Mackenzie Gas Project Greenhouse Gas Analysis – A Consolidated Report by the Pembina Institute

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Sustainable Energy Solutions

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The Pembina Institute for Appropriate Development creates sustainable energy solutions through research, education, consulting and advocacy. It promotes environmental, social and economic sustainability in the public interest by developing practical solutions for communities, individuals, governments and businesses. The Pembina Institute provides policy research leadership and education on climate change, energy issues, green economics, energy efficiency and conservation, renewable energy, and environmental governance. More information about the Pembina Institute is available at www.pembina.org or by contacting: info@pembina.org

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Executive Summary

This report was written for the Sierra Club of Canada for presentation to the Joint Review Panel (JRP) conducting the environmental assessment of the Mackenzie Gas Project (MGP). After providing a brief background on GHG's and the current scientific concern, it estimates the greenhouse gas (GHG) emissions that are likely to be associated with the MGP, both from operations (upstream) and through combustion of sales gas (downstream). It then provides comparisons to put those emissions in context; including considering natural gas use in the oil sands. Lastly it provides ideas for reducing GHG emissions resulting from the operation of the MGP.

This report considers six different MGP development scenarios as based on a report commissioned by Imperial Oil Resources Venture Ltd.[1] These scenarios are considered plausible given the likelihood that industry proponents will use the Mackenzie gas pipeline indefinitely as long as natural gas resources are available in the area and can be accessed in an economically sound manner. *Calculations are based on the emissions data provided for the Environmental Impact Statement in the June 8th 2005 Information Request Response to the Sierra Club of Canada, and do not account for any changes project proponents may have made in the design of the MGP since that time.*

The following are the primary conclusions of the report for consideration by the JRP, based on the specific objectives of the analysis.

How significant are the estimated annual and total lifetime-of-the-project (cumulative) greenhouse gas emissions for the different MGP development scenarios– for both the operation of the pipeline (upstream) and combustion of the gas (downstream)?

- The development scenarios contribute up to four times the GHG emissions than the EIS scenario.
- The Maximum Capacity and Sproule scenarios have over double the maximum annual GHG emissions than the other scenarios.
- All non-EIS scenarios generate emissions 10 to 20 years further into the future than the EIS scenario.
- GHG emissions actually increase over the life of the project due to inlet compression requirements.
- Natural gas sold that ends up being combusted is seven to thirteen times more than the upstream emissions over the life of the project.
- Further work is needed to determine the additional downstream GHG emissions from NGL use.

[1] Gilbert Laustsen Jung Associates Ltd., *Mackenzie Gas Project, Gas Resource and Supply Study – A Study Prepared for Imperial Oil Resources Ventures Limited* May 1, 2004

How significant are GHG emissions associated with the MGP project in the context of the NWT and Canada?

- The EIS scenario, having the least gas production, would represent an increase of 41% over the cumulative 'business as usual' GHG emissions in the NWT between 2006 and 2053.
- The Sproule Scenario, producing the most gas, would represent an increase of 167% over the cumulative (and conservative) 'business as usual' GHG emissions in the NWT between 2006 and 2053.
- Considering the total upstream and downstream emissions for each of the scenarios, the more conservative estimate shows that this would constitute 1 – 6% of Canada's projected cumulative emissions out to 2053 based on a steady 1% annual increase in Canada's emissions beyond 2020. This would be a higher proportion assuming Canada reduced its emissions over time based on federal and provincial policies.

How does the MGP relate to Canada's Oil Sands?

- Oil sands projects could easily consume all the gas supplied by the MGP based on supply and demand estimates, with the MGP never supplying more than 40% of the natural gas demand projected for the oil sands.
- Delivering 10 Mm^3/d (0.35 BCF) of natural gas to the oil sands enables the emission of 40 Mt CO2eq/yr in the oil sands from natural gas production, bitumen production and upgrading, crude oil transmission, crude oil refining, transport fuel delivery and transport fuel combustion.
    - This amount is approximately thirty times higher than the average annual upstream emissions for the EIS scenario, and four times higher than the average total annual upstream and downstream emissions associated with the EIS scenario.
    - GHG emissions associated with the MGP operation (upstream) would only account for less than 2% of the total life-cycle emission generated in this example.
- It should be considered whether cleaner burning natural gas is actually suitable for the oil sands should carbon capture and storage technology (CCS) be planned for the industrial region; in which case the waste product 'petcoke' could be a primary fuel source in the oil sands. Natural gas could instead be more beneficially employed for end-uses at which CCS is unlikely to be available.
- For each kilometre driven, a vehicle powered by natural gas would generate 48% less GHG emissions than a vehicle powered by gasoline originating from oil sands on a life-cycle basis.

How significant are the GHG emissions resulting from the operation of the MGP relative to emissions from vehicle use?

- The peak annual GHG emissions generated by operating the MGP (i.e. upstream emissions) are expected to be equivalent to the GHG emissions from between 400,000 and 800,000 light vehicles operating annual, representing between 2 and 5% of all light vehicles registered in Canada.

- When downstream emissions are included, the total emissions are equivalent to the emissions from between 5.5 and 8.4 million light vehicles operating annual, representing 31 to 48% of all light vehicles registered in Canada (this assumes 100% combustion). The Sproule scenario, for which annual ghg emissions were not available, would be significantly higher.

What are possible options to reduce or offset GHG emissions from the operation of the pipeline?

Possible options for reducing or offsetting GHG emissions generated by operating the MGP (i.e. upstream emissions) include:

- using eco-efficient technologies for combustion, flaring, venting, and preventing leaks;
- purchasing GHG offsets through the Kyoto Protocol's Clean Development Mechanism;
- purchasing or investing in domestic GHG offsets and offset projects,
- establishing internal corporate GHG emissions trading system

GHG offsets vary greatly in there quality and environmental integrity. A fundamental criterion when purchasing offsets is to ensure the project generating the reductions is beyond business as usual practice. Otherwise the seller of the offset gets credit for what he or she would have done anyway, and we are no further ahead in reducing total emission as the purchaser of the offset simply continues to pollute (leading to no net reductions).

1. Introduction

This report was prepared on behalf of the Sierra Club of Canada for presentation to the joint review panel conducting the review of the Mackenzie Gas Project. The report estimates the greenhouse gas (GHG) emissions anticipated to be associated with the Mackenzie Gas Project . This report is a consolidation of the following previous reports written by the Pembina Institute:

Matthew McCulloch, Derek Neabel, and Ellen Francis. *Greenhouse Gas Emissions Calculations for the Mackenzie Gas Project*: The Pembina Institute, May 2005.
Matthew McCulloch, Jeremy Moorhouse, Greg Powell, and Ellen Francis. *Mackenzie Gas Project Greenhouse Gas Analysis - An Update*: The Pembina Institute, June 2006.
Matthew McCulloch, Jeremy Moorhouse, Greg Powell, and Ellen Francis. *Mackenzie Gas Project Greenhouse Gas Analysis - An Update (revised)*: The Pembina Institute, December 2006.

The primary purpose of this analysis is to develop the full extent of potential GHG emissions associated with the operating the Mackenzie Gas Project and to put this into context.[2]

Note that estimates in this report are based on the GHG emissions data provided for the Environmental Impact Statement in a June 8th 2005 Information Request Response (IRR), and do not account for any changes project proponents have made in the design of the MGP since that time.[3] It was noted at the October17th 2006 JRP hearing by the project proponent that maximum annual emissions were now approximately 10% lower than report in the June 8th IRR to the Sierra Club of Canada.[4]

The specific objectives of this report are to:

- *Estimate the annual and total lifetime-of-the-project (cumulative) greenhouse gas emissions for the different MGP production scenarios– for both the operation of the pipeline (upstream) and combustion of the gas (downstream).*
- *Put the estimated GHG emissions in the context of the NWT and Canada.*
- *Put the MGP in context with Canada's Oil Sands*

[2] The May 2005 report provided an initial estimate of the potential GHGs associated with the operation of the Mackenzie Gas Project; the June 2006 report provided an update to the original estimate based on new published information; and the December 2006 version included corrections to the June 2006 to fulfill undertaking U-42 for the National Energy Board hearing for the Construction and Operation of the Mackenzie Gas Pipeline. This report supersedes all three previous submissions.

[3] [3] Imperial Oil Resources Venture Limited, *Joint Review Panel Round 2 Intervenor Information Request Response* June 8, 2005, SCC 2.19-1.

[4] 1720 rather than 1902 kt CO2e/year due to one less compressor and utilization of waste heat recovery: JRP for the MGP transcript 'VOLUME 58, Hearing held at: Tree of Peace Friendship Centre, 5009 51st Street, Yellowknife, NWT, October 17, 2006.'

- *Contextualize projected increases in GHG emissions resulting from the operation of the MGP.*
- *Describe possible options to reduce or offset GHG emissions from the operation of the pipeline*

Key Assumptions and Limitations in this Report

- The relationship between operations emissions and total sales gas is assumed to be linear,
- The scope of this report does not include
  - Emissions associated with the exploration of the natural gas (and natural gas liquids) to supply the pipeline.[5]
  - A comprehensive examination of emission reduction technologies,
  - Alternatives to the pipeline as proposed by the proponents,
  - Impacts of climate change and/or climate change adaptation strategies,
  - Other (e.g. non-greenhouse gas) emissions associated with the operation of the pipeline,
  - Air quality impacts resulting from the operation of the MGP,
  - Emissions associated with producing the materials used to fabricate the pipeline,
  - Other bio-physical or socio-economic impacts of the MGP,
  - Potential risks or hazards associated with the operation of the MGP, and
  - An uncertainty analysis.

1.1 Brief Background on Greenhouse Gases

Human activities have caused a dramatic increase in the amount of carbon dioxide (CO_2) in the earth's atmosphere. Since about the year 1750, the concentration of CO_2 has risen from about 280 parts per million by volume (ppmv) to reach 377 ppmv in 2004 — a value that has likely not been exceeded during the past 20 million years. CO_2 is a "greenhouse gas" (GHG) that captures heat and warms the atmosphere. The primary greenhouse gases are carbon dioxide, methane(CH_4), and nitrous oxide (N_2O), each have different global warming potentials. Both N_2O and CH_4 are typically associated with industrial activity, and both have significantly higher warming potentials than CO_2. The total combined effect is referred to as 'CO_2 equivalent' (CO_2e). Reference to a 'low carbon economy' is because CO_2 is the primary greenhouse gas in the atmosphere, even though what is meant is a 'low GHG emissions' economy.

The main causes of increasing CO_2 concentrations are the burning of fossil fuels — coal, petroleum products, natural gas — and deforestation. Various industrial, transportation and agricultural activities are also responsible for increases in the atmospheric concentrations of

[5] Note that when referring to the Mackenzie Gas Pipeline, the gas pipeline and the NGL pipeline beginning at the Inuvik Area Facility and ending 1km past the Normal Wells facility (at the Enbridge internconnect facility) is considered.

other GHGs, such as methane and nitrous oxide. Unlike local air quality issues, greenhouse gases emitted anywhere in the world contribute equally to the climate effect.

1.2 Scientific Concern of Climate Change

By 1988 governments had become sufficiently concerned to establish the Intergovernmental Panel on Climate Change (IPCC). The IPCC's mandate is to advise governments on the science of global climate change caused by GHGs from human activities, and on how to prevent it. The IPCC's reports are authored by hundreds of the world's most respected physical and social scientists specializing in climate change.

The IPCC's Third Assessment Report (2001) concluded that if no explicit action is taken to curb GHG emissions from human activities, the global average surface temperature is projected to increase by 1.4 to 5.8°C between 1990 and 2100. Temperature increases like these are not small: the difference in global average surface temperature between the last ice age and today is only about 4 to 6°C.

The global average surface temperature has already risen by approximately 0.6°C over the past century, a warming trend unprecedented in the past millennium. The IPCC concluded that "most of the observed warming over the last 50 years is likely to have been due to the increase in greenhouse gas concentrations."

There is now quite wide support, both in the scientific community and among governments, for defining "dangerous" climate change as a rise in the global average surface temperature of 2°C above the pre-industrial level. Research shows that if we are serious about keeping within this limit, we need to adopt an objective of stabilizing atmospheric GHG concentrations at 400 ppmv of CO_2 equivalent.

Meeting this objective requires that global GHG emissions fall to at least 30-50% below the 1990 level by 2050, and that industrialized countries reduce their emissions by 25-30% below 1990 levels by 2020 and by 85-90% below 1990 levels by 2050.

Canada’s commitment under the Kyoto Protocol to the UNFCCC is to reduce its total GHG emissions to 6.0% below 1990 levels over 2008-2012 to 563 Mt. Total GHG emissions in Canada in 2004 were 758 Mt which represents a 26.6% increase over the 1990 total of 599 Mt. and 34.6% above the Kyoto target. While Canada only emitted 2.3% of the world’s human-generated CO2 in 1990, and 2.4% in 2002, it has the second highest CO2 intensity per capita and the highest CO2 intensity per dollar of GDP among the G7. [6]

Given the scale of this challenge, both internationally and for Canada, any rational strategy will immediately initiate an emissions trajectory that leads to deep reductions.

[6] Information taken from ‘2006, Canada’s Fourth National Report on Climate Change’, Government of Canada.

2. Mackenzie Gas Project GHG Emissions Scenarios

This section provides estimates of annual GHG emissions and cumulative emissions over the next 50 years that are directly related to the Mackenzie Gas Project based upon information from the GLJ report[7], the MGP Environmental Impact Statement (EIS)[8], the intervenor request for information responses[9], and the Sproule Report[10]. New information provided by intervenor request for information responses have been incorporated into each of the scenarios.

This section presents ghg emissions from 'upstream' (those associated with the gas pipeline) then from 'downstream' (those associated with end-use of the gas), and then estimates the total them. For each, both annual emissions are presented as well as the 'cumulative' emissions. Cumulative emissions are the total aggregate of the emissions. It is the cumulative emissions that are of the greatest important, as this is the total amount of emissions generated by the project (only estimated for the gas portion, and not the NGL).

The upstream and downstream GHG emissions will depend on the amount of gas produced and transported through the Mackenzie Valley Pipeline, and eventually combusted. Given that, over time, there are different production scenarios beyond that presented in the initial Environmental Impact Assessment for the MGP, we begin with a discussion of a number of plausible scenarios having different volumes of gas being transported.

2.1 Scenario Descriptions

The Environmental Impact Statement (EIS) scenario initially presented by the project proponents, which includes three reservoirs other 'discovered' fields, considers the pipeline is to be operating at full capacity for only three years. While, assessing the economic feasibility of operating the pipeline at capacity for only three years is beyond the scope of this report, three years of operating at full capacity can be considered extremely short for any major infrastructure project. Thus, it may be assumed that if the pipeline is constructed, its proponents will ensure that full-capacity operation occurs for a longer period of time in order to maximize the economics associated with the project; i.e. gas fields other than those presented in the EIS scenario are likely to be developed if the Mackenzie Gas Project proceeds. Therefore, the EIS scenario is not considered a likely scenario. As a result, several other scenarios are considered.

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[7]Gilbert Laustsen Jung Associates Ltd., *Mackenzie Gas Project, Gas Resource and Supply Study – A Study Prepared for Imperial Oil Resources Ventures Limited* May 1, 2004

[8] Imperial Oil Resources Ventures Limited, *Environmental Impact Statement* August 2004.

[9] Imperial Oil Resources Venture Limited, *Joint Review Panel Round 2 Intervenor Information Request Response* June 8, 2005

[10]Sproule Associates Limited, *Natural Gas Resource Assesments and Deliverability Forecasts, Beaufort-Mackenzie and Selected Northern Canadian Basins – Prepared for the Mackenzie Explorer Group* May 2005.

Table 1 below shows the different scenarios considered with the respective associated peak gas flow rates, the fields considered, and the number of years of operation at full capacity (i.e. peak gas output). Refer to Appendix A for a list of assumptions used to develop these scenarios.

If the MGP is constructed, the most likely GHG emissions scenario is the scenario that delivers the greatest amount of natural gas over the greatest time period assuming a sustained demand for natural gas. This scenario is the Sproule scenario.

Table 1: Scenario descriptions

Scenario	Project Time Period	Peak Flow Rate *(Mm^3/day)*	Description
Environmental Impact Statement (EIS)	2006-2034	34 (1.2 BCF/d)	As per the proponent's Environmental Impact Statement and GHG data from intervenor request responses. Considers the following reservoirs: Taglu, Parsons Lake, Niglingtgak, 'Other Mackenzie Delta Discovered', Colville Hills Discovered. Years of operation at full capacity: 3
Onshore Only	2006-2046	34	As per EIS, plus the following fields: Basin Margin Undiscovered, Colville Hills Undiscovered, and Listric Onshore Undiscovered. Years of operation at full capacity: 18
Onshore & Offshore	2006-2053	34	As per Onshore Only scenario, plus Beaufort Sea Discovered and Beaufort Sea Undiscovered. Years of operation at full capacity: 26
NEB P_{50}	2006-2053	34	As per Onshore & Offshore scenario with full capacity operation reduced by three years. This is an NEB estimate using Monte Carlo analysis considering a 50% probability that the quantities actually recovered will equal or exceed the estimate. Years of operation at full capacity: 23
Maximum Capacity	2006-2046	51 (1.8 BCF/d)	As per the Maximum Capacity scenario described in the EIS, this scenario considers additional facilities (ie. More compressors beyond the EIS scenario) required. Plant-based and fugitive GHG emissions are based on EIS scenario, increased proportional to increase in capacity. Years of operation at full capacity: 15
Sproule	2009-2059	91 (3.2 BCF/d)	Considers the necessary fields required to operate this size pipeline operating at full capacity for 20 years. Fields considered are all onshore, shallow offshore and deep offshore fields. Truncations were used to determine viable fields and these assumptions are available in appendix A. Years of operation at full capacity: 20

2.2 Upstream Emissions

Table 2 summarizes the upstream GHG emissions for the six scenarios. The 'upstream' emissions refer to the emissions sources reported in the original EIS. This includes the production area and the pipeline corridor. Namely, these are emissions sources from:

- Construction activities
- Compressors
- Power generation for pipeline operation, and
- Process equipment.

These include:

- Annual emissions for well testing,
- Fugitive emissions,
- Emissions from changes in land use, and
- Annual emissions for blowdown venting emissions.

The GHG emissions under the non-EIS scenarios are calculated based on a linear relationship between sales gas flow and emissions in the EIS scenario. Appendix A explains the methodology used to calculate the emissions for each scenario in detail.

A description of the headings for Table 2 follows:

- Cumulative GHG emissions – this are the total emissions summed for the life of the project.
- Maximum Annual GHG emissions – the highest level of emissions for one year duringthe life of the project.
- Average Annual GHG emissions – the total emissions divided by the total years.

Table 2: Upstream GHG emissions for each scenario (operations/upstream only) (kt – kilotonnes)

Scenario	Peak Gas Flow	Average Annual GHG Emissions	Maximum Annual GHG Emissions	GHG Emissions During Kyoto Commitment 2008-2012	Cumulative GHG Emissions
	(Mm^3/day)	*(kt CO2eq/yr)*	*(kt CO2eq/yr)*	*(kt CO2eq)*	*(kt CO2eq)*
EIS	34	1,443	1,902	5,380	44,730
Onshore Only	34	1,472	1,928	4,940	61,820
Onshore & Offshore	34	1,427	1,881	4,940	68,470
NEB P50	34	1,460	1,938	4,850	70,080
Maximum Capacity	51	2,712	3,709	6,370	111,200
Sproule	91	N/A	5,034	N/A	183,270

As can be seen from Table 2, the total cumulative emissions range from about 45 Mt (Megatonnes) CO2eq to 183 Mt CO2eq for the EIS and the Sproule scenarios respectively.[11] Due to lack of annual flow rate data for the Sproule scenario (only totals provided) the emissions during the Kyoto commitment period are not available.

Table 2 illustrates that:

- Other plausible development scenarios contribute to much higher, up to four times, the GHG emissions than the EIS scenario.

[11] 1 megatonne = 1,000 kilotonnes.

- The Maximum Capacity and Sproule Scenarios have over double the maximum annual GHG emissions than the other scenarios.

- The EIS scenario generating 5.4 MT CO_2e during the Kyoto commitment period represent about 3% of Canada's current gap (based on Canada's 2004 emissions) in meeting our Kyoto requirements (see Section 1.2). While this of course does not take into consideration the delay in begin construction in 2009, it is puts the project in context with the reductions needed to meet Kyoto.

Further 'contextualization' of the values provided in Table 2 numbers is provided below.

Figure 1 graphically represents the annual upstream emissions for each scenario. The Sproule scenario is not included, again due to a lack of necessary annual data. Please see Appendix A for details on the methodology used to calculate these emissions.

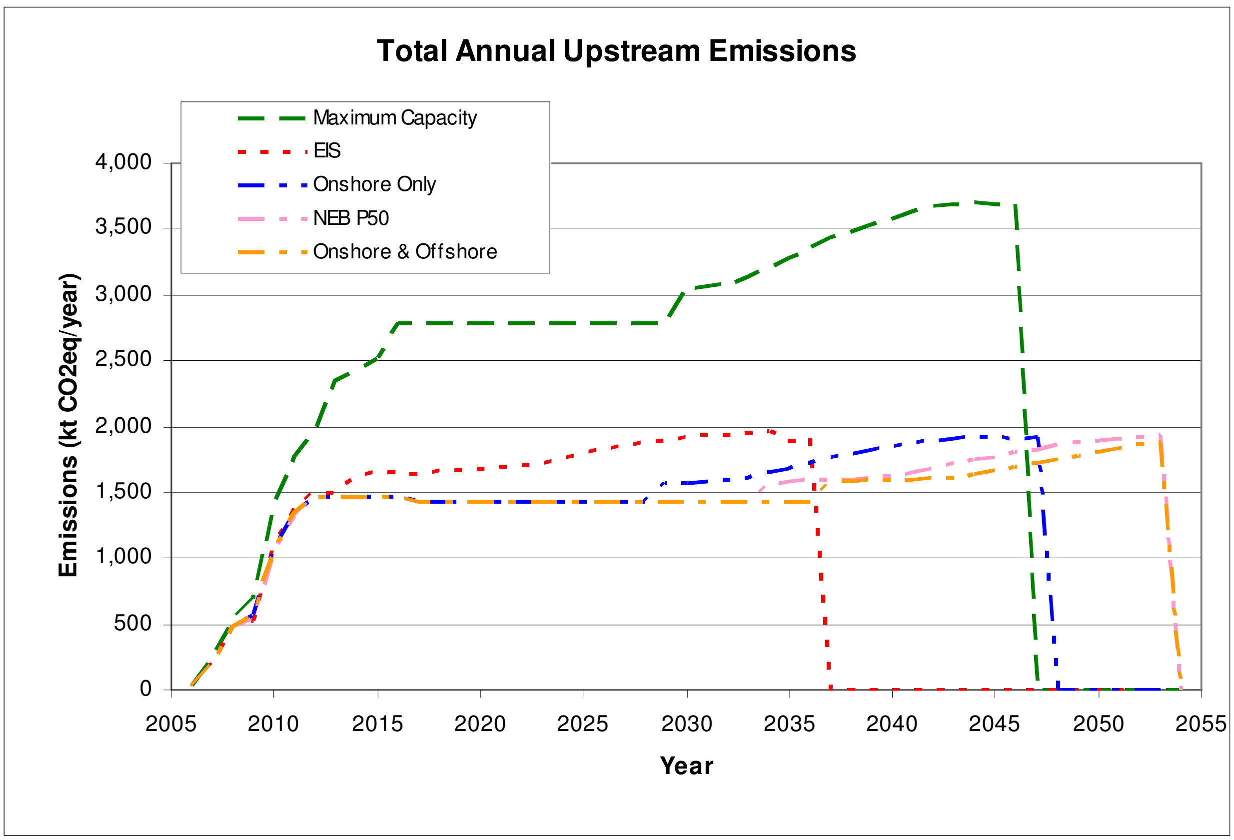

Figure 1: Graphical comparison of upstream CO2eq emissions from five scenarios ***(the Sproule scenario is not included due to a lack of data on annual flow rates)***

Figure 1 illustrates that all scenarios will have a peak emissions at the end of their operations phase. The flat portion of each curve represents max flow, i.e. peak gas conveyance through the pipeline. GHG emissions increase after peak gas production due to energy-intensive inlet compression, which is due to increased compression requirements required as the volume of gas in the reservoir decreases[12].

The GHG emissions associated with the Maximum Capacity scenario are significantly greater than the other four scenarios included in the graph. This is a direct result of higher gas flow rates expected under the Maximum Capacity scenario. Notably, the Sproule scenario would be even higher since it keeps a larger capacity pipeline full.

There is a decrease in emissions for the EIS scenario in year 2009 due to decreasing emissions from construction, which is expected to be completed prior to the pipeline operating at full capacity in 2012.[13]

The timing of the various fields coming online, and there associated flow volumes, accounts for the differences between the curves for the different scenarios.

Some immediate conclusions are:

- The Maximum Capacity scenario has the highest associated GHG emissions (the Sproule would likely be higher, given a higher capacity the 'Maximum Capacity')
- All other non-EIS scenarios generate emissions 10 to 20 years further into the future than the EIS scenario.
- GHG emissions actually increase over the life of the project due to inlet compression requirements.

2.3 Downstream Emissions

Downstream emissions, or those emissions associated with the combustion of the gas transported by the pipeline, are provided in this section. These are important to consider as this constitutes the majority of the total life-cycle emission (upstream and downstream, over the life of the project), and the final end-use of this gas is the reason the project exists in the first place.

Downstream emissions estimates here are generated from the sales gas associated MGP. Not all gas produced is necessarily combusted, however. A portion of natural gas produced is used as a chemical input to industrial activities such as fertilizer and petrochemical production. The estimates provided here for combustion are based on the proportion of natural gas that is combusted in Canada, Alberta and the United States compared to total natural gas produce in those regions.

Table 3 below summarizes the percent of natural gas (NG) demand in Alberta, Canada and the United States that is combusted. This is based upon data from the National Energy Board, the Alberta Energy and Utilities Board and the US Environmental Protection Agency respectively.

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[12] Imperial Oil Resources Venture Limited, *Joint Review Panel Round 2 Intervenor Information Request Response* , 8 June 2005, Table JRP SCC 2.19-1 "Annual Greenhouse Gas Emissions", pg. 16 footnote 6

[13] The years have not been updated to reflect current potential start dates for construction and commissioning. However, life-cycle GHG emissions would not change as a result.

Each of these jurisdictions are considered to be potential locations for the supply of natural gas from the MGP.

Table 3: Portion of Natural Gas Demand Combusted vs. Non-Combusted in Select Jurisdictions[14, 17]

	Alberta	Canada	United States
% of NG Demand Combusted	87%	93%	98%
% of NG Demand Not Combusted	13%	7%	2%

As Table 3 shows, 87% of all the natural gas used in Ablerta is combusted while the natural gas combusted in Canada represents 93% of total natural gas use in the country. The proportion of natural gas combusted in Alberta is lower than the Canadian average because Alberta's large petrochemical industry utilizes natural gas and other hydrocarbon resources as an input to create commercial and industrial products. The natural gas combusted in the United States represents 98% of total natural gas use in the country.

Based on the values provided in Table 3, and applying emission factors to the associated sales gas for the different scenarios, Table 4 summarizes the downstream GHG emissions for the six scenarios.

Table 64 reports emissions as a range to best reflect how the gas conveyed in the MGP may ultimately be used. The low to high range reflects the 87% of natural gas produced that is combusted in Alberta to the 98% of combusted natural gas in the U.S.

Note that Imperial Oil Resources Ventures Limited estimates 23,420 kt CO2eq/yr for downstream emissions[15] under the EIS scenario based on an emissions factor of 1,887 g/m^3 *as per* Environment Canada's 1999 Greenhouse Gas Inventory. The emissions factor applied in Table 4 is based on Environment Canada's revised factor of 1,902 g/m^3 *as per* its 2004 Greenhouse Gas Inventory.

Table 4: Downstream GHG emissions for each scenario

Scenario	Peak Gas Flow	Total Sales Gas (for life of project) [16]	Cumulative Downstream GHG Emissions		Maximum Annual Downstream GHG Emissions		Average Annual Downstream GHG Emissions	
			(Low) †	(High) ‡	(Low) †	(High) ‡	(Low) †	(High) ‡
	(Mm3/day)	*(Mm^3)*	*(kt CO2eq)*		*(kt CO2eq/yr)*		*(kt CO2eq/yr)*	
EIS	34	193,800	320,330	361,246	20,518	23,139	10,333	11,653
Onshore Only	34	340,800	563,594	635,584	20,518	23,139	14,451	16,297
Onshore & Offshore	34	472,900	782,056	881,950	20,518	23,139	17,379	19,599

[14] Canadian data from NEB, 2005. Short-term outlook for NG and NGL to 2006 and Alberta data from EUB, 2007. ST98: Alberta's Energy Reserves and Supply/Demand Outlook.

[15] Imperial Oil Resources Venture Limited, *Joint Review Panel Round 2 Intervenor Information Request Response* 8 June 2005

[16] Gilbert Laustsen Jung Associates Ltd., *Mackenzie Gas Project, Gas Resource and Supply Study – A Study Prepared for Imperial Oil Resources Ventures Limited* May 1, 2004. Table 11.

NEB P50	34	428,800	709,034	799,601	20,518	23,139	15,756	17,769
Maximum Capacity	51	476,000	787,004	887,531	30,778	34,709	20,711	23,356
Sproule	91	1,265,700	2,092,692	2,359,997	NA	NA	NA	NA

† - "Low" corresponds to the downstream combustion of 87% of the natural gas conveyed by the MGP, based on natural gas uses in Alberta (See Appendix F)

‡ - "High" corresponds to the downstream combustion of 98% of the natural gas conveyed by the MGP, based on natural gas uses in the US[17]

Table 4 shows that the natural gas sold that ends up being combusted over the life of the project is seven to thirteen times more than the upstream emissions shown in Table 2, whether it be annual or cumulative.

2.3.1 Downstream GHG Emissions from Natural Gas Liquids

Table 5 summarizes the demand for natural gas liquids (NGLs) in Canada and Alberta[18] and the proportion of NGLs that are combusted in each jurisdiction. Data on NGL production from the MGP is currently not available to put the MGP NGL production into context.

Table 5: Natural Gas Liquids Demand in Canada and Alberta[19]

Gas	Canada	Alberta
	(billion m^3/y)	*(billion m^3/y)*
Ethane (Combustion)	35,889 (90%)	2,646 (7%)
Ethane (Non-Combustion)	3,811 (10%)	35,154 (93%)
Propane (Combustion)	4,201 (50%)	3,700 (100%)
Propane (Non-Combustion)	4,134 (50%)	0 (0%)
Butane (Combustion)	17,542 (83%)	4,986 (83%)
Butane (Non-Combustion)	3,568 (17%)	1,014 (17%)
Pentanes Plus (Combustion)	0 (0%)	0 (0%)
Pentanes Plus (Non-Combustion)	24,180 (100%)	20,300 (100%)
Total	**93,325**	**67,800**

[17] Hockstad, Leif. Climate Change Division,k Office of Atmospheric Programs, U.S. Environmental Protection Agency, *CO2 emissions from natural gas use.* Email to K. Ferguson, Sierra Club of Canada, February 12, 2007.

[18] The NEB and the EUB do not quantify NGL use data as rigorously as natural gas use data; this difference in rigour is manifested by data gaps in the sources the authors referenced. Specifically, the NEB and the EUB did not explicitly present end use data for ethane, propane, butane, and pentanes plus in the respective papers. Therefore, the authors inferred end-uses based on the information the NEB and EUB presented. Appendix F explains the calculations.

[19] Canadian data from NEB, 2005. Short-term outlook for NG and NGL to 2006 and Alberta data from EUB, 2007. ST98: Alberta's Energy Reserves and Supply/Demand Outlook with emission factors derived from Environment Canada, 2006. Canada's Greenhouse Gas National Inventory Report 1990-2004.

The majority of the demand for propane and butane in Canada and Alberta is for direct combustion uses. In Canada as a whole, the demand for ethane is mostly for combustion uses whereas in Alberta, ethane is mostly used for non-combustion purposes. Pentanes Plus is used only for non-combustion uses in Canada as a whole and in Alberta specifically.

As can be seen from Table 5, a significant amount of total NGL is combusted in both Alberta and Canada. As such, it is important to understand the amount of NGL produced from the MGP for the different scenarios. Further work is therefore needed to determine the additional downstream GHG emissions from NGLs, and the total downstream emissions in Table 4 above.

2.4 Total Emissions

Table 6 summarizes the upstream and downstream GHG emissions for the six scenarios, which is the sum of Tables 2 and 4 above.

Table 6: Total (upstream and downstream) GHG emissions for each scenario

Scenario	Peak Gas Flow	Total Sales Gas	Total (Upstream + Downstream) Cumulative GHG Emissions		Maximum Total Annual GHG Emissions		Average Total Annual GHG Emissions	
			(Low) †	(High) ‡	(Low) †	(High) ‡	(Low) †	(High) ‡
	(Mm^3/day)	*(Mm^3)*	*(kt CO2eq)*		*(kt CO2eq/yr)*		*(kt CO2eq/yr)*	
EIS	34	193,800	365,100	406,000	22,100	24,700	11,800	13,100
Onshore Only	34	340,800	625,400	697,400	22,100	24,700	14,900	16,600
Onshore & Offshore	34	472,900	850,500	950,400	22,100	24,700	17,700	19,800
NEB P50	34	428,800	779,100	869,700	22,100	24,700	16,200	18,100
Maximum Capacity	51	476,000	898,200	998,700	33,800	37,800	21,900	24,400
Sproule	91	1,265,700	2,276,000	2,543,300	NA	NA	NA	NA

† - “Low” corresponds to the downstream combustion of 87% of the natural gas conveyed by the MGP, based on natural gas uses in Alberta (See Appendix F)

‡ - “High” corresponds to the downstream combustion of 98% of the natural gas conveyed by the MGP, based on natural gas uses in the US

The total upstream and downstream cumulative GHG emissions range from 365 Mt CO2eq under the EIS scenario to 2,543 Mt CO2eq under the Sproule scenario, considering the same range for end-use combustion as applied in Section 2.3.

The proponent’s project update of May 15, 2007 notes an increase in GHG emissions during the construction phase compared with original estimates. The values provided herein do not account for this increase because the increase represents only a small proportion of the overall project emissions.

2.5 Key Points

- The EIS scenario, under which full-capacity operation would last only three years, is not considered a likely scenario since sustained market demand for natural gas is expected to lead to the development of other gas fields within close proximity of the MGP.
- The Sproule scenario is considered the most likely because it provides the highest amount of gas in a likely demand driven environment. Due to the higher gas flow, this scenario has associated GHG emissions of approximately 183 Mt CO2eq.
- Average annual upstream emissions during the operational life of the project range from 1,427 kt CO2eq/yr under the Onshore & Offshore scenario to 2,712 kt CO2eq/yr under the Maximum Capacity scenario.

- The total cumulative upstream emissions range from 45 Mt CO2eq for the EIS scenario to 183 Mt CO2eq for the Sproule scenario.
- Total downstream emissions are the most significant, and as such it is important to consider the different types of end-uses, potential implications, and CCS opportunities.
- The greenhouse gas implications associated with NGL production from the MGP need to be assessed.
- The total cumulative upstream and downstream emissions range from 365 Mt CO2eq under the EIS scenario to 2,543 Mt CO2eq under the Sproule scenario.

3. Comparison with Projected Upstream GHG Emissions

To put the numbers from the previous section for upstream and downstream GHG emissions into context, Section 3 compares them with total emissions from the NWT and from Canada.

3.1 Northwest Territories' Greenhouse Gas Emissions

Excluding potential emissions from the Mackenzie Gas Project, Natural Resources Canada (NRCan) expects the Northwest Territories' GHG emissions to increase incrementally from 1,708 kt CO2eq/yr in 2005 to 2,041 kt CO2eq/yr in 2020[20]. This is shown in Figure 2 below as NRCan's 'business as usual' (BaU) (i.e. excluding the MGP). The projected 'business as usual' GHG emissions from NRCan extend until year 2020; with the emissions estimated (by Pembina) to increase by 1% annually after that year. This is considered a conservative growth rate as there was 4.2% economic growth in the NWT in 2004[21].

Figure 2 also shows NWT's emissions adding in the upstream GHG emissions as provided in Section 2.2 for each of the five scenarios. Once again, the potential annual GHG emissions under the Sproule scenario are not included due to a lack of annual data. Downstream emissions are not included as the end-use is not expected to be in the NWT.

The data for the five scenario curves are calculated by adding the 'business as usual' emissions (NRCan projections) to the estimated emissions for each scenario.

[20] Natural Resources Canada, *Canada's Emissions Outlook 1996-2020*, April 1997

[21] Government of the NWT, *2005 NWT Socio-Economic Scan*, Section 6, June 2005. http://www.stats.gov.nt.ca/Statinfo/Generalstats/Scan/Socio-Econ%20(2005).pdf. Accessed May 26, 2005.

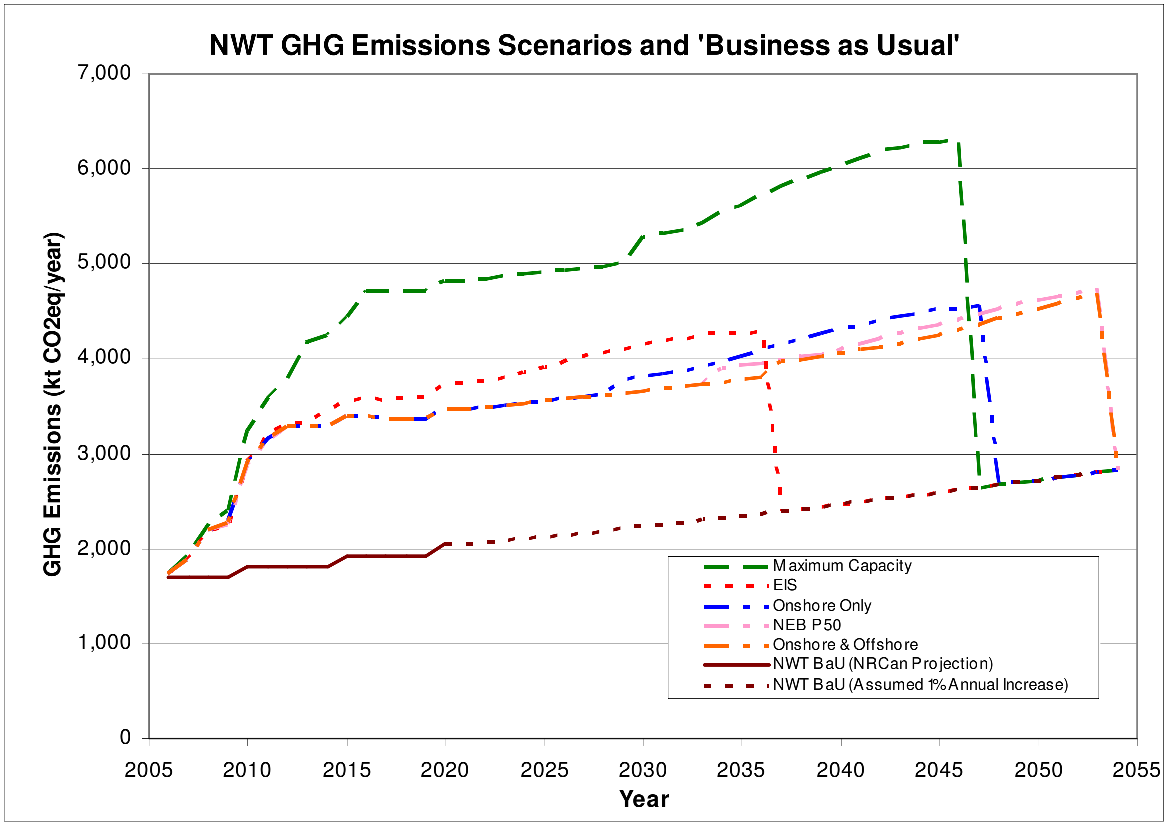

Figure 2: Total GHG emissions for NWT (Business as Usual and five scenarios shown)

Figure 2 shows that the emissions generated under the Maximum Capacity scenario would more than double the NWT's 'business as usual' GHG emissions during peak operation. The other scenarios nearly double NWTs 'business as usual' emissions during peak operation. Table 7 shows the total cumulative GHG emissions for the NWT between 2006 and 2053.

Table 7: Total cumulative projected emissions (2006 to 2053) compared to cumulative NWT 'business as usual' projected emissions (MGP upstream emissions only)

Scenario	Cumulative MGP GHG Emissions	Cumulative Total (MGP + NWT BaU) GHG Emissions	Percentage Increase over Cumulative NWT 'Business as Usual'
	kt CO2eq	*kt CO2eq*	
NWT 'Business as Usual'	-	109,760	0%
EIS	44,730	154,490	41%
Onshore Only	61,819	171,578	56%
Onshore & Offshore	68,474	178,233	62%
NEB P_{50}	70,083	179,843	64%
Maximum Capacity	111,204	220,963	101%
Sproule	183,268	293,028	167%

As Table 7 above shows, the total upstream emissions generated over the life of the MGP under the Sproule scenario would be over double the NWT's total 'business as usual' emissions. The emissions under the EIS scenario would add nearly another half of the NWT's 'business as usual' GHG emissions. The contribution of emissions under the other scenarios lie between the EIS scenario and the Sproule scenario.

In light of northern Canada's sensitivity to climate change, that the MGP emissions could more than double NWT's 'business as usual' emissions is noteworthy.

3.2 Canada's Greenhouse Gas Emissions

The most recent projections of Canada's greenhouse gas emissions were publicized by Natural Resources Canada (NRCan) in 1999[22] and are presented in Table 8.

Table 8: Projections of Canada's Greenhouse Gas Emissions 1997-2020

Year	Observed		Projected as of 1997				6% Below 1990 Levels
	1990	2004	2005	2010	2015	2020	
Canada's GHG Emissions *(Mt CO2eq)*	602	758	728	763	814	845	563

Considering, for example, the unexpected rate of development that occurred in Canada during the period from 2000-2005 (particularly in Alberta's oil sands), the projections generated in 1999 presented in Table 8 may be significantly lower than more current projections. Therefore, the data in Table 8 are intended to provide only the general trend in Canada's GHG emissions. In 2002, Canada ratified the Kyoto Protocol and has thereby legally committed to reducing its total GHG emissions to 6% below its emissions recorded in 1990 during the period of 2008-2012.

Table 9 provides a comparison of the upstream emissions associated with the MGP and Canada's 'business as usual' emissions based on NRCan's 1999 projections.

Table 9: Total projected cumulative emissions generated between 2006 and 2053: MGP compared to Canada's 'business as usual' projections (upstream emissions only)

Scenario	Cumulative MGP GHG Emissions	Cumulative MGP + Cumulative Canada BaU GHG Emissions[23]	Percentage Increase over Canada 'Business as Usual' GHG Emissions
	(kt CO2eq)	*(kt CO2eq)*	
Canada 'Business as Usual'	-	37,074,650	0.0%
EIS	44,730	37,119,380	0.1%

22 Natural Resources Canada, "Emissions Outlook 1997-2020" http://www.nrcan.gc.ca/es/ceo/cantable.pdf Accessed August 3, 2007.

23 A 1% growth rate was applied to Canada's emission post 2020, which is obviously counter to reducing emissions below current (or past) emissions.

Scenario	Cumulative MGP GHG Emissions	Cumulative MGP + Cumulative Canada BaU GHG Emissions[23]	Percentage Increase over Canada 'Business as Usual' GHG Emissions
Onshore Only	61,819	37,136,236	0.2%
Onshore & Offshore	68,474	37,141,525	0.2%
NEB P_{50}	70,083	37,144,733	0.2%
Maximum Capacity	111,204	37,185,854	0.3%
Sproule	183,268	37,273,750	0.5%

As shown in Table 9 above, the total upstream emissions generated over the life of the MGP under the Sproule scenario would add 0.5% to Canada's total 'business as usual' emissions. The emissions under the EIS scenario would add 0.1% to Canada's 'business as usual' GHG emissions. The contribution of emissions under the other scenarios would be between the EIS scenario and the Sproule scenario.

Should the total upstream and downstream emissions be considered for each of the scenarios, considering the low range (recall: 83% of gas is combusted), this would be 1 – 6% of Canada's project cumulative emissions. Of course this is assuming a constant growth in emissions, which is counter to the objectives of the Kyoto Protocol to reverse emissions growth. Thus, when Canada does reduce its emission closer to 1990 levels, the MGP project would be a larger portion of Canada's total emissions.

3.3 Key Points

- The upstream emissions from the Sproule scenario would more than double the NWT's emissions over the life of the MGP. Note that the estimate of upstream emissions under the Sproule scenario does not include the likely GHG emissions from supporting activities associated with the pipeline (e.g. additional exploration, transportation activities, or growth associated with subsequent infrastructure development).
- Over the life of the MGP, the emissions generated under the EIS scenario would add another 44% of NWT's total emissions.
- Over the life of the MGP, the emissions generated under the Maximum Capacity scenario would double NWT's GHG emissions.
- Total cumulative upstream and downstream emissions for the MGP, considering the low range, would be 1 – 6% of Canada's project cumulative emissions. This proportion would be higher should Canada reduce its emissions as per the Kyoto Protocol.

4. The MGP in Context with Canada's Oil Sands

This section compares the volume of gas supplied with the projected gas demands at the Oil Sands to the gas supplied from the MGP for the different scenarios considered in this report. A life-cycle perspective for the oil sands is also taken to understand the full GHG implications of gas supplied to it.

4.1 MGP and the Oil Sands

Operations in Alberta's oil sands have been identified as a potential end use of the natural gas conveyed by the MGP. This section compares the demand for natural gas in the oil sands to the projected supply via the MGP in this section.

Figure 3 compares the natural gas demand for oil sands operations to the total natural gas supply via the MGP under various possible scenarios. The data related to the demand for natural gas are based on information from Alberta Chamber of Resources[24].

[24] Alberta Chamber of Resources, "Oil Sands Technology Road Map: Unlocking the Potential" 30 January 2004

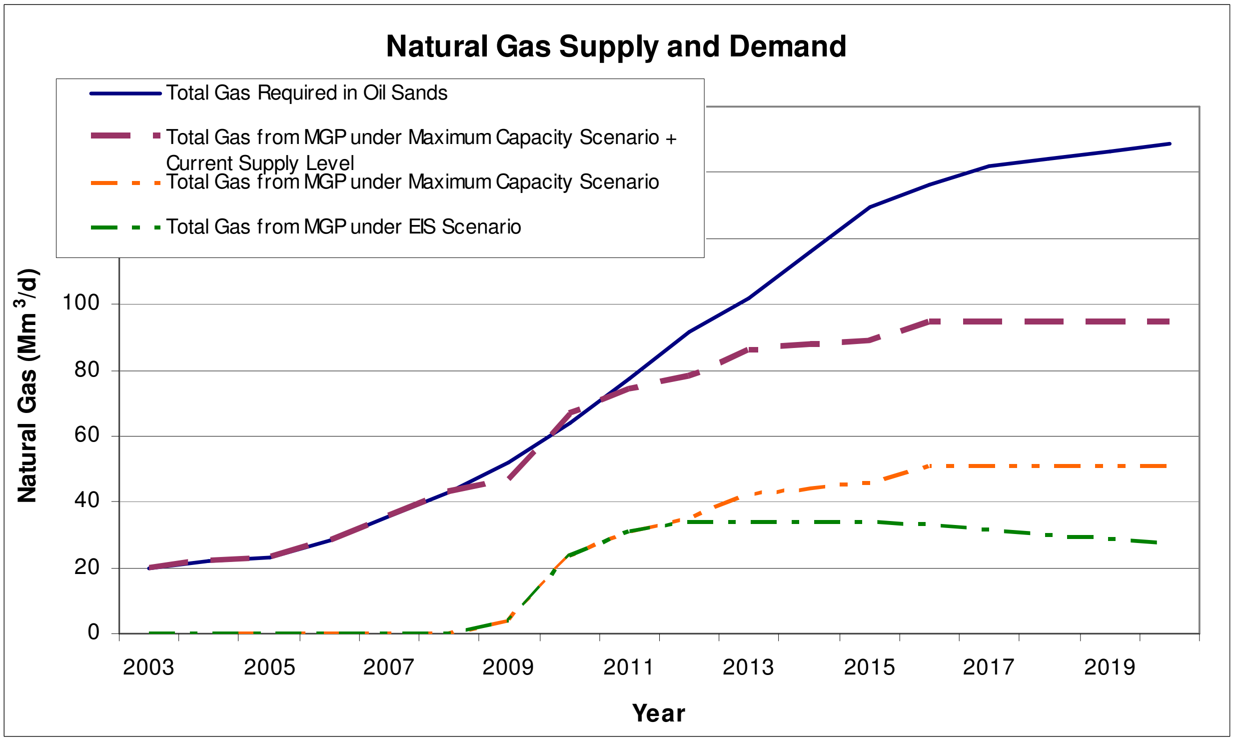

Figure 3: Comparison between natural gas supplied via the MGP and the total potential natural gas demanded by oil sands projects

Figure 3 demonstrates that the MGP will never be able to supply more than 40% of the natural gas demand projected for the oil sands. This peak percentage of supply will occur in 2011 (assuming A 2009 construction start) and will decrease relatively quickly under the EIS scenario and less quickly under the Maximum Capacity scenario. The demand for natural gas in the oil sands would exceed the potential combined supply of natural gas from the MGP plus the current supply of 40 Mm^3/d from existing sources, based on natural gas constituting the primary fuel for future oil sands operations. Based on this potential for a short supply of natural gas, it seems likely that alternatives to natural gas will have to be developed if oil sands are developed at current projected rates[25].

Figure 4 below shows the different uses of natural gas in the oil sands sector. Based on the Alberta Energy Utility Boards data, all oil sands activities will demand increasing amounts of natural gas. The greatest growth in demand for natural gas in the oil sands will be due to in situ extraction.

[25] The Pembina Institute for Appropriate Development, *Oil Sands Fever – The Environmental Implications of Canada's Oil Sands Rush,* November, 2005.

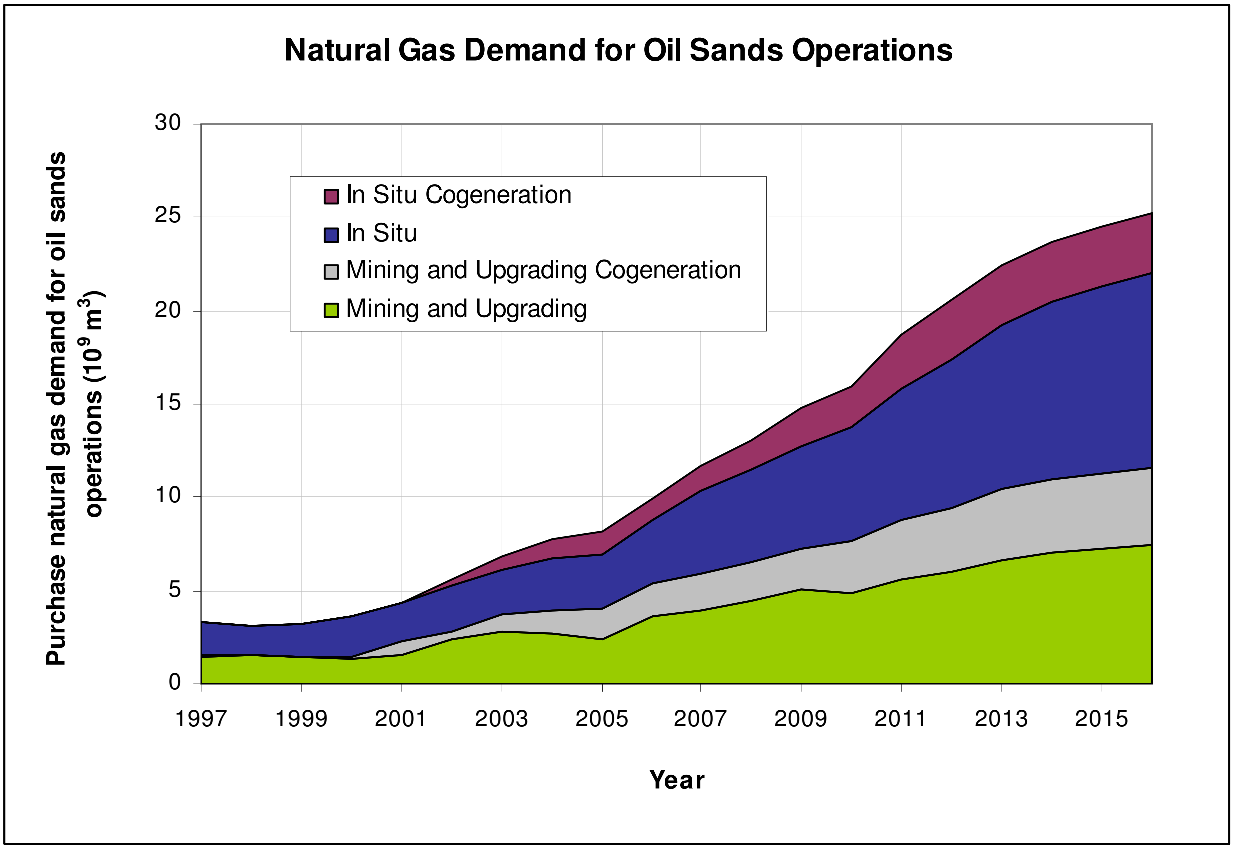

Figure 4: Purchased natural gas demand for oil sands operations[26]

4.2 Fuel Cycle GHG Emissions Related to the Oil Sands

Natural gas from the MGP will be transmitted to the Alberta-based NOVA (TransCanada) natural gas pipeline network. At least a portion of this gas can be considered likely to supply the oil sands operations given the amount of natural gas that it will likely require. This section indicates the life-cycle (ie. upstream and downstream) greenhouse gas emissions associated with natural gas delivered to the oil sands. This information is calculated to provide a more complete picture of the total GHG emissions associated with the MGP if the natural gas is supplied to the oil sands where it will be combusted and induce further downstream activities having GHG emissions.

The life-cycle, i.e. full upstream and downstream emissions when considering the oil sands, GHG emissions provided are based on an estimate of 10 Mm^3/day, or 3,650 Mm^3/year, of natural gas delivered to the of oil sands. This estimate was selected as a conservative volume based on the maximum flow rate of 34 Mm^3/day through the Mackenzie gas pipeline.

Figure 5 below shows the ‘activities’ or processes involved in the life-cycle of natural gas supply and use in the oil sands.[27]

[26] EUB, 2007. ST98: Alberta's Energy Reserves and Supply/Demand Outlook

Emissions resulting from the delivery of natural gas to the oil sands are shown in Figure 6. The emissions are broken into six activities beginning with the initial production of natural gas through to the combustion of the resulting transport fuel produced. Table B5 in Appendix B provides the GHG data for each of the activities. The authors assume the synthetic crude oil is refined in Edmonton, and the associated product is consumed in Calgary.

[27] The ratio of in-situ bitumen production and bitumen mining was calculated based on remaining established reserves ("Treasure in the Sand, An Overview of Alberta's Oil Sands Resources", April 2005, Canada West Foundation). Detailed assumptions and the calculation methodology for oil sands based GHG emissions are in Appendix B (all data is provided based on a per m^3 of natural gas from the MGP supplied to the life-cycle activities requiring natural gas input).

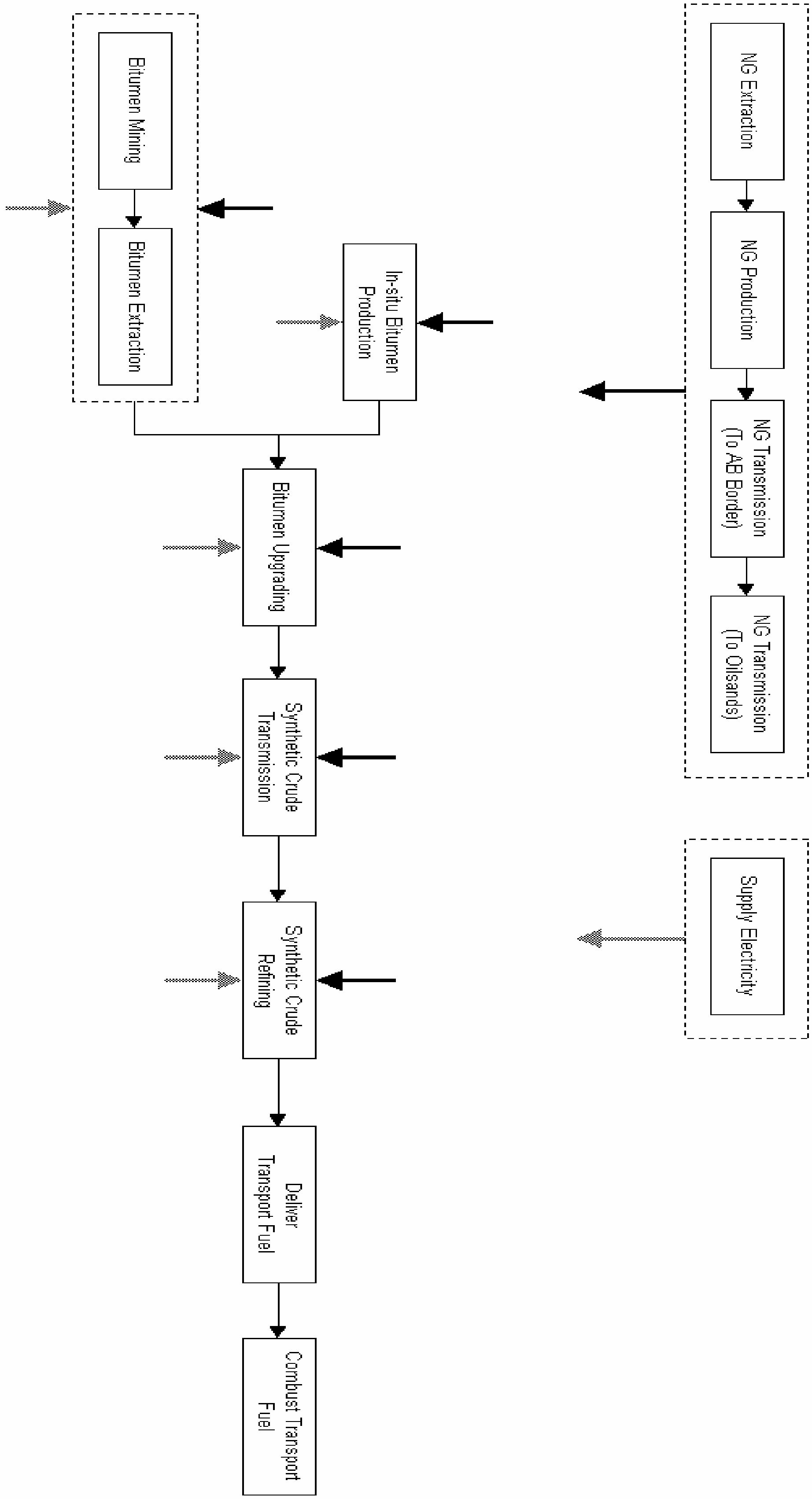

Figure 5: Life-cycle activity map of natural gas delivered to the oil sands

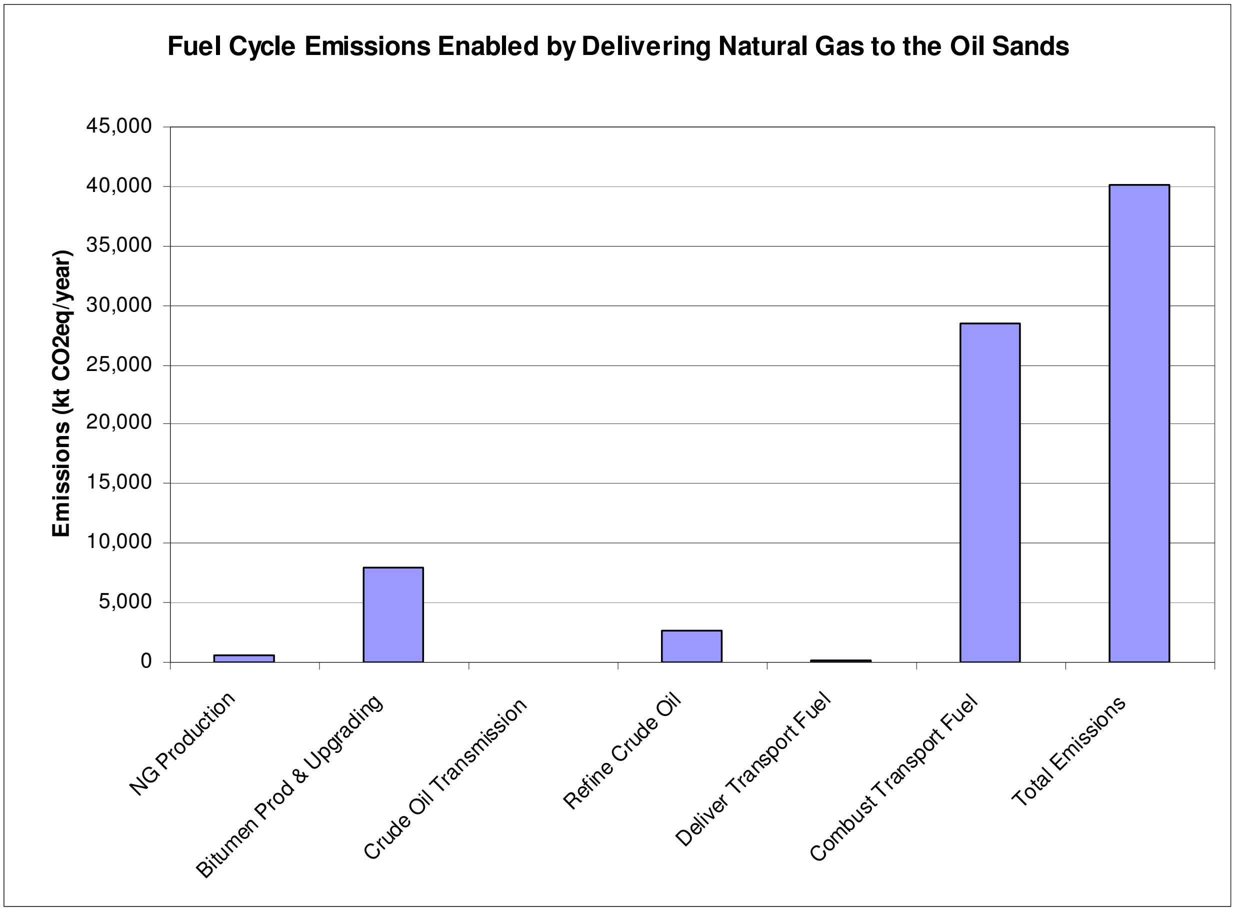

Figure 6: Fuel cycle emissions from the delivery of 10 Mm^3/day of natural gas to the oil sands

Figure 6 shows that the total GHG emissions produced by supplying of 10 Mm^3/day to the oil sands are 40 Mt CO2eq/yr. This amount is approximately thirty times higher than the average annual upstream emissions for the EIS, and four times higher than the average total annual upstream and downstream emissions associated with the EIS scenario. The largest contributor to the total emissions is the combustion of transport fuels produced from oil sands crude oil, at 70% of the total. Bitumen production and upgrading contribute almost 8,000 kt CO2eq/yr to the total or 20%, and refining the synthetic crude oil contributes 2,600 kt CO2eq/yr, or just over 6% to the total emissions.

Figure 6 also indicates that production and transmission of natural gas, at 1.65% of the fuel cycle GHG emissions, enables a significant amount of downstream GHG emissions. This raises the question of how the natural gas is used, and whether it could not be used directly (rather than in the oil sands) as an energy source for similar functional purposes. A comparison of conventional fuel (gasoline & diesel) for transportation purposes to a natural gas vehicle is provided to help address this question.

4.2.1 Comparison to Compressed Natural Gas (CNG) Vehicle

The following discussion illustrates that using 1m^3 of natural gas to provide mobility would be better served, from a GHG perspective, if it were used directly in a CNG vehicle rather than being sent to the oil sands for the same ultimate purpose.

For the purposes of this example, it is assumed that all gasoline and diesel produced from a refinery is used for mobile transportation purposes. Here, a conventional gasoline Honda Civic is compared to a compressed natural gas (CNG) Honda Civic.

As per the analysis in Appendix B, for every 1 m^3 of natural gas delivered to the oil sands, a total of 3 L of gasoline and diesel (combined) are produced. Given an efficiency of 6.85 L / 100 km on average[28] for a gasoline powered Honda Civic, this translates into 44 km of travel for every 1 m^3 of natural gas delivered from the MGP.

Based on 2005 data, the fuel consumption for a CNG Honda Civic is 6.7 m^3 of compressed gas per 100 km[29]. This translates into 15 km driven for every m^3 of natural gas delivered from the MGP.

Life-cycle emissions for the oil sands-based fuel cycle are 11 kg CO2eq for every m^3 of natural gas delivered from the MGP (see Appendix B). Comparatively, only 2 kg CO2eq for every m^3 of natural gas delivered are generated throughout the CNG vehicle's fuel cycle.[30] Thus, while the oil-sands fuel cycle can provide almost three times the distance in mobility, it also generates over five times the GHG emissions relative to the natural gas fuel cycle for a CNG vehicle.

Based on distance traveled, the oil sands based vehicle would generate 0.25 kg CO2eq/km, whereas the CNG vehicle would generate 48% less GHG emissions at 0.13 kg CO2eq/km.

4.3 Implications and Opportunities Associated with End-Use of Natural Gas from the MGP

As natural gas is a lower carbon fuel compared to coal or oil (meaning it emits less GHGs when combusted), it can play an important role in transitioning to a low carbon economy. However, we will have to think carefully about how we use what natural gas remains as low-cost access to gas reserves is in decline worldwide, increasing the value of existing natural gas reserves. Therefore given the climate change and the economic value of natural gas, opportunities for its commercial use must be wisely considered.

Specifically, consumption of natural gas in regions abundant with lower cost and higher carbon fuels (such as coal) for which carbon capture & storage (CCS) technology can be applied may not be in the best interest of avoiding the impacts of global warming. For example, using natural gas with instead of 'petcoke' (a waste byproduct similar to coal with slightly lower energy content) in the oilsands or coal for power generation in Alberta where CCS opportunities may soon be available (as the technology currently exists) should be carefully considered. This is particularly true if there are opportunities to use natural gas from the MGP sometime further into the future where CCS opportunities might not exist; for example, with smaller distributed sources such as residential heating for which CCS is not suited.

[28] Fuel economy for Honda Civic is 8.0 L/100km for city driving and 5.7L/100 km for highway driving. Source: http://www.honda.ca/Honda/Models/CivicCoupe/2005/Specifications.asp?L=E , accessed May 2005.

[29] "Model Year 2005 Fuel Economy Guide", U.S. Department of Energy. www.fueleconomy.gov.

[30] Fuel Cycle GHG emissions for CNG vehicle: 3,650 Mm^3/year of natural gas would generate 6,935 kt CO2eq/year or 7,596 kt CO2eq/year (6,935 kt + 661 kt) on a life-cycle basis (see Table B2, Appendix B) = 2.1 kg CO2eq/m3 NG

Carbon Capture and Storage

Whether economic CCS technology is relatively near term or not is still under investigation. While there is an international pilot project occurring in France, as well as pilot projects in Alberta and a full scale project in Weyburn, Saskatchewan, other potential projects by Shell, Statoil, and BP have recently been cancelled. More economic CCS opportunities exist when there is higher purity stream of CO2 available (i.e. the more CO2 in a given volume of gas the lower the cost per tonne of CO2 to remove it) and where secure storage capacity exists. The economics are improved if the CO2 is used for Enhanced Oil Recovery (EOR) applications (however this leads to reduced net CO2 stored). Thus, CCS may not be suitable in all locations and is site-specific.

While Alberta has geological reservoirs that can receive large volumes of CO2 for hundreds of years, this may be a rationale to focus on storing CO2 emitted from the combustion of lower cost coal and petcoke fuels, rather than developing scarce natural gas for potential use in Alberta. To determine this, a proper environmental and socio-economic life-cycle assessment should be completed.

Should the MGP be developed, then CCS should be a consideration for as many suitable end-uses as possible. This argument is reinforced given the potential contribution to global warming by the MGP as shown in Table 2 and Table 4above. Given that CCS is best suited for large stationary sources, it can be seen from Appendix F that up to 53% GHG emissions in Canada (industrial and electricity generation), and 54% in Alberta (oil sands, other industrial, electricity generation), would have potential opportunities for CCS applications (i.e. not necessarily all of the 50%+ emission sources).[31] This is safely assuming that many industrial uses of natural gas are large scale enough for economic capture and storage of CO2. It should be noted that once a CO2 pipeline network is in place in suitable regions, smaller sources of CO2 might be more readily able to capture and store as well. For the foreseeable future, however, there will be end uses for fossil fuels (such as for residential heating) that ccs will not be available for and therefore the relatively cleaner natural gas will be ideal for.

4.4 Key Points

- The projected primary energy demands of oil sands operations would exceed the supply of natural gas from the MGP by 40 Mm^3/d.
- Oil sands projects could consume all the gas supplied by the MGP based on supply and demand estimates.
- Delivering 10 Mm^3/d of natural gas to the oilsands enables the emission of 40 Mt CO2eq/yr in the oil sands from natural gas production, bitumen production and upgrading, crude oil transmission, crude oil refining, transport fuel delivery and transport fuel combustion.
    - This amount is approximately thirty times higher than the average annual upstream emissions for the EIS, and four times higher than the average total annual upstream and downstream emissions associated with the EIS scenario.

[31] Natural gas use in the oil sands is broken out in Figure 4 above. Opportunities and potential cost for implementing CCS in the oil sands is explored in the Pembina Institute paper 'Carbon Neutral by 2020: A Leadership Opportunity in Canada's Oil Sands', available at: http://www.pembina.org/pub/1316.

- For each kilometre driven, a vehicle powered by natural gas would generate 48% less GHG emissions than a vehicle powered by gasoline derived from oil sands on a life-cycle basis.

5. Contextualizing the Mackenzie Gas Project Greenhouse Gas Emissions

This chapter presents some more familiar activities to give the reader a sense of the magnitude of the GHG emissions associated with the MGP.

5.1.1 Light Vehicle Equivalent

The GHG emissions associated with operating the MGP for one year at peak conditions under the EIS, Maximum Capacity, Onshore Only, Onshore & Offshore, and NEB P_{50} scenarios are compared to the emissions from operating light vehicles in order to provide a scale and context. The emissions generated by operating the pipeline (i.e. upstream) are considered along with the end-use emissions (i.e. downstream). The results are provided in Table 10 below. For example, under the EIS scenario, up to 1.9 Mt CO2/eq are expected to be emitted annually from the MGP upstream operations. This is the same as the GHG emissions from 415,038 light vehicles (i.e. cars, pickup trucks, etc), which represents 2% of all light vehicles in Canada.

Table 10: Total number of cars that would generate the same amount of GHG emissions as operating the MGP for one year at peak capacity.

Scenario	Upstream Only			Upstream and Downstream		
	Peak Annual GHG Emissions	Light Vehicle Equivalent	% of Total Light Vehicles in Canada	Maximum [32]Annual GHG Emissions	Light Vehicle Equivalent	% of Total Light Vehicles in Canada
	(kt CO2eq/yr)			*(kt CO2eq/yr)*		
EIS	1,902	415,038	2%	25, 198	5,499,308	31%
Onshore Only	1,928	420,716	2%	25, 198	5,496,292	31%
Onshore & Offshore	1,881	410,476	2%	25, 198	5,496,292	31%
NEB P50	1,938	422,910	2%	25,198	5,496,292	31%
Maximum Capacity	3,709	809,575	5%	38,474	8,396,773	48%

[32] Note that this assumes 100% combustion of sales gas, thus the actual amount would be slightly less based on the reasons provided in Section 2.3.

To put Table 10 into perspective, there were 17.5 million light vehicles registered in Canada in 2003. Approximately 20,000 of these were registered in the Northwest Territories[33]. The emissions associated with the peak annual operation of the pipeline under the EIS scenario are roughly equivalent to the annual emissions from 415,000 light vehicles (2% of all light vehicles in Canada). Similarly, the emissions associated with the peak annual operation of the pipeline under the Maximum Capacity scenario are roughly equivalent to the annual emissions from 800,000 light vehicles (5% of all vehicles in Canada).

[33] "Transportation in Canada 2004 – Annual Report", Section 7, Road Transportation, Minister of Public Works and Government Services, Canada, 2004. ISBN 0-662-40464-5

6. GHG Emissions Reduction and Offset Options

This section considers ways that upstream GHG emissions might be reduced. It is beyond the scope of this report to consider how downstream emissions might be reduced, outside of general solutions such as energy efficiency and CCS for large point sources.

Owners and operators of the MGP should explore all potential GHG reduction opportunities associated with pipeline operations. This would include eliminating all fugitive (unintentional) GHG emissions) and engineered (intentional) methane emissions, improving energy efficiency performance, and fuel switching where possible (e.g. using ethanol blended gasoline in vehicle fleets). Table 11 below identifies some GHG reduction opportunities for the MGP industry proponents to explore within the MGP pipeline operations.[34]

Table 11: Pipeline Operation Emission Reduction Opportunities

Emission Category	Emission Subcategory	Opportunities
Combustion - Gas Turbines	Combustion - Gas Turbines	Improved performance monitoring, optimization and servicing practices, replacement with more appropriately sized units, and possible utilization of waste heat from exhaust.
Combustion - Heaters/Boilers	Combustion - Heaters/Boilers	Improved design practices, improved performance monitoring, optimization and servicing practices and conversion from natural draft to forced air systems.
	Combustion - Propane	Improved performance monitoring, optimization and servicing practices.
Combustion - Reciprocating Engines	Combustion - Diesel Engines	Improved performance monitoring, optimization and servicing practices, and conversion to high-efficiency engines.
	Combustion - Reciprocating Engines	Improved performance monitoring, optimization and servicing practices, replacement with more appropriately sized units, and possible utilization of waste heat from exhaust and cooling water.
Flaring	Flaring	Flare gas recovery, monitoring and control of leakage into flare headers, optimization of purge gas rates, and reduced use of fuel-gas operated venturi systems for collection of waste gas streams.
Fugitive Equipment Leaks	Fugitive Equipment Leaks	Formal leak detection and repair programs, seal vent monitoring and/or control systems, and specification of low-leak or no-leak components.
Other	Accidents/Equipment Failures	Improved, safety, inspection and maintenance and design practices.
	Formation CO_2	Reinjection as part of enhanced recovery scheme, or injection into disposal well.
Venting	Glycol Dehydrator Off-Gas	Regular optimization of glycol circulation rates and installation of vent control systems (e.g., condensers with off-gas utilization, flares, incinerators).

[34] Information provided by Petroleum Technology Alliance Canada, Calgary, Alberta. (www.ptac.org)

Emission Category	Emission Subcategory	Opportunities
	Product Loading/Unloading	Vapour recovery or disposal systems may be practical at larger facilities. Vapour exchange is a significant opportunity.
	Storage Losses	Vapour recovery or disposal systems, and use of upstream flash tanks, gas boots and/or stabilizers as appropriate.
	Reported Venting	Same as above.
	Unreported Venting	Switch to use of compressed air instead of natural gas as the supply medium, and convert to low consumption devices.

While the above methods would allow for a reduction in upstream emissions, they would likely not completely eliminate them. Thus other methods for industry MGP proponents to reduce emissions associated with the MGP (upstream) is to have another entity reduce GHG emissions on their behalf: namely, purchase GHG offsets. Until federal regulation is in place by 2010, this can be done through the voluntary offset market. Beyond 2010, a market based offset trading system should be in place with clear guidelines. Regardless, offsets of only the highest environmental integrity (i.e. additional to what would be considered business as usual reduction) should be acquired. The following are some examples of how this could be achieved.

i) Purchase GHG offsets through the Kyoto Protocol's 'Clean Development Mechanism'

- This entails purchasing internationally recognized GHG offsets from countries in transition. The average price for the first three months of 2006 in the international carbon market (i.e. not just the CDM) were CDA$14.04 per tonne CO2eq.[35] Again, high quality offsets with demonstrable environmental integrity, such as Gold Standard offsets already approved through the CDM, should be considered.

ii) Purchase existing domestic based 'additional' GHG offsets:

- There are multiple offset providers of Canadian based offsets that exist today. However, offset wholesalers and retailers provide a range of products each with potential issues; thus it is important to apply due diligence in assessing what is being purchased.

iii) Establish internal corporate GHG emissions trading system

- Using BP International as a successful example, MGP companies can set up their own internal GHG trading system using the creativity and innovation of employees to capitalize on GHG reduction opportunities elsewhere within their own operations, internationally. Reductions achieved can then be applied to the MGP operations.

iv) Invest in domestic GHG reduction offset project(s)

- This would ideally be northern based, as a way of supporting economic development in local communities. As an example, project types that could be considered relevant are:
    - *Biofuel development:* this might include in investing in the collection of waste forestry and agricultural products for use as biofuels. Projects could include heat or electricity production for local needs, or as a feedstock for ethanol or biodiesel production for use in transportation.

[35] World Bank, *State and Trends of the Carbon Market, 2006*, May 2006,
Converted from US$11.45 per ton CO2eq using: US$1 = CDA$1.112, as of 10:50 a.m., May 17, 2006, and; 1 ton = 0.907 tonnes.

- *Ice rink energy reduction technology:* There is a proven technology to drastically reduce the energy requirements and associated (diesel fuel-based) GHG emissions associated with ice rink cooling. Very well suited for northern climates, it has the potential to reduce the associated emissions by 95%. This is significant when considering the number of smaller northern communities with ice rinks, and would be an ideal way for MGP companies to reduce emissions while contributing to the development of local northern economies.[36]
- *Energy-efficiency housing retrofits:* Natural Resources Canada's recently terminated EnerGuide for Houses program reduced household GHG emissions by 3.9 t CO2eq/yr for an average retrofit[37]. In order to offset all the upstream emissions associated with the operation of the MGP under the EIS scenario, 370,000 homes could be retrofit. In order to offset the emissions under the Maximum Capacity scenario including upstream and downstream emissions, 6.4 million homes could be retrofit.
- *Wind power procurement:* Commissioning 450 MW (installed capacity) of wind turbines and scaling back the coal-based electricity production in Alberta accordingly would offset all of the upstream emissions under the EIS scenario. Offsetting the upstream and downstream emissions under the Maximum Capacity scenario would require 7,690 MW of installed wind power capacity.

[36] Contact Rick Owen of Rink Pro, rmowen@telusplanet.net. 403-742-5402.

[37] Green Communities Association, *EnerGuide for Houses Retrofit Incentive - Fact Sheet*, 11 May 2004 http://www.gca.ca/indexcms/downloads/EGH%20factsheets.pdf

7. Conclusions

Key conclusions for each of the specific objectives are listed below. The estimates provided in this report may be over estimated by 10%, based on one less compressor used and incorporation of waste heat recovery since the writing of the original June 2006 Pembina Institute report update.

Estimate the annual and total lifetime-of-the-project (cumulative) greenhouse gas emissions for the different MGP production scenarios– for both the operation of the pipeline (upstream) and combustion of the gas (downstream).

This report considers six different MGP development scenarios.

- Other plausible development scenarios contribute to much higher, up to four times, the GHG emissions than the EIS scenario.
- The Maximum Capacity and Sproule Scenarios have over double the maximum annual GHG emissions than the other scenarios.
- All other non-EIS scenarios generate emissions 10 to 20 years further into the future than the EIS scenario.
- GHG emissions actually increase over the life of the project due to inlet compression requirements.
- Natural gas sold that ends up being combusted is seven to thirteen times more than the upstream emissions over the life of the project.
- Further work is needed to determine the additional downstream GHG emissions from NGL use.

Put the estimated GHG emissions in the context of the NWT and Canada.

- The EIS scenario having the least gas production would represent an increase of 41% over the cumulative ‘business as usual’ GHG emissions in the NWT between 2006 and 2053.
- The Sproule Scenario, producing the most gas, would represent an increase of 167% over the cumulative ‘business as usual’ GHG emissions in the NWT between 2006 and 2053.
- Considering the total upstream and downstream emissions for each of the scenarios, the more conservative estimate shows that this would constitute 1 – 6% of Canada’s projected cumulative emissions out to 2053 based on a steady 1% annual increase in Canada’s emissions beyond 2020. This would be a higher proportion assuming Canada reduced its emissions over time based on federal and provincial policies.

Put the MGP in context with Canada's Oil Sands

- Oil sands projects could consume all the gas supplied by the MGP based on supply and demand estimates.
- Delivering 10 Mm^3/d (0.35 BCF) of natural gas to the oil sands enables the emission of 40 Mt CO2eq/yr in the oil sands from natural gas production, bitumen production and upgrading, crude oil transmission, crude oil refining, transport fuel delivery and transport fuel combustion.
    - This amount is approximately thirty times higher than the average annual upstream emissions for the EIS scenario, and four times higher than the average total annual upstream and downstream emissions associated with the EIS scenario.
    - GHG emissions associated with the MGP operation (upstream) would only account for less than 2% of the total emission generated.
- It should be considered whether cleaner burning natural gas is actually suitable for the oil sands should carbon capture and storage technology (CCS) be planned for the industrial region; in which case the waste product 'petcoke' could be a primary fuel source in the oil sands. Natural gas could instead be more beneficially employed for end-uses at which CCS is unlikely to be available.
- For each kilometre driven, a vehicle powered by natural gas would generate 48% less GHG emissions than a vehicle powered by gasoline originating from oil sands on a life-cycle basis.

Contextualize projected increases in GHG emissions resulting from the operation of the MGP.

- The peak annual GHG emissions generated by operating the MGP (i.e. upstream emissions) are expected to be equivalent to the GHG emissions from between 400,000 and 800,000 light vehicles operating annual, representing between 2 and 5% of all light vehicles registered in Canada.
- When downstream emissions are included, the total emissions are equivalent to the emissions from between 5.5 and 8.4 million light vehicles operating annual, representing 31 to 48% of all light vehicles registered in Canada (this assumes 100% combustion). The Sproule scenario, for which annual ghg emissions were not available, would be significantly higher.

Describe possible options to reduce or offset GHG emissions from the operation of the pipeline

Possible options for reducing or offsetting GHG emissions generated by operating the MGP (i.e. upstream emissions) include:

- using eco-efficient technologies for combustion, flaring, venting, and preventing leaks;
- purchasing GHG offsets through the Kyoto Protocol's Clean Development Mechanism;
- purchasing or investing in domestic GHG offsets and offset projects,
- establishing internal corporate GHG emissions trading system

GHG offsets vary greatly in there quality and environmental integrity. A fundamental criteria when purchasing offsets is to ensure the project generating the reductions goes beyond business as usual practices. Otherwise, we are no further ahead in reducing total emission as the purchaser of the offset simply continues to pollute (leading to no net reductions).

Appendix A: Emissions Estimates, Methodologies, and Assumptions

The estimates of greenhouse gas emissions under each scenario and the methodologies used to derive those estimate are discussed in this section. A brief explanation of how the scenarios were generated is also provided.

EIS Scenario

The EIS scenario was originally derived from the scenario presented in Imperial Oil Resources Ventures Limited's *Environmental Impact Statement,* August 2004. The GHG emissions estimate under the EIS scenario was updated with new information presented in the Information Request Response[38], which included annual emissions estimates.

The total emissions for the EIS Scenario are calculated in Table A1 and Table A2. A list of assumptions and explanations used to calculate the emissions follows each table.

Table A1: Maximum Annual Operations Emissions for EIS Scenario

Annual Operations Emissions at Full Load	Full Load	Annual Total Emissions at Full Load	Maximum Annual Emissions	Years at Full Capacity
(kt CO2eq/yr)	*Mm^3/d*	*(kt CO2eq/yr)*	*(kt CO2 eq/yr)*	
1,386.8	34.0	1,501.9	1,901.7	3

The annual operations emissions of 1,387 kt CO2eq/yr in Table A1 includes the emissions from the production area, the Inuvik area facility, and the pipeline corridor at max flow. The total annual emissions are calculated to be 1,502 kt CO2eq/yr and include fugitive emissions from the pipeline.

[38] Imperial Oil Resources Venture Limited, *Joint Review Panel Round 2 Intervenor Information Request Response* 8 June 2005

Table A2: Total Annual and Cumulative Emissions for the upstream EIS Scenario.

		Emissions							
Year	Total Sales Gas[39]	Operations Emissions[40]	Fugitive Emissions	Emissions from Changes in Land Use[41]	Construction Emissions[42]	Well Testing Emissions[43]	Blowdown Venting Emissions[44]	Total Annual Emissions	Cumulative Emissions
	(Mm^3/d)	*(kt CO2eq/yr)*	*(kt CO2eq/yr)*	*(kt CO2eq/yr)*	*(kt CO2eq/yr)*	*(kt CO2eq/yr)*	*(kt CO2eq/yr)*	*(kt CO2eq/yr)*	*(kt CO2eq)*
2006	0	0.0	0.0	0	24.9	0	0	25	25
2007	0	0.0	0.0	43.7	153.5	4.5	0	202	227
2008	0	0.0	0.0	56.6	363.2	63.4	0	483	710
2009	3.8	0.0	0.0	56.6	246.2	58.9	0	362	1,071
2010	23.5	1,386.8	50.9	44.6	32.1	0	19.6	1,534	2,605
2011	31.0	1,386.8	50.9	44.6	0	0	19.6	1,502	4,107
2012	34.0	1,386.8	50.9	44.6	0	0	19.6	1,502	5,609
2013	34.0	1,386.8	50.9	44.6	0	0	19.6	1,502	7,111
2014	34.0	1,471.1	50.9	44.6	0	0	19.6	1,586	8,697
2015	33.8	1,471.1	50.9	44.6	0	0	19.6	1,586	10,283
2016	33.2	1,516.3	50.9	44.6	0	0	19.6	1,631	11,915
2017	31.5	1,516.3	50.9	13.1	0	0	19.6	1,600	13,515
2018	29.9	1,571.2	50.9	13.1	0	0	19.6	1,655	15,170
2019	28.7	1,655.5	50.9	13.1	0	0	19.6	1,739	16,909
2020	27.6	1,655.5	50.9	13.1	0	0	19.6	1,739	18,648
2021	26.3	1,655.5	50.9	13.1	0	0	19.6	1,739	20,387
2022	25.2	1,700.7	50.9	13.1	0	0	19.6	1,784	22,171
2023	23.8	1,700.7	50.9	13.1	0	0	19.6	1,784	23,955
2024	22.0	1,785.1	50.9	13.1	0	0	19.6	1,869	25,824
2025	18.1	1,785.1	50.9	13.1	0	0	19.6	1,869	27,693
2026	14.8	1,785.1	50.9	13.1	0	0	19.6	1,869	29,562
2027	12.1	1,785.1	50.9	0.9	0	0	19.6	1,857	31,418
2028	9.9	1,830.3	50.9	0.9	0	0	19.6	1,902	33,320
2029	8.5	1,830.3	50.9	0.9	0	0	19.6	1,902	35,221
2030	6.6	1,830.3	50.9	0.9	0	0	19.6	1,902	37,123
2031	5.1	1,830.3	50.9	0.9	0	0	19.6	1,902	39,025

[39] GLJ Report, Table 11, Pg 66

[40] Table JRP SCC 2.19-1 "Annual Greenhouse Gas Emissions", pg 15, of Mackenzie Gas Project, Joint Review Panel Round 2 Intervenor Information Request Response, June 8th 2005

[41] The Fugitive emissions of 50.87 kt/a are taken from Table JRP DGMA 1.02-4, pg. 7 of Mackenzie Gas Project, Joint Review Panel Round 2 Intervenor Information Request Response, March 31, 2005.

[42] The construction emissions are taken from Table JRP DGMA 1.02-5, pg. 8 of Mackenzie Gas Project, Joint Review Panel Round 2 Intervenor Information Request Response, March 31, 2005.

[43] Table JRP SCC 2.19-1 "Annual Greenhouse Gas Emissions", pg. 15, of Mackenzie Gas Project, Joint Review Panel Round 2 Intervenor Information Request Response, June 8th, 2005

[44] Table JRP SCC 2.19-1 "Annual Greenhouse Gas Emissions", pg. 15, of Mackenzie Gas Project, Joint Review Panel Round 2 Intervenor Information Request Response, June 8th, 2005

Year	Total Sales Gas[39]	Operations Emissions[40]	Fugitive Emissions	Emissions from Changes in Land Use[41]	Construction Emissions[42]	Well Testing Emissions[43]	Blowdown Venting Emissions[44]	Total Annual Emissions	Cumulative Emissions
		Emissions							
	(Mm^3/d)	(kt CO2eq/yr)	(kt CO2eq/yr)	(kt CO2eq/yr)	(kt CO2eq/yr)	(kt CO2eq/yr)	(kt CO2eq/yr)	(kt CO2eq/yr)	(kt CO2eq)
2032	4.3	1,830.3	50.9	0.9	0	0	19.6	1,902	40,927
2033	3.5	1,830.3	50.9	0.9	0	0	19.6	1,902	42,828
2034	2.5	1,830.3	50.9	0.9	0	0	19.6	1,902	44,730
2035	2.2	0.0	0.0	0.0	0	0	0	0	44,730
2036	0.9	0.0	0.0	0.0	0	0	0	0	44,730
2037	0	0.0	0.0	0.0	0	0	0	0	44,730
2038	0	0.0	0.0	0.0	0	0	0	0	44,730
2039	0	0.0	0.0	0.0	0	0	0	0	44,730
2040	0	0.0	0.0	0.0	0	0	0	0	44,730
2041	0	0.0	0.0	0.0	0	0	0	0	44,730
2042	0	0.0	0.0	0.0	0	0	0	0	44,730
2043	0	0.0	0.0	0.0	0	0	0	0	44,730
2044	0	0.0	0.0	0.0	0	0	0	0	44,730
2045	0	0.0	0.0	0.0	0	0	0	0	44,730
2046	0	0.0	0.0	0.0	0	0	0	0	44,730
2047	0	0.0	0.0	0.0	0	0	0	0	44,730
2048	0	0.0	0.0	0.0	0	0	0	0	44,730
2049	0	0.0	0.0	0.0	0	0	0	0	44,730
2050	0	0.0	0.0	0.0	0	0	0	0	44,730
2051	0	0.0	0.0	0.0	0	0	0	0	44,730
2052	0	0.0	0.0	0.0	0	0	0	0	44,730
2053	0	0.0	0.0	0.0	0	0	0	0	44,730

The total annual emissions in Table A2 include operations emissions, emissions resulting from land disturbance and construction emissions. Emissions from land disturbance and construction varied from year to year as shown in the table.

Methodology for Maximum Capacity, Onshore Only, Onshore & Offshore, and NEB P_{50} Scenarios

Prior to and During Maximum Natural Gas Flow

The emissions under the EIS scenario were provided in the Information Request Response dated June 8, 2005 to the Sierra Club of Canada. The emissions under the other scenarios are calculated based on the relationship between sales gas flow and emissions in the EIS scenario. This methodology is described below.

From the beginning of operations to the end of maximum flow through the pipeline, the operations (ops) GHG emissions are determined based on a linear relationship with sales gas. Once the GHG emissions at max flow are calculated, the GHG emissions prior to this are determined by prorating the GHG emissions at max flow based on sales gas. This relationship is illustrated by the following equation:

$$\frac{\text{Ops GHG Emissions for Year } X}{\text{Ops GHG Emissions at Max Flow}} \propto \frac{\text{Gas Sales for Year } X}{\text{Gas Sales at Max Flow}}$$

Rearranging,

$$\text{Ops GHG Emissions for Year } X = 0.73 \times \text{Gas Sales for Year } X \times \frac{\text{Ops GHG Emissions at Max Flow}}{\text{Gas Sales at Max Flow}}$$

The constant, 0.73, is the ratio of emissions at peak operation originally presented in the Environmental Impact Statement to the emissions at peak operation presented in the June 8th 2005 Information Request Response.

The total annual emissions are the sum of operations emissions, emissions from changes in land use, construction emissions, well testing emissions, and blowdown venting emissions.

A sample calculation for the year 2009 under the Maximum Capacity scenario is shown below:

$$\text{Ops GHG Emissions for Year 2009} = 0.73 \times \text{Gas Sales for Year 2009} \times \frac{\text{Ops GHG Emissions at Max Flow}}{\text{Gas Sales at Max Flow}}$$

$$\text{Ops GHG Emissions for Year 2009} = 0.73 \times 3.8\ \text{Mm}^3/\text{d} \times \frac{3{,}621\ \text{kt CO2eq/yr}}{51\ \text{Mm}^3/\text{d}}$$

$$\text{Ops GHG Emissions for Year 2009} = 199\ \text{kt CO2eq/yr}$$

$$\text{Total GHG Emissions for Year 2009} = (199 + 84.9 + 246 + 88.4 + 0)\ \text{kt CO2eq}$$

$$\text{Total GHG Emissions for Year 2009} = 618\ \text{kt CO2eq}$$

After Natural Gas Maximum Flow (Throughput)

The June 8th 2005 Information Request Response, which reports the GHG emissions accounting for inlet compression under the EIS scenario, formed the basis for estimating GHG emissions after maximum flow under the Maximum Capacity, Onshore Only, Onshore & Offshore, and NEB P_{50} scenarios.

Similar to the emissions estimate prior to max flow, the relationship between the ratio of sales gas during a given year to sales gas at max flow and the ratio of operations GHG emissions during a given year to the operations GHG emissions during max flow is used to estimate the GHG emissions after max flow. In other words, the relationship

$$\frac{\text{Ops GHG Emissions for Year } X}{\text{Ops GHG Emissions at Max Flow}} \propto \frac{\text{Gas Sales for Year } X}{\text{Gas Sales at Max Flow}}$$

is assumed to apply both prior to max flow and after max flow. The constants in this relationship, however, are different after max flow from prior to max flow due to the requirement for inlet compression. All gas fields are assumed to require inlet compression as gas is extracted from the field. This is considered reasonable as reduced flow (after peak) is the result of reduced pressure (which did exist prior to and during peak) for transport purposes, for which compensation is required.

A regression analysis based on the GHG emissions under the EIS scenario compared to sales gas under the EIS scenario after max flow yielded the following relationship with R^2=0.82:

$$\frac{\text{Ops GHG Emissions for Year } X}{\text{Ops GHG Emissions at Peak Output}} = -0.2815 \times \frac{\text{Gas Sales for Year } X}{\text{Gas Sales at Peak Output}} + 1.3849$$

Rearranging,

$$\text{Ops GHG Emissions} = \text{Ops GHG Emissions at Peak Output} \times \left(-0.2815 \times \frac{\text{Gas Sales}}{\text{Gas Sales at Peak Output}} + 1.3849 \right)$$

There are several assumptions inherent in this methodology:

- All gas fields are assumed to behave similarly;
- Inlet compression is assumed to only apply at the end of max flow; and
- The relationship between GHG Emissions relative to GHG Emissions at Max flow and Sales Gas relative to Sales Gas at Max flow is assumed to be linear.

Similar to the emissions prior to max flow, the total annual emissions are the sum of operations emissions, emissions from changes in land use, construction emissions, well testing emissions, and blowdown venting emissions.

A sample calculation for the year 2045 is shown below:

$$\text{Ops GHG Emissions} = \text{Ops GHG Emissions at Peak Output} \times \left(-0.2815 \times \frac{\text{Sales Gas}}{\text{Sales Gas at Peak Output}} + 1.3849 \right)$$

$$\text{Ops GHGEmissions} = 3{,}621\ \text{kt CO2eq/yr} \times \left(-0.2815 \times \frac{0.3\ \text{Mm}^3/\text{d}}{51\ \text{Mm}^3/\text{d}} + 1.3849 \right)$$

$$\text{Ops GHG Emissions} = 3{,}693\ \text{kt CO2eq/yr}$$

$$\text{Total GHG Emissions} = (3{,}693 + 0 + 0 + 0 + 0)\ \text{kt CO2eq}$$

$$\text{Total GHG Emissions} = 3{,}693\ \text{kt CO2eq}$$

Maximum Capacity Scenario

The Maximum Capacity scenario was generated by multiplying the EIS scenario by 1.5, which is based on estimates provided in the GLJ Report[45]. Therefore, the full load capacity, fugitive emissions, operations emissions, emissions due to land use change, blowdown venting emissions, and well testing emissions are increased by 50% over the EIS scenario.

The GHG emissions under the Maximum Capacity scenario are calculated in Table A3 and Table A4. A list of assumptions and explanations used to calculate the emissions follows the second table.

Table A3: Maximum Annual Operations Emissions for Maximum Capacity Scenario

Annual Operations Emissions at Full Load	Full Load	Annual Total Emissions at Full Load	Maximum Annual Emissions	Years at Full Capacity
(kt CO2 eq/yr)	*(Mm^3/d)*	*(kt CO2 eq/yr)*	*(kt CO2 eq/yr)*	
2,613.7	50.9	2,786.3	3,709.5	15

Table A4: Total Annual and Cumulative Emissions for the upstream Maximum Capacity Scenario.

		Emissions							
Year	Total Sales Gas[46]	Operations Emissions	Fugitive Emissions	Emissions from Changes in Land Use	Construction Emissions	Well Testing Emissions	Blowdown Venting Emissions	Total Annual Emissions	Cumulative Emissions
	(Mm^3/d)	*(kt CO2eq/yr)*							*(kt CO2eq)*
2006	0	0	0	0.0	25	0.0	0.0	25	25
2007	0	0	0	65.6	153	6.8	0.0	226	251
2008	0	0	0	84.9	363	95.1	0.0	543	794
2009	3.8	195	76	84.9	246	88.4	0.0	690	1,484
2010	23.5	1,204	76	66.9	32	0.0	29.4	1,409	2,893
2011	31.0	1,589	76	66.9	0	0.0	29.4	1,761	4,655
2012	34.9	1,789	76	66.9	0	0.0	29.4	1,961	6,616
2013	42.5	2,178	76	66.9	0	0.0	29.4	2,351	8,967
2014	44.2	2,265	76	66.9	0	0.0	29.4	2,438	11,404
2015	45.7	2,342	76	66.9	0	0.0	29.4	2,515	13,919
2016	51.0	2,614	76	66.9	0	0.0	29.4	2,786	16,705
2017	51.0	2,614	76	66.9	0	0.0	29.4	2,786	19,492
2018	51.0	2,614	76	66.9	0	0.0	29.4	2,786	22,278
2019	51.0	2,614	76	66.9	0	0.0	29.4	2,786	25,064
2020	51.0	2,614	76	66.9	0	0.0	29.4	2,786	27,851
2021	51.0	2,614	76	66.9	0	0.0	29.4	2,786	30,637
2022	51.0	2,614	76	66.9	0	0.0	29.4	2,786	33,423
2023	51.0	2,614	76	66.9	0	0.0	29.4	2,786	36,210

[45] Gilbert Laustsen Jung Associates Ltd., *Mackenzie Gas Project, Gas Resource and Supply Study – A Study Prepared for Imperial Oil Resources Ventures Limited* May 1, 2004

[46] GLJ Report, Table 36, pg. 82

Year	Total Sales Gas[46]	Operations Emissions	Fugitive Emissions	Emissions from Changes in Land Use	Construction Emissions	Well Testing Emissions	Blowdown Venting Emissions	Total Annual Emissions	Cumulative Emissions
		Emissions							
	(Mm³/d)	(kt CO2eq/yr)							(kt CO2eq)
2024	51.0	2,614	76	66.9	0	0.0	29.4	2,786	38,996
2025	51.0	2,614	76	66.9	0	0.0	29.4	2,786	41,782
2026	51.0	2,614	76	66.9	0	0.0	29.4	2,786	44,569
2027	51.0	2,614	76	66.9	0	0.0	29.4	2,786	47,355
2028	51.0	2,614	76	66.9	0	0.0	29.4	2,786	50,141
2029	51.0	2,614	76	66.9	0	0.0	29.4	2,786	52,927
2030	51.0	2,884	76	66.9	0	0.0	29.4	3,057	55,984
2031	50.3	2,894	76	66.9	0	0.0	29.4	3,067	59,051
2032	46.2	2,953	76	19.7	0	0.0	29.4	3,079	62,129
2033	42.1	3,012	76	19.7	0	0.0	29.4	3,138	65,267
2034	37.1	3,084	76	19.7	0	0.0	29.4	3,210	68,477
2035	32.7	3,148	76	19.7	0	0.0	29.4	3,273	71,750
2036	27.2	3,227	76	19.7	0	0.0	29.4	3,353	75,103
2037	21.9	3,304	76	19.7	0	0.0	29.4	3,429	78,532
2038	16.9	3,376	76	1.4	0	0.0	29.4	3,483	82,015
2039	13.4	3,426	76	1.4	0	0.0	29.4	3,533	85,548
2040	10.7	3,465	76	1.4	0	0.0	29.4	3,572	89,121
2041	6.9	3,520	76	1.4	0	0.0	29.4	3,627	92,748
2042	4.0	3,562	76	1.4	0	0.0	29.4	3,669	96,417
2043	2.5	3,584	76	1.4	0	0.0	29.4	3,691	100,108
2044	1.2	3,602	76	1.4	0	0.0	29.4	3,709	103,817
2045	0.3	3,615	76	0.0	0	0.0	0.0	3,692	107,509
2046	0.1	3,618	76	0.0	0	0.0	0.0	3,695	111,204
2047	0.0	0	0	0.0	0	0.0	0.0	0	111,204
2048	0.0	0	0	0.0	0	0.0	0.0	0	111,204
2049	0.0	0	0	0.0	0	0.0	0.0	0	111,204
2050	0.0	0	0	0.0	0	0.0	0.0	0	111,204
2051	0.0	0	0	0.0	0	0.0	0.0	0	111,204
2052	0.0	0	0	0.0	0	0.0	0.0	0	111,204
2053	0.0	0	0	0.0	0	0.0	0.0	0	111,204

Assumptions

- The operations emissions under the Maximum Capacity scenario can be estimated by prorating the operations emissions under the EIS scenario based on sales gas.

Notes

- Ten extra compressor stations are required for operation at maximum capacity[47]. The GHG emissions from currently planned compressor stations are 108 kt CO2eq/yr[48]. This

[47] Ten additional compressor stations is taken from Figure 1-3, pg 1-14 in Application for Approval of the Mackenzie Valley Pipeline, Volume 1 – Pipeline Project Overview, August 2004

value was used for the expected emissions from future compressor stations for the maximum capacity scenario.

- Two extra NGL pumping stations are required for operation at maximum capacity[49]. The GHG emissions for a pumping station are unknown and not included in this analysis; therefore, the total emissions are considered low.
- The maximum total annual emissions under the Maximum Capacity scenario are calculated to be 3,695 kt CO2eq/yr.
- The total annual emissions in Table A4 include operations emissions, emissions resulting from land disturbance, and construction emissions.

Onshore Only Scenario

The Onshore Only scenario was assumed to include the fields identified in the EIS scenario as well as the following fields: Basin Margin Undiscovered, Colville Hills Undiscovered, and Listric Onshore Undiscovered. The emissions for the Onshore Only scenario are calculated in Table A5 and Table A6.

Table A5: Maximum Annual Operations Emissions for Onshore Only Scenario.

Annual Operations Emissions at Full Load	Full Load	Annual Total Emissions at Full Load	Maximum Annual Emissions	Years at Full Capacity
(kt CO2 eq/yr)	*(Mm^3/d)*	*(kt CO2eq/yr)*	*(kt CO2eq/yr)*	
1,349.3	34	1,464.4	1,927.7	18

Table A6: Total Annual and Cumulative Emissions for the upstream Onshore Only Scenario.

		Emissions							
Year	Total Sales Gas[50]	Operations Emissions	Fugitive Emissions	Emissions from Changes in Land Use	Construction Emissions	Well Testing Emissions	Blowdown Venting Emissions	Total Annual Emissions	Cumulative Emissions
	(Mm^3/d)	*(kt CO2eq/yr)*							*(kt CO2eq)*
2006	0	0	0	0	24.9	0	0	25	25
2007	0	0	0	43.7	153.5	4.5	0	202	227
2008	0	0	0	56.6	363.2	63.4	0	483	710
2009	3.8	151	51	56.6	246.2	58.9	0	563	1,273
2010	23.5	933	51	44.6	32.1	0	19.6	1,080	2,353

[48] The total GHG emissions from a compressor station is taken from Table 2-97, pg 2-102 in Environmental Impact Statement for the Mackenzie Gas Project, Volume 5 – Biophysical Impact Assessment, 2004.

[49] Two additional pumping stations is taken from Figure 1-3, pg 1-14 in Application for Approval of the Mackenzie Valley Pipeline, Volume 1 – Pipeline Project Overview, August 2004

[50] GLJ Report, Table 36, pg. 82

Year	Total Sales Gas[50]	Emissions: Operations Emissions	Fugitive Emissions	Emissions from Changes in Land Use	Construction Emissions	Well Testing Emissions	Blowdown Venting Emissions	Total Annual Emissions	Cumulative Emissions
	(Mm^3/d)	*(kt CO2eq/yr)*							*(kt CO2eq)*
2011	31.0	1,230	51	44.6	0	0	19.6	1,345	3,698
2012	34.0	1,349	51	44.6	0	0	19.6	1,464	5,162
2013	34.0	1,349	51	44.6	0	0	19.6	1,464	6,627
2014	34.0	1,349	51	44.6	0	0	19.6	1,464	8,091
2015	34.0	1,349	51	44.6	0	0	19.6	1,464	9,556
2016	34.0	1,349	51	44.6	0	0	19.6	1,464	11,020
2017	34.0	1,349	51	13.1	0	0	19.6	1,433	12,453
2018	34.0	1,349	51	13.1	0	0	19.6	1,433	13,886
2019	34.0	1,349	51	13.1	0	0	19.6	1,433	15,319
2020	34.0	1,349	51	13.1	0	0	19.6	1,433	16,751
2021	34.0	1,349	51	13.1	0	0	19.6	1,433	18,184
2022	34.0	1,349	51	13.1	0	0	19.6	1,433	19,617
2023	34.0	1,349	51	13.1	0	0	19.6	1,433	21,050
2024	34.0	1,349	51	13.1	0	0	19.6	1,433	22,483
2025	34.0	1,349	51	13.1	0	0	19.6	1,433	23,916
2026	34.0	1,349	51	13.1	0	0	19.6	1,433	25,349
2027	34.0	1,349	51	13.1	0	0	19.6	1,433	26,781
2028	34.0	1,349	51	13.1	0	0	19.6	1,433	28,214
2029	34.0	1,489	51	13.1	0	0	19.6	1,572	29,787
2030	33.9	1,490	51	13.1	0	0	19.6	1,573	31,360
2031	32.6	1,504	51	13.1	0	0	19.6	1,588	32,948
2032	31.4	1,518	51	13.1	0	0	19.6	1,601	34,550
2033	30.2	1,531	51	13.1	0	0	19.6	1,615	36,164
2034	27.1	1,566	51	13.1	0	0	19.6	1,649	37,814
2035	24.2	1,598	51	13.1	0	0	19.6	1,682	39,496
2036	19.9	1,646	51	13.1	0	0	19.6	1,730	41,226
2037	16.3	1,687	51	13.1	0	0	19.6	1,770	42,996
2038	13.5	1,718	51	0.9	0	0	19.6	1,789	44,785
2039	10.5	1,751	51	0.9	0	0	19.6	1,823	46,608
2040	7.9	1,780	51	0.9	0	0	19.6	1,852	48,459
2041	5.7	1,805	51	0.9	0	0	19.6	1,876	50,336
2042	4.1	1,823	51	0.9	0	0	19.6	1,894	52,230
2043	2.8	1,837	51	0.9	0	0	19.6	1,909	54,139
2044	1.8	1,849	51	0.9	0	0	19.6	1,920	56,059
2045	1.1	1,856	51	0.9	0	0	19.6	1,928	57,986
2046	0.5	1,863	51	0.0	0	0	0	1,914	59,900

Year	Total Sales Gas[50]	Emissions							
		Operations Emissions	Fugitive Emissions	Emissions from Changes in Land Use	Construction Emissions	Well Testing Emissions	Blowdown Venting Emissions	Total Annual Emissions	Cumulative Emissions
	(Mm^3/d)	*(kt CO2eq/yr)*							*(kt CO2eq)*
2047	0.1	1,868	51	0.0	0	0	0	1,918	61,819
2048	0.0	0	0	0.0	0	0	0	0	61,819
2049	0.0	0	0	0.0	0	0	0	0	61,819
2050	0.0	0	0	0.0	0	0	0	0	61,819
2051	0.0	0	0	0.0	0	0	0	0	61,819
2052	0.0	0	0	0.0	0	0	0	0	61,819
2053	0.0	0	0	0.0	0	0	0	0	61,819

Assumptions

- The relationship between sales gas and operations emissions is assumed to be linear.
- The land use change emissions are assumed to be the same under the Onshore Only scenario as under the EIS scenario.
- The blowdown venting emissions are assumed to be the same under the Onshore Only scenario as under the EIS scenario.

Onshore & Offshore Scenario

The Onshore & Offshore scenario was assumed to include the fields identified in the Onshore Only scenario as well as the following fields: Beaufort Sea Undiscovered and Beaufort See Discovered. The emissions for the Onshore & Offshore Scenario are calculated in Table A7 and Table A8.

Table A7. Maximum Annual Operations Emissions for Onshore & Offshore Scenario.

Annual Operations Emissions at Full Load	Full Load	Annual Total Emissions at Full Load	Maximum Annual Emissions	Years at Full Capacity
(kt CO2eq/yr)	*(Mm^3/d)*	*(kt CO2eq/yr)*	*(kt CO2eq/yr)*	
1,349.3	34	1,464.4	1,880.8	26

Table A8. Total Annual and Cumulative Emissions for the upstream Onshore & Offshore Scenario.

Year	Total Sales Gas[51]	Emissions							
		Operations Emissions	Fugitive Emissions	Emissions from Changes in Land Use	Construction Emissions	Well Testing Emissions	Blowdown Venting Emissions	Total Annual Emissions	Cumulative Emissions
	(Mm^3/d)	*(kt CO2eq/yr)*							*(kt CO2eq)*
2006	0	0	0	0	24.9	0	0	25	25
2007	0	0	0	43.7	153.5	4.5	0	202	227
2008	0	0	0	56.6	363.2	63.4	0	483	710
2009	3.8	151	51	56.6	246.2	58.9	0	563	1,273
2010	23.5	933	51	44.6	32.1	0	19.6	1,080	2,353
2011	31.0	1,230	51	44.6	0	0	19.6	1,345	3,698
2012	34.0	1,349	51	44.6	0	0	19.6	1,464	5,162
2013	34.0	1,349	51	44.6	0	0	19.6	1,464	6,627
2014	34.0	1,349	51	44.6	0	0	19.6	1,464	8,091
2015	34.0	1,349	51	44.6	0	0	19.6	1,464	9,556
2016	34.0	1,349	51	44.6	0	0	19.6	1,464	11,020
2017	34.0	1,349	51	13.1	0	0	19.6	1,433	12,453
2018	34.0	1,349	51	13.1	0	0	19.6	1,433	13,886
2019	34.0	1,349	51	13.1	0	0	19.6	1,433	15,319
2020	34.0	1,349	51	13.1	0	0	19.6	1,433	16,751
2021	34.0	1,349	51	13.1	0	0	19.6	1,433	18,184
2022	34.0	1,349	51	13.1	0	0	19.6	1,433	19,617
2023	34.0	1,349	51	13.1	0	0	19.6	1,433	21,050
2024	34.0	1,349	51	13.1	0	0	19.6	1,433	22,483
2025	34.0	1,349	51	13.1	0	0	19.6	1,433	23,916
2026	34.0	1,349	51	13.1	0	0	19.6	1,433	25,349
2027	34.0	1,349	51	13.1	0	0	19.6	1,433	26,781
2028	34.0	1,349	51	13.1	0	0	19.6	1,433	28,214
2029	34.0	1,349	51	13.1	0	0	19.6	1,433	29,647
2030	34.0	1,349	51	13.1	0	0	19.6	1,433	31,080
2031	34.0	1,349	51	13.1	0	0	19.6	1,433	32,513
2032	34.0	1,349	51	13.1	0	0	19.6	1,433	33,946
2033	34.0	1,349	51	13.1	0	0	19.6	1,433	35,379
2034	34.0	1,349	51	13.1	0	0	19.6	1,433	36,811
2035	34.0	1,349	51	13.1	0	0	19.6	1,433	38,244
2036	34.0	1,349	51	13.1	0	0	19.6	1,433	39,677
2037	34.0	1,489	51	13.1	0	0	19.6	1,572	41,250
2038	33.2	1,498	51	13.1	0	0	19.6	1,581	42,831

[51] GLJ Report, Table 36, pg. 82

Year	Total Sales Gas[51]	Emissions: Operations Emissions	Fugitive Emissions	Emissions from Changes in Land Use	Construction Emissions	Well Testing Emissions	Blowdown Venting Emissions	Total Annual Emissions	Cumulative Emissions
	(Mm^3/d)	*(kt CO2eq/yr)*							*(kt CO2eq)*
2039	32.4	1,507	51	13.1	0	0	19.6	1,590	44,421
2040	31.8	1,513	51	13.1	0	0	19.6	1,597	46,018
2041	31.3	1,519	51	13.1	0	0	19.6	1,603	47,621
2042	30.9	1,523	51	13.1	0	0	19.6	1,607	49,228
2043	30.6	1,527	51	13.1	0	0	19.6	1,610	50,838
2044	28.3	1,552	51	13.1	0	0	19.6	1,636	52,474
2045	25.7	1,582	51	13.1	0	0	19.6	1,665	54,139
2046	23.1	1,611	51	13.1	0	0	19.6	1,694	55,833
2047	20.4	1,641	51	13.1	0	0	19.6	1,724	57,558
2048	17.6	1,672	51	13.1	0	0	19.6	1,756	59,313
2049	14.3	1,709	51	0.9	0	0	19.6	1,780	61,093
2050	11.9	1,736	51	0.9	0	0	19.6	1,807	62,901
2051	9.8	1,759	51	0.9	0	0	19.6	1,831	64,731
2052	7.0	1,790	51	0.9	0	0	19.6	1,862	66,593
2053	5.3	1,809	51	0.9	0	0	19.6	1,881	68,474

Assumptions

- The relationship between sales gas and operations emissions is assumed to be linear.
- The land use change emissions are assumed to the same under the Onshore & Offshore case as under the EIS case.
- The blowdown venting emissions are assumed to the same under the Onshore & Offshore case as under the EIS case.

NEB P_{50} Estimate Scenario

The NEB P_{50} scenario includes all the fields in the Onshore & Offshore scenario with full capacity operation reduced by three years. Based on a Monte Carlo analysis by the National Energy Board, there is a 50% probability that the quantities actually recovered will equal or exceed the estimate. The emissions for the NEB P_{50} scenario are calculated in Table A9 and Table A10.

Table A9. Maximum Annual Operations Emissions for NEB P50 Estimate Scenario.

Annual Operations Emissions at Full Load	Full Load	Annual Total Emissions at Full Load	Maximum Annual Emissions	Years at Full Capacity
(kt CO2eq/yr)	*(Mm^3/d)*	*(kt CO2eq/yr)*	*(kt CO2eq/yr)*	
1,349.3	34.0	1,313.6	1,937.8	23

Table A10. Total Annual and Cumulative Emissions for the upstream NEB P_{50} Estimate Scenario.

Year	Total Sales Gas[52]	Emissions							
		Operations Emissions	Fugitive Emissions	Emissions from Changes in Land Use	Construction Emissions	Well Testing Emissions	Blowdown Venting Emissions	Total Annual Emissions	Cumulative Emissions
	(Mm³/d)	(kt CO2eq/yr)							(kt CO2eq)
2006	0	0	0	0	24.9	0	0	25	25
2007	0	0	0	43.7	153.5	4.5	0	202	227
2008	0	0	0	56.6	363.2	63.4	0	483	710
2009	3.2	127	51	56.6	246.2	58.9	0	540	1,249
2010	22.7	901	51	44.6	32.1	0	19.6	1,048	2,297
2011	30.2	1,198	51	44.6	0	0	19.6	1,314	3,611
2012	34.0	1,349	51	44.6	0	0	19.6	1,464	5,075
2013	34.0	1,349	51	44.6	0	0	19.6	1,464	6,540
2014	34.0	1,349	51	44.6	0	0	19.6	1,464	8,004
2015	34.0	1,349	51	44.6	0	0	19.6	1,464	9,468
2016	34.0	1,349	51	44.6	0	0	19.6	1,464	10,933
2017	34.0	1,349	51	13.1	0	0	19.6	1,433	12,365
2018	34.0	1,349	51	13.1	0	0	19.6	1,433	13,798
2019	34.0	1,349	51	13.1	0	0	19.6	1,433	15,231
2020	34.0	1,349	51	13.1	0	0	19.6	1,433	16,664
2021	34.0	1,349	51	13.1	0	0	19.6	1,433	18,097
2022	34.0	1,349	51	13.1	0	0	19.6	1,433	19,530
2023	34.0	1,349	51	13.1	0	0	19.6	1,433	20,963
2024	34.0	1,349	51	13.1	0	0	19.6	1,433	22,396
2025	34.0	1,349	51	13.1	0	0	19.6	1,433	23,828
2026	34.0	1,349	51	13.1	0	0	19.6	1,433	25,261
2027	34.0	1,349	51	13.1	0	0	19.6	1,433	26,694
2028	34.0	1,349	51	13.1	0	0	19.6	1,433	28,127
2029	34.0	1,349	51	13.1	0	0	19.6	1,433	29,560
2030	34.0	1,349	51	13.1	0	0	19.6	1,433	30,993
2031	34.0	1,349	51	13.1	0	0	19.6	1,433	32,426
2032	34.0	1,349	51	13.1	0	0	19.6	1,433	33,858
2033	34.0	1,349	51	13.1	0	0	19.6	1,433	35,291
2034	34.0	1,489	51	13.1	0	0	19.6	1,572	36,864
2035	33.0	1,500	51	13.1	0	0	19.6	1,584	38,447
2036	32.3	1,508	51	13.1	0	0	19.6	1,591	40,039
2037	31.7	1,515	51	13.1	0	0	19.6	1,598	41,637

[52] GLJ Report, Table 36, pg. 82

		Emissions							
Year	Total Sales Gas[52]	Operations Emissions	Fugitive Emissions	Emissions from Changes in Land Use	Construction Emissions	Well Testing Emissions	Blowdown Venting Emissions	Total Annual Emissions	Cumulative Emissions
	(Mm³/d)	*(kt CO2eq/yr)*							*(kt CO2eq)*
2038	31.3	1,519	51	13.1	0	0	19.6	1,603	43,239
2039	31.0	1,522	51	13.1	0	0	19.6	1,606	44,845
2040	29.1	1,544	51	13.1	0	0	19.6	1,627	46,472
2041	26.2	1,576	51	13.1	0	0	19.6	1,660	48,132
2042	23.6	1,605	51	13.1	0	0	19.6	1,689	49,820
2043	20.9	1,635	51	13.1	0	0	19.6	1,719	51,539
2044	18.3	1,664	51	13.1	0	0	19.6	1,748	53,287
2045	15.0	1,701	51	0.9	0	0	19.6	1,772	55,059
2046	12.3	1,731	51	0.9	0	0	19.6	1,803	56,862
2047	10.1	1,756	51	0.9	0	0	19.6	1,827	58,689
2048	7.1	1,789	51	0.9	0	0	19.6	1,861	60,550
2049	5.5	1,807	51	0.9	0	0	19.6	1,879	62,428
2050	4.2	1,822	51	0.9	0	0	19.6	1,893	64,321
2051	3.1	1,834	51	0.9	0	0	19.6	1,905	66,227
2052	1.9	1,847	51	0.9	0	0	19.6	1,919	68,145
2053	0.2	1,866	51	0.9	0	0	19.6	1,938	70,083

Assumptions

- The relationship between sales gas and operations emissions is assumed to be linear.
- The land use change emissions are assumed to the same under the NEB P_{50} case as under the EIS case.
- The blowdown venting emissions are assumed to the same under the NEB P_{50} case as under the EIS case.

Sproule Scenario

This scenario was developed differently from the previous scenarios and is based on analysis done by Sproule Associates Limited for the Mackenzie Explorer Group in May 2005[53]. For this scenario the pipeline size of 91 Mm^3/d was selected and the resources necessary to maintain operation at capacity for 20 years were determined. However, this data was not presented in a format conducive to an incremental analysis of GHG emissions as done for the previous five scenarios. The resource development necessary for this size of pipeline is presented in Table A11 below.

[53] Note: Any and all calculations, estimates, conclusions, and statements made in the present report based on the Sproule Report are the responsibility of the present report's authors exclusively. Sproule Associates Limited neither implicitly nor explicitly endorses the contents of the present report in any way.

Table A11[54]: Resource development requirements for 20 years of full-capacity operation of a 91 Mm^3/d pipeline

Year	Description	Resource Requirements
2009	Onshore fully developed to minimum field size	Onshore and Colville > 700 Mm^3 (25 Bcf)
2021	Shallow offshore onstream	All Mackenzie Delta and Onshore connected > 700 Mm^3 (25 Bcf) Start Beaufort Sea > 5650 Mm^3 (200 Bcf)
2039	Deep offshore onstream	Deep sea > 14,000 Mm^3 (500 Bcf)

This scenario was modeled as a scaled up version of the Onshore & Offshore scenario. It was assumed that a pipeline of this capacity would take the form of looping a pipeline slightly smaller than the one in the Onshore & Offshore scenario. The scenario was also chosen due to its longer full-capacity operation and total operation time. The factor used to scale up the Onshore & Offshore scenario was determined using the following formula.

Where:
PC_1 = Pipeline capacity of the Onshore & Offshore scenario (34 Mm^3/d)

PC_2 = Pipeline capacity of Sproule scenario (91 Mm^3/d)

$$1+\left(\frac{PC_2-PC_1}{PC_1}\right)$$

Entering the values:

$$1+\left(\frac{91-34}{34}\right)=2.68$$

This value was then multiplied by the maximum annual greenhouse gas emissions and the total cumulative emissions in order to obtain an estimate of these values for this pipeline scenario. This basic information was used, when possible, to compare this scenario to the other five. This factor was not used to determine the incremental increase in annual GHG emissions because it was felt that this method was too simplistic and would not accurately reflect the likely development of this scenario, especially in regards to the ramp up time, peak production period and rate of decline of the fields.

[54] Data tabulated from Sproule Associates Limited “Natural Gas Resource Assessments and Deliverability Forecasts, Beaufort-Mackenzie and Selected Northern Canadian Basins”, Pipeline Capacity Analysis pg. 2 and figure5 and figures 6a-6d, May 2005.

Appendix B: Oil Sands Related Calculations

Assumptions of Development of Oil Sands Natural Gas Requirements

The demand for natural gas in the oil sands was estimated using information from the Oil Sands Technology roadmap, where steam-assisted gravity drainage (SAGD) requires 41.9 m^3 of natural gas for each barrel of synthetic crude oil (SCO) and mining requires 20.6 m^3 of natural gas for each barrel of SCO[55]. Oil sands projections until 2020 were found in the Raymond James report and include updates for new oil sands projects since July 2005. This information was used to calculate the natural gas demand in the oil sands if it remains the primary fuel. A sample calculation for the required can be found after Table B1.

Table B1: Future Oil Sands Natural Gas Requirements

Year	Total In-Situ Production[56]	NG Required for In-Situ	Total Mining Production[57]	NG Required for Mining	Total NG Required in OS
	(bbl)	*(Mm^3)*	*(bbl)*	*(Mm^3)*	*(Mm^3)*
2003	217,801	9.1	503,915	10.4	19.5
2004	234,356	9.8	600,090	12.4	22.2
2005	288,850	12.1	522,444	10.8	22.9
2006	352,403	14.8	651,397	13.5	28.2
2007	495,525	20.8	715,164	14.8	35.5
2008	626,421	26.3	821,700	17.0	43.2
2009	797,825	33.4	910,000	18.8	52.2
2010	965,071	40.4	1,125,000	23.3	63.7
2011	1,159,675	48.6	1,396,000	28.9	77.5
2012	1,375,425	57.6	1,651,333	34.1	91.8
2013	1,541,425	64.6	1,801,125	37.2	101.8
2014	1,821,625	76.3	1,921,750	39.7	116.1
2015	2,017,625	84.6	2,161,708	44.7	129.2
2016	2,122,625	89.0	2,296,500	47.5	136.4
2017	2,222,625	93.1	2,354,625	48.7	141.8

[55] Alberta Chamber of Resources, *Oil Sands Technology Roadmap – Unlocking the Potential*, Figure 7.1, pg. 52. January 30, 2004

[56] Raymond James, *The Oil Sands of Canada – The world Wakes Up: First Peak Oil, Second to the Oil Sands of Canada*, Figure 65 pg. 61. July 28, 2005

[57] Raymond James, *The Oil Sands of Canada – The world Wakes Up: First Peak Oil, Second to the Oil Sands of Canada*, Figure 60 pg. 56. July 28, 2005

Year	Total In-Situ Production[56]	NG Required for In-Situ	Total Mining Production[57]	NG Required for Mining	Total NG Required in OS
	(bbl)	*(Mm^3)*	*(bbl)*	*(Mm^3)*	*(Mm^3)*
2018	2,252,625	94.4	2,400,250	49.6	144.0
2019	2,282,625	95.7	2,469,208	51.0	146.7
2020	2,312,625	96.9	2,516,500	52.0	148.9

Sample Calculation:

In-Situ NG required:

NG_{is} = 41.91 m^3/bbl

In-Situ Production 2005:

IS_{2010} = 965,071 bbl

Therefore, the total natural gas required for In-Situ production in 2010 TNG_{is} will be the multiple of these two factors.

$$TNG_{is} = NG_{is} \times IS_{2010}$$

TNG_{is} = 41.91 m^3/bbl x 965,071 bbl

= 40,400,000 m^3

Assumptions and Calculations of Life-cycle Oil Sands-based Emissions

GHG emissions associated with the specific life-cycle activities from the supply of 1 m^3 of natural gas for the production of transport fuel from the oil sands is shown in Figure B1.

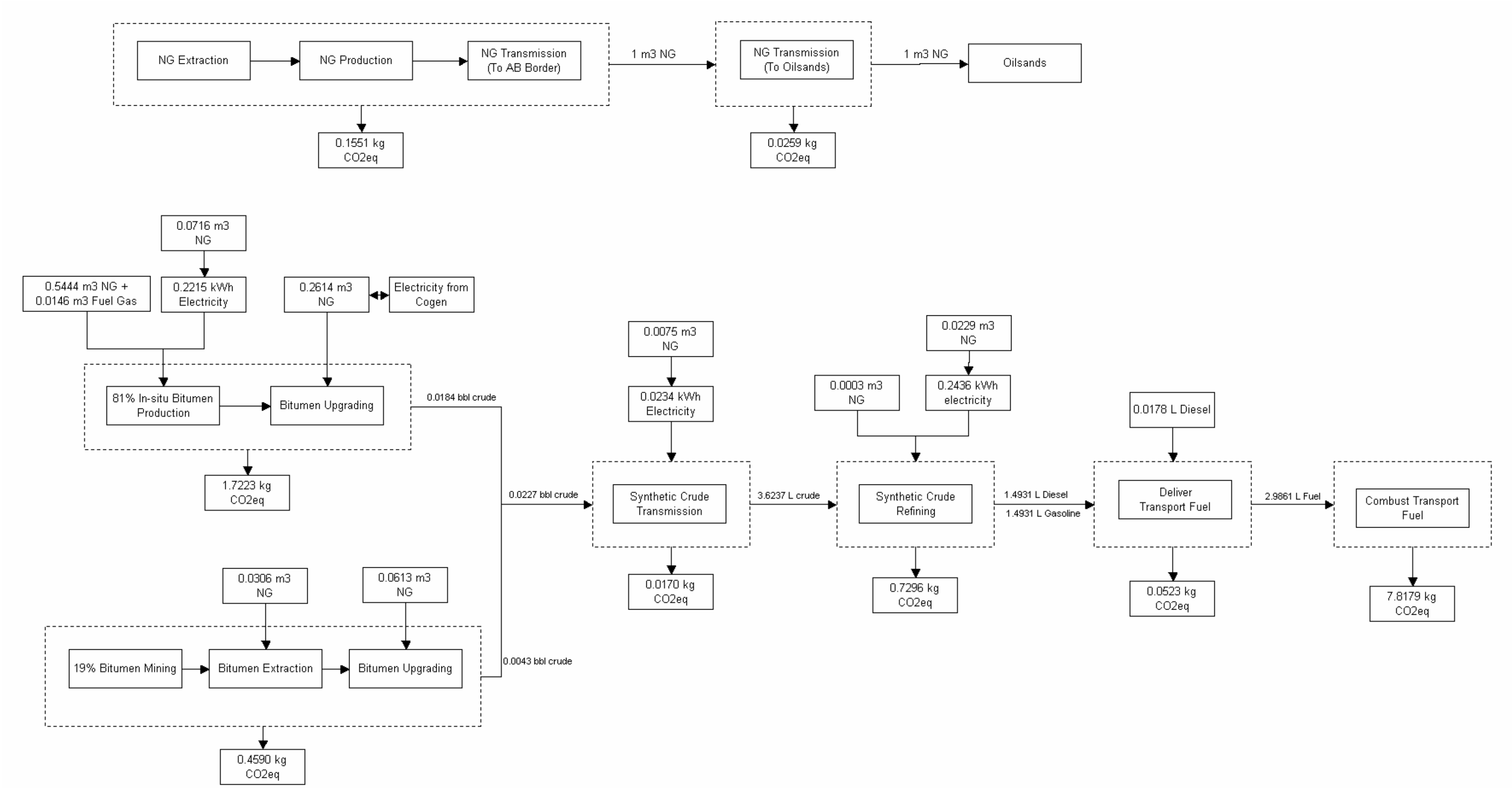

Figure B1. Life Cycle Activity Map of 1m^3 of Natural Gas Delivered to the Oil sands

The calculations and associated assumptions of each of the major activities along the fuel cycle of natural gas use at the oil sands (Figure B1) are provided below. All results are normalized to one cubic metre of natural gas delivered from the MGP.

Extraction, Production and Transmission of NG to Alberta Border via the MGP

At the design capacity of 34 Mm^3/d, the maximum total emissions are estimated (by the project proponents) to be 1,925 kt CO2eq/yr (see Table 1). Thus, the resulting emissions per cubic metre of natural gas delivered to the Alberta border are:

$$\frac{1925 \times 10^6 \text{ kgCO2eq}}{34 \text{ Mm}^3\text{/d} \times 365 \text{ d/y}} = 0.1551 \text{ kgCO2eq/m}^3$$

Natural Gas Transmission from Alberta Border to Oilsands

The length of pipeline from the Alberta border to the Oilsands is approximately 830 km, based upon data from TransCanada's Systems Facilities map of existing and proposed pipelines.

GHG emissions for this section of the pipeline are extrapolated based on information provided in the EIS report. Given the proposed MGP is 1,220 km long[58] and requires 4 compressor stations[59], therefore one compressor station is required for every 305 km of pipeline. Thus, the remaining distance of 830 km of pipeline to the Oilsands would require 2.7 compressor stations. Assuming 3 compressor stations would be required, each producing 107.64 kt CO2eq/yr[60]. The resulting emissions per cubic metre of natural gas are;

$$\frac{107.64 \times 10^6 \text{ kgCO2eq} \times 3}{34 \text{ Mm}^3\text{/d} \times 365 \text{ d/y}} = 0.0259 \text{ kgCO2eq/m}^3$$

Bitumen Production and Upgrading

The ratio of in-situ bitumen production and bitumen mining was calculated based on remaining established reserves noted in Table B2. In-situ bitumen production will contribute 81% of all crude oil from the oil sands while mining is estimated to contribute the remaining 19%. Calculations for in-situ and mining take into account the split of bitumen production activities and are indicated on Figure B1.

Table B2. Bitumen Resources in Alberta[61]

Measure	Mineable	In-Situ	Total
	Billions of barrels		
Remaining Established Reserves	32.7 (19% of total)	141.5 (81% of total)	174.2

[58] Section 1.1.1.2, Pg 1-2 of Application for Approval of the Mackenzie Valley Pipeline, Volume 1 – Pipeline Project Overview, August 2004.

[59] Figure 1-2, Pg 1-3 of Application for Approval of the Mackenzie Valley Pipeline, Volume 1 – Pipeline Project Overview, August 2004.

[60] The total GHG emissions from a compressor station is taken from Table 2-97, pg 2-102 in Environmental Impact Statement for the Mackenzie Gas Project, Volume 5 – Biophysical Impact Assessment, 2004.

[61] Taken from Figure 2, pg 3 of *Treasure in the Sand, An Overview of Alberta's Oil Sands Resources*, Canada West Foundation, Todd Hirsch Chief Economist, April 2005

In-Situ Production and Upgrading

Inputs for in-situ bitumen production are determined to be 185.5 m^3/d of natural gas, 5 m^3/d of produced gas and 3.1 kW of electricity to produce 1 m^3/d of bitumen[62]. Thus the allocated amount of natural gas required for in-situ production is 0.54 m^3. The volume of produced gas required 0.015 m^3 of produced gas as indicated in Figure B1.

Electricity is assumed to come from natural gas power production. 0.072 m^3 of natural gas is required to provide 0.22 kWh of electricity for in-situ bitumen production (see Figure B1). A conversion factor of 0.32 m^3/kWh[63] was used to calculate the required natural gas.

Upgrading of bitumen requires 14.2 m3 of natural gas per barrel of bitumen produced[64]. The normalized amount of natural gas required for bitumen upgrading is 0.26 m3. It was assumed that that natural gas supplied to the upgrader includes electricity production. This assumption ensures a conservative estimate.

The GHG emissions were calculated using the emissions factor in Table B3. The total emissions from the production of 0.018 bbl of crude (see crude output from in-situ bitumen production on Figure B1) are 1.72 kg CO2eq.

Table B3. Emissions Factor for the Combustion of Natural Gas[65]

Natural Gas	CO_2 (g/m^3)	CH_4 (g/m^3)	N_2O (g/m^3)	CO_2eq (g/m^3)
Industrial Combustion	1,891	0.037	0.033	1,902

Bitumen Mining & Upgrading

The mining of bitumen requires 7.1 m^3 of natural gas and the upgrading of bitumen requires 14.2 m^3 of natural gas[66]. The normalized amount of natural gas required for mining is 0.031 m^3 and upgrading requires 0.061 m^3 of natural gas (see Figure B1).

Emissions for bitumen mining were calculated using an emission factor of 0.106 t CO2eq/bbl of crude[67], which includes emissions from diesel and gasoline for mine and light vehicle fleets (including contractors' vehicles onsite), propane, jet fuel for a company-owned aircraft, as well as indirect CO2 emissions attributed to imported (or exported) electrical power[68]. The resulting emissions are 0.46 kg CO2eq per 0.0043 bbl of crude (see crude output from mining bitumen production on Figure B1).

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[62] Taken from Table B.6.2.1, pg. B-35. Deer Creek Energy - Joslyn SAGD Project Phase IIIA, Alberta Energy and Utilities Board, Alberta Environment Integrated Application, Volume One, February 2005.

[63] 1000 kWh requires 324 m3 of natural gas - Supplied by TransAlta Utilities, 1995 data. Information was obtained through a study performed by Monenco Agra Inc. in 1996.

[64] Oil Sands Technology Roadmap: Unlocking the Potential. Alberta Chamber of Resources. January 2004. pg 14.

[65] Annex 7: Emissions Factors. Environment Canada. 2004. Canada's Greenhouse Gas Inventory, 1990-2002. Ottawa, ON. ISBN 0-660-18894-5.

[66] Oil Sands Technology Roadmap: Unlocking the Potential. Alberta Chamber of Resources. January 2004. pg 14.

[67] An Action Plan for Reducing Greenhouse Gas Emissions, Action Plan and 2003 Progress Report for the Syncrude Project, Submitted to VCR Inc. 2004. Pg 7.

[68] An Action Plan for Reducing Greenhouse Gas Emissions, Action Plan and 2003 Progress Report for the Syncrude Project, Submitted to VCR Inc. 2004. Pg 12.

Note that GHG emissions associated with upgrading are included in both the in-situ calculations and the mining calculations. Based on the consumption of 1 m^3 of natural gas from the MGP over the life-cycle, 0.023 bbl of synthetic crude would be produced from the upgrading.

Synthetic Crude Transmission

Crude oil is transmitted approximately 500 km to refineries in Edmonton, where it is refined (for the purposes of this analysis). The electricity required to transport 1 bbl (159 litres) of crude for 500 km is calculated using a factor of 12.9 kWh per 1,000,000 litre*km of crude[69]. The resulting electricity required to transport 0.023 bbl of crude (see total crude output from bitumen production on Figure B1) is 0.023 kWh.

Electricity is assumed to be produced using natural gas only, and therefore can be considered a conservative estimate. To produce 0.0234 kWh of electricity, 0.0075 m^3 of NG is required. The resulting emissions from the production of electricity are 0.017 kg CO2eq when using an emission factor of 2.26 kg CO2eq/m^3 of natural gas[70].

Refine Synthetic Crude

The production of 1000 L of diesel and 1000 L of unleaded gasoline (for a total of 2000 L of transport fuel) requires an input of 2,427 L of synthetic crude oil[71]. Based on these nominal outputs, and the production of 600 L of "other refinery products", the refining process emits a total of 643 kg CO2eq. This value is assumed to account for GHG emissions from electricity production (not sufficient detail in data source), and is thus a conservative estimate.

It is assumed that all emissions from the refinery can be attributed to the production of transport fuel, as this is the primary product. Actual allocation of GHG emissions should include an assessment of the market value of the "other refinery products" as compared to the value of the transport fuel.

Refining 0.023 bbl of crude (3.62 L) requires 0.0003 m^3 of natural gas and 0.24 kWh of electricity (see Figure B1)[69]. To produce 0.24 kWh of electricity, 0.023 m^3 of natural gas supplied from the MGP is required assuming that 29% of electricity in Alberta[72] is produced by natural gas.

Refining 0.0227 bbl of crude (3.62 L) produces 1.49 L of diesel and 1.49 L of unleaded gasoline for a total of 2.99 L of transport fuel.

The resulting emissions from refining 0.023 bbl of synthetic crude are 0.73 kg CO2eq.

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[69] "Emission of Greenhouse Gases from the Use of Transportation Fuels and Electricity", Volume 2, Appendix A, US Dept. of Energy, M.Deluchi, 1991.

[70] The combustion of 324 m3 of natural gas to produce electricity produces 731 kg of CO2eq - Supplied by TransAlta Utilities, 1995 data. Information was obtained through a study performed by Monenco Agra Inc. in 1996.

[71] Shell Canada Products Ltd. Application for License Renewal under the AEP Enhancement Act for the Scotford Refinery, 1993.

[72] Jem Energy. 2004. "A Study on the Efficiency of Alberta's Electrical Supply System." Project # CASA-EEEC-02-04 for the Clean Air Strategic Alliance (CASA). Edmonton, AB.

Delivery of Transport Fuel

The delivery of transport fuel was assumed to be 600 km round trip for a transport truck using diesel fuel. This was based on the distance from Edmonton to Calgary (approx 300 km one way). A transport truck was assumed to have a fuel storage capacity of 9600 US gal[73], or 36,339 litres.

The emission factor applied for transport by heavy-duty diesel powered truck is 1.06 kg CO2eq/km and the trucks fuel efficiency is 2.8 km/L consumed[74].

The resulting emissions from the transport of approximately 3 L of transport fuels are 0.052 kg CO2eq.

Combust Transport Fuel

The emissions factors applied for the combustion of fuel in gasoline and diesel automobiles are found in Table B3. These factors were used to calculate the emissions from the combustion of 1.49 L of gasoline and the combustion of 1.49 L of diesel.

Table B4. Emissions Factor for the Combustion of Natural Gas[75]

Vehicle Type	CO_2 (g/L)	CH_4 (g/L)	N_2O (g/L)	CO_2eq (g/L)
Light Duty Gas Auto, Tier 1	2,360	0.12	0.26	2,443.12
Light Duty Diesel Auto, Advanced Control	2,730	0.05	0.02	2,793.05

The combustion of the 3 L of transport fuels results in a total of 7.82 kg CO2eq emissions.

Total Emissions

Total life-cycle emissions from the consumption of one cubic metre of natural gas throughout the life-cycle of oil sands-based transport fuel production are 10.8 kg CO2eq. Emissions from the production and transmission of one cubic metre of natural gas to the oil sands are noted to be 0.181 kg CO2eq. The total life-cycle emissions associated with the use of one cubic metre of natural gas across the life-cycle are 11 kg CO2eq. Appendix C provides these values on an annual basis, assuming 10 Mm^3 of natural gas supply from the MGP.

[73] Transport truck and trailer capacity is 9,600 US gal for a bulk petroleum vehicle with a bulk hauling trailer attached. Source: http://usapc.army.mil/contract_management/bulk_fuel/efbhelp.htm, accessed May 2005.

[74] Mobile 5A National Vehicle Emissions Laboratory Report, US EPA, Office of Mobile Sources, 1995. Fuel consumption was provided by Diamond International, Edmonton, AB, 1999.

[75] Annex 7: Emissions Factors. Environment Canada. 2004. Canada's Greenhouse Gas Inventory, 1990-2002. Ottawa, ON. ISBN 0-660-18894-5

Emissions from the Delivery of Natural Gas to the Oil Sands Fuel Cycle

Table B5 considers the total GHG emissions based on one cubic metre of natural gas delivered to the oil sands-based fuel cycle as provided in "Assumptions and Calculations of Life-cycle Oil Sands-based Emissions" above. The emissions are scaled up using a supply of 10 Mm^3/d over one year for a total of 3,650 Mm^3/year.

Table B5: Emissions from the Delivery of Natural Gas to the Oil Sands Fuel Cycle (@ 10 Mm^3/day)

NG Production & Transmission	Bitumen Production & Upgrading	Crude Oil Transmission	Refine Crude Oil	Deliver Transport Fuel	Combust Transport Fuel	Total Emissions
(kt CO2eq/yr)						
661	7,962	62	2,663	191	28,535	40,074

Appendix C: Assumptions for Estimating Downstream Emissions

The downstream emissions produced from the extraction of gas for the MGP was calculated using typical downstream combustion values for residential use. The value used is 1,903 g/m^3 CO2eq[76]. The downstream emissions were then added to the upstream or operations emissions in order to determine the total emissions associated with the production, transport and combustion of the natural gas.

Sample Calculation:

Year 2014, EIS scenario

Given:

Total Sales Gas: TSG_{is} = 34.0 Mm^3/d

Operations Emissions: OE_{is} = 1,586 kt CO2eq/yr

Natural Gas Combustion: NGC = 1,902.63 g/m^3

Where,

Downstream Emissions: DE_{is} = *[To be determined]*

$$DE_{is} = \frac{TSG_{is} \times 365 \times NGC}{1000} + OE_{is}$$

Subbing in values,

$$DE_{is} = \frac{34.0\text{Mm}^3/\text{d} \times 365\text{d} \times 1902.63\text{g/m}^3}{1000} + 1586 \text{ kt CO2eq/yr}$$

$$= 25{,}198 \text{ kt CO2eq/yr}$$

[76] "Canada's Greenhouse Gas Inventory", August 2004. Annex 7, Table A7-1, Pg. 169

Appendix D: Assumptions and Methodology Used to Contextualize Emissions

Light vehicle Equivalent

The light vehicle equivalent numbers presented in this report represent the number of light vehicles that would generate the same amount of GHG emissions as the operation of the MGP over a one-year period. The assumptions and sample calculation follow.

Given:

All data is based on the emissions of a light vehicle classified as a light duty gasoline vehicle weighted for the various efficiencies and distances driven for differet types of light duty vehicles (e.g. cars, SUVs, trucks, hybrids, and vans).

CO2eq/yr emitted per litre of fuel[77]:	$CO_{2,average}$	= 2.46 kg/L
Fuel Efficiency[78]:	FE_{car}	= 11.4 L/100km
Average Travel Distance[79]:	$ATD_{average}$	= 16,300 km

Where,

The annual fuel consumption (AFC) is,

$$AFC = \frac{FE_{car} \times ATD_{car}}{100 \frac{\text{km}}{\text{100km}}}$$

$$AFC = \frac{11.4 \frac{\text{L}}{\text{100km}} \times 16310\text{km}}{100 \frac{\text{km}}{\text{100km}}} = 1860.7 \frac{\text{L}}{\text{yr}}$$

[77] Natural Resources Canada, *Canada's Greenhouse Gas Inventory 1990 – 2002*, Emission Factors for Energy Mobile Combustion Sources. Annex 7,Table A7-5 pg. 173

[78] Minister of Public Works and Government Services, Canada , *Transportation in Canada 2004 – Annual Report*, pg. 58, Table 7-4 Road Transportation, , 2004. ISBN 0-662-40464-5

[79] Ibid.

The total emissions (TE_{car}) per year are,

$$TE_{car} = AFC \times CO_{2car}$$

$$TE_{car} = \frac{1860.7\,\frac{\mathrm{L}}{\mathrm{yr}} \times 2.46\mathrm{kg/L}}{1000\,\frac{\mathrm{kg}}{\mathrm{tonne}}} = 4.58\,\frac{\mathrm{t}}{\mathrm{yr}}$$

This value was then used to determine the numbers of cars (NC) that would generate the same amount of GHG emissions as the MGP in one year. This example is based on the Maximum Capacity scenario in 2030.

Total upstream and downstream emissions: TOD_{is} = 38,474 kt CO2eq/yr

$$NC = \frac{TOD_{is}}{TE_{car}}$$

$$NC = \frac{38{,}474\,\frac{\mathrm{ktCO_2eq}}{\mathrm{yr}} \times \frac{1000\mathrm{t}}{\mathrm{kt}}}{4.58\,\frac{\mathrm{t}}{\mathrm{yr}}} = 8{,}396{,}773$$

Appendix E: Assumptions and Methodology for Offset Options

The "wind power procurement" offset option was estimated based on the following methodology.

Installed Capacity (Wind): IC_{Wind} = *[To be determined]*

Capacity Factor (Wind): CF_{Wind} = 35% [80]

Energy Generation (Coal): EG_{Caol} = *[To be determined]*

Carbon intensity (Coal): CI_{Coal} = 1.05 kg CO2eq/kWh[81]

Average Emissions (EIS): AE = 1,443 kt CO2eq/yr

$$EG_{Coal} = \frac{AE}{CI_{Coal}}$$

$$EG_{Coal1} = \frac{1{,}443\ \text{t CO2eq/yr}}{1.05\ \text{t CO2eq/kWh}}$$

$$EG_{Coal} = 1{,}373{,}000\ \text{MWh/yr}$$

$$IC_{Wind} = \frac{EG_{Coal}}{Time \times CF_{Wind}}$$

$$IC_{Wind} = \frac{1{,}373{,}000\ \text{MWh/yr}}{365.25\frac{\text{d}}{\text{yr}} \times 24\frac{\text{h}}{\text{d}} \times 35\%}$$

$$IC_{Wind} = 450\ \text{MW}$$

The "energy-efficiency housing retrofits" offset option was estimated based on the following methodology.

Number of retrofits required: *Retrofits* = *[To be determined]*

Emissions reduction per retrofit: RR = 3.9 t CO2eq/yr[82]

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[80] Greenwind Power Corp. http://www.greenwindpower.com/projects_current.html Accessed June 7, 2006.

[81] NRCan *RETScreen International - Combined Heat and Power Project Model* 2005. Accessible at www.retscreen.net

$$Retrofits = \frac{AE}{RR}$$

$$Retrofits = \frac{1{,}443 \text{ kt CO2eq/yr}}{3.9 \text{ t CO2eq/yr}}$$

$$Retrofits = 370{,}000$$

Joint Review Panel for the Mackenzie Gas Project. *Mackenzie Gas Project*, October 17 2006.

[82] Green Communities Association, *EnerGuide for Houses Retrofit Incentive - Fact Sheet*, 11 May 2004 http://www.gca.ca/indexcms/downloads/EGH%20factsheets.pdf

Appendix F: Assumptions and Methodology for Natural Gas End Use

Table F1 below summarizes natural gas demand in Canada, Alberta and the United States based upon data that the National Energy Board, the Alberta Energy and Utilities Board and the US Environmental Protection Agency report respectively.

Table F1: Natural Gas Demand in Alberta, Canada and the Unites States[83, 17]

	Alberta	Canada	United States
	(billion m^3/y)	*(billion m^3/y)*	
NG Demand (Combustion)	35 (87%)	80 (93%)	(98%)
NG Demand (Non-Combustion)	5 (13%)	5 (7%)	(2%)

Figure F1 and Figure F2 present natural gas end use data by sector for Canada and for Alberta respectively. Both figures incorporate combustion and non-combustion end uses.

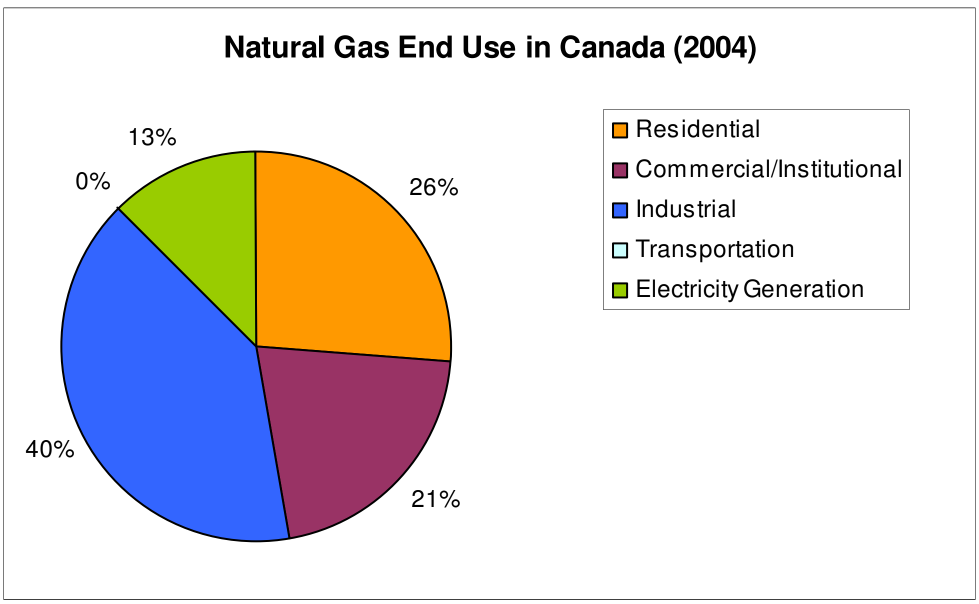

Figure F1: Natural Gas End-Use in Canada by Sector (2004)[84] ***(Based upon data published by the National Energy Board)***

[83] Canadian data from NEB, 2005. Short-term outlook for NG and NGL to 2006 and Alberta data from EUB, 2007. ST98: Alberta's Energy Reserves and Supply/Demand Outlook.

[84] NRCan, August 2006. Energy Use Data Handbook. Accessed online July 2007 at http://www.oee.nrcan.gc.ca/Publications/statistics/handbook06/pdf/handbook06.pdf

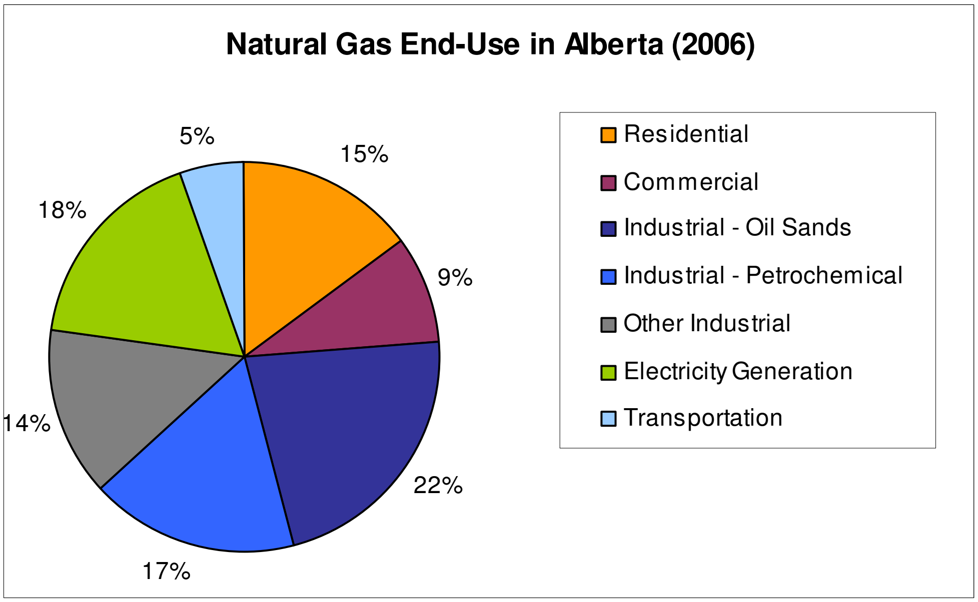

Figure F2: Natural Gas End-Use in Alberta by Sector (2006)[85] ***(Based upon data published by the Alberta Energy and Utilities Board)***

[85] EUB, 2007. ST98: Alberta's Energy Reserves and Supply/Demand Outlook. Accessed online July 2007 at http://www.eub.ca/portal/server.pt/gateway/PTARGS_0_0_277_240_0_43/http%3B/extContent/publishedcontent/publish/eub_home/publications_catalogue/publications_available/serial_publications/st98.aspx

Table F2 is the same as Table 5 with footnoted information about the data.

Table F2: Natural Gas Liquids Demand in Canada and Alberta[86]

	Canada		Alberta	
	Demand (billion m3/y)	Emissions (Mt CO2e)	Demand (billion m3/y)	Emissions (Mt CO2e)
Ethane Demand (Combustion)	3,811[87] (10%)	38,747	2646[88] (7%)	2,582
Ethane Demand (Non-Combustion)	35,889**Error! Bookmark not defined.** (90%)	-	35,154[88] (93%)	-
Propane Demand (Combustion)	4201[89] (50%)	12,786	3,700[90] (100%)	5,676
Propane Demand (Non-Combustion)	4134**Error! Bookmark not defined.** (50%)	-	0[90] (0%)	-
Butane Demand (Combustion)	17,542[91] (83%)	37,238	4986[92] (83%)	9,526
Butane Demand (Non-Combustion)	3,568**Error! Bookmark not defined.** (17%)	-	1014**Error! Bookmark not defined.** (17%)	-
Pentanes Plus Demand (Combustion)	0[93] (0%)	42,653	0[94] (0%)	0
Pentanes Plus Demand	24,180[93]	-	20,300[94]	-

[86] Canadian data from NEB, 2005. Short-term outlook for NG and NGL to 2006 and Alberta data from EUB, 2007. ST98: Alberta's Energy Reserves and Supply/Demand Outlook with emission factors derived from Environment Canada, 2006. Canada's Greenhouse Gas National Inventory Report 1990-2004.

[87] Ethane feedstock demand in the East quoted at 1600 m3/d with 36,880 m3/d total demand in the west. Feedstock demand in the West was calculated by multiplying the total Western demand by 93% obtained from EUB, 2007. ST98: Alberta's Energy Reserves and Supply/Demand Outlook. Adding Eastern and Western demand for ethane as a feedstock yields ethane demand for non-combustion end use. The remainder is assumed to be combusted.

[88] Combustion breakdown values were calculated based on total ethane demand multiplied by 93% used for feedstocks as noted in EUB report.

[89] Propane feedstock demand in the East noted at 1750 m3/d and the West noted as an average of 793 and 3970 m3/d. Adding these yields a value of 4132 m3/d total used for feedstock purposes. The remainder is assumed to be combusted.

[90] Values for combustion versus non-combustion were calculated based on total propane demand multiplied by 100% used for combustion as the EUB report notes that "Propane is used primarily as a fuel in remote areas for space and water heating, as an alternative fuel in motor vehicles, and for barbecues and grain drying" and that only small volumes are used to supplement ethane supplies. As there is no definitive data, it is assumed that 100% is combusted.

[91] Butane feedstock demand in Canada taken to be an average of the range of demand noted as 3170 m3/d and 3970 m3/d. The remainder is assumed to be combusted.

[92] The EUB report notes that butane is used in gasoline blend as an octane enhancer and is also used as a feedstock to produce vinyl acetate. Data for combustion versus non-combustion is unavailable in this report so the 83% noted in the NEB report was used as an approximation.

[93] Assume the same ratio as EUB report as Pentanes Plus combustion breakdown not explicitly noted in NEB data

[94] Largest use of Pentanes Plus is used as diluent as noted in report. Assumed that 100% is used as diluent and no pentanes plus is combusted.

(Non-Combustion)	(100%)		(100%)	
Total		131,424		17,784