

Formatted: Left: 89.85 pt, Right: 89.85 pt, Section start: New column

Deleted: End of Section ¶

QUANTIFICATION PROTOCOL FOR
INSTRUMENT GAS TO INSTRUMENT AIR CONVERSION
IN PROCESS CONTROL SYSTEMS

Submitted to:
Alberta Environment
And
Climate Change Central

March, 2009

Deleted: <sp>November

Deleted: 8

1

Table of Contents

2 1.0. Project and Methodology Scope and Description 1

3 1.1. Protocol Scope and Description..... 1

4 1.2. Glossary of New Terms..... 5

5 2.0. Quantification Development and Justification..... 9

6 2.1. Identification of Sources and Sinks (SS's) for the Project 9

7 2.2. Identification of Baseline 14

8 2.3. Identification of SS's for the Baseline 14

9 2.4. Selection of Relevant Project and Baseline SS's 19

10 2.5. Quantification of Reduction, Removals, and Reversals of Relevant SS's 22

11 2.5.1. Quantification Approach 22

12 2.5.2. Contingent Data Approach 31

13 2.6. Management of Data Quality..... 31

14 2.6.1. Record Keeping 31

15 2.6.2. Quality Assurance/Quality control (QA/QC)..... 31

16 APPENDIX A - Explanation on Gas Equivalency and Leaks 35

17 APPENDIX B - Quantification Procedures for Flexibility Mechanisms 42

18 APPENDIX C - Emissions Factor for Selected Fuels 51

19

20

List of Figures

21 FIGURE 1.1: Process Flow Diagram for Project Condition 7

22 FIGURE 1.2: Process Flow Diagram for Baseline Condition..... 8

23 FIGURE 2.1: Project Element Life Cycle Chart..... 10

24 FIGURE 2.2: Baseline Element Life Cycle Chart 15

25

26

List of Tables

27 TABLE 2.1: Project SS's 11

28 TABLE 2.2: Baseline SS's..... 16

29 TABLE 2.3: Comparison of SS's 20

30 TABLE 2.4: Quantification Procedures 23

31 TABLE 2.5: Contingent Data Collection Procedures 32

32

33

34

35

36

37

38

1 **1.0. Project and Methodology Scope and Description**

2 This quantification protocol is written for the gas and/or oil operator or any operator in
3 the oil and gas industry where natural gas is used to provide pressure for process control
4 systems. Some familiarity with, or understanding of, the operation of gas and/or oil
5 operations and control systems is assumed.

Deleted: systems

6 Wells, oil producing and gas producing facilities, and gas processing facilities sometimes
7 use pneumatic devices for process control. Pneumatic instruments may be powered by
8 compressed air, natural gas, or propane. Readily available pressurized natural gas has
9 made it the power source of choice among operators in the industry. Natural gas is used
10 to power process control equipment, which includes pressure controllers, temperature
11 controllers, transducers, liquid level controllers, and flow rate regulators. These devices
12 have one or two emission rates depending on the design: continuous or bleed rate and
13 intermittent or vent rate. Once the gas has powered the instrument, it is left to vent and
14 bleed to the atmosphere. The vent and bleed rate will depend on the type of device, age
15 and operating condition. For the purpose of this protocol, the sum of these two emission
16 rates will be referred to as **vent rate or vented gas**, which is the term commonly used in
17 the oil and gas industry. Bleed rate or bleed gas is also used in industry to express the
18 sum of these two emissions.

Deleted: sometimes

Deleted: equipment

Deleted: controllers

Deleted:

19 The opportunity for generating carbon offsets with this protocol arises from the direct and
20 indirect reduction of greenhouse gas emissions resulting from the conversion of
21 instrument gas to instrument air in process control systems. Instrument air will be
22 provided by compressed air. Therefore, a complete air compressor system will be needed
23 for this conversion.

Deleted: instrument gas to instrument air in process control systems

24 It must be stated that this protocol does not stipulate a process change but rather a change
25 in the pressure source for typical process control systems. It is assumed that a natural gas
26 pressure source will be converted to an air pressure source. It should be noted that any
27 volume that would have been vented will now be avoided by this conversion. The final
28 fate of the gas may be assumed to be combustion by end-users, unless otherwise
29 indicated.

30 **1.1. Protocol Scope and Description**

31 This protocol serves as a generic ‘recipe’ for project proponents to follow in order to
32 meet the measurement, monitoring, and greenhouse gas quantification requirements for
33 reductions resulting from conversion of instrument gas to instrument air in process
34 control systems. A process flow diagram for a typical project using compressed air to
35 provide pressure to instrument controllers is shown in **FIGURE 1.1**. Upon conversion,
36 all methane that would have been vented will be replaced by compressed air.

Deleted: Emissions in the project stem from electricity consumption used to compress the air and to manage the air.

Deleted: ¶

Deleted: conversion to instrument air

37 **Protocol Approach:**

38 The baseline condition for this protocol is defined as the volume of natural gas vented or
39 flared/combusted to the atmosphere prior to the conversion to instrument air. In this
40 baseline scenario, instrument gas is typically sourced from the fuel supply for the entire

Deleted: In this baseline scenario, instrument gas is typically sourced from the fuel supply for the entire facility.

1 | facility. This is a major source of greenhouse gas emissions for the baseline. A process
2 | flow diagram for a typical baseline using fuel gas to provide pressure to pneumatic
3 | controllers is shown in **FIGURE 1.2**. Other sources of emission include greenhouse
4 | gases from fuel extraction and processing.

5 | In the baseline condition, vented, or flared/combusted gas is typically not metered.
6 | Establishing volumes of vented, or flared/combusted gas will have to be performed by
7 | converting metered volumes of air to volumes of gas through an equivalency. This
8 | protocol therefore uses data from metered air to establish the volume of natural gas that
9 | would have been vented, or flared/combusted had the project not taken place. Further
10 | explanation of how to establish this equivalency is **APPENDIX A.1**. Establishing the
11 | amount of compressed air for the project will depend on the facility implementing the air
12 | conversion system. For facilities installing an air compressor system to power pneumatic
13 | instruments, metering air is straightforward. Metered air will provide volumes that can be
14 | used to establish emissions from:

- 15 | • Equivalent fuel gas vented, or flared/combusted; and
- 16 | • Emissions from fuel gas extraction and processing.

17 | However, some facilities may have an air compressor system already installed for other
18 | applications. In such cases, air consumed by the pneumatic instruments will have to be
19 | prorated against total air compressed.

Formatted: Bullets and Numbering

Deleted: In addition to the previously mentioned emissions, prorated air consumption can be applied to total electricity consumed to:
Establish electricity used to compress air for pneumatic instruments; and
Emissions from air management.

Deleted: Lastly, electricity consumption must also be metered to establish consumption and emissions.

20 | Prorated quantities may also be reconciled quantities on a periodic basis. In other
21 | words, a balance can be carried out to determine the quantities used in air compression.

22 | Equations have been developed in order to quantify these emissions from the project and
23 | baseline conditions. These equations have been developed considering choked conditions
24 | in the pneumatic devices. This assumption yields equations that are accurate, yet
25 | underestimate emissions. This is a conservative approach and assures that emissions are
26 | not overestimated. In addition, this assumption makes the protocol easy to use and data
27 | collection simple and manageable. Refer to **APPENDIX A.1** for more details.

28 | Metering will be carried out for a minimum period of **ONE** month for compressed air.
29 | The project proponent should choose a month that is **representative** of normal operating
30 | conditions. Emissions from this period are assumed to be **representative** of normal
31 | instrument operations during the project and baseline conditions and will represent a cap
32 | for the project's time span. This cap represents the maximum emissions that project
33 | proponent may claim, even if the facility increases operations and consequently its
34 | emissions from control instruments. Furthermore, since control instruments work at a
35 | steady rate in a given facility, this period of metering will reflect a static condition for
36 | both the baseline and the project for the reporting period. This protocol therefore assumes
37 | that the baseline and project condition are static, unless adjusted. The one month
38 | metering period ensures a conservative approach. This is because leaks are prone to
39 | appear in pneumatic systems over time. Therefore by setting the baseline close to the leak
40 | inspection and repair program, and for a short period of time, the risk of overestimating

Deleted: all metered quantities

1 measured emissions is reduced. Furthermore, the longer the system is metered the
2 increased likelihood that these quantities include leaks.

3 To facilitate verification, the project proponent should identify the run time of principle
4 equipment such as compressors, dehydrators, or other equipment within the facility to
5 show continuity and typical runtimes. The runtime of this equipment in subsequent
6 months should be compared to the hours it operated during the period of one month
7 metering. The percentage difference is then applied against the offsets calculated for that
8 month to account for any variations in facility operation.

9 **Protocol Applicability:**

10 To demonstrate that a project meets the requirements under this protocol, the project
11 developer must supply sufficient evidence to demonstrate that:

12
13 1. The instrument air system replaces an existing instrument gas system that
14 provides equivalent function. The instrument air conversion must not impair the
15 functionality of the process control system as demonstrated by unit operational
16 performance data, and/or facility process flow diagrams and/or other equipment
17 technical specifications. Functional equivalence may also be demonstrated
18 through an affirmation by the project developer or a third party.

19 2. The project is a conversion from instrument gas to instrument air and not facilities
20 originally constructed to use instrument air or replacements due to end-of-life.
21 This may be demonstrated by facility process flow diagrams and/or accounting
22 records, work orders, invoices or other vendor/third party
23 documentation/evidence. Instrument air conversions may also be demonstrated
24 through an affirmation by the project developer or a third party.

25 3. To facilitate verification and allow for changes in the facility, the proponent will
26 develop an inventory of devices to be maintained annually. Any changes to the
27 inventory, i.e. devices removed, will impact net offsets claimed as illustrated in
28 APPENDIX A.3. The list will also help in determining what fraction of the
29 pneumatic devices was vented and what fraction was flared. Refer to Flexibility
30 Mechanism section and APPENDIX B for more details.

31 4. The key concept in this applicability criterion is for the project proponent to
32 inspect and repair leaks prior to actual metering to reduce and mitigate risks
33 associated with overestimation of emissions.

34 Prior to the implementation of the instrument air system and metering, the project
35 proponent must demonstrate that the instrument air system's piping network has
36 been inspected for leaks as pursuant to section 8.7 in Directive 60. This directive
37 60 states that an operator of an oil or gas facility must develop and implement a
38 program to detect and repair leaks meeting or exceeding the CAPP *Best*
39 *Management Practice (BMP) for Fugitive Emissions Management.* This BMP
40 suggests annual or quarterly leak monitoring frequencies depending on the

Formatted: Font: 12 pt, English (Canada)

Formatted: Space After: 12 pt

Deleted: ¶

Formatted: English (U.S.)

Formatted: Space Before: 12 pt

Formatted: Justified, Don't adjust right indent when grid is defined, Space After: 12 pt, Numbered + Level: 1 + Numbering Style: 1, 2, 3, ... + Start at: 1 + Alignment: Left + Aligned at: 18 pt + Tab after: 36 pt + Indent at: 36 pt, Don't adjust space between Latin and Asian text, Don't adjust space between Asian text and numbers

Deleted: . The instrument air system will replace the instrument gas system in process control. Functional equivalence between the instrument gas system and the instrument air system has not been compromised

Formatted: Font: 12 pt, English (Canada)

Formatted: Bullets and Numbering

Formatted: Font: 12 pt, Bold, English (Canada)

Formatted: Font: 12 pt, English (Canada)

Formatted: Font: 12 pt

Formatted: Font: 12 pt

Deleted: .

Formatted: Numbered + Level: 1 + Numbering Style: 1, 2, 3, ... + Start at: 1 + Alignment: Left + Aligned at: 18 pt + Tab after: 36 pt + Indent at: 36 pt

Formatted: Indent: Left: 36 pt

Deleted: The key concept in this applicability criterion is for the project proponent to inspect and repair leaks prior to actual metering to reduce and mitigate risks associated with overestimation of emissions. ¶ Prior to the implementation of the instrument air system and metering, the project proponent must demonstrate that the instrument air system's pip ... [1]

1 process equipment device. Following these steps should guarantee that leaks have
2 been minimized as much as practically possible. This will ensure that metering
3 does not overestimate volumes of air, which in turn determines the volumes of gas
4 that would have been vented, had the project not taken place. If inspection for
5 leaks is not performed according to suggested monitoring frequencies, metered air
6 must be reduced using a Discount Factor. This factor is developed in detail in
7 **APPENDIX A.2.**

Deleted: d

Deleted: f

8 For projects installed prior to this protocol that are currently not metered, the
9 same principle applies as detailed above. Prior to the installation of a metering
10 system, leaks should be minimized as much as practically possible.

Deleted: that

11 5. This protocol has been designed for specific use in natural gas processing plants.
12 However, other facilities in the oil and gas industry use instrument gas to provide
13 pressure to pneumatic devices. This protocol may be applied to projects where
14 existing gas provides pressure to instrumentation or Chemical Injection Pumps
15 (CIP), or other types of equipment.

Formatted: Bullets and
Numbering

Deleted: instrument gas

Deleted: pressure to pneumatic
devices

16 6. The project must meet the requirements for offset eligibility as specified in the
17 applicable regulation and guidance documents for the Alberta Offset System. [Of
18 particular note:

- 19 a. [The date of equipment installation, operating parameter changes or
20 process reconfiguration are initiated or have effect on the project on or
21 after January 1, 2002 as indicated by facility records;]
- 22 b. [The project may generate emission reduction offsets for a period of 8
23 years unless an extension is granted by Alberta Environment, as indicated
24 by facility and offset records. Additional credit duration periods require a
25 reassessment of the baseline condition; and,]
- 26 c. [Ownership of the emission reduction offsets must be established as
27 indicated by facility records.]

28 **Protocol Flexibility:**

29 Flexibility in applying the quantification protocol is provided to project developers in the
30 following ways:

- 31 1. Site specific emissions factors may be substituted for the generic emission factors
32 indicated in this protocol document. The methodology for generation of these
33 emission factors must be sufficiently robust to ensure accuracy. ▼
- 34 2. Baseline and project metering may be carried out for more than one month if the
35 project proponent deems necessary to show more accurate and representative
36 emissions. It is up to the project proponent to justify this flexibility mechanism.
- 37 3. For cases in which projects were implemented but the air was not metered, carbon
38 offsets are claimable. This claim is based on instrument counts from the facility
39 and the metered air. Emissions from the one month metering are used as a

Deleted: As an example, the most probable source of energy to power the air system will be electrical. The most current electricity displacement factor for on-grid electricity in Alberta can be found in Environmental Canada references documents such as Canada's emissions inventory. This value will be reviewed and updated periodically and the most current value should be used by the proponent. If the operator is a self-generator, the emissions factor can be calculated from the fuel source the project proponent is using.

1 baseline. This baseline is adjusted by subtracting the sum of the devices added
2 multiplied by their respective vent rate. Details of this flexibility mechanism are
3 provided in **APPENDIX B.1**. It should be noted that the lists in **APPENDIX B**
4 are not complete lists and therefore not authoritative. More instruments may exist
5 or are under development and have not been included. These lists only serve as an
6 illustrative example of the emissions that may be encountered by project
7 developer. It is up to the project developer to use emission or vent rates that are
8 most current by contacting the manufacturer of specific devices and request
9 information for those specific devices. Manufacturers of control devices usually
10 publish the emission rates for each type of device, and for each type of operation.

11 4. For projects where part of the vented gas is flared or collected for combustion, the
12 project proponent may claim credits using this protocol's flexibility mechanism.
13 The total metered air is divided into two fractions; X represents the vented
14 fraction and (1-X) represents the flared or combusted fraction. X represents a
15 fraction that is established using vendor's technical specifications for bleed rates
16 (BR). Refer to **APPENDIX B.2** for a detailed explanation on how these
17 percentages are established. Assuming all instrument gas is vented, the value of X
18 is 1.

19 5. Instrument air conversions can be installed at single or multiple sites. As such, the
20 protocol allows for flexibility in quantifying offsets from multiple conversion
21 projects. If applicable, the proponent must indicate and justify why flexibility
22 provisions have been used.

23 **1.2. Glossary of New Terms**

<u>Instrument Air</u>	Any instrument that uses <u>pressurized</u> compressed air to function and provided the necessary level of control required for its intended use.
Bleed Rate	Rate at which a device uses air or natural gas continuously due to design requirements. Rates may vary in the field due to changing conditions.
Fuel Gas	Portion of the sales gas used for facility operations such as fuel for engines and compressors, pressure supply for pneumatic devices, etc...
Functional Equivalence	The project and the baseline should provide the same function and quality of products or services. This type of comparison requires a common metric or unit of measurement (such as flow rate) for comparison between the Project and Baseline activity (Refer to the Guidance Document for the Alberta Offset System). The functional equivalence in this protocol is the pressure provide by the natural gas and air pneumatic system <u>in terms of metered volumes</u> .
<u>Instrument Gas</u>	Any instrument that uses <u>pressurized</u> natural gas to function and provided the necessary level of control required for its intended use.

Deleted: <#>If emissions are reduced because of decommissioning of devices, the metered baseline must be adjusted. Decommissioned devices are subtracted from the baseline. Details of this flexibility mechanism are provided in **APPENDIX B.3.**¶

Formatted: Bullets and Numbering

Deleted: Instrument Air

Deleted: pressurized

Deleted:

Deleted: Instrument Gas

Deleted: pressurized

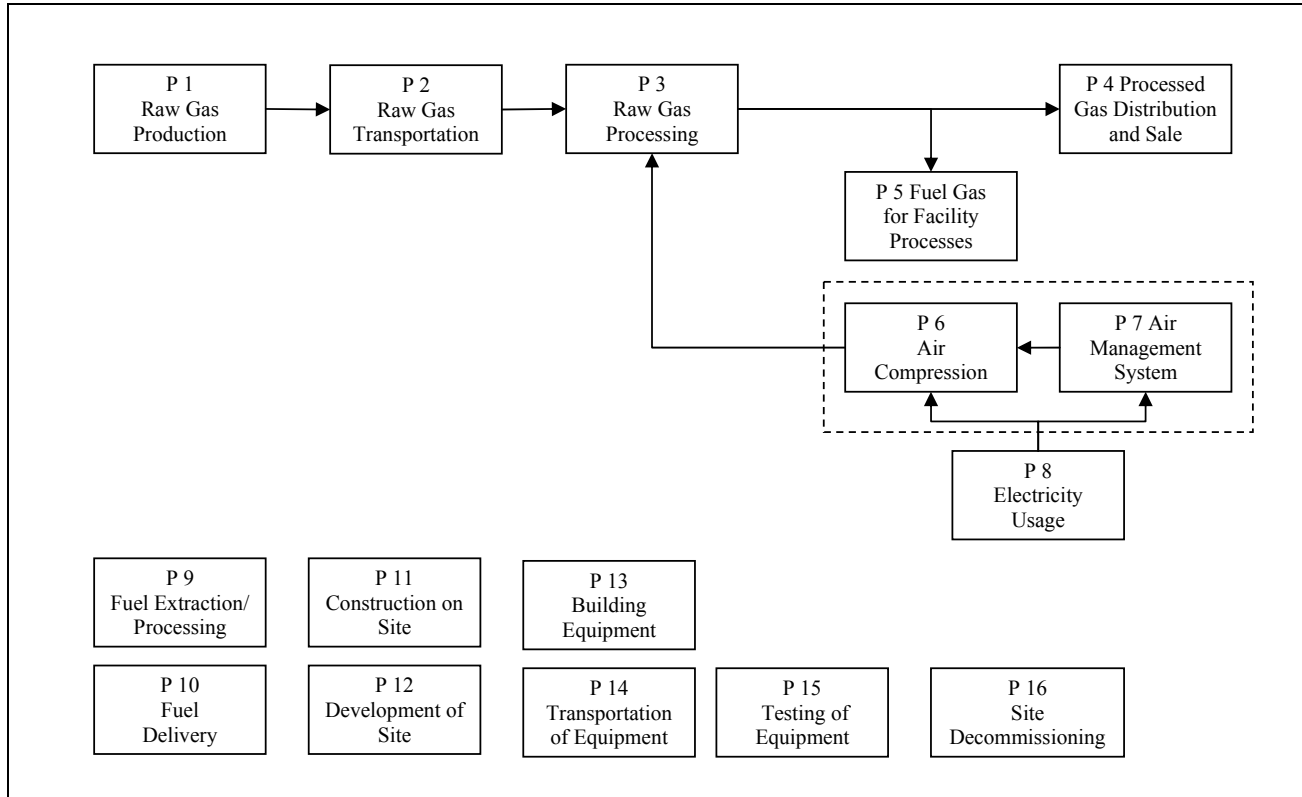
Leak Unwanted emissions from worn seals, gaskets, and diaphragms, nozzle corrosion or wear from poor quality gas leading to increased flow, and loose control tube fittings in a pneumatic instrument

Vent Rate Rate at which a device uses air or natural gas intermittently due to design requirements. Rates may vary in the field due to changing conditions. In this protocol, vent rate is used to describe the sum of both bleed and vent rates.

1

1
2
3

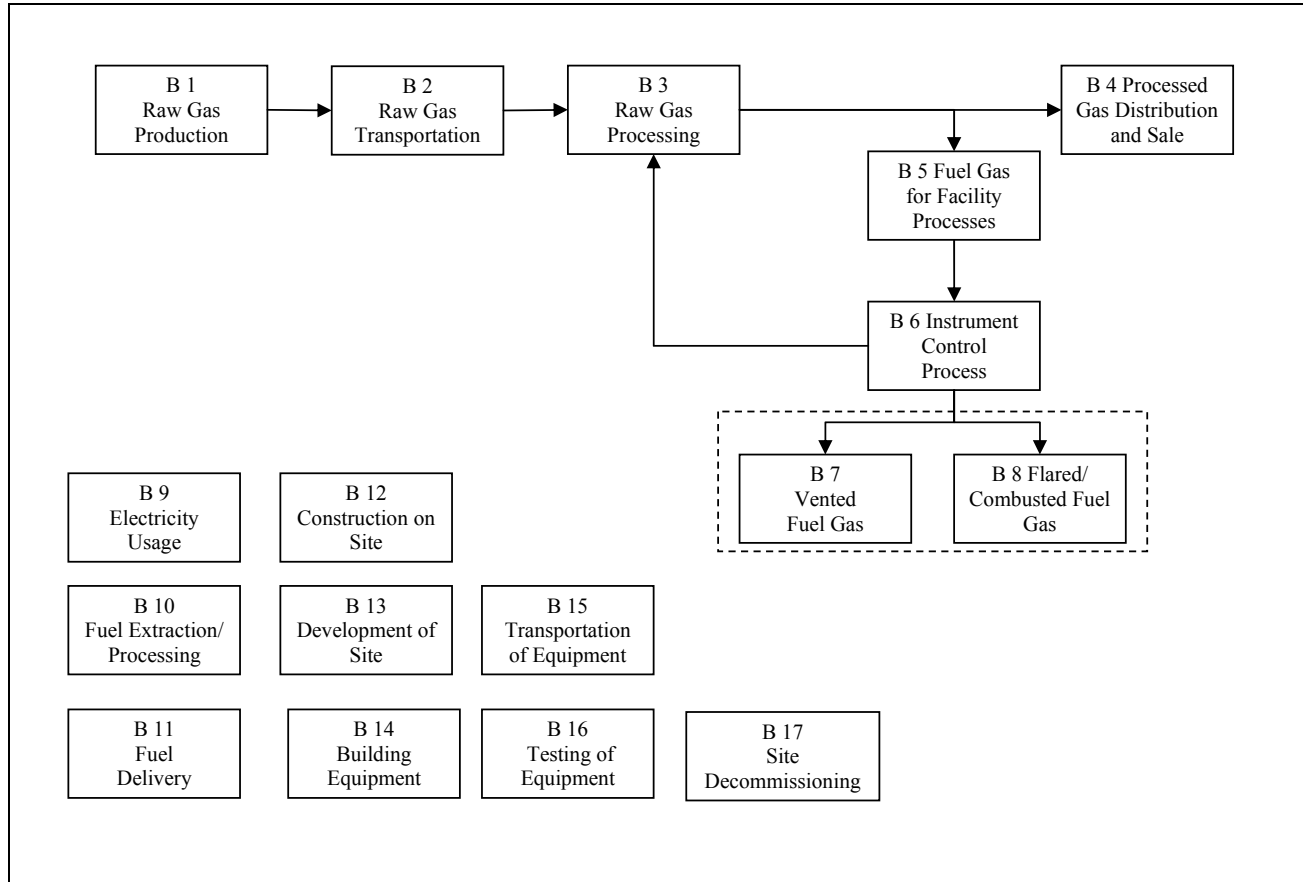
FIGURE 1.1: Process Flow Diagram for Project Condition



4
5
6
7
8
9

1
2
3

FIGURE 1.2: Process Flow Diagram for Baseline Condition



4

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21

2.0. Quantification Development and Justification

The following sections outline the quantification development and justifications.

2.1. Identification of Sources and Sinks (SS's) for the Project

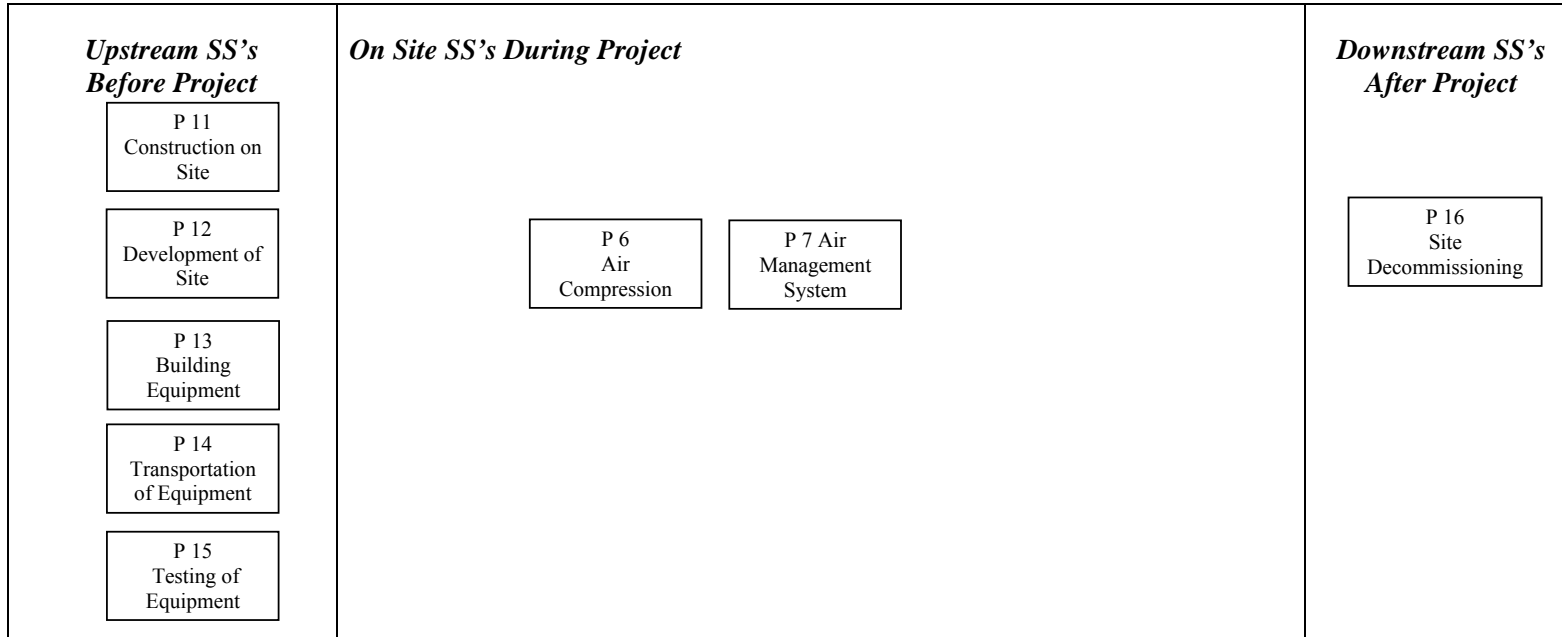
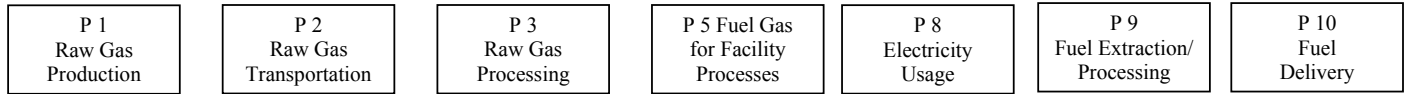
SS's were identified for the project by reviewing the seed documents and relevant process flow diagrams pertaining to the operation of natural gas processing facilities. This process confirmed that the SS's in the process flow diagrams covered the full scope of eligible project activities under the protocol.

Based on the process diagrams provided in **FIGURE 1.1**, the project's SS's were organized into life cycle categories in **FIGURE 2.1**, Description of each of the SS's and their classification as controlled, related or affected are provided in **TABLE 2.1**.

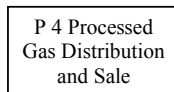
1 **FIGURE 2.1: Project Element Life Cycle Chart**

2

Upstream SS's During Project



Downstream SS's During Project



1 **TABLE 2.1: Project SS's**

2

1. SS	2. Description	3. Controlled, Related or Affected
Upstream SS's during Project Operation		
P 1 Raw Gas Production	The raw gas is collected from a group of adjacent wells where moisture content is reduced by removing water and condensate. Condensate is transported to oil refineries for further processing and wastewater is disposed. The quantity of greenhouse gases in the raw gas would need to be tracked. The types and quantities of fuels used in extraction equipment would also need to be tracked. Leaks may also be present in the production facility and should be tracked too.	Related
P 2 Raw Gas Transportation	The raw gas is piped to a natural gas processing plant. The types and quantities of fuels used in transportation would need to be tracked. Leaks may also be present in the pipeline and should be tracked also.	Related
P 3 Raw Gas Processing	Processing of raw gas is required to remove hydrogen sulphur, carbon dioxide, water vapour, and heavier hydrocarbons. Clean gas is ready to be distributed and sold. Heavier hydrocarbons are also removed and transported to oil refineries. The quantity of greenhouse gas in the processed gas would need to be tracked. Leaks may also be present in the production facility and should be tracked too. Possibility of venting gas must also be considered and tracked.	Related
P 5 Fuel Gas For Facility	Many processes in the facility require clean gas to function. This clean gas, also referred to as fuel gas, is drawn from the processed gas that will be sold. Equipment in the processes includes compressors, boilers, heaters, engines, glycol dehydrators, refrigerators, and chemical injection pumps (CIP). The types and quantities of fuels used in processing would need to be tracked. Leaks may also be present in the production facility and should be tracked too.	Related
P 8 Electricity Usage	Electricity may be required for operating the facility. This power may be sourced either from internal generation, connected facilities or the local electricity grid. Metering of electricity may be netted in terms of the power going to and from the grid. Quantity and source of the power are the important characteristics to be tracked as they directly relate to the quantity of greenhouse gas emissions. For facilities located near the electricity grid, P6 and P7 will most likely use this electricity source. Electricity for P6 and P7 for facilities located in remote areas may include fossil fuels such as diesel or natural gas.	Related
P 9 Fuel Extraction/ Processing	Each of the fuels used throughout the project will need to be sourced and processed. This will allow for the calculation of greenhouse gas emissions from the various processes involved in the production, refinement, and storage of the fuels. The total volumes of fuel for each of the SS's in this project are considered in this SS. Types and quantities of fuels used would need to be tracked.	Related

P 10 Fuel Delivery	Each of the fuels used throughout the project will need to be transported to the site. This may include shipments by tanker or by pipeline, resulting in the emissions of greenhouse gases. It is reasonable to exclude fuel sourced by taking equipment to an existing commercial fuelling station as the fuel used to take the equipment to the site is captured under other SS's and there is no other delivery.	Related
Onsite SS's during Project Operation		
P 6 Air Compression	Air will be used to supply pressure to the pneumatic control instruments. The energy required for the compressors to function will come from various sources. Quantity and source of the electricity source are the important characteristics to be tracked as they directly relate to the quantity of greenhouse gas emissions.	Controlled
P 7 Air Management System	Compressed air will pass from the air compressor to the volume tanks and then through the control instrumentation when activated. This air may require conditioning such as drying by specialized equipment prior to distribution in the air instrument network. Equipment for the air <u>management</u> system may consume energy and needs to be tracked.	Controlled
Downstream SS's during Project Operation		
P 4 Processed Gas Distribution and Sale	Natural gas and other commercially viable NGL products may be <u>sent</u> to a pipeline system or transported by rail or truck to customers at another point. Avoided greenhouse gas emissions from the fuel gas supply to the control instrumentation should be included here. It is assumed that the mostly likely use of avoided greenhouse gas emissions would be <u>controlled combustion to produce carbon dioxide</u> .	Related
Other		
P 11 Construction on Site	The process of construction at the site may require a variety of heavy equipment, smaller power tools, cranes, and generators. The operation of this equipment will have associated greenhouse gas emissions from the use of fossil fuels and electricity.	Related
P 12 Development of Site	The site may need to be developed. This could include civil infrastructure such as access to electricity, gas and water supply, as well as sewer. This may also include clearing, grading, building access roads, etc. There will also need to be some building of structures for the facility such as storage areas, storm water drainage, offices, vent stacks, firefighting water storage lagoons, etc., as well as structures to enclose, support and house the equipment. Greenhouse gas emissions would be primarily attributed to the use of fossil fuels and electricity used to power equipment required to develop the site such as graders, backhoes, trenching machines, etc.	Related
P 13 Building of Equipment	Equipment may need to be built either on-site or off-site. This includes all of the components of the storage, handling, processing, combustion, air quality control, system control, and safety systems. These may be sourced as pre-made standard equipment or custom built to specification. Greenhouse gas emissions would be primarily attributed to the use of fossil fuels and electricity used to power equipment for the extraction of the raw materials, processing, fabrication and assembly.	Related

Deleted: management

Deleted: sent

Deleted: controlled combustion to produce carbon dioxide

P 14 Transportation of Equipment	Equipment built off-site and the materials to build equipment on-site will all need to be delivered to the site. Transportation may be completed by train, truck, barge, or by some combination, or even by courier. Greenhouse gas emissions would be primarily attributed to the use of fossil fuels to power the equipment delivering the equipment to the site.	Related
P 15 Testing of Equipment	Equipment may need to be tested to ensure that it is operational. This may result in running the equipment using test anaerobic digestion fuels or fossil fuels in order to ensure that the equipment runs properly. These activities will result in greenhouse gas emissions associated with the combustion of fossil fuels and the use of electricity	Related
P 16 Site Decommissioning	Once the facility is no longer operational, the site may need to be decommissioned. This may involve the disassembly of the equipment, demolition of on-site structures, disposal of some materials, environmental restoration, re-grading, planting or seeding, and transportation of materials off-site. Greenhouse gas emissions would be primarily attributed to the use of fossil fuels and electricity used to power equipment required to decommission the site.	Related

~~Deleted: planting~~

~~Deleted: Greenhouse gas~~

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22

Formatted: Section start:
New column

2.2. Identification of Baseline

The baseline condition for projects applying this protocol is defined as the operating condition prior to the conversion of instrument gas to instrument air. The baseline is site specific and depends on the facility operation. Baseline fuel venting from pneumatic controls depends on the type of pneumatic device, operating condition, age, among other factors.

The most accurate method to establish a baseline is to meter vented fuel gas from individual devices. However, this is not a standard practice in industry because it can be time consuming, resource intensive, and costly. ~~As a result,~~ baseline emissions are determined from the metered quantity of compressed air through ~~a~~ gas equivalence formula as described in ~~APPENDIX A.~~ Once the air has been metered, the gas equivalency is applied. This will yield the amount of fuel gas that would have been vented. Note that this equivalency is in terms of pure methane (100% in gas composition). The equivalent volume is then be adjusted so it can take into account the percent of methane and carbon dioxide present in this fuel gas based on an annual gas analysis.

Deleted: So,

Deleted: Therefore, the air conversion project will need to have a metering system installed to measure the amounts of compressed air powering the pneumatic devices, the energy used to compress this air, and the energy used to manage the air.¶

Formatted: Font: Bold

~~The aforementioned baseline approach is justified as follows. Pneumatic devices are designed to run at a specific supply pressure, regardless of the pressure source. In the gas equivalency formula presented in APPENDIX A, pressure is assumed to be equal in the instrument gas and instrument air condition. To solve the gas equivalency formula, both fuel gas and air pressure are assumed to be equal. Therefore when the formula is solved, the energy loss in both the fuel gas and air condition is equal. This allows us to establish a relationship between the volume of air in the project condition and the volume of fuel gas in the baseline condition. As a result, this baseline methodology ensures functional equivalence because pressures in baseline and project conditions are assumed to be equal. Furthermore, this is an industry-accepted methodology to compare air and fuel gas emissions.~~

Formatted: Font: Bold

It must be noted that the fuel gas used to power the pneumatic instruments is not raw gas, but rather processed natural gas. Therefore, the equivalent volume is used to estimate the emissions from extraction and processing of raw gas.

Formatted: Space Before:
12 pt

The baseline condition is defined, including the relevant SS's and processes, as shown in **FIGURE 1.2**. More detail on each of these SS's is provided in the following section, section 2.3.

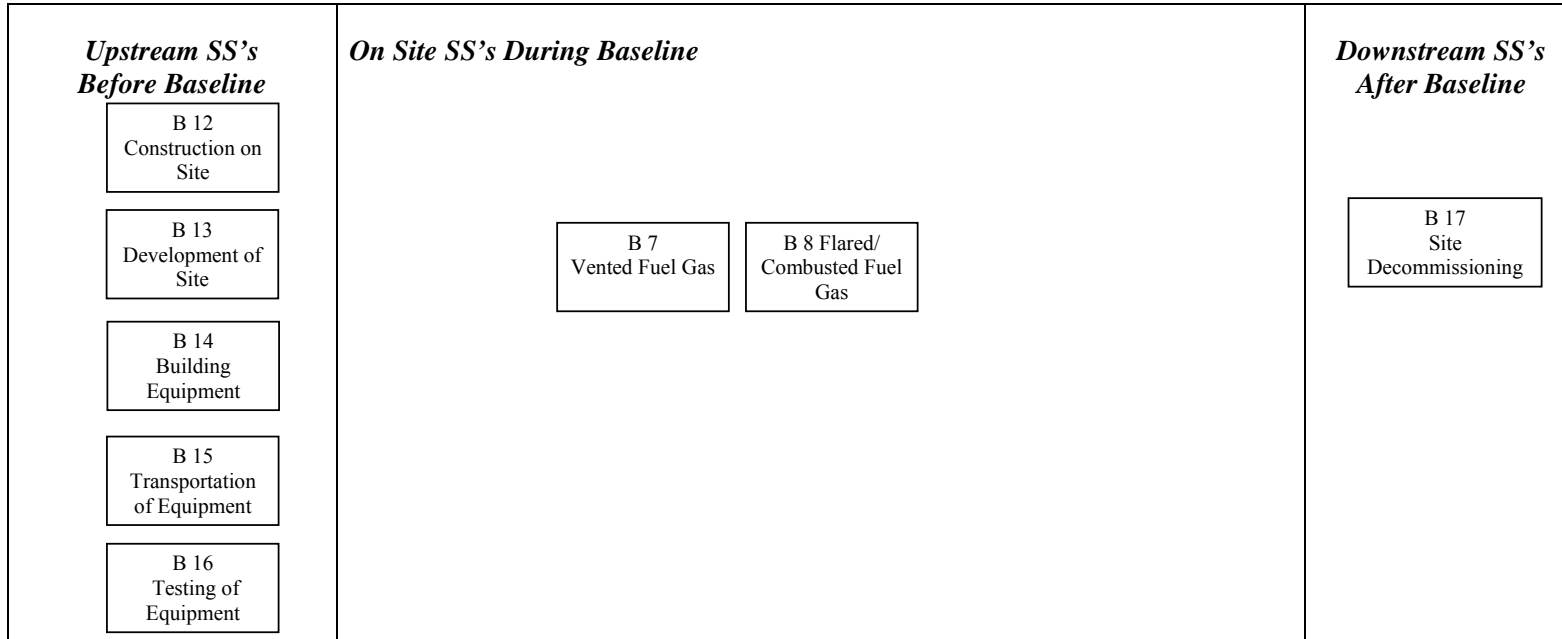
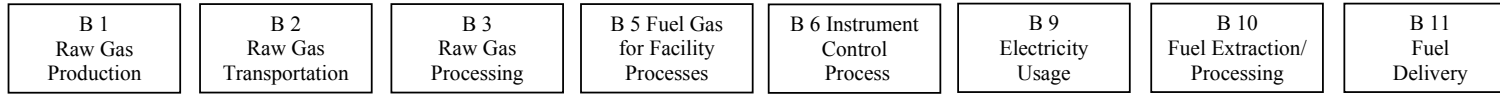
2.3. Identification of SS's for the Baseline

Based on the process diagrams provided in **FIGURE 1.2**, the project's SS's were organized into life cycle categories in **FIGURE 2.2**. Description of each of the SS's and their classification as 'controlled', 'related' or 'affected are provided in **TABLE 2.2**.

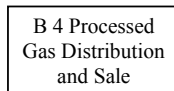
Deleted: ¶
¶
¶
¶

1 **FIGURE 2.2: Baseline Element Life Cycle Chart**

Upstream SS's During Baseline



Downstream SS's During Baseline



2

1 **TABLE 2.2: Baseline SS's**

1. SS	2. Description	3. Controlled, Related or Affected
Upstream SS's during Baseline Operation		
B 1 Raw Gas Production	The raw gas is collected from a group of adjacent wells where moisture content is reduced by removing water and condensate. Condensate is transported to oil refineries for further processing and wastewater is disposed. The quantity of greenhouse gas in the raw gas would need to be tracked. The types and quantities of fuels used in extraction equipment would also need to be tracked. Leaks may also be present in the production facility and should be tracked too.	Related
B 2 Raw Gas Transportation	The raw gas is piped to a natural gas processing plant. The types and quantities of fuels used in transportation would need to be tracked. Leaks may also be present in the pipeline and should be tracked also.	Related
B 3 Raw Gas Processing	Processing of raw gas is required to remove hydrogen sulphur, carbon dioxide, water vapour, and heavier hydrocarbons. Clean gas is ready to be distributed and sold. Heavier hydrocarbons are also removed and transported to oil refineries. The quantity of greenhouse gas in the processed gas would need to be tracked. Leaks may also be present in the production facility and should be tracked too. Possibility of venting gas must also be considered and tracked.	Related
B 5 Fuel Gas For Facility	Many processes in the facility require clean gas to function. This clean gas, also referred to as fuel gas, is drawn from the processed. Equipment in the processes include compressors, boilers, heaters, engines, glycol dehydrators, refrigerators, and chemical injection pumps (CIP), The types and quantities of fuels used in processing would need to be tracked. Leaks may also be present in the production facility and should be tracked too.	Related
B 6 Instrument Control Process	Pressurized gas will pass from the fuel gas supply and then through the control instruments when activated. The pressure of the gas is equivalent to the pressure that the project will provide to the instruments once the conversion has taken place.	Controlled
B 9 Electricity Usage	Electricity may be required for operating the facility. This power may be sourced either from internal generation, connected facilities or the local electricity grid. Metering of electricity may be netted in terms of the power going to and from the grid. Quantity and source of the power are the important characteristics to be tracked as they directly relate to the quantity of greenhouse gas emissions.	Related
B 10 Fuel Extraction/ Processing	Each of the fuels used throughout the project will need to be sourced and processed. This will allow for the calculation of greenhouse gas emissions from the various processes involved in the production, refinement, and storage of the fuels. The total volumes of fuel for each of the SS's in this project are considered in this SS. Types and quantities of fuels used would need to be tracked.	Related

B 11 Fuel Delivery	Each of the fuels used throughout the project will need to be transported to the site. This may include shipments by tanker or by pipeline, resulting in the emissions of greenhouse gas. It is reasonable to exclude fuel sourced by taking equipment to an existing commercial fuelling station as the fuel used to take the equipment to the site is captured under other SS's and there is no other delivery.	Related
Onsite SS's during Baseline Operation		
B 7 Vented Fuel Gas	Quantity of gas will need to be tracked because it represents the amount of fuel gas that is vented to the atmosphere once it has been used by pneumatic instruments. The quantity can be calculated or estimated.	Controlled
B 8 Flared/ Combusted Fuel Gas	Quantity of gas will need to be tracked because it represents the amount of fuel gas that might be collected and sent to a flare or combustion source. The quantity can be calculated or estimated.	Controlled
Downstream SS's during Baseline Operation		
B 4 Processed Gas Distribution and Sale	Natural gas and other commercially viable NGL products may be <u>sent</u> to a pipeline system or transported by rail or truck to customers at another point. The mostly likely use would be controlled combustion to produce carbon dioxide.	Related
Other		
B 12 Construction on Site	The process of construction at the site may require a variety of heavy equipment, smaller power tools, cranes, and generators. The operation of this equipment will have associated greenhouse gas emissions from the use of fossil fuels and electricity.	Related
B 13 Development of Site	The site may need to be developed. This could include civil infrastructure such as access to electricity, gas and water supply, as well as sewer. This may also include clearing, grading, building access roads, etc. There will also need to be some building of structures for the facility such as storage areas, storm water drainage, offices, vent stacks, firefighting water storage lagoons, etc., as well as structures to enclose, support and house the equipment. Greenhouse gas emissions would be primarily attributed to the use of fossil fuels and electricity used to power equipment required to develop the site such as graders, backhoes, trenching machines, etc.	Related
B 14 Building of Equipment	Equipment may need to be built either on-site or off-site. This includes all of the components of the storage, handling, processing, combustion, air quality control, system control, and safety systems. These may be sourced as pre-made standard equipment or custom built to specification. Greenhouse gas emissions would be primarily attributed to the use of fossil fuels and electricity used to power equipment for the extraction of the raw materials, processing, fabrication and assembly.	Related
B 15 Transportation of Equipment	Equipment built off-site and the materials to build equipment on-site will all need to be delivered to the site. Transportation may be completed by train, truck, barge, or by some combination, or even by courier. Greenhouse gas emissions would be primarily attributed to the use of fossil fuels to power the equipment delivering the equipment to the site.	Related

Deleted: sent

B 16 Testing of Equipment	Equipment may need to be tested to ensure that it is operational. This may result in running the equipment using test anaerobic digestion fuels or fossil fuels in order to ensure that the equipment runs properly. These activities will result in greenhouse gas emissions associated with the combustion of fossil fuels and the use of electricity.	Related
B 17 Site Decommissioning	Once the facility is no longer operational, the site may need to be decommissioned. This may involve the disassembly of the equipment, demolition of on-site structures, disposal of some materials, environmental restoration, re-grading, planting or seeding, and transportation of materials off-site. Greenhouse gas emissions would be primarily attributed to the use of fossil fuels and electricity used to power equipment required to decommission the site.	Related

Deleted: planting

1
2
3
4
5
6
7
8
9

1 **2.4. Selection of Relevant Project and Baseline SS's**

2 Each of the SS's from the project and baseline condition were compared and evaluated as
3 to their relevancy using the guidance provided in Annex VI of the "Guide to
4 Quantification Methodologies and Protocols: Draft", dated March 2006 (Environment
5 Canada). The justification for the exclusion or conditions upon which SS's may be
6 excluded is provided in **TABLE 2.3**, below. All other SS's listed previously are included.
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28
29
30
31
32
33
34
35
36
37
38
39
40
41
42
43
44
45
46

1 **TABLE 2.3: Comparison of SS's**

1. Identified SS	2. Baseline (C, R, A)	3. Project (C, R, A)	4. Include or Exclude from Quantification	5. Justification for Exclusion
Upstream SS's				
P 1 Raw Gas Production	N/A	Related	Excluded	Excluded as the production of raw gas is not impacted by the implementation of the project and as such the baseline and the project conditions will be functionally equivalent.
B 1 Raw Gas Production	Related	N/A	Excluded	
P 2 Raw Gas Transportation	N/A	Related	Excluded	Excluded as the transportation of raw gas is not impacted by the implementation of the project and as such the baseline and the project conditions will be functionally equivalent.
B 2 Raw Gas Transportation	Related	N/A	Excluded	
P 3 Raw Gas Processing	N/A	Related	Excluded	Excluded as the processing of raw gas is not impacted by the implementation of the project and as such the baseline and the project conditions will be functionally equivalent.
B 3 Raw Gas Processing	Related	N/A	Excluded	
P 5 Fuel Gas For Facility	N/A	Related	Excluded	Excluded as the fuel gas for facility is not impacted by the implementation of the project and as such the baseline and the project conditions will be functionally equivalent.
B 5 Fuel Gas For Facility	Related	N/A	Excluded	
P 9 Fuel Extraction/ Processing	N/A	Related	Included	N/A
B 10 Fuel Extraction/ Processing	Related	N/A	Included	N/A
P 8 Electricity Usage	N/A	Related	Excluded	Excluded as these SS's are not relevant to the project as the emission from these practises are covered under proposed greenhouse gas regulations.
B 9 Electricity Usage	Related	N/A	Excluded	Fuel gas processing does not use electricity in this case.
P 10 Fuel Delivery	N/A	Related	Excluded	Excluded as the fuel delivery is not impacted by the implementation of the project and as such the baseline and the project conditions will be functionally equivalent.
B 11 Fuel Delivery	Related	N/A	Excluded	
Onsite SS's				
P 6 Air Compression	N/A	Related	Included	N/A
P 7 Air Management System	N/A	Related	Included	N/A
B 7 Vented Fuel Gas	Related	N/A	Included	N/A
B 8 Flared/ Combusted	Related	N/A	Included	N/A

Deleted: Included in P 6 and P 7

Deleted: Excluded

Deleted: .

Formatted Table

Fuel Gas				
Downstream SS's				
P 4 Processed Gas Distribution and Sale	N/A	Related	Excluded	Excluded as the emissions from the distribution and sale of avoided vented gas is the sole responsibility of the end user. It is assumed the final use of this gas will be controlled combustion to produce carbon dioxide. Accountability of this gas is in the hands of end users.
B 4 Processed Gas Distribution and Sale	Related	N/A	Excluded	Excluded as the emissions from the distribution and sale of gas is the sole responsibility of the end user and it is assumed the final use of this gas will be controlled combustion to produce carbon dioxide.
Other				
P 11 Construction on Site	N/A	Related	Excluded	Emissions from construction on site are not material given the long project life and the minimal construction on site typically required.
B 12 Construction on Site	Related	N/A	Excluded	Emissions from construction on site are not material for the baseline condition given the minimal construction on site typically required.
P 12 Development of Site	N/A	Related	Excluded	Emissions from development of site are not material given the long project life and the minimal development of site typically required.
B 13 Development of Site	Related	N/A	Excluded	Emissions from development of site are not material for the baseline condition given the minimal development of site typically required.
P 13 Building of Equipment	N/A	Related	Excluded	Emissions from building of equipment are not material given the long project life and the minimal building equipment typically required.
B 14 Building of Equipment	Related	N/A	Excluded	Emissions from building of equipment are not material for the baseline given the minimal building equipment typically required.
P 14 Testing of Equipment	N/A	Related	Excluded	Emissions from testing of equipment are not material given the long project life and the minimal testing of equipment typically required.
B 15 Testing of Equipment	Related	N/A	Excluded	Emissions from testing of equipment are not material for the baseline given the minimal testing of equipment typically required.
P 15 Transportation of Equipment	N/A	Related	Excluded	Emissions from transportation of equipment are not material given the long project life and the minimal transportation of equipment typically required.
B 16 Transportation of Equipment	Related	N/A	Excluded	Emissions from transportation of equipment are not material for the baseline given the minimal transportation of equipment typically required.
P 16 Site Decommissioning	N/A	Related	Excluded	Emissions from decommissioning of site are not material given the long project life and the minimal decommissioning typically required.
B 17 Site Decommissioning	Related	N/A	Excluded	Emissions from decommissioning of site are not material for the baseline given the minimal decommissioning typically required.

1 **2.5. Quantification of Reduction, Removals, and Reversals of Relevant SS's**

2 **2.5.1. Quantification Approach**

3 Quantification of the reductions, removals and reversals of relevant SS's for each of the
4 greenhouse gases will be completed using the methodologies outlined in **TABLE 2.4**,
5 below. These calculation methodologies serve to complete the following three equations
6 for calculating the emission reductions from the comparison of the baseline and project
7 conditions.

8
$$\text{Emission Reduction} = \text{Emissions}_{\text{Baseline}} - \text{Emissions}_{\text{Project}}$$

9
$$\text{Emissions}_{\text{Baseline}} = \text{Emissions}_{\text{Fuel Extraction / Processing}} + \text{Emissions}_{\text{Vented Fuel Gas}} + \text{Emissions}_{\text{Flared/Combusted Fuel Gas}}$$

10
$$\text{Emissions}_{\text{Project}} = \text{Emissions}_{\text{Fuel Extraction / Processing}} + \text{Emissions}_{\text{Air Compression}} + \text{Emissions}_{\text{Air Management System}}$$

11 where:

12 $\text{Emissions}_{\text{Baseline}}$ = sum of the emissions under the baseline condition.

13 $\text{Emissions}_{\text{Fuel Extraction / Processing}}$ = emissions under SS B 10 Fuel Extraction and Processing

14 $\text{Emissions}_{\text{Vented Fuel Gas}}$ = emissions under SS B 7 Vented Fuel Gas

15 $\text{Emissions}_{\text{Flared/Combusted Fuel Gas}}$ = emissions under SS B 8 Flared/Combusted Fuel Gas

16 $\text{Emissions}_{\text{Project}}$ = sum of the emissions under the project condition.

17 $\text{Emissions}_{\text{Fuel Extraction / Processing}}$ = emissions under SS P 9 Fuel Extraction and Processing

18 $\text{Emissions}_{\text{Air Compression}}$ = emissions under SS P 6 Air Compression

19 $\text{Emissions}_{\text{Air Management System}}$ = emissions under SS P 7 Air Management System

1 **TABLE 2.4: Quantification Procedures**

1. Project / Baseline SS	2. Parameter / Variable	3. Unit	4. Measured / Estimated	5. Method	6. Frequency	7. Justify measurement or estimation and frequency
Project SS's						
P 9 Fuel Extraction/ Processing	Emissions _{Fuel Extraction / Processing} = $\Sigma (\text{Vol. Fuel}_i * \text{EF}_{\text{Fuel}_i \text{CO}_2}); \Sigma (\text{Vol. Fuel}_i * \text{EF}_{\text{Fuel}_i \text{CH}_4}); \Sigma (\text{Vol. Fuel}_i * \text{EF}_{\text{Fuel}_i \text{N}_2\text{O}})$					
	Emissions _{Fuel Extraction / Processing}	kg of CO ₂ e	N/A	N/A	N/A	Quantity being calculated in aggregate form as fuel use on site is likely aggregate for each of these SS's. Deleted: and electricity u
	Volume of Fossil Fuel _i Combusted for P 6 and P 7 / Vol. Fuel _i	m ³	Measured	Direct metering or reconciliation of volumes	Annual	Both methods are standard practice. Frequency of metering is highest level possible. Frequency of reconciliation provides for reasonable diligence. Deleted: transferred volumes
	CO ₂ Emissions Factor for Fuel Including Production and Processing / EF _{Fuel CO₂}	kg CO ₂ per m ³	Estimated	From Environment Canada reference documents	Annual	Reference values adjusted annually as part of Environment Canada reporting on Canada's emissions inventory.
	CH ₄ Emissions Factor for Fuel Including Production and Processing / EF _{Fuel CH₄}	kg CH ₄ per m ³	Estimated	From Environment Canada reference documents	Annual	Reference values adjusted annually as part of Environment Canada reporting on Canada's emissions inventory.
	N ₂ O Emissions Factor for Fuel Including	kg N ₂ O per m ³	Estimated	From Environment Canada reference documents	Annual	Reference values adjusted annually as part of Environment Canada

	Production and Processing / EF Fuel _{N20}					reporting on Canada's emissions inventory.
P 6 Air Compression	The following equation (1) should be used to calculate emissions from Air Compression for projects that use on-site electricity generated from fossil fuels.					
	1. Emissions_{Air Compression} = $\frac{\sum (\text{Vol. Fuel}_i * \text{EF Fuel}_{i\text{CO}_2} * \text{Compressed Air}_{\text{Control Instruments } i})}{\sum (\text{Total Produced Air } i)}$; $\frac{\sum (\text{Vol. Fuel}_i * \text{EF Fuel}_{i\text{CH}_4} * \text{Compressed Air}_{\text{Control Instruments } i})}{\sum (\text{Total Produced Air } i)}$; $\frac{\sum (\text{Vol. Fuel}_i * \text{EF Fuel}_{i\text{N}_2\text{O}} * \text{Compressed Air}_{\text{Control Instruments } i})}{\sum (\text{Total Produced Air } i)}$					
	Emissions _{Air Compression}	kg of CO ₂ e	N/A	N/A	N/A	Quantity being calculated in aggregate form as fuel use on site is likely aggregate for each of these SS's.
	Compressed Air Used for Pneumatic Instrument _i / Compressed Air Control Instruments _i	m ³	Measured	Direct metering of volume being compressed and sent to control instrument pipe network	1 month continuous metering or monthly reconciliation	Both methods are standard practice. Frequency of metering is highest level possible. Frequency of reconciliation provides for reasonable diligence.
	Total Air Produced in Air Compressor System by Compressor _i / Produced Air _i	m ³	Measured	Direct metering of volume being compressed	1 month continuous metering or monthly reconciliation	Both methods are standard practice. Frequency of metering is highest level possible. Frequency of reconciliation provides for reasonable diligence.
	<u>Volume of Fossil Fuel_i Combusted for P 6 to Produce Electricity for the Air Compression</u>	<u>m³</u>	<u>Measured</u>	<u>Direct metering or reconciliation of volumes</u>	<u>1 month continuous metering or monthly reconciliation</u>	<u>Both methods are standard practice. Frequency of metering is highest level possible. Frequency of</u>

- ~~Deleted: The following equation (1) should be used to calculate emissions from Air Compression for projects that use electricity from the grid. Note that this emission factor can be based on electricity displacement factor for Alberta or from an approved displacement factor for self-generators. Also note that the emission from Air Compression should be prorated by a fac... [2]~~
- ~~Deleted: 2~~
- ~~Deleted: Note that this emission factor can be based on elec... [3]~~
- ~~Formatted: Bullets and Numbering~~
- ~~Deleted: and~~
- ~~Deleted: kg of CO₂e/kWh~~
- ~~Deleted: Estimated~~
- ~~Deleted: From Environment Canada reference documents~~
- ~~Deleted: Annual~~
- ~~Deleted: electricity~~
- ~~Deleted: Emission Factor for Grid-Generated or Self-Ge... [4]~~
- ~~Deleted: kWh~~
- ~~Deleted: Measured~~
- ~~Deleted: Direct metering of electricity consumption or... [5]~~
- ~~Deleted: 1 month continuous metering or monthly... [6]~~
- ~~Deleted: Electricity Used by Compressor_i / Electricity Use_i~~
- ~~Deleted: ¶ Reference values adjusted... [7]~~

	<u>System/ Vol. Fuel_i</u>					<u>reconciliation provides for reasonable diligence.</u>
	CO ₂ Emissions Factor Each Type of Fuel i / EF Fuel CO ₂	kg CO ₂ per m ³	Estimated	From Environment Canada reference documents	Annual	Reference values adjusted annually as part of Environment Canada reporting on Canada's emissions inventory.
	CH ₄ Emissions Factor for Each Type of Fuel i / EF Fuel CH ₄	kg CH ₄ per m ³	Estimated	From Environment Canada reference documents	Annual	Reference values adjusted annually as part of Environment Canada reporting on Canada's emissions inventory.
	N ₂ O Emissions Factor for Each Type of Fuel i / EF Fuel N ₂ O	kg N ₂ O per m ³	Estimated	From Environment Canada reference documents	Annual	Reference values adjusted annually as part of Environment Canada reporting on Canada's emissions inventory.
P 7 Air Management System	<p><u>The following equation (1) should be used to calculate emissions from Air Management System for projects that use on-site electricity generated from fossil fuels.</u></p> <p>1. Emissions_{Air Management System} =</p> $\frac{\sum (\text{Vol. Fuel}_i * \text{EF Fuel}_{i\text{CO}_2} * \text{Managed Air}_{\text{Control Instruments } i})}{\sum (\text{Total Managed Air } i)};$ $\frac{\sum (\text{Vol. Fuel}_i * \text{EF Fuel}_{i\text{CH}_4} * \text{Managed Air}_{\text{Control Instruments } i})}{\sum (\text{Total Managed Air } i)};$ $\frac{\sum (\text{Vol. Fuel}_i * \text{EF Fuel}_{i\text{N}_2\text{O}} * \text{Managed Air}_{\text{Control Instruments } i})}{\sum (\text{Total Managed Air } i)}.$					
	Emissions _{Air Compression}	kg of CO ₂ e	N/A	N/A	N/A	Quantity being calculated in aggregate form as fuel use on site is likely aggregate for each of these SS's.
	Managed Air <u>by</u>	m ³	Measured	Direct metering of	1 month	Both methods are

Deleted: The following equation (1) should be used to calculate emissions from Air Management System for projects that use electricity from the grid. Note that this emission factor can be based on electricity displacement factor for Alberta or from an approved displacement factor for self-generators. Also note that the emission from Air Management System should be prorated (... [8])

Formatted Table

Deleted: 2

Deleted: Note that this emission factor can be based on elec (... [9])

Formatted (... [10])

Formatted: Bullets and Numbering

Deleted: =

Deleted:

Deleted:

Deleted: and

Deleted: ¶ kg of CO₂e/kWh¶ (... [11])

Deleted: ¶ Estimated¶ (... [12])

Deleted: ¶ From Environment Cana (... [13])

Deleted: ¶ Annual¶ (... [14])

Deleted: electricity

Deleted: ¶ Emission Factor for Grid (... [15])

Deleted: ¶ Reference values adjusted (... [16])

<u>Air Management system i</u> Managed Air Control Instruments i			volume being <u>managed</u> and sent to control instrument pipe network	continuous metering or monthly reconciliation	standard practice. Frequency of metering is highest level possible. Frequency of reconciliation provides for reasonable diligence.
Total Air <u>Managed</u> by Air Management System i / Total Managed Air i	m ³	Measured	Direct metering of volume being <u>managed</u>	1 month continuous metering or monthly reconciliation	Both methods are standard practice. Frequency of metering is highest level possible. Frequency of reconciliation provides for reasonable diligence.
Volume of Fossil Fuel i Combusted for P 7 to Produce Electricity for the Air Management System/ Vol. Fuel i	m ³	Measured	Direct metering or reconciliation of volumes	1 month continuous metering or monthly reconciliation	Both methods are standard practice. Frequency of metering is highest level possible. Frequency of reconciliation provides for reasonable diligence.
CO ₂ Emissions Factor Each Type of Fuel i / EF Fuel CO ₂	kg CO ₂ per m ³	Estimated	From Environment Canada reference documents	Annual	Reference values adjusted annually as part of Environment Canada reporting on Canada's emissions inventory.
CH ₄ Emissions Factor for Each Type of Fuel i / EF Fuel CH ₄	kg CH ₄ per m ³	Estimated	From Environment Canada reference documents	Annual	Reference values adjusted annually as part of Environment Canada reporting on Canada's emissions inventory.
N ₂ O Emissions Factor for Each Type of Fuel i / EF	kg N ₂ O per m ³	Estimated	From Environment Canada reference documents	Annual	Reference values adjusted annually as part of Environment Canada

- Deleted: compressed
- Formatted Table
- Deleted: Used for Pneumatic Instrument i
- Deleted: Managed
- Deleted: in Air Compressor System
- Deleted: s
- Deleted: compressed

	Fuel N ₂ O					reporting on Canada's emissions inventory.
Baseline SS's						
B 10 Fuel Extraction/ Processing	Emissions _{Fuel Extraction / Processing} = Σ (Emissions _{Fuel Gas for Control Instruments} * EF _{Fuel_i CO₂}); Σ (Emissions _{Fuel Gas for Control Instruments} * EF _{Fuel_i CH₄}); Σ (Emissions _{Fuel Gas for Control Instruments} * EF _{Fuel_i N₂O})					
	Emissions _{Fuel Extraction / Processing}	kg of CO ₂ e	N/A	N/A	N/A	Quantity being calculated in aggregate form as fuel use on site is likely aggregate for each of these SS's.
	Volume of Fossil Fuel _i Consumed for B 7 and B 8 / Emissions _{Fuel Gas for Control Instruments}	m ³	Estimated	Estimated based on volumes from B 7 and B 8	1 month continuous metering or monthly reconciliation	Both methods are standard practice. Frequency of metering is highest level possible. Frequency of reconciliation provides for reasonable diligence.
	CO ₂ Emissions Factor for Fuel Including Production and Processing / EF _{Fuel CO₂}	kg CO ₂ per m ³	Estimated	From Environment Canada reference documents	Annual	Reference values adjusted annually as part of Environment Canada reporting on Canada's emissions inventory.
	CH ₄ Emissions Factor for Fuel Including Production and Processing / EF _{Fuel CH₄}	kg CH ₄ per m ³	Estimated	From Environment Canada reference documents	Annual	Reference values adjusted annually as part of Environment Canada reporting on Canada's emissions inventory.
	N ₂ O Emissions Factor for Fuel Including	kg N ₂ O per m ³	Estimated	From Environment Canada reference documents	Annual	Reference values adjusted annually as part of Environment Canada

Deleted: ¶

Deleted: and electricity

Deleted: 6

Deleted: 7

Deleted: 6

	Production and Processing / EF Fuel _{N2O}					reporting on Canada's emissions inventory.
B 7 Vented Fuel Gas	<p>The following equations are used to establish baseline emissions based on metered compressed air powering the pneumatic instruments once the air conversion has taken place. Equation (1) is for the vented CH₄ and will always be used. Typically, the percentage of CH₄ in fuel gas is in excess of 85% and can be as much as 99%. Equation (2) is used to establish baseline emission for vented CO₂. If the percentage of CO₂ is in excess of 10%, equation (2) is used to establish baseline CO₂ emissions from vented fuel. If the percentage of CO₂ emissions is inferior to 10%, it is advisable not to include CO₂ emissions as the volumes are insignificant.</p> <p>1. Emissions_{Fuel Gas for Control Instruments} =</p> $\Sigma \text{ Compressed Air}_{\text{Control Instruments } i} * (1 - DR) * \sqrt{\frac{G_{AIR}}{G_{CH4}}} * \frac{\left(1 - \frac{1}{3 * F_k}\right)}{\left(1 - \frac{1}{3 * F_{AIR}}\right)} * \%CH_4 * \rho_{CH4};$ <p>2.</p> $\Sigma \text{ Compressed Air}_{\text{Control Instruments } i} * (1 - DR) * \sqrt{\frac{G_{AIR}}{G_{CH4}}} * \frac{\left(1 - \frac{1}{3 * F_k}\right)}{\left(1 - \frac{1}{3 * F_{AIR}}\right)} * \%CH_4 * \rho_{CH4} * \frac{\%CO_2 * 44}{\%CH_4 * 16};$ <p>where</p> $F_k = \frac{k}{1.4}$					
	Emissions _{Fuel Gas For Control Instruments}	kg of CH ₄ ; CO ₂	N/A	N/A	N/A	Quantity being calculated in aggregate form as fuel use on site is likely aggregate for each of these SS's.
	Compressed Air Used for	m ³	Measured	Direct metering of volume being	1 month continuous	Both methods are standard practice.

Deleted: and electricity

Pneumatic Instruments _i / Compressed Air Control Instruments _i			compressed and sent to control instrument pipe network as determined in P6	metering or monthly reconciliation	Frequency of metering is highest level possible. Frequency of reconciliation provides for reasonable diligence. <u>Values must be adjusted for standard temperature and pressure STP.</u> ¹
Discount Rate due to Leaks / DR	%	Estimated	<u>1. DR(%)=0 if inspection occurred < 1 year</u> <u>2. DR(%)= 2.5 %*minimum year interval for 1 < year < 10</u> <u>3. DR(%)= 25% for year > 10</u>	N/A	Leaks are taken into account when air is metered to adjust the baseline. The year of last documented inspection and maintenance is taken into account in parameter 'minimum year interval'. A <u>2.5%</u> per annum increase due to leaks is assumed.
Specific Gravity of Air / G _{AIR}	̄	Estimated	1.00 at NTP	N/A	Accepted value.
Specific Gravity of Methane / G _{CH4}	̄	Estimated	0.5537 at NTP	N/A	Accepted value.
Density of Methane / ρ _{CH4}	Kg / m ³	Estimated	0.717kg/m ³ at STP	N/A	If this value is used all values must be adjusted for standard temperature and pressure <u>STP.</u>

Deleted: 1. DR(%)=0 if inspection occurred ≤ 1 year
2. DR(%)= 2.5 %*minimum year interval
for 1 < year ≤ 10
3. DR(%)= 25% for year > 10

Deleted: -

Deleted: -

Deleted: .

¹ The pressure at which the instrument air system operates under steady state conditions is constant and is found in the design considerations of the compressed air system.

	Specific Heat Ratio for CH ₄ / k _{CH4}	-	Assumed	1.31 at STP	N/A	Accepted value.
	Specific Heat Ratio for air /1.4	-	Assumed	1.40 at STP	N/A	Accepted value.
	Methane Composition in Fuel Gas / % CH ₄	%	Measured	Direct measurement	Annual	Fuel gas composition should remain relatively stable during steady-state operation.
	Carbon Dioxide Composition in Fuel Gas / % CO ₂	%	Measured	Direct measurement	Annual	Fuel gas composition should remain relatively stable during steady-state operation.
B 8 Flared/Combusted Fuel Gas	Refer to Flexibility Mechanism for details (Appendix B.2)					

Deleted: .

Deleted: .

2.5.2. Contingent Data Approach

Contingent means for calculating or estimating the required data for the equations outlined in section 2.5.1 are summarized in **TABLE 2.5**, below.

2.6. Management of Data Quality

In general, data quality management must include sufficient data capture such that the mass and energy balances may be easily performed with the need for minimal assumptions and use of contingency procedures. The data should be of sufficient quality to fulfill the quantification requirements and be substantiated by company records for the purpose of verification.

The project proponent shall establish and apply quality management procedures to manage data and information. Written procedures should be established for each measurement task outlining responsibility, timing and record location requirements. The greater the rigor of the management system data, the more easily an audit will be to conduct for the project.

2.6.1. Record Keeping

Record keeping practices should include:

- a. Electronic recording of values of logged primary parameters for each measurement interval;
- b. Printing of monthly back-up hard copies of all logged data;
- c. Written logs of operations and maintenance of the project system including notation of all shut-downs, start-ups and process adjustments;
- d. Retention of copies of logs and all logged data for a period of 7 years; and
- e. Keeping all records available for review by a verification body.

2.6.2. Quality Assurance/Quality control (QA/QC)

QA/QC can also be applied to add confidence that all measurements and calculations have been made correctly. These include, but are not limited to:

- a. Protecting monitoring equipment (sealed meters and data loggers);
- b. Protecting records of monitored data (hard copy and electronic storage);
- c. Checking data integrity on a regular and periodic basis (manual assessment, comparing redundant metered data, and detection of outstanding data/records);
- d. Comparing current estimates with previous estimates as a 'reality check';
- e. Provide sufficient training to operators to perform maintenance and calibration of monitoring devices;
- f. Establish minimum experience and requirements for operators in charge of project and monitoring; and
- g. Perform recalculations to make sure no mathematical errors have been made.

1 TABLE 2.5: Contingent Data Collection Procedures

1. Project / Baseline SS	2. Parameter / Variable	3. Unit	4. Measured / Estimated	5. Method	6. Frequency	7. Justify measurement or estimation and frequency
Project SS's						
P 9 Fuel Extraction and Processing	Volume of <u>Fossil Fuel i Combusted for P6 and P7</u> Type of Fuel / Vol. Fuel i	L / m ³ / other	Estimated	Reconciliation of volume of fuel purchased within given time period	Monthly	Provides reasonable estimate of the parameter, when the more accurate and precise method cannot be used.
P 6 Air Compression	<u>Volume of Fossil Fuel i Combusted for P 6 to Produce Electricity for the Air Compression System/ Vol. Fuel i</u>	<u>L / m³ / other</u>	<u>Estimated</u>	<u>Reconciliation of volume of fuel purchased within given time period</u>	<u>Monthly</u>	<u>Provides reasonable estimate of the parameter, when the more accurate and precise method cannot be used.</u>
	Compressed Air Used <u>for Pneumatic Instruments / Compressed Air Control Instruments i</u>	m ³	Estimated	Reconciliation of compressed air used in air compression system within given time period based on equipment efficiency specifications and average flow rates	Monthly	Provides reasonable estimate of the parameter, when the more accurate and precise method cannot be used.
	Total Air Produced in Air Compressor System by Compressor i / Produced Air i	m ³	Estimated	Reconciliation of total air produced in air compression system within given time period based on equipment efficiency specifications and average flow rates.	Monthly	Provides reasonable estimate of the parameter, when the more accurate and precise method cannot be used.

Deleted: .

P 7 Air Management System	<u>Volume of Fossil Fuel i Combusted for P 7 to Produce Electricity for the Air Management System/ Vol. Fuel_i</u>	<u>L / m³ / other</u>	<u>Estimated</u>	<u>Reconciliation of volume of fuel purchased within given time period</u>	<u>Monthly</u>	<u>Provides reasonable estimate of the parameter, when the more accurate and precise method cannot be used.</u>
	<u>Managed Air by Air Management system i / Managed Air_{Control Instruments i}</u>	<u>m³</u>	<u>Estimated</u>	<u>Reconciliation of managed air used in air management system within given time period based on equipment efficiency specifications and average flow rates</u>	<u>Monthly</u>	<u>Provides reasonable estimate of the parameter, when the more accurate and precise method cannot be used.</u>
	<u>Total Air Managed by Air Management System i/ Total Managed Air_i</u>	<u>m³</u>	<u>Estimated</u>	<u>Reconciliation of managed air used in air management system within given time period based on equipment efficiency specifications and average flow rates</u>	<u>Monthly</u>	<u>Provides reasonable estimate of the parameter, when the more accurate and precise method cannot be used.</u>
Baseline SS's						
B 10 Fuel Extraction and Processing	<u>Volume of Fossil Fuel i Consumed for B 7 and B 8 / Emissions_{Fuel Gas for Control Instruments}</u>	<u>m³</u>	<u>Estimated</u>	<u>Estimated based on volumes from B 7 and B 8</u>	<u>Monthly</u>	<u>Provides reasonable estimate of the parameter, when the more accurate and precise method cannot be used.</u>
B 7 Vented Fuel Gas	Compressed Air Used for <u>Pneumatic Instruments / Compressed Air Control Instruments i</u>	<u>m³</u>	<u>Estimated</u>	Reconciliation of compressed air used in air compression system within given time period based on equipment efficiency specifications	<u>Monthly</u>	Provides reasonable estimate of the parameter, when the more accurate and precise method cannot be used.

Deleted: Provides reasonable estimate of the parameter, when the more accurate and precise method cannot be used.

Formatted Table

Deleted: Estimated based on volume of air managed and desiccant characteristics

Deleted: kWh

Deleted: Estimated

Deleted: Monthly

				and average flow rates		
	Methane Composition in Fuel Gas / % CH ₄	%	Estimated	From accredited references or industry standards	Annually	Estimating gas composition from accredited references provides a reasonable estimate when the more accurate method cannot be used.
	Carbon dioxide Composition in Fuel Gas / % CO ₂	%	Estimated	From accredited references or industry standards	Annually	Estimating gas composition from accredited references provides a reasonable estimate when the more accurate method cannot be used.

Formatted Table

1
2
3
4
5
6
7
8
9
10
11 |
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28
29
30
31
32
33
34
35
36
37

APPENDIX A - Explanation on Gas Equivalency and Leaks

1 A.1 Gas Equivalence

2 The capacity of a device to flow air or gas is expressed in terms of C_V , or flow
3 coefficient. The C_V measures the impact on flow from diverse factors to a device such as:

- 4 • Orifice size (diameter of the piping or opening through the valve);
- 5 • Length of piping or opening through the valve;
- 6 • Turbulence caused by bends or turns in the piping;
- 7 • Restrictions, or anything that reduces the orifice size or the flow path; and
- 8 • Shape of the orifice.

9 For this protocol, the formula employed by the Instrument Society of America (ISA)
10 based on L.R. Driskell's work will be used to develop equivalence between air
11 consumption and natural gas that would have been consumed. This formula may be found
12 in *ANSI/ISA-75.02-1996 Control Valve Capacity Test Procedures* and is an established
13 method used by industry to calculate the C_V for pneumatic devices. Expanded formula
14 can be found in L.R. Driskell's *New approach to Control Valve Sizing*.

15 Gas and air are considered compressible fluids. In pneumatic devices, flow can be choked
16 or non-choked. Flow in a duct or passage such that the flow upstream of a certain critical
17 section cannot be increased by a reduction of downstream pressure is defined as choked.
18 For the purpose of this protocol, choked conditions will be used because these conditions
19 represent a conservative approach in estimating air volumes. In order to demonstrate this,
20 mathematical and graphical approaches are taken.

21 For compressible fluid flow in non-choked conditions, the flow rate can be expressed as

$$22 \quad Q_{SCFH} = 1,360 * C_V * P_{1psia} * Y \sqrt{\frac{x}{G_g * T_{\circ R}}} \quad (1)$$

23 where

$$24 \quad Y = 1 - \frac{x}{3 * F_k * X_T} \quad (\text{Limits } 1.0 \geq Y \geq 0.667) \quad (2)$$

25 Q_{SCFH} = fluid volumetric flow rate;

26 C_V = flow coefficient;

27 P_{1PSIA} = inlet pressure;

28 Y = expansion factor;

29 x = pressure drop ratio to absolute inlet pressure

30 G_g = gas specific gravity (this is the density of the gas divided by the density of air at the
31 same conditions);

32 $T_{\circ R}$ = temperature in degrees Rankine;

33 F_k = ratio of specific heats (equal to the specific heat ratio of the gas divided by the
34 specific heat ratio of air); and

35 X_T = maximum pressure before choking.

1 When choking occurs, (1) and (2) are still valid with the exception that $x=X_T$. Equation
2 (2) becomes

$$3 \quad Y = 1 - \frac{1}{3 * F_k} \quad (Y=0.667) \quad (3)$$

4 where

$$5 \quad F_k = \frac{k}{1.4}$$

6 where

7 k = ratio of specific heats for a given gas (1.4 is the ratio specific heat for air, 1.3 for
8 methane)

9 **1st Approach- Mathematical**

10 In order to establish the equivalence of how much natural gas would have been vented if
11 the air system had not been installed, the assumption of equal C_V for both gas and air
12 powered devices must be established. Therefore (1) for CH_4 can be expressed as

$$13 \quad Q_{CH_4} = 1,360 * C_V * P_{psia} * Y_{CH_4} * \sqrt{\frac{x}{G_{CH_4} * T_{\circ R}}} \quad (4)$$

14 where

15 Q_{CH_4} = CH_4 volumetric fluid flow rate

16 Similarly, (1) for air can be expressed as

$$17 \quad Q_{AIR} = 1,360 * C_V * P_{psia} * Y_{AIR} * \sqrt{\frac{x}{G_{AIR} * T_{\circ R}}} \quad (5)$$

18 where

19 Q_{AIR} = air volumetric flow rate

20 By substituting (5) into (4) as a function of C_V and eliminating common terms,

$$21 \quad Q_{CH_4} = Q_{AIR} * \frac{1}{\sqrt{\frac{1}{G_{AIR}}}} * \frac{1}{Y_{AIR}} * Y_{CH_4} * \sqrt{\frac{1}{G_{CH_4}}} \quad (6)$$

22 Rearranging terms and assuming choked conditions (3)

$$Q_{CH_4} = Q_{AIR} * \sqrt{\frac{G_{AIR}}{G_{CH_4}}} * \frac{1 - \frac{1}{3 * F_k}}{1 - \frac{1}{3 * F_{AIR}}} \quad (7)$$

2 Specific gas gravities for greenhouse gases present in fuel supply gas at NTP² are
3 summarized below.

4 **TABLE A.1 Specific gravity of gases present in fuel gas**

Gas	S.G.
Air	1.000
Carbon dioxide	1.519
Methane	0.5537
Natural Gas	0.60 - 0.70

5 Source: http://www.engineeringtoolbox.com/specific-gravities-gases-d_334.html

6 Using $G_{CH_4} = .5537$, $G_{AIR} = 1$, and $k = 1.31$ for pure methane, (7) becomes

$$Q_{CH_4} = 1.2977 * Q_{AIR}$$

8 **2nd Approach-Graphic**

9 As the gas passes from the orifice to the atmosphere, it will undergo expansion. This
10 expansion is dependant on gas characteristics and is represented by a lumped parameter;
11 Y . Y is a function of the expansion of the gas, F_k . F_k is plotted as a function of the
12 specific heat of the gas and β (orifice to inlet diameter ratio) as shown in Figure A.1 (i).
13 The relationship between F_k and k , as depicted in Figure A.1 (ii), using a 3 point linear fit
14 for $k = 1.1, 1.4, 1.65$ and $\beta = .8$ is

$$F_k = .2336 * k + .6675$$

16 Typical value of k for methane is 1.31, yielding $Y = .974$ for pure methane. For air, Y is
17 assumed as 1. If $F_k = .974$ is plotted versus $\beta = .8$, then a linear correlation is established as
18 illustrated in Figure A.1 (iii). From this correlation, F_k can be expressed as function of β :

$$F_k = -0.0331 * \beta + 1$$

20 Assuming $G_{AIR} = 1$, $G_{CH_4} = .5537$, $k = 1.31$, and $\beta = .8$, (7) yields

$$Q_{CH_4} = 1.3087 * Q_{AIR}$$

22 If $\beta = 1$, (7) yields

² Normal Temperature and Pressure is defined as air at 20°C (293.15 K, 68°F) and 1 atm (101.325 kN/m², 101.325 kPa, 14.7 psia, 0 psig, 30 in Hg, 760 torr)

1
$$\underline{Q_{CH_4} = 1.2994 * Q_{AIR}}$$

2 This represents the volumes of pure methane that would have been vented instead of air.
 3 In general terms, pure methane is not vented. Instead, vented gas composed mainly of
 4 methane and to a lesser extent carbon dioxide is vented. Consequently, the amount of
 5 greenhouse gases that would have been emitted in the absence of air is adjusted as
 6 follows in terms of mass flow rate:

7
$$\dot{m}_{CH_4} = Q_{AIR} * \sqrt{\frac{G_{AIR}}{G_{CH_4}}} * \frac{\left(1 - \frac{1}{3 * F_k}\right)}{\left(1 - \frac{1}{3 * F_{AIR}}\right)} * \%CH_4 * \rho_{CH_4} \quad (8)$$

8 where

9 \dot{m}_{CH_4} = CH₄ mass fluid flow rate

10 %CH₄ = volume fraction of CH₄ in fuel supply gas;

11 ρ_{CH_4} = methane density; and

12 and

13
$$\dot{m}_{CO_2} = Q_{AIR} * \sqrt{\frac{G_{AIR}}{G_{CH_4}}} * \frac{\left(1 - \frac{1}{3 * F_k}\right)}{\left(1 - \frac{1}{3 * F_{AIR}}\right)} * \%CH_4 * \rho_{CH_4} * \frac{\%CO_2}{\%CH_4} * \frac{44}{16} \quad (9)$$

14 where

15 \dot{m}_{CO_2} = CO₂ mass fluid flow rate

16 %CH₄ = volume fraction of CH₄ in fuel supply gas;

17 %CO₂ = volume fraction of CO₂ in fuel supply gas;

18 44 = molecular weight of CO₂; and

19 16 = molecular weight of CH₄.

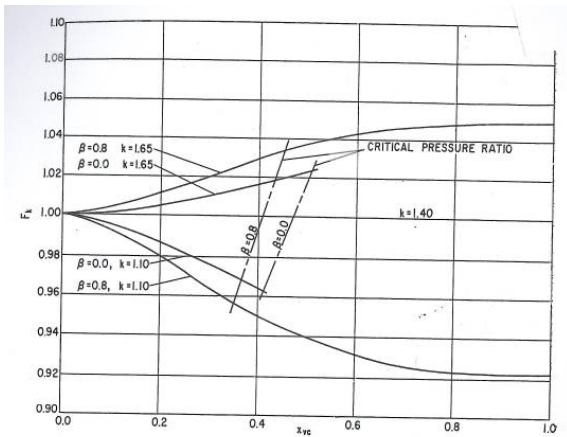
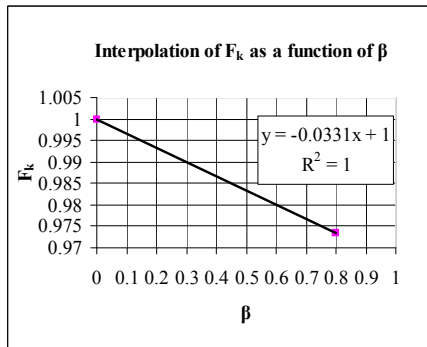
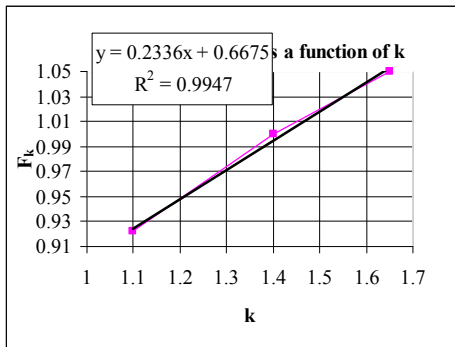


Fig. 3—Correction factor for ratio of specific heats.

Source: Driskell, L.R. (1969). New Approach to Control Valve Sizing. Hydrocarbon Processing, Vol. 48, No.7, July, p. 131-134.

i) Correction factor for ratio of specific heats



ii) F_k as a function of k

ii) F_k as a function of β

1 **FIGURE A.1 Expansion factor for types of gases for known k and β**

2 **A.2 Leaks**

3 Minimizing leaks by making use of a regular inspection and maintenance program
 4 ensures that metered air volumes are not overestimated, and hence gas that would have
 5 been vented had the instrument air conversion not taken place. At times a regular
 6 inspection and maintenance program is not practical or programmed at different time
 7 periods that do not coincide with the implementation of the instrument air conversion
 8 project. Estimates based on best practices and emission factors from credited references
 9 are used to discount metered air volumes to safeguard conservativeness in these
 10 estimations.

11 The discount factors presented here are based on rates from the EPA's Natural Gas STAR
 12 Program *Lessons Learned-Convert Gas Pneumatic Controls to Instrument Air*.
 13 Instrument control devices in service and that have not been repaired will leak as time
 14 passes. A 2.5 % yearly linear increase in leaks is assumed. For devices that have been

1 recently inspected and repaired, the discount rate is assumed to be zero. For devices or
 2 pipe networks that have not been inspected and repaired in the last 10 years, the discount
 3 rate increases linearly until reaching 25%. The maximum discount rate is 25% for devices
 4 with more than 10 years without inspection and repairs. The equations used to calculate
 5 the discount rate are as follows:

Deleted: 25%

Deleted: 25%

6 $DR (\%) = \underline{2.5\%} * (\text{minimum year interval}) \quad \text{for } 0 < \text{year} < 10 \quad (10)$

Deleted: 2.5 %

7 $DR (\%) = \underline{25\%} \quad \text{for year} > 10 \quad (11)$

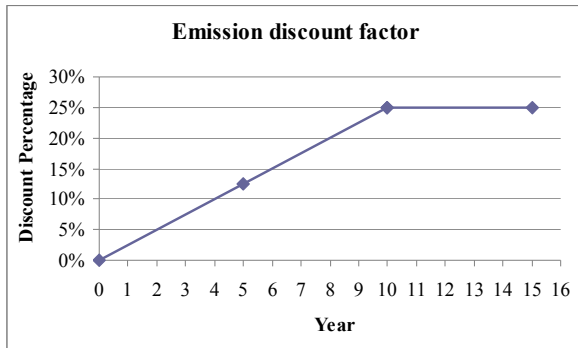
Deleted: 25%

8 This relationship is assumed linear and is illustrated in Figure A.1. As an example, if the
 9 last inspection and repair took place 5.5 years ago, then the minimum of that year interval
 10 is 5.5 times 2.5 % yearly increase due to leaks yields a 12.5 % leak rate. The DR is
 11 therefore 12.5%.

Deleted:

Deleted: 12.5 %

Deleted: 12.5%



12
 13 **Figure A.1 Linear relationship between elapsed time and discount factor.**

Deleted: factor

14 This discount rate is used to adjust the baseline and maintain a conservative approach.
 15 Equations (10) and (11) are incorporated into equations (8) and (9) as coefficients as
 16 illustrated in the following equations:

17
$$\dot{m}_{CH_4} = (1 - DR) * Q_{AIR} * \sqrt{\frac{G_{AIR}}{G_{CH_4}}} * \frac{\left(1 - \frac{1}{3 * F_k}\right)}{\left(1 - \frac{1}{3 * F_{AIR}}\right)} * \%CH_4 * \rho_{CH_4} \quad (12)$$

18
$$\dot{m}_{CO_2} = (1 - DR) * Q_{AIR} * \sqrt{\frac{G_{AIR}}{G_{CH_4}}} * \frac{\left(1 - \frac{1}{3 * F_k}\right)}{\left(1 - \frac{1}{3 * F_{AIR}}\right)} * \%CH_4 * \rho_{CH_4} * \frac{\%CO_2}{\%CH_4} * \frac{44}{16} \quad (13)$$

19
 20
 21

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28
29
30
31
32
33
34
35
36
37

APPENDIX B - Quantification Procedures for Flexibility Mechanisms

1 **B.1 Retroactive Credits**

Deleted: ¶
¶

2 To facilitate verification of retroactive credits, the project proponent should identify the
3 run time of principle equipment such as compressors, dehydrators, or other equipment
4 within the facility, or provide other facility-specific supporting documentation to
5 demonstrate continuity of operations. In the event that instrument counts cannot be
6 developed for a facility in the past, the proponent can use the aforementioned evidence to
7 demonstrate that a significant change to the facility had (or had not) occurred.

8 The project developer will then use the baseline and project quantities metered during the
9 one month metering period and adjust those using engineering calculations to reflect
10 emissions in the unmetered period. Adjustments are based on instrument counts and vent
11 rates from the manufacture’s technical specifications. The pneumatic device’s vent rate is
12 adjusted for leak inspection and repair, and then multiplied by the complete hours of
13 operation (i.e. 8,760 hours per year). Finally, this value is subtracted from the measured
14 baseline as follows:

Deleted: Existing projects may claim carbon offsets. This claim is based on the metered baseline with adjustments.

Deleted: .

Deleted: Adjustments

Deleted: are

15
$$BE' = BE * t - \sum_{i=1}^n VR_i * (1 + DR_i) * t_i$$

16 where

17 BE' = adjusted baseline emissions from time project was implemented to time when
18 project was metered;

19 t = time of project implementation;

20 BE = metered emissions from project;

21 VR_i = vent rate of instrument i using manufacture’s technical specifications;

22 DR = leak discount rate; and

23 t_i = time from installation of instrument to time when project was metered.

Deleted: B

Deleted: bleed

24 This method uses measured amounts and adjustments based on a conservative approach.
25 By assuming complete hours of operation (i.e. 8,760 per year) for the unmetered period
26 and adding instead of subtracting the DR, the retroactive emissions are underestimated
27 and as a result the net offsets claims are also underestimated.

28 As an example, a project was implemented 4 years ago but was not metered and no
29 inspection for leaks or repairs occurred. If the baseline emissions were calculated at BE
30 after the first month of metering, and 1 instrument (Type A with 54 scfh emission rate)
31 was placed 3 years ago, the BE' would be

Deleted: but was not metered and no inspection for leaks or repairs occurred

Formatted: Font: 12 pt

Formatted: Font: 12 pt

32
$$BE_{AIR}' = BE_{AIR} * (4 * 12) - \sum_{i=1}^1 54_i * (1 + 7.5\%_i) * (4 * 8,760)_i$$

Deleted: ¶

33 **B.2 Fraction of Vented and Combusted Emissions**

34
35 Vent and bleed natural gas may be collected and sent to a flare or other combustion
36 sources for various reasons. Therefore this protocol allows the project developer to claim

1 credits from combusted and vented gas. The vent or bleed gas fraction X is estimated as
 2 follows based on vendor's technical specifications:

$$3 \quad X = \frac{\sum_{i=1}^n VR_i * n_i}{\sum_{i=1}^n VR_i * n_i + \sum_{j=1}^m VR_j * m_j}$$

4 where
 5

7 VR_i = vent rate for device i from manufacturer's technical specifications that vent gas to
 8 the atmosphere;

9 n_i = number of type i devices;

10 VR_j = vent rate for device j from manufacturer's technical specifications for gas that is
 11 combusted;

12 m_j = number of type j devices;

- Deleted: B
- Deleted: bleed
- Deleted: bleed
- Deleted: B
- Deleted: bleed
- Deleted: for gas that is combusted

13 The denominator is simply the addition of all devices at the facility. The combusted
 14 emissions are the remaining fraction and are calculated as:

$$15 \quad 1 - X = 1 - \left(\frac{\sum_{i=1}^n VR_i * n_i}{\sum_{i=1}^n VR_i * n_i + \sum_{j=1}^m VR_j * m_j} \right)$$

16 Care must be taken to use bleed rates that are either expressed in terms of air or natural
 17 gas as well as the same units.

1. Project / Baseline SS	2. Parameter/ variable	3. Unit	4. Measured/ estimated	5. Contingency Method	6. Frequency	7. Justify measurement or estimation and frequency
Flexibility Mechanism						
B 6 Vented Fuel Gas	<p>The following equations are used to establish baseline emissions based on metered compressed air powering the pneumatic instruments once the air conversion has taken place. Equation (1) is for the vented CH₄ and will always be used. Typically, the percentage of CH₄ in fuel gas is in excess of 85% and can be as much as 99%. Equation (2) is used to establish baseline emission for vented CO₂. If the percentage of CO₂ is in excess of 10%, equation (2) is used to establish baseline CO₂ emissions from vented fuel. If the percentage of CO₂ emissions is inferior to 10%, it is advisable not to include CO₂ emissions as the volumes are insignificant. Equations (3) and (4) are used to establish CO_{2e} emissions from flared fuel gas</p> <p>(1) Emissions_{Vented Fuel Gas} =</p> $\sum \text{Compressed Air}_{\text{Control Instruments } i} * X * (1 - DR) * \sqrt{\frac{G_{AIR}}{G_{CH_4}}} * \left(\frac{1 - \frac{1}{3 * F_k}}{1 - \frac{1}{3 * F_{AIR}}} \right) * \%CH_4 * \rho_{CH_4};$ <p>(2) $\sum \text{Compressed Air}_{\text{Control Instruments } i}$</p>					

$$* X * (1 - DR) * \sqrt{\frac{G_{AIR}}{G_{CH4}}} * \left(\frac{1 - \frac{1}{3 * F_k}}{1 - \frac{1}{3 * F_{AIR}}} \right) * \%CH_4 * \rho_{CH4} * \frac{\%CO_2}{\%CH_4} * \frac{44}{16};$$

where

$$F_k = \frac{k}{1.4}$$

(3) Emissions Flared/Combusted Fuel Gas = Σ Compressed Air Control Instruments

$$* (1 - X) * (1 - DR) * \sqrt{\frac{G_{AIR}}{G_{CH4}}} * \left(\frac{1 - \frac{1}{3 * F_k}}{1 - \frac{1}{3 * F_{AIR}}} \right) * \%w * \frac{44}{12} * \%EF;$$

where

w = average carbon content of fuel gas (kg C/m³ fuel gas)³

Emissions Vented Fuel Gas	kg of CH ₄ ; CO ₂	N/A	N/A	N/A	Quantity being calculated in aggregate form as fuel use on site is likely aggregate for each of these SS's.
Emissions Flared/Combusted Fuel Gas	kg of CH ₄ ; CO ₂	N/A	N/A	N/A	Quantity being calculated in aggregate form as fuel use on site is likely aggregate for each of these SS's.
Compressed Air Used for Pneumatic Instruments / Compressed Air Control Instruments i	m ³	Measured	Direct metering of volume being compressed and sent to control instrument pipe network as determined in P6	Continuous metering or monthly reconciliation	Both methods are standard practice. Frequency of metering is highest level possible. Frequency of reconciliation provides for reasonable diligence.
Fraction of vented emissions/ X	-	Estimated	Estimated using $X = \frac{\sum_{i=1}^n V_{R_i} * n_i}{\sum_{i=1}^n V_{R_i} * n_i + \sum_{j=1}^m V_{R_j} * m_j}$	N/A	This represents the fraction of vented emissions from control devices
Discount Rate due to Leaks / DR	%	Estimated	1. DR(%)=0 if inspection occurred < 1 year 2. DR(%)= 2.5	N/A	Leaks are taken into account when air is metered to adjust the baseline. The year of last

Deleted: and electricity

Deleted: and electricity

Deleted: 1. DR(%)=0 if inspection occurred ≤ 1 year
2. DR(%)= 2.5 %*minimum year interval
for 1 < year ≤ 10
3. DR(%)= 25% for year > 10

³ The average carbon content of the fuel gas is used to calculate CO₂ emissions. Average carbon content can be calculated from the annual gas composition data of the fuel gas using a weighted average technique. Alternatively, the average carbon content can be determined from an elemental analysis of the gas itself using various methods available. Other methods are also applicable.

				for 1 < year < 10 3. DR(%)= 25% for year > 10		maintenance is taken into account in parameter 'year'.
Specific Gravity of Air / G _{AIR}	▼	Estimated	1.00 at NTP	N/A	Accepted value.	Deleted: 1.00
Specific Gravity of Methane / G _{CH4}	▼	Estimated	0.5537 at NTP	N/A	Accepted value.	Deleted: m ³ Deleted: Kg / m ³ Deleted: 0.5537
Density of Methane / ρ _{CH4}	Kg / m ³	Estimated	0.717kg/m ³ at STP	N/A	If this value is used all values must be adjusted for standard temperature and pressure.	Deleted: 0.717kg/m ³ at STP.
Specific Heat Ratio for CH ₄ / k _{CH4}	-	Assumed	1.31 at STP	N/A	Accepted value	Deleted: Constant value of 1.31 at NTP.
Specific Heat Ratio for air / 1.4	-	Assumed	1.40 at STP	N/A	Accepted value	Deleted: Constant value of 1.40 at NTP.
Methane Composition in Fuel Gas / % CH ₄	-	Measured	Direct measurement	Annual	Fuel gas composition should remain relatively stable during steady-state operation	
Carbon Dioxide Composition in Fuel Gas / % CO ₂	-	Measured	Direct measurement	Annual	Fuel gas composition should remain relatively stable during steady-state operation	
Carbon Compound with n number of carbon molecules in fuel gas/ C _n	%	Measured	Direct measurement	Annual	Fuel gas composition should remain relatively stable during steady-state operation	
Flare Destruction Efficiency/ %EF	▼	Estimated	From accredited sources such as CAPP or API	▼	Provides reasonable estimate of the parameter. by accredited sources	Formatted: Font: 9 pt Deleted: % Deleted: Measured Deleted: Annual Deleted: Direct measurement Deleted: Carbon Compound with n number of carbon molecules in fuel gas/ C _n Deleted: Fuel gas composition should remain relatively stable during steady-state operation Deleted: altered

1 **B.3 Discounting Devices due to decommissioning or other uses for air.**

2 If devices are decommissioned after the implementation of the project, the baseline will
 3 be altered and the metered air may reflect higher vented fuel volumes once the gas
 4 equivalency has been applied. To avoid overestimating the baseline, the metered air is
 5 reduced by a factor equal to the sum of the decommissioned devices as illustrate in the
 6 following equation

⁴ A destruction efficiency of 98% is typically reported in literature. Refer to Canadian Association of Petroleum Producer's (CAPP) Guide –Calculating Greenhouse Gas Emissions (April 2003) section 1.7.3 for more guidance.

$$Q_{AIR}' = Q_{AIR} - \sum_{i=1}^n CR_i * n_i$$

2 where

3 CR_i = consumption rate for device i from manufacturer's technical specifications;

4 n_i = number of type i devices;

5 Consumption rates for pneumatic devices are termed bleed rates (BR). The following
6 tables list bleed rates (BR) from devices commonly used in the field. These rates are
7 expressed in terms of natural gas. An inverse application of gas equivalency should be
8 used to adjust metered air volumes.

9 This is also applicable for devices during the metered period that do not contribute to
10 instrument process control. Such devices consume air and if metered would reflect higher
11 air and therefore vented gas. These devices should be discounted from the metered air as
12 shown in the previous equation.

13 Instrument Characteristics⁵

14 **TABLE 1: Bleed Rates for Pneumatic Devices Used in the Oil and Gas Industry**

Controller Model	Signal Pressure (Psi)	Manufacturer Data (scfh)
Pressure Controller		
Ametek Series 40	20	6
	35	6
Bristol Babcock Series 5453-Model 10F	20	3
	35	3
Bristol Babcock Series 5455-Model 624-III	20	2
	35	3
Bristol Babcock Series 502 A/D (recording controller)	20	<6
	35	<6
Fisher 4100 Series (Large Orifice)	20	50
	35	50
Fisher 4150 and 4160	20	10 – 35
	35	10 - 42
Fisher 4194 Series (Differential Pressure)	20	3.5
	35	5
Fisher 4195	20	3.5
	35	5
Foxboro 43AP	20	18
	35	18
ITT Barton 338	20	6
	35	6
ITT Barton 335P	20	6
	35	6

⁵ Source: CETAC-West Efficient (May, 2008). Use of Fuel Gas in Pneumatic Instruments Module 3 of 17 (Refer to original manufacturer's product information data sheet for more accurate information on product performance.

Natco CT	20	35
	35	35
Transducers		
Bristol Babcock Series 9110-00A	20	.42
	35	.42
Fisher 546	20	21
	35	30
Fisher 646	20	<1
	35	<1
Fisher 846	20	<1
	35	<1
Level Controllers		
Fisher 2900	20	23
	20	23
	35	23
	35	23
Fisher 2500	20	42
	35	42
Fisher 2660 Series	20	1
	35	1
Fisher 2100 Series	20	<1
	35	<1
Fisher 2680	20	<1
	35	<1
Fisher L2		
Invalco CT Series	20	
	35	40
Norriseal 1001	20	N/A
	35	N/A
Norriseal 1001 (A)	20	0.007
	20	0.2
	35	0.007
	35	0.2
Wellmark 2001	20	0.007
	20	0.2
	35	0.007
35	0.2	
Positioners		
Fisher 3582	20	14
	35	18
Fisher 3661	20	8.8
	35	12.1
Fisher 3590 (Electro-pneumatic)	20	24
	35	36
Fisher 3582i (Electro-pneumatic)	20	17.2
	35	24
Fisher 3620J (Electro-pneumatic)	20	18.2
	35	35
Fisher 3660	20	6
	35	8
Fisher Fieldvue Digital	20	14
	35	49
Masoneilan 4600B Series	20	

	35	18 - 30
Masoneilan 4700B Series	20	
	35	18 - 30
Masoneilan SVI Digital	20	<1
	35	<1
Masoneilan 7400 Series	20	24 – 50
	35	24 - 50
Moore Products – Model 750P	20	
	35	42
Moore Products – 73 – B PtoP	20	36
	35	
PMV D5 Digital	20	<1
	35	<1
Sampson 3780 Digital	20	<1
	35	<1
VRC Model VP7000 PtoP	20	<1
	35	<1

1
2
3
4

TABLE 2: Gas-Driven Pneumatic Device CH₄ Emission Factors by Segment⁶

Device Type	Emission Factor (Original Units)	Precision (+%)	CH ₄ Emissions Factor* (Converted to Tonnes Basis)
Production Segment			
Continuous bleed	654 scfd gas/device	31	Based on 78.8 mole % CH ₄ 3.608 tonnes/device-yr
Intermittent bleed	323 scfd gas/device	34	1.782 tonnes/device-yr
Production Average (if device type is unknown)	345 scfd CH ₄ /device	40	2.415 tonne I/P Positioner
Transmitter (140 kPag)	0.12 m ³ gas/hr/device	Precision not specified	0.56 tonnes/device-yr
Transmitter (240 kPag)	0.2 gas/hr/device		0.94 tonnes/device-yr
Controller (140 kPag)	0.6 gas/hr/device		2.8 tonnes/device-yr
Controller (240 kPag)	0.8 gas/hr/device		3.7 tonnes/device-yr
Controller (pressure not specified)	.1996 gas/hr/device		0.9332 tonnes/device-yr
I/P Transducer (140 kPag)	0.6 gas/hr/device		2.8 tonnes/device-yr
I/P Transducer (240 kPag)	0.8 gas/hr/device		3.7 tonnes/device-yr
P/P Positioner (140 kPag)	0.32 gas/hr/device		1.5 tonnes/device-yr
P/P Positioner (240 kPag)	0.5 gas/hr/device		2.3 tonnes/device-yr
I/P Positioner (140 kPag)	0.4 gas/hr/device		1.9 tonnes/device-yr
I/P Positioner (240 kPag)	0.6 gas/hr/device	2.8 tonnes/device-yr	
Processing			
Continuous bleed	497,584 scf gas/device-yr	29	Based on 87 mole % CH ₄ 8.304 tonnes/device-yr
Piston valve operator	48 scf gas/device-yr	49	8.0101E-04 tonnes/device-yr
Pneumatic/hydraulic valve operator	5,627 scf gas/device-yr	112	0.0939 tonnes/device-yr
Turbine valve operator	67,599 scf gas/device-yr	276	1.128 tonnes/device-yr
Processing average (if device type is unknown)	164,949 scfy gas CH ₄ /plant	113	3.160 tonnes/plant-yr
	7,454 scf CH ₄ /MMscf processed		
Transmission and Storage			

⁶ Source: American Petroleum Institute (February, 2004). Compendium for Greenhouse as Emissions Methodologies for the Oil and Gas Industry. Table 5-15.

Continuous bleed	497,584 scf gas/device-yr	29	Based on 93.4 mole % CH ₄ 8.915 tonnes/device-yr
Pneumatic/hydraulic valve operator	5,627 scf gas/device-yr	112	0.1008 tonnes/device-yr
Turbine valve operator	67,599 scf gas/device-yr	276	1.211 tonnes/device-yr
Transmission or storage average	162,197 scfy gas CH ₄ /device	44	3.111 tonnes/device-yr
Distribution			
Pneumatic isolation valves based on 93.4 mole% CH ₄	0.366 tonnes CH ₄ /device -yr	Precision not specified	0.366 tonnes /device -yr
Pneumatic control loops based on 93.4 mole% CH ₄	3.465 tonnes CH ₄ /device -yr	Precision not specified	3.465 tonnes /device -yr
Distribution average (if device is unknown) based on 93.4 mole% CH ₄	2.941 tonnes/device-yr	Precision not specified	2.941 tonnes/device-yr

* CH₄ emission factors converted from scf and m³ are based on 60°F and 14.7 psia.

TABLE 3: Gas Consumption Rates (m³/h) For Standard (High Bleed) Pneumatic Instruments

Instrument	Operating Pressure (140 kpag)	Operating Pressure (240 kpag)
Transmitter	0.12	0.2
Controller	0.6	0.8
I/P Transducer	0.6	0.8
P/P Positioner	0.32	.05
I/P	0.4	0.6
Chem. injection pumps (diaphragm)	0.4	0.6
Chem. injection pumps (piston)	0.04	0.06

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28
29
30
31
32
33
34
35
36
37
38
39
40
41
42

Deleted: ¶

Deleted: ¶
¶
¶
¶
¶
¶

Deleted: ¶
¶
¶

Deleted: ¶
¶

APPENDIX C - Emissions Factor for Selected Fuels⁷

⁷ Source: Environment Canada (2006). NATIONAL INVENTORY REPORT, 1990-2005: GREENHOUSE GAS SOURCES AND SINKS IN CANADA. (Subject to Updates-Project developers should contact Environment Canada for the latest factors).

Relevant Emission Factors

Deleted: ¶
¶
¶

TABLE B.1: Emission Intensity of Fuel Extraction and Production (Diesel, Natural Gas and Gasoline)

Diesel		
Production		
Emissions Factor (CO ₂)	0.138	kg CO ₂ per Litre
Emissions Factor (CH ₄)	0.0109	kg CH ₄ per Litre
Emissions Factor (N ₂ O)	0.000004	kg N ₂ O per Litre
Natural Gas		
Extraction		
Emissions Factor (CO ₂)	0.043	kg CO ₂ per m ³
Emissions Factor (CH ₄)	0.0023	kg CH ₄ per m ³
Emissions Factor (N ₂ O)	0.000004	kg N ₂ O per m ³
Processing		
Emissions Factor (CO ₂)	0.090	kg CO ₂ per m ³
Emissions Factor (CH ₄)	0.0003	kg CH ₄ per m ³
Emissions Factor (N ₂ O)	0.000003	kg N ₂ O per m ³
Gasoline		
Production		
Emissions Factor (CO ₂)	0.138	kg CO ₂ per Litre
Emissions Factor (CH ₄)	0.0109	kg CH ₄ per Litre
Emissions Factor (N ₂ O)	0.000004	kg N ₂ O per Litre

TABLE B.2: Emissions Factors for Natural Gas and NGL's

Source	Emissions Factor		
	CO ₂ g/m ³	CH ₄ g/m ³	N ₂ O g/m ³
Natural Gas			
Electric Utilities	1891	0.49	0.049
Industrial	1891	0.037	0.033
Producer Consumption	2389	6.5	0.06
Pipelines	1891	1.9	0.05
Cement	1891	0.037	0.034
Manufacturing Industries	1891	0.037	0.033
Residential, Construction, Commercial/Institutional, Agricultural	1891	0.037	0.035
g/L			
Propane			
Residential	1510	0.027	0.108
All Other Uses	1510	0.024	0.108
Ethane			
	976	N/A	N/A
Butane			
	1730	0.024	0.108

1 **TABLE B.3: Emissions Factors for Refined Petroleum Products**

Source	Emissions Factor (g/L)		
	CO ₂	CH ₄	N ₂ O
Light Fuel			
Electric Utilities	2830	0.18	0.031
Industrial	2830	0.006	0.031
Producer Consumption	2830	0.006	0.031
Residential	2830	0.026	0.006
Forestry, Construction, Public Administration, and Commercial/Institutional	2830	0.026	0.031
Heavy Fuel Oil			
Electric Utilities	3080	0.034	0.064
Industrial	3080	0.12	0.064
Producer Consumption	3080	0.12	0.064
Residential	3080	0.057	0.064
Forestry, Construction, Public Administration, and Commercial/Institutional	3080	0.057	0.064
Kerosene			
Electric Utilities	2550	0.006	0.031
Industrial	2550	0.006	0.031
Producer Consumption	2550	0.006	0.031
Residential	2550	0.006	0.031
Forestry, Construction, Public Administration, and Commercial/Institutional	2550	0.006	0.031
Diesel	2730	0.133	0.4

Deleted: 0.057

2

The key concept in this applicability criterion is for the project proponent to inspect and repair leaks prior to actual metering to reduce and mitigate risks associated with overestimation of emissions.

Prior to the implementation of the instrument air system and metering, the project proponent must demonstrate that the instrument air system’s piping network has been inspected for leaks as pursuant to section 8.7 in Directive 60. This d

The following equation (1) should be used to calculate emissions from Air Compression for projects that use electricity from the grid. Note that this emission factor can be based on electricity displacement factor for Alberta or from an approved displacement factor for self-generators. Also note that the emission from Air Compression should be prorated by a factor of $\Sigma(\text{Compressed Air}_{\text{Control Instruments } i}) / \Sigma(\text{Produced Air } i)$ for existing air compression systems or systems that supply air for other uses in addition to control instruments.

$$\text{Emissions}_{\text{Air Compression}} = \frac{\Sigma (\text{EF}_{\text{Electricity}} * \text{Electricity Use }_i * \text{Compressed Air}_{\text{Control Instruments } i})}{\Sigma (\text{Total Produced Air }_i)}$$

Note that this emission factor can be based on electricity displacement factor in Alberta or from an approved displacement factor for self-generators.

Emission Factor for Grid-Generated or Self-Generated Electricity / $\text{EF}_{\text{Electricity}}$

Direct metering of electricity consumption or reconciliation of consumption

1 month continuous metering or monthly reconciliation

Reference values adjusted annually as part of Environment Canada reporting on Canada’s emissions inventory.

Both methods are standard practice. Frequency of metering is highest level possible. Frequency of reconciliation provides for reasonable diligence.

The following equation (1) should be used to calculate emissions from Air Management System for projects that use electricity from the grid. Note that this emission factor can be based on electricity displacement factor for Alberta or from an approved displacement factor for self-generators. Also note that the emission from Air Management System should be prorated by a factor of $\Sigma(\text{Compressed Air}_{\text{Control Instruments } i}) / \Sigma(\text{Produced Air } i)$ for existing air compression systems or systems that supply air for other uses in addition to control instruments In case no management system is used, this may be assumed as zero since including them would increase the total amount of project emissions.

$$\text{Emissions}_{\text{Air Management System}} = \frac{\Sigma (\text{EF}_{\text{Electricity}} * \text{Electricity Use }_i * \text{Managed Air}_{\text{Control Instruments } i})}{\Sigma (\text{Total Managed Air }_i)}$$

Page 25: [9] Deleted ohurtad1 2/24/2009 2:55:00 PM

Note that this emission factor can be based on electricity displacement factor in Alberta or from an approved displacement factor for self-generators.

Page 25: [10] Formatted ohurtad1 2/17/2009 12:07:00 PM

Indent: Left: 0 pt, Hanging: 17.85 pt, Space After: 12 pt

Page 25: [11] Deleted ohurtad1 2/27/2009 2:32:00 PM

kg of CO₂e/kWh
kWh

Page 25: [12] Deleted ohurtad1 2/27/2009 2:32:00 PM

Estimated
Measured

Page 25: [13] Deleted ohurtad1 2/27/2009 2:32:00 PM

From Environment Canada reference documents
Direct metering of electricity consumption or reconciliation of consumption

Page 25: [14] Deleted ohurtad1 2/27/2009 2:32:00 PM

Annual
1 month continuous metering or monthly reconciliation

Page 25: [15] Deleted ohurtad1 2/27/2009 2:32:00 PM

Emission Factor for Grid-Generated or Self-Generated Electricity / EF_{Electricity}
Electricity Used by Desiccant i / Electricity Use_i

Page 25: [16] Deleted ohurtad1 2/27/2009 2:32:00 PM

Reference values adjusted annually as part of Environment Canada reporting on Canada's emissions inventory.
Both methods are standard practice. Frequency of metering is highest level possible. Frequency of reconciliation provides for reasonable diligence.