SNC·LAVALIN

UNDERSTANDING & IMPROVING MANAGEMENT OF VOCS FROM THE UPSTREAM OIL & GAS INDUSTRY

Petroleum Technology Alliance Canada

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This report presents an analysis of the Canadian Association of Petroleum Producers (CAPP) report entitled "*A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminants (CAC) and Hydrogen Sulphide Emissions by the Upstream Oil and Gas Industry*". SNC-Lavalin Inc., (SNC-Lavalin) was mandated to complete the following scope of work as per the Petroleum Technology Alliance Canada (PTAC) requirements:

- Review the 2004 CAPP inventory, current practices used in the upstream oil and gas industry, and regulatory changes that have occurred since 2000 to identify any VOC sources not considered in previous emission inventories. The Alberta Upstream Petroleum Research Fund (AUPRF) funding is focused on conventional oil and gas operations, hence sources specific to oil sands operations need not be considered. However, sources common to both conventional oil and gas and oil sands are to be included in the scope of this project.
- For any new sources of volatile organic carbon (VOC) emissions, provide an order of magnitude of the expected emissions so these sources may be ranked.
- For the most significant sources identified in **Table A: Summary of 2004 Inventory VOC Emissions** [1] and those new sources identified in bullet 2 above the following is required:
    - Review the methods and activity data currently used to estimate VOC emissions and suggest methods to improve estimation and lower uncertainty.
    - If new activity data, emission factors and speciation profiles are needed to improve the estimation methods, develop a testing plan to gather the required information.
    - Document the review and recommendations in a technical report and arrange for review and approval of the testing plan through the PTAC ARPC.

[1] Refer to section 4 Table A for details

This study focuses only on current and new VOC sources from the following activities:

- Casing vent gas;
- Gas migration;
- Surface casing vent flows;
- Venting – pneumatics;
  - Pneumatic instrumentation; and
  - Chemical injection pumps.
- Glycol dehydration;
- Land applications;
- Process sewers and drains;
- Site/well abandonments or orphaned sites;
- Combustion dual fuel and bi-fuel;
- Marine sources;
  - Marine tanker loading-unloading;
  - Marine facilities
- Rail transport.

SNC-Lavalin understands that VOCs sources from Storage Losses and Fugitive Equipment Leaks are being addressed by other projects.

The ranking of current and new VOC emissions are summarized below. Ranking was based on criteria such as magnitude, impact on industry and resource, public perception and health impacts to prioritize VOC sources and consequently identity those where efforts should be focused in order to close the knowledge gap. Some sources have equal ranking indicating a tie in points assigned.

Land applications	1
Marine tanker loading/unloading	2
Glycol dehydration	3
Pneumatic instrumentation	4
Marine facilities	5
Orphaned wells and sites	6
Rail transport	7
Process sewers and drains	8
Bi-fuel/dual fuel combustion	9
Venting casing gas	10
Chemical injection pumps	11
Surface casing vent flows	12
Gas migration	13

Uncertainty was associated with the following items:

- Lack of information or not enough details on activity levels;
- Use of average or generic emission factors versus site or activity specific; and
- Use of average or generic gas composition versus site or activity specific gas composition.

The report is organized into sections as follows:

Section 1- Introduction, introduces the project.

Section 2- Acknowledgments, acknowledges individuals and organizations that contributed time and information to develop this report.

Section 3- Definitions, defines common terms used in this report.

Section 4- Scope of Work, establishes the objectives of the project and current knowledge gaps.

Section 5- VOC Sources Excluded from This Study, provides a summary of VOC sources not covered in this report although covered in other PTAC studies.

Section 6- Review of Calculation Methods, provides a summary of documents and methodologies that were used to calculate VOC emissions for the CAPP 2004 VOC emissions inventory. The section also identifies new potential VOC sources not considered in the CAPP 2004 VOC emission inventory.

Section 7- Estimation of VOC Emission Sources, is dedicated to the estimation of current VOC emission sources based on up-to-date available data and information. The section also estimates a new potential VOC sources based on the best available data and information as well as assumptions. Some VOC sources were not estimated due to lack of accurate data/information or assumptions.

Section 8- Ranking of VOC Emissions, presents current and new VOC sources ranked according to selected criteria.

Section 9- Proposed Testing Plan, is the final chapter and proposes a testing plan for acquiring data/information that are missing or are necessary but could not be found and proxies were used to approximate values to estimate the magnitude of the VOC emission.

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1.0. INTRODUCTION

Petroleum Technology Alliance Canada (PTAC) mandated SNC-Lavalin Inc., (SNC-Lavalin) to respond to the project **"**Understanding and Improving Management of VOCs from the Upstream Oil and Gas Industry**"** under project Reference #09-9181-50.

This project has been formulated with input from the PTAC facilitated Air Research Planning Committee (ARPC) and is a priority for the Western Canadian upstream oil and gas industry. PTAC believes that a collaborative approach on this project will be of broad benefit to industry and governments.

PTAC is an association that facilitates innovation, collaborative research, and technology development, demonstration and deployment for a responsible Western Canadian upstream hydrocarbon energy industry. PTAC's objective is to improve the industry's financial, environmental, and safety performance through the application of new technology and research.

2.0. ACKNOWLEDGMENTS

SNC-Lavalin would like to acknowledge the following people for their time in collaborating and providing information for this study:

- Denis Paradine - Climate Change Secretariat, British Columbia Ministry of Environment
- Gerald Palanca – Energy Resources Conservation Board (ERCB)[2]
- Catherine Thistlethwaite - ERCB
- Brian Ross - Nexen Inc.
- Carolyn Ussher - Nexen Inc.
- Ray McDonald - Orphan Well Association
- Mike D'Antoni - Pacific Carbon Trust
- Wendy Petruk - Port MetroVancouver
- Lorie Frei - PTAC
- Tanis Such - PTAC
- Stewart Deyell - Statistics Canada

[2] As of July 2013, the ERCB has changed its name to Alberta Energy Regulator (AER). For consistency with source documents and because the report was elaborated prior to the name change, ERCB is used throughout this report to refer to the AER.

3.0. DEFINITIONS

The terms defined in this section are used throughout this study and are consistent with uses in CAPP and PTAC documents. The definitions of the terms in this section have been sourced from documents consulted to complete this study.

Terms	Definitions
BTEX	Any gas combination that includes a mixture of aromatic compounds such as benzene, toluene, ethylbenzene, and xylenes.
Casing gas	These are volumes of gas that vent through the well casing. The annulus or space between the casing and the tubing of a well may build up gas. This gas accumulates in the annulus and is either vented or recovered.
Fugitive equipment leaks	These are hydrocarbon gas and liquids losses to the atmosphere past mechanical connections, seals and valve seats due to normal wear and inefficiencies in these mechanisms.
Pneumatic	Any system that uses gas pressure to power a control instrument.
THC	Total hydrocarbons or the total amount of gases containing carbon and hydrogen including methane, ethane and excluding carbon dioxide.
Source	An activity where VOCs are expected to be emitted to atmosphere
Storage losses	These losses come from normal evaporation losses due to breathing and working effects, as well as flashing losses where the received liquids have an initial vapour pressure similar or greater than local atmosphere pressure.
VOC	A volatile organic compound or VOC is any substance containing carbon, excluding carbon monoxide and carbon dioxide. VOCs will react with nitrogen oxides in the presence of solar radiation to produce photochemical oxidants such as ozone. The VOC category excludes methane and ethane (Clearstone Engineering Ltd., 2004a).
Venting	The action of emitting vapors directly to atmosphere via ducts or apertures designed to release vapors to the atmosphere.

4.0. SCOPE OF WORK

Knowledge Gap

Based on available inventory data, the upstream oil and gas industry is a significant contributor to VOC emissions inventory in Canada. However, for some sources, the uncertainties associated with the emission estimates may be significant. The most recent detailed inventory of VOC emissions for the industry was published in 2004 based on 2000 activity data. As part of that inventory, an assessment of the uncertainty in the emission estimates was also conducted. **Table A: Summary of 2004 Inventory VOC Emissions** provides a ranking of the most significant VOC emission sources, their percentage contribution to the overall uncertainty in the total VOC emission estimate, and the sources that are currently being addressed by other work. The remaining 2.3% represents other VOC sources.

TABLE A: Summary of 2004 Inventory VOC Emissions

Source	% of Total VOC Emissions	% of Total Uncertainty	Comments
Storage Losses	31.5	21.4	Being addressed by other projects
Fugitive Equipment Leaks	24.1	4.8	Being addressed by other projects
Venting – Casing Gas	16.2	2.9	
Surface Casing Vent Flows	11.4	64.8	
Venting – Pneumatics	3.8	0.02	
Tanker Loading	3.0	0.3	
Pipeline Ruptures	2.9	5.7	
Glycol Dehydration	2.9	0.003	
Spills	2.0	0.000	
Total	97.7	100.0	

4.2. Objectives

Given the knowledge gap and uncertainty related to upstream oil and gas VOC emissions, the following scope of work has been determined as per PTAC's requests:

- Review the 2004 CAPP inventory, current practices used in the upstream oil and gas industry, and regulatory changes that have occurred since 2000 to identify any VOC sources not considered in previous emission inventories. AUPRF is focused on conventional oil and gas operations, so sources specific to oil sands operations need not be considered. However, sources common to both conventional oil and gas and oil sands are to be included in the scope of this project.
- For any new sources of VOC emissions, provide an order of magnitude of the expected emissions so these sources may be ranked.
- For the most significant sources identified in **Table A: Summary of 2004 Inventory VOC Emissions**[3] and those new sources identified in the previous bullet, the following is required:
  - Review the methods and activity data currently used to estimate VOC emissions and suggest methods to improve estimation and lower uncertainty.
  - If new activity data, emission factors and speciation profiles are needed to improve the estimation methods, develop a testing plan to gather the required information.
  - Document the review and recommendations in a technical report and arrange for review and approval of the testing plan through the PTAC ARPC.

[3] Refer to section 4 Table A for details

This study will focus only on new VOC sources, or on VOC sources from the following activities:

- Casing vent gas;
- Gas migration;
- Surface casing vent flows;
- Venting – pneumatics;
    - Pneumatic instrumentation; and
    - Chemical injection pumps.
- Glycol dehydration;
- Land applications;
- Process sewers and drains;
- Site/well abandonments or orphaned sites;
- Combustion dual fuel and bi-fuel;
- Marine sources;
    - Marine tanker loading-unloading;
    - Marine facilities;
- Rail transport.

SNC-Lavalin understands that VOC sources from Storage Losses, Fugitive Equipment Leaks and VOC emissions from Hydraulic Fracturing are being addressed by other projects.

A partial fist of documents reviewed is summarized below.

Storage Losses

1. Alberta – ERCB – issued updated Directive 060 in 2006, revised economic criteria for solution gas conservation, and improved venting reporting.
2. B.C. – OGC adopted ERCB Directive 060 equivalent standards, in their Flaring and Venting Reduction Guideline.
3. Saskatchewan – Ministry of Environment and Resources (MER) adopted ERCB Directive 060 equivalent standards in 2011.

Fugitive Equipment Leaks

1. CAPP Best Management Practice (BMP) Management of Fugitive Emissions at Upstream Oil and Gas Facilities issued January 2007.
2. CAPP Best Management Practice (BMP) referenced in ERCB Directive 060 (2006), requirement to meet or exceed LDAR programs for implementation.
3. CAPP Best Management Practice (BMP) referenced in BC OGC Flaring and Venting Reduction Guideline, requirement to meet or exceed LDAR programs for implementation.
4. Environmental Protection and Enhancement Act (EPEA) Approvals for some facilities (eg, SAGD, larger sour gas plants) specified in Canadian Council of Ministers of the Environment (CCME) Guidelines.

Venting – Casing Gas

1. Alberta – ERCB – Interim Directive ID 2003-01 (and Bulletin 2011-35) including testing, reporting and repair.

Surface Casing Vent Flows

1. ERCB ID 2003-01 including testing, reporting and repair.

Venting – Pneumatics

1. ERCB Directive 060, GHG reduction protocols and energy efficiency initiatives have contributed (in part) to change industry practices to use fuel or vented gas more efficiently gas.

Glycol Dehydration

1. ERCB Directive 039 (2006, 2008) formally regulates these sources, sets limits for benzene emissions.
2. BC OGC IL #OGC 07-03- The purpose of this letter is to set out the rationale and requirements for controlling the emissions of benzene from glycol dehydrators.

3. Saskatchewan – Ministry of Environment and Resources (MER) Directive S-18 (2010)[4] -This guideline sets out the requirements for the reduction of benzene emissions from glycol dehydrators.

Benzene data are collected annually as part of these regulations, but emission data for other VOC's emitted from these sources are not.

Additional documents included

- ERCB Directive 050 for drilling waste management;
- US Federal Register; and
- Australian National Pollutant Inventory (2002 and 2012).

[4] Saskatchewan Upstream Petroleum Industry Guideline to Reduce Benzene Emissions from Glycol Dehydrators S-18

5.0. VOC SOURCES EXCLUDED FROM THIS STUDY

5.1. Documents Review

SNC-Lavalin reviewed the list of documents present in **Section 4.2**. This chapter details sources that were excluded while the following chapter describes current and new VOC emission sources and knowledge to date.

The introduction of new regulations and directives post 2000 will understandably have an impact on the VOC inventory developed in 2004 by CAPP. For example, the Greenhouse Gas (GHG) reduction program under Alberta's Specified Gas Emitters Regulation (SGER) came into force in 2007; numerous new Directives under ERCB have come into force post-2000; and carbon offsets reduction opportunities for vent gas reduction and energy efficiency.

5.2. Overview of VOC Emission Sources Excluded in this Study

5.2.1. Storage Losses

The following storage losses are difficult to account for due to a lack of appropriate emission factors (Clearstone Engineering Ltd., 2004a):

- Gas carry-through to storage tanks due to leakage past drain valves into inlet heaters;
- Inefficient gas-liquid separation in upstream vessels;
- Malfunctioning level controllers or leakage past the seat of level control valves; and
- Unintentional storage of high vapor pressure liquids in atmospheric tanks.

The above emission sources require testing to develop appropriate emission factors and consequent VOC emission profiles. SNC-Lavalin understands that these emission sources are being addressed by another study.

5.2.2. Fugitive Equipment Leaks

VOC emissions from fugitive equipment leaks stem from equipment wear and tear over time. CAPP advocates a periodic maintenance schedule in their Best Management Practice to reduce these emissions and meet ERCB Directive 060 requirements under section 8.6 and to cost effectively manage the most likely significant sources (CAPP, 2007). These emissions represent 24.1 % of the total 2004 inventory and have likely changed due to new industry practices. SNC-Lavalin understands these emissions are being addressed by another study.

5.2.3. Hydraulic Fracturing

Hydraulic fracturing is a drilling technique in which the rock formation is fractured using high pressure water, a proppant (typically sand), and other chemicals injected into the borehole to enhance oil or gas production. Typical composition of hydraulic fracturing fluid includes water and sand (99.51%) and chemical additives (0.49%) (CSUR, 2012). The borehole and surrounding rock is made more porous by newly formed fractures and the proppant is used to keep the fractures in place and prevent them from collapsing. Produced water from drilling and production processes can either be disposed of down the well or stored in open ponds for reuse in further drilling and development of adjacent areas.

The 2004 inventory of VOC emission does not include VOC emissions from hydraulic fracturing per se. Specifically, VOC emissions potentially stem from the following activities:

- Transportation of produced water;
- Evaporation from flow back water in storage ponds;
- Wastewater treatment for recycling and reusing fracking water; and
- Trucks associated with water hauling.

The above are considered to be new VOC emission sources. Also, trucking activities related to hauling water for fracturing is a potential source of VOCs from fossil fuel combustion in internal combustion engines. Water hauling is required when water is not readily accessible near the drill site and must be trucked in from a water body a considerable distance from the site.

Air emissions from hydraulic fracturing are being addressed by another PTAC project[5]. However, testing for VOC emissions in a field setting could elucidate values and uncertainties related to hydraulic fracture emission factors and merits further research.

5.2.4. Spills

Spills have been excluded in this report. Spills represent the lowest percentage of total VOC emissions, have the lowest percentage of uncertainty and were covered sufficiently in depth (Clearstone Engineering Ltd., 2004a).

[5] http://www.ptac.org/projects/127

6.0. REVIEW OF CALCULATION METHODS

6.1. Document Review

SNC-Lavalin reviewed the methods and assumptions used in the 2004 inventory to estimate VOC emissions and have made suggestions to update and improve the accuracy of emission estimates. These suggestions are based on current industry concerns and best available technologies to test VOC emissions.

6.2. Current VOC Sources & Potential Improvements

6.2.1. Casing Vent Gas

Alberta and Saskatchewan produce heavy crude oil. Cold production heavy crude oil wells are:

- Relatively shallow (typically 300 to 900 m deep) and,
- Have low reservoir pressures (typically 4000 kPa or less).

To achieve reasonable flow potential it is indispensable to relieve formation gas pressure from the well bore (down-hole pressure of about 250 kPa is maintained). Appropriately, the wells usually are not equipped with a production packer (a device that isolates the annulus from the formation). This allows the well pressure to be controlled using the casing vent (Clearstone Engineering Ltd., 2004b).

For the 2004 inventory, the total amount of casing gas produced was estimated based on a moisture-free basis by applying typical gas-to-oil ratios (GORs) to the total amount of crude oil production. A number of sources of GOR data were used such as data reported the EUB (now AER), and company supplied data for GOR from Saskatchewan oil production as well as default GOR values in Saskatchewan where no data were available. Average casing vent gas emissions were assumed to be 55.7 m^3/m^3 of produced oil in Saskatchewan per capable well (Clearstone Engineering Ltd., 2004a).

There has been a slight revival in conventional oil production for the first time in many years and this growth expected to continue until at least 2017 as illustrated in **Figure 1: Conventional and Nonconventional Canadian Oil Production (2012 – 2030)** (CAPP, 2012). Conventional oil production is projected to grow from 1.1 million barrels per day in 2011 and peak at about 1.3 million barrels a day by 2020. Although not as significant in growth as other areas, new wells continue to be drilled to extract this conventional oil and casing vent gas VOC emissions can be expected to increase.

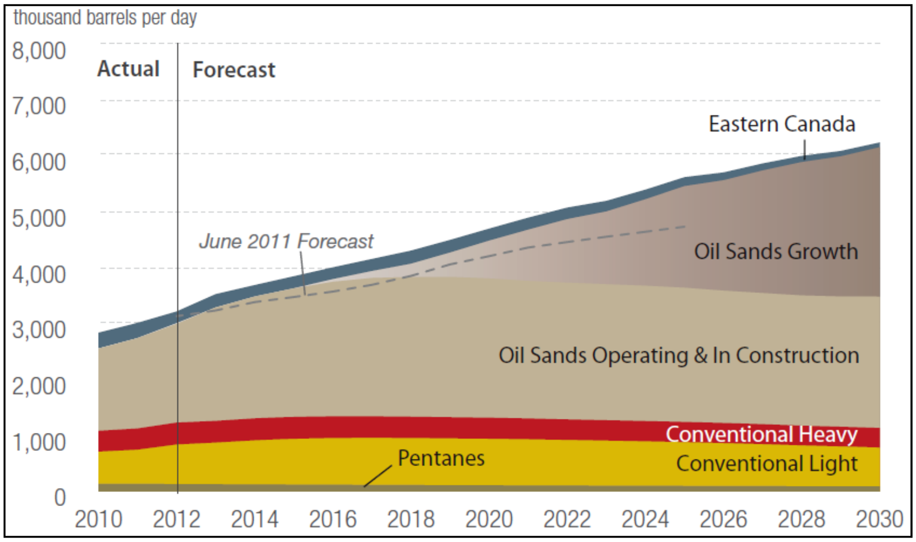

Figure 1:
Conventional and Nonconventional Canadian Oil Production (2012 – 2030)

The ERCB Bulletin 2011-35 regarding Interim Directive ID 2003-01 requires wells without vent assemblies to test for surface casing annular flow (ERCB, 2011). Several gas identification techniques are permitted and include:

- Soap test
- Portable gas analyzer test
- Photoionization detection instrument (PID)
- Toxic vapor analyzer (TVA)
- Portable laser methane detector
- Infrared camera method

This requirement allows valuable data acquired by operators to compliment the 2004 inventory. The Directive outlines methods and requires data to be submitted through the ERCB's Digital Data Submission (DDS) system. The digital data from 2003 to 2012 could be used to refine the 2004 emission factors used in the inventory. Furthermore, site-specific emission factors can be developed based on well location.

6.2.2. Gas Migration

When a natural gas or oil well is drilled, a steel casing is placed around the borehole to protect the borehole and prevent contamination of groundwater. The borehole is cemented once it has reached a designated depth. Over time the cement casing may develop cracks and gas will begin to migrate to the surface. Gas migration for the 2004 inventory were estimated by applying an emission factor of 3.85 m^3/d to the total number of wells with identified gas migration problems or about 7.8 % of heavy oil wells (Clearstone Engineering Ltd., 2004a). The emission factor was derived from a study performed in the Lloydminster area by Husky Oil Operations using the flux chamber technique with an associated error of 5% or less based on laboratory experiments (Erno & Schmitz, 1996). Field measurements were taken by placing a flux chamber at various locations around the well and recording the position and distance relative to the well. A grid or structured approach was not used when collecting field measurements. Rather, measurements were taken selectively within a three meter radius of the well, avoiding patches of contaminated soils or surface equipment. This method would not record fluxes between flux chamber positions. Also, Alberta and Saskatchewan wells were assumed to be leaking at the same rate however this may not the case.

Flux chambers are the preferred method to measure surface emissions because of their simplicity and low costs but can have errors which are largely dependent on chamber dimensions, including chamber height, surface gas flux rate, and time interval over which the data are collected (Senevirathna, Achari, & Hettiaracthi, 2006). The flux chamber used in the Erno and Schmitz (1996) study was 61 cm in diameter.

There is merit in assessing gas migration emissions using a flux chamber however better technologies are now available to enhance quantification of surface emissions. These include laser surface scanning or imaging using diodes which have now seen commercial application worldwide. The following technologies or techniques could be used to improve accuracy in gas migration:

- Laser scanning to accurately measure the surface flux. Several technologies have been developed and include Open Path - Fourier Transformation Infrared (OP-FTIR), Infrared Differential Absorption Light detection and ranging (DIAL) and tunable diode lasers. Although the DIAL technology focuses on large areas, modifying the application for small areas may help establish a better emission factor. Tunable laser are also used in large areas but portable units are available commercially and are more suited for this application.

The range of flux emissions may vary and accuracy may be an issue. In other words, each well will have a unique or characteristic emission and if extremely low may not be detected by any proposed technique or technology.

6.2.3. Surface Casing Vent Flows

Alberta and BC were the only provinces with readily accessible data and emission factors for the 2004 VOC emission inventory; average surface casing vent gas emissions were assumed to be 3.42 kg/d of vented gas per capable well based on data from these provinces (Clearstone Engineering Ltd., 2004a). Saskatchewan data[6] could be used to improve the average, but data quality has not yet been assessed. The 2004 inventory used this emission factor applied to assumed activity levels including:

- The emission factor is constant throughout Canada although Alberta and BC were the only provinces with readily accessible data
- Release of only gas
- Vented gas is not flared
- Capable wells

6.2.4. Venting Pneumatics

The need to reduce GHG emissions has become a priority in Canada. The reduction of vented gas from natural gas operations will equate to a reduction in VOC emissions because vented gas contains small amounts of VOCs.

Pneumatic instrumentation gas venting activity levels have likely decreased due to new regulations (eg, Alberta SGER) and current industry best practices (eg, oil and gas companies' voluntary internal energy efficiency programs) to reduce GHG emissions and efficient use of fuel gas in recent years. Logically, a reduction effort in GHG emissions will also impact VOC emissions as these are intimately linked.

[6] Available at http://www.economy.gov.sk.ca/Default.aspx?DN=0d34292d-843d-4666-81d0-6ea37157558e

In Alberta, the Specified Gas Emitter Regulation (SGER), enacted in 2007, sets a 12% GHG reduction intensity for facilities emitting over 100,000 tCO_2e per annum (Alberta Government, 2007a). The SGER allows three options (Alberta Government, 2007b) for regulated facility owners and operators to reduce GHG emissions including:

- Emission performance credits - GHG credits by achieving reductions below those required.
- Emission offsets - GHG reductions from unregulated facilities (eg, below the 100,000 tCO_2e) that generate credits that can be sold for compliance purposes to an end user.
- Fund credits - invest $15/tonne into the Climate Change and Emission Management Fund to develop or invest in technologies, programs and other priority areas.

Parallel to this regulation, several oil and gas companies have developed voluntary internal energy efficiency programs to reduce GHG emissions from operations beyond business as usual to generate emission offsets.

It is understood that any efforts to reduced vented natural gas would also reduce VOC emissions.

6.2.4.1. Pneumatic Instrumentation

In 2008, EnCana spearheaded the development of GHG reduction quantification protocols for the following project types to reduce pneumatic instrumentation gas venting for the following project types:

- Engine efficiency and vent gas capture with the participation of Spartan Controls[7]. Version 1 of this protocol was officially approved in October 2009. The technology driver for this protocol was the installation of Air Fuel Ratio Controllers (AFRC) to control fuel gas for compressor engines. Controlling fuel gas based on brake horse power and load allows for efficient use of natural gas in the engine. Additionally, the protocol quantifies vented gas either from pneumatic instrumentation or other venting sources that may be captured and directed towards a compressor engine to reduce main fuel gas usage.
- Instrument gas to instrument air conversion in process control systems[8]. This protocol was officially approved in October 2009 under version 1. The protocol's purpose is to quantify emission reductions stemming from the use of compressed air to power the pneumatic instrumentation in lieu of compressed fuel gas.

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[7] GHG quantification protocol available at http://environment.gov.ab.ca/info/library/8202.pdf

[8] GHG quantification protocol available at http://environment.gov.ab.ca/info/library/8201.pdf

CAPP's Fuel Gas Best Management Practices on Efficient Use of Fuel Gas in Pneumatic Instruments (Module 3 of 17) aim is to provide practical guidance to operators for achieving fuel gas efficient operations while recognizing the specific requirements of individual pneumatic instruments' and their service requirements (CAPP, 2008a). Several oil and gas companies contracted BlueSource Canada to adapt these two Alberta protocols and others into the Pacific Carbon Trust under a Meta Protocol for Oil & Gas Emission Reduction Projects (BlueSource Canada, 2011). Additional protocols related to pneumatic instrumentation gas venting reduction under this Meta Protocol include:

- High-bleed to low-bleed conversion of pneumatic controllers[9]. This protocol was adapted from the American Carbon Registry's Conversion of High-Bleed Pneumatic Controllers in Oil & Natural Gas Systems[10]. Basically, a low bleed valve, commonly referred to as a Mizer valve, is installed on a high-bleed pneumatic device to reduce vented fuel gas. Alternatively, the high bleed device is replaced by a newer generation low/no-bleed device.
- Pump system conversion[11]. This protocol is based on a draft protocol that was developed for the Alberta Offset System but not finalized in that GHG program. The protocol's purpose is to quantify GHG emission reductions from converting pneumatic gas-powered chemical injection pumps into pumps using solar power. Also, the protocol is applicable to vent gas recapture systems.

A summary of the GHG reduction protocols is provided in the **Table B: Summary of GHG Reduction Protocols Related to Pneumatic Instrumentation Vent Gas** below.

TABLE B: Summary of GHG Reduction Protocols Related to Pneumatic Instrumentation Vent Gas

Province	GHG reduction project type
Alberta	• Engine efficiency and vent gas capture • Instrument gas to instrument air conversion
British Columbia	• Engine efficiency and vent gas capture • High-bleed to low-bleed conversion of pneumatic controllers • Instrument gas to instrument air conversion • Pump system conversion

[9] GHG quantification protocol available at http://pacificcarbontrust.com/assets/Uploads/Protocols/High-Bleed-Low-Bleed-ModuleMay-24-2011.pdf

[10] GHG quantification protocol available at http://americancarbonregistry.org/carbon-accounting/methodology-for-conversion-of-high-bleed-pneumatic-controllers-in-oil-natural-gas-systems/documents/ACR%20Pneumatic%20Controllers%20Conversion%20Methodology%20March%202010.pdf

[11] GHG quantification protocol available at http://pacificcarbontrust.com/assets/Uploads/Protocols/Pump-Conversion-ModuleMarch-1-2011.pdf

Currently, there are a number of projects being developed and registered in the Alberta Offset System. As well, engine efficiency and vent gas capture projects have received funding from the Climate Change and Emission Management Corporation (CCEMC). Funded companies and project names include:

- EnCana Corp-. – Vent gas capture for engine fuel use
- Cenovus Energy Inc.- REMVue/Slipstream Air/Fuel Ratio Control and Vent Capture Project
- ConocoPhillips- Company-Wide Rollout of a Systematic Energy Efficiency Program Leading to Significant GHG Reductions in Alberta's Oil and Gas Industry

Several oil and gas companies are cooperating together to aggregate GHG reductions from vent gas capture projects and other project types. An energy efficiency platform to automate and standardize the reporting is being developed.

Fuel gas used for pneumatic instrumentation and pumps is typically not metered. In order to generate carbon offsets from GHG reduction projects related to vented fuel gas, it is necessary to meter air flow rates to estimate how much fuel gas would have been vented using a gas equivalency formula as well as track gas composition data to fulfill verification criteria established in the quantification protocols. Thus, these projects offer an excellent source of credible fuel gas consumption that may be used to update the VOC inventory.

The ERCB published a study analyzing fuel gas usage in the upstream oil and conventional oil industry (ERCB, 2012). The study identified a general trend of declining fuel gas usage after 2006 as illustrated in **Figure 2: Fuel Gas Use & Raw Gas Production Trends (2003 – 2010)**. Data are deemed credible as ERCB Directive 007 requires monthly reporting of fuel gas usage although not itemized as to the origin whether for engines fuel gas or pneumatic instrumentation.

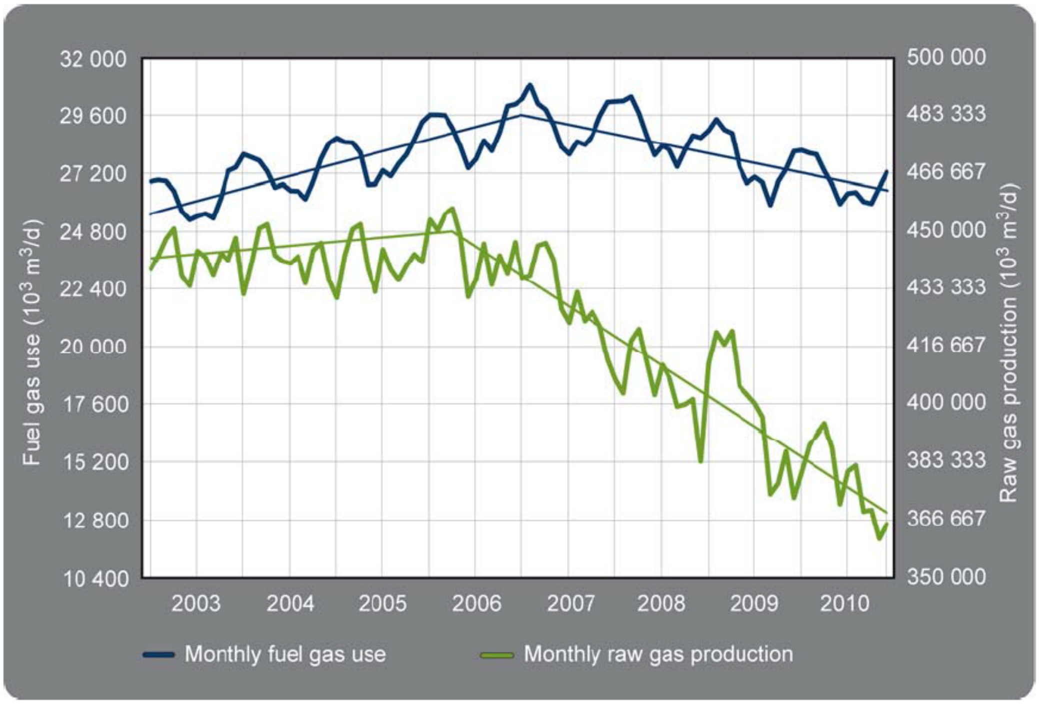

Figure 2:
Fuel Gas Use & Raw Gas Production Trends (2003 – 2010)

Fuel gas usage reduction as a function of motivator is illustrated in **Figure 3: Fuel Gas Usage Reduction as a Function of Motivator**. The pie chart includes motivators related to vented fuel gas sources and it is clear the CO2 regulations and lowering operational costs are the main drivers.

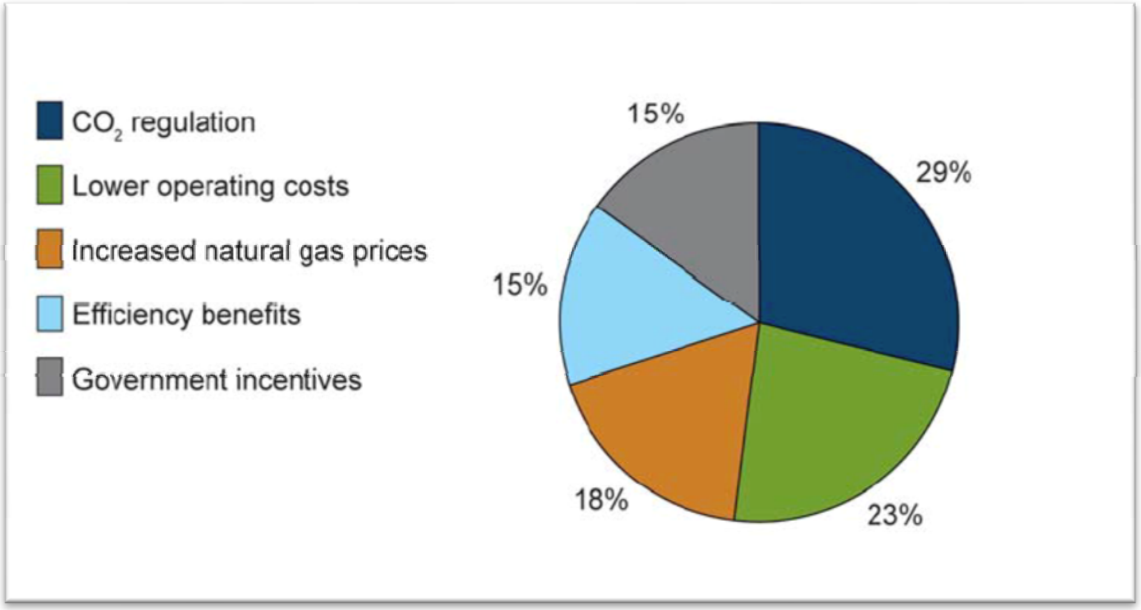

Figure 3:
Fuel Gas Usage Reduction as a Function of Motivator

The CAPP 2004 inventory considered pneumatic instrumentation venting as unreported venting source; this is still the case with the exception of BC. The BC government now requires companies to report GHG emissions using an accepted methodology as part of commitments acquired consequent to signing the Western Climate Initiative (WCI) (British Columbia Ministry of Environment, 2009) based on final essential requirements of mandatory reporting under the WCI (Western Climate Initiative (WCI), 2011). The following **Table C: GHG Emissions in BC from Pneumatic Instrumentation Venting** provides a summary of GHG emissions from instrument venting in BC. Unfortunately, it does not distinguish between natural gas, primarily methane a potent GHG, and propane. Propane is used at sites where sour gas is produced. Industry best estimates recognize that about 30% of pneumatic instrumentation venting comes from bottled propane (CAPP, 2008a) and is a potential source of VOC emission since bottled propane is 99%+ pure. **Table C: GHG Emissions in BC from Pneumatic Instrumentation Venting** summarizes GHG emissions from venting in BC and data are used in section 7 to estimate VOC emissions.

TABLE C: GHG Emissions in BC from Pneumatic Instrumentation Venting

Emissions source	Total (tCO_2e)	Total (%)
Continuous High Bleed Device Vents	311,100	3.0
Continuous Low Bleed and Intermittent Device Vents	68,900	0.7

Understandably, a reduction in GHGs from pneumatic instrumentation venting attributed to energy efficiency initiatives would affect current venting levels. Vented pneumatic instrumentation gas is rich in methane and contains VOCs. Therefore, a reduction in GHG will directly correlate with a reduction in VOCs.

6.2.4.2. Chemical Injection Pumps

Other pneumatic devices that vent gas include chemical injection pumps. Advances in solar chemical injection pumps have allowed costs to decline and many solar chemical injection pumps have been installed throughout oil and natural gas operating facilities. Moreover, CAPP's Fuel Gas Best Management Practices on Efficient Use of Fuel Gas in Chemical Injection Pumps (Module 5 of 17) aim is to provide practical guidance to operators to achieve fuel gas efficient operations while recognizing the specific requirements of individual chemical injection pumps and their service requirements (CAPP, 2008b). Some examples of solar pump applications made in the recent years include the following (Encana, 2009):

- Petro-Canada - In 2006, 75 chemical injection pumps in northeastern BC were replaced with solar powered pumps as part of the Solar Powered Chemical Pump Retrofit Program. Petro-Canada was nominated for the 2007 Steward of Excellence from CAPP. The lesson learned was that replacing pumps was possible only if projects are implemented at a large scale.
- EnCana Corporation has replaced about 300 chemical injection pumps with solar powered chemical injection pumps in northern BC.
- In BC, there are an estimated 15,800 chemical injection pumps in operation; various suppliers have indicated that 1,873 solar chemical injection pumps have been sold in BC between 2005 and 2007 (D'Antoni, 2012). Assuming that these numbers are accurate, market penetration is 11.8%, but could be higher if solar pump sales from 2007 onwards are taken into account. The main driver for solar chemical pump installs seems to be the fact that acid gas (H_2S in particular) is more prevalent in BC than Alberta; market penetration rates could be lower in Alberta (D'Antoni, 2012).

Technologies also exist to reduce vented fuel gas or recapture the fuel gas and reintroduce it into the sales pipeline.

Understandably, a reduction in GHGs from chemical injection pumps venting fuel gas is affecting current venting levels. Vented pneumatic instrumentation gas is rich in methane and contains VOCs. Therefore, a reduction in GHG will directly correlate with a reduction in VOCs. Activity levels from the CAPP 2004 report should be revisited and based on more recent data.

6.2.5. Pipeline Ruptures

Pipeline ruptures are created when unexpected mechanical failures or events occur and hydrocarbons or gas are spilled along the pipeline's adjacent area or vented to atmosphere, respectively. Pipeline rupture spills are intermittent and complicated to quantify since they are accidental and can occur at any given time. The National Energy Board (NEB) regulates spills and ensures they are reported. Pipeline ruptures are complicated to estimate due to their characteristics. Emission from pipeline ruptures have not been included in this report

6.2.6. Glycol Dehydration

Glycol dehydration emissions for the CAPP 2004 inventory were estimated using GRI GLY-Calc (Clearstone Engineering Ltd., 2004a). Emission factors were developed for glycol dehydrators in different segments of the upstream oil and gas industry. This software is endorsed by the EPA to calculate glycol flow rates and benzene emissions (US Government Printing Office, 2012).

ERCB Directive 039 originally issued in July 2008, with the latest version issued in January 22, 2013, sets out new benzene emission limits. Two tables in Directive 039 (Tables 1 and 2) are applicable for grandfathered dehydrators based on applicable calendar year. Starting 2018, all glycol dehydrators must comply with emission limits based on distance to a permanent residence or public facility. Emission limits are provided in Table 3 of Directive 039 and reproduced in **Table D: Summary of Benzene Emission Limits under ERCB Directive 039**, below; (ERCB, 2013).

TABLE D: Summary of Benzene Emission Limits under ERCB Directive 039

Reduced Benzene Emission Requirements		
	Distance in metres (m)	Emission limit in tonne (t) in each calendar year
No control or a control other than an appropriately designed flare or incinerator	≤100	0.0
	101-250	0.1
	251-750	0.5
	>750	1.0
After control emission limit for appropriately designed flare or incinerator source	≤750	1.0
	>750	3.0

VOC emissions from glycol dehydrators have changed for various reasons including:

- New requirements and benzene emission limits as detailed in the **Table D: Summary of Benzene Emission Limits under ERCB Directive 039** above.
- As of 2004, there were about 3,863 glycol dehydrators in Canada (CAPP, 2006). The inventory of Canadian dehydrators has likely changed due to increase in natural gas production in recent years.
- The availability of alternative technology to dehydrate natural gas beyond the traditional glycol dehydration (CAPP, 2006) including:
  - Methanol or glycol injection
  - Separator packages
  - Line heaters
  - Solid desiccant/molecular sieve plants
  - Membrane technology
  - And other processes commercially available

The USEPA now requires that small glycol dehydrators also limit benzene emission to below 1 tonne/year (USEPA, 2012). This also applies to large glycol dehydrators.

Understandably, more mature technology and cost-effectiveness combined with lower emission requirements may have stimulated companies to try some of the aforementioned technologies. In order to develop a more accurate VOC emissions inventory, the following improvements are suggested:

- Obtain data from the annual inventory of glycol dehydrators to assess the number of dehydrators operating as of 2011-12.
- Obtain emission factors from the inventory as calculated by the licensees. These emission factors will provide a more accurate value on a dehydrator-by-dehydrator basis rather than a general emission factor developed for glycol dehydrators for different segments of the upstream oil and gas industry. The CAPP 2004 inventory (page 41) does admit that site-by-site information is generally not available however information will be more readily available under the new requirements from ERCB Directive 039.
- Calculate the emission factors and emissions from associated VOCs (benzene plus non-benzene) from glycol dehydration.

This emission source only includes benzene. Other hydrocarbons, including ethylbenzene, toluene, xylene, and semi volatile organic compounds (SVOC) can dissolve in water and be released in the dehydration process.

6.2.7. Land Applications

Land applications for drilling waste for land-farming and landspraying (excluding landfilling) are regulated under ERCB Directive 050. Landfilling applications are regulated under ERCB Directive 058. Activities are summarized in the **Table E: Land Application Activities in the Upstream Oil & Gas Industry** below.

TABLE E: Land Application Activities in the Upstream Oil & Gas Industry

Type	Description
Land-farming	Refers to remediation of contaminated soils. Typcially, the soil is excavated and exposed to atmospheric conditons whereby VOCs volatilized and heavier compounds are biodegraded by bacteria.
Landspraying	Related to drilling muds. VOC may volatilize and some indirect reference is made to this as drilling muds/fluids (invert fluids) in the CAPP 2004 inventory. During drilling, drilling muds may be spread across a designated area.
Landfilling	Landfilling waste is done for conventional oil and gas operations as well as oil sands development. Landfilling may generate landfill gas (LFG) which contains VOCs.

Land treatment facilities dispose of oily wastes by biodegradation (Clearstone Engineering Ltd., 2004a). Oily wastes are also partially remediated by volatilization of the VOC portion; other treatment mechanisms include adsorption into the soil matrix (Maila & Cloete, 2004). The 2004 VOC inventory does not include VOC emissions from land treatment because the information was not in an “easy-to-use format” (Clearstone Engineering Ltd., 2004a) and no justification is given. Consequently, any information on VOC emissions from land treatment is unavailable and not included in the total upstream oil and gas emissions inventory. This source mentioned brielfy in the 2004 inventory but not addressed in depth, merits further research.

The various methods for applying waste to land set out in the 1996 edition of Directive 050 have been retained, but the requirements for each method are now based on preventing the buildup of hydrocarbon and metal concentrations in the receiving soil to concentrations that exceed Alberta soil remediation guidelines.

6.3. *Potential New VOC Sources*

6.3.1. Process Sewers & Drains

There is a general consensus that sewers and drains where organic liquids are collected and disposed of are a potential source of VOC emissions (CAPP, 2007) & (USEPA, 2006). The 2004 VOC inventory does not include VOC emissions from sewers or drains however they could be a significant source of VOC emissions from upstream oil and gas facilities.

Process sewers and drains are found throughout oil and gas operations from oil batteries and compressor stations to centralized facilities. This source of VOC emissions has not been estimated in this report due to limited information and wide-ranging assumptions but is recommended to be investigated in the proposed testing plan.

6.3.2. Open-Ended Valves & Lines

Many processes involve piping and open-ended valves and lines which may vent gas if not properly managed. This would also include pressure relief systems. Also, leaking liquid hydrocarbons may contain VOCs and volatilize when exposed to atmospheric conditions. This could potentially be a large source of VOC emissions. CAPP recommends that all open-ended valves and lines be capped (CAPP, 2007). This source of VOC emissions is understood to be addressed under a fugitive emissions project and has been excluded in this report.

6.3.3. Site & Well Abandonments/Orphaned Sites

When a well is finished producing, it is plugged and abandoned in several ways. In the United States, each state has specific requirements for well abandonments. In California, regulations require that heavy drilling mud and several cement plugs be placed at specific intervals. These plugs are strategically placed to prevent migration of residual oil and gas to other zones, aquifers, or to the surface. Sometimes, when CO_2 has been used for enhanced secondary or tertiary recovery, part of the abandonment procedure involves blowing down the well to release any existing pressure. If this is done, large amounts of CO_2 could be released into the atmosphere. In Alberta, ERCB Directive 020 regulates well abandonments and also requires well plugging once a well has ceased to produce or is no longer in service. The Directive also distinguishes abandonment requirements for Non-Oil Sands and Oil Sands wells (ERCB, 2010).

Beginning in September 2012, the ERCB requires oil and gas companies to contact owners of properties where the board indicates abandoned wells are located near buildings. The companies' goals are to assure public safety and assess the integrity of the wellbore through board-dictated testing. Companies retain ongoing responsibility for wellbore integrity and any identified issues must be addressed to the regulator's satisfaction. The ERCB requires testing to be complete by July 31, 2013 (CAPP, 2009). Testing is geared towards detection of methane in soil and air by any appropriate testing method.

Wells are usually drilled in rural areas. However, some abandoned wells are now located in urban areas as a result of population growth and community expansion in Alberta. Since 1996, municipalities and developers have been encouraged, but not required, to check for abandoned wells with the ERCB. Effective November 1, 2012, the Alberta government requires municipalities and developers province-wide to conduct the checks for abandoned wells before approving, designing and building new subdivisions and developments. Industry supports the regulation because it provides an additional level of safety to the public. It is understood that testing requirements for wells would allow VOC emissions data to be generated and evaluated in an urban setting. As stated above, testing is geared towards detection of methane in soil and air by any appropriate testing method.

Figure 4: Summary of Wells Drilled, Abandoned, Reclaimed (1963 – 2011) is a summary of the number of wells drilled, abandoned, and reclaimed between 1963 and 2012. A few observations can be made based on Alberta Environment and Sustainable Resource Development (AESRD) data (AESRD, 2012):

- There were 53,831 uncertified wells at the end of 2012. Approximately 32 % (16,975) of unclaimed wells were abandoned between 1963 and 2002, while 68% were abandoned in the last 10 years.
- Over the last 10 years 4,177 wells were abandoned and 1,721 wells were certified.
- The certification rate is approximately 41.2 % of the abandonment rate.
- Almost 400,000 oil and gas wells have been drilled in Alberta to the end of 2012. 154,111 have been abandoned and 101,280 have been certified as reclaimed. New wells are being drilled at a rate of 13,788 per year (10 year average).

A certified well is a well that has been abandoned because it is no longer economically viable to produce or for other reasons, reclaimed so as to fulfill regulatory requirements for abandonment, and recognized by the regulator as being properly abandoned.

Well abandonment trends were developed using licensed data from 1963 to 2012 from the ERCB, as well as AESRD. Well abandonments are derived over a 50-year time span by comparing the number of reclaimed (certified and exempted) wells to the number of abandoned wells. Wells not included in this indicator are wells where the ERCB licenses were cancelled because the wells were not drilled. The information presented in **Figure 4: Summary of Wells Drilled, Abandoned, Reclaimed (1963 – 2011)** includes wells abandoned by a known operator. Orphan wells are wells that do not have an operator due to bankruptcy, disappearance of the company or sudden abandonment and are not included. Older orphan wells are hard to identity because of age and loss or scarcity of information and may vent gas to atmospheres for many years before they are reclaimed.

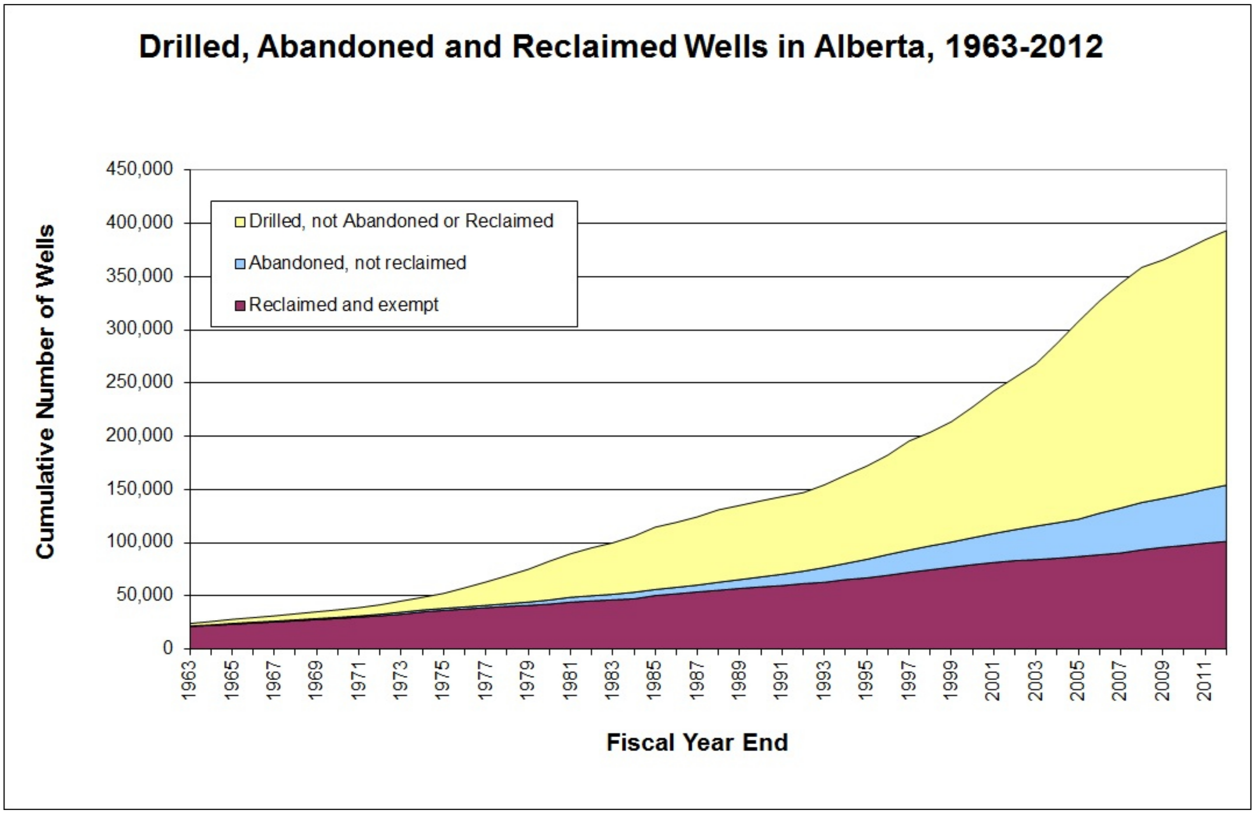

Figure 4:
Summary of Wells Drilled, Abandoned, Reclaimed (1963 – 2011)

Abandoned wells need to be certified to get clearance from the ERCB; however, there is a growing gap between abandoned and certified wells. It is not clear whether the abandoned wells in the **Figure 4: Summary of Wells Drilled, Abandoned, Reclaimed (1963 – 2011)** have been properly abandoned. Over time, certified wells or those abandoned by operators prior to certification may begin to leak to atmosphere due to cap failure and gas may also accumulate in the soil matrix (Kudienko, 2013). As such, this would result in another source of VOC emissions.

6.3.4. Combustion-Dual Fuel & Bi-Fuel

Natural gas has been acknowledged as one of the cleanest burning fossil fuels. The current abundance and low price of natural gas has motivated oil and gas companies to adopt it as an alternative fuel source in many segments of the upstream oil and gas industry. Specifically, natural gas can be used with other liquid hydrocarbons in a bi-fuel or dual fuel mode in combustion to lower GHGs and fuel costs. Additionally, natural gas can be compressed or liquefied for the end-users' specific needs. The following **Table F: Natural Gas Definitions** provides definitions for the different applications for natural gas combustion and storage.

TABLE F: Natural Gas Definitions

Natural gas application	Definition
Bi-fuel	A combustion application where natural gas or another liquid fuel is combusted independently without the fuel types mixing.
Dual fuel	A combustion application where natural gas and another liquid fuel are combusted simultaneously with the two fuel types mixing.
Compressed natural gas (CNG)	Storage of natural gas under high pressure, normally at 3,600 psi. It is 95% plus methane. 1,000 cubic feet of CNG has the equivalent energy content of 7.77 U.S. gallons of diesel.
Liquefied natural gas (LNG)	Storage of natural gas near atmospheric pressure under cryogenic conditions (less than -160°C) to reduce volume. The liquefied natural gas occupies 1/600 the space compared to standard conditions. One gallon of diesel has the energy content of 1.77 gallons of LNG.

The following **Table G: Natural Gas Usage in Upstream Oil & Gas** is a summary of the different areas where natural gas has been introduced in the upstream oil and gas industry in recent years.

TABLE G: Natural Gas Usage in Upstream Oil & Gas

Industry segment	Activity
On-shore Drilling	• Bi-fuel drilling rigs- engines • Dual fuel drilling rigs- engines • LNG drilling rings- engines
On-shore Drilling **Production Distribution**	• Dual fuel vehicles • Bi-fuel vehicles • Engines for power generation
Offshore Drilling	• Engines for power generation

6.3.5. Marine Sources

This section discusses VOC emission from marine sources. Although the report focuses on upstream emissions, certain activities have been included here that may extend to downstream activities. This has been done so that readers are aware that future activities in the downstream segment will no doubt become potential sources of VOC emissions and as such should be kept in mind for future research efforts.

6.3.5.1. Marine Tanker Loading/Unloading

The 2004 CAPP inventory for VOC emissions from *handling losses-tankers* is based on stationary loading and unloading VOC emissions from land transport. **Table S: VOC Emission from Tankers** in section 7.1.3.1 provides a summary of crude petroleum tonnage handled in Canadian ports. Considerations for tankers include:

- High vapor pressure carriers such as rail tank cars and trucks.
- Low vapor carriers for transport of crude oil, condensate and pentane - plus.

The CAPP 2004 inventory does not mention carrier losses from marine transport of crude oil or refined petroleum products. The 2004 inventory can be further improved by including marine handling losses. Understandably, most products in tankers will have been refined but a significant percentage of VOC emissions from marine handling losses may come from crude oil that has not been processed. Furthermore, crude oil managed at marine terminals may come from conventional or unconventional sources. VOC emissions can be estimated based on marine tanker throughput. Marine tanker throughput data are provided in **Table S: VOC Emission from Tankers** in the following section. Another potential source of VOC emission is emissions from tankers in transit waiting to leave port.

AP-42 compendium also provides a detailed analysis of emission factors in Chapter 5.2 (USEPA, 2008).

The USEPA cited a study by the National Acid Precipitation Assessment Program (NAPAP) which estimated emissions from the loading and unloading of petroleum products and crude oil from marine vessels; the inventory was estimated at 29,564 tons per year (Ramadan, Sleva, Dufner, Snow, & Kersteter, 1993). This same study also cites a Marine Board estimate of vapors displaced by filling the vessel tanks of 56,600 tonnes per year.

Marine facilities are considered a new source of VOC emissions and potential source types within these are summarized in **Table H: VOC Emissions from Marine Crude Oil Loading**, below. Emissions stem from volatilization of crude oil during handling and from combustion of fossil fuels by machinery to load or unload crude oil. Emission factors for this source are based on U.S. operations and may vary for Canadian operations, but should provide reasonable estimate. It should be noted that VOC emissions to atmosphere from tankers worldwide have not been measured and assessed systematically (Martens, Oldervik, Neeraas, & Strom, 2000).

TABLE H: VOC Emissions from Marine Crude Oil Loading

Source type	Emission Factor (mg/L)		
	Alaska	Crude oil Lower 48 States-tanker	Crude oil Lower 48 States-barge
In-transit losses	135	135	135
Uncontrolled loading losses	292	73	120
Uncontrolled ballasting losses	39	39	0
Controlled effectiveness, loading	0.920	0.900	0.860
Controlled flow, fraction on all flow through the stage	1.000	0.794	0.38
Petroleum through the stage, fraction of total gasoline consumed	0.053	0.007	0.035

6.3.5.2. Marine Facilities

Marine facilities are present in Canada's eastern and western coasts with associated production and storage facilities. The **Table I: Canadian Coastal Crude Oil & Natural Gas Facilities** below summarizes some of the marine facilities where crude oil or natural gas is handled and as such may represent potential sources of VOC emissions. **Table I: Canadian Coastal Crude Oil & Natural Gas Facilities**, below, illustrates the size of potential marine VOC sources from stationary or floating production facilities. Many of these facilities are dedicated to upstream activities. Some are dedicated to downstream activities and have been included here for informative purposes. VOC emissions will stem from equipment leaks, engineered emissions and accidental releases such as ruptures or equipment failures.

TABLE I: Canadian Coastal Crude Oil & Natural Gas Facilities

Facility	Description	Start date (First oil/gas)	Production or Capacity
Port or seashore facility			
Port of Vancouver, BC	Tanker transportation of crude oil and refined products for Shell, Chevron and other energy companies	-	Variable
Kitimat LNG, BC	Shipping terminal for LNG consisting of five to seven shipments per month	Expected 2013	Initially 5 MM[12]t/y with capacity to double
Canaport, NS	LNG receiving terminal consisting of three LNG storage tanks	2009	Maximum capacity of 1.2 billion ft^3/d of natural gas
Offshore facility or field			
Hibernia, NS	Offshore transportation using shuttle tankers to bring conventional light crude oil to onshore facilities	1997	56.28 MMbbl (2011 – 2012)
Terra Nova oil field, NS	This oilfield produces conventional light crude oil using a Floating Producing Storage and Offloading (FPSO) vessel, Terra Nova FPSO	2002	16.45 MMbbl (2011 – 2012)
White Rose Oil Field, NS	This oilfield produces conventional light crude oil using a Floating Producing Storage and Offloading (FPSO) vessel, SeaRose FPSO	2005	12.29 MMbbl (2011 – 2012)
North Amythist	This oilfield produces conventional light crude oil using a Floating Producing Storage and Offloading (FPSO) vessel, SeaRose FPSO	2009	12.34 MMbbl (2011 – 2012)
Deep Panuke, NS	Offshore transportation using shuttle tankers to bring conventional light crude oil to onshore facilities	Expected 2013	-

6.3.6. Rail Transport

The use of rail to transport conventional crude oil and refined products is expected to grow (CAPP, 2012). In March 2012 alone, 707,647 tonnes were transported by rail. The CAPP 2004 inventory only assessed rail transport for liquid petroleum gas (LPG). This VOC emission source merits further research given the trend and lack of emissions factors for rail transport during transit.

The following **Table J: Rail Transport Annual Tonnage** is a summary of tonnage transported by rail from 2006 to 2010 (Statistics Canada, 2012). However, the data source does not segregate fuel oils from crude petroleum.

[12] MM refers to million units

TABLE J: Rail Transport Annual Tonnage

Commodities and commodity groups (tonnes)	2006	2007	2008	2009	2010
Fuel oils and crude petroleum	4,787,055	5,434,288	5,293,739	5,126,558	5,246,516
Gaseous hydrocarbons, including liquid petroleum gas (LPG's)	4,821,261	4,793,654	4,439,703	4,122,681	4,418,511

Domm (2013) indicates that 150,000 barrels of crude oil per day (or 7,467,900 tonnes/year[13]) are currently being transported; details on potential growth of rail transport for crude oil is provided in the **Figure 5: Planned Rail Movements from Western Canada (2011 – 2016)** below.

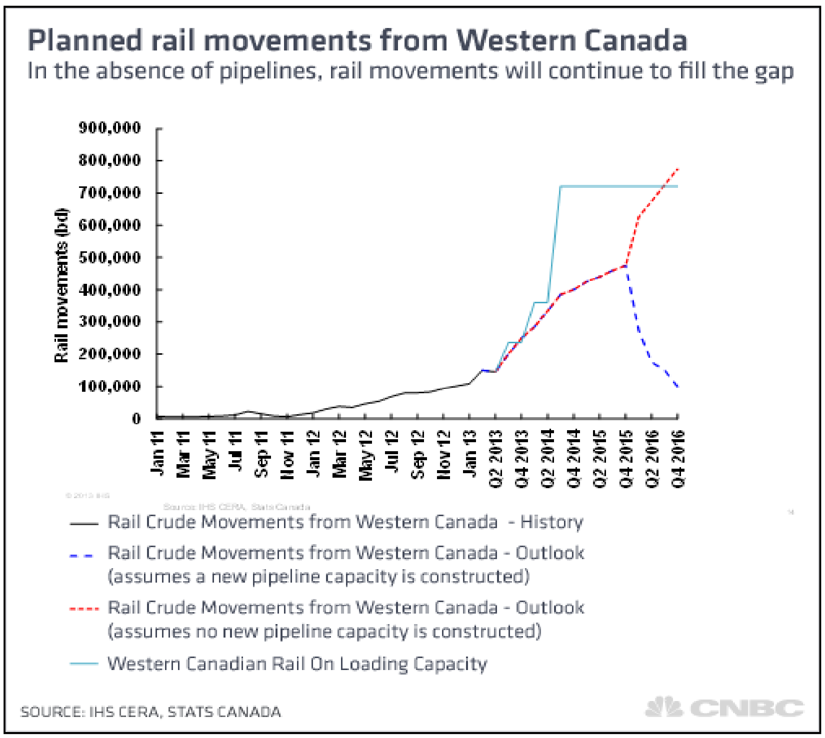

Figure 5:
Planned Rail Movements from Western Canada (2011 – 2016)

[13] 150,000 barrels per day is equal to 54,750,000 barrels per year or 7,467,900 tonnes/year using a conversion factor of 1 barrel = 0.1346 tonnes (BP, 2013).

7.0. ESTIMATION OF VOC EMISSIONS SOURCES

This study has identified both current and new sources of VOC emissions. The quantity of emissions from the various sources were estimated to approximate orders of magnitude and ranked. The estimations in this report and in particular in this section require further analysis as there are uncertainties in assumed values, assumed activity levels, and ranges. A rigorous study or testing plan is required to refine these estimates as proposed in section 9.0, PROPOSED TESTING PLAN.

In general, VOC emissions are estimated using the following equation:

$$ER_i = EF_i * AL$$

Where,

ER_i = emission rate of substance i for any given source

EF_i = emission factor for estimating emission of substance i from any given source

AL_i = activity level of substance i from any given source

Emission factors (EF_i) for these calculations are found in literature. In cases where the emission factor is not available, a best estimate approach is used based on one of the following criteria:

- EF from similar activities in other industrial sectors; and
- Field data if available.

7.1. *Current Sources*

7.1.1. Venting Pneumatics

7.1.1.1. Pneumatic Instrumentation

VOC emissions for instrument gas were calculated based on data available from BC's GHG reporting (Government of British Columbia). GHG reporting must be verified by a third party and as such data are deemed accurate. Pneumatic instrumentation venting is categorized into two main emission sources for reporting proposes, namely:

- Continuous High Bleed Device Vents, and
- Continuous Low Bleed and Intermittent Device Vents

VOC emission quantities from pneumatic instrument venting are included in **Table K: VOC Emissions from Pneumatic Instrumentation Venting**. GHG emissions from pneumatic instrumentation venting are understood to be composed primarily of methane with smaller amounts of other gases including VOC, carbon dioxide, and nitrogen. The following assumptions were used to infer VOC emissions:

- GHG emissions are entirely composed of methane gas. Contributions of CO_2 are assumed to be 6.5% on average to take into account the CO_2 content in BC gas and nitrous oxides are considered negligible.
- GHG emissions were discounted for 10% CO_2 content and then divided by 21 (the global warming potential of methane) to arrive at a real mass versus an equivalent carbon dioxide mass as calculated in column 2 of **Table K: VOC Emissions from Pneumatic Instrumentation Venting**. Column 3 represents the average percent mass of methane assumed from the CAPP 2004 inventory's Table 33, page 62, volume 4. Column 4 represents the total gas and is calculated simply by dividing column 2 by column 3.
- Column 5 is the average percent mass of VOC assumed from the CAPP 2004 inventory's Table 33, page 62- volume 4. Column 6 represents annual VOC emissions from BC. In order to calculate the annual VOC emissions, values in column 6 were divided by daily average gas production in BC for 2012 (NEB, 2013). These values are located in column 7.

  Total gas production in Canada for 2012 (NEB, 2013) and values from column 7 were used to calculate total VOC emissions from pneumatic instrumentation venting. These values can be found in **ATTACHMENT 1 – MARKETABLE NATURAL GAS PRODUCTION IN CANADA 2012.**

The general consensus is that about 30% of pneumatic instrumentation is powered by bottled propane at sour gas wells (CAPP, 2008a); however, VOC emissions from propane are not included in the calculations. Uncertainties are associated with number of wells using propane and propane purity but could represent as much as 604.4 tVOC (if 30 % is assumed) of the calculated 2,015 tVOC. Normalizing with respect to 2.331% VOC and assuming 95% VOC content in bottled propane yields a potential of **24,632 tVOC** being vented annually from pneumatic instrumentation[14].

TABLE K: VOC Emissions from Pneumatic Instrumentation Venting

	1	2	3	4	5	6	7	8
Pneumatic instruments	**tCO_2e**	**tCH_4**	**CH_4 (% mass)**	**t gas**	**VOC (% mass)**	**tVOC BC/yr**	**tVOC/ e^3m^3/d**	**tVOC/yr**
Continuous High Bleed Device Vents	311,100	16,224	91.8%	17,674	2.331	412	0.004	1,649
Continuous Low Bleed and Intermittent Device Vents	68,900	3,593	91.8%	3,914	2.331	91	0.001	365
Total emissions (tVOC)								2,015
70% total emissions (tVOC)								1410.5

[14] This calculation is equal to 604.4 tVOC/.02331=25,928 tVOC*.95=24,632 tVOC.

7.1.1.2 Chemical Injection Pumps

VOC emissions for chemical injection pumps were calculated based on data available from BC's GHG reporting (Government of British Columbia). GHG reporting must be verified by a third party and as such data are deemed accurate. GHG emissions from chemical injection pumps are understood to be composed primarily of methane with smaller amounts of other gases. The following assumptions were used to infer VOC emissions:

- GHG emissions are entirely composed of methane gas and contributions of CO_2 or nitrous oxides are considered negligible.
- GHG emissions were divided by 21 (the global warming potential of methane) to arrive at a real mass versus an equivalent carbon dioxide mass as calculated in column 2 of **Table L: VOC Emissions from Chemical Injection Pumps**. Column 3 represents the average percent mass of methane assumed from the CAPP 2004 inventory's Table 33, page 62, volume 4. Column 4 represents the total gas and is calculated simply by dividing column 3 by column 2.
- Column 5 is the average percent mass of VOC assumed from the CAPP 2004 inventory's Table 33, page 62, volume 4. Column 6 represents annual VOC emissions from BC. In order to calculate the annual VOC emissions, values in column 6 were divided by daily average gas production in BC for 2012 (NEB, 2013). These values are located in column 7.
- Total gas production in Canada for 2012 (NEB, 2013) and values from column 7 were used to calculate total VOC emissions.

TABLE L: VOC Emissions from Chemical Injection Pumps

	1	2	3	4	5	6	7	8
Pneumatic instruments	**tCO_2e**	**tCH_4**	**CH_4 (% mass)**	**t_{gas}**	**% VOC mass**	**tVOC BC/yr**	**$tVOC/e^3m^3$ /d**	**t VOC/yr**
Pneumatic Pump Vents	173,700	8,271	91.7957%	9,011	2.33%	210	0.002	841

Total VOC emissions from pneumatic instrumentation venting is the sum of the VOC emissions from pneumatic instrumentation (**Table K: VOC Emissions from Pneumatic Instrumentation Venting**) and chemical injection pumps (**Table L: VOC Emissions from Chemical Injection Pumps**) or **2,856 tVOC/year**, If bottled propane is assumed to contribute to VOC emissions, the total could be as much as **28,882 tVOC/year.** This value comes from 70% of VOCs from pneumatic instrumentation plus vented propane plus vented VOCs from pneumatic pumps Bottled propane is propane that is stored in pressurized cylinders and delivered to site. This amount does not reflect VOC emissions from other sources such as gas analyzers or gas-driven motor starts.

Sources of uncertainty include the following:

- Assuming that VOC emissions stem from only natural gas production. It is an established fact that emissions from pneumatic instrumentation also comes from crude oil production but for the purposes of this evaluation only natural gas was used as the natural gas/crude oil pneumatic instrumentation venting split is unknown. In other words, venting from natural gas pneumatic instrumentation versus venting from oil production is not distinguished in the reporting.
- Assuming that activity levels in BC are mirrored in other provinces. In other words, assuming that emissions and natural gas production in BC, which have been used to derive VOC emissions in other provinces is valid. Because oil and gas development is relatively new in BC compared to Alberta, the case exists in which emissions in BC correlated with gas production yet in Alberta emissions are underestimated or overestimated because the assumed correlation is not valid. In essence, new technology in BC and use of instrument air can be correlated to gas production in BC, but this correlation may not hold true in Alberta where older gas fields exist or in other Canadian provinces where instrument gas is still deployed in lieu of newer pneumatic instrumentation.

7.1.2. Casing Vent Gas

VOC emissions from casing vent gas were calculated based on VOC emissions from the 2004 inventory. The following assumptions were used to infer VOC emission:

- Base emissions are 528 ktVOC (Clearstone Engineering Ltd., 2004a)
- The fraction of VOC emissions stemming from casing vent gas was 16.2% (Clearstone Engineering Ltd., 2004a).
- A 10 year time span has been assigned to portray emissions between the last inventory and the present.
- A 3.8% increase in annual wells drilled. This average increase is assumed using data provided by the ERCB for wells drilled between 2009 and 2012.
- A 0.05% decrease in annual gas production from wells

TABLE M: VOC Emissions from Casing Vent Gas

Item	Vent	Unit
Base Emissions	528	kt VOC/year
% Emission	16.2	%
VOC emissions	85.54	kt VOC/year
Elapsed time period	10	years
Annual well increase	3.81	%
Accumulated well increase	1.453	times
Production decrease	0.05	%
Accumulated decrease	0.995	times
Total VOC emissions	123,700	t VOC/year

The final results show that casing gas venting is roughly 123,700 tVOCs.

The uncertainties in this calculation are deemed high hence there is a need to accurately determine the following parameters:

- The original base emission used from the 2004 inventory is based on data with associated limitations and may have changed over time.
- Percent increase in annual wells drilled may vary and the chosen value may not reflect the true nature of drilling programs given only data between 2009 and 2012 was used.
- Percent increase in wells casing failure. The 1% is assumed from a study (Thermal Well Casing Failure Risk Assessment Subcommittee, 1992) for thermal wells, but may not be indicative of heavy conventional crude oil. Additionally, well failure is less than 1% with a tendency to decrease given improvements in well casing technology over the years.

A 0.05% decrease in annual gas production from the well was assumed but this value may need to be verified using actual field conditions.

7.1.3. Gas Migration

VOC emissions from gas migration were calculated based on VOC emissions from the 2004 inventory. The following assumptions were used to infer VOC emission:

- Base emissions are 782 tVOC (Clearstone Engineering Ltd., 2004a).
- A 10 year time span has been assigned to portray emissions between the last inventory and the present.
- A 3.81 % increase in annual wells drilled. This average increase is assumed using data provided by the ERCB for wells drilled between 2009 and 2012.
- A 1 % increase in well casing failure. This well failure statistic is supported by an industry study for thermal well casing failure risk assessment made in 1992 (Thermal Well Casing Failure Risk Assessment Subcommittee, 1992).
- A 0.05% decrease in annual gas production from wells.

TABLE N: VOC Emissions from Gas Migration

Item	Vent	Unit
VOC emissions	782	t VOC/year
Elapsed time period	10	years
Annual well increase	3.81	%
Accumulated well increase	1.454	times
Annual casing failure	1.00%	%
Accumulated failure	1.105	times
Production decrease	0.05	%
Accumulated decrease	0.995	times
Total VOC emissions	1,250	tVOC/year

The uncertainties in this calculation are deemed high hence there is a need to accurately determine the following parameters:

- The original base emission used from the 2004 inventory is based on data with associated limitations and may have changed over time.
- Percent increase in annual wells drilled may vary and the chosen value may not reflect the true nature of drilling programs given only data between 2009 and 2012 was used.
- Percent increase in wells casing failure. The 1% is assumed from a study (Thermal Well Casing Failure Risk Assessment Subcommittee, 1992) for thermal wells, but may not be indicative of heavy conventional crude oil. Additionally, well failure is less than 1% with a tendency to decrease given improvements in well casing technology over the years.

A 0.05% decrease in annual gas production from the well was assumed but this value may need to be verified using actual field conditions.

7.1.4. Surface Casing Vent Flows

VOC emissions from surface casing vent flows were calculated based on VOC emissions from the 2004 inventory. The following assumptions were used to infer VOC emission:

- Base emissions are 528 ktVOC (Clearstone Engineering Ltd., 2004a).
- The fraction of VOC emissions stemming from casing vent gas was 11.4% (Clearstone Engineering Ltd., 2004a).
- A 10 year time span has been assigned to portray emissions between the last inventory and the present.
- A 3.8% increase in annual wells drilled. This average increase is assumed using data provided by the ERCB for wells drilled between 2009 and 2012.
- A 0.05% decrease in annual gas production from wells.

TABLE O: VOC Emissions from Surface Casing Vent Flows

Item	Vent	Unit
Base Emissions	528	kt VOC/year
% Emission	11.45	%
VOC emissions	60.46	kt VOC/year
Elapsed time period	10	years
Annual well increase	3.81	%
Accumulated well increase	1.453	times
Production decrease	0.05	%
Accumulated decrease	0.995	times
Total VOC emissions	87,430	t VOC/year

The final results show that casing gas vent is roughly 87,430 tVOCs.

The uncertainties in this calculation are deemed high hence there is a need to accurately determine the following parameters:

- The original base emission used from the 2004 inventory is based on data with associated limitations and may have changed over time.
- Percent increase in annual wells drilled may vary and the chosen value may not reflect the true nature of drilling programs given only data between 2009 and 2012 was used.
- Percent increase in wells casing failure. The 1% is assumed from a study (Thermal Well Casing Failure Risk Assessment Subcommittee, 1992) for thermal wells, but may not be indicative of heavy conventional crude oil. Additionally, well failure is less than 1% with a tendency to decrease given improvements in well casing technology over the years.
- A 0.05% decrease in annual gas production from the well was assumed but this value may need to be verified using actual field conditions.

7.1.5. Glycol Dehydration

VOC emissions from glycol dehydration were calculated based on benzene emissions reported to the ERCB. The ERCB provided annual benzene emission factors for over 2,000 sites that report benzene emissions under Directive 39. Understandably, upstream oil and gas operators perform their own evaluations using industry-wide accepted methods and software for reporting purposes. In addition to the data provided by the ERCB, the following assumptions were used to infer VOC emissions from glycol dehydration:

- An average emission factor of 764 tonnes/year of benzene was developed from ERCB data and assumed to reflect only benzene emissions.
- The fraction of VOC emissions stemming from glycol dehydrators is composed primarily of benzene, toluene, ethylbenzene, and xylene which are commonly referred to as BTEX. A typical gas composition for BTEX was assumed from a study evaluating BTEX emissions from amine sweetening and glycol dehydration (Collie, Hlavinka, & Ashworth, 1998). Values are in parts per million (ppm) and are listed in **Table P: VOC Emissions from Glycol Dehydration**.
- Based on the gas composition, toluene, ethylbenzene and xylene were prorated using the ERCB-derived average emission factor for benzene. The total VOC emission factor is the sum of the benzene, toluene, ethylbenzene and xylene of Total BTEX emissions in **Table P: VOC Emissions from Glycol Dehydration**.
- Additionally, the average gas production in Alberta was used as a base to prorate total gas production in Canada to arrive at total BTEX emission. The final value is **2,994 tVOC/year**.

TABLE P: VOC Emissions from Glycol Dehydration

	Proxy Gas Analysis	Units	Prorated	Emissions
Benzene	215	ppm	1	764.38
Toluene	180	ppm	0.83721	639.94
Ethylbenzene	100	ppm	0.46512	355.52
Xylene	95	ppm	0.44186	337.75
Total Alberta BTEX				2,097.61
Average Alberta gas production	275,237	(10^3 m^3/d)		
Average Canadian gas production	392,898	(10^3 m^3/d)		
Total BTEX emissions in Canada		tonnes/year		2,994.32

There are limitations and uncertainties associated with the chosen approach. These include the following:

- The benzene and consequently the BTEX emission factors are based on emission factors that are either calculated (generated by operators using proprietary software such as GRI-GLYCalc™ or HYSYS™) or actual field data from field samples as indicated by an industry best management practices guide for calculating benzene emissions (CAPP, 2006). As such, the data sources have associated uncertainties including analysis and data acquisition methods.
- The assumption that only BTEX is present in the glycol vent. There is a strong possibility that other trace VOCs exist in the vent stream, even in small volumes. Additionally, it is assumed that alkanes are not soluble in glycol. This is especially true depending on the type of glycol being used, whether ethylene glycol (EG), diethylene glycol (DEG), or triethylene glycol (TEG) is used by the operator is unknown. TEG is the most common type of glycol used (CAPP, 2006). VOCs in the vented gas stream may represent about 85% of total emissions based on simulations for TEG dehydration units (Ebeling, Lyddon, & Convington, 1998) . Normalizing 2,994 t BTEX with respect to 85% VOC and 15% BTEX yields a potential of **16,966 tVOC** total BTEX plus non-BTEX VOCs[15].
- The assumed gas stream may not reflect typical or average BTEX composition for gases across Canada. Justifiably, gas compositions vary from province to province and from basin to basin. For example, BTEX inlet concentrations for facilities in Alberta are roughly an order of magnitude less according to literature (Alva-Argaez, Holoboff, & Khoshkbarchi, 2012).
- The configuration of dehydration units as well as glycol circulation rates will also affect emission.

7.1.6. Land Applications

SNC-Lavalin reviewed ERCB Directive 50 and documents related to land applications. Land applications have been limited to land-farming, land-spraying and landfilling. ERCB Directive 50 establishes maximum levels for soil quality and BTEX concentrations. Uncertainties associated with land applications include:

- Emission factors – There is limited information for hydrocarbon emissions from remediation sites, and few field studies have been performed (Ausma, Edwards, Fitzgerald-Hubble, Halfpenny-Mitchell, Gillespie, & Mortimer, 2002). The aforementioned cited source focused on diesel emissions which differ from hydrocarbon mixtures of unrefined crude oil.
- Activity levels – There is limited information regarding activity levels. Several news stories provide anecdotal information but do not provide details such as volumes of soil treated. SNC-Lavalin contacted the ERCB for additional information but did not receive a response at the time of this publication. However, ERCB Directive 50 allows for land spreading for certain types of waste so here is a potential to release VOCs to atmosphere.

Soil quality for land applications is monitored with operators keeping records (ERCB, 2012).

[15] Calculated as 2,994 tVOC/0.15=19960*.85=16966 tVOC.

7.2. New Sources

7.2.1. Process Sewers & Drains

As stated earlier in this report, there is a general consensus that sewers and drains where organic liquids are collected and disposed of are a potential source of VOC emissions (CAPP, 2007) & (USEPA, 2006). The 2004 VOC inventory does not include VOC emissions from sewers or drains however they could be a significant source of VOC emissions from upstream oil and gas facilities.

Process sewers and drains are found throughout oil and gas operations from oil batteries and compressor stations to centralized facilities. This source of VOC emissions has not been estimate in this report due to limited information and wide-ranging assumptions and therefore merits further investigation. A proposed plan on testing and estimating calculations is provided in section 9, Proposed Testing Plan.

7.2.2. Orphaned Sites & Wells

VOCs emissions from orphaned sites and wells were calculated based on the following assumptions:

- Five wells are leaking each year for a period of 10 years prior to reclamation but only one year is used as reference year for leakage since all emissions in this report are on an annual basis. These values are assumed based on reports from the Orphan Well Association.
- One site (facility or compressor station) is leaking each year for a period of 10 years prior to reclamation but only one year is used as reference year for leakage since all emissions in this report are on an annual basis. This value is assumed based on reports from the Orphan Well Association.
- An emission factor of 3.42 kg/d/well (Clearstone Engineering Ltd., 2004b) is assumed as a proxy for orphan wells venting to atmosphere in the absence of data for abandoned wells. This value is for surface casing vent flows and is used as an approximation as data on orphan well venting gas to atmosphere are scarce.
- The gas composition for all oil and gas facilities contains 25% VOC content by mass to account for heavier hydrocarbons.

TABLE Q: VOC Emissions from Orphan Wells and Sites

Parameter	Value	Unit
Number of orphaned wells/ year	5	well/year
Leak time until reclamation	1	year
Emission factor	3.42	kg vented gas/day-well
Mass of gas vented	1,248.3	kg vented gas/year-well
VOC content	25%	20% to 40% depending on source
VOC emission	1.56	(tonnes/year)
Facilities	**Value**	**Unit**
Number of orphaned sites/ year	1	well/year
Leak time until reclamation	1	year
Emission factor	34.2	kg vented gas/day-well
Mass of gas vented	12,483	kg vented gas/year-well
VOC content	25	%
VOC emission	3.12	tonnes/year
Total	4.68	tonnes/year

There is a great deal of uncertainty due to limited information or data. Although the Orphan Well Association produces annual reports on wells and sites that have been identified and reclaimed, data are scarce.

The calculations presented in this section refer to wells and sites that have been orphaned and not abandoned. Abandoned wells are understood to undergo a rigorous certification process and have clear ownership whereas orphaned wells do not have clear ownership. Even if wells are abandoned and certified, over time they may begin to leak and the extent of leakage is not known at present.

7.2.3. Combustion – Dual Fuel & Bi-Fuel

VOC emissions from dual fuel or bi-fuel combustion were not calculated for this study. Although there is some information regarding emission factors from credible sources such as AP-42 and regarding dual-fuel engines; there is not enough information on activity levels or fuel type used to perform a calculation with reduced uncertainty. For more accurate data on USEPA emission factors, table 3.4-1 of AP-42 can be referred to (USEPA, 2011). Also, the Australian Government (2002) National Pollutant Inventory guidance document presents data for VOC emissions according to fuel type as follows:

- Diesel -1.32 kg/m^3
- Dual fuel- 3.49×10^{-3} kg/m^3

As can be noted on a volumetric basis there are VOC emission reductions. However care must be taken when comparing power output as VOC emissions may be higher:

- Diesel -3.84×10^{-4} kg/m^3
- Dual fuel- 8.03×10^{-4} kg/m^3

There is certainly a lot of information available regarding company initiatives to switch to natural gas or combined natural gas usage with other fuel types, no concrete volumes or project types are available and if so are limited to project description type or qualitative information. It should also be noted that these systems may increase VOC emissions as noted by emission factors encountered in literature.

7.2.4. Marine Sources

Estimation of VOC marine sources were limited to marine tanker loading-unloading for crude petroleum and marine port facilities. Floating and stationary production platforms were not evaluated for Eastern Canada.

7.2.4.1. Marine Tanker Loading – Unloading

Marine tanker loading-unloading VOC emissions are based on an SNC-Lavalin Inc. study carried out for Environment Canada entitled **2010 National Marine Emissions Inventory for Canada** (SNC-Lavalin Inc., 2012). The fugitive emission calculations required an estimate of the type and amount of fuel transported to/from Canadian ports. Since the Canadian Coast Guard data does not contain cargo tonnages, estimates were achieved by assuming most of a vessel deadweight tonnage (DWT) is comprised of fuel cargo for the appropriate ship classes. More specifically, the equations used to estimate the fugitive emissions are defined below.

Transit:

$E\ (mg) = DWT * LF * TF * EF_{transit}$

Load/Unload:

$E\ (mg) = DWT * LF * EF_{load}$

Where:

E = emissions (mg)

DWT = deadweight tonnage (tonnes assumes the majority of weight is from fuel cargo)

LF = load factor (assumed to be 0.9)

TF = transit factor (assumed to be 0.5)

$EF_{transit}$ = transit emission rate (mg/week/L transported)

EF_{load} = loading/unloading emission rate (mg/L transferred)

The emission rates for fugitive VOC emissions are from Table 3-7 of the EPA compilation of emission factors[16]. LNG vapors were assumed to be captured and used as fuel for the vessel engines. As noted above, the load factor (LF) is less than 1.0 since DWT accounts for the mass of engine fuel as well as crew and supplies on board. The transit factor (TF) assumes the cargo is transported one way only (eg, the return leg of a voyage is done under ballast).

TABLE R: Fugitive VOC Emission Rates as per the USEPA

Vessel Class	Transit Emission Rate (mg/week-L)	Load/Unload Emission Rate (mg/L)
Crude Oil Tanker	150	73
Distillate Oil Tanker	0.54	0.55
Gasoline Tanker	320	215
LNG Tanker	0.0	0.0

The total VOC emissions from the Environment Canada study entitled **2010 National Marine Emissions Inventory for Canada** (SNC-Lavalin Inc., 2012) amounted to 9,339 tVOC/year from hydrocarbon combustion by tankers. The study encompasses all tankers transporting hydrocarbon products and does not distinguish between refined products and crude petroleum. It is assumed that a large percentage of this value is dedicated to VOC emissions from crude petroleum tankers.

[16] These rates are published in the US EPA AP-42 Compilation of emission factors, Chapter 5.2.

Additionally, VOC emissions from crude petroleum cargo shipping were also estimated. Domestic and international crude oil cargos loaded and unloaded from Canadian ports are from a study entitled "**Regulating oil tankers in Canadian waters"** (Anderson & Spears, 2012)**.** The study presents annual crude petroleum cargos for 2008. It is understood that crude petroleum represents unrefined products only. The study summarizes crude petroleum cargo for 6 major ports: 5 located in Eastern Canada and 1 located in Western Canada. The Western crude oil was assumed to be lighter than Eastern crude oil with densities of 0.931 t/m^3 (CAPP, 2012) and 0.9 t/m^3 (NEB, 2004) which are typical densities segregating heavy and light crude, respectively.

Further assumptions were made in order to estimate annual VOC emissions from tanker loading and unloading including:

- Emissions were assumed to stem from loading/unloading and transit with emission factors of 73 mg total hydrocarbon per liter (THC/L) transferred and 150 mg THC/L-week transferred, respectively[17]. These are for evaporative losses only.
- Transit time was assumed to stem from 1 week port transit.
- Total emission factor for THC emission from marine source is therefore 223 mg THC/L or 0.000223 t THC/m^3 assuming one week as per above assumption.
- Emission factors for crude petroleum organic emissions are in terms of THC. Therefore, an 85 % VOC content was assumed as per AP-42 guidance for Table 5.2-6. The remaining 15% were assumed to be methane and ethane.

[17] These rates are published in the US EPA AP-42 Compilation of emission factors, Chapter 5.2.Table 5.2-6

TABLE S: VOC Emission from Tankers

	Domestic		International		Total Handled	Density	Volume	Mass
	Loaded	Unloaded	Loaded	Unloaded				
Port	tonnes ('000)					t/m^3	m^3	t VOC/year
Come-By-Chance	3,007.3	10,131.2	6,881.2	4,932.8	24,952.5	0.9	27,725,000	6,182.68
Port Hawkesbury	0.0	3,369.9	10,674.9	7,153.3	21,198.1		23,553,444	5,252.42
Newfoundland Offshore	14,949.1	0.0	1,919.3	0.0	16,868.4		18,742,667	4,179.61
Saint John	0.0	2,798.7	28.4	10,511.5	13,338.6		14,820,667	3,305.01
Quebec	0.0	0.0	0.0	9,631.8	9,631.8		10,702,000	2,386.55
Port Metro Vancouver	0.0	0.0	2,159.3	0.0	2,159.3	0.931	2,319,334	517.21
Total (t THC)	17,956.4	16,299.8	21,663.1	32,229.4	88,148.7	-	-	21,823.47
Total (t VOC)	VOC content of 85%							18,549.95

The assessment of tanker marine VOC emissions was based on two major activities: fuel consumption for engines and evaporative losses. These do not include uncontrolled emissions stemming from actual filling or unloading activities that create splashing effect whereas the emissions presented in **Table S: VOC Emission from Tankers**, above, are understood to emerge from tankers breathing while at port. Emission factors stemming from uncontrolled activities should be further investigated.

Uncertainties associated with evaluating VOC emissions from tanker loading/unloading include the following:

- Use of emissions factors for generic crude versus actual crude. The generic crude used to evaluate total organic emission (TOE) from the AP-42 table has a Reid Vapor Pressure (RVP) of 69 kPa. A more precise VOC emission inventory can be developed using crude petroleum loading and unloading data from operators. Additionally, crude petroleum properties can be identified using established crude petroleum properties database such as Crude Monitor (Crude Quality Inc., 2013).
- Assuming that no VOC emissions occur during loading/unloading activities- According to Petruk (2013), VOC emissions from venting are minimal or non-existent in marine operations due to regulatory requirements. Furthermore, venting is only permitted if there is a vapor recovery system in place. However, not allowing venting or required vapor recovery systems if venting is allowed is not synonymous with having zero net emission and this should be investigated further.

VOC emissions were assumed to be 15% of THC; the AP-42 table 5.2-6 uses typical crude, presumably for American type crude. Depending on the crude type (eg, heavy or synthetic crude petroleum in Western Canada), this value may change.

7.2.4.2. Marine Facilities

In Canada, there is currently only one operating Liquefied Natural Gas (LNG) port located in St. John, New Brunswick. The LNG terminal in Kitimat, British Columbia has received approvals and is set to begin construction in the near future. The following assumptions were made to estimate VOC emissions from LNG ports:

- LNG volumes transported per year were taken from maximum design throughput of:
  - 1.2 billion cubic feet meters per day capacity (Canaport LNG, 2008) or equivalent to 7.6 million tonnes per year (tpy).
  - 5 million tonnes per annum (MMtpa) with capacity (NEB license) to expand to 10 MMtpa (Kitimat LNG, N/A).
- VOC losses from LNG processing were assumed to vary between 0.005% and 0.1% as per good practice guidance (IPCC, 2000).
- VOC content of LNG (in liquid form) was assumed to be composed of 1% butane.

LNG losses from two LNG marine facilities are listed in the **Table T: VOC Emissions for Canaport LNG Terminal**, below. Canaport VOC emissions could potentially range between 3.8 tVOCs and 76 tVOCs per year. The soon to be built Kitimat facility VOC emissions could potentially range between 2.5 tVOCs and 50, tVOCs tpy.

TABLE T: VOC Emissions for Canaport LNG Terminal

Parameter	Loss scenarios			Units
Throughput	7.6	7.6	7.6	MMtpa
	7,600,000	7,600,000	7,600,000	tpy
Losses	low	medium	high	
Fraction	0.005	0.05	0.1	%
% VOC composition	1	1	1	%
Losses	3.8	38.0	76.0	t VOCs/y
LNG emissions	Kitimat (to be constructed in near future)			
Throughput	5	5	5	MMtpa
	5,000,000	5,000,000	5,000,000	tpa
Losses	low	medium	high	
Fraction	0.005	0.05	0.1	%
% VOC composition	1	1	1	%
Losses	2.5	25.0	50.0	t VOCs/y

Uncertainties are associated with the following:

- LNG VOC content was assumed to be 1%, however this may not be the case. Although LNG is primarily composed of methane, it also contains heavier hydrocarbons which vary in composition depending on the geographic location (CEE, 2007).
- Throughput used was assumed to be the maximum. In reality many plants operate sub maximum design capacity.
- Plant losses vary within a range of values so portraying an actual narrow band of losses to reduce uncertainty is not achievable unless actual field assessments are carried out.

7.2.5. Rail Transport

Rail transport VOC emissions were calculated according to the following assumptions and methodology:

- The crude oil transported by rail is assumed to be Western Canada crude oil[18].
- LPG is assumed to be propane[19].

Emission factors and percent VOC content are summarized in **Table U: Summary of Emission Factors and Chemical Characteristics of Hydrocarbons**, below. These values were taken from AP-42 Chapter 5.2 Table 5.2-5. The table provides uncontrolled losses for various organic substances. Crude oil is a generic substance with a RVP of 34 kPa (5Psi). In the absence of any information on LPG, gasoline was used as a proxy substance. All emission factors and LPG reflect gasoline properties that could be refined using a more rigorous exercise.

TABLE U: Summary of Emission Factors and Chemical Characteristics of Hydrocarbons

Parameter	Low range	Unit	High range	Unit
Emission factors				
Emission factor crude oil	240	mg/L	580	mg/L
Emission factor LPG	590	mg/L	1430	mg/L
Chemical characteristics				
Western Canada crude oil[20]	930	kg/m^3		
LPG (propane[21])	510	kg/m^3		
Crude oil VOC content	85	%		
LPG VOC content	100	%		

[18] Refer (CAPP, 2012) for details.

[19] http://www.elgas.com.au/files/Safety_Data_Sheet_for_LPG_Jan_2011.pdf

[20] Refer (CAPP, 2012) for details.

[21] http://www.elgas.com.au/files/Safety_Data_Sheet_for_LPG_Jan_2011.pdf

Tonnage transported by rail is provided in **Table V: Summary of Rail Transport Tonnage**, below[22]. However, the data does not segregate fuel oils from crude petroleum and therefore may overestimate VOC emissions. A more accurate estimate of crude oil transported by rail is 150,000 barrels of crude oil per day (or 7,467,900 tonnes/year[23]) as indicated by Domm (2013).

TABLE V: Summary of Rail Transport Tonnage

Commodities and commodity groups	2006	2007	2008	2009	2010	5-year average
Fuel oils and crude petroleum (tonnes)	4,787,055	5,434,288	5,293,739	5,126,558	5,246,516	5,177,631
Gaseous hydrocarbons, including liquid petroleum gas (LPG's) (tonnes)	4,821,261	4,793,654	4,439,703	4,122,681	4,418,511	4,519,162

Calculations do not include equipment leaks or transit losses as there are no data available in AP-42 for crude oil. The values presented here are therefore conservative and it is understood that these values could actually be much higher. Calculations are presented to give a sense of the magnitude of the emissions and possible ranges. The **Table W: Summary of Annual VOC Emission from Rail Transportation LPG** below is a summary of the possible ranges of VOC emissions for gaseous hydrocarbons including liquid petroleum gas (LPGs).

TABLE W: Summary of Annual VOC Emission from Rail Transportation LPG

Fuel type	2006	2007	2008	2009	2010	5-year average
Lower range (tonnes/year)						
Gaseous hydrocarbons, including liquid petroleum gas (LPG's)(tonnes)	5,578	5,546	5,136	4,769	5,112	5,228
Upper range (tonnes/year)						
Gaseous hydrocarbons, including liquid petroleum gas (LPG's)(tonnes)	13,518	13,441	12,449	11,560	12,389	12,671
Average (tonnes/year)						
Gaseous hydrocarbons, including liquid petroleum gas (LPG's)(tonnes)	9,548	9,493	8,792	8,165	8,750	8,950

[22] Data available from http://www5.statcan.gc.ca/cansim/a26?lang=eng&retrLang=eng&id=4040021&pattern=&csid=

[23] 150,000 barrels per day is equal to 54,750,000 barrels per year or 7,467,900 tonnes/year using a conversion factor of 1 barrel = 0.1346 tonnes.

For crude oil VOC emissions from rail transport, 7,467,900 tonnes/year was assumed and emission factors applied in the same manner as for LPG. VOC emissions are presented in the **Table X: Summary of Annual VOC Emission from Rail Transportation Crude Oil** below.

TABLE X: Summary of Annual VOC Emission from Rail Transportation Crude Oil

Fuel type	2013
Lower range (tonnes/year)	
Crude petroleum (tonnes)	1,638
Upper range (tonnes/year)	
Crude petroleum (tonnes)	3,959
Average (tonnes/year)	
Total Average (tonnes)	2,798

VOC emissions from rail transport are estimated to be 11,748 tVOCs.

Uncertainties associated with the calculations include:

- Loading/unloading operations methods or techniques
- Crude oil and LPG chemical and physical properties such as vapour pressure and chemical composition
- Time of transit
- State of rail car and associated equipment whether new or old
- Ambient temperature
- Operating pressure

8.0. RANKING OF VOC EMISSIONS

In this report, VOC emissions were assessed using the following criteria:

- Magnitude of annual vented emissions – VOC emission calculated from available technical data such as emission factors, activity levels, VOC concentration is gas/liquid streams
- Knowledge gap – The amount of information available to perform adequate calculations of VOC emissions from credible or updated sources as well as regulations and directives that impact the VOC emission source.

However, other criteria were included in this section to rank VOC emissions and provide a more global understanding as to the nature of VOC emissions from the upstream oil and gas sector. Additional criteria included the following:

- Public perception - Or how the public would perceive the VOC source. The visual impact of equipment is also highlighted here. As an example, smaller equipment such has exposed or uncapped wells, or ground surface where migration occurs will not be easily observed compare to dehydration towers or bulky facilities.
- Health or proximity to VOC source and potential health effects – VOC emission may have negative impacts in terms of exposure in daily life or repercussions from an occupational health and safety standpoint. This is especially true when dealing with benzene, a known carcinogen.
- Resource growth - VOC sources whether from oil or gas upstream operations. At present, oil developed would have a priority over natural gas development given the current commodity price environment.
- Resource commodity price - Whether from oil or gas upstream operations and the perceived value of the commodity in the near future. There is currently a wide gap between oil and natural gas prices that skew resource development towards oil development, and this development is either conventional or non-conventional oil development.
- Industry best practices - How industry has been managing VOC sources to minimize impacts through different practices. Best Management Practices is an example of how industry is reducing emissions by adopting cleaner production procedures and techniques.

Each criterion was ranked using a numbered scale of 1 to 5 with 1 representing the lowest impact and 5 representing the highest impact as illustrated below

- 1 = low impact
- 3 = medium impact
- 5= highest impact

It is understood that while magnitude of VOC emissions and knowledge gap are quantitative in nature, the other criteria are subjective and qualitative. Therefore, the final ranking is a mixture of quantitative and qualitative criteria. As an example, glycol dehydration received a 4 in knowledge gap because there are still uncertainties in quantification, as most values are based on software simulations rather than actual field measurements. Pneumatic instrumentation received 2 because there are numerous studies and field or laboratory measurements to quantify this emission source.

The criteria numbers were then summed horizontally to arrive at total points for each VOC source. Total points are presented in column "Total Points" and are used to rank the VOC sources assessed in this study.

The results for the 13 VOC sources assessed in this report are summarized in **Table Y: Summary of VOC Ranking (In Detail)** and **Table Z: Summary of VOC Ranking**.

TABLE Y: Summary of VOC Ranking (In Detail)

VOC Source	Volume (t VOC)	Ranking Criteria: Magnitude VOCs	Public perception	Health (proximity)	Resource growth	Resource price	Best practices	Knowledge gap	Total	Comments	Include in test plan
Bi-fuel combustion	TBD	5	1	3	5	3	4	3	24	Uncertainty as to who is adopting technology Many news articles but no concrete numbers Emission factors available from EPA	**Yes**
Venting Casing Gas	123,700	5	3	3	1	5	4	3	24		
Surface Casing Vent Flows	87,430	4	3	3	1	5	4	3	23		**Yes**
Gas migration	1,250	2	3	2	1	5	4	3	20	Assumes an increase of 1% casing failure Assumes a .05% decrease in gas production Assumes 1% well increase	**Yes**
Glycol dehydration	16,966	3	5	5	3	5	4	4	29	Assumes BTEX composition from a study by Bryan Research and Engineering, Uncertainty related to VOC in vented gas. Potential of 16,966 tVOC if non-BTEX compounds are included	**Yes**
Marine emissions											
Marine tanker loading	27,889	4	5	5	3	5	4	3	29	Represents 9ktVOC of VOC emissions from engine use. 18 ktVOC vessel sources loading, transiting etc…	**Yes**
Port facilities	6	1	5	5	3	5	4	3	26	Assumes only 0.005% loss although range can be from .0.005 to .1% Canaport emissions, does not include soon to be built Kitimat LNG	**Yes**
Total Marine	27,895										**Yes**
Pneumatic venting											
Pneumatic Instrumentation	26,041	4	5	5	3	5	4	2	28	May not include facilities under 10,000 tCO2e Overestimated in 2004 inventory, but this calculation may be higher due to above consideration Includes VOC emissions from bottled propane.	**Yes**
Chemical Injection Pumps	841	1	4	5	3	5	4	2	24	May not include facilities under 10,000 tCO2e Overestimated in 2004 inventory, but this calculation may be higher due to above consideration	**Yes**
Pneumatic total	26,882										**Yes**
Rail transport	11,748	3	5	1	5	5	3	3	25	Fairly accurate activity level. Unknown leaks from equipment. Includes VOC emissions from LPG (8,950 tVOC), and crude oil rail transport (2,798 tVOC),	**Yes**
Well abandonments	5	1	5	3	3	5	4	5	26	Based on a reports from the Orphan Well Association	**Yes**
Land applications	TBD	5	5	3	3	5	4	5	30	Not enough information to make an accurate estimation. No activity data	**Yes**
Process sewers and drains	TBD	5	3	5	2	2	3	5	25		
Total	295,803	18	22	19	18	28	23	19			

The ranking of current and new VOC emissions are summarized in the **Table Z: Summary of VOC Ranking** below. Some sources have equal ranking indicating a tie in points assigned.

Land applications are considered the priority because

- Quantification are currently unavailable or inaccurate;
- Unknown magnitude;
- Unknown impact on public health; and
- General knowledge gap,

Surface migration is considered as low priority as it has a known magnitude, but is an unrecoverable resource with low and resource growth in the near future as well as limited human exposure only to field personnel and unperceivable to the human eye.

TABLE Z: Summary of VOC Ranking

	Source	Rank
1	Land applications	1
2	Marine tanker loading/unloading	2
3	Glycol dehydration	2
4	Pneumatic instrumentation	4
5	Marine facilities	5
6	Orphaned wells and sites	5
7	Rail transport	7
8	Process sewers and drains	7
9	Bi-fuel/dual fuel combustion	9
10	Venting casing gas	9
11	Chemical injection pumps	9
12	Surface casing vent flows	12
13	Gas migration	13

9.0. PROPOSED TESTING PLAN

This section of the report outlines a proposed testing plan to improve estimation and lower uncertainty of VOC emissions from the upstream oil and gas industry. The plan accounts for both current and new VOC sources, including emission factors and activity levels and includes both research and field testing. It is understood that the testing plan is a proposition and that certain components of the plan, although necessary to accurately estimate emissions, may not be feasible. Implementation of the plan will require strict industry, SNC-Lavalin and facilitator(s) health, safety and environment (HSE) policies and procedures. Since data are sensitive, a Non-Disclosure Agreement (NDA) or Confidentiality Agreement (CA) will be required to report data or information to the general public.

9.1. Land Applications

SNC-Lavalin will contact the ERCB and environmental services companies engaged in land farming as well as oil service companies engaged in drilling and land spreading. A survey and data acquisition field campaign will be carried out to:

- Collect gas samples from treated surfaces
- Determine volumes of treated soil

This will help establish emission factors for land applications depending on the activity, whether land farming or spreading, as well as an indication of activity levels from major service companies.

The key questions to be answered are:

- What is a credible emission factor?
- What are the current activity levels for landfarming and spraying?

9.2. Marine Tanker Loading-Unloading

Marine emissions were evaluated using generic emission factors for example crude petroleum from AP-42 literature. SNC-Lavalin proposes to contact major crude petroleum transporting companies in order to assess the type of crude being loaded/unloaded into harbors as well as volumes transported. This data may also be available public in sources such as NPRI reports. This will help identify the crude type and activity level. Chemical and physical properties can be researched depending on crude type in credible sources such as Crude Monitor (Crude Quality Inc., 2013) and for those unlisted crude types or types whose properties are hard to determine, samples will be collected and analyzed.

Additionally, floating production facilities where not looked into in detail. SNC-Lavalin proposes to contact offshore operators to identify the types of vessel used and therefore components that may be emitting VOCs. Also, scanning for VOC emissions may provide a high-level emissions inventory.

Key questions to be answered may include:

- Are the characteristic VOC emissions from Canadian crude petroleum loading/unloading similar or different from emissions found in AP-42 and other literature?
- If so by how much?
- What is an adequate emission factor for floating production facilities developed from component inventory for a Canadian setting?
- What is the current level of vapor control in loading/unloading operations?

9.3. Glycol Dehydration

SNC-Lavalin proposes to test gas from glycol dehydrators venting to atmosphere to develop a typical gas composition profile. The analysis should include all possible VOCs in addition to BTEX and an extended gas analysis is recommended. Several analytical labs may be contacted to provided sampling and analysis services. SNC-Lavalin will also identify the number of glycol dehydrators operating in gas producing regions as well as natural gas processed in order to arrive at a more accurate estimate of VOC emissions in lieu of the common practice of predicting emissions using commercially available software.

Key questions to be answered may include

- Is the field emission factor and emissions profile similar to those generated by software simulations?

9.4. Pneumatic Instrumentation

The data used to calculate VOC emissions from pneumatic instrumentation venting is based on third party verified data. However, only linear facilities emitting over 10,000 tCO_2e are required to report GHG emissions to the BC government. SNC-Lavalin proposes to contact the BC Ministry of Environment to acquire raw data and process to identify production areas and determine the split between natural gas and oil as well as possible facilities that do not report because they are below the annual 10,000 tCO_2e emissions threshold.

Key questions to be answered are:

- What is the split between natural gas and oil reported venting?
- Is this split applicable to all of Canadian hydrocarbon operations?

9.5. Marine Facilities

Marine facility VOC emissions were based on classification of gas losses from low, medium and high scenarios based on natural gas throughput. This leaves a range of values for VOC emissions from LNG facilities with high variability and uncertainty.

SNC-Lavalin proposes to establish contact with LNG operators to obtain P&ID (piping and instrumentation) diagrams for the facilities and to conduct a field study. An inventory of emissions would be developed based on component count and AP-42 VOC emission factors. The field study will measure leaks during routine operations. The Canaport LNG Terminal is currently the only operational LNG terminal in Canada; the Kitimat LNG Terminal is beginning construction in the near future. As such, the field study will focus only on Canaport.

Once components have been identified from P&ID diagrams, various methods can be used to evaluate emissions in a field setting. SNC-Lavalin will use a Toxic Vapor Analyzer (TVA) to measure emissions using USEPA method 21 (USEPA, 2012). This method is used to determine VOC leaks in terms of methane equivalent using a TVA and allows for a more accurate qualification of emissions. Additional information needed to develop accurate VOC emissions includes gas analyses.

A comparison can be made using actual VOC emissions data acquired from the field and theoretical VOC emissions established using credible emission factors.

Key questions to be answered may include:

- Are the characteristic VOC emissions from Canadian crude petroleum loading/unloading similar or different from emissions found in AP-42 and other literature?
- What is an accurate VOC emission factor for Canadian facilities in terms of % loss or m^3 VOC /m^3 natural gas processed (or m^3 VOC/ barrel crude oil shipped)?

9.6. Orphaned Sites & Wells

An emission factor is critical to accurately estimate emissions from site and well abandonments. SNC-Lavalin proposes to conduct leak testing at abandoned wells/sites in collaboration with the Orphan Well Association. As soon as an abandoned site or well is located and tested for leaks, SNC-Lavalin will carry out leak testing at the site/well using a calibrated hi-flow sampler and collect gas samples for laboratory analyses to determine gas composition with a special focus on VOC stream. These will be sent to an accredited laboratory for analysis.

The key questions to be answered are:

- What is an accurate and credible emission factor for orphaned wells?
- Is it possible to establish a typical gas composition for orphaned wells?

The same methodology and analysis will be carried out for abandoned wells. These key questions would also apply to well abandonments where leakage rates after well capping have not been assessed.

9.7. Rail Transport

An accurate emission factor is critical to estimate emissions from rail transport. It is necessary to determine emission from both loading/unloading and transit.

SNC-Lavalin proposes to establish a chain of communication with major rail transportation companies such as the Canadian National Railway Company (CN), Canadian Pacific Railway Ltd. (CP) and the Alberta Department of Transportation. SNC-Lavalin will acquire the transportation itinerary to identify when and where crude petroleum shipments will take place. This step will provide a time frame of how long crude is maintained in rail cars during transit.

SNC-Lavalin will arrive at the loading terminal or facility and carry out leak identification using an IRCamera or TVA and a hi-flow sampler to measure leak rates during loading/unloading and stationary. SNC-Lavalin will also obtain information and samples as follows:

- Type of product being shipped;
- Rail car operating conditions;
- Gas and liquid samples will be collected and analyzed for chemical composition;
- Loading/unloading techniques and sources of VOC emissions vented to atmosphere; and
- Ambient conditions.

Emissions from sealed railcars about to dispatch product will be used to provide an accurate estimate of leaks during transit as. It is understood that emissions cannot be measure while the railcar is in movement so a stationary approach is necessary.

All information will be analyzed statistically to arrive at confidence intervals and most likely emission factors.

Additionally, equations in AP-42 chapter 5.2 Transportation and Marketing of Petroleum Liquids will be analyzed for validity for rail truck emission losses. The equations used in this chapter were developed mainly for marine transport. A rigorous review will elucidate any concerns or deviations these equations may have when applied to rail transport.

The key questions to be answered are:

- What is an accurate and credible VOC emission factor for equipment leaks for rail transport?
- What are the differences between field emission factors and those found in literature?
- Is there a significant variation and if so why?

9.8. Process Sewers & Drains

SNC-Lavalin will contact select oil and gas operators to solicit facility data. Data will be reviewed to determine facility type and number of sewers and drains per facility. It is understood that facilities may be grouped under typical facilities due to size or characteristics. Once typical facilities have been established, a field campaign will be carried out to assess emission from sewers and drains. Sewers and drains will be monitored for flow rates and gas composition.

Key questions to be answered are:

- What facilities have sewers and drains?
- What are the conditions and state of these sewers and drains?
- What is the emission profile of these sewers and drains?
- Is the emission factor affected by the state and condition of the sewer and drain?
- What is the composition of gas emitted from sewers and drains?
- How many process sewers, open ended-lines are directed to sewers?

9.9. Combustion – Dual Fuel & Bi-Fuel Combustion

The investigative process has shown that emission factors for stationary dual fuel engines exist however the level of activity is uncertain. SNC-Lavalin proposes to contact its oil and gas clientele base as well as PTAC members and technology vendors to survey bi-fuel/dual fuel adoption. A survey will identify what companies are developing bi-fuel or dual fuel programs as well as quantify projects. News articles reviewed represent a starting point to identify these companies and confidentiality measures should be adopted in case these companies want to remain anonymous.

This testing plan should allow for accurate values to be obtained in the field.

The key questions to be answered are:

- What is the current level of adoption for bi-fuel or dual fuel systems?
- What is a credible emission factor for these systems?
- Where are dual fuel and bi-fuel systems more commonly used?

9.10. Casing Vent Gas

SNC-Lavalin will contact the AER to solicit venting data submitted by operators. Data will be reviewed to determine what venting activities companies are reporting and select casing vent gas data to develop an emission factor. The data presented in the ERCB vent and flaring report (ERCB, 2012) does not segregate venting activities and determining venting sources or activities will require additional efforts.

SNC-Lavalin also proposes to identify wells with casing gas vents to gather samples and establish flow rates using a hi-flow sampler. The data will allow for a credible emissions factor to be determined from field testing. A statistical analysis to establish confidence intervals as well as uncertainties and standard deviations will be carried out.

Ultimately, there will be two data sources; ERCB reported vents and field data, which will be compared to determine variances. In theory, the results should be similar and the steps outlined in this section will elucidate this assumption.

Key questions that need to be answer are:

- What is the current emission factor for casing vent gas?
- Given two approaches to determine an emission factor for casing vent gas, one from reported data and another from field testing, what is the variance?

9.11. Chemical Injection Pumps

The data used to calculate VOC emissions from pneumatic chemical injection pumps is based on third party verified data. However, only linear facilities emitting over 10,000 tCO_2e are required to report GHG emissions to the BC government. SNC-Lavalin proposes to contact the BC Ministry of Environment to acquire raw data and process to identify production areas and determine the split between natural gas and oil as well as possible facilities that do not report because they are below the annual 10,000 tCO_2e emissions threshold.

Key questions to be answered are:

- What is the split between natural gas and oil reported venting from pneumatic pumps?
- Is this split applicable to all of Canadian hydrocarbon operations?
- What is the replacement level of pneumatic chemical injection pumps using solar or other power sources?

9.12. Surface Casing Vent Flows

SNC-Lavalin will contact the AER to solicit venting data submitted by operators. Data will be reviewed to determine what venting activities companies are reporting and select casing vent gas data to develop an emission factor. SNC-Lavalin will also contact other regulatory agency across Canada to solicit data for surface casing vent flows.

SNC-Lavalin also proposes to identify wells with surface casing vent flows to gather samples and establish flow rates. The data will allow for a credible emissions factor to be determined from field testing. A statistical analysis to establish confidence intervals as well as uncertainties and standard deviations will be carried out.

Ultimately, there will be two data sources; reported vents and field data, which will be compared to determine variances. In theory, there should not be much difference but the steps outlines in this item will confirm or this assumption not.

Key questions that need to be answer are:

- What is the current emission factor for surface casing vent flows?
- Given two approaches to determine an emission factor for casing vent gas, one from reported data and another from field testing, what is the variance?
- What is the difference, if any, if using data from Alberta and British Columbia as a proxy emission factor instead of using data from all the provinces?

9.13. Gas Migration

The extent to which surface migration is occurring has been estimated based on assumed failure rates and values found in literature. SNC-Lavalin proposes to retest wells in the area (eg, old and new ones) using current technology. Additionally, the proposed testing should focus on select natural gas wells as these might also experience casing failure and surface gas migration may occur.

The following key questions should be answered once the testing has been completed:

- Is the emission factor used in the CAPP 2004 inventory for conventional oil vent gas casing still valid?
- Has is it changed (eg, increased or decreased) and by how much?
- What fraction of conventional oil wells is experiencing surface casing failure?
- What fraction of conventional natural wells is experiencing surface casing failure?

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