS B6b)} = TG \times \%nC_8H_{18} \times \rho nC_8H_{18} \times \left[8 \text{ x } \frac{44 \frac{g}{mole} CO_2}{114 \frac{g}{mole} nC_8H_{18}}\right]$$

$$\text{Emissions of } nC_9H_{20} \text{ (SS B6b)} = TG \times \%nC_9H_{20} \times \rho nC_9H_{20} \times \left[9 \text{ x } \frac{44 \frac{g}{mole} CO_2}{128 \frac{g}{mole} nC_9H_{20}}\right]$$

$$\text{Emissions of } nC_{10}H_{22} \text{ (SS B6b)} = TG \times \%\ nC_{10}H_{22} \times \rho nC_{10}H_{22} \times \left[10 \text{ x } \frac{44 \frac{g}{mole} CO_2}{142 \frac{g}{mole} nC_{10}H_{22}}\right]$$

$$\text{Emissions of } N_2O \text{ (SS B6b)} = TG \times EF_{N2O-COM} \times GWP_{25}$$

Therefore, emissions from SS B6b:

$$= 27{,}901.1 \text{ tonnes } CO_2e$$

Densities used in the above equations are based on assuming ideal gas behaviour of each hydrocarbon species and presented in the following table:

Table 3. Densities of gas species (tonnes/e³m³) [2]

Species	CO_2	CH_4	C_2H_6	C_3H_8	iC_4H_{10}	nC_4H_{10}	Neo-C_5H_{11}	nC_5H_{12}	nC_6H_{14}	nC_7H_{16}	nC_8H_{18}	nC_9H_{20}	$nC_{10}H_{22}$
Density	1.861	0.678	1.272	1.865	2.458	2.458	3.051	3.051	3.645	4.238	4.831	5.424	6.017

d. SS P12 (Fuel Extraction and Processing)

$$\text{Emissions of } CO_2 = NG_{Project} \times EF_{CO2-XP}$$

$$\text{Emissions of } CH_4 = NG_{Project} \times EF_{CH4-XP} \times GWP_{CH4}$$

[2] Gas Processors Association (2008). GPA Standard 2145-09: Table of Physical Properties for Hydrocarbons and Other Compounds of Interest to the Natural Gas Industry.

$$\text{Emissions of } N_2O = NG_{Project} \times EF_{N2O-XP} \times GWP_{N2O}$$

Where:

$NG_{Project}$ (e^3m^3) = Fuel gas volumes used for upset flaring, and the catadyne heaters in the compressor building and EFM, 98.81 e^3m^3:

$$NG_{Project} = FG_{Heaters} + FG_{Flare}$$

$EF_{CO2\text{-}XP}$/$EF_{CH4\text{-}XP}$/$EF_{N2O\text{-}XP}$ (tonnes/e^3m^3) = Emission factor for natural gas extraction and processing of CO_2, CH_4, and N_2O as per the Handbook (2015), see Table 4;

Therefore, emissions from SS P12:

$$\text{Emissions of } CO_2 = 98.81\ e^3m^3 \times 0.133\ t\ CO_2e/e^3m^3$$

$$\text{Emissions of } CH_4 = 98.81\ e^3m^3 \times 0.003\ t\ CO_2e/e^3m^3 \times GWP_{25}$$

$$\text{Emissions of } N_2O = 98.81\ e^3m^3 \times 0.000007\ t\ CO_2e/e^3m^3 \times GWP_{298}$$

$$= 19.77 \text{ tonnes } CO_2e$$

e. SS P6 (Acid Gas Dehydration and Compression)

$$\text{Emissions of } CO_2 = (P_{AC} + P_{Coolers}) \times EF_{ELEC}$$

Where:

EF_{ELEC} (t CO_2e/MWh) = Grid electricity intensity emission factor, based on the Handbook (2015), see Table 4;

P_{AC} (MWh/month) = Metered power usage of the acid gas compressor K-12; 3027.03 MWh

$P_{Coolers}$ (MWh/month) = Power usage of the fan motor used, 193.06 MWh;

$$= R \times kW_{Fan}$$

And:

R (hrs) = Operating hours of the acid gas compressor, 8,627.2 annual hours;

kW_{Fan} (kW) = kW rating of the fan motor, 22.38 kW

Therefore, emissions from SS P6:

$$\text{Emissions of } CO_2 = (3027.03 \text{ MWh} + 193.06 \text{ MWh}) \times 0.64\ t\ CO_2e/\text{MWh}$$

$$= 2060.9 \text{ tonnes } CO_2e$$

f. SS P8a (Upset Flaring Fuel Gas)

$$\text{Emissions of } CO_2 \text{ (SS P8a)} = FG_{Flare} \times EF_{CO2-Turin}$$

$$\text{Emissions of } CH_4 \text{ (SS P8a)} = FG_{Flare} \times EF_{CH4-COM} \times GWP_{CH4}$$

$$\text{Emissions of } N_2O \text{ (SS P8a)} = FG_{Flare} \times EF_{N2O-COM} \times GWP_{N2O}$$

Where:

FG_{FLARE} (e^3m^3) = metered volume of fuel gas sent to flare (meter 151), 80.69 e^3m^3;

$EF_{CO2\text{-}Turin}$ (tonnes/e^3m^3) = Turin site-specific CO_2 emission factor for natural gas combustion at the Turin plant, see Table 4;

$EF_{CH4\text{-}COM}$/$EF_{N2O\text{-}COM}$ (tonnes/e^3m^3) = Emission factor for natural gas combustion of CH_4 and N_2O as per the Handbook (2015), see Table 4;

Therefore, emissions from SS P8a:

$$\text{Emissions of } CO_2 \text{ (SS P8a)} = 80.69\ e^3m^3 \times 2.0493\ \text{t } CO_2e/e^3m^3$$

$$\text{Emissions of } CH_4 \text{ (SS P8a)} = 80.69\ e^3m^3 \times 0.0064\ \text{t } CO_2e/e^3m^3 \times GWP_{25}$$

$$\text{Emissions of } N_2O \text{ (SS P8a)} = 80.69\ e^3m^3 \times 0.00006\ \text{t } CO_2e/e^3m^3 \times GWP_{298}$$

$$= 179.7 \text{ tonnes } CO_2e$$

g. SS P8b. (Upset Flaring Acid Gas)

Below are the equations used to determine the tonnes CO_2e of each hydrocarbon species due to flaring of acid gas in the project condition.

$$\text{Emissions of } CO_2 \text{ (SS P8b)} = AG_{Flare} \times \%CO_{2,\ Combined} \times \rho CO_2$$

$$\text{Emissions of } CH_4 \text{ (SS P8b)} = AG_{Flare} \times \%CH_{4,\ Combined} \times \rho CH_4 \times \left[\frac{44 \frac{g}{mole} CO_2}{16 \frac{g}{mole} CH_4}\right]$$

$$\text{Emissions of } C_2H_6 \text{ (SS P8b)} = AG_{Flare} \times \%C_2H_{6,\ Combined} \times \rho C_2H_6 \times \left[2 \text{ x } \frac{44 \frac{g}{mole} CO_2}{30 \frac{g}{mole} C_2H_6}\right]$$

$$\text{Emissions of } C_3H_8 \text{ (SS P8b)} = AG_{Flare} \times \%C_3H_{8,\ Combined} \times \rho C_3H_8 \times \left[3 \text{ x } \frac{44 \frac{g}{mole} CO_2}{44 \frac{g}{mole} C_3H_8}\right]$$

$$\text{Emissions of } iC_4H_{10} \text{ (SS P8b)} = AG_{Flare} \times \%iC_4H_{10,\ Combined} \times \rho iC_4H_{10} \times \left[4 \text{ x } \frac{44 \frac{g}{mole} CO_2}{58 \frac{g}{mole} iC_4H_{10}}\right]$$

$$\text{Emissions of } nC_4H_{10} \text{ (SS P8b)}$$

$$= AG_{Flare} \times \%nC_4H_{10,\ Combined} \times \rho nC_4H_{10} \times \left[4 \text{ x } \frac{44 \frac{g}{mole} CO_2}{58 \frac{g}{mole} nC_4H_{10}}\right]$$

$$\text{Emissions of } neoC_5H_{12} \text{ (SS P8b)}$$

$$= AG_{Flare} \text{ x } \%neoC_5H_{12,\ Combined} \text{ x } \rho neoC_5H_{12} \times \left[5 \text{ x } \frac{44 \frac{g}{mole} CO_2}{72 \frac{g}{mole} neoC_5H_{12}}\right]$$

$$\text{Emissions of } iC_5H_{12}\ (\text{SS P8b}) = AG_{\text{Flare}} \text{ x } \%iC_5H_{12,\ \text{Combined}} \text{ x } \rho iC_5H_{12} \times \left[5 \text{ x } \frac{44\frac{g}{\text{mole}}CO_2}{72\frac{g}{\text{mole}}iC_5H_{12}}\right]$$

$$\text{Emissions of } nC_5H_{12}\ (\text{SS P8b}) = AG_{\text{Flare}} \text{ x } \%nC_5H_{12,\ \text{Combined}} \text{ x } \rho nC_5H_{12} \times \left[5 \text{ x } \frac{44\frac{g}{\text{mole}}CO_2}{72\frac{g}{\text{mole}}nC_5H_{12}}\right]$$

$$\text{Emissions of } nC_6H_{14}\ (\text{SS P8b}) = AG_{\text{Flare}} \text{ x } \%nC_6H_{14,\ \text{Combined}} \text{ x } \rho nC_6H_{14} \times \left[6 \text{ x } \frac{44\frac{g}{\text{mole}}CO_2}{86\frac{g}{\text{mole}}nC_6H_{14}}\right]$$

And:

AG_{FLARE} (e^3m^3) = acid gas volumes flared during upset conditions, 162.03 e^3m^3

Therefore, emissions from SS P8b:

$$= 292.5 \text{ tonnes } CO_2e$$

h. SS P9 (Injection Unit Operation)

P9 Heating emissions:

$$\text{Emissions of } CO_2\ (\text{SS P9}) = FG_{\text{Heater}} \text{ x } EF_{\text{CO2-Turin}}$$

$$\text{Emissions of } CH_4\ (\text{SS P9}) = FG_{\text{Heater}} \text{ x } EF_{\text{CH4-COM}} \times GWP_{\text{CH4}}$$

$$\text{Emissions of } N_2O\ (\text{SS P9}) = FG_{\text{Heater}} \text{ x } EF_{\text{N2O-COM}} \times GWP_{\text{N2O}}$$

Where:

FG_{Heater} (e^3m^3) = Volume of natural gas required to operate the fuel gas Catadyne heaters in compressor building and EFM, 18.1 e^3m^3:

$$= \frac{PC_{\text{HEATER}} \text{ x } 3.6 \text{ MJ/kWh}}{LHV_{FG} \text{ x } 1000 \text{ m}^3/\text{e}^3\text{m}^3}$$

LHV_{FG} (MJ/m^3) = lower heating value of fuel gas, based on fuel gas composition and mole fraction, 36.23 MJ/m^3;

PC_{HEATER} (kWh) = power consumption of fuel gas Catadyne heaters, 182.4 MWh

$$= (kW_{\text{FGH-Compressor}} \times Qty_{\text{Compressor}} \times Hrs) + (kW_{\text{FGH-EFM}} \times Qty_{\text{EFM}} \times Hrs)$$

$kW_{FGH\text{-}Compressor}$ (kW) = power rating of fuel gas heater = 2.93 kW

$kW_{FGH\text{-}EFM}$ (kW) = power rating of fuel gas heater = 2.93 kW

$Qty_{Compressor}$ = number of catadyne heaters compressor building = 16

Qty_{EFM} = number of catadyne heaters in EFM = 1

Hrs = annual runtime hours for the five cooling months in the year:

$$= 5 \text{ months} \times 30.5 \frac{\text{days}}{\text{month}} \times 24 \frac{\text{hrs}}{\text{day}}$$

$$= 3{,}660 \text{ hours}$$

Therefore, emissions from SS P9 heating:

$$\text{Emissions of } CO_2 \text{ (SS P9)} = 18.1 \text{ e}^3\text{m}^3 \times 2.0493 \text{ tonnes/e}^3\text{m}^3$$

$$\text{Emissions of } CH_4 \text{ (SS P9)} = 18.1 \text{ e}^3\text{m}^3 \times 0.0064 \text{ tonnes/e}^3\text{m}^3 \times GWP_{25}$$

$$\text{Emissions of } N_2O \text{ (SS P9)} = 18.1 \text{ e}^3\text{m}^3 \times 0.00006 \text{ tonnes/e}^3\text{m}^3 \times GWP_{298}$$

$$= 40.36 \text{ tonnes } CO_2e$$

Additionally, **P9 Electricity** emissions:

$$\text{Emissions of } CO_2e \text{ (SS P9)} = PC_{ELECTRIC} \times EF_{CO2eEF}$$

Where:

$PC_{ELECTRIC}$ (MWh)	= power consumption of electric Viking Vapour Pump and the building at the injection well for lights and power, 11.9 MWh; $= VIKING_{POWER} + 9010_{POWER}$
9010_{POWER} (MWh)	= Fortis power consumption at site ID 0040497319010, the injection well, 10.3 MWh
$VIKING_{POWER}$ (kWh)	= power consumed by the electric Viking Vapour Pump when the K-12 compressor is down, 1,600.2 kWh; $= (kW_{EP} \times Qty \times Hrs)$ $= 1{,}600.2 \text{ kWh}$
kW_{EP} (kW)	= power rating of electric pump = 12 kW
Qty	= number of electric pumps = 1
Hrs	= runtime hours, the pump only operates when the K-12 compressor is down, 133.4 hours; $= (24 \text{ hrs} \times 365 \text{ days}) - K12_{op\ hrs}$ $= 8{,}760 \text{ hrs} - 8{,}626.7 \text{ hrs}$ $= 133.4 \text{ hrs}$

Therefore, electricity emissions in SS P9:

$$\text{Emissions of } CO_2e \text{ (SS P9)} = (10.3 \text{ MWh} + (1{,}600.2 \text{ kWh} \div 1000)) \times 0.64 \text{ t } CO_2e/\text{MWh}$$

$$= 7.6 \text{ tonnes } CO_2e$$

Table 4 provides the emission factors used for the project.

Table 4. Emission factors used by the Project in this reporting period.

Parameter	Relevant SS	CO_2 Emission Factor	CH_4 Emission Factor	N_2O Emission Factor	CO_2e Emission Factor	Source:
Natural Gas Combustion	B5b, B6a, P8a	2.0493 tonnes/ e^3m^3	0.0064 tonnes/ e^3m^3	0.00006 tonnes/ e^3m^3	-	CO_2: site specific based on CAPP[3] formula $[(a+2b + 3c + 4d + 5e + f) \times 44.01]/23.64$ = kg CO_2/m^3 fuel burned (equivalent to tonnes/e^3m^3) CH_4/N_2O: Carbon Offset Emission Factors Handbook Version 1.0, March 2015
Natural Gas Extraction	B9, P12	0.043 tonnes/ e^3m^3	0.0023 tonnes/ e^3m^3	0.000004 tonnes/ e^3m^3	-	Carbon Offset Emission Factors Handbook Version 1.0, March 2015
Natural Gas Processing	B9, P12	0.090 tonnes/ e^3m^3	0.0003 tonnes/ e^3m^3	0.000003 tonnes/ e^3m^3	-	Carbon Offset Emission Factors Handbook Version 1.0, March 2015
Electricity Consumption	P6, P9	-	-	-	0.64 tonnes/ MWh	Carbon Offset Emission Factors Handbook Version 1.0, March 2015

[3] Canadian Association of Petroleum Producers (2003) GUIDE – Calculating Greenhouse Gas Emissions, pg. 12.

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