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National Round Table on the Environment and the Economy
Table ronde nationale sur l'environnement et l'économie

Potential of Including Non-Combustion Sources of GHG Emissions in a Domestic Emissions Trading Program

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CHEMINFO

1. Executive Summary

This issue paper examines the types of emissions trading systems suitable for non-combustion sources of greenhouse gas (GHG) emissions in Canada. It presents background information and analysis of 15 non-combustion sources of GHGs which account for 141 megatonnes (Mt) of CO_2 equivalents, or 23% of the total 1995 GHG emissions in Canada. The sources studied include 13 sources defined by Environment Canada as "non-energy" sources, which account for 102 Mt of CO_2 equivalents in 1995. In addition, two other non-combustion sources of GHGs from the energy production sector are included, since they also involve fugitive and process GHG emissions.

Three primary types of emissions trading systems were considered for each of these non-combustion GHG sources: emission rights trading; substance trading; and credit trading. Various criteria were used to determine which types of trading programs would be more suitable for each situation. For each source studied, the paper discusses: the source and quantity of emissions; the nature of the emissions stream; the measurability of the emissions; options for emission reductions; and the suitability for emissions trading. The following table summarizes the key data and findings of the study.

Suitability of Trading Systems for Non-Combustion Sources

Non-Combustion GHG Source	Gas	No. of Sources	Total (kt CO_2 eq)	Emission Rights Trading	Substance Trading	Credit Trading
Upstream Oil & Gas*	CH_4, CO_2	100,000	47,350	√		√
Landfills	CH_4, CO_2	10,000	18,250	√		√
Enteric Fermentation	CH_4	30,000	15,225			√
Adipic Acid Production	N_2O	1	10,850	√		√
Undiff'd Petroleum Uses	CO_2	10-50	10,000	not analyzed		
Aluminum Smelting	CO_2, PFCs	11	9,600	√		√
Lime & Cement	CO_2	45	7,630	√		√
Livestock Manure	CH_4	35,000	5,700	√		√
Fertilizer Use	N_2O	12	4,030		√	
Ammonia (less Urea)	CO_2	10	3,800	√		√
Agricultural Soils	CO_2	250,000	2,480			
Magnesium Smelting	SF_6	<10	1,890		√	
Coal Mining *	CH_4	28	1,700	√		√
Nitric Acid Production	N_2O	9	930	√		√
Other Flurocarbons Uses	SF_6 ,PFCs, HFCs	millions	500		√	
Other	many small areas		1,450	not studied		
Total (kt CO_2 eq.)			141,385			

* Fugitive and process emissions from energy production and distribution operations

2. Introduction

2.1 Background

The NRTEE has established the Multistakeholder Expert Group on Domestic Emissions Trading to discuss the issues related to, and the potential design of, a GHG emissions trading system in Canada. As an input to the multistakeholder discussions on emissions trading, the NRTEE has identified a number of issues to be studied which address various aspects of a domestic GHG emissions trading program in Canada. One of the studies was to assess the types domestic GHG emissions trading programs suitable for various non-combustion sources of GHG emissions.

In 1995, total greenhouse gas emissions in Canada were 619 megatonnes (Mt) of CO_2 equivalents, which represents approximately 2% of the global total. Carbon dioxide (CO_2) is the primary GHG, representing 81% of total GHG emissions in Canada. The other greenhouse gases defined by the Framework Convention on Climate Change include: methane (CH_4), nitrous oxide (N_2O), and three types of fluorocarbons: hydrofluorcarbons (HFCs), perfluorcarbons (PFCs) and sulphur hexafluoride (SF_6).

The six types of greenhouse gases have different abilities to trap heat in the atmosphere and different atmospheric lifetimes. The concept of Global Warming Potential (GWP) has been developed as the relative measure of the warming effect of a greenhouse gas on the atmosphere versus the effect of carbon dioxide[1]. Each greenhouse gas has its own 100-year GWP ratio, which allows comparison between different greenhouse gases. By definition, CO_2 has a GWP of 1. Methane has a GWP of 21 and nitrous oxide has a GWP of 310. The fluorocarbons generally have high GWPs, most of which are above 1,000. The most common hydrofluorocarbon is HFC-134a, which has a GWP of 1,300. The most common perfluorcarbon is CF_4, which has a GWP of 6,500. Sulphur hexafluoride (SF_6) has a GWP of 23,900. In Canada, the total emissions of greenhouse gases are expressed as CO_2 equivalents. The high GWPs of the fluorocarbons means that very small volumes of gases can have significant global warming effects.

The GWP issue is particularly important with CO_2 and methane. Methane has 21 times the GWP of CO_2. Howver, when fully combusted, 1 kg of methane is converted to 2.75 kg of CO_2. If methane that is vented to atmosphere can be captured and oxidized to carbon dioxide, the net global warming effect can be reduced by a factor of 7.6 times.

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1 GWP is defined as the time-integrated change in radiative forcing ("warming effect") due to the instantaneous release of 1 kg of a trace gas expressed relative to the radiative forcing ("warming effect") from the release of 1 kg of CO_2. While any time period can be chosen for comparison, the 100-year GWP is used as a standard.

2.2 Purpose and Scope

The purpose of this issue paper is to analyze which of 3 primary forms of emission trading systems lend themselves to various non-combustion GHG sources. Specifically, the report delineates the non-combustion sources of GHG emissions in Canada in terms of: (i) their emissions; (ii) the nature of the emitting stream; (iii) the potential to measure, calculate and monitor GHG emissions for the purposes of emissions trading; (iv) options to reduce emissions; and (v) their potential to be included in a domestic GHG emissions trading program.

The analysis is intended to present a starting point for discussions regarding the potential design and development of a domestic trading system covering these sources. It should be noted that there are many additional issues that will have to be considered in this process which are beyond the scope of the study, including:

- the choice of which entities to regulate (large, medium, small participants);
- the appropriate basis of the system (substance, sector, type of process, technology);
- the degree of emissions coverage (what volumes are too small)
- detailed measurement, monitoring, and verification issues
- appropriate boundaries of the system (national, North American, global).

The scope of this study includes all non-combustion sources of GHGs in Canada, which totaled 141 Mt of CO_2 equivalents in 1995, or roughly 23% of the total GHGs in Canada. All emission volumes in this analysis are based on the 1995 Greenhouse Gas Inventory by Environment Canada[2]. The sources covered are summarized in the table on the next page. The GHG emissions from non-combustion sources includes GHG emissions from non-energy sources (102 Mt of CO_2 Eq) and fugitive emissions of GHGs from energy sources such as oil, gas and coal production (39 Mt of CO_2 Eq). In comparison, combustion sources of GHG emissions (led by transportation, power generation and industrial energy) accounted for about 77% of total GHGs in Canada.

Non-combustion emissions of GHGs are usually calculated using estimated emission factors applied to activity level data. In many cases, the emissions are fugitive in nature and the emission factors can have high levels of uncertainty. For many of the sources in this report, a error level of ±30% is considered quite good.

Fifteen source areas, representing 99% of non-combustion GHG emissions, were examined in this paper as listed on the following table. The "Other" category includes many smaller sources of GHG emissions such as wastewater treatment, MSW incineration, prescribed burning, composting, anaesthetics and propellants, which

2 Jaques, A., et al, "Trends in Canada's Greenhouse Gas Emissions (1990 to 1995)", Environment Canada, April 1997.

collectively account for about 1% of total non-combustion emissions. These sources were not assessed in this report.

Canada's Non-Combustion Sources of GHG Emissions, 1995

(Includes Fugitive and Process Emissions of CO_2 and Methane from Energy Sources)

Non-Combustion Source	CO_2 (kt)	CH_4 (kt)	N_2O (kt)	Others* (kt)	Total (kt CO_2 eq)
Upstream Oil & Gas*	10,600	1,750	0		47,350
Landfills		869	0		18,250
Livestock - Enteric Fermentation		725	0		15,225
Adipic Acid Production			35		10,850
Other Non-Energy Petroleum Uses	10,000		0		10,000
Aluminum Smelting (CO_2 & PFCs)	3,600		0	1	9,600
Lime, Limestone & Cement	7,630		0		7,630
Livestock - Manure		271	0		5,700
Fertilizer Use			13		4,030
Ammonia (less Urea)	3,800		0		3,800
Agricultural Soils	2,480		0		2,480
Magnesium Smelting (SF_6)			0	<<1	1,890
Coal Mining *		82	0		1,700
Nitric Acid Production			3		930
Other Uses of SF_6, PFCs and HFCs			0	3	500
Other (many smaller sources)	490	15	0		1,450
Total (kt actual)	38,600	3,712	51	n/a	
Total (kt CO_2 eq.)	**38,600**	**77,952**	**15,810**	**~9,000**	**141,385**

Source: adapted from Environment Canada, *Trends in Canada's Greenhouse Gas Emissions 1990-1995*

* Fugitive and process emissions from energy production and distribution operations

A significant portion of these non-combustion GHG emissions are made up of sources emitting GHGs other than carbon dioxide. Methane is the largest contributor (on a CO_2 equivalent basis) to non-combustion GHG emissions, accounting for about 55% of the 141 Mt total, while carbon dioxide accounted for only 28%. Nitrous oxide and the various fluorocarbons accounted for the remainder.

Fugitive and process emissions from energy (oil, gas and coal) production accounted for roughly 34% of the total non-combustion emissions. Various industrial sources accounted for another 34% of the total. These include non-ferrous metals (aluminum and magnesium) production, lime kilns (including kilns at cement and kraft pulp and paper mills), and the petrochemicals and chemicals industry (i.e., adipic and nitric acid production). Approximately 17% of non-combustion GHG emissions originate from agricultural sources, namely enteric livestock fermentation, manure decomposition, fertilizer application and soils. Thousands of landfills across Canada contribute

approximately 13% to the total. Other non-combustion emissions result from the use of a variety of fluorocarbon gases: HFCs for refrigerants, SF_6 in electrical switchgear and PFCs for various cleaning applications.

2.3 Criteria for Evaluating Potential of GHG Emissions Trading[3]

A number of criteria were applied to the various GHG emission sources that were the focus of this study. The various criteria were developed by Dr. Erik Haites of Margaree Consultants Ltd. These criteria were used to determine if the specific GHG emission sources were amenable to any of the following GHG emissions trading programs:

1. emissions rights trading;
2. substance trading; and
3. credit trading.

2.3.1 Emissions Rights Trading

An emissions rights trading system limits aggregate emissions of a greenhouse gas by specified sources at the point of release to the atmosphere. An annual cap on specified greenhouse gas emissions by the regulated sources is established. Allowances equal to the annual cap are allocated to participating sources. Each source is required to monitor its actual emissions and to remit allowances equal to its actual emissions to the regulator. Due to the cost of monitoring actual emissions, participation probably would be limited to utilities and large industrial sources. This limitation however, may miss a significant fraction of the total emissions and may have to be complemented by policies to address GHG emissions from smaller sources.

2.3.2 Substance Trading

An allowance trading system can be implemented for substances, such as HFCs, the carbon content of fossil fuels and the nitrogen content of fertilizers, that are ultimately emitted as greenhouse gases. An annual cap on the total quantity of the substance consumed (production + imports - exports) in the country is established. All producers, importers and exporters of the substance, and products containing the substance, are required to participate in the trading system.

A substance trading program is essentially a quota on consumption of the regulated substance. In general, it is important to implement an emissions cap as close as possible to the point at which emissions occur, to provide the widest possible range of mitigation options. The main effect of a substance trading system is to change the prices of products containing the substance. Price increases for fertilizers due to a nitrogen content trading

3 Much of this section was provided by Dr. Erik Haites, Margaree Consultants.

system induce farmers to change their patterns of fertilizer use. Similarly, price increases for fossil fuels due to a carbon content trading system induce customers to switch to less carbon-intensive fuels and to implement energy conservation measures. And price increases for HFCs induce a shift to substitutes.

2.3.3 Credit Trading

In a credit trading system a source can create "credits" by documenting emission reductions achieved. The credits can be sold to other sources to use for regulatory compliance under specified conditions. Credit creation and use are voluntary. Sources may choose to buy credits if they are less costly than alternative compliance options.

A credit trading system supplements voluntary or regulatory policies. A package of voluntary and regulatory policies and measures would be implemented to meet the national greenhouse gas emissions limitation commitment. If credit trading is allowed, some sources reduce their emissions below the level required by the applicable voluntary and regulatory policies and measures. Other sources buy credits to achieve compliance with the voluntary or regulatory policies and measures under specified conditions.

The following table summarizes the key criteria used to assess the suitability of various trading programs for non-combustion GHG sources.

Evaluation Criteria to Determine Suitability for Inclusion in GHG Emissions Trading Programs

Emissions Rights Trading	Substance Trading	Credit Trading
• actual emissions can be measured or calculated accurately at reasonable cost by the sources	• the substance is a good proxy for actual GHG emissions	• actual emissions can be measured or calculated accurately at reasonable cost by the sources
• sources are able to implement measures to change their actual emissions	• the quantity of the substance can be measured or calculated accurately at reasonable cost	• sources are able to implement measures to change their actual emissions
• a relatively large share of the total emissions of this gas/source category can be controlled by regulating a reasonable number of sources	• production, sale or use of the substance can be controlled by regulating a reasonable number of entities	• a realistic baseline for emissions in the absence of the emission reduction actions can be defined
	• a relatively large share of the total emissions of this gas/source category can be controlled by regulating a reasonable number of entities	• a relatively large share of the total emissions of this gas/source category can be controlled by regulating a reasonable number of sources

Some gases/sources lend themselves to more than one form of GHG emissions trading. In these instances, the gases/sources were compared on the basis of the share of emissions covered (i.e., higher coverage is better) and number of participants (fewer is better). For example, a trading program for the carbon content of fossil fuels will cover a larger share of total energy-related CO_2 emissions with fewer sources than either an emissions rights program or a credit trading program for CO_2 emissions by large industrial, commercial and institutional sources.

2.4 Methodology

To prepare this study, CHEMinfo drew upon information gathered in support of a previously completed CHEMinfo study entitled, *Powering GHG Reductions Through Technology Advancement*, which was completed for Environment Canada in April of 1998. As mentioned earlier, that study discussed the respective non-energy emission sources in Canada, the options to reduce their emissions and the research and development necessary to advance these options so that they are technically and economically feasible. The content of the final report for that study was drawn upon in several instances to assess the emissions trading potential of the various non-energy GHG emitting sources. In addition, information contained in the reports, journal articles, interviews notes, etc. that were gathered/developed in support of the Environment Canada study were also utilized to incorporate specific information pertinent to the assessment of the emissions trading potential of the various non-energy GHG emitting sources.

Three specific GHG emitting sources were not covered in CHEMinfo's previous study for Environment Canada: (i) soils; (ii) oil & gas operations; and (iii) coal mining. Additional research was conducted to: characterize their emissions; identify and assess options to reduce their GHG emissions; and to describe their industry structure. Emissions from oil & gas production and distribution operations and coal mining are mostly fugitive (non-combustion) CO_2 and methane emissions that Environment Canada includes under energy sources.

Approximately 15 interviews were conducted during the course of this study to gather information that was not available through CHEMinfo's previous study for Environment Canada. This information was focused on a number of topics, for instance: uncertainty levels for GHG emission estimates attributed to certain emission sources; activity data/industry structure in the respective non-energy "sectors"; and data pertaining to the measurement/monitoring of GHG emissions from those "sectors". In addition, several interviews were conduced to gather information on those GHG emission sources which CHEMinfo had not previously assessed.

CHEMinfo worked in conjunction with Dr. Erik Haites of Margaree Consultants to develop the set of criteria upon which to apply to the various GHG emitting sources to determine their applicability for inclusion in a domestic emissions trading program and the specific trading scheme most appropriate. Once the criteria were developed, CHEMinfo and Dr. Haites applied these criteria to the 15 non-combustion sources examined in this study.

3. Upstream Oil & Gas

3.1 Source and Quantity of GHG Emissions

The Canadian oil & gas sector produces most of the fossil fuel that is the source of the majority of greenhouse gas emissions from combustion sources in Canada. However, the oil & gas sector also is a significant source of process or fugitive greenhouse gas emissions from non-combustion activities. Methane and carbon dioxide are two naturally occurring greenhouse gases that are emitted from various sources within the oil & gas sector. According to data compiled for Environment Canada's 1995 Greenhouse Gas Inventory, the oil & gas sector emitted an estimated 47,350 kt of CO_2 equivalents. This represents about 8% of total Canadian GHG emissions and is the largest sector contributing to non-combustion GHGs in Canada, accounting for 34% of the total.

Fugitive Emissions from Oil & Gas Operations

Source	CO_2	CH_4	Total
	(kt)	(kt)	(kt CO_2 Eq)
Oil Production	0	500	10,500
Gas Production	10,600	600	23,200
Gas Transmission	0	500	10,500
Gas Distribution	0	150	3,150
Total	10, 600	1,750	47,350

Source: 1995 Greenhouse Gas Inventory

3.1.1 Emission Sources

The largest source of fugitive GHG emissions from the oil & gas sector is natural gas production. In 1995, a total of 193 billion m^3 of natural gas was produced in Canada. Both methane and carbon dioxide are emitted from this source. An estimated 600 kt of methane is emitted from the collection and processing of natural gas (equivalent to about 12,600 kt of CO_2). The sources of this methane are the 45,000 natural gas wells and roughly 650 natural gas processing plants operating in Canada in 1996.

Carbon dioxide is present in raw natural gas at levels as high as 26%, and must be removed at the gas processing plant to meet pipeline specifications. The amount of CO_2 emitted from natural gas processing is calculated at 10,600 kt, based on an assumed average CO_2 content of 7%. These emissions come from the estimated 650 natural gas processing plants in Canada. Most of these emissions are concentrated in Alberta, which

has 550 major installations processing natural gas and produces 84% of total Canadian gas production. BC and Saskatchewan are the other two significant provincial sources.

In crude oil production, an estimated 500 kt of methane was emitted from processing activities. These include fugitive leaks, non-combustion equipment exhaust, and production upsets. Roughly 70% of calculated methane emissions from crude oil production come from the processing of heavy oil, despite the fact that heavy oil accounts for only 20% of total production. There were an estimated 55,000 oil wells operating in Canada at the end of 1996. Several wells usually are connected to a crude oil battery where gases are separated from liquids. Again, methane emissions from crude oil are concentrated in Alberta, which has 85% of Canadian oil production. Saskatchewan is the second largest provincial source, having 10% of Canadian oil production.

Regional Distribution of Oil & Gas GHG Emissions

	Oil Production	Gas Production	Gas Transmission	Gas Distribution
Alberta	85%	84%	37%	17%
Saskatchewan	10%	5%	23%	4%
BC	2%	11%	4%	13%
Manitoba	--	--	17%	3%
Ontario	--	--	16%	35%
Quebec	--	--	2%	21%
Atlantic Canada				

Source: Natural Resources Canada

In long-distance natural gas transmission, an estimated 500 kt of methane was emitted. The principal source of emissions is fugitive leakage and pipeline and compressor station blowdown. The country's network of natural gas pipelines spans from BC to Quebec and there are methane emissions from each province. Alberta has the largest volume of natural gas pipelines and accounts for 37% of transmission emissions. Since the major volume of gas flows east from Alberta to Ontario, the provinces of Saskatchewan, Manitoba and Ontario have decreasing shares of transmission pipeline methane emissions.

The natural gas distribution networks supplying end users have relatively low levels of methane losses. An estimated 150 kt of methane was emitted from natural gas distribution network losses. The largest source of these emissions is in Ontario, which has the largest volume of marketable natural gas consumption in Canada, due to the large population and industrial base. The Canadian Gas Association, which represents natural gas distribution utilities reports that total methane losses are 0.13% of marketable production, which in 1995 was 148 billion m^3. This marketable production volume number is lower than the total Canadian production cited above, due to exports.

3.1.2 Industry Structure

There are an estimated 450 exploration and production companies operating in the Canadian oil & gas sector. This sector has a high level of concentration, due to the high degree of capital investment required and its risky nature. The top 8 Major companies account for about half of total production and the next 18 Senior companies add another 25%. Together, the two groups of 26 companies (6% of the total companies) produce 76% of the oil & gas in Canada.

Concentration in the Canadian Oil & Gas Sector

(Exploration and Production Companies)

Type of Company	Production Range (000's BOE/d)	Number of Companies	Per Cent Production
Major Companies	100-400	8	51%
Seniors	20-100	18	25%
Mediums	5-20	27	8%
Juniors	2-5	47	6%
Others	<2	350*	10%
Total		450*	100%

Source: Human Resources in the Upstream Oil & Gas Industry, HRCanada

Notes: * estimate; BOE/d - Barrels of Oil Equivalent per day (an energy based conversion)

Natural gas transmission is controlled by less than 5 large companies who are regulated by the provincial and federal governments. Two significant pipeline companies are Trans Canada Pipelines of Calgary and Westcoast Transmission of Vancouver.

There are less than 10 major natural gas distribution utilities in Canada that supply gas to industrial, commercial and residential end users. Each company operates specific pipeline networks based on distribution rights for specific regions. Some of the major gas utilities include: Consumer's Gas (south central Ontario), Union Gas (southwest Ontario), and Gaz Metropolitain (Quebec).

3.2 Nature of GHG Emissions Stream

In oil and gas production, fugitive methane emissions can occur at various points from the wellhead through the battery to the gathering systems. Most methane gas present in oil is emitted from wellheads, separators, venting and flaring and from other treatment equipment. Some methane emissions come from crude oil storage tanks.

In natural gas production, processing plants are used to remove impurities such as carbon dioxide, hydrogen sulphide and water from the raw gas. Hydrogen sulphide and CO_2 are removed from raw gas using amine treatment systems in gas processing plants. The CO_2 is separated from the hydrogen sulphide gas and released in a point source. Methane emissions, however, are fugitive and can come from many points between the wellhead and the transmission pipeline.

In natural gas transmission, methane emissions come from equipment at compressor stations (blowdown vents, compressor packing, seals and valves) or from leaks along the pipeline. There are no true point source emissions. Fugitive emissions from natural gas distribution come from equipment at gate stations and pipeline leaks.

3.3 Potential for Measuring, Monitoring and Calculating the GHG Emissions Stream

In oil production, the methane content of the oil in any well is known from chemical analysis upon well completion. However, since a large portion of methane emissions in the wellhead, collection and processing system are fugitive it is very difficult to measure emissions on a regular basis. Rough emission factors are used for the entire sector, not for individual sites.

The same is true for methane emissions from natural gas production. Methane emissions occur at various parts of the system and are not present in a measurable point source stream. Calculation of losses tends to be done based on calculations in methane mass balances. Since the amount of methane in and out of a processing system is calculated based on gas flow rates and gas composition measured by gas chromatographs, the measurement error could easily be greater than the magnitude of the methane loss.

Carbon dioxide emissions from natural gas stripping are measurable, however, since CO_2 is stripped out of natural gas in a processing plant and would be present in a single point source off-gas stream.

Methane emissions from transmission and distribution systems are somewhat easier to calculate from mass balances, because the volumes are larger and more accurate metering systems are used.

3.4 Options to Reduce GHG Emissions

For carbon dioxide stripped from natural gas, there are few options for reducing emissions. The gas must be removed at the processing plants to meet pipeline specifications. Often these plants are decentralized and the volumes of carbon dioxide are too small to justify long distance CO_2 pipelines for capture, recovery and possible sequestration.

For methane emissions from oil production, and natural gas production, transmission and distribution, there is always room to improve the operating practices to reduce system losses. Better leak detection and repair programs, capture and recovery of system blowdowns, and better flaring systems can be used. Since methane emissions from natural gas companies represent losses of marketable product, there is already a strong incentive in place to reduce emissions.

3.5 Suitability for GHG Emissions Trading

A GHG emissions trading program would be difficult to impose on carbon dioxide emissions from natural gas, because carbon dioxide must be removed from the natural gas and there are currently no economically feasible control options available. However, the CO_2 stream is a point source that is measurable with some accuracy.

It would be difficult to establish emission rights trading or credit trading programs for fugitive methane emissions from oil production, and the production, transmission, and distribution of natural gas because of the difficulty of accurate calculations. Substance trading programs make no sense for these sources, since the methane substance is either a small part of, or the major constituent of, the marketable product.

An emission rights or credit trading program is more suitable for gas transmission and distribution operations, because the emissions are more easily calculated on an overall basis and the number of entities is lower. Since throughput can be variable, a rate-based methane credit trading system would likely be preferable, since methane emissions are often expressed as a per cent of throughput or marketable production. This would be give transmission and distribution utilities additional incentive to reduce losses.

4. Landfills

4.1 Source and Quantity of GHG Emissions

Methane, carbon dioxide, minor amounts of oxygen and nitrogen, trace amounts of hydrogen sulphide, hexane, 1-1-1-trichloroethane, methylene chloride, and other volatile substances result from the decomposition of solid waste and are released from waste-containing landfills. This mix of substances is referred to as landfill gas (LFG).

In 1995, landfills accounted for a total of 869 kilotonnes (kt) of CH_4 emissions (18,249 kt of CO_2 equivalent) which represented approximately 13% of total non-combustion GHG emissions in Canada as well as 3% of total Canadian GHG emissions.

Trends in CH_4 Emissions From Landfills in Canada

Year	CH_4 Emissions	CO_2 Equivalent Emissions
	(kilotonnes)	
1990	821	17,241
1991	812	17,052
1992	826	17,346
1993	845	17,745
1994	855	17,955
1995	869	18,249

Source: Environment Canada, Trends in Canada's Greenhouse Gas Emissions 1990-1995.

Environment Canada's estimates do not explicitly detail the CO_2 that is directly emitted from landfills, nor the CO_2 that is emitted due to the flaring of some of the methane. It is estimated these emissions contribute approximately 4 kt of CO_2 annually. These emissions are not outlined in the table above. It is believed that Environment Canada accounts for these emissions at other points in the GHG life cycle and it is assumed they are included in their annual GHG emissions inventory.

4.2 Nature of GHG Emissions Stream

Methane is generated from landfills by the anaerobic decomposition of waste organic matter by anaerobic bacteria. Under anaerobic conditions, the products of decomposition are CH_4, CO_2 and stabilized organic material.

There are upwards of 10,000 landfill sites in Canada[4]. While some jurisdictions have information on landfill sites they manage, a comprehensive inventory of landfill sites in Canada has yet to be conducted. Such an inventory would be useful to identify and better characterize GHG emissions, and establish priorities for action plans in this area. There are several different sizes of landfills, with the GHG emissions profile varying within each of these categories.

Estimated Emissions and Reduction Potential From Different Landfill Sizes

Size of Landfill (million tonnes of waste)	Estimated Number of Landfills in Canada	Range of Annual Methane Production	Portion of Total (869 kt/yr) Methane Generated
		(kt/yr/landfill)	
Small (less than 2)	7,000 to 10,000	0 to 10	35%
Medium (2 to 8)	30 to 100	5 to 75	50%
Large (greater than 8)	10 to 20	10 to 120	15%
Total / overall*	**~10,000**		**100%**

Estimates are very rough and are meant to indicate the weight of emissions from different sized landfills.

While there are thousands of individual landfills located in Canada, CH_4 emissions are concentrated among a handful of sites. For instance, there are approximately 100-200 medium and large sized landfills in Canada, which combined emit approximately 65% of Canada's CH_4 emissions from landfills (this is after some CH_4 is captured by these landfills).

Typically the ratio of CH_4 to CO_2 is approximately 50:50 on a volume basis in LFG, but can range substantially from one landfill to another, as well as over the life span of a landfill site. A portion of the CH_4 available in LFG is already being captured and oxidized to CO_2. As of December 1995, there were approximately 25 to 30 landfill sites in Canada where LFG extraction systems (see options to reduce GHG emissions below)

4 Jaques, A., et al, "Trends in Canada's Greenhouse Gas Emissions (1990 to 1995)", Environment Canada, April 1997.

have been installed, or were under construction. The amount of CH_4 reduction has been estimated at 270 kilotonnes or 5,700 kilotonnes of CO_2 equivalent[5]. At nearly half of these sites, CH_4 is collected and utilized as an energy source for heating purposes or for generation of electricity. At the other sites, the LFG is flared.

Most of the very large sites (landfills with greater than 8 million tonnes of waste capacity) already have gas collection and treatment facilities. There may be a few very large sites which have yet to install collection and treatment systems. A small percentage of the medium sized landfills (between 2 and 8 million tonnes of waste capacity) have installed collection and treatment systems. It is estimated there may be between 30 and 100 sites across Canada in this category. A low portion (less than 5%) of the thousands of small sites (less than 2 million tonnes of waste capacity) across Canada have installed gas collection systems.

4.3 Potential for Measuring, Monitoring and Calculating the GHG Emissions Stream

Environment Canada estimated CH_4 emissions from landfills in Canada by utilizing the U.S. EPA's landfill gas generation model and data on the quantity of refuse deposited in Canadian landfills over each of the past 50 years. This model takes several characteristics into account to estimate CH_4 emissions such as mass of refuse and age of the landfills. Based on this methodology, Environment Canada has indicated that the uncertainty factor for this emission estimate is +/- 30%, which is one of the more accurate emission estimates among non-energy GHG sources.

As the majority of CH_4 emissions are concentrated among a relatively small number of landfills (i.e., 100-200), there is potential to assess the progress of CH_4 emissions reduction from landfills by monitoring these landfills and their attempts to reduce CH_4 emissions. These larger landfills account for the majority of GHG emissions.

4.4 Options to Reduce GHG Emissions

There are several different technologies that are available to reduce CH_4 emissions at landfills. While many of the landfills have already adopted some of these technologies, additional CH_4 emission reductions are possible at several of the individual landfills and among the sector as a whole. Some options to reduce GHG emissions from landfills, include: flaring the methane; collecting the methane in the LFG and using as a fuel; and reduced waste generation.

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5 Hickling, Emcon Associates, "Options for Managing Emissions From Solid Waste Landfills", 1994, Prepared for Solid Waste Management Division and Air Issues Branch, EPS, Environment Canada.

The basic technology infrastructures for addressing emissions and utilizing methane available at large landfill sites already exists and has been applied successfully at sites in Canada, the United States and other countries. However, technology to lower the costs of addressing small sites where the rate of methane is low needs to be researched and developed.

The costs to reduce GHG emissions from landfills relate to the level of emissions reduction desired, as well as the technology options adopted. A low cost option to achieve 20 to 30% reduction is to capture, collect and flare (i.e., oxidize) the methane generated from the largest sites. This option has no associated direct financial incentive. Some of the landfills generate enough methane to support a larger investment in gas utilization equipment, such as electrical generating equipment. This option is more capital intensive but can provide a return to investors, through sale of the electricity. The greatest portion of the costs in achieving a higher (10 to 20% more) level of GHG reduction is associated with reducing emissions from thousands of small landfills spread across Canada. Even flaring at these sites could cost hundreds of millions of dollars.

4.4.1 Flaring

Landfills (or celled portions of the landfill) are usually capped with an impermeable layer to prevent gas from escaping, and to prevent oxygen from infiltrating the landfill, thereby affecting the anaerobic methane-generating bacteria. Thick layers of soil, clay and synthetic polymeric geomembranes are used to create capping layers and retaining walls around the site. These precautions maximize the efficiency of the collection system.

Gas collection systems consist of drilled wells or horizontal trenches, interconnecting pipes and a compressor creating negative pressure on the system that ensures gas flows to a central collection point. The efficiency (recovery of methane versus that contained in site) of the system will vary depending on the design. While some well designed systems can achieve close to 100% efficiency, 70 to 80% is more typical. Gas can also be recovered from unsealed landfills with lower efficiency.[6]

Flaring is a simple and low cost option to reduce methane emissions from landfills. This reduction option can achieve a significant reduction in GHG emissions since the methane is oxidized to carbon dioxide, reducing the overall global warming potential of the emitted gas. The efficiency of the flare system can reach as high as 98% methane control. A disadvantage of this system is that the methane is not used as a fuel. Flaring can be used as a stand-alone control option or as a back-up with energy recovery systems. Energy recovery systems which cannot fully utilize the methane fuel may need to flare the stream intermittently.

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6 US EPA., "Options for Reducing Methane Emissions Internationally, Volume I: Technology Options for Reducing Methane Emissions, Report to Congress", July 1993.

Flaring can occur in an open or closed flare. Closed flaring systems offer better control of air (oxygen) and gas flow to maximize the efficiency of the combustion process and achieve the greatest GHG reduction. Closed flaring is aesthetically preferred, and can be more easily maintained and tested for operating efficiency and emissions. However, the cost of an open flaring system can be 5 to 10 times less than closed units.

Estimated Capital and Operating Costs For Flaring Systems

(order-of-magnitude estimates only - will vary substantially site to site)

Landfill capacity	Capital Costs	Annualized Capital	Annual Operating	Total Annualized Costs
Less then 2 million tonnes	$100,000	$20,000	$3,000	$23,000
Between 2 and 8	$150,000	$23,000	$4,600	$27,600
Greater than 8	$200,000	$35,000	$7,000	$42,000

Based on cost equations developed by U.S. EPA[7], and simplifying assumptions on methane flow rate from landfills.
Exclude collection system.

On a weight basis, the GHG reduction level possible with flaring systems is 87% of the methane oxidized. (Carbon dioxide generated from oxidizing methane lowers the GHG reduction potential). The reduction efficiency of the process is also affected by the capture efficiency of the LFG. This may lower overall GHG reduction to approximately 30 to 70% for a particular site, and will be influenced by the design of the gas containment and collection systems.

4.4.2 Methane Utilization

The methane stream collected from landfill gas, instead of simply being flared, can be used as an energy source for applications as:

- electricity generation;
- co-generation of steam and electricity;
- supply into natural gas distribution systems for heating; and
- compressed methane for transportation fuel.

The larger landfill sites in Canada are more likely to have installed electricity generating equipment. Medium sized facilities tend to utilize the LFG for heating, often selling to a

7 Hickling, Emcon Associates, "Options for Managing Emissions From Solid Waste Landfills", 1994, Prepared for Solid Waste Management Division and Air Issues Branch, EPS, Environment Canada.

nearby industrial user. In many cases, these landfills have the option of flaring the LFG if customer requirements are less than the generation rate. Smaller facilities, generally with lower rates of production merely flare the LFG, without any energy recovery. Approximately 40% of the landfills with collection systems operated flaring systems only in Canada in 1995.

4.4.3 Reduced waste generation and landfilling

Reducing waste can reduce the amount of methane emitted from landfills. There are several general approaches to achieving lower waste generation and landfilling. One approach is to divert the recycling of organic waste products that generate methane during anaerobic degradation in landfills to municipal composting systems which capture methane. Another approach is to increase the use of alternative disposal methods, such as aerobic composting and waste incineration (which may produce CO_2 but lesser quantities of methane).

4.5 Suitability for GHG Emissions Trading

Credit trading was determined to be the most applicable emission trading program for GHG's released from landfills. Both large and small landfills could be included in the credit trading program. However, large landfills would verify their credits by installing meters (if not installed already) while small landfills would have their credits verified through the application of emission factors and the accepted landfill gas generation model[8]. Due to the fact that the amount of waste being shipped to landfills is continually increasing, a credit trading program using an emission rate baseline would be preferred over a baseline of total GHG emissions. This would provide more flexibility to landfills in the future to continue to expand the size of their landfill yet still undertake measures to obtain credits for reduced GHG emissions.

The majority of GHG emissions (i.e., approximately 65%) originate at a relatively small amount of landfills in Canada, estimated to be between 100 and 200 sites. The remaining 35% of emissions are dispersed among thousands of sites. Therefore, a large proportion of the total emissions from this source can be controlled/monitored by addressing a relatively small proportion of the total landfill population.

Many of the larger sources (i.e., large and medium sized landfills) have installed methane capture systems so that relatively accurate estimates of potential and actual emissions can be made. Landfills have one of the more accurate (represented by uncertainty levels) GHG emission estimates attributed to non-energy GHG sources as reported in Canada's latest GHG inventory. Therefore, a relatively accurate projection of future GHG emission from this source could be made if the available GHG mitigating options were not

8 US EPA, Scholl Canyon landfill gas generation model.

installed. This would allow a process where relatively accurate credits for action taken (i.e., GHG mitigated) could be estimated.

An emissions rights trading program is also amenable to landfills. The specific characteristics of landfills in Canada fulfill the respective criteria outlining appropriate sources for an emissions rights trading program. However, the credit trading program was deemed most appropriate because of the potential to accurately estimate credits for action taken to reduce GHG emissions. However, it should be noted that emission reductions could be relatively easily verified at large and medium sized landfills, for the purposes of an emissions rights trading program. The potential of this type of emissions trading program should not be discounted.

The substance trading program is discounted because there is no substance that is an appropriate proxy for the GHG emissions from landfills. The logical candidate would be the quantity of refuse handled over a specific time period. However, GHG emissions vary widely among the different types of refuse that are sent to landfills. Therefore, applying data on the quantity of refuse to estimate GHG emissions/reductions would not be accurate. Instead data would need to be developed on the quantity of the different types of refuse that are landfilled. This information gathering process may be quite costly and would still not yield accurate estimates of GHG emissions, especially when one considers that many landfills have metering systems to measure GHG emissions.

5. Enteric Fermentation

5.1 Source and Quantity of GHG Emissions

In Canada, beef cattle represent the majority of CH_4 emissions attributed to enteric fermentation. This large contribution is due to the size of the herd population and the high emission rates per head versus other livestock such as swine, horses, etc. Poultry contribute negligible amounts of enteric CH_4 emissions. In 1995, enteric fermentation accounted for a total of 725 kt of CH_4 emissions (15,225 kt of CO_2 equivalent) which represented approximately 11% of total non-combustion GHG emissions in Canada as well as 2.5% of total Canadian GHG emissions.

Trends in CH_4 Emissions From Livestock Manure in Canada

Year	CH_4 Emissions	CO_2 Equivalent Emissions
	(kilotonnes)	
1990	646	13,566
1991	650	13,650
1992	641	13,461
1993	671	14,091
1994	701	14,721
1995	725	15,225

Source: Environment Canada, Trends in Canada's Greenhouse Gas Emissions 1990-1995.

Both ruminant (e.g., cattle, sheep) and non-ruminant (e.g., swine, horses) agricultural livestock generate CH_4 emissions. Most of the CH_4 is generated from ruminant animals, in which microbial metabolism of nutrients is the major source of the gas[9].

5.2 Nature of GHG Emissions Stream

As will be the case with other agricultural GHG emissions, there are thousands/millions of sources attributed to enteric fermentation in Canada. As mentioned, beef cattle are the primary sources of these emissions. There were approximately 12.4 million beef cattle in Canada in 1995, with 3 to 4 million on feedlot or newborns. The remainder are on range feeding (which makes management more difficult and expensive).

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9 Jaques, A., et al, "Trends in Canada's Greenhouse Gas Emissions (1990 to 1995)", Environment Canada, Page, 49, April 1997.

Domestic Livestock Population, Related Enteric Fermentation GHG Emissions in 1995

	Population 1995	CH_4 Emissions	CO_2 Emissions
	(million)	(kt CH_4)	(kt CO_2-Eq)
Beef cattle	12.4	563	11,800
Dairy cattle	1.3	133	2,800
Swine	11.9	19	400
Sheep, goats	0.7	5	100
Horses, mules,	0.4	5	100
Poultry (all types)	116.1	neg.	neg.
Total		**725**	**15,200**

Source: Environment Canada, Trends in Canada's Greenhouse Gas Emissions 1990-1995.

Many factors influence annual CH_4 emissions from enteric fermentation, including temperature, diet, animal population, animal size, feed additives and livestock management practices. Emissions are affected by the efficiency at which the animal utilizes feed. This will vary on many factors, such that there is substantial variance from different animals or various animal segments.

5.3 Potential for Measuring, Monitoring and Calculating the GHG Emissions Stream

Environment Canada uses several different emission factors, based on different varieties of cattle, pigs, etc., to develop CH_4 emissions attributed to enteric fermentation. Due to the wide dispersal and types of sources, emission factors are necessary to develop emission estimates.

In order to estimate future reductions in CH_4 emissions from the adoption of technologies or management practices (see below), emission factors will have to be developed which take into account the reduction in CH_4 emissions that can be attributed to that technology or management practice. For instance, CH_4 emission factors would have to be developed for beef cattle that were not injected with steroids as well as CH_4 emission factors for beef cattle that have been injected with steroids. Credits can then be obtained by adopting the management practice of injecting steroids if this practice was not used in 1990 and since has been adopted. Of course, verification of this method remains an issue.

5.4 Options to Reduce GHG Emissions

Technologies outlined in this section which can reduce the amount of CH_4 emitted from livestock include: greater use of feed additives (e.g., ionophores, antibiotics); steroid implants; improved livestock management and feeding practices; and bioengineering. All of these technologies and practices increase the production of milk or meat in relation to the amount of feed utilized or time taken and so achieves CH_4 reductions.

Examples of Cattle Methane Emission Reduction Options

Dairy Cattle	**Reductions Per Head**
Management practices that improve productivity	10 to 15%
Use of bST hormone to increase production	3 to 7%
Beef Cattle	
Management practices that improve productivity (improve cow-calf sector reproductive performance)	20 to 35%
Improve efficiency using ionophores	5 to 15%
Steroid implants on range cattle	<5%

The costs of applying various techniques are difficult to quantify, while the benefits can be significant. In some cases the costs provide immediate financial gain for producers - (e.g., feed cost reductions). These may be offset by increased labour, land costs and materials.

5.4.1 Management Practices

There are many management practices available to increase the productivity of cow-calf operations. Animal nutrition programs can be applied to some degree by all owners to achieve increases in productivity and reductions in CH_4 emissions.

Nutrition related problems contribute to low pregnancy rates (therefore low weaning percentages), and difficulty in getting cows to calve at 24 months. In forage based production programs (as may be the case in many western Canadian operations), producers can improve nutritional management by:[10]

- assessing soil conditions (through proper testing) to determine fertilizer requirements for their forage;
- assessing forage quality to determine supplementary nutrients (minerals, proteins, etc.) required; and
- eliminating toxic plants that can influence animal productivity.

10 Ibid

It is estimated that these and other management techniques (such as artificial insemination to ensure high pregnancy rates, veterinary care, vaccinations) can theoretically increase productivity by 20 to 35%, and achieve similar reductions in GHG emissions.

5.4.2 Ionophores

Ionophores are complex molecules which can modify the movement of ions across biological membranes and can therefore affect the metabolism of various microbes. Ionophores are incorporated in ruminant animal feeds to increase the feed-efficiency (production per unit of nutrient), as well as assist in control of diseases. It is estimated that 30 to 40% of the total Canadian cattle population already use ionophores. Over 90% of the beef cattle that are in feedlots use ionophores. However, beef cattle that are range grazing are not typically using ionophores. Industry suppliers of ionophores estimate 50% of dairy cattle use this feed additive.

Ionophores can reduce methane emissions, although the exact amount per head is difficult to quantify and is dependent on many factors. One Canadian researcher claims reductions of 8 to 10% were observed upon initial ionophore treatment.[11] Ionophores reduce CH_4 emissions by increasing the efficiency of feed utilization and therefore overall productivity. Livestock on ionophores can produce more product (i.e., milk, meat) faster and with less feed. This results in a lower amount of CH_4 emissions per unit of production.

5.4.3 Hormones and Steroids

Bovine somatotropin (bST) is a naturally occurring growth hormone found in cattle. Over the last couple of decades, the ability to synthesize the hormone using recombinant DNA techniques has increased the availability of the product and lowered its price. Studies indicate that bST injections in lactating dairy cows can increase milk production and lower methane emissions by nearly 10%[12].

Anabolic steroids are effective in increasing the rate of weight gain and improving feed conversion in beef cattle. Small pellets of steroids are often implanted under the skin of the animal's ear. The implants will increase the rate of weight gain by 10 to 15% and improve the feed efficiency by 5 to 10%[13]. As a result, animals generate less CH_4 over their lifetime. A large portion (as high as 80%) of feedlot beef cattle, especially in Western Canada, are already on steroids. The portion of range cattle or cattle on small farms on steroids is not well defined, although it is estimated to be substantially lower.

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11 Personal conversation Frank D. Sauer, Agriculture Canada, January 12, 1998.

12 Opportunities to Reduce Methane Emissions in the United States - Report to Congress, USEPA, EPA 430-R-93-012, Oct. 1993

13 Ibid

5.4.4 Bioengineering

Bioengineering involves application of biotechnology to develop livestock with greater product yield per unit of nutrients consumed. There are various potential biotechnology innovations which increase yield while reducing CH_4 emissions. These include twinning, rumen microbe manipulation and hormones manipulation, to mention some. These practices have not been broadly adopted in Canada.

5.5 Suitability for GHG Emissions Trading

A credit trading program is believed to be the logical choice to apply to CH_4 emissions attributed to enteric fermentation in Canada. This program would operate by developing baseline emission factors which would be applied to each animal contributing to enteric fermentation emissions in Canada. There would be several different emission factors developed representing different livestock (e.g., beef cattle, dairy cattle, swine, etc.) as well as different varieties within that livestock category (e.g., bull, steers, calves, etc.). It should be noted that these emission factors already exist. Additional emission factors would be developed which reflect the reduction in CH_4 emissions (i.e., enteric fermentation) from specific animals should specified best management practices/technologies (see above) be applied. Farmers would obtain credits for applying these best management practices/technologies. Before obtaining credits, farmers would have to demonstrate that they, in fact, applied these best management practices/technologies. Farmers would receive credits at the point of sale, where the livestock is sold for slaughter or to another farmer.

It is recommended that the baseline for determining future credits be set as an CH_4 emission rate and not at total CH_4 emissions from the animal. For instance, enteric fermentation from a dairy cow would be set at a baseline emission rate of 105 kilograms/year of CH_4. Applying various best management practices/technologies may yield an emission rate of 95 kilograms/year of CH_4. Therefore at the point of sale, a credit of 10 kilograms/year of CH_4 is obtained. It should be noted that this is a simplistic example of how the system would operate.

It terms of the criteria for a credit trading program, actual enteric fermentation emissions can be estimated relatively accurately by the application of emission factors across the range of livestock that contribute to these emissions. Environment Canada currently indicates that the uncertainty level for the total of these emissions is +/-20%. In addition, Statistics Canada develops livestock population statistics frequently which would provide a base of data on the activity level of enteric fermentation emissions.

Farmers have a wide range of best management practices/technologies that can be employed to reduce CH_4 emissions attributed to enteric fermentation. Emission reduction

estimates for these practices/technologies have already been developed. Some form of verification of application of those practices/technologies would be required to ensure that credits should be received. This may not be easily carried out, considering the number of farms Canada. Baseline CH_4 emissions should these practices not be employed can also be easily estimated.

The major problem involved in this credit trading system would be the large number of sources where the practices/technologies could be applied and where the credits should be distributed. Even if only large farms were included in the program, this would not solve this problem as there are many hundreds/thousands of farms that have a large amount of livestock.

An alternative system might be to have meat packing plants and dairies hold permits for the total animals or milk purchased. This reduces the number of entities in the system, but adds the complication that foreign trade may not be properly captured. For example, live Canadian-raised cattle may be exported to the US outside of the control of a permit, while US-raised cattle might be purchased by a meat packing plant and require an exemption.

Substance trading was not deemed appropriate for enteric fermentation GHG emissions as there is not one substance that is a good proxy for actual GHG emissions. An emissions rights trading program was also discounted as the number of sources upon which emission rights would have to be allocated would be prohibitive. It was believed that the accounting system for this emissions trading program would be simplified if a credit trading program was implemented.

6. Adipic Acid Production

6.1 Source and Quantity of GHG Emissions

Nitrous oxide (N_2O) is a significant by-product from the production of adipic acid. Adipic acid [$COOH(CH_2)_4COOH$], a 6-carbon dibasic acid, is an important chemical intermediate used in the manufacture of nylon fibres and resins, plasticizers and other plastics. Adipic acid is manufactured at one industrial chemical plant in Canada.

In 1995, adipic acid production accounted for 35 kt of N_2O emissions (10,850 kt of CO_2 equivalent), which represented approximately 8% of total non-combustion GHG emissions and 1.8% of total Canadian GHG emissions. In 1995, this was the single largest source of N_2O emissions, representing about 34% of total N_2O emissions in Canada. From 1990 to 1995, the estimated level of nitrous oxide emissions from adipic acid manufacture ranged from 29 to 35 kt/yr, based directly on production levels of adipic acid. In 1997, control technology was applied to the N_2O emission stream, reducing emissions to a level estimated to be less than 5 kt/yr.

Nitrous Oxide Emissions (1990-2000)

	1990	1991	1992	1993	1994	1995	2000
N_2O Emissions (kt)	34.6	32.3	32.1	29.3	35.4	34.6	5.0
N_2O Emissions (CO_2 Eq kt)	10718	10000	9951	9080	10968	10726	1550
Adipic Acid Production (kt)	97.4	103.4	107.0	98.0	118.0	111.5	136.4
N_20/Adipic Acid Ratio	0.35	0.31	0.30	0.30	0.30	0.31	0.04

Source: DuPont Canada, VCR Progress Report, Sep. 24, 1996

There is only one adipic acid plant operating in Canada, the DuPont Canada plant in Maitland, ON. This plant has a capacity of about 136 kt/yr and is the smallest of three plants that DuPont operates in North America[14]. The Maitland, ON plant represents just less than 15% of the total North American production of 1000 kt/yr. North American adipic acid production represents about 45% of worldwide production. There are only a few manufacturers of adipic acid worldwide. Solutia and AlliedSignal operate the only other 2 adipic acid plants in North America.

14 Others are locatied in Victoria, TX (318 kt/yr) and Orange, TX (181 kt/yr)

6.2 Nature of GHG Emissions Stream

Adipic acid is produced by a two-step oxidation of the raw material, cyclohexane (C_6H_{12}). Nitrous oxide is generated as a by-product in the second step of this oxidation process. Nitrous oxide gases are stripped from the oxidation products and exhausted through a single point source. The amount of nitrous oxide generated in the nitric acid oxidation reaction is proportional to the production volume of adipic acid at typical levels of about 30%. In 1995, roughly 35 kt/yr of N_2O was produced as a by-product from production of about 112 kt/yr of adipic acid at Maitland.

Adipic acid manufacturing is the largest industrial source of N_2O emissions, since the N_2O is a significant by-product from the oxidation reaction. The other industrial source of N_2O emissions is the production of nitric acid, covered in the next section. In nitric acid production, the N_2O emissions from individual point sources are trace by-products and the volumes are significantly smaller.

6.3 Potential for Measuring, Monitoring and Calculating the GHG Emissions Stream

The N_2O emissions from the adipic acid plant are emitted from one point source on the outlet of the catalytic abatement installation. Emissions are calculated based on measurements of N_2O concentrations in the gas stream and the gas flow rate, which can both be easily measured. The reduction of N_2O emissions is measured by the difference between the inlet and outlet concentrations of N_2O at the abatement equipment. The variations within the process or the abatement technology are not known. The calculations must take into account the time when the abatement technology is shut down or not performing at high efficiency, since emissions are not controlled during these periods.

6.4 Options to Reduce GHG Emissions

There are two possible treatments of nitrous oxide emissions from adipic acid production plants. The first is the conversion of nitrous oxide back to nitric acid (oxidation). The second is its catalytic reduction to inert nitrogen and oxygen gases. The second method was selected by DuPont for all three of its North American adipic acid plants and is described below. No information applicable to adipic acid plants was found for the first treatment method.

In August 1997, DuPont started up a $15 million catalytic abatement installation (CAI) to treat the emitted nitrous oxide gas stream. The DuPont CAI uses catalytic reduction

technology to convert N_2O gases to inert nitrogen gas at specified operating conditions. The catalyst technology is new and specific for N_2O gas, developed for DuPont in the early 1990's by Engelhard, a leading catalyst and pollution control technology supplier.

The planned reduction in nitrous oxide emissions is about 80-90% in the first year of operation (1997) with higher levels of utilization expected in the second and third years. DuPont reports that the installation is operating well and currently meeting expectations. The abatement technology is reported to have a reduction efficiency percentage "in the high 90's" when operating steadily. Since the unit has only recently started up, there has been occasional downtime. For example, the abatement unit cannot operate during the occasional startup and shutdown sequences of the adipic acid plant. Other mechanical problems also require short term shutdowns for maintenance. With continued learning curve experience, DuPont intends to increase the operational "up-time" above 90% in future years[15]. DuPont summarizes their success with nitrous oxide reduction as follows:

> "Over the longer period, we hope to achieve up to 95 per cent abatement, so that by the year 2000 and beyond, we will achieve more than our earlier commitments. It should be noted, however, that business growth will result in higher production levels of adipic acid, so that the 95 per cent abatement will show growing levels of nitrous oxide after 1998-99. [16]"

6.5 Suitability for GHG Emissions Trading

Since the N_2O emissions are created in the industrial manufacturing process and not as a result of purchased substances, a substance trading program is not applicable in this situation. There is only one point source of N_2O emissions from adipic acid and emissions are easily measurable and calculated accurately. The emissions have already been significantly reduced from 1990 and 1995 levels and further incremental reductions are believed to be possible. However, production increases due to business activity may increase the total volume of N_2O emissions over time. The two possible programs that would be considered are: emissions rights trading or credit trading. The trading program for adipic acid would, of course, need to be part of a broader emissions trading systems given the single adipic acid source in Canada.

An emissions rights trading program would involve an annual allowance for N_2O emissions. If set at current N_2O emissions levels, there may not be much room for further control reductions and it may have to be adjusted upward to accommodate higher emissions from business activity. The allowance for DuPont may have to be set at a higher level than current emissions to accommodate business growth.

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15 DuPont Canada Ltd., Steve Lauridsen, conversation Feb. 20, 1998

16 DuPont Canada Ltd., VCR Progress Report, Sep. 24, 1996.

DuPont will likely want to receive credits for its reduction efforts and would favour a credit trading program based on absolute reductions from a baseline set at 1990 levels. This would give them substantial annual benefits. If the baseline were set at current (post-abatement) levels, DuPont would not receive any credit for their abatement initiatives and a rate-based credit system would be more appropriate. In this system, a baseline level of X tonnes N_2O per tonne adipic acid produced would give incentive for DuPont to minimize downtime of their high-efficiency abatement equipment, while accommodating growth.

7. Undifferentiated Non-Energy Petroleum Uses

7.1 Source and Quantity of GHG Emissions

This section briefly examines possible industrial sources where CO_2 emissions are assumed to be emitted from non-energy uses of petroleum commodity streams. There is no assessment of the suitability of trading programs provided because of the uncertainty of the information in this area.

Petroleum commodities are used as an raw material in the production of several derivative products. Some of these products completely sequester the carbon contained in the petroleum products (e.g., plastic, rubber, resins) while some end uses of petroleum products release CO_2 during the production process or later in the product life through combustion.

In 1995, Environment Canada estimated that the undifferentiated non-energy uses of petroleum products accounted for a total of 10,000 kt of CO_2 emissions. This estimate represents approximately 7% of total non-combustion GHG emissions in Canada as well as 1.6% of total Canadian GHG emissions. This calculation excludes the net CO_2 emissions from ammonia manufacture using methane, which was treated as a separate industrial source. Ammonia manufacture is examined in section 11.

Environment Canada examined non-energy use data for several different petroleum commodities from Statistics Canada. The main petroleum commodities for which non-energy data was available included: natural gas used as feedstocks, coal and coke, and the liquified petroleum gases (LPGs) of ethane, propane and butane. Since detailed end use of these products was not clearly known, Environment Canada used various simplifying assumptions about the degree of sequestration of carbon in the ultimate life cycle use. The following percentages represent assumptions about the portion of carbon contained in the non-energy petroleum volumes which was emitted as CO_2: for non-energy uses of natural gas, 67%; for LPGs, 20%; and for coals & coke, 100%.[17]

Based on Statistics Canada data provided by Environment Canada, two areas have been assumed to account for the majority of GHG emissions associated with undifferentiated "non-energy" petroleum uses. These are:

17 Environment Canada, Trends in Canada's Greenhouse Gas Emissions 1990-1995, pg. 42.

- use of natural gas liquids (NGLs) and crude oil based liquid feedstocks for the production of ethylene and co-products (i.e., propylene, butadiene, etc.) in large scale facilities; and
- use of natural gas - methane - mostly for the production of methanol and derivatives.

7.2 Nature of GHG Emissions Stream

The general assumption on made is that 20% of the carbon contained in the NGL feed for ethylene plants is ultimately emitted as CO_2 in the production process, while 80% is sequestered in the form of derivatives of ethylene (polyethylene, polystyrene and ethylene glycol, which is used to make polyester fabrics). The two most likely sources of CO_2 are found in the CO_2 created from burning coke off the furnace tubes and CO_2 from burning fuel gas, which is a by-product of the ethylene reaction.

The assumption on natural gas is that 67% of the carbon in natural gas is eventually emitted as CO_2 from methanol combustion. Some carbon contained in methanol is sequestered in formaldehyde resins, which is a major derivative of methanol used in the panelboard industry.

Canada's petrochemical plants, which currently number approximately 150[18], are concentrated in three provinces. This total includes primary petrochemicals production as well as many smaller secondary facilities involved in polymers and derivative intermediates production. Ontario is home to approximately half of the total. Most Ontario establishments are located near Sarnia where there are both petroleum refineries and pipeline terminals for natural gas and its liquid by-products (NGLs). Alberta has a burgeoning petrochemical industry based almost exclusively on natural gas. Quebec has plants in the Montreal area as well as down river at Bécancour. Their primary raw materials are mainly derived from crude oil based feedstocks. A methanol plant situated at Kitimat, BC is the largest facility not operating within the aforementioned provinces.

In Canada, ethylene is produced at four different locations and utilized at nearby plants to make intermediate derivatives which can be feasibly transported globally. The industry's major derivative end-products are polymers such as polyethylene, polypropylene, polyvinyl chloride and styrenic resins. Synthetic rubber and other polymers used in the manufacture of synthetic fibres, paints and coatings, printing inks and adhesives are also outputs from Canada's petrochemical sector. Ethylene is also used to make ethylene oxide (most of which is converted to ethylene glycol), ethylene dichloride and a variety of other intermediate chemicals.

Primary NGL and Crude Oil Based Petrochemical Producers

18 Statistics Canada, CCPA

Company	Location	Major Products
Novacor Chemicals	Joffre, AB	Ethylene, polyethylene
Novacor Chemicals	Corunna, ON	Ethylene, polyethylene, propylene, styrene
Imperial Oil Ltd.	Sarnia, ON	Ethylene, polyethylene
Petromont Inc.	Varennes, QC	Ethylene, polyethylene
Dow Chemical Canada	Fort Saskatchewan, AB	Ethylene, polyethylene, ethylene oxide, glycol, vinyl chloride monomer, dichloroethane

7.3 Potential for Measuring, Monitoring and Calculating the GHG Emissions Stream

Environment Canada reports that the uncertainty level associated with their non-energy emission estimates of undifferentiated non-energy uses of petroleum products is +/-30%. The methodology used by Environment Canada to estimate GHG emissions from this source is based on the application of broad emission factors (as described above). Much more detailed emission estimation methodologies may be required for this sector, if emission reductions are going to be credited for emission trading purposes. The emission factors that are currently being applied may be too broad to be acceptable as a verifiable accounting of emission reductions. The potential for stack testing at petrochemical facilities is problematic as there are sometimes hundreds of point sources of emissions at these facilities. Therefore, more research may be required to develop appropriate emission factors specific to the major petrochemical products that are releasing the carbon dioxide.

There is a manageable number of participants in the Canadian petrochemical sector for the purposes of emissions trading. This is especially true when one considers that the major sources of emission credits may be located at only a few firms (e.g., ethylene producers that are not using ethane as a feedstock, and methanol producers).

7.4 Options to Reduce GHG Emissions

Technologies to reduce GHG emissions from the petrochemical sector analyzed in this report include the following:

- alternative feedstocks for ethylene produced from the NGLs: ethane, propane, butane;
- anticoking additives for ethylene production from NGLs.
- increased production of methanol using available hydrogen and carbon dioxide.

7.4.1 Alternative Ethylene Feedstocks

Ethylene producers typically operate their plants to minimize operating costs and maximize ethylene production. Ethane feedstock provides the best ratio of ethylene produced versus carbon dioxide generated. Of the commercial feedstocks available, ethane requires the least energy consumption per unit of ethylene made. Naphtha and other crude based liquid feedstocks (e.g., gas oils) are the most energy intensive for petrochemicals production.

Ratio of Ethylene Produced to CO_2 Emissions

(CO_2 from combustion of internally produced methane only)

Petrochemical Feedstock	$C_2^=/CO_2$
Ethane	3.45
Propane	0.52
Naphtha	0.88

* Approximate ratios, will vary depending on actual plant operating conditions

Approximately 80% of the ethylene made in Canada is based on cracking ethane. All ethylene produced in Alberta uses ethane. Only eastern Canadian petrochemical facilities, rely partially on propane, butane and crude oil liquid based feedstocks such as gas oils and naphthas to make ethylene. Historically, ethane, most of which has been produced in Western Canada, has not been available to eastern Canadian petrochemical facilities. Ethylene producers in Ontario (Imperial Oil Ltd. in Sarnia and Novacor Chemicals in Corunna) have been able to access ethane from various sources and have increased the use of this feedstock over time. However, a pipeline to deliver western ethane has not reached Quebec. Therefore, Petromont's plant in Varennes, QC continues to rely mostly on propane, butane and naphtha feedstocks.

Switching to ethane from propane and crude oil based gas oils and naphthas can result in a 30 to 40% reduction, or approximately 500 kt in carbon dioxide emissions (associated with combustion of internally generated methane, only) from ethylene petrochemical plants. A technical factor to consider is the ability of the operational units to

accommodate ethane and the unique ratio of co-products produced. Facilities are typically designed to handle a narrow range of feedstocks. Therefore, expensive modifications may be required to major equipment such as furnaces, distillation columns and compressors.

The costs to reduce carbon dioxide emissions by switching to ethane from propane and crude oil based feedstocks (naphtha and gas oils) can vary substantially for several key reasons. A major factor is the variability of the feedstock prices and the value of co-products (i.e., propylene, butadiene, etc.). The operating cost of reducing carbon dioxide emissions in this area can range from 100 $/t to a benefit of 20 $/t-$CO_2$, or more. These costs do not take into consideration capital costs for plant modifications, or pipeline infrastructure required to deliver ethane to Quebec. These one-time costs can be on the order of $100 to $200 million - furnace modifications and downstream processing changes required.

7.4.2 Anticoking Additives

Coke, which is essentially carbon, forms on the inside of furnace tubes as a result of the cracking reactions in the production of ethylene. As coke builds up the efficiency of the reaction (with respect to energy requirement per unit of production) is reduced. Furnace tubes at ethylene plants need to be decoked. The frequency of decoking operations can range from 20 to over 100 days depending on the type of feedstock, furnace design, use of anti-coking agents, and operational factors.

Chemical additives which can reduce coke build-up are proprietary blends that minimize the degradation reaction making carbon (C) from the feedstock molecules. They are incorporated in the feedstock in minute quantities, typically in part per million concentrations. Additives typically increase the operating time of the furnaces by 5% to 50%. This would have a comparable reduction in carbon dioxide emissions associated with this source.

Anticoking additives are already used by most petrochemical producers to extend the service time of the furnaces. However, new chemical additive systems are being developed which offer marginal improvements in anticoking capability, and therefore marginal improvements in carbon dioxide emission reductions. It is estimated that the level of carbon dioxide emission reduction from this technology would amount only to 5 to 20% (of CO_2 from decoking activities). This represents less than 1% of total carbon dioxide emissions from petrochemical sources.

7.4.3 Increased Production of Methanol Using Hydrogen, Carbon Dioxide

Methanol is a commodity chemical made by reacting hydrogen with carbon dioxide or monoxide. Increased production of methanol which uses carbon dioxide does not necessarily translate into reduced carbon dioxide emissions. The problem is that hydrogen is required for the reaction, and the hydrogen is often derived from steam methane reforming which uses energy and generates carbon dioxide. More work is required to better define the stoichiometric and energy uses (which generate carbon dioxide) for hydrogen and carbon dioxide around methanol and other petrochemical complexes. Matching available hydrogen (i.e., where hydrogen is used as a fuel) for combination with carbon dioxide sources for the production of methanol can reduce emissions.

Canadian Methanol Capacity

Company	Location	1995
		(kt)
Methanex	Medicine Hat, AB	1,120
Methanex	Kitimat, BC	500
Celanese Canada	Edmonton, AB	780
Celanese Canada	Millhaven, ON	5
Total Capacity		**2,405**

Source: Camford Information Services

7.5 Suitability for GHG Emissions Trading

No discussion is provided in this report with respect to undifferentiated non-energy petroleum uses and their suitability to a GHG emissions trading program. There is not enough information provided by Environment Canada on the sources of these emissions and to what extent the emissions actually exist to assess their suitability for various trading programs. This section has been included in order to provide a general description of this portion of the 1995 GHG inventory.

This issue is being addressed in a separate paper that is being prepared for the NRTEE on the use of feedstocks and the implications for an emissions trading program. In addition, the energy aspects involved with undifferentiated non-energy uses of petroleum products is addressed in the various papers being prepared for the NRTEE on energy related GHG emissions.

8. Aluminum Smelting

8.1 Source and Quantity of GHG Emissions

Two different greenhouse gas emissions come from the anode in smelting pots in the primary aluminum production industry. In 1995, an estimated 3,600 kt/yr of CO_2 was emitted from the consumption of carbon anodes and another 6,000 kt/yr of CO_2 equivalent was emitted in the form of about 880 tonnes of perfluorcarbons (PFCs) formed in anode events. Together, these GHGs from aluminum smelting accounted for 9,600 kt of CO_2 equivalents, representing 7% of total non-combustion GHG emissions and about 1.6% of total Canadian GHG emissions.

There has been a 33% increase in emissions from 1990 levels. Increases in aluminum production have driven total anode consumption while initiatives to reduce anode consumption rates have partially offset the increase in emissions. Efforts to replace older technologies through capital stock replacement will continue to reduce average anode consumption rates over the next 15 years. However, production increases due to economic growth with related increases in aluminum demand (particularly automobile and aerospace growth) will likely drive total GHG emissions higher.

CO_2 and PFC Emissions from Aluminum Smelting

	Units	1990	1991	1992	1993	1994	1995	2000
CO_2 Emissions	kt	2,700	3,000	3,000	3,800	3,600	3,600	4,000
PFC Emissions	kt CO_2Eq	5,700	6,700	6,700	7,800	6,800	6,000	<5,000
Sum of GHGs	kt CO_2Eq	8,400	9,700	9,900	11,600	10,400	9,600	<9,000
CF_4 Emissions	kt	0.82	0.97	0.97	1.13	0.98	0.80	
C_2F_6 Emissions	kt	0.08	0.10	0.10	0.11	0.10	0.08	
Aluminum Production	kt	1,567	1,822	1,972	2,309	2,255	2,172	2,400

Notes: 1. Source: Trends in Canada's Greenhouse Gas Emissions 1990-1995, Environment Canada
2. CF_4 emissions trend estimated from total PFC trend using GWP of CF4=6500
3. C_2F_6 emissions trend estimated from CF_4 trend using factor of 10%.

Perfluorocarbon (CF_4 and C_2F_6) emissions were 0.88 kt in 1995 (a CO_2 equivalent of 6,000 kt/yr, on a GWP basis). Emissions in 1995 were relatively unchanged from 1990, despite peaking in 1993 at a CO_2 equivalent of 7,800 kt. The trend will likely continue downward as smelters continue their installation of process control systems to control alumina levels and minimize anode events.

In 1995, the Canadian primary aluminum industry had a total production capacity of 2.3 million tonne of aluminum per year from a total of 11 smelters operated by 5 companies. Since electrical energy is the single most important variable cost for aluminum smelting, all Canadian smelters are located near sources of inexpensive, hydroelectric power. With the exception of Alcan's Kitimat, BC smelter, all smelters are found in Quebec.

Primary aluminum production in Canada in 1995 was 2172 kt, represented about 95% of capacity. Roughly 40% of this unalloyed primary production is exported. The major domestic end uses are: transportation (29%), packaging (23%) and building and construction (19%).

Primary Aluminum Production Capacity in Canada, 1992

Company	Location	Origin Year	Capacity (kt/yr)
Alcan Smelters and Chemicals Ltd.	Kitimat, BC		272
	Isle-Maligne, Alma, QC	1950's	73
	Beauharnois, QC	1950's	48
	Grande Baie, QC	1983	180
	Arvida, Jonquière, QC: #1	1950's	84
	Arvida, Jonquière, QC: #2	1960's	148
	Laterrière, QC	1987	204
	Shawinigan, QC	1901	84
Aluminerie de Bécancour	Bécancour, QC	1986	360
Canadian Reynolds Metals Co. Ltd.	Baie-Comeau, QC	1957	400
Aluminerie Lauralco Inc.	Deschambault, QC	1992	215
Aluminerie Aloulette Inc.	Sept-Iles, QC	1992	215
Total			2283

Source: Aluminum Association of Canada

Alcan Smelters and Chemicals, based in Montreal, operates 7 of the 11 Canadian smelters and has just under 50% of the total capacity. Alcan has recently announced a new smelter starting up in 2000 which will replace several older smelters which use outdated technology. The four other companies are subsidiaries or joint ventures of US or international aluminum companies. They operate one smelter each.

8.2 Nature of GHG Emissions Stream

Carbon dioxide emissions are generated by the consumption of carbon anodes in the electrolytic reduction of alumina (Al_2O_3) to elemental aluminum. In a smelter, carbon anodes are made from finely crushed petroleum coke mixed with pitch to form a paste which is formed and baked into a solid anode. Oxygen is removed from the alumina (leaving elemental aluminum) at the carbon anodes and reacts with the carbon to produce carbon dioxide gas. The carbon dioxide gas bubbles up from the anode in the smelting pot and is released into the atmosphere. Carbon anodes are consumed slowly in this process and must be replaced regularly; typically every 20 days of production.

The theoretical minimum rate of carbon anode consumption in aluminum production has been calculated as 350 kg carbon per tonne aluminum produced. The older technology smelters have high carbon anode consumption rates ranging from 450-540 kg C per tonne aluminum. Most new smelters operate at consumption rates ranging from 410 to 450 kg C per tonne aluminum. With best practices and technologies currently available, the industry has only been able to achieve best rates of 400 kg/t. There is a lot of potential for ongoing research to close this gap between theory and practice through better process developments.

PFC emissions are generated from within the smelting pots during irregular "anode effects." Anode effects are described as the overvoltage disturbance of the smelting process that occurs when the concentration of alumina falls below a certain minimum level in the smelting pot. During these events, the fluorine from the cryolite solution present in the electrolytic bath reacts with the carbon anode to form CF_4 and, to a much smaller extent, C_2F_6. These disturbances are caused by poor feed control, which allows alumina levels to decline faster than they can be replenished by the feed supply. The perfluorocarbons (CF_4 and C_2F_6) are emitted from the pot in bubbles and released to the atmosphere.

8.3 Potential for Measuring, Monitoring and Calculating the GHG Emissions Stream

Neither of the two GHGs (CO_2 or PFCs) generated from aluminum smelting processes are measured directly. Carbon dioxide emissions from carbon anode consumption are calculated based on the amount of carbon used in the anodes. PFC emissions are calculated through correlations to measured operating parameters such as pot voltage levels, and duration time of the anode effect. These correlations were developed by a Canadian research firm which developed a measurement method for PFC emissions.

The accuracy of the indirect CO_2 calculations are high, since direct carbon measurement is quite accurate. The accuracy of the PFC calculations, while using indirect correlations, is also thought to be quite accurate and accepted by the industry.

8.4 Options to Reduce GHG Emissions

The primary technologies to reduce GHG emissions include: research work to develop on inert anodes; replacement of old anode technology with prebake anode technology; and better feed control systems.

8.4.1 Inert Anodes

The generation of CO_2 and PFCs from carbon anode consumption could be eliminated by the use of inert anodes, also known as "dimensionally stable" anodes. This subject has been an area of primary research for every major aluminum company over the last 40 years without significant progress. Aluminum companies have yet to find the right alternative material which: i) will not react with the oxygen generated from the alumina, ii) remain insoluble in the cryolite (Na_3AlF_6) bath, and iii) be extremely conductive incurring no economic penalty.

The most promising materials presently being evaluated are ceramic/metal composites consisting primarily of nickel oxide and nickel ferrite with a copper/nickel metal phase. Tin oxide has also been studied.

The CO_2 emissions reduction potential with this technology is 100% if it can be commercialized. A few international aluminum companies are researching this area, but Alcan is conducting direct research at present.

8.4.2 Replacement with Prebake Anode Technology

Older smelter technologies have higher rates of carbon anode consumption than modern technologies. The differences are due to the methods of preparing (forming, baking) the carbon anodes and the complexity of the process control systems used for smelting pot operation. By replacing capacity using older technologies with new capacity employing modern technology, the rate of carbon anode consumption can be reduced slightly.

For example, Alcan has stated that it is in the midst of a long-term project to replace all older technologies by higher performance centre-work prebake (CWPB) technology. The project will be complete by the year 2015. This smelter conversion project will gradually decrease the average rate of carbon consumption to more efficient levels. In 1982, the Alcan average carbon consumption was about 540 kg/t aluminum. This has been reduced to about 500 kg/t aluminum by 1995 and is projected to be reduced to the low 400 kg/t levels when current technologies are fully installed in all smelters by 2015.

8.4.3 Improved Feed Process Control

Perfluorocarbon emissions can only be reduced through improved control of the alumina feed to all points in the process to prevent the onset of anode events. There are two main elements of improvement in control. The first is a change in smelting technology which incorporates a redesigned feed system involving a more distributed feed point network. The second is the use of better distributed process control systems to sense and adjust conditions in the electrolytic bath given existing pot technologies.

An example of the feed system improvement is given by the conversion from older Horizontal Slab Söderberg (HSS) process smelters to a point breaker feeder system. In one example of a typical HSS process, the crust on electrolytic bath is broken on the side every 6 hours or so and alumina is injected into the bath. The feed injection frequency is low and the number of feed points per pot is low. In the modern point breaker system, pistons break the bath crust at several locations to inject a small amount (1.0 - 1.5 kg per injection per point) of alumina at much shorter intervals. With better cell signal measurements and the use of a neural network, each distributed feed point can be controlled individually, resulting in better control of the alumina concentration throughout the bath. Theoretically, there is no technical limit to PFC reductions with increased neural networks and distributed feed control. Practically, it is assumed that a 20% reduction is easily possible with improved process control systems.

8.5 Suitability for GHG Emissions Trading

In aluminum smelting, the emissions of the two GHGs can be calculated with a reasonable degree of accuracy, based on carbon anode consumption and measurement of acceptable operating parameters. The number of sources in the industry responsible for 100% of the emissions is relatively small (11 smelters operated by 5 companies), so control can be established at this level.

Aluminum smelting is suitable for an emissions rights program, assuming that PFC emissions can measured to the required level of accuracy. An absolute industry level could be set, but the companies may be somewhat restricted in the control technologies that are available. The inevitable growth of production may increase GHG emissions higher than levels which can be controlled.

A credit trading program is also suitable for the industry. With respect to CO_2 emissions, the industry uses a rate-based benchmark for carbon anode consumption per tonne of aluminum produced. If a reasonable baseline level can be established among the different producers, then credits can be earned by the continuing efforts to reduce overall carbon anode consumption rates closer to the theoretical minimum. For PFC emissions, a similar

baseline could be established based on the rate of PFC emissions per tonne of aluminum or an absolute level of PFC emissions in a base year.

A substance trading program may not be appropriate in this industry because the GHG emissions do not come directly from measurable substances. In the case of CO_2 emissions, it may be possible to measure the volume of carbon in anodes, but these are produced at the smelter sites, from two purchased materials containing varying concentrations of carbon. In the case of PFCs, emissions are generated in the process and there is no correlation to the amount of carbon in the anodes.

9. Lime and Cement Production

9.1 Source and Quantity of GHG Emissions

Carbon dioxide is generated through calcining of limestone or other calcareous material. In large lime kilns, the calcining process thermally decomposes the calcium carbonate ($CaCO_3$) contained in limestone to yield lime (CaO) and carbon dioxide (CO_2). Carbon dioxide is also generated as a result of natural gas, oil, coal or waste hydrocarbons that serve as fuel sources for the calcining process, or other energy requirements associated with site operations. Total emissions associated with calcination of limestone are estimated at 7,350[19] kilotonnes in 1995, and represented 5% of non-combustion GHG emissions and approximately 1% of total Canadian emissions.

Lime kilns are found at merchant lime producers as well as cement plants, kraft pulp mills and some iron and steel facilities which use lime within their operations. Merchant producers of lime also supply these industrial users as well as a broader customer base.

Process Emissions From Lime Production

	1995	
	(kt-CO_2)	
Cement plants#	5,360	63%
Merchant lime production#	1,990	27%
Total*	7,350	100%

Source:# Environment Canada - Jaques, et al

+ Includes production at iron and steel and other producers which use lime in their own processes as well as to sell to the merchant market.

* Excluded from this analysis are GHG emissions associated with lime production at kraft pulp and paper mills.

This analysis deals with GHG emissions and the suitability of several emissions trading systems only for cement plants and merchant lime production. Practically all of Canada's 42 kraft pulp mills make lime on-site and may employ renewable fuels (wood fibres) for a large portion of their energy requirements. Within the pulp industry, some of the carbon contained in the carbon dioxide emitted from calcining calcium carbonate originates from the raw material wood used to make pulp. Some energy and carbon dioxide emissions

19 This figure excludes 216 kilotonnes of CO_2 emissions from a variety of other limestone uses (not individually quantified by industrial sector), as well as 64 kilotonnes of emissions from soda ash made from limestone and used in glass production. Estimates from Environment Canada.

from lime production at kraft pulp mills may also derive from non-renewable sources. Detailed, (possibly mill specific) investigation is required to differentiate renewable and non-renewable GHG emission sources associated with lime production. This is better undertaken as part of the total energy and GHG emissions analysis at pulp mills and possibly encompassing carbon sequestering/sinks analysis encompassing the forestry sector. Emissions from lime production at pulp mills is not undertaken here.

There are approximately 45 facilities in Canada where lime kilns are in operation (excluding pulp and paper mills). In Canada, there are 18 cement plants having kilns to provide lime for internal requirements. There are approximately 17 merchant lime producers in Canada, operating close to 20 facilities. These producers sell lime to the pulp and paper, iron and steel industry, non-ferrous smelters, sugar refineries, waste water treatment, gas scrubbing and other for miscellaneous uses. Some sugar refineries, iron and steel plants, and chemical plants also have their own lime kilns on-site.

9.1.1 Merchant Lime Supply and Consumption

Total Canadian production from merchant lime suppliers was reported at 2,490 kilotonnes in 1996 with an associated value of $212 million. Between 50 and 55% of the production was in Ontario. Lime prices vary on grade and transportation costs. High calcium, quicklime delivered in bulk quantities is typically in the 60 to 80 $/tonne price range. High calcium hydrated lime can sell for 10 $/tonne more. Between U.S. and Canada, lime is traded duty-free.

Merchant Lime Producers

(excludes kraft pulp mills producing for internal consumption)

Company	Plants	Capacity (kt)	Locations
BeachviLime Ltd.	2	710	ON(2)
Greybec Calc Inc.	2	582	PQ(2)
Continental Lime*	4	515	MB(2),AB,BC
Steetley Industries	1	345	ON
General Chemicals*	1	292	ON
Algoma Steel *	1	275	ON
Global Stone (Ingersoll) Ltd.	1	225	ON
Koch Minerals	1	200	ON
Havelock Lime, div. of Goldcorp Inc.	1	175	NB
Texada Lime	1	170	BC
Other producers	5	311	
Total	20	3,800	

* Captive uses as well as merchant supply

Typically the merchant lime industry operates well below nameplate capacity. In 1996, it is estimated that the capacity utilization rate was less than 70%. Canadian imports

amounted to only 37 kilotonnes (less than 2% of domestic consumption) while exports were 217 kilotonnes in 1996 or approximately 8% of production[20].

Merchant Lime Supply and Consumption

	1996
	(kt)
Production	2,490
Imports	37
Total merchant supply	2,527
Domestic consumption	2,310
Exports	217

Source: Natural Resource Canada

The largest end-use of lime is in the steel industry, where it is used as a fluxing material to remove impurities, adjust physical properties of steel, protect equipment from aggressive acidic materials and provide an artificial cover of slag on ladles. Lime is also used in paper production as a feedstock for precipitated calcium carbonate (PCC) production, a fine white filler. In construction, lime is often used for soil stabilization and asphalt paving. In water treatment, lime acts to precipitate "hardness" from water and provides a cheap alkali to adjust pH in wastewater.

Canadian Merchant Lime Consumption

Application	% Use
Iron and steel	50%
Pulp & paper*	10%
Construction	9%
Water treatment	9%
Sugar refineries	4%
All other uses	18%

* Includes precipitated calcium carbonate (PCC) production.
Excludes internal production of lime at pulp mills for causticizing.

Merchant production and domestic consumption of lime have remained essentially flat over the last 16 years. Canadian production in 1980, reported at 2,554 kt is virtually the same at 2,490 kt in 1996. Similarly, domestic consumption of merchant lime has only increased 5% since 1980, averaging 0.3% annual growth. The long term outlook for the Canadian lime industry is that it will grow at an average annual rate of 0 to 2%. Most of

20 Natural Resources Canada, *1996 Canadian Minerals Yearbook, Review and Outlook,* 1997.

the growth will come from waste water treatment, flue-gas desulphurization and use in making PCC paper fillers. Consumption within the iron and steel industry is expected to decline in the longer term as result of improved efficiencies, improved ore grades, increase in the use of scrap fed to basic oxygen furnaces (by-passing the need to use lime) and increased use of fluxed iron ore pellets.[21]

9.1.2 Cement Suppliers and Consumption

Portland cement is a mixture of inorganic chemicals - mostly, calcium oxide (lime), silica, alumina (Al_2O_3), iron and calcium sulphate (gypsum). Portland cement is made by combining clinker with a small amount of gypsum which is used to control setting time. Clinker is made by combining lime with silica containing materials. Most grades of Portland cement contain 60 to 67% lime by weight.

Capacities of Major Cement Producers in Canada

Company	Location		1995 Grinding Capacity (kt/yr)
Lafarge Canada Inc.	Exshaw	AB	1400
Inland Cement Ltd.	Edmonton	AB	1512
Lafarge Canada Inc.	Kamloops	BC	300
Lafarge Canada Inc.	Richmond	BC	478
Tilbury Cement Ltd.	Delta	BC	1000
North Star Cement Ltd.	Corner Brook	NF	245
Lafarge Canada Inc.	Brookfield	NS	600
Blue Circle Canada Inc.	St. Mary's	ON	800
Blue Circle Canada Inc.	Bowmanville	ON	1300
St. Lawrence Cement Inc.	Mississauga	ON	1969
Lafarge Canada Inc.	Woodstock	ON	610
Lafarge Canada Inc.	Bath	ON	1000
ESSROC Italcementi Group	Picton	ON	818
Federal White Cement Ltd.	Woodstock	ON	185
Lafarge Canada Inc.	St. Constant	PQ	1100
Ciment Quebec Inc.	St-Basile	PQ	940
St. Lawrence Cement	Joliette	PQ	1200

Source: Portland Cement Association, Natural Resources Canada (1995)
Note: Ownership and capacity changes between 1995 and 1998 have occurred.

The Canadian cement industry has undergone some rationalization over the last decade. Whereas ten years ago there were 23 producing plants operating nearly 50 kilns, there are now close to 18 plants operating 32 kilns. As the average size of the plants has increased, the total capacity of the industry has remained virtually unchanged in the last 16 years. Capacity utilization typically varies between 50% and 82%.

21 Natural Resources Canada, *1996 Canadian Minerals Yearbook, Review and Outlook,* 1997.

Cement Supply and Consumption

	1996
	(kt)
Production (includes exported clinker)	12,303
Imports	631
Total supply	12,934
Domestic consumption	7,580
Exports	5,354

Source: Natural Resource Canada

The Canadian cement industry exported 44% of its production in 1996, with nearly 97% of exports shipped to the United States. Imports accounted for approximately 8% of domestic consumption. Over 97% of these were from the United States. These figures exclude trade on various value-added articles, such as pipes, stones, and building components containing cement. Canada's production and consumption of cement has grown very slowly. Production has grown only 0.7% per year between 1980 and 1996.

Cement is typically mixed with aggregates (e.g., stones, sand) and other additives and applied as concrete mixtures in a large number of end-uses, including building construction (residential, commercial, industrial, institutional), pipes, roads and sidewalks, marine terminals, shaped products (bricks, blocks, steps, etc.), and used in many possible special construction projects (e.g., Hibernia platform, dams, etc.). Canada's cement producers are largely forward integrated to concrete production.

9.2 Nature of GHG Emissions Stream

Carbon monoxide (CO), nitrogen (N_2), carbon dioxide (CO_2), sulphur dioxide (SO_2), water (H_2O) and nitrogen oxides (NOx) are all produced in merchant lime kilns and cement plants. Carbon dioxide content can range from 5% to 40% by volume, but is typically 10% to 20%. Kiln gas streams also contain carbon dioxide resulting from combustion of hydrocarbon energy sources (e.g., oil, gas, coal, coke or biomass), nitrogen, oxygen, minor amounts of other gases and a substantial amount of particulate, largely composed of fine calcium carbonate particles. Before gas streams can be processed through carbon dioxide capture and treatment equipment, particulate in the gas stream may need to be removed.

The flow rate of the emissions streams is high. For example, at one 1,000 kilotonnes per year plant, the flow rate from a single kiln is 6,000 to 7,000 cubic meters per minute. Smaller plants and smaller kilns have gas flow lower rates.

9.3 Potential for Measuring, Monitoring and Calculating the GHG Emissions Stream

In general, emissions of carbon dioxide resulting from production of lime can be easily and relatively inexpensively calculated through carbon mass balance methods involving raw materials or finished products. Measurement of the efficiency of potential emissions control technologies may be somewhat more complicated, depending on reduction options applied.

Carbon dioxide emissions resulting from calcining limestone to make lime in either cement plants or in merchant lime kilns can be estimated from the mass of limestone used in production. For example, if 1,000 tonnes of limestone (with 100% $CaCO_3$ content) is calcined, 440 tonnes of carbon dioxide would be generated from the reaction. This excludes GHG emissions from energy consumption. However, if impure limestone (e.g., containing $CaCO_3 \cdot MgCO_3$) is used as a raw material, as may be the case at some lime/cement plants, the emission factor can be different. In the case of dolomitic limestone used for making lime, more CO_2 is emitted per unit of raw material used than for limestone alone. For dolomitic limestone ($CaCO_3 \cdot MgCO_3$), the emission factor (exclusive of energy) is 478 kg of CO_2 per 1,000 kg of raw material. Using this simple approach requires chemical analysis of the raw materials to define the carbonate (CO_3) content which can vary from one "limestone" source to another.

Another approach is to calculate the emissions from the amount of lime (CaO) made or, as in the case of cement production, lime contained in the final cement product. Lime production and sales quantities (expressed in mass units) are well documented for commercial reasons. In the case of cement, producers closely monitor the composition of the cement content to ensure quality standards and performance requirements (strength, setting time, etc.) are maintained. The lime content of the final cement product is typically within a relatively narrow composition range and well documented, often on a production lot basis. Environment Canada[22] applies an emission factor of 500 kg of CO_2 per 1,000 kg of cement produced by the industry. The uncertainty in the estimated emissions of 5,360 kilotonnes from cement production (excluding energy) is +/-12%. This emission factor derived based on the assumption that the average lime content of the clinker in Canada is 63.5% by weight. Clinker, and minor amounts of gypsum (calcium sulfate) and additives are combined to make the final cement product.

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22 Jaques, A., et al, "Trends in Canada's Greenhouse Emissions, 1990 to 1995", Environment Canada, April 1997.

For lime production, Environment Canada[23] applies the emission factor of 790 kg of carbon dioxide per 1,000 kg of lime produced. This emission factor is very close to the theoretical release factor of 786 kg of CO_2 per 1000 kg of lime produced. The uncertainty in Environment Canada's estimate for 1995 emissions from lime production is +/- 15%. Part of this uncertainty may result from uncertainty in Canada's total merchant lime production estimates.

Measuring, monitoring and calculating CO_2 emissions based on lime kiln or cement kiln stacks testing of carbon dioxide concentration levels is possible, but likely to be relatively expensive versus using simplified emission factors applied to production and/or raw material quantities and contents. However, some cement plants in Canada are required to continuously monitor emissions of various pollutants. These CEM systems can measure carbon dioxide as well as volumetric gas emissions flow rate. One cement company claims that capital cost for its system was $0.5 million and required $0.1 million in annual operating costs (labour, maintenance, verification, etc.). Total annualized capital and operating costs of monitoring for most plants would be between 0.1 and 1 $/tonne of carbon dioxide emitted. Lower incremental costs may be applicable if a CEM is already in place.

If the reduction option is to control CO_2 emissions from stacks through capture, treatment and sequestration technologies, periodic testing of the efficiency of these systems may be required. Some of the considerations involved in measuring the efficiency of capture and treatment devices for carbon dioxide emissions from lime and cement operations include:

- contribution to total emissions from energy combustion and calcining process;
- variability in exhaust gas flow rate and concentration; and
- variability in efficiency of potential treatment systems.

The range of variability in process operations may be influenced by changes in: the types and quality of fuels; raw materials; production rates; heat zone temperatures; and mechanisms of potential emissions treatment systems. Other factors may also be involved that are specific to the operations of individual plants. The monitoring system and how regularly measurements are taken will relate to the variation in potential emissions and process variability of the emissions treatment devices. These factors will relate to the accuracy and cost of measurements, monitoring and calculating potential emissions, reduction efficiencies and net emissions.

Periodic or continuous stack gas flow rates and concentrations measurement may not be necessary if the amount of treated (e.g., sequestered) carbon dioxide can be measured through metering and mass balance methods. For example, if the carbon dioxide was captured and sequestered as an inorganic carbonate (e.g., sodium carbonate), then the weight of the carbonate could be measured to estimate the amount of carbon dioxide it

23 ibid

contained. Periodic chemical analyses may be required of the sequestered products may be required. These measurements and calculations could be combined with mass balances calculations involving carbon contained in the limestone as well as in the fossil fuels used as energy sources. This would allow for the separation of energy and non-energy related emissions and impacts on each of emissions reduction options.

9.4 Options to Reduce GHG Emissions

No lime or cement producers have been identified which capture and treat potential emissions of carbon dioxide from their operations. However, technologies are available to indirectly reduce carbon dioxide emissions associated with the production of lime. Many facilities have increased their energy and overall production efficiencies over time. In the cement industry, technology evolution and conservation programs have reduced energy consumption per unit of production by about 24% since 1974.[24] Carbon dioxide process emissions associated with the calcination of limestone (excluding energy) can be indirectly reduced by reducing the amount of lime required in cement or other lime application markets (steel making, water treatment, etc.). This would reduce the amount of lime produced and associated emissions.

This brief analysis of technology options to reduce GHG emissions considers areas for reducing process emissions from lime production through different approaches. One relates to technologies that address emissions through reductions in lime consumption in major applications steel production and cement[25]. The second approach is to address carbon dioxide emissions with the installation of capture, treatment and extraction equipment. The extracted carbon dioxide would then need to be sequestered or stored to prevent releases to air. These systems have yet to be applied and consequently the analysis presented here should be considered theoretical. Some sequestering options are described. Significant chemical alteration of the cement (i.e., substantial replacement of calcium oxide) is not been considered by the industry.

Although, there are technologies available to remove carbon dioxide from lime kiln gas streams, rarely are these technologies applied, since the gas does not contain commercially useful products. Typically, a low concentration (10 to 20%) of CO_2 in the high flow rate gas stream makes capture and extraction of the dioxide uneconomical. The capital and variable operating costs to separate CO_2 (largely power) increases as the ratio of final concentration to starting concentration increases. Merchant carbon dioxide

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24 Natural Resources Canada, *1996 Canadian Minerals Yearbook, Review and Outlook,* 1997.

25 An analysis of technical options to reduce lime consumption in the steelmaking industry is quite complex and considered beyond the scope of this study, since there is a requirement to consider complex metallurgy and many components of the steel making process. Since steel producers are already practicing some lime reduction strategies (i.e., minimizing the presence of acidic silicon dioxide - SiO_2 - which is neutralized with lime). It also requires a benchmarking of the consumption of lime versus potential targets for each of the steel producers.]

suppliers, who rely on chemical plants, ammonia facilities, crude oil refineries and other sources for higher purity carbon dioxide, have largely ignored lime kilns as a source for their carbon dioxide needs.

As a result, of the lack of application of emission control systems, the operating experience in handling dilute carbon dioxide streams is not defined. While general CO_2 reduction options are available, which technology best fits the particular requirements of each facility in the lime and cement industry has yet to be determined. Generally, lime producers have yet to analyze options for controlling and ultimately disposing carbon dioxide currently emitted. Additional research is required to identify optimal solutions for the lime kilns in controlling their emissions and finding a sink for the output.

9.4.1 Reducing Lime Consumption and Production

Fly ash, metal slags, and volcanic ash are being incorporated in cement and concrete formulations in Canada and other countries. These materials are typically waste products generated from industrial processes producing electrical energy (e.g., coal power plants) or making metals. These products can be incorporated in cement formulations without materially affecting the performance for various end-uses.

Fly ash is a mixture of inorganic chemicals produced from the combustion of powdered coal or other fuel containing inorganic matter. In Canada, fly ash is being used in minor amounts in cement, although it is being used in a greater amount by concrete products producers. While cement formulations can use up to 8% by weight fly ash, nearly all Portland cement sold contains less than 2%. In other countries, fly ash is typically incorporated in greater amounts. The fly ash is incorporated into the mixture at the cement plant through various process operations.

Most European countries have allowed use of slags or fly ash in cements, even though the ingredient produces cements with different properties. There are reports that slags or fly ash containing cements last longer and are more tolerant of salt water than pure clinker cements[26]. However, increasing the slag or fly ash content to very high levels will compromise the performance of the cement.

A recent study[27] concluded that substituting fly ash for clinker can reduce GHG emissions by 5 to 20%. This rate of reduction not only takes into account the lower levels of process CO_2 emissions resulting from less lime use, but energy-related savings resulting from processing (e.g., grinding) a lesser quantity of clinker. Other benefits of this technology

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26 Oak Ridge National Laboratory, et al, "Scenarios of U.S. Carbon Reductions, Potential Impacts of Energy Technologies by 2010 and Beyond", Prepared for the Office of Energy Efficiency and Renewable Energy", U.S. Department of Energy, Sept. 1997.

27 Sauer, G., "Cement, Concrete and Greenhouse Gas", Paper presented at the CGLI Second Roundtable on North American Energy Policy, April 1997

option are that reductions in NO_x, SO_2 and other pollutants associated with cement production are also realized.

Fly ash or slags may be available at low cost, free of charge, or incentives may even be available to cement makers to incorporate this waste material in their product. Some producers of fly ash may have financial interest in shipping fly ash waste to cement plants, rather than disposal at landfill sites at higher costs. Concrete producers have interest in adopting fly ash, since they view the material as a means to lower material costs. International cement technology suppliers, active in Canada and have previously expressed a willingness to develop new specifications for cement containing fly ash[28]. They point to their business operations in other countries where fly ash has already been adopted.

Before fly ash could be incorporated in greater amounts in cement, cement and concrete product specifications and standards may need to be changed. This process may represent the largest cost component to this option. Changing cement product standards (or any standards) is usually not easily achieved.

It should be kept in mind that slags, fly ash and other materials are already incorporated into concrete formulations, although the amount of such materials is not well defined. Concrete mixes are largely composed of aggregate materials and minor portions of cement that acts as the binder. The concrete manufacturing industry is composed of many participants. According to cement producers, this industry group is not interested in having cement manufacturers incorporate slags, fly ash and other similar materials in cement, preferring to do it themselves at less cost.

9.4.1.1 Carbon Dioxide Capture and Sequestering Technologies

There are various potential technologies (yet to be proven) that could capture and sequester carbon dioxide from lime production. Several technologies are available for separating gases contained in the gas emission stream. These include:

- cryogenic separation;
- pressure swing adsorption; and
- membranes.

Cryogenic separation relies on distillation. Distillation requires gases be condensed to liquids. Cryogenic systems must liquefy the oxygen, nitrogen and carbon dioxide which are gases at room temperatures and atmospheric pressures before separation can occur. This requires low temperatures and high pressure operating conditions. In pressure swing adsorption (PSA) units molecular sieves (carbon or zeolite based) with pore dimensions similar to the gases being separated are placed in vessels. Hollow polymeric fibre membranes can be designed to selectively allow passage of one molecule while

28 *Powering Greenhouse Gas Emission Reductions Through Technology Advancement*, April 1998.

restricting others. Gas separation is achieved by designing systems that take into consideration differences in membrane solubility and diffusion of molecules to be separated.

9.4.1.2 Sequestering and Disposition of Carbon Dioxide

Once the carbon dioxide has been captured and extracted the question arises, "what can be done with it?" Existing commercial uses for carbon dioxide for beverages, refrigeration, neutralization and other applications are well serviced by gas suppliers. Typically merchant suppliers have not needed to extract carbon dioxide from dilute sources (such as lime kilns), since the cost of extraction are high relative to sources which offer a high concentration carbon dioxide stream. Gas suppliers have sought opportunistic sources of carbon dioxide from ammonia plants, hydrogen plants (e.g., at crude oil refineries), and chemical plants.

Carbon dioxide can be reacted with salt solutions and various alkali hydroxides to form carbonates. One commercial process uses the carbon dioxide produced from a lime kiln as a reactant with sodium chloride to make calcium chloride and sodium carbonate. The overall reaction is as follows:

$$\underset{\text{limestone}}{CaCO_3} + \underset{\text{salt}}{2NaCl} \longrightarrow \underset{\text{calcium chloride}}{CaCl_2} + \underset{\text{soda ash}}{Na_2CO_3}$$

Whether this process results in a "permanent" sequestration of the carbon dioxide depends on the application of the soda ash. A large portion of the soda ash commercially produced in this process is used in glass manufacture. In this case, carbon dioxide contained in the carbonate is dissociated and released during heating in the glass making process. However, in other applications, such as detergents, water treatment and some chemicals manufacturing, the carbonate may remain sequestered.

Carbon dioxide can be dissolved in water to produce weak carbonic acid. This acid has many possible neutralization applications in a variety of end-use markets. Potential markets for carbon dioxide would include a portion of the existing hydrochloric, nitric, sulphuric and phosphoric acid markets. However, the portion of acid market in which carbon dioxide would fit would be low, since in many applications, the type of acid being used is specific to the equipment and chemistry of the process. In addition, carbonic acid works best at high pH levels, and large quantities are required to achieve results in the lower pH range.

9.5 Suitability for GHG Emissions Trading

The lime and cement industry is suitable for emissions trading systems. Credit trading may be preferable for the non-energy emissions resulting from the calcination of limestone.

Credit emissions trading would be suitable for participants in Canada's lime and cement industry. Emissions from calcining could be treated differently from a potentially separate energy-related emissions trading program, if required, since the two sources of GHG can be easily distinguished in these operations. The main features of the lime and cement industry which favour credit emissions trading include:

- actual emissions of carbon dioxide from calcining limestone in making lime can be accurately measured and/or calculated at the plant as well as industry level;
- the cost of measuring and monitoring emission rates is reasonably low (in some cases incremental to existing monitoring systems employed for other pollutants);
- although few technology options are available to reduce emissions, a baseline of emissions can be readily established for the industry and individual plants; and
- nearly all facilities are large emitters and can be readily identified. Practically 100% of the emission sources can be covered under a trading program.

This industry is also suitable for an emissions trading allowance program, potentially linked with other industries which would allow the industry to grow. While the industry's production has been has growing very slowly, increased production can be expected in the long term. Since carbon dioxide emissions from calcining limestone are inherent in the chemical reaction used to make the final products (lime and cement) capping the total industry emissions would cap production of lime or cement. The ability to purchase some emissions rights would allow the industry to expand slowly over time.

Substance trading may be most suitable on the portion of the cement industry that is forward integrated to concrete production. Trading allowances could potentially be established on cement sales, or limestone raw material usage. The ability to reduce lime consumption though the increased substitution of cement alternatives (such as fly ash) would result in reduced emissions in the cement production process. Cement producers not integrated to concrete production may have less interest in applying this emissions reduction option since they have less influence on the use of cement in their customers concrete formulations. The merchant lime producing industry which is typically not forward integrated would not be very suitable for substance product trading.

10. Livestock Manure

10.1 Source and Quantity of GHG Emissions

Methane emissions from livestock manure are predominately attributed to beef cattle, pigs and dairy cattle. Other much smaller sources include sheep and poultry. In 1995, livestock manure accounted for a total of 271 kt of CH_4 emissions (5,700 kt of CO_2 equivalent) which represented approximately 4% of total non-combustion GHG emissions in Canada as well as 1% of total Canadian GHG emissions.

Trends in CH_4 Emissions From Livestock Manure in Canada

Year	CH_4 Emissions	CO_2 Equivalent Emissions
	(kilotonnes)	
1990	246	5,166
1991	248	5,208
1992	247	5,187
1993	257	5,397
1994	263	5,523
1995	271	5,691

Source: Environment Canada, Trends in Canada's Greenhouse Gas Emissions 1990-1995.

Livestock waste decomposition occurs either aerobically or anaerobically. Under aerobic conditions, organic material in the waste is decomposed by aerobic and facultative bacteria using oxygen. The end products of aerobic decomposition are CO_2 and stabilized organic material. Under anaerobic conditions, organic material in livestock waste is decomposed by anaerobic and facultative bacteria. End products of anaerobic decomposition are CH_4, CO_2, and stabilized organic material. Bacteria responsible for CH_4 production in animal waste are strictly anaerobic.

Three factors influence CH_4 emissions from livestock manure, namely the: (i) type of livestock feed utilized (i.e., high energy content and digestibility of feed results in greater CH_4 emissions from the waste); (ii) characteristics of the animal waste management system utilized; and (iii) climatic conditions.

Manure management systems which utilize anaerobic conditions (e.g., liquid/slurry storage systems, pit storage systems, and anaerobic lagoons) contribute the most CH_4 emissions. A small percentage of livestock manure worldwide is managed with these systems, however it has been estimated that these types of systems are responsible for about 60% of global livestock manure CH_4 emissions. Manure management systems

which involve contact of the manure with air (e.g., uncollected on the range) have low CH_4 production potential.[29]

With respect to climatic conditions, the factors that influence the level of CH_4 emissions are: (i) temperature - CH_4 production generally increases with rising temperature; and (ii) moisture - moisture content of the livestock waste determines the rate of bacterial growth and waste decomposition. Moist conditions promote CH_4 production.[30]

10.2 Nature of GHG Emissions Stream

There are thousands of individual sources of CH_4 emissions from livestock manure in Canada. Due to their large population, beef cattle represent approximately 50% of all manure related CH_4 emissions. Dairy cattle, because their manure management systems are more likely to promote anaerobic decomposition contribute 16% to total CH_4 emissions even though there is a relatively small population in Canada. Beef cattle are more likely to be ranging animals which promote aerobic decomposition of manure while dairy cattle are herded into barns frequently and thus the manure is often stored in pits, lagoons, etc. which promote anaerobic decomposition.

1995 Canadian CH_4 Emissions from Livestock Manure

	Number of Animals (1,000)	Emission Estimates (kt CH_4)	Emission Factor (kg CH_4 per animal)
Cattle - Beef	12,448	135	10.8
Cattle - Dairy	1,271	44	34.4
Goats	22	nil	0.0
Sheep	717	4	5.1
Pigs	11,939	77	6.4
Horses/Mules/Asses	356	nil	0.0
Buffalo			
Camels and Llamas			
Poultry	116,113	12	0.1
Other			
Total	**142,865**	**271**	**1.9**

Source: Environment Canada, *Trends in Canada's Greenhouse Gas Emissions 1990-1995.*

29 Ibid.

30 U.S. EPA, Global Methane Emissions from Livestock and Poultry Manure, February 1992, pg. 11-15.

It has been suggested that manure management systems that store manure under anaerobic conditions contribute approximately 60% to CH_4 emissions from this source. The larger farms in Canada are where these complex manure management systems have been installed and are therefore where the manure related CH_4 emissions are concentrated.

Large Livestock Farms in Canada

Province	Farms with > 100 Dairy Cows	Farms with > 1,000 Pigs	Farms with > 50 Beef Cows
Newfoundland	14	1	0
Prince Edward Island	10	31	65
Nova Scotia	34	48	150
New Brunswick	21	30	69
Quebec	214	1126	1,244
Ontario	311	734	1,821
Manitoba	72	373	3,731
Saskatchewan	48	151	8,104
Alberta	224	460	13,870
British Columbia	214	56	1,340
Canada	**1,162**	**3,010**	**30,394**

Source: Statistics Canada

10.3 Potential for Measuring, Monitoring and Calculating the GHG Emissions Stream

Due to the wide dispersal of sources of livestock manure in Canada, the most logical approach to estimate total CH_4 emissions, and the approach currently utilized by Environment Canada, is to apply emission factors to the number of livestock in Canada. The emission factors that were utilized by Environment Canada to estimate livestock emissions were outlined earlier in this section. Currently, Environment Canada indicates that the uncertainties with respect to these emission estimates are +/- 50-30% (this means that the actual CH_4 emissions from manure may be 50% higher or 30% lower than the 271 kt). This relatively high uncertainty can be attributed to the large number of variables that affect CH_4 emissions generated from livestock manure, for instance: composition of the feed; size of the animal; climatic conditions; manure management system utilized, etc.

Developing data on these variables as they relate to actual conditions on Canadian farms and then applying individual emission factors which incorporate these specific conditions will increase the accuracy and reduce the uncertainty attributed to CH_4 emissions from

livestock manure. For instance, determining exactly what percentage of dairy and beef cattle reside on farms which have installed those manure management systems which promote the anaerobic decomposition of manure and thus methane emissions, will serve to increase the accuracy of the respective emission estimates. If these data were developed, then an emission factor could be applied to the number of livestock that are located on farms with those manure management systems while another emission factor (a smaller one) would be applied to the number of livestock which reside on farms without those manure management systems.

Monitoring for reductions in CH_4 emissions from livestock manure in Canada would require data on these variables. Currently, the main variable that alters CH_4 emissions from livestock manure form year to year are changes to the total herd in Canada.

10.4 Options to Reduce GHG Emissions

There are technologies that exist that can reduce CH_4 emissions from livestock manure on Canadian farms. However currently, CH_4 emissions from livestock manure in Canada are for the most part uncontrolled. Two main types of technologies are discussed in this section, namely: aerobic composting; and anaerobic digesters.

There are several types of aerobic composting technologies that are currently being developed in Canada. These systems use various different processes to aerobically compost liquid livestock manure to produce fertilizer which can be applied to fields or can even be sold on the commercial or consumer markets. The two large categories of aerobic composters are continuous and batch. Continuous system require that manure be fed into the composting system daily while batch composters may only need liquid manure to be fed into the system approximately 6 times over a 30 day period. Aerobic composting through the utilization of manure to produce an organic fertilizer, reduces CH_4 emissions. It should be noted that there are few, if any commercial farms (outside of pilot projects) in Canada that have installed aerobic composting systems. However, there are several Canadian companies that are quite close to full-scale commercialization of their respective aerobic composting systems for manure.

Most of the research to date to reduce CH_4 emissions from livestock manure has been focused on anaerobic digesters to collect the biogas that results from the microorganism decomposition of manure. Biogas technology is a manure management tool that recovers and uses methane as an energy source. Collected biogas can then: be used as a fuel source to generate electricity for use on the farm; be sold to the electrical grid; or be used for heating or cooling needs.[31] The largest potential to reduce CH_4 emissions are at farms

31 U.S. EPA, AgSTAR Handbook, A Manual for Developing Biogas Systems at Commercial Farms in the United States, July 1997, pg. 1-1.

where manure is managed anaerobically in liquid or slurry form or stored over time as a solid.

There are three main types of anaerobic digesters, namely: covered lagoons; plug-flow digesters; and complete mix digesters. These digesters are suitable for large-scale, intensive farm operations that are common in North America, Europe, and regions of Asia and Australia. It has been shown that when anaerobic digesters are introduced at farms that have been emitting large amounts of CH_4, emissions have been reduced by up to 70-80%.

Covered lagoon digesters contain a floating impermeable cover placed over the surface of a manure treatment/storage lagoon. Biogas from the decomposing manure is collected under the cover. Covered lagoon digesters have been shown to be quite applicable to swine and dairy operations. At these operations, recycled water flushes the manure from the confinement facilities. Water and manure then run into the primary lagoon (through a solids separator at dairy operations) which has a large cover made of durable membrane. Under this cover, microorganisms work to break down the manure and produce biogas, which is about 70% CH_4 and 30% CO_2. The biogas bubbles to the surface and is captured under the cover. The gas is then piped out and used to generate electricity, heat water, and even to run chillers.[32]

Economics for Actual Anaerobic Digesters in the U.S. (C$)

	Covered Lagoon	Plug Flow	Complete Mix
Farm Description	1,000 Milker Dairy	15,000 total head with 5,000 milkers	1,500 sow farrow to finish
Total Capital Costs	$370,000	$435,000	$360,000
Annual Electricity Benefits	$81,000	$180,000-$230,000/yr	$72,000/yr
Annual Operating Costs	$15,000	$17,500-$22,000/yr	$7,000
Payback Period	5.5 years	<3 years	4-5 years

Source: U.S. EPA, *Methane Recovery from Animal Manures - The 1997 Opportunities Casebook.*

Plug flow digesters are constant volume, flow-through units that decompose high solids (>11%) dairy manure (plug flow digesters only work with dairy scraped manure and cannot be used with other livestock manure) to produce biogas and a biologically stabilized effluent. The plug flow digester design is a long tank, often built below ground level, with a gas-tight, expandable cover. The tank volume equals the volume of the manure input times the manure retention time, which is typically 15 to 20 days. Plug flow

32 Ibid.

digester systems also include the manure collection system, mixing pit equipment, and an effluent storage system. [33]

Complete mix digesters are heated, constant volume, mechanically-mixed, tanks that decompose swine or dairy manure (3-8% total solids) to produce biogas and a biologically stabilized effluent. The basic complete mix digester design is a vertical, poured concrete or steel circular container, with a gas-tight collection cover. Because complete mix digesters are heated to optimize methane production, they can be economically sized for use in any climate.

10.5 Suitability for GHG Emissions Trading

The discussion of the suitability of emissions trading programs to encompass CH_4 emissions from manure management is quite similar to the discussion of enteric fermentation (elsewhere in this report). The most appropriate emissions trading program would be a credit trading program based on an emission rate (i.e., emission factor) for baseline emissions as well as an emission rate once certain best management practices/technologies are employed. The farmer would receive credit once it is verified that these practices/technologies were employed. The credits would be received at the point of sale.

A distinction between enteric fermentation and manure management is that significant quantities of CH_4 emissions are concentrated at fewer farms for manure management. It is those farms that employ manure management systems that promote anaerobic decomposition of manure where there are greater quantities of CH_4 emissions. Large beef cattle farms, for instance, where the cattle are free roaming for the most part, and where the manure would be decomposed aerobically would not contribute significant amounts to manure related CH_4 emissions, even though there may be a very large number of livestock located on that farm. However despite this distinction, the recommend emissions trading program is the same as that recommended for CH_4 emissions from enteric fermentation (i.e., a credit trading program).

Having made this recommendation, it is important to note that an emissions rights trading program may be more attractive for this emissions source than for enteric fermentation because of the fact that there are not as many "major" sources. Emissions rights could be allocated among those largest farms which promote anaerobic decomposition of manure. There are several technologies/best management practices that could be employed to reduce CH_4 emissions and that can be easily verifiable. Emissions trading could then take place among those large farms. It is not recommended that the smaller farms, which only contribute minor amounts to overall manure related CH_4 emissions, be included in any such emissions rights trading program. The inequity of allocating rights to those farmers

33 U.S. EPA, AgSTAR Technical Series: Plug Flow Digesters, February 1997, pg. 1-2.

that promote anaerobic decomposition of manure while not distributing rights to those farmers who do not employ those manure management systems, would have to be addressed.

The substance trading program was discounted because there is no one substance that is an appropriate proxy for CH_4 emissions from manure management. The level of CH_4 emissions at farms result from a number of factors including feed used, size and type of animal, weather conditions, manure management systems in place, etc. Due to these wide ranging factors and no one appropriate substance to base a trading program upon, the substance trading system is not considered appropriate.

11. Fertilizer Use

11.1 Source and Quantity of GHG Emissions

In 1995, fertilizer application accounted for a total of 13 kt of N_2O emissions (4,030 kt of CO_2 equivalent) which represented approximately 3% of total non-combustion GHG emissions in Canada as well as 0.6% of total Canadian GHG emissions. A significant increase in N_2O emissions from fertilizer application in Canada has occurred in the first half of the 1990's (i.e., >24%). The rationale for this upward trend in N_2O emissions in the early 1990's has been the increase in fertilizer application, specifically nitrogen based fertilizers.

Trends in N_2O Emissions From Fertilizer Application in Canada

Year	N_2O Emissions	CO_2 Equivalent Emissions
	(kilotonnes)	
1990	11	3,410
1991	11	3,410
1992	12	3,720
1993	13	4,030
1994	13	4,030
1995	13	4,030

Source: Environment Canada, Trends in Canada's Greenhouse Gas Emissions 1990-1995.

When nitrogen-based fertilizers are applied to soil, N_2O emissions generally increase unless the amount of nutrient applied precisely matches the plant uptake and soil capture. N_2O emissions from fertilizer application occur due to anaerobic and aerobic processes. When either inorganic or organic fertilizers are applied to soil, most of the nitrogen is oxidized to nitrates before it is taken up by the plants. This process is referred to as nitrification. Anaerobic emissions of N_2O occur when soils become waterlogged. In an anaerobic environment, such as that of waterlogged soil, nitrates are reduced by facultative anaerobic bacteria to N_2O and N_2 gas, which are emitted to atmosphere. This process is referred to as denitrification; the loss of nitrogen in the soil.[34]

Several factors control the rate of the two microbial processes (nitrification and denitrification) that result in N_2O emissions. Among these variables are soil water

34 Jaques, A., et al, "Trends in Canada's Greenhouse Gas Emissions (1990 to 1995)", Environment Canada, April 1997.

content, temperature, nitrate or ammonium concentrations, available organic carbon for identification, and pH.[35]

11.2 Nature of GHG Emissions Stream

Emissions of N_2O are dispersed across the country, wherever fertilizer is applied. However, a large portion of these emissions would be located in the agricultural belt on the Prairies. No data currently exists in Canada on the consumption of urea, anhydrous ammonia or the other nitrogen based fertilizers by large farms in Canada. Therefore, it is difficult to estimate just how many farms in Canada would represent, say 50%, of nitrogen based fertilizer application (and potentially N_2O emissions) in Canada.[36]

Nitrogen based fertilizers are used to increase the nitrogen content of soils to a point which maximizes crop yield. Different types of nitrogen based fertilizers are applied in Canada. Urea and anhydrous ammonia are the two most commonly used fertilizers, together representing approximately 72% of the mineral nitrogen applied as fertilizer annually in Canada.

Based on current estimates, the application of anhydrous ammonia is the source of 85% of fertilizer related N_2O emissions in Canada. Compared to anhydrous ammonia, 750,000 more tonnes of urea are applied in Canada (which corresponds to a total of 158,000 more tonnes of nitrogen nutrient applied with urea than anhydrous ammonia). However, urea only represents approximately 8% of N_2O emissions while anhydrous ammonia represents 85%. This disparity is due to the fact that anhydrous ammonia has such a high emission factor (i.e., 1.63%) compared to urea (i.e., 0.11%) and all the other nitrogen based fertilizers.

35 Intergovernmental Panel on Climate Change, Climate Change 1995. Impacts, Adaptations and Mitigations of Climate Change, 1996, pg. 761.

36 Interview with Mr. Jim Farrell, Canadian Fertilizer Institute, August 5, 1998.

Canadian Fertilizer Use and Related N_2O Emissions in 1995

Fertilizer Material	Quantity (tonnes)	N Content (tonnes)	Average Loss (% N)	N_2O (tonnes)
Nitrogen				
Urea	1,304,730	600,176	0.11	1,037
Ammonia Sulphate	205,330	43,119	0.12	81
Ammonium Nitrate	256,697	87,957	0.26	369
Anhydrous Ammonia	553,727	442,581	1.63	11,336
Nitrogen Solutions	232,906	66,029	0.11	114
Other Nitrogen	3,199	0	0.11	0
Calcium Ammonium Nitrate	32,849	8,470	0.03	4
Phosphate				
Monoammonium Phosphate	937,031	103,073	0.12	194
Diammonium Phosphate	180,785	32,541	0.12	61
10-34-0	1,705	238	0.11	0
Other Fertilizers	293,804	64,171	0.11	111
Total	**4,002,765**	**1,448,355**		**13,300**

Environment Canada, *Trends in Greenhouse Gas Emission, 1990-96.*

11.3 Potential for Measuring, Monitoring and Calculating the GHG Emissions Stream

There is currently very high uncertainty in the N_2O emissions attributed to fertilizer application in Canada. In fact, Environment Canada does not even allocate an uncertainty factor to estimates of N_2O emissions attributed to fertilizer application in their GHG inventory. Currently, Environment Canada utilizes emission factors (i.e., average loss (% N) in table above) for the various different nitrogen based fertilizers and applies these factors to fertilizer application quantities.

International work on this subject has indicated that up to 50% of N_2O releases from fertilizer application may not be included in current estimates. Current N_2O emission estimates are based on emission factors developed from on-field emission measurements, while much of the fertilizer applied to fields is released off-site due to runoff and losses of ammonia. Future emission estimates for Canada may reflect these additional sources as the new GHG inventory procedures document, published by the IPCC, details some new methodologies to estimate emissions from these additional sources.

Emission factors will be the method used to estimate N_2O emissions in the future. To incorporate those technologies, practices, etc. (see below) that can reduce N_2O emissions, adjusted emission factors will have to be developed that reflect their relative contribution to a reduction in N_2O emissions and therefore quantify the credit that would be accrued and used for emissions trading purposes.

11.4 Options to Reduce GHG Emissions

A wide variety of farm management practices and technologies have been developed or are in the development stage that can reduce N_2O emissions from fertilizer application.[37]

Expected Reduction of N_2O Emissions Assuming Global Application of Mitigation Practices

Practice Followed	Estimated Decrease in N_2O Emissions
	(Mt N/yr)
Match N Supply with Crop Demand Use soil/plant testing to determine fertilizer N needs Minimize fallow periods to limit mineral N accumulation Optimize split application schemes Match N application to reduced production goals in regions of crop overproduction	0.24
Tighten N Flow Cycles Integrate animal & crop production systems - manure reuse in plant production Maintain plant residue N on the production site	0.14
Use Advanced Fertilization Techniques Controlled-release fertilizers Place fertilizers below the soil surface Foliar application of fertilizers Use nitrification inhibitors Match fertilizer type to seasonal precipitation	0.15
Optimize Tillage, Irrigation, and Drainage	0.15
Total	**0.68**

Source: Intergovernmental Panel on Climate Change, *Climate Change 1995. Impacts, Adaptations and Mitigation of Climate Change*, 1996, pg. 763.

Three technologies or management practices are discussed in this section, namely: (i) fertilizer management practices; (ii) nitrification inhibitors; and (iii) irrigation water management.

11.4.1 Fertilizer Management Practices

37 Carbon dioxide emissions from soil are not included in this investigation.

A better matching of mineral fertilizer to crop requirements would result in a reduced demand for fertilizer and consequently reduced N_2O emissions. This increased efficiency can be achieved by:[38] [39]

- using nitrogen testing kits to more closely match crop requirements to nutrient inputs;
- regularly calibrating machinery to ensure accurate delivery of fertilizers;
- paying careful attention to the frequency, timing and appropriate placement of fertilizer applications;
- dispensing with the maintenance concept, which fails to recognize the amount of residual N in the soil and the soil's nitrification potential;
- adjusting the rate of N to a reasonable yield goal for the specific crop and field or soil;
- placing N deep enough in the soil to lower the N_2O/N_2 ratio when denitrification does occur; and
- taking into account soil N mineralization and the N from legumes, manures, organic wastes, irrigation water and other potential sources.

It has been estimated that increased fertilizer efficiency has the potential to reduce N_2O emissions by 0.3-0.9 Mt N_2O-N/yr globally. In addition, fertilizer production is very energy intensive so by reducing fertilizer use, and therefore production, CO_2 emissions will also be reduced.

11.4.2 Nitrification Inhibitors

Nitrification inhibitors are chemicals applied with fertilizers to maintain the added nitrogen as ammonium. Nitrification inhibitors stabilize fertilizer applied as NH_3 or in the NH_4+ form by inhibiting activity of the *Nitrosomonas* bacteria in the first step of the nitrification process. Nitrogen losses are reduced if applied nitrogen remains in the NH_4+ form for several weeks after application, especially when applied in the fall or when there may be heavy rainfall during the spring. An inhibitor, such as nitrapyrin or acetylene, can be effective in many field crop situations.[40]

11.4.3 Irrigation Water Management

Usually emissions of denitrification gases occur immediately following each irrigation. Since N_2O can be further altered to N_2 during transport to the soil surface, there is greater opportunity to decrease the N_2O/N_2 ratio of the resulting gases when the mineral N is

38 Organization for Economic Cooperation and Development, Policies and Measures for Common Action Working Paper 7 - Agriculture and Forestry, Identification of Options for net GHG Reduction, July 1996, pg. 26.

39 Centre for Agricultural Science and Technology, Preparing U.S. Agriculture for Global Climate Change, June 1992, pg. 76.

40 Centre for Agricultural Science and Technology, Preparing U.S. Agriculture for Global Climate Change, June 1992, pg. 77.

placed deeper in the soil. Infrequent irrigation (compared to more frequent irrigation) decreases the number of denitrification cycles and also helps move soluble N deeper into the soil where supplies of O_2 are more limited which reduces the amount of N_2O that may form from N_2.[41]

There has not been a significant level of economic analyses undertaken on the practices to reduce N_2O emissions from fertilizer application. The rationale for this lack of work is that some of the practices may not be used by a large number of farmers and where they are, they relate to complex farming systems and it is therefore difficult to isolate costs and benefits.[42] Fertilizer management practices, nitrification inhibitors and irrigation water management technologies are all available and have low reported capital costs.[43] These practices are more likely to be economically feasible on crops that have high N demands (e.g., corn, cotton and wheat)..[44]

11.5 Suitability for GHG Emissions Trading

A substance trading program is believed to be the most appropriate emissions trading system to address N_2O emissions from fertilizer application. The substance that the trading would be based upon would be adjusted nitrogen, which is actually the quantity of nitrogen used to produce fertilizer adjusted to take the respective N_2O emission factors of different fertilizers into account. The system would be applied at the fertilizer production level since there are only a handful of nitrogen containing fertilizer producers in Canada. Each of the Canadian fertilizer producers would be provided a cap on the amount of adjusted nitrogen that could be used to produce fertilizer. The adjustment to the nitrogen serves to link potential N_2O emissions that would result from the application of fertilizer to Canadian soil to the fertilizer that is produced in Canada. With this adjustment, producers can decide how to allot their adjusted nitrogen among the various different nitrogen based fertilizers that can be produced.

The consumption of nitrogen has to be adjusted to take into account the various different emission factors that exist for the application of nitrogen containing fertilizers. Therefore this is not a typical substance trading program because there is a wide variation in N_2O emissions from different nitrogen containing fertilizers. For instance, if only nitrogen was simply allocated and not linked to N_2O emissions, then producers could conceivably use

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41 Symbiotic Environmental Research and Consulting, Inventory of Technologies to Reduce Greenhouse Gas Emissions from Agriculture, pg. 16-17.

42 Organization for Economic Cooperation and Development, Policies and Measures for Common Action Working Paper 7 - Agriculture and Forestry, Identification of Options for net GHG Reduction, July 1996, pg. 32.

43 Symbiotic Environmental Research and Consulting, Inventory of Technologies to Reduce Greenhouse Gas Emissions from Agriculture, pg. 26.

44 Intergovernmental Panel on Climate Change, Climate Change 1995. Impacts, Adaptations and Mitigation of Climate Change, 1996, pg. 765.

all available nitrogen allocated to them in order to produce those fertilizers with the highest N_2O emission factor with the result being higher N_2O emissions. The key to the program would be link nitrogen use to the estimated N_2O emissions from the fertilizer produced by each fertilizer producer in Canada. The use of the N_2O emission factor for the various different fertilizers provides this link.

Canadian Nitrogen Based Fertilizer Producers

Company	Plant location
Agrium	Redwater, AB
Agrium	Ft Saskatchewan, AB
Saskferco Products	Belle Plaine, SK
Agrium	Carseland, AB
Terra International	Courtright, ON
Agrium	Joffre, AB
Hydro Agri Canada	Maitland, ON
Orica Canada	Carseland, AB
Simplot Canada	Brandon, MB
Western Cooperative Fertilizers	Calgary, AB
Pacific Ammonia	Kitimat, BC

For instance, if a producer chose to manufacture anhydrous ammonia with their allotted adjusted nitrogen, then this producer would use up a large proportion of their allotted adjusted nitrogen on a small quantity of anhydrous ammonia because of the high emission factor. For example, if a producer was allocated 100 tonnes of adjusted nitrogen, the company could use 61 tonnes of nitrogen to produce anhydrous ammonia which has an N_2O emission factor of 1.63 (i.e., 61 tonnes of nitrogen multiplied by 1.63 = 100 tonnes). The manufacturer could also opt to use 909 tonnes of nitrogen to produce urea which has an N_2O emission factor of 0.11 (i.e., 909 tonnes of nitrogen multiplied by 0.11 = 100 tonnes). Applying the adjustment equalizes the disparity in emission factors between the different nitrogen based fertilizers.

However, the actual emission trading system may have to take several other factors into consideration, for instance: the fact that urea production sequesters CO_2; the effect that applying different fertilizers has on crop yields (i.e., different potential sequestering rates); urea production requires more energy than other nitrogen based fertilizers; and urea releases CO_2 in the field but anhydrous ammonia does not.

Since emissions take place from farms, a substance trading program administered at the producer level would have to take fertilizer trade into account. Producers and importers of fertilizers may have to hold permits, while producers would be entitled to receive credits

for any fertilizer exports if the destination country does not participate in a trading program. This would match the permits with the domestic consumption of fertilizer and therefore, the N_2O emissions.

There are other potential emissions trading programs that could be applied to address N_2O emissions from fertilizer application. For instance an emissions rights, substance trading and credit trading program may all be applied at the farm level. However, these options are not viewed as favourable due to the much larger number of participants in this system as compared to applying the emissions trading program at the fertilizer producer level. It should be noted that a credit trading program could also be applied at the producer level, with credits being accumulated from a shift in production to fertilizers with a lower N_2O emission factor.

12. Ammonia Production

12.1 Source and Quantity of GHG Emissions

Ammonia (NH_3) is produced in large industrial plants from nitrogen gas and hydrogen gas, mixed in a 1:3 ratio and reacted over a catalyst. Nitrogen gas is derived from air through liquefaction and separation. Hydrogen gas is usually produced from natural gas in a process known as steam methane reforming. In this process, carbon dioxide is produced as a co-product with hydrogen and must be separated as a fairly pure gas stream. If CO_2 from ammonia manufacture cannot be used further, it is emitted to atmosphere.

Urea [$(NH_2)_2CO$] is a solid form nitrogen-based fertilizer which is produced from ammonia and carbon dioxide. Urea production is often integrated with ammonia production to use the by-product carbon dioxide produced in the steam methane reforming process. In the form of urea, the carbon can be sequestered in plants or may be released to atmosphere after application to soils.

Environment Canada estimates that the net amount of CO_2 emitted from ammonia production is 3,800 kt in 1995. This represents about 3% of non-combustion GHG emissions and about 0.6% of total GHG emissions. The calculation is based on emission factors and the industrial production levels of ammonia and urea. The net emissions of CO_2 from ammonia production take into account the CO_2 used in the manufacture of urea.

Trends in CO_2 from Ammonia Production

	1990	1991	1992	1993	1994	1995
Net CO_2 Emissions (kt)	3,200	3,400	3,500	3,600	3,800	3,800
Gross Ammonia Production (Mt)	3.7	3.7	3.8	4.1	4.2	4.2
Urea Production (Mt)	2.6	2.4	2.5	2.9	2.9	2.9

Source: 1995 GHG Inventory

Urea is made by reacting ammonia with carbon dioxide. Approximately 0.6 kg of ammonia and 0.75 kg of carbon dioxide are required for every 1 kg of urea made. A large portion of the carbon dioxide produced from ammonia plants is already used to make urea. Canadian production of urea represents 55% of the total domestic demand for ammonia.

Canadian Ammonia and Urea Capacities, 1995

Company	Location	Ammonia	Urea
		(kt)	(kt)
Agrium Inc.	Redwater, AB (2)	880	600
Agrium Inc.	Ft Saskatchewan, AB	440	370
Agrium Inc.	Carseland, AB	550	730
Agrium Inc.	Joffre, AB	420	0
Canadian Fertilizers Ltd.	Medicine Hat, AB	1050	680
Pacific Ammonia Inc.	Kitimat, BC	260	0
Saskferco Products Inc.	Belle Plaine, SK	630	930
Sherritt International	Ft Saskatchewan, AB	150	100
Simplot Canada Ltd.	Brandon, MB	190	150
Terra International	Courtright, ON	380	250
Total capacity		4950	3810

Source: Canadian Fertilizer Institute

12.2 Nature of GHG Emissions Stream

The CO_2 emitted from ammonia manufacture is concentrated as a fairly pure stream (greater than 90% purity) in a single point source from the steam methane reforming plant. CO_2 is usually separated from hydrogen gas in a pressure swing absorption (PSA) unit on the tail end of the steam methane reforming unit.

12.3 Potential for Measuring, Monitoring and Calculating the GHG Emissions Stream

Since the CO_2 gas stream is fairly concentrated and emanates from a single point source, emissions can be calculated fairly accurately from gas flow rates and concentration measurements.

12.4 Options to Reduce GHG Emissions

The model for reducing carbon dioxide emissions by sequestering with ammonia in increased amounts of urea involves one of three options:

- increasing production of urea at Canadian facilities to fill existing capacity;
- expansion of existing urea facilities
- construction of new urea production facilities

Urea production is currently dictated by the market demand for urea fertilizers. Urea demand in North America has grown steadily over the last decade at an average annual rate of about 7% per year. Roughly half of all Canadian production of urea is exported, mostly to the US midwest. The capital cost to construct a new 750 kt/year urea plant in Canada is roughly estimated at C$200 to 300 million[45].

12.5 Suitability for GHG Emissions Trading

The fact that there are only 10 ammonia plants and 8 urea plants operated by 7 companies in Canada means that most of the CO_2 emissions from ammonia manufacture are covered by a small number of entities in a trading system. The emissions are measurable and verifiable. Producers have the ability to increase the amount of urea production, either through increased production at existing plants or through the addition of new capacity.

An emission rights trading program or a credit trading program would be suitable for the CO_2 emissions from ammonia production. Since CO_2 is created in the production process, a substance trading program is not suitable.

45 Industry sources

13. Agricultural Soils

13.1 Source and Quantity of GHG Emissions

Agriculture and Agri-Food Canada applies a computer model (i.e., the Century model) to develop an estimate of CO_2 emissions that adequately reflects the complexities that impact carbon fluxes in agricultural soils. The Century model requires several different inputs, such as: multiple soil organic matter compartments; decomposition rates that vary as a function of soil temperature and precipitation; and carbon and nitrogen flows. In addition, the Century model takes several agricultural management practices into account, including planting, fertilizer application, tillage, and grazing.[46]

Environment Canada estimates that in 1995, there were 2,480 kt of CO_2 emitted from agricultural soils, which represents approximately 2% of total non-combustion GHG emissions in Canada or about 0.4% of total Canadian GHG emissions.

Trends in CO_2 Emissions From Agricultural Soils in Canada

Year	CO_2 Emissions
	(kt)
1990	7,090
1991	5,820
1992	5,000
1993	3,940
1994	3,490
1995	2,480

Source: Environment Canada, Trends in Canada's Greenhouse Gas Emissions 1990-1995.

There has been a decrease in CO_2 emissions from agricultural soils over the 1990-1995 time period. The trend in net emissions is towards an overall state of equilibrium of carbon in Canadian soils, which was predicted to occur in 1997. The Century model has estimated that the rate of decline in CO_2 emissions from 1990-1996 is approximately five times greater than for the period 1980 to 1990, reflecting changes in agricultural practices.[47]

46 Environment Canada, Trends in Canada's Greenhouse Gas Emissions 1990-1995, pg. 52.
47 Ibid.

13.2 Nature of GHG Emissions Stream

CO_2 emissions from agricultural soils occur over a vast number of farms across Canada. There are a total of 250,000 commercial farm operations in Canada, most of which use their soil area for some sort of plant growth. CO_2 emissions result from the aerobic decomposition of organic matter in soils. When the carbon in soils is in equilibrium, the amount of carbon sequestered in organic matter offsets the emissions from organic matter decomposition and the net carbon stock is stable. There are many factors which affect the rate of decomposition, including climate conditions and soil management practices.

It should be noted that the CO_2 emissions profile for agricultural soils varies across Canada. Regionally, most of the CO_2 would be emitted or sequestered on the agricultural belt on the Prairies as well as in Ontario.

CO_2 emissions from agricultural soils can vary widely among farms even if the same crops are grown on these farms. There are several different agricultural management practices that can either promote CO_2 fluxes or the sequestration of CO_2. The implementation of the mix of these agricultural practices has significant impacts on overall net CO_2 fluxes from individual farms. A brief discussion of a number of these agricultural practices is provided below.

13.3 Potential for Measuring, Monitoring and Calculating the GHG Emissions Stream

Both Environment Canada and the Intergovernmental Panel on Climate Change (IPCC) have recognized that there is a relatively high uncertainty with respect to estimating CO_2 fluxes from agricultural soils. Environment Canada has not developed uncertainty levels for CO_2 emission estimates from agricultural soils as they have done for several other non-energy sources of GHG emissions. The IPPC suggests that there is a high degree of uncertainty in their estimates concerning both flux rate and carbon (C) storage capacity, as well as in the level at which various mitigation options could be implemented.[48]

As mentioned, the Century model is currently being used in Canada to estimate CO_2 fluxes from agricultural soils. Several data sources are required as inputs to the model. On a Soil Landscape of Canada polygon basis, Statistics Canada agricultural census data were used to obtain crop cover and percentage of conventional and no-tillage figures for census years. Yearly crop coverage from 1990 to 1995 was taken from Statistics Canada core data. Soil data were derived from the Canadian Soil Information System, and recent fertilizer consumption and tillage practices were derived from the Farm Income Policy

48 Intergovernmental Panel on Climate Change, Climate Change 1995. Impacts, Adaptations and Mitigation of Climate Change, 1996, pg. 757.

and Programs Directorate of Agriculture and Agri Food Canada. Based on these inputs, the Century model was used to estimate annual CO_2 fluxes for 1990-1995.

The Century model will probably have to be used in the future to estimate the increased sequestration of CO_2 due to the implementation of agricultural practices which discourage CO_2 fluxes. However, the verifiability of these emission estimates is questionable as there are several factors which influence CO_2 fluxes from agricultural soils. Implementing agricultural practices to sequester more C in the soil can have a range of success based on weather conditions as well as many other factors. The ability to capture all of these conditions at an individual farm level, for the purposes of an GHG emissions trading program, is questionable.

13.4 Options to Reduce GHG Emissions[49]

Soil organic carbon in permanently cropped fields can be increased through a number of management practices, for instance: increased return of organic materials to soil; decreased periods of fallow; use of perennial and winter cover crops; recycling of organic wastes; reduced tillage; erosion control; and agroforestry. Several long-term experiments have demonstrated that for many soils, organic carbon levels are directly proportional to the annual rate of carbon input. Increasing crop production through better nutrient management, reduced fallow periods, and improved cultivars can increase C inputs to soil if crop residues are retained.

Summer fallow is used extensively in semi-arid areas of Canada to offset rainfall variability and increase soil waste storage. Eliminating or reducing summer fallow through better water management could significantly increase C in semi-arid croplands and decrease soil erosion.

Greater use of perennial forage crops can also significantly increase soil C levels, due to high root C production, lack of tillage disturbance, and protection from erosion. Where climate permits, winter cover crops decrease erosion and provide additional inputs of C, thereby increasing soil organic carbon. Another management practice to sequester more C is to apply large quantities of manure to the fields. Reduced or no-tillage often (but not always) increases soil C. Several studies have shown however genuine increases in soil organic content as a result of reduced tillage.

The potential carbon sequestration in Canadian agricultural soils over the next 50 years was recently estimated using long-term field data and the Century model. The researchers applied the following assumptions to the Century model: cropland area in Canada would remain within 5% of the current area; there would be a major reduction in summer/fallow

49 Majority of this section was taken from Intergovernmental Panel on Climate Change, *Climate Change 1995. Impacts, Adaptations and Mitigation of Climate Change*, 1996.

in the Chernozemic soil zone; and cropping practices would be intensified, with increased fertilizer use, improved residue management with reduced tillage, and better erosion control. Over a 50 year period, the researchers estimated an increase storage of 22 Mt C due to reduction of summer fallow and 69 Mt C from increased hay crops in rotations. Proper fertilization and erosion control through zero-tillage and other measures were also projected to further increase C storage. Summing all of these management practices resulted in estimates of annual C storage equivalent to 3.4% of Canada's present CO_2 emissions.

The potential costs associated with promoting C storage in agricultural soils include fossil fuel requirements (e.g., fertilizers), lost production (e.g., set-aside programs), and additional labour and financial requirements (e.g., land restoration). These potential costs may constrain the potential for increasing C storage.

13.5 Suitability for GHG Emissions Trading

An emissions trading program for agricultural soils can be evaluated in regards to C fluxes as well as to the sequestration of C. With respect to C fluxes, soils are not deemed to be an appropriate source for emissions trading for a number of reasons, among them: agricultural soils are thought to be too small of a source of CO_2 to warrant inclusion in an emissions trading program; there are thousands of sources of CO_2 from agricultural soils distributed throughout Canada; the actual credits that could be obtained by farmers would for the most part be minimal; and soils are expected to become a net C sink in 1997, although future runs of the Century model will have to determine if this expectation is correct. Therefore based on these factors, the potential of including agricultural soils in a GHG trading program would be as a sink, that is as a sequester of C.

The potential of agricultural soils to be included in a trading program as a sink would also be problematic for some of the same reasons. For instance, accounting for the sequestration of C would be very cumbersome due to the wide range of farms that could potentially be claming credits (i.e., in the thousands). In addition, the accuracy of the current estimates of the sequestering capabilities of certain agricultural practices may not be acceptable, especially when one considers the wide range of factors that can influence the overall sequestering capability of implementing those practices. Furthermore, the verifiability of sequestering C is unclear and should it be required may prove to be quite problematic and resource intensive.

Nevertheless should a trading program be developed for agricultural soils on a sink basis, then it should be noted that sequestration and storage actions are only suitable for credit trading. Emissions rights cannot be allocated and then traded as agricultural soils are expected to be a net sink in the near future, if not already. In addition, there is no one substance that could be traded which would reflect the sink potential or gross emissions of agricultural soils.

The key to any trading program for agricultural soils would be the ability to estimate and then verify the C sequestering capabilities of various agricultural practices on a farm basis, or potentially even on a regional basis.

14. Magnesium Smelting and Die Casting

14.1 Source and Quantity of GHG Emissions

SF_6 is a heavy, inert specialty gas that has a GWP estimated to be 23,900 times that of carbon dioxide. Small amounts of this gas have a significant impact on greenhouse gas totals. This section examines its use and emissions in primary and secondary magnesium production as a component of inert blanket gases used to prevent molten magnesium from igniting explosively in air.

The primary and secondary magnesium industry is the largest industrial source of sulphur hexafluoride (SF_6) emissions in Canada, accounting for an estimated 75 tonnes of SF_6 in 1995, or about 1,900 kt/yr of CO_2 equivalent. This represents just over 1% of total non-combustion GHG emissions and 0.3% of total Canadian GHG emissions.

In Canada, the 75 t/yr of SF_6 used for magnesium operations is estimated to be about 35-40% of the total demand of 200 t/yr. Worldwide, the magnesium end use represents only about 10-15% of SF_6 use, but Canada has a greater fraction because of its large primary magnesium industry.

The other significant end use of SF_6 is as an insulating gas (dielectric) for electrical utility equipment, representing roughly 60% of use in Canada. There are numerous miscellaneous uses for high purity SF_6 in the electronics, small metal parts and medical products industries which may account for less than 5% of use. These other end uses are examined in section 17.

Estimated Canadian SF_6 Demand, 1995

	Volume (t/yr)
Electric Equipment	120
Primary Magnesium Production	50
Secondary Magnesium Processing	25
Miscellaneous (Electronic, Medical, Analytical)	5
Total (all imported)	200

Source: Interview with Canadian distributor, CHEMinfo estimates

14.1.1 Magnesium Production

There are two primary magnesium production plants currently operating in Canada. The Norsk Hydro facility in Bécancour, PQ is the largest, and one of several, this market-leading company operates worldwide. It has a capacity of about 43 kt/yr, but is increasing capacity to 68 kt/yr by the year 2000 and there are plants to increase again to 86 kt/yr thereafter, due to high demand growth for diecast automotive parts. A second, much smaller facility is operated by Timminco in Haley Station, ON. It has a capacity of about 4 kt/yr and produces magnesium, calcium and strontium alloys. Magnola Metallurgy is building a new 58 kt/yr magnesium smelter in Asbestos, PQ, which will start up in June 2000. It represents potential future source of SF_6 emissions.

Primary and Secondary Magnesium Production in Canada

Company	Location
Primary Producers	
Norsk Hydro	Bécancour, QC
Timminco	Haley Station, ON
Secondary Processing	**(Diecasters)**
Trimag	Haley Station, ON
Dynacast	Pointe Claire, PQ
Magnesium Products Ltd.	Strathroy, ON
ITM	Quebec City, PQ
Indalloy	Rexdale, ON

Source: company interviews

In secondary magnesium processing, magnesium ingots are die casted into auto and aerospace parts. The die casting process also requires the use of a SF_6 blanket gas on small furnaces, since the magnesium is cast as molten metal. Roughly 30% of the magnesium produced in Canada is used by domestic die casters. The remainder is exported. There are only about 5 or 6 die casters who work with magnesium in Canada.

Over the 1990-1995 period, emissions have been steadily decreasing due to continuing efforts to decrease utilization rates. While primary production increased marginally, SF_6 utilization rates were lowered to levels around 0.7-0.8 kg SF_6 per tonne of magnesium produced. Norsk Hydro, who account for a good portion of SF_6 usage, claims they have decreased their utilization rate to 0.64 kg/t in 1997 and are projecting a rate of 0.53 kg/t in 1998. In theory, there is a practical minimum limit in the range of 0.4 - 0.5 kg/t.

SF_6 Emissions from Magnesium Manufacturing

	1990	1991	1992	1993	1994	1995	2000
SF_6 Emissions(t)	120	136	91	84	85	79	100
CO_2 Eq (kt)	2,870	3,250	2,170	2,010	2,030	1,980	2,390

Source: Environment Canada

The planned increase in capacity at Norsk Hydro and startup of Magnola Metallurgy will likely add another 25-30 t/yr of SF_6 emissions after 2000. The projected emissions for the year 2000 assume this extra usage.

14.1.2 Supply

All Canadian supply is imported. The total Canadian market demand for SF_6 is estimated roughly at 200 t/yr. The gas is produced in the US by only 2 producers: Air Products (Hometown, PA) and AlliedSignal Specialty Chemicals (Metropolis, IL), who participate in the highly specialized fluorinated compounds industry.

The Canadian market is supplied by specialty gas distributors who ship SF_6 in small cylinders in three different grades (by increasing purity): commercial, instrument and very-large scale integration (VLSI). The major Canadian distributors are: Air Products Canada Ltd., Praxair Canada Ltd., and Canadian Liquid Air.

14.2 Nature of GHG Emissions Stream

When casting molten magnesium in primary production or secondary processing operations, an inert blanket gas is required to protect the magnesium surface from oxygen, because of the strong tendency of magnesium to oxidize explosively in air. While the inert gas is composed largely of nitrogen or carbon dioxide, SF_6 is used as a small component in the mixture to aid the protection of the magnesium surface and control burning. SF_6 concentration levels are very low and, over the last few years, have been reduced to lower than 1% in the inert gas. SF_6 is a very heavy gas (roughly 3 times heavier than air) and settles quickly to the surface with little turbulence in a contained surface area. When SF_6 contacts molten magnesium, a small portion of it chemically reacts with the magnesium to form a thin, impermeable molecular skin which is non-oxidizing. The "skin" can be separated later from the molten magnesium, leaving the latter in high purity form. This technique is preferred to the mixing of non-oxidizing fluxes with the magnesium because the purity issue is critical in diecasting operations.

SF_6 is also not harmful to humans in the range of concentrations used for magnesium production. The threshold limit value (TLV) issue is not significant. Sulphur and sulphur dioxide have been used for this purpose in the past, but use was discontinued due to health concerns and odour problems. Concentrations of SO_2 above 3 ppm are considered a workplace hazard.

14.3 Potential for Measuring, Monitoring and Calculating the GHG Emissions Stream

The SF_6 emissions from magnesium processing are not directly measurable, because they are a small portion of the inert gas which is not emitted as a point source. Emissions are believed to occur mostly through leakage from the magnesium smelting furnaces. To maintain the concentration levels required, a make up of fresh SF_6 is supplied from purchased cylinders. The purchased SF_6 is easily measurable. It is assumed that the portion of SF_6 that reacts with magnesium is small, such that the volume of purchases is roughly equal to the volume of atmospheric emissions.

14.4 Options to Reduce GHG Emissions

There are two basic technologies for reducing SF_6 emissions from magnesium production: reducing the utilization rate; and replacement with another blanket gas.

14.4.1 Reducing Consumption

Increased attention to process control has allowed average concentrations of SF_6 in the inert blanket gas to be lowered from the 1% level several years ago to levels reaching as low as 0.1% at times. The key to these improvements has been the improved ability to measure minute concentrations of SF_6 at various points on the molten magnesium surface. A better system of gas injection with improved metering has been used. A control system minimizes variations. Both Norsk Hydro and Timminco report use of these process control techniques. A second approach to reduction is the recycling of SF_6 gas. Timminco reports that some gas is recycled, but no details were provided for proprietary reasons. Norsk Hydro, as an industry leader is likely to practice some form of reuse or recycling. From the Norsk Hydro utilization rate numbers, it appears that further reductions in the SF_6 utilization rate will be small, as it is approaching the theoretical minimum. Therefore, the potential to reduce SF6 emissions through better process control is thought to be small.

14.4.2 Replacement with Alternate Blanket Gas Component

In theory, any inert gas would be able to replace SF_6 if it were able to completely block out oxygen. The chemical reaction with magnesium involves the sulphur atom. Sulphur and sulphur dioxide have been identified as the most promising alternative (albeit older) technologies. The use of argon (a heavy, inert gas) is also being explored in research work, although this does not involve a chemical reaction with magnesium. The critical technology issue with the SO_2 option is how to control SO_2 emissions to protect health and odour. The capital requirements would likely include special distributed feed systems, process control systems, containment systems and pollution control systems.

Norsk Hydro is conducting research into the replacement of SF_6 gas with SO_2 at its research centre in Oslo, Norway. The cost of the research project is bracketed at between 1 and 10 million dollars by a Canadian staff member. Norsk Hydro claims that they will definitely be replacing SF_6 gas in the future, but they don't know the timetable. Among the issues to resolve are the type of pollution control technology to protect the health of workers and the containment of the gases. Timminco only conducts process research. It is not known whether an SO_2 system could be adapted for use at smaller die casters.

The reduction potential with this system would be 100%, since a complete replacement is involved. The price of SO_2 is significantly lower than SF_6, (C$440/tonne bulk SO_2 vs. C$30,000/tonne packaged SF_6), but the consumption rate may be higher.

14.5 Suitability for GHG Emissions Trading

SF_6 emissions from primary and secondary magnesium production are not directly measurable, but the use of the purchased substance is measurable. Although Norsk Hydro is researching a replacement system, it is not known whether this technology can be transferred to other companies. The small magnesium die casters may find it prohibitive to develop their own replacement systems.

A substance trading program is most likely suited for this industry because of the ease of measurement of gas purchases. The use of SF_6 in magnesium production is concentrated in only a few firms (2 primary producers and about 5-10 die casters). Furthermore, the supply of the gas is concentrated in only a few distributors and could be regulated easily.

This application area is too small to have its own competitive trading program. it would have to be combined with other GHG sources. Since the other emissions of SF_6 are also based on volumes purchased by a limited number of utility companies, the entire SF_6 supply should probably be considered for a substance trading program.

15. Coal Mining

15.1 Source and Quantity of GHG Emissions

This section deals with methane (CH_4) emissions from coal mining and related coal processing activities. Carbon dioxide emissions associated with combustion of coal as an energy source and other uses are not included in this analysis.

Environment Canada's estimated methane emissions from coal in 1995 were 82 kilotonnes, or 1,700 kt of CO_2 equivalents. This represented 1.2 % of non-combustion GHGs or 0.3% of total Canadian GHG emissions.

Methane is contained naturally in coal deposits. The methane concentration relative to the amount of surrounding coal varies depending on such factors as the type of coal, geology of the region, and depth of the coal bed. Methane concentrations can range from seam to seam and even different sections of the same seam. For example, the methane concentration at the centre may be different than at the edge of the seam, where some of the methane may have already migrated to the surrounding soil. Soils or overburden around coal beds also contain methane that has desorbed from the coal and migrated into the soil. At coal fields where the coal is close to the surface, some of this methane may be continually released to air.

Coal Production and Exports by Province

Province	1996 Coal Production	% of Production	Exports
	(million tonnes)		
Alberta	36.1	48%	10.1
British Columbia	25.4	33%	25.0
Saskatchewan	10.9	14%	0.0
Nova Scotia	3.1	4%	0.1
New Brunswick	0.3	1%	0.0
Total Canada	75.8	100%	35.2

Methane is released to the atmosphere when coal is mined (or extracted) and during related post-mining activities. Mining activities result in emissions from the exposed coal surfaces and the coal rubble, as well as release of pressure on the coal. Emissions from post-mining activities occur during preparation, transportation, storage or final crushing,

before combustion. In 1996, Canada exported approximately 46% of its coal production. Approximately 70% of exports was coal mined in British Columbia. Nearly all the rest was exported from Alberta. A portion of methane emissions may be emitted during post-mining activities for coal exported to offshore markets.

15.2 Nature of GHG Emissions Stream

The concentration of methane contained in coal is different across Canada. In general, coal in Alberta, which is open pit or strip mined is low in methane, while coal mined underground in Nova Scotia has a much higher methane content and can result in much higher emissions. Underground coal is subject to higher pressure which favours the adsorption of methane with the coal matrix.

Provincial GHG Emissions From Coal Mining

Province	1996 Coal Production	Emission Factors[50]	Total GHG Emissions	
	(million tonnes)	(tonne CH_4/kt coal)	(Equivalent CO_2)	
Alberta	36.1	0.19 - 0.45	300	17%
British Columbia	25.4	0.58	570	34%
Saskatchewan	10.9	0.06	14	1%
Nova Scotia	3.1	13.79	830	48%
New Brunswick	0.3	0.13	1	<1%
Total Canada	75.8		1,700*	100%

Source: Environment Canada. * Rounded

Methane released during underground mining of coal is removed from the mine since it presents a hazard to the working environment. High flow ventilation systems are designed to pump fresh air through mine and move methane from the mine for release to the surface. The concentration of methane in the vented air is low, typically 0.2 to 1.0% by volume. One industry source[51] provided an example of one underground mine where the air flow rate was 12,000 cubic meters/minute. This makes treatment (e.g., combusting the methane - or essentially air) of these streams economically and potentially environmentally not feasible (e.g., it may be that more CO_2 emissions may result from combustion of the air than the reduction in the methane/CO_2-equivalent released, although this needs to be confirmed through analysis).

50 Jaques, A., et al, "Trends in Canada's Greenhouse Emissions, 1990 to 1995", Environment Canada, April 1997.

51 King, B., Neill & Gunter, Halifax, NS - Personal Conversation

In open-pit or strip mining operations, there are no contained methane streams. Methane is released to air from the surface of all coal exposed to air during the mining process. Similarly, there are no contained methane streams from post-mining activities. Not all of the methane in the coal will be released during post-mining activities (prior to combustion). The amount released will depend on such factors as the time duration between mining and use (e.g., combustion, steel making) and the surface area of the coal particles, ambient temperatures and other factors.

15.3 Potential for Measuring, Monitoring and Calculating the GHG Emissions Stream

In general, estimates of Canada's GHG emission associated with coal mining and post-mining activities are not highly accurate. Environmental Canada reports the uncertainty in its estimates of total emissions of 1,700 kilotonnes for Canada in 1995 as +/-50-20% (i.e., interpreted to mean the upper range of emissions could be 2,550 kt and the lower level of emissions could be 1,360 kilotonnes). One expert claims that individual coal fields within a province or even mined seams within a field can have methane concentrations which vary substantially. More research would be required to better define uncertainty levels for one portion of a defined coal bed boundary to another (e.g., between the "centre" of the seam and the edge).[52] There are different issues with respect to measuring, monitoring and calculating emissions from underground mining, surface mining and post-mining activities.

The best measurement of emissions are at underground mines. There have only been direct monitoring techniques applied to methane emissions from underground mines. The methane content of vented air can be relatively easily and inexpensively monitored, and is often undertaken due to operational safety considerations. [53] Therefore only incremental costs are likely to be required to calculate total mine emissions. However, in Canada there were only several underground producing mines in 1996 (assumed to be the same for 1995), which accounted for less than 5% of 1995 Canadian coal production, but nearly 48% of estimated GHG emissions. It is not clear in these estimates what portion of GHG emissions were attributable to actual underground mining activity versus post-underground mining activities. This split may be useful in that emissions reduction activities (i.e., reducing the time between mining and use) could be implemented on that portion of emissions.

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52 King, B., Neill & Gunter, Halifax, NS - Personal Conversation

53 Fiedler, J., Sussman, F., *Methane Emissions Trading: Determining the Suitability of Methane Sources for Trading, and of Integrating Methane and Carbon Dioxide Sources in Single Trading System, - Draft,* Prepared for the Centre for Clean Air Policy's GHG Trading Braintrust, June 24, 1998

Mining Types For Members of The Coal Association of Canada

Mining Type	1996 Coal Production		Producing Mines
	(million tonnes)		
Strip	34.7	47%	12
Open pit	33.4	45%	11
Underground	2.6	4%	2
Surface and Underground	3.0	4%	1
Total Coal Association Members	73.7	100%	26
Total Canada	75.8		28

Source: The Coal Association of Canada, 1997 Directory

The accuracy of continuous emissions monitoring equipment to monitor methane emissions from underground mines is relatively high and can be readily applied to estimating emissions for the mine given the measured flow rate of vented air[54].

Most of Canada's coal is produced in western Canada from strip and open mining operations. Although the amount of coal produced is carefully measured and monitored due to its commercial value, the amount of methane emissions from surface mining are not typically measured or monitored. To provide a rough estimate of these emissions, samples of coal to be mined were analyzed for methane concentrations and to estimate the amount of emissions that may result. Methane concentration estimates for some coal fields in Alberta, Saskatchewan and British Columbia ranged from 0.15 to 2.0 m3 per tonne of coal[55]. Environment Canada assumed that 60% of contained methane is emitted. It is not clear as to whether current estimates include methane emissions released from overburden at surface mining operations. Overburden can contain methane[56].

Methane emissions from post-mining coal activities are not easily measured, monitored or calculated. While the general emission factor of 60% on contained methane is applied to estimate total coal emissions, it is unclear what portion of these are emitted during post-mining activities. With a large amount of coal exported, some of these emissions may not be occurring in Canada.

In general, emissions from post-mining activity have yet to be well defined. Specific emission factors have not been identified (at least in this study) for each of the post-

54 King, B., Neill & Gunter, Halifax, NS - Personal Conversation

55 Jaques, A., et al, "Trends in Canada's Greenhouse Emissions, 1990 to 1995", Environment Canada, April 1997.

56 King, B., Neill & Gunter, Halifax, NS - Personal Conversation

mining activities (transportation, processing, grinding, etc.). These emission factors may be useful since they would relate to estimating the impact of applying potential GHG emission technologies or practices.

15.4 Options to Reduce GHG Emissions

In Canada, no mine operators are treating methane emissions from coal mines. While methane from underground coal operations is being captured and routed for venting, none of the mines treats the dilute methane contained in these streams. The main problem is that the stream contains too low a concentration of methane (mixed with air - oxygen and nitrogen) and too high a volume. Attempting to heat the methane/air stream in order to oxidize/combust the contained methane may be possible, but economically unattractive and potentially technically and environmental not feasible[57]. Such will be the case if the amount of carbon dioxide emitted as a result of the energy used to heat the gas stream is greater than GHG emissions reduced as a result of destroying the methane. Methane is oxidized at high temperatures. In addition, treating these dilute streams may even result in emissions of other pollutants (NOx, CO, etc.). The dilute streams do not offer significant heating value due to the contained methane.

In Canada, past examinations of piping mine vent streams to provide the air/oxygen requirements of boiler systems even at nearby (2-4 kilometers) has not proved to be economically feasible. In some cases, these systems can cost tens of millions of dollars with little incentive[58]. However, this control option may be more feasible in the United States where large mines may have nearby energy users which could utilize these methane containing streams.

No known methane emission control options are employed at surface mining operations in Canada. With emissions resulting from all surface coal exposed surface area, there is not practical way to collect and treat the methane.

Methane gas can theoretically be collected from the coal prior to mining. This is referred to as degasification. This option may be more suitable to underground mines which have a higher methane content in the coal. Degasification involves drilling wells or boreholes into the coal and sucking the methane out under pressure (using energy). The concentration of methane in this air stream can be as high as 60% by volume. At this high level the gas has heating value[59]. According to one report, 21 U.S. underground coal mines operate degasification systems, with 15 of these using the gas. Up to 60% of the

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57 Oxidizing methane to produce water and carbon dioxide reduces GHG emissions in that the methane molecule has 21 times more Global Warming Potential (GWP) than carbon dioxide (on a mass basis). However, carbon dioxide has a high molecular weight such that theoretical reduction potential is only 87% when methane is oxidized.

58 King, B., Neill & Gunter, Halifax, NS - Personal Conversation

59 King, B., Neill & Gunter, Halifax, NS - Personal Conversation

gas could be captured using these systems.[60] There are no known cases of surface mines employing degasification techniques. Surface mines have lower methane concentrations and the option may not be technically, economically or environmental feasible.

Although no practices have been documented that reduce methane emissions from post-mining activities, it is possible to contemplate some that may work at low cost. One practice could be to consume the coal as soon after it is mined as possible. In this way the more methane contained in the coal is oxidized during combustion (either as a fuel or in steel production). After approximately one month the amount of methane contain in mined coal is likely to be low or practically gone.[61] Another option may be to increase the particle size of the coal. This would extend the time the methane is contained in the coal. These are only suggestions of possible options that may be practical to reduce methane emissions from post-mining sources.

15.5 Suitability for GHG Emissions Trading

An allowance trading system would be most applicable to the few underground mines operating in Canada. The few, easily identifiable underground mines all in Atlantic Canada represent nearly 50% of estimate emissions from this area. Techniques are readily available to measure emissions from these sources in support of an allowance trading system. However, proven and cost effective options (i.e., degasification) have not been applied in Canada for reducing emissions from these sources. An emissions trading program applied to underground mines may have to be linked with other industrial sources since there are only a few underground mines in Canada. This would not provide for a robust market.

For surface mining, allowances could be based on emission factors, although some improvements in testing may be required and a better understanding of how emissions relate to coal extracted from different seams at different levels.

Similarly, emission factors could be developed to address emissions and corresponding allowances from post-mining activities. It may be important to incorporated these into the trading program since it is not currently known what portion of total emissions from coal these constitute and post-mining reduction practices may achieve better emissions reduction results than during mining.

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60 Fiedler, J., Sussman, F., *Methane Emissions Trading: Determining the Suitability of Methane Sources for Trading, and of Integrating Methane and Carbon Dioxide Sources in Single Trading System, - Draft,* Prepared for the Centre for Clean Air Policy's GHG Trading Braintrust, June 24, 1998

61 King, B., Neill & Gunter, Halifax, NS - Personal Conversation

With relatively few mines in Canada (29, or so) the trading system would have a high level of coverage from this source area. All mine operators could be involved with the administration trading system remaining manageable.

An issue with the trading system would be measurement and verification issues, especially at surface mining operations and post-mining operations in general. The variation in methane concentration in different regions, areas of the coal field, mine or seam may provide difficulties in establishing acceptable emission factors on which to base allowances. In addition, the ability to validate these emission factors as reasonably representative of actual emissions may also pose problems which could reduce the credibility of the system.

An alternative to the allowance trading system is to allow coals mines to generate credits for emissions reduction associated with recovery. The key advantage of this system would apply to underground mines which can accurately measure their emissions. This system may be less suitable for surface mining operations, where emissions are much more difficult to measure or monitor. In this system the difficulty of assigning and verifying compliance with allowance terms would not arise for underground mines. The key disadvantage is that a credit system only reduces and redistributes the overall cost of control, but does not provide additional controls on emissions. Other issues are that early credits, profitable recovery, baseline determination, etc. become more important than under an allowance system. In addition, in contrast to an allowance system, a credit system provides no incentive to reduce coal production, which is also an effective way to reduce emissions.[62]

62 Fiedler, J., Sussman, F., *Methane Emissions Trading: Determining the Suitability of Methane Sources for Trading, and of Integrating Methane and Carbon Dioxide Sources in Single Trading System, - Draft,* Prepared for the Centre for Clean Air Policy's GHG Trading Braintrust, June 24, 1998

16. Nitric Acid Production

16.1 Source and Quantity of GHG Emissions

Nitrous oxide (N_2O) is emitted in trace amounts as a combustion by-product in the nitric acid production process. The emissions of nitrous oxide from nitric acid production have been estimated at about 3 kt/yr over the last 5 years[63]. This level is equivalent to about 1,000 kt of CO_2 emissions and represents only about 1% of total non-combustion GHG emissions or less than 0.2% of total Canadian GHG emissions.

The emission estimates were originally based on the use of an average emission factor for all Canadian industry multiplied by the total Canadian production of nitric acid. The average emission factor employed in the inventory was 8.5 kg N_2O per tonne of ammonia used, which corresponds roughly to 3 kg N_2O per tonne nitric acid produced[64].

Nitrous oxide emissions have remained stable at this level over the last 5 years because nitric acid production has been relatively stable, ranging from 910 to 991 kt. Emissions are forecast to increase slightly as nitric acid production increases to fill new capacity.

Nitrous Oxide Emissions from Nitric Acid Production

	1990	1991	1992	1993	1994	1995	2000
N_2O Emissions (kt)	3.0	2.7	2.9	2.8	2.7	3.0	3.5
N_2O Emissions (kt CO_2 equivalent)	930	840	900	870	840	930	1090
Nitric Acid Production (kt)	990	912	960	917	910	991	1150

Average Emission Factor Used: 3 kg N_2O/ tonne HNO_3
Source: Camford Information Services, Nitric Acid profile, Aug. 1996

Nitric acid (HNO_3) is an important inorganic chemical, manufactured from ammonia. Over 80% of nitric acid is used as an intermediate in the production of ammonium nitrate (NH_4NO_3), an inorganic solid used as a nitrogen fertilizer and for explosives. Nitric acid is also used in adipic acid manufacturing, uranium extraction and the preparation of specialty explosives.

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63 Jaques, A., et al, "Trends in Canada's Greenhouse Gas Emissions (1990 to 1995)", Environment Canada, April 1997.

64 The average was calculated from various emission factors ranging from 2 to 20 kg N_20 per tonne ammonia used, as provided by European industry in 1990 and 1991.

In 1995, five (5) companies operated a total of 9 nitric acid plants at 6 site locations in Canada. Two companies are expanding their facilities by each adding a new plant, each coming onstream in 1998, which will bring the total to 11 plants by the end of 1998. In 1995, the total nitric acid production capacity was 1150 kt/yr and total domestic production was 991 kt.

Canadian Nitric Acid Plants

Company	Location	Process	Capacity	Control	Est'd N_2O
Existing (1995)			(kt/yr)		(kt/yr)
Agrium Inc.	Ft. Sask, AB	HP	175	NSCR	0.15
Orica (once ICI)	Beloeil, PQ	DP	90	NSCR	0.08
Orica (once ICI)	Carseland, AB	DP	290	none	2.24
Hydro-Agri (#1)	Maitland, ON	HP	65	NSCR	0.06
Hydro-Agri (#2)	Maitland, ON	HP	85	NSCR	0.07
Hydro-Agri (#3)	Maitland, ON	HP	160	NSCR	0.14
Simplot Canada (#1)	Brandon, MB	HP	100	NSCR	0.09
Simplot Canada (#2)	Brandon, MB	HP	65	NSCR	0.06
Terra International	Courtright, ON	HP	120	NSCR	0.10
Existing Total			**1150**		**3.00**
New in 1998					
Orica (#2)	Carseland, AB	HP	90	SCR	0.70
Simplot Canada (#3)	Brandon, MB	HP	100	NSCR	0.09

Note: HP - high pressure; DP - dual pressure
Source: CHEMinfo interviews; Camford Information Services

Revised information collected in a recent study suggests that the majority of N_2O emissions are concentrated at one plant site in Canada as shown in the table. The next section explains this situation.

16.2 Nature of GHG Emissions Stream

Nitrous oxide (N_2O) is formed in trace amounts in the first stage of the two-stage manufacturing process, the catalytic oxidation of ammonia to nitrogen dioxide. The reaction products pass through an absorber tower, where nitrogen dioxide is converted to nitric acid (the second-stage of the process). Depending on the configuration, the tail gases that leave the absorber tower to atmosphere consist mostly of nitrogen, a small concentration of oxygen, and trace quantities of nitrous oxide (N_2O), nitric oxide (NO), nitrogen dioxide (NO_2) and other nitrogen oxides. NOx levels (NO and NO_2) in the absorber tail gas usually range from 2,000 to 6,000 ppm. The N_2O concentration is usually less than half of the NOx concentration in this stream, typically ranging from 1000 to 2000 ppm. NOx levels must be controlled to a low limit (150 ppm) under permit to meet provincial ambient air objectives.

The N_2O emissions are not shared equally among the nine existing plants. The Orica (former ICI Canada) Carseland, AB plant is believed to account for about 2.24 kt/yr of N_2O or over 75% of total emissions, while all eight others are believed to contribute the remaining 0.7 kt. This is due to the types of controls that are installed in the nine plants.

There are two basic types of nitric acid production technologies: high pressure and dual pressure. Eight of the nine existing Canadian nitric acid plants are high pressure process designs, which have non-selective catalytic reduction (NSCR) abatement technology installed to control NOx emissions to outlet levels of about 150 ppm for provincial NOx objectives. This abatement technology also reduces N_2O emissions to less than 150 ppm. The total N_2O emissions from eight of the nine plants which use N_2O controls is estimated to be only about 700 tonnes, or roughly one-quarter of the industry total.

The other existing Canadian nitric acid plant (Orica in Carseland, AB) is a dual pressure process design, which does not use any abatement technology to control NOx emissions. In the dual pressure design, the more efficient absorption in the tower reduces NOx emissions to acceptable levels, and no NOx abatement is necessary. Although the control of NOx emissions has been designed into the process, the extended absorption process has no significant effect on reduction of N_2O emissions. Orica reports that they have no actual tail gas data, but that an emission factor of 9 kg per tonne HNO_3 has been assumed for their Carseland plant. This is an upper bound estimate based on Orica's knowledge of other dual pressure design plants. Using this emission factor, the Carseland plant emissions (max 2.3 kt/yr) may represent up to about three-quarters of the total nitrous oxide emissions (3.0 kt/yr) calculated in the inventory.

The two new nitric acid plants starting up in 1998 are also high pressure designs. The new Simplot plant #3 in Brandon, MB will use an NSCR abatement technology (which will control N_2O emissions), but the new Orica Carseland, AB plant will use a selective catalytic reduction (SCR) abatement unit which does not address N_2O emissions.

16.3 Potential for Measuring, Monitoring and Calculating the GHG Emissions Stream

N_2O emissions from nitric acid production are all from single point sources within industrial plants. Emissions are easily calculated, based on measurements of N_2O concentrations in the gas stream and the gas flow rate. The reduction of N_2O emissions is measured by the difference between the inlet and outlet concentrations of N_2O at the abatement equipment. The variations within the process or the abatement technology are not known. The calculations must take into account the time when the abatement technology is shut down or not performing at high efficiency, since emissions are not controlled during these periods.

16.4 Options to Reduce GHG Emissions

The control of nitrous oxide emissions is a new issue for nitric acid plants. To date, plants have installed technology to control NOx emissions only. NOx control technologies include: catalytic reduction (nonselective and selective) and thermal reduction (nonselective and selective).

The only technology which is known to effectively reduce N_2O emissions from a tail gas stream is non-selective catalytic reduction (NSCR). NSCR abatement uses a reducing gas (such as natural gas or hydrogen purge gas) in the presence of a reduction catalyst (often platinum on a honeycomb ceramic base). In the NSCR process, natural gas (chiefly methane, CH_4), first consumes the excess oxygen in the tail gas stream and then, once starved of free oxygen, uses the various nitrogen oxides as an oxygen source, thereby reducing them to nitrogen. Water and carbon dioxide are also present in the exhaust gases. The operating temperatures are high, usually about 1200°F. This process can only be used on tail gas streams having excess oxygen concentrations less than 2.5%, since the reactions would generate too much heat for the catalyst to remain viable at oxygen concentrations beyond this level. The high pressure design plants commonly use NSCR abatement technology. The conversion of N_2O is reported to be at least as high as the conversion of NOx using NSCR.

Selective catalytic reduction (SCR) is an alternative NOx abatement process, but it does not reduce N_2O emissions. SCR abatement uses ammonia as a reducing gas in the presence of a catalyst. It operates at lower temperatures (550 - 1100°F) than the NSCR process. Like the NSCR process, the ammonia first consumes the excess oxygen and then reduces nitrogen oxides to nitrogen and water. NOx emissions, (NO and NO_2) are reduced up to 95%, but N_2O is not reduced because of the lower temperatures. No existing Canadian plant currently uses SCR abatement, but the new Orica Carseland nitric acid plant (#2) has an SCR unit in the design.

Thermal reduction technologies have been identified for NOx control, but it is not known whether they are effective for N_2O control. Two types of thermal reduction technologies identified are: Non-Selective, Non-Catalytic Reduction (NSNCR) and Selective Non-Catalytic Reduction (SNCR). Like NSCR, NSNCR uses hydrocarbon gases, such as natural gas, in a low oxygen environment, but without a catalyst. The fuel reduces the nitrogen oxides. This process, known as "burnout", operates above 1500°F. The SNCR process can be used in higher oxygen environments, but uses urea to reduce nitrogen oxides. The temperatures range from 1700 - 2100 °F. This process is patented by Nalco FuelTech. The higher temperatures drive up the costs for these processes, due to increased heat exchange requirements and fuel usage.

There have been some developments in catalyst technology that have been identified as having a minor effect of reducing the amount of nitrous oxide generated in the first stage

ammonia oxidation reaction. Catalysts containing low palladium levels or none at all have been found to create marginally lower concentrations of N_2O by-product. The effect is called a "secondary effect" since it only deals with reductions of a few percent. For example, with a palladium-free catalyst, the emission factor for N_2O might be reduced from 3.0 to 2.9 kg per tonne HNO_3. However, this catalyst has roughly the same cost as the typical Pt/Pd/Rh catalysts and poses no known significant cost barrier.

16.5 Suitability for GHG Emissions Trading

Like the adipic acid production source, N_2O emissions from nitric acid are from point sources within a limited number of industrial plants. N_2O is created within the process and levels depend on reaction conditions such as residence time, catalyst life, temperature and pressure. Therefore, this source is not considered for a substance trading program. The two programs that could be considered are emission rights trading and emission credit trading.

Emissions are easily calculated based on measurements of gas concentration and flow rates. These measurements are already being done to show compliance with NOx emission limits.

It appears that most companies in this industry have already achieved significant N_2O reductions using the best available control technology. One company appears to require the installation of similar control technology to achieve the same level as the others. Since there are only 5 companies and about 11 point sources, the number of sources is relatively small and would need to be integrated into a larger greenhouse gas trading market.

An emissions rights trading system could be established in this industry, giving allowances to each company. Regulatory authorities would have to decide whether to give the one higher emitting plant an allowance based on current levels or on maximum achievable reduction levels.

A credit trading system is also possible for this industry. A rate-based system measured on x tonnes of N_2O per tonne of nitric acid is a possibility.

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17. Other Uses of SF_6, PFCs and HFCs

17.1 Source and Quantity of GHG Emissions

The three types of greenhouse gases, sulphur hexafluoride (SF_6), perfluorocarbons (PFCs) and hydrofluorocarbons (HFCs), are considered as high-GWP gases beyond the main three naturally-occurring greenhouse gases of CO_2, CH_4 and N_2O. This secondary group has several factors in common. All gases are synthesized compounds containing fluorine, which forms very strong bonds with carbon and sulphur. Most of these gases have very high 100-year global warming potentials. With the exception of PFCs generated in aluminum smelting, these gases are all purchased, used in closed systems and emitted in small volumes (from leakage or maintenance activities) from many multiple sources.

The major source of PFC emissions is from aluminum smelting. A major source of SF_6 emissions is from primary magnesium manufacturing. These two emission sources are covered separately in the Greenhouse Gas Emissions Inventory and have separate sections in this report. This section deals with the other uses of SF_6, PFCs and HFCs.

The 1995 Greenhouse Gas Emissions Inventory only accounted for 3 kt of HFC emissions from refrigeration systems or 500 kt of CO_2 equivalents. The other uses of SF_6 and PFCs were not identified in that study. This estimate represents only 0.3% of non-combustion GHG emissions or less than 0.1% of total Canadian GHG emissions.

Additional research has determined that the total estimated emissions from these three gases in other uses are closer to 1,200 kt of CO_2 equivalents.

Summary of 1995 SF_6, PFC and HFC Use and Emissions

(excludes SF6 Use in Magnesium & PFCs from Aluminum)

Greenhouse Gas		GWP	1995 Use (tonnes)	Emission Factor	1995 Emissions (CO_2 Eq - kt)
SF6	Electrical Equip.	23,900	120	0.05	140 *
SF6	Electronics, Misc.	23,900	5	1.0	120 *
PFCs		6,500-9,200	50	1.0	400 *
HFCs		140-11,700	3198	various	500
Total					1200

Source: 1995 Greenhouse Gas Inventory, CHEMinfo estimates (see sections for details)
Note: * CHEMinfo Service estimates.

Less than half of the estimated emissions (500 kt of CO_2 equivalents) are accounted for by HFCs used in air conditioning and refrigeration applications. Of the three types sold in commercial markets, HFCs had the highest consumption in Canada in 1995, with about 3,200 tonnes consumed. The total consumption of SF_6 in Canada is estimated at about 200 tonnes, about 75 tonnes of which is used in inert cover gases in primary and secondary magnesium production. The use of PFCs in Canada is estimated at about 50 tonnes.

None of the three types of gases are produced commercially in Canada, all being imported from the US. The following table lists the major suppliers of these gases.

Company	SF6	PFC	HFC
Air Products and Chemicals	√	√	
AlliedSignal Specialty Chemicals	√		√
DuPont		√	√
3M Specialty Chemicals		√	
Elf Atochem			√

Canadian sales are distributed through the Canadian subsidiaries of these companies, a limited number of chemical distributors and refrigeration wholesalers.

17.2 Nature of GHG Emissions Stream

17.2.1 SF6 - Electrical Switchgear and Miscellaneous Uses

The largest end use for SF_6 is as an insulating gas (a dielectric) in high voltage electrical circuit interrupters or circuit breakers, generally known as "gas-insulated switchgear" or GIS. SF_6 gas is sealed under pressure inside large, grounded, aluminum-cased cylinders called switchgear arrays. The majority of SF_6 insulated switchgear is used in urban substations handling the junction points of high voltage transmission lines. The use of SF_6 has allowed the dense concentration of transmission lines in urban substations having a limited ground area.

The majority of SF_6 used in electrical equipment is for maintenance replenishment of existing switchgear. The remainder is used to fill original equipment. Major utility companies in charge of high voltage systems purchase SF_6 for both purposes. The gas insulation is designed to be at a certain pressure and is periodically checked under leak detection and repair programs. Switchgear manufacturers quote standard leak rates of 1% of charge per year, which is low enough to have no significance to electrical protection. Ontario Hydro says that they are achieving better leak performance than this. A study of SF_6 use in this area has not been done publicly. SF_6 emissions are estimated based on a total stock estimate of 600 tonnes and average leak rate of 1% (6 t/yr - 140 kt/yr CO_2 Eq).

There are also a variety of very small volume miscellaneous uses in the electronics, analytical and medical industries. For example, SF_6 can be used as an etchant in integrated circuit board production. One Canadian distributor reports sales of one to three cylinders per year to hundreds of small companies and laboratories which account for less than 2% of total sales volume. The market use is estimated at 5 t/yr and all use is assumed emitted, representing about 120 kt/yr of CO_2 equivalents.

17.2.2 PFCs

A small quantity of PFCs are purchased and used in commercial markets in Canada. The main PFC compounds are: CF_4 (R-14), C_2F_6 (R-116), C_3F_8 (R-218) and C_4F_{10} (R-410). The lighter compounds have low boiling points and require very low temperatures for separation. The total Canadian market is assumed to be about 50 t/yr, all of which is assumed to be emitted. At an average GWP of 8,000, this represents about 400 kt/yr of CO_2 equivalents.

Most commercial uses for perfluorocarbons are in low volume niche markets. PFCs are used as replacements for ozone depleting substances in specialty ultra-low temperature refrigerant blends, aerospace, electronics (plasma etching, chemical vapour deposition (CVD) and CVD chamber cleaning in semiconductor manufacturing), computer, telecommunications, medical, metal working, specialty cosmetics and other applications where high purity and cleanliness is required. PFCs have been successfully applied in Advanced Vapour Degreasing processes and are the preferred solvents for use with Teflon and other amorphous copolymers containing trifluoroethylene. Higher molecular weight PFCs such as perfluorobutane and perfluorohexane have been used to replace halons in fire extinguishing applications.

17.2.3 HFCs

HFCs are used as refrigerant working fluids in various types of refrigeration systems. In 1995, the volume of HFCs consumed in Canada was 3.2 kt. About 90% of this volume is HFC-134a, a replacement for CFC-12. The remainder of the HFC volume is accounted for by HFC-125 and HFC-143a, two gases closely related to HFC-134a. The dominant use of HFCs is in mobile air conditioning, where HFC-134a was unanimously selected by automobile manufacturers to replace CFC-12. All new vehicles are now charged with HFC-134a. Existing vehicles with CFC-12 systems, when maintenance is required, are being retrofitted with HFC-134a. HFC-134a has also been selected as the primary replacement for CFC-12 in domestic refrigeration in North America. HFC-134a is used in some commercial and industrial refrigeration systems for medium temperature applications, but it generally is not as efficient as HCFCs (particularly HCFC-22 and R-502 blends), which are used more often. Only a small amount of HFCs are used as propellants in air and auxiliary blowing agents. HCFCs dominate the use in these areas.

The volume of HFC use has grown from less than 1 kt in 1993 and may reach as high as 22 kt in 25 years with the phase-out of CFCs and HCFCs under the Montreal Protocol.

Estimated CFC, HCFC and HFC Use in Canada, 1990-2020

(assumes complete HFC replacement for all HCFCs)

Type of Fluorocarbon	1990	1993	1996	2015	2020
			(kt)		
CFCs	13	8	0	0	0
HCFCs	<1	4	11	4	0
HFCs	<<1	<1	3	14	22
Total Fluorocarbons	**14**	**12**	**14**	**18**	**22**

Source: Environment Canada Commercial Chemicals Branch, CHEMinfo Services estimates

According to Environment Canada, the majority of HFC emissions (60% of the 500 kt of CO_2 equivalents) come from air conditioning applications, including mobile and stationary sources, where HFC-134a is used. The other significant source of emissions, accounting for 29% of the total, is refrigeration, including domestic, commercial and industrial types. In each of these applications, emissions are assumed to come from leaks during OEM charging and during the life cycle, as estimated by replenishment service volumes.

17.3 Potential for Measuring, Monitoring and Calculating the GHG Emissions Stream

Virtually all emissions from these three gases are not directly measurable. Most emissions are due to unmeasurable fugitive leaks and can occur over a long time period. Emissions from maintenance work occur all at once, but the total emissions volume still cannot be measured directly. There are too many small emission sources where the gases are used for an accurate accounting of emissions.

The only method currently used to estimate total emissions is to measure use and apply certain emission factors. This method accounts for any recycling volumes that may be achieved. For the use of gases into original equipment, an emission factor based on the estimated charge loss is used. For the use of gases in maintenance or service of existing closed systems, the emission factor is assumed to be 1.0. (i.e. the replacement gas is equal to the volume that has been lost over time). For use of gases in non-closed systems, an emission factor of 1.0 must be used.

17.4 Options to Reduce GHG Emissions

For most applications of these gases, there are few commercial alternatives. The focus among the users of these GHGs has been on reducing emissions through improved capture and control. Some of the options for reduction of GHG emissions are briefly outlined below. For more details about each of these options, see Environment Canada's study[65].

17.4.1 SF_6

- Better switchgear equipment design (high quality impermeable seals)
- Stringent leak detection and repair programs (use of gas handling and recycling carts)
- Air insulated or vacuum switchgear (less effective)
- Fluid-filled (oil/paper) switchgear (older technology)

17.4.2 PFCs

- use of hydrofluoroethers (HFEs), a family of CFC substitutes for cleaning purposes
- capture and recycling systems

17.4.3 HFCs

- lower GWP HFCs (these tend to be more flammable)
- propane/butane (flammable, but currently used in European domestic refrigeration)
- ammonia (toxic, but used in large commercial refrigerated warehouses and ice arenas)
- carbon dioxide (requires very high compression pressures)
- capture and recycling systems (legislated for all auto A/C and refrigeration service)

17.5 Suitability for GHG Emissions Trading

The emissions of all the high GWP GHGs are difficult to measure directly at the emission source. This rule out emissions rights and credit trading programs. Since emissions are calculated based on substance use, a substance trading program is the most suitable for these gases. Since there are too many small volume end uses, the program would be more easily administered at the supplier or distributor level, which involves only a few participating companies. This system would be similar to those currently in place for some of the ozone depleting substances.

65 Environment Canada, Environmental Technology Advancement Directorate, "Powering GHG Reductions Through Technology Advancement", 1998.