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

November, 2008

Table of Contents

1.0. Project and Methodology Scope and Description 1
1.1. Protocol Scope and Description 1
1.2. Glossary of New Terms 5
2.0. Quantification Development and Justification 8
2.1. Identification of Sources and Sinks (SS's) for the Project 8
2.2. Identification of Baseline 13
2.3. Identification of SS's for the Baseline 13
2.4. Selection of Relevant Project and Baseline SS's 18
2.5. Quantification of Reduction, Removals, and Reversals of Relevant SS's 21
  2.5.1. Quantification Approach 21
  2.5.2. Contingent Data Approach 30
2.6. Management of Data Quality 30
  2.6.1. Record Keeping 30
  2.6.2. Quality Assurance/Quality control (QA/QC) 30
APPENDIX A- 35
Explanation on Gas Equivalency and Leaks 35
APPENDIX B - 42
Quantification Procedures for Flexibility Mechanisms 42
APPENDIX C- 51
Emissions Factor for Selected Fuels 51

List of Figures

FIGURE 1.1: Process Flow Diagram for Project Condition 6
FIGURE 1.2: Process Flow Diagram for Baseline Condition 7
FIGURE 2.1: Project Element Life Cycle Chart 9
FIGURE 2.2: Baseline Element Life Cycle Chart 14

List of Tables

TABLE 2.1: Project SS's 10
TABLE 2.2: Baseline SS's 15
TABLE 2.3: Comparison of SS's 19
TABLE 2.4: Quantification Procedures 22
TABLE 2.5: Contingent Data Collection Procedures 31

1.0. Project and Methodology Scope and Description

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

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

The opportunity for generating carbon offsets with this protocol arises from the direct and indirect reduction of greenhouse gas emissions resulting from the conversion of natural gas pneumatic to instrument air for control instruments. Instrument air will be provided by compressed air. Therefore, a complete air compressor system will be needed for this conversion.

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

1.1. Protocol Scope and Description

This protocol serves as a generic ‘recipe’ for project proponents to follow in order to meet the measurement, monitoring, and greenhouse gas quantification requirements for reductions resulting from conversion of natural gas pneumatic to instrument air in process control systems. A process flow diagram for a typical project using compressed air to provide pressure to instrument controllers is shown in **FIGURE 1.1.** Upon conversion, all methane that would have been vented will be replaced by compressed air. Emissions in the project stem from electricity consumption used to compress the air, and to manage and condition the air.

Protocol Approach:

The baseline condition for this protocol is defined as the volume of natural gas vented, or flared/combusted to the atmosphere prior to the conversion to the air system. In this baseline scenario, processed natural gas is used to supply fuel gas for facility processes. This gas is typically sourced from the fuel supply for the entire facility. This is a major source of greenhouse gas emissions for the baseline. A process flow diagram for a typical baseline using fuel gas to provide pressure to pneumatic controllers is shown in **FIGURE 1.2.** Other sources of emission include greenhouse gases from fuel extraction and processing.

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

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

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

Prorated quantities may also be reconciliated quantities on a periodic basis. In other words, a balance be carried out to determine the quantities used in air compression. Lastly, electricity consumption must also be metered to establish consumption and emissions.

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

Metering will be carried out for a minimum period of **ONE** month for all metered quantities. The project proponent should choose a month that is **representative** of normal operating conditions. Emissions from this period are assumed to be **representative** of normal instrument operations during the project and baseline conditions and will represent a cap for the project's time span. This cap represents the maximum emissions that project proponent may claim, even if the facility increases operations and consequently its emissions from control instruments. Furthermore, since control instruments work at a steady rate in a given facility, this period of metering will reflect a static condition for both the baseline and the project for the reporting period. This protocol therefore assumes that the baseline and project condition are static.

Protocol Applicability:

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

1. Demonstrate functional equivalence between the instrument gas system and the instrument air system. The instrument air system will replace the instrument gas system in process control.

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 directive states that an operator of an oil or gas facility must develop and implement a program to detect and repair leaks meeting or exceeding the CAPP *Best Management Practice (BMP) for Fugitive Emissions Management.* This BMP suggests annual or quarterly leak monitoring frequencies depending on the process equipment device. Following these steps should guarantee that leaks have been minimized as much as practically possible. This will ensure that metering does not overestimate volumes of air, which in turn determines the volumes of gas that would have been vented, had the project not taken place. If inspection for leaks is not performed according to suggested monitoring frequencies, metered air must be reduced using a discount factor. This factor is developed in detail in **APPENDIX A.2**.

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

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

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

  a. [The date of equipment installation, operating parameter changes or process reconfiguration are initiated or have effect on the project on or after January 1, 202 as indicated by facility records;]
  b. [The project may generate emission reduction offsets for a period of 8 years unless an extension is granted by Alberta Environment, as indicated by facility and offset records. Additional credit duration periods require a reassessment of the baseline condition; and,]
  c. [Ownership of the emission reduction offsets must be established as indicated by facility records.]

Protocol Flexibility:

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

1. Site specific emissions factors may be substituted for the generic emission factors indicated in this protocol document. The methodology for generation of these emission factors must be sufficiently robust to ensure accuracy. 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.

2. Baseline and project metering may be carried out for more than one month if the project proponent deems necessary to show more accurate and representative emissions. It is up to the project proponent to justify this flexibility mechanism.

3. For cases in which projects were implemented but the air was not metered, carbon offsets are claimable. This claim is based on instrument counts from the facility and the metered air. Emissions from the one month metering are used as a baseline. This baseline is adjusted by subtracting the sum of the devices added multiplied by their respective vent rate. Details of this flexibility mechanism are provided in **APPENDIX B.1**. It should be noted that the lists in APPENDIX B are not complete lists and therefore not authoritative. More instruments may exist or are under development and have not been included. These lists only serve as an illustrative example of the emissions that may be encountered by project developer. It is up to the project developer to use emission or vent rates that are most current by contacting the manufacturer of specific devices and request information for those specific devices. Manufacturers of control devices usually publish the emission rates for each type of device, and for each type of operation.

4. For projects where part of the vented gas is flared or collected for combustion, the project proponent may claim credits using this protocol's flexibility mechanism. The total metered air is divided into two fractions; X represents the vented

fraction and (1-X) represents the flared or combusted fraction. X represents a fraction that is established using vendor's technical specifications for bleed rates (BR). Refer to **APPENDIX B.2** for a detailed explanation on how these percentages are established. Assuming all instrument gas is vented, the value of X is 1.

5. 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**.

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

1.2. Glossary of New Terms

Air Pneumatic Instrument	Any instrument that uses 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 as 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). In this protocol. The functional equivalence in this protocol is the pressure provide by the natural gas and air pneumatic system.
Gas Pneumatic Instrument	Any instrument that uses compressed natural gas to function and provided the necessary level of control required for its intended use.
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.

FIGURE 1.1: Process Flow Diagram for Project Condition

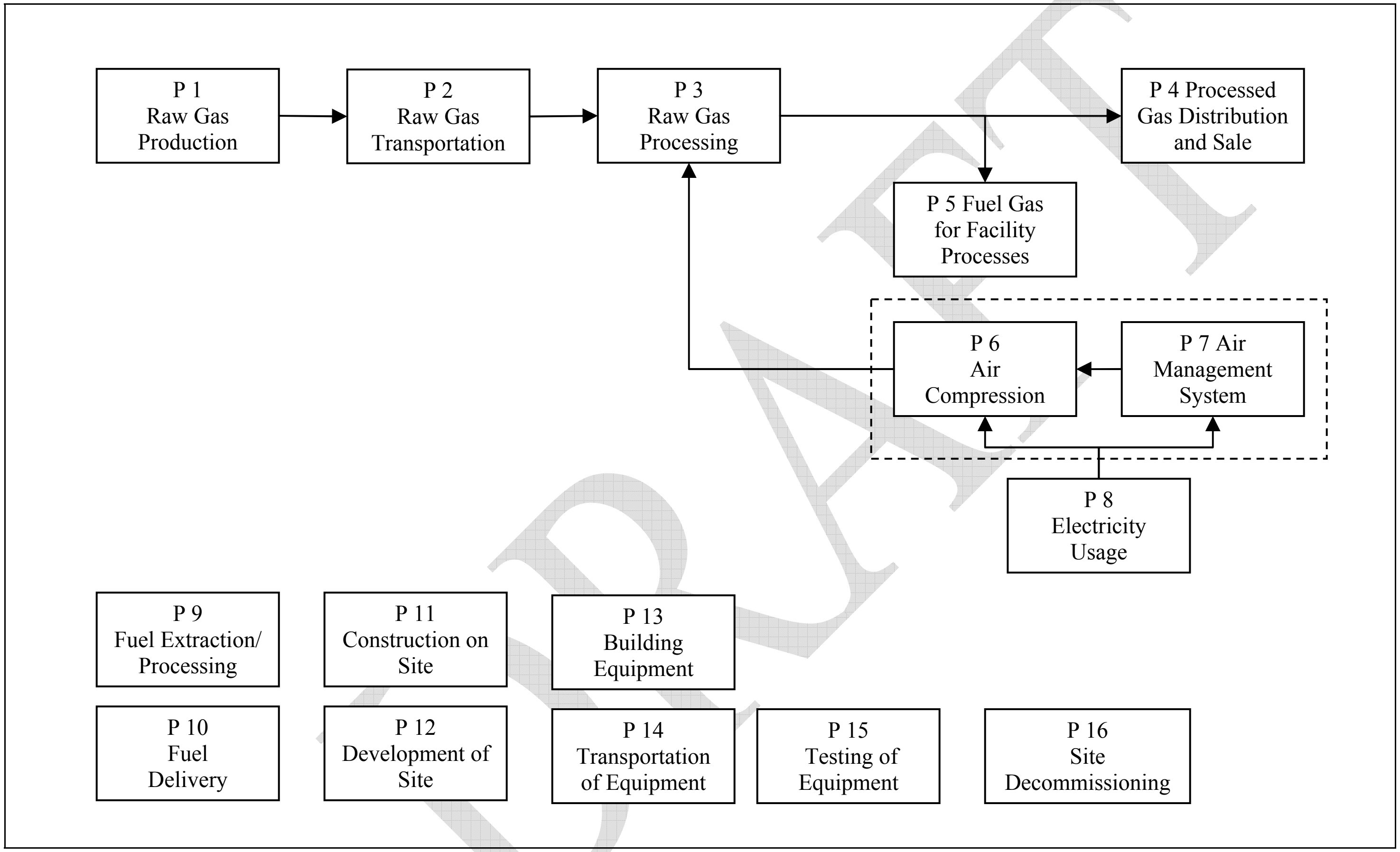
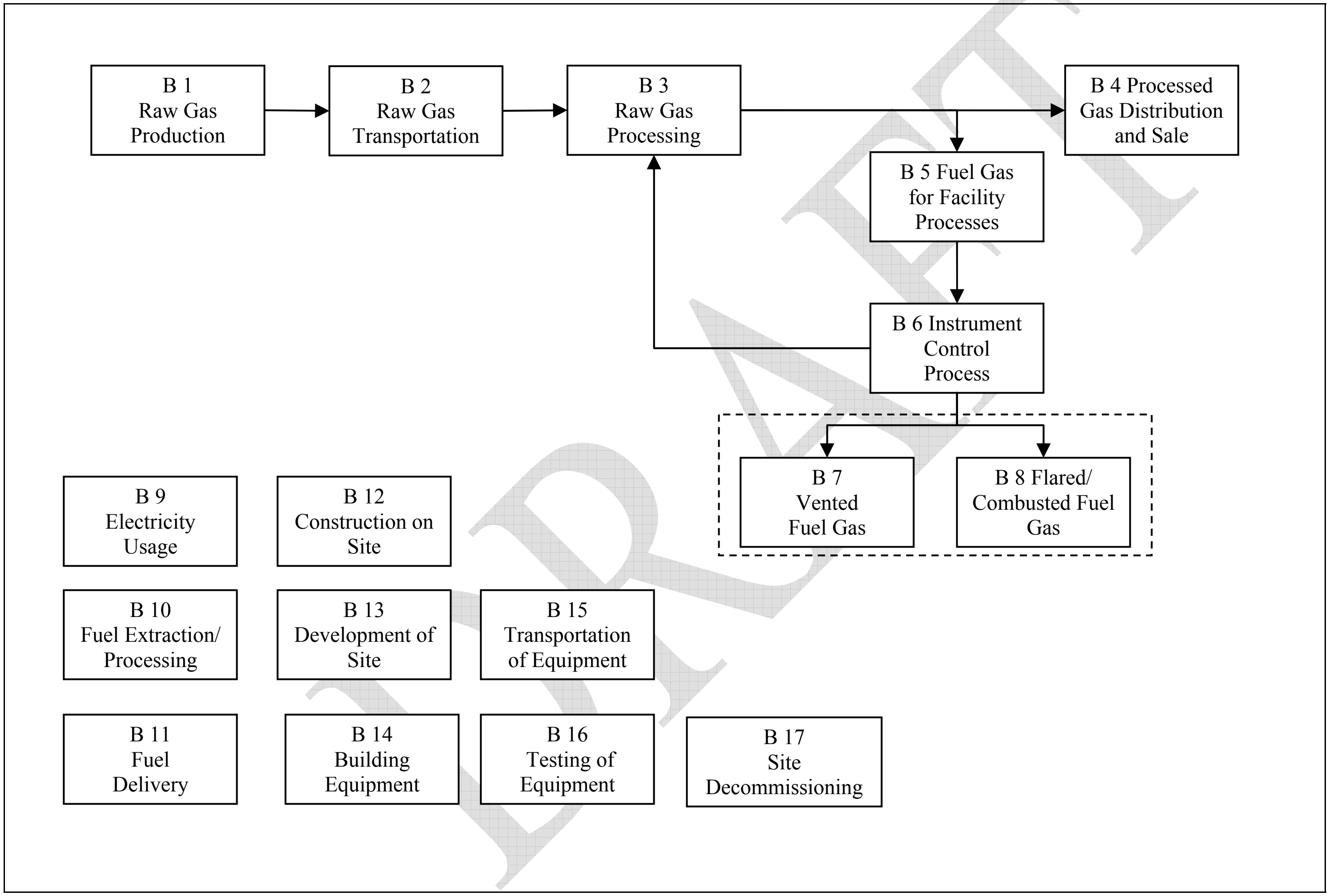


FIGURE 1.2: Process Flow Diagram for Baseline Condition



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**.

FIGURE 2.1: Project Element Life Cycle Chart

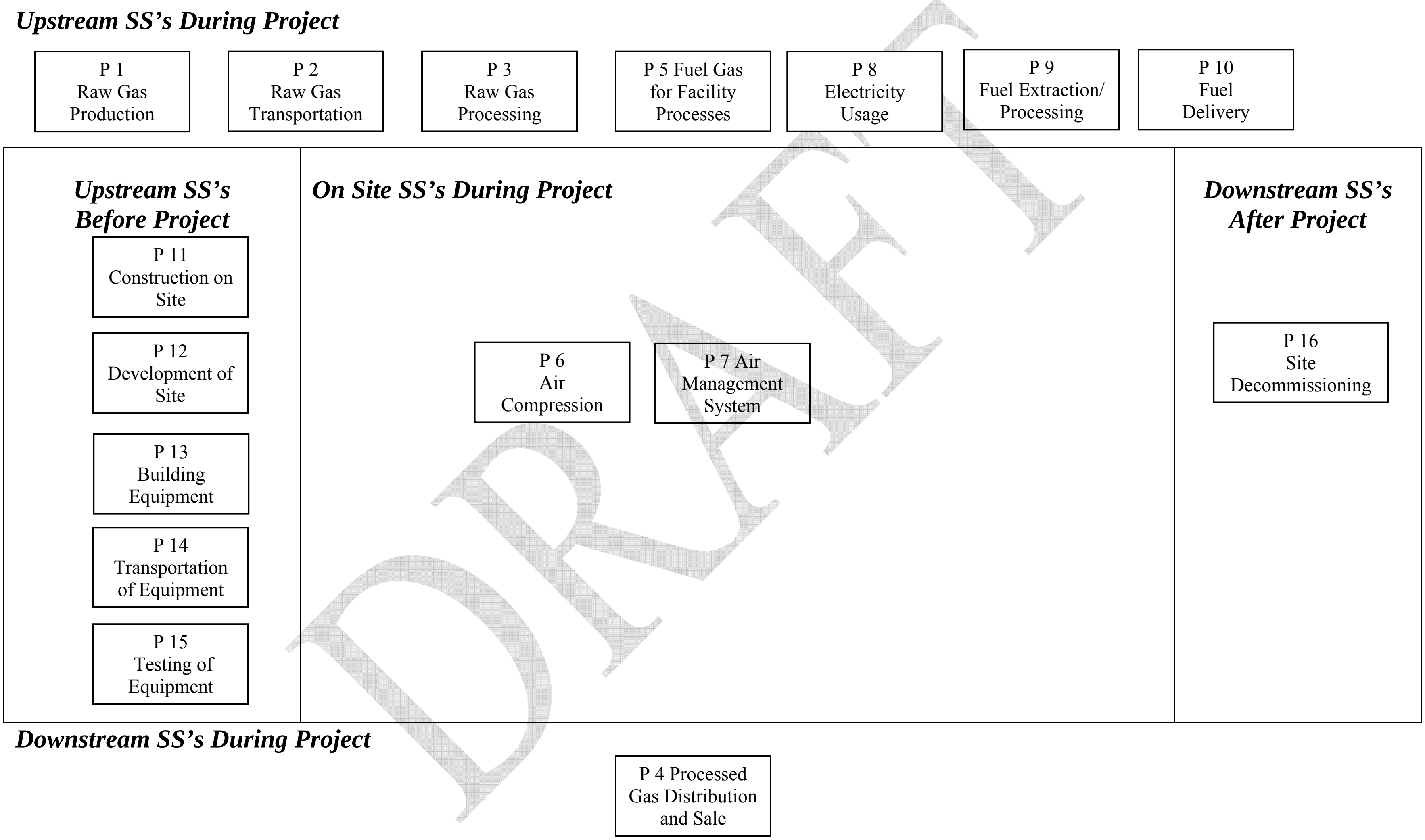


TABLE 2.1: Project SS’s

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 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
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 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 input 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. 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 controlled combustion to produce carbon dioxide.	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,	Related

	fabrication and assembly.	
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, plating or seeding, and transportation of materials off-site. GH emissions would be primarily attributed to the use of fossil fuels and electricity used to power equipment required to decommission the site.	Related

2.2. Identification of Baseline

The baseline condition for the projects applying this protocol is defined as the operating condition prior to the conversion of instrument pneumatic 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 monitor 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. So, baseline emissions are determined from the metered quantity of compressed air through gas equivalence. 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 and condition the air.

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.

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 to fuel gas. Finally, this fuel gas might need to be conditioned; therefore, the equivalent volume is used to deduce emissions due to fuel gas management and conditioning.

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**.

FIGURE 2.2: Baseline Element Life Cycle Chart

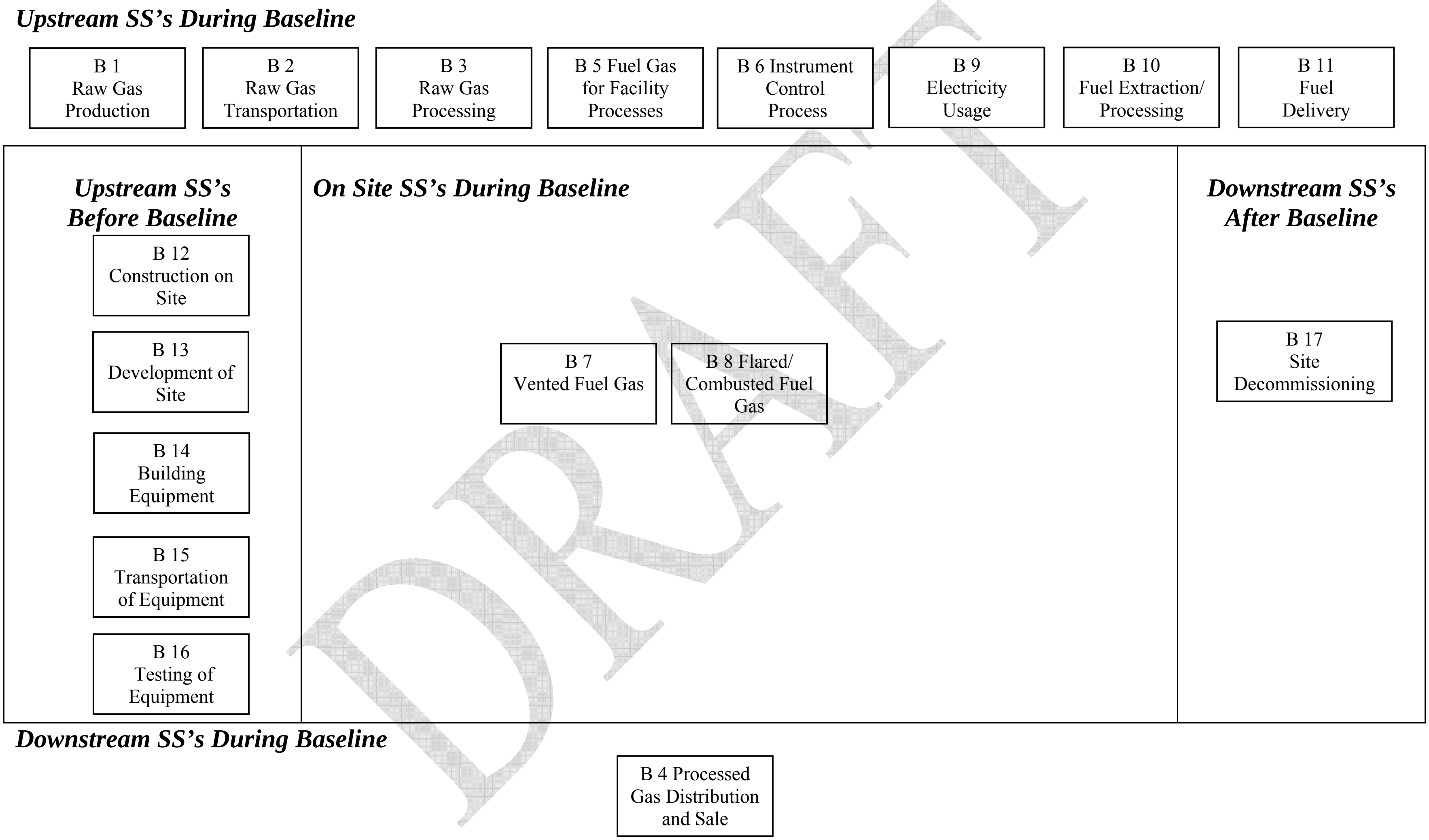


TABLE 2.2: Baseline SS's

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. Emissions from processing pressurized fuel gas should be tracked. These emissions are likely to take place during activity B10.	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	Related

	SS's in this project are considered in this SS. Types and quantities of fuels used would need to be tracked.	
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 using various methods prescribed in this protocol.	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 using various methods prescribed in this protocol.	Controlled
Downstream SS's during Baseline Operation		
B 4 Processed Gas Distribution and Sale	Natural gas and other commercially viable NGL products may be input 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	Related

	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.	
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, plating 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

2.4. Selection of Relevant Project and Baseline SS's

Each of the SS's from the project and baseline condition were compared and evaluated as to their relevancy using the guidance provided in Annex VI of the "Guide to Quantification Methodologies and Protocols: Draft", dated March 2006 (Environment Canada). The justification for the exclusion or conditions upon which SS's may be excluded is provided in **TABLE 2.3**, below. All other SS's listed previously are included.

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	Included in P 6 and P 7
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 Fuel Gas	Related	N/A	Included	N/A

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.

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

2.5.1. Quantification Approach

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

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

$$\boxed{\begin{aligned}\text{Emissions}_{\text{Baseline}} = {} & \text{Emissions}_{\text{Fuel Extraction / Processing}} + \text{Emissions}_{\text{Vented Fuel Gas}} \\ & + \text{Emissions}_{\text{Flared/Combusted Fuel Gas}}\end{aligned}}$$

$$\boxed{\begin{aligned}\text{Emissions}_{\text{Project}} = {} & \text{Emissions}_{\text{Fuel Extraction / Processing}} + \text{Emissions}_{\text{Air Compression}} \\ & + \text{Emissions}_{\text{Air Management System}}\end{aligned}}$$

where:

$\text{Emissions}_{\text{Baseline}}$ = sum of the emissions under the baseline condition.
$\text{Emissions}_{\text{Fuel Extraction / Processing}}$ = emissions under SS B 10 Fuel Extraction and Processing
$\text{Emissions}_{\text{Vented Fuel Gas}}$ = emissions under SS B 7 Vented Fuel Gas
$\text{Emissions}_{\text{Flared/Combusted Fuel Gas}}$ = emissions under SS B 8 Flared/Combusted Fuel Gas

$\text{Emissions}_{\text{Project}}$ = sum of the emissions under the project condition.
$\text{Emissions}_{\text{Fuel Extraction / Processing}}$ = emissions under SS P 9 Fuel Extraction and Processing
$\text{Emissions}_{\text{Air Compression}}$ = emissions under SS P 6 Air Compression
$\text{Emissions}_{\text{Air Management System}}$ = emissions under SS P 7 Air Management System

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 and Processing	$\text{Emissions}_{\text{Fuel Extraction / Processing}} = \Sigma (\text{Vol. Fuel}_i * \text{EF Fuel}_{i\ CO2}); \Sigma (\text{Vol. Fuel}_i * \text{EF Fuel}_{i\ CH4}); \Sigma (\text{Vol. Fuel}_i * \text{EF Fuel}_{i\ N2O})$					
	Emissions $_{\text{Fuel Extraction / Processing}}$	kg of CO2e	N/A	N/A	N/A	Quantity being calculated in aggregate form as fuel and electricity use on site is likely aggregate for each of these SS's.
	Volume of Fossil Fuel i Combusted for P 6 and P 7 / Vol. Fuel $_i$	m^3	Measured	Direct metering or reconciliation of volumes transferred volumes	Annual	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_2O Emissions Factor for Fuel Including	kg N_2O 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 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.* 1. $\text{Emissions}_{\text{Air Compression}} = \Sigma\,(\text{EF Electricity} * \text{Electricity Use i} * \text{Compressed Air}_{\text{Control Instruments i}}) / \Sigma\,(\text{Produced Air}_{\text{i}})$ *The following equation (2) should be used to calculate emissions from Air Compression for projects that use on-site electricity generated from fossil fuels. Note that this emission factor can be based on electricity displacement factor in Alberta or from an approved displacement factor for self-generators.* 2. $\text{Emissions}_{\text{Air Compression}} = \Sigma\,(\text{Vol. Fuel}_{\text{i}} * \text{EF Fuel}_{\text{i CO2}} * \text{Compressed Air}_{\text{Control Instruments i}}) / \Sigma\,(\text{Produced Air}_{\text{i}})$; $\Sigma\,(\text{Vol. Fuel}_{\text{i}} * \text{EF Fuel}_{\text{i CH4}} * \text{Compressed Air}_{\text{Control Instruments i}}) / \Sigma\,(\text{Produced Air}_{\text{i}})$; $\Sigma\,(\text{Vol. Fuel}_{\text{i}} * \text{EF Fuel}_{\text{i N2O}} * \text{Compressed Air}_{\text{Control Instruments i}}) / \Sigma\,(\text{Produced Air}_{\text{i}})$					
	$\text{Emissions}_{\text{Air Compression}}$	kg of COe_2	N/A	N/A	N/A	Quantity being calculated in aggregate form as fuel and electricity use on site is likely aggregate for each of these SS's.
	Emission Factor for Grid-Generated or Self-Generated Electricity / EF Electricity	kg of CO_2e/kWh	Estimated	From Environment Canada reference documents	Annual	Reference values adjusted annually as part of Environment Canada reporting on Canada's emissions inventory.
	Electricity Used by Compressor i /Electricity Use	kWh	Measured	Direct metering of electricity consumption or reconciliation of consumption	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.
	Compressed Air Used for Pneumatic Instrument $_i$ / Compressed Air $_{\text{Control Instruments i}}$	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.
	CO_2 Emissions Factor Each Type of Fuel i / 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 Each Type of Fuel i / 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_2O Emissions Factor for Each Type of Fuel i / EF Fuel $_{N2O}$	kg N_2O 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	*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*					

System	*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.* 1. $\text{Emissions}_{\text{Air Management System}} = \Sigma\,(\text{EF Electricity} * \text{Electricity Use } i * \text{Managed Air}_{\text{Control Instruments } i}) / \Sigma\,(\text{Produced Air}_{i})$ *The following equation (2) should be used to calculate emissions from Air Management System for projects that use on-site electricity generated from fossil fuels. Note that this emission factor can be based on electricity displacement factor in Alberta or from an approved displacement factor for self-generators.* 2. $\text{Emissions}_{\text{Air Management System}} = \Sigma\,(\text{Vol. Fuel}_{i} * \text{EF Fuel}_{i\ CO2} * \text{Managed Air}_{\text{Control Instruments } i}) / \Sigma\,(\text{Total Managed Air}_{i});$ $\Sigma\,(\text{Vol. Fuel}_{i} * \text{EF Fuel}_{i\ CH4} * \text{Managed Air}_{\text{Control Instruments } i}) / \Sigma\,(\text{Total Managed Air}_{i});$ $\Sigma\,(\text{Vol. Fuel}_{i} * \text{EF Fuel}_{i\ N2O} * \text{Managed Air}_{\text{Control Instruments } i}) / \Sigma\,(\text{Total Managed Air}_{i})$					
	$\text{Emissions}_{\text{Air Compression}}$	kg of COe$_2$	N/A	N/A	N/A	Quantity being calculated in aggregate form as fuel and electricity use on site is likely aggregate for each of these SS's.
	Emission Factor for Grid-Generated or Self-Generated Electricity / EF Electricity	kg of CO$_2$e/kWh	Estimated	From Environment Canada reference documents	Annual	Reference values adjusted annually as part of Environment Canada reporting on Canada's emissions inventory.
	Electricity Used by Desiccant i /Electricity Use	kWh	Measured	Direct metering of electricity consumption or reconciliation of consumption	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.
	Managed Air Used for Pneumatic	m^3	Measured	Direct metering of volume being	1 month continuous	Both methods are standard practice.

	Instrument $_{i}$ / Managed Air $_{\text{Control Instruments i}}$			compressed and sent to control instrument pipe network	metering or monthly reconciliation	Frequency of metering is highest level possible. Frequency of reconciliation provides for reasonable diligence.
	Total Air Managed in Air Compressor System by Air Management system i/ Total Managed 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.
	CO_2 Emissions Factor Each Type of Fuel i / 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 Each Type of Fuel i / 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_2O Emissions Factor for Each Type of Fuel i / EF Fuel $_{N2O}$	kg N_2O 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.
Baseline SS's						
B 10 Fuel Extraction and Processing	Emissions $_{\text{Fuel Extraction / Processing}}$ = Σ (Emissions $_{\text{Fuel Gas for Control Instruments}}$ * EF Fuel $_{\text{i CO2}}$); Σ (Emissions $_{\text{Fuel Gas for Control Instruments}}$ * EF Fuel $_{\text{i CH4}}$); Σ (Emissions $_{\text{Fuel Gas for Control Instruments}}$ * EF Fuel $_{\text{i N2O}}$)					
	Emissions $_{\text{Fuel Extraction / Processing}}$	kg of CO_2e	N/A	N/A	N/A	Quantity being calculated in aggregate form as fuel and electricity use on site

						is likely aggregate for each of these SS's.
	Volume of Fossil Fuel i Consumed for B 6 and B 7 / Emissions $_{\text{Fuel Gas for Control Instruments}}$	m^3	Estimated	Estimated based on volumes from B 6	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_2O Emissions Factor for Fuel Including Production and Processing / EF Fuel $_{N2O}$	kg N_2O 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.
B 7 Vented Fuel Gas	*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 CH_4 and will always be used. Typically, the percentage of CH_4 in fuel gas is in excess of 85% and can be as much as 99%. Equation (2) is used to establish baseline emission for ventedCO_2. If the percentage of CO_2 is in excess of 10%, equation (2) is used to establish baseline CO_2 emissions from vented fuel. If the percentage of CO_2 emissions is inferior to 10%, it is advisable not to include CO_2 emissions as the volumes are insignificant.*					

1. Emissions $_{\text{Fuel Gas for Control Instruments}}$ =

$$\Sigma \text{ Compressed Air}_{\text{Control Instruments } i} * (1-DR) * \sqrt{\frac{G_{AIR}}{G_{CH4}}} * \frac{\left(1-\frac{1}{3*F_k}\right)}{\left(1-\frac{1}{3*F_{AIR}}\right)} * \%CH_4 * \rho_{CH4};$$

2. $$\Sigma \text{ Compressed Air}_{\text{Control Instruments } i} * (1-DR) * \sqrt{\frac{G_{AIR}}{G_{CH4}}} * \frac{\left(1-\frac{1}{3*F_k}\right)}{\left(1-\frac{1}{3*F_{AIR}}\right)} * \%CH_4 * \rho_{CH4} * \frac{\%CO_2}{\%CH_4} * \frac{44}{16};$$

where

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

	Emissions $_{\text{Fuel Gas For Control Instruments}}$	kg of CH_4 ; CO_2	N/A	N/A	N/A	Quantity being calculated in aggregate form as fuel and electricity use on site is likely aggregate for each of these SS's.
	Compressed Air Used for Pneumatic Instruments $_i$/ Compressed Air $_{\text{Control Instruments } i}$	m^3	Measured	Direct metering of volume being compressed and sent to control instrument pipe network as determined in P6	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.
	Discount Rate due to Leaks / DR	%	Estimated	1. DR(%)= 2.5 %*minimum year interval for 0< year < 10	N/A	Leaks are taken into account when air is metered to adjust the baseline. The year of last

				2. DR(%)= 20% for year > 10		documented inspection and maintenance is taken into account in parameter ‘minimum year interval’. A 5% per annum increase due to leaks is assumed.
	Specific Gravity of Air /G $_{AIR}$	m^3	Estimated	1.00	N/A	Accepted value.
	Specific Gravity of Methane / G $_{CH4}$	Kg / m^3	Estimated	0.5537	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.
	Specific Heat Ratio for CH_4 / k_{CH4}	-	Assumed	Constant value of 1.31 at NTP.	N/A	Accepted value
	Specific Heat Ratio for air /1.4	-	Assumed	Constant value of 1.40 at NTP.	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)					

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 de 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.

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 Each 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.
	Compressed Air Used for Instruments / Compressed Air $_{\text{Control Instruments i}}$	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.
P 6 Air Compression	Compressed Air Used for Instruments / Compressed Air $_{\text{Control Instruments i}}$	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.
	Electricity Used by Desiccant i/	kWh	Estimated	Estimated based on volume of air managed	Monthly	Provides reasonable estimate of the parameter,

	Electricity Use			and desiccant characteristics		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.
P 7 Air Management System	Volume of Each Type of Fuel / Vol. Fuel $_i$	L / m^3 / other	Estimated	Reconciliation of volume of fuel consumed 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.
	Electricity Used by Compressor i/ Electricity Use	kWh	Estimated	Estimated based on volume of air compressed and compressor characteristics	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.
Baseline SS's						
B 10 Fuel Extraction and Processing	Volume of Each 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.
	Compressed Air Used for Instruments / Compressed Air Control Instruments i	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.
B 7 Vented Fuel Gas	Compressed Air Used for Instruments / Compressed Air Control Instruments i	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.
	Methane Composition in Fuel Gas / % CH_4	-	Estimated	From accredited references or industry standards	Annually	Fuel gas composition should remain relatively stable during steady-state operations within industry. Estimating gas composition from accredited references provides a reasonable estimate when the more accurate method cannot be used.
	Carbon dioxide	-	Estimated	From accredited	Annually	Fuel gas composition

	Composition in Fuel Gas / % CO_2			references or industry standards		should remain relatively stable during steady-state operations within industry. Estimating gas composition from accredited references provides a reasonable estimate when the more accurate 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.

APPENDIX A - Explanation on Gas Equivalency and Leaks

A.1 Gas Equivalence

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

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

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

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

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

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

where

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

Q_{SCFH} = fluid volumetric flow rate;
C_V = flow coefficient;
$P_{1\ PSIA}$ = inlet pressure;
Y = expansion factor;
x = pressure drop ratio to absolute inlet pressure
G_g = gas specific gravity (this is the density of the gas divided by the density of air at the same conditions);
$T_{\circ R}$ = temperature in degrees Rankine;
F_k = ratio of specific heats (equal to the specific heat ratio of the gas divided by the specific heat ratio of air) ; and
X_T = maximum pressure before choking

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

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

where

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

where

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

<u>1st Approach- Mathematical</u>

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

$$Q_{CH4} = 1{,}360 * C_V * P_{1psia} * Y_{CH4} * \sqrt{\frac{x}{G_{CH4} * T_{\circ R}}} \tag{4}$$

where

Q_{CH4} = CH_4 volumetric fluid flow rate

Similarly, (1) for air can be expressed as

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

where

Q_{AIR} = air volumetric flow rate

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

$$Q_{CH4} = Q_{AIR} * \frac{1}{\sqrt{\frac{1}{G_{AIR}}}} * \frac{1}{Y_{AIR}} * Y_{CH4} * \sqrt{\frac{1}{G_{CH4}}} \tag{6}$$

Rearranging terms and assuming choked conditions (3)

$$Q_{CH4} = Q_{AIR} * \sqrt{\frac{G_{AIR}}{G_{CH4}}} * \frac{1 - \frac{1}{3 * F_k}}{1 - \frac{1}{3 * F_{AIR}}} \qquad (7)$$

Specific gas gravities for greenhouse gases present in fuel supply gas at NTP[1] are summarized below.

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

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

Using G_{CH4}= .5537, G_{AIR}=1, and k=1.31 for pure methane, (7) becomes

$$\underline{Q_{CH4} = 1.2977 * Q_{AIR}}$$

2nd Approach-Graphic

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

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

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

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

Assuming G_{AIR} = 1, G_{CH4} = .5537, k=1.31, and β= .8, (7) yields

$$Q_{CH4} = 1.3087 * Q_{AIR}$$

If β= 1, (7) yields

---

[1] 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)

$$\underline{Q_{CH4} = 1.2994 * Q_{AIR}}$$

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

$$\dot{m}_{CH4} = Q_{AIR} * \sqrt{\frac{G_{AIR}}{G_{CH4}} * \frac{\left(1 - \frac{1}{3 * F_k}\right)}{\left(1 - \frac{1}{3 * F_{AIR}}\right)}} * \%CH_4 * \rho_{CH4} \qquad (8)$$

where

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

$\%CH_4$ = volume fraction of CH_4 in fuel supply gas;

ρ_{CH4} = methane density; and

and

$$\dot{m}_{CO2} = Q_{AIR} * \sqrt{\frac{G_{AIR}}{G_{CH4}} * \frac{\left(1 - \frac{1}{3 * F_k}\right)}{\left(1 - \frac{1}{3 * F_{AIR}}\right)}} * \%CH_4 * \rho_{CH4} * \frac{\%CO_2}{\%CH_4} * \frac{44}{16} \qquad (9)$$

where

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

$\%CH_4$ = volume fraction of CH_4 in fuel supply gas;

$\%CO_2$ = volume fraction of CO_2 in fuel supply gas;

44 = molecular weight of CO_2; and

16= molecular weight of CH_4.

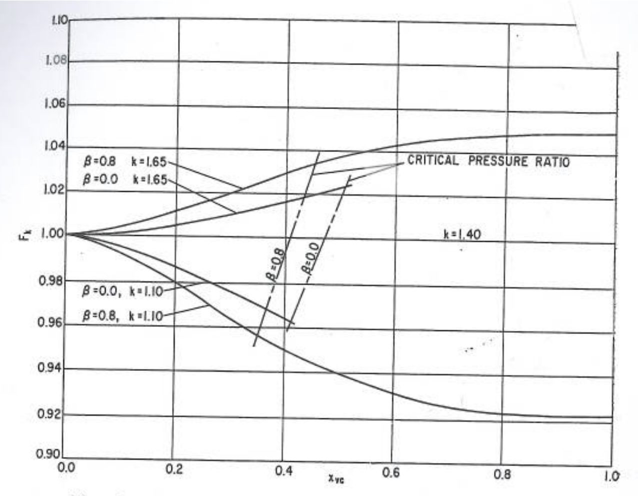
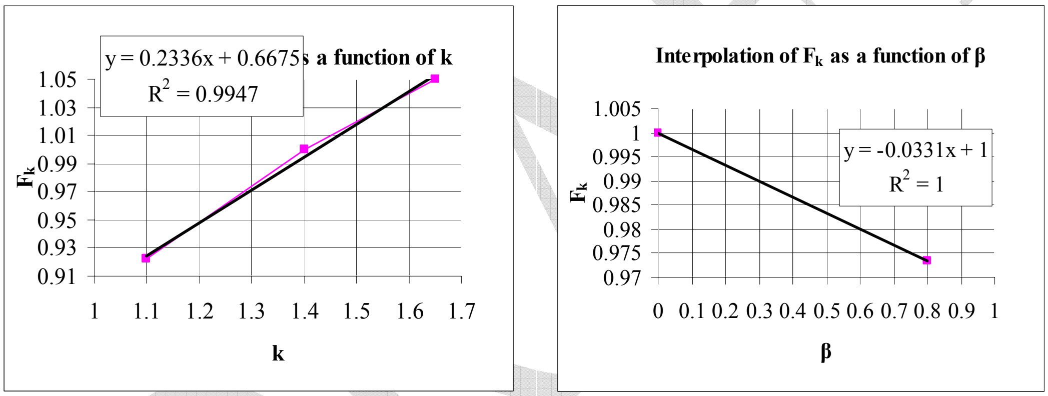


Fig. 3—Correction factor for ratio of specific heats.

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**

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

A.2 Leaks

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

The discount factors presented here are based on rates from the EPA's Natural Gas STAR Program *Lessons Learned-Convert Gas Pneumatic Controls to Instrument Air*. Instrument control devices in service and that have not been repaired will leak as time passes. A 2.5 % yearly linear increase in leaks is assumed. For devices that have been recently inspected and repaired, the discount rate is assumed to be zero. For devices or pipe networks that have not been inspected and repaired in the last 10 years, the discount rate increases linearly until reaching 20%. The maximum discount rate is 20% for devices with more than 10 years without inspection and repairs. The equations used to calculate the discount rate are as follows:

DR(%)= 2.5 %*(minimum year interval) for 0< year < 10
(10)

DR(%)= 25% for year > 10 (11)

This relationship is assumed linear and is illustrated in Figure A.1. As an example, if the last inspection and repair took place 5.5 years ago, then the minimum of that year interval is 5. 5 times 2.5 % yearly increase due to leaks yields a 12.5 % leak rate. The DR is therefore 10%

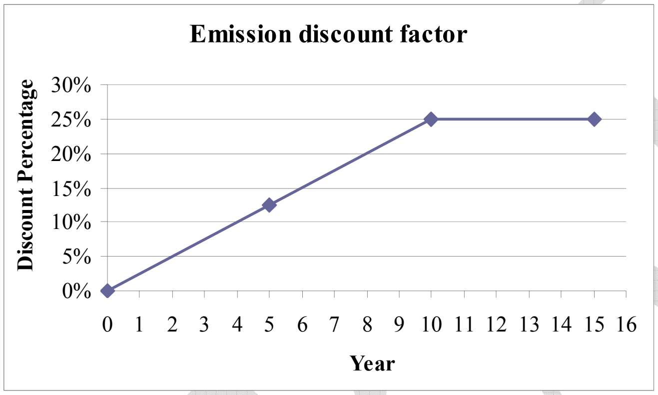


Figure A.1 Linear relationship between elapsed time and discount percentage.

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

$$\dot{m}_{CH4} = (1-DR) * Q_{AIR} * \sqrt{\frac{G_{AIR}}{G_{CH4}}} * \frac{\left(1-\frac{1}{3*F_k}\right)}{\left(1-\frac{1}{3*F_{AIR}}\right)} * \%CH_4 * \rho_{CH4} \tag{12}$$

$$\dot{m}_{CO2} = (1-DR) * Q_{AIR} * \sqrt{\frac{G_{AIR}}{G_{CH4}}} * \frac{\left(1-\frac{1}{3*F_k}\right)}{\left(1-\frac{1}{3*F_{AIR}}\right)} * \%CH_4 * \rho_{CH4} * \frac{\%CO_2}{\%CH_4} * \frac{44}{16} \tag{13}$$

APPENDIX B - Quantification Procedures for Flexibility Mechanisms

B.1 Retroactive Credits

Existing projects may claim carbon offsets. This claim is based on the metered baseline with adjustments. Adjustments are based on instrument counts. Adjustments are subtracted from the baseline as follows:

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

where

BE' = adjusted baseline emissions from time project was implemented to time when project was metered;
t = time of project implementation;
BE = metered emissions from project;
BR_i = bleed rate of instrument i using manufacture's technical specifications;
DR = leak discount rate; and
t_i = time from installation of instrument to time when project was metered.

As an example, a project was implemented 4 years ago but was not metered. If the baseline emissions were calculated at BE after the first month of metering, and 1 instrument (Type A with 54 scfh emission rate) was placed 3 years ago, the BE' would be

$$BE_{AIR}' = BE_{AIR} * (4 * 12) - \sum_{i=1}^{1} 54_1 * (1 + 6\%_1) * (3 * 8{,}760)_1$$

B.2 Fraction of Vented and Combusted Emissions

Vent and bleed natural gas may be collected and sent to a flare or other combustion sources for various reasons. Therefore this protocol allows the project developer to claim credits from combusted and vented gas. The vent or bleed gas fraction X is estimated as follows based on vendor's technical specifications:

$$X = \frac{\sum_{i=1}^{n} BR_i * n_i}{\sum_{i=1}^{n} BR_i * n_i + \sum_{j=1}^{m} BR_j * m_j}$$

where

BR_i= bleed rate for device i from manufacturer's technical specifications that bleed gas to the atmosphere;
n_i = number of type i devices;
BR_j = bleed rate for device j from manufacturer's technical specifications that combust gas;
m_j = number of type j devices;

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

$$1 - X = 1 - \left(\frac{\sum_{i=1}^{n} BR_i * n_i}{\sum_{i=1}^{n} BR_i * n_i + \sum_{j=1}^{m} BR_j * m_j} \right)$$

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

<table>
<tr><th>1. Project / Baseline SS</th><th>2. Parameter/ variable</th><th>3. Unit</th><th>4. Measured/ estimated</th><th>5. Contingency Method</th><th>6. Frequency</th><th>7. Justify measurement or estimation and frequency</th></tr>
<tr><td colspan="7">Flexibility Mechanism</td></tr>
<tr><td>B 6
Vented
Fuel Gas</td><td colspan="6"><i>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 CH_4 and will always be used. Typically, the percentage of CH_4 in fuel gas is in excess of 85% and can be as much as 99%. Equation (2) is used to establish baseline emission for ventedCO_2. If the percentage of CO_2 is in excess of 10%, equation (2) is used to establish baseline CO_2 emissions from vented fuel. If the percentage of CO_2 emissions is inferior to 10%, it is advisable not to include CO_2 emissions as the volumes are insignificant. Equations (3) and (4) are used to establish CO_2e emissions from flared fuel gas</i>
(1) Emissions $_{\text{Vented Fuel Gas}}$ =
Σ Compressed Air $_{\text{Control Instruments i}} * X * (1 - DR) * \sqrt{\frac{G_{AIR}}{G_{CH4}}} * \frac{\left(1 - \frac{1}{3 * F_k}\right)}{\left(1 - \frac{1}{3 * F_{AIR}}\right)} * \%CH_4 * \rho_{CH4}$;
(2) Σ Compressed Air $_{\text{Control Instruments i}}$
$* X * (1 - DR) * \sqrt{\frac{G_{AIR}}{G_{CH4}}} * \frac{\left(1 - \frac{1}{3 * F_k}\right)}{\left(1 - \frac{1}{3 * F_{AIR}}\right)} * \%CH_4 * \rho_{CH4} * \frac{\%CO_2}{\%CH_4} * \frac{44}{16}$;
where
$F_k = \frac{k}{1.4}$
(3) Emissions $_{\text{Flared/Combusted Fuel Gas}}$ =
Σ Compressed Air $_{\text{Control Instruments i}} * (1 - X) * (1 - DR) * \sqrt{\frac{G_{AIR}}{G_{CH4}}} * \frac{\left(1 - \frac{1}{3 * F_k}\right)}{\left(1 - \frac{1}{3 * F_{AIR}}\right)} * \%w * \frac{44}{12}$;</td></tr>
</table>

	where w= average carbon content of fuel gas (kg C/m^3 fuel gas)[2]					
	Emissions $_{\text{Vented Fuel Gas}}$	kg of CH_4 ; CO_2	N/A	N/A	N/A	Quantity being calculated in aggregate form as fuel and electricity use on site is likely aggregate for each of these SS's.
	Emissions $_{\text{Flared/Combusted Fuel Gas}}$	kg of CH_4 ; CO_2	N/A	N/A	N/A	Quantity being calculated in aggregate form as fuel and electricity use on site is likely aggregate for each of these SS's.
	Compressed Air Used for Pneumatic Instruments $_i$/ Compressed Air $_{\text{Control Instruments i}}$	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 $X = \frac{\sum_{i=1}^{n} BR_i * n_i}{\sum_{i=1}^{n} BR_i * n_i + \sum_{j=1}^{m} BR_j * m_j}$	N/A	This represents the fraction of vented emissions from control devices
	Discount Rate due to Leaks / DR	%	Estimated	1. DR(%)= 2.5 %*year for 0< year < 10 2. DR(%)= 20% for year > 10	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 'year'.
	Specific Gravity of Air /G $_{\text{AIR}}$	m^3	Estimated	1.00	N/A	Accepted value.
	Specific Gravity of Methane / G $_{\text{CH4}}$	Kg / m^3	Estimated	0.5537	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.
	Specific Heat Ratio for CH_4 / k_{CH4}	-	Assumed	Constant value of 1.31 at NTP.	N/A	Accepted value

---

[2] The average carbon content of the fuel gas is used to calculate CO_2 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.

	Specific Heat Ratio for air /1.4	-	Assumed	Constant value of 1.40at NTP.	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
	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

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

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

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

where
CR_i= consumption rate for device i from manufacturer's technical specifications;
n_i = number of type i devices;

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

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

Instrument Characteristics[3]

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
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

---

[3] 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.

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

TABLE 2: Gas-Driven Pneumatic Device CH_4 Emission Factors by Segment[4]

Device Type	Emission Factor (Original Units)	Precision (±%)	CH4 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 m3 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			
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

* CH_4 emission factors converted from scf and m^3 are based on 60°F and 14.7 psia.

TABLE 3: Gas Consumption Rates (m^3/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

---

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

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

APPENDIX C - Emissions Factor for Selected Fuels[5]

---

[5] 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

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_2O)	0.000004	kg N_2O 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_2O)	0.000004	kg N_2O 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_2O)	0.000003	kg N_2O 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_2O)	0.000004	kg N_2O per Litre

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

Source	**Emissions Factor**		
	CO_2	**CH_4**	**N_2O**
	g/m^3	**g/m^3**	**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	**g/L**	**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

TABLE B.3: Emissions Factors for Refined Petroleum Products

Source	Emissions Factor (g/L)		
	CO_2	CH_4	N_2O
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		0.064
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