Hearing Order ___________

IN THE MATTER OF THE NATIONAL ENRGY BOARD PURSUANT TO THE *NATIONAL ENERGY BOARD ACT* and the *CANADIAN ENVIRONMENTAL ASSESSMENT ACT*

of the

PROPOSED CONSTRUCTION OF THE MACKENZIE GAS PROJECT

WRITTEN EVIDENCE OF MATT MCCULLOCH

A. STATEMENT OF QUALIFICATIONS

1. I am a professional engineer and Co-Director of the Pembina Institute's Eco-Solutions Group. I focus on corporate sustainability, where I work closely with energy industry companies facilitating triple bottom line thinking into their decision making and project design processes using a systems approach. A copy of my curriculum vitae is attached as Exhibit A to this written evidence, and I adopt it as setting out my relevant experience and credentials. In brief, I have extensive experience :

   a Leading numerous analyses and life-cycle value assessments on greenhouse gas (GHG) emission reduction projects from conventional and renewable energy projects, for the conventional energy industry.

b Aiding industry in comprehending the benefits and risks of Canada's emerging policies and mechanisms for implementing the Kyoto Protocol through supporting the development of greenhouse gas reduction strategies.

c Participating in national strategy development for GHG emission reduction, specifically by serving as an NGO representative at the national Greenhouse Gas Emission Reduction Pilot (GERT) Table from 1998 to 2001.

d In developing in-country capacity for evaluation of GHG reduction projects in Indonesia and Bangladesh.

2. Sierra Club of Canada has retained Pembina to prepare a report that demonstrates the full extent of potential greenhouse gas emissions (GHGs) from the Mackenzie Gas Project, based on its Environmental Impact Statement (EIS) and associated reports.

3. On behalf of Pembina I prepared a report entitled "Greenhouse Gas Emissions: Calculations for the Mackenzie Gas Project". The major objectives of my report are:

   ? To comment on the validity of the GHG data included in the EIS report, including associated initial responses to intervenor requests for information.

   ? To quantify annual and cumulative GHG emissions for different reservoir development scenarios over the life of the Mackenzie Gas Project. The scenarios considered were: the EIS case, a maximum capacity case, onshore only, and onshore & offshore.

   ? To quantify and demonstrate the GHG emissions associated with oil sands development in Northern Alberta, as a result of natural gas supply from the Mackenzie Gas Project.

   A copy of my report is attached as Exhibits B to this written evidence.

4. I am responsible for the analysis and conclusions expressed in the Pembina Report, and I adopt that analysis and conclusions as my written evidence in this proceeding.

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C U R R I C U L U M   V I T A E

Pembina Institute for Appropriate Development *1998 - Present*
Calgary, Alberta

? CO-DIRECTOR OF PEMBINA CORPORATE ECO-SOLUTIONS GROUP

? LEAD FACILITATOR OF CORPORATE DECISION MAKING AND DESIGN THROUGH LIFE CYCLE THINKING AND 'TRIPLE-BOTTOM-LINE' THINKING.

? SENIOR ADVISOR ON CORPORATE SUSTAINABILITY CONCEPTS AND TOOLS.

? SENIOR ADVISOR FOR TECHNICAL INPUT ON ECO-EFFICIENCY PROJECTS IN MULTIPLE INDUSTRIAL SECTORS.

? LCVA COURSE INSTRUCTOR FOR THE INDUSTRIAL ECOLOGY PROGRAM, MT. ROYAL COLLEGE, CALGARY, ALBERTA

? LIFE CYCLE EVALUATION OF DOMESTIC AND INTERNATIONAL GREENHOUSE GAS EMISSION REDUCTION PROJECTS

? IN-COUNTRY GREENHOUSE GAS EMISSION REDUCTION PROJECT DEVELOPMENT IN INDONESIA & BANGLADESH FOR THE CLEAN DEVELOPMENT MECHANISM OF THE KYOTO PROTOCOL

? CO-DEVELOPER OF GHG REDUCTION STRATEGY FOR SELECTED SMALL TO MEDIUM SIZE ENTERPRISES (SME'S) IN ALBERTA, AND FACILITATED STRATEGY IMPLEMENTATION.

? TECHNICAL COMMITTEE MEMBER ON CANADA'S GREENHOUSE GAS EMISSION REDUCTION PILOT (GERT) EVALUATION SELECTED PRACTICES AND TECHNOLOGIES.

? PROJECT LEAD FOR ECONOMIC AND TECHNICAL PRE-FEASIBILITY OF COMMUNITY–BASED SUSTAINABILITY PROJECTS, INCLUDING SELECTED TECHNOLOGIES.

? COMMUNITY ENERGY PLANNING: BASELINE DEVELOPMENT, DSM AND SUPPLY-SIDE OPTION ANALYSIS OF ENERGY TECHNOLOGIES.

? LEAD ANALYST AND REPORT WRITER IN CHARACTERIZING RENEWABLE ENERGY BUSINESS OPPORTUNTIES IN CANADA

? MANAGER OF THE PEMBINA INSTITUTE CORPORATE LCVA CLEARINGHOUSE SUBSCRIBER-BASED WEBSITE

Golder Associates Ltd. *1997 - 1998, Summer 1995*

Mississauga, Ontario

- PHASE I ENVIRONMENTAL ASSESSMENTS (NON-INTRUSIVE INVESTIGATION)
- PHASE II ENVIRONMENTAL ASSESSMENTS (BOREHOLE DRILLING, SAMPLE COLLECTION, DATA ANALYSIS, REPORT WRITING)
- ACTING ENVIRONMENTAL CONSULTANT AND ADVISER FOR THE DECOMMISSIONING OF A HEAVILY CONTAMINATED 200 ACRE BRICK QUARRY
- ASSISTED IN THE CREATION OF A STATEMENT OF QUALIFICATIONS FOR RISK RELATED PROJECTS
- SPEARHEADED PROBLEM FORMULATION OF THREE CONTAMINATED SITES IN NORTHERN ONTARIO FOR ENVIRONMENTAL RISK MANAGEMENT DECISION MAKING
- ANALYSIS OF LANDFILL LEACHATE IMPACT
- MULTIPLE PROPOSAL WRITINGS AND COST-ESTIMATES

Guyana Water Authority

Summer 1996

Guyana, South America

- PREPARED PROPOSAL OF NECESSARY ORGANIZATIONAL STRATEGY FOR FIELD CREWS AND SUPERVISED INSTALLATION OF WATER DISTRIBUTION NETWORKS
- DESIGNED SMALL SCALE WATER DISTRIBUTION SYSTEM FOR A COMMUNITY OF OVER 500 PEOPLE
- TAUGHT WEEKLY COMPUTER CLASSES TO OFFICE STAFF COVERING WORD PERFECT AND LOTUS 1-2-3

EDUCATION

Queen's University *1992 - 1996*

Kingston, Ontario

- B.ENG. CIVIL ENVIRONMENTAL

Oakville Trafalgar High School *1988 - 1992*

Oakville, Ontario

- GRADUATED WITH HONOURS

P O S I T I O N S

- 2002 - 2004 – REGISTERED PROFFESSIONAL ENGINEER OF THE ALBERTA PROFESSIONAL ENGINEERS, GEOLOGISTS, AND GEOPHYSICISTS ASSOCIATION.
- 2000 - 2002 - LEAD FACILITATOR IN YWCA'S BOYS LIFEPRINTS PROGRAM, CALGARY, ALBERTA
- 2002 – PRESENT – SQUASH COACH, CALGARY
- 2001 – SKI INSTRUCTOR, CANADIAN OLYMPIC PARK, CALGARY, ALBERTA
- 2000 – 2001 – SQUASH COACH, DRAYTON VALLEY OMNIPLEX, ALBERTA
- 1998 – SKI COACH, HOLIMONT, ELLICOTTVILLE, NEW YORK
- 1992-1994 – CAMP COUNSILLOR, KILCOO CAMP, ONTARIO

OTHER INTERESTS

- WHITEWATER CANOEING, CAMPING, HIKING, BIKING, ULTIMATE FRISBEE, DISC GOLF, GOLF, SOCCER
- SUSTAINABLE DEVELOPMENT, ECO-EFFICIENT HOUSING, HISTORY, ASTRONOMY, NATURAL SCIENCE, GEOLOGY, RELIGION, READING

REFERENCES AVAILABLE UPON REQUEST.

Greenhouse Gas Emissions Calculations for the Mackenzie Gas Project

Matthew McCulloch

Derek Neabel • Ellen Francis

May 2005

Sustainable Energy Solutions

About the Authors

Matthew McCulloch

Matthew is the Co-Director of the Pembina Institute's Corporate Eco-Solutions Group. Matthew's main area of focus is on corporate sustainability, where he works closely with energy industry companies facilitating triple bottom line thinking into their decision making and project design processes using a systems approach. Matthew has extensive experience with the conventional energy industry. He has lead numerous analyses and life-cycle value assessments on GHG reduction projects from conventional and renewable energy projects. He works closely with Pembina's Climate Change Group in Ottawa, helping industry understand the benefits and risks of Canada's emerging policies and mechanisms for implementing Kyoto's through supporting the development of greenhouse gas reduction strategies. Matthew played a key role as an NGO representative at the national GERT table from 1998 to 2001, and has also been involved with developing in-country capacity for evaluation GHG reduction projects in Indonesia and Bangladesh.

Derek Neabel, E.I.T.

Derek Neabel is an eco-efficiency analyst and is primarily involved in technical research and analysis of environmental, financial, and social considerations of practices and technologies in the energy sector. He also supports research and analysis for life-cycle value assessments of energy related projects with respect to the 'triple bottom line'. His background is in HVAC building and plumbing design and also as a drilling services engineer. Derek holds a Bachelor of Science in Mechanical Engineering from the University of Saskatchewan.

Ellen Francis

Ellen Francis has been with the Pembina Institute since 2003. As an Environmental Policy Analyst in the Corporate Change Group she provides contract research and advisory services to private sector corporations, government agencies, First Nations, public interest groups and non-government organizations. Ellen managed Pembina's pilot One Tonne Corporate Challenge in 2004 and currently manages Pembina's Arctic Northern Oil and Gas and the Environment Program, as well as international development projects in Latin America and the Caribbean. She has a Masters of Environmental Design in Environmental Science from the University of Calgary and an honours degree in Biological Sciences from the University of Guelph.

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About the Pembina Institute

The Pembina Institute creates sustainable energy solutions through research, education 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 http://www.pembina.org or by contacting: info@pembina.org

Greenhouse Gas Emissions Calculations for the Mackenzie Gas Project

Table of Contents

1.0 INTRODUCTION

This report was prepared for and resourced by Ecology North and the Sierra Club of Canada. The primary purpose of this report is to demonstrate the full extent of potential greenhouse gas emissions (GHGs) from the Mackenzie Gas Project, based on its Environmental Impact Statement (EIS) and associated reports. Specifically, there are three main objectives of this report:

i. To comment on the validity of the GHG data included in the EIS report, including associated initial responses to intervenor requests for information. Further questions were also generated as part of Ecology North's and the Sierra Club of Canada's second round of intervenor requests for information from the project proponents to better understand the completeness and nature of certain data..

ii. To quantify annual and cumulative GHG emissions for different reservoir development scenarios over the life of the Mackenzie Gas Project. The scenarios considered were: the EIS case, a maximum capacity case, onshore only, and onshore & offshore.

iii. To quantify and demonstrate the GHG emissions associated with oil sands development in Northern Alberta, as a result of natural gas supply from the Mackenzie Gas Project.

2.0 MGP EIS GHG Data Review

2.1 General Results of GHG Data Review

The Pembina Institute reviewed the relevant sections of the EIS and the initial responses to ensure the information provided was accurate and complete. The conclusions of this review were that:

- Generally, the data used in the EIS and its application was considered reasonable.
- There is a lack of transparency in how GHG emissions from power generation and compression were calculated.
- Information provided in the initial responses around well testing and blowdown events are incomplete.
- Overall, the total maximum annual GHG emissions, based on the base case maximum of 34 Mm^3/d, appear to be an acceptable estimate (pending review of compression and power generation GHG calculations).

Based on this review, further questions were generated for the project proponents. These questions are provided in Section 2.2.

2.2 Further Questions & Rationale

The following questions were generated for (and submitted to) Ecology North's and the Sierra Club of Canada's second round of information requests to the NEB, May 25th 2005 to better understand the extent of GHG emissions and how certain data were generated.

GHG sources, calculation breakdown, & power generation

Reference: EIS Volume 5, Section 2.4

Rationale: The information on the GHG is a total of the values for compression, power generation and process equipment for each location. These values do not provide enough detail to determine what equipment is used or if there are better options available.

1. Please provide a detailed breakdown of GHG calculations for compressors, power generation, and process equipment (i.e. fuel input per equipment & emission factor).

Please include information on the size of compressors and output of power generation units.

2. Please provide information on the sources of emissions for process equipment.
3. Please describe how the power is being generated, e.g. is it through a cogeneration application in conjunction with compression?
4. If power generation is through cogeneration processes, please provide a breakdown of the associated GHG allocation calculations per facility.
5. Where is the power generated being consumed?

Total GHG Emissions

Reference: EIS Volume 5, Section 2.1.2.2 and Section 2.4.10.8

Rationale: There is a discrepancy between two total greenhouse gas emissions for the project:

2.1.2.2: "Greenhouse gas emissions from the project will be about 720 kt/a ECO2 (ie. equivalent carbon dioxide values) in the production area, about 550 kt/a ECO2 at the Inuvik area facility, and about 465 kt/a ECO2 in the pipeline corridor." [total 1,735 kt/a ECO2]

2.4.10.8: "… combined GHG emissions of 1,830 kt/a of ECO2 exceed 1% of Northwest Territories totals but are less than 1% of national emissions."

6. Total annual emissions from V5 p2-2 (1735 kt ECO2/a) are different from the total listed on V5 p2-106 (1830 kt ECO2/a). Why are they different, and which is correct?

Natural Gas Consumption

Reference: EIS Volume 1, Section 2.1.3

Rationale: The amount of 0.5 Mm3/d of natural gas fuel is listed but it is never indicated where this fuel is consumed. There is also no indication of what the other fuel sources are for different areas of the project, i.e. production and treatment facilities.

7. What is the total fuel consumption volume, per type of fuel, on an annual basis? For what part of the project does the 0.5 Mm3/d use of natural gas fuel refer to? Please describe where in the project any fuel that is not natural gas is used.

GHG Emissions from NGL Facilities

Reference: EIS Volume 5, Section 2.4

Rationale: It is unclear if the GHG emissions include emissions from NGL facilities.

8. Do the GHG emissions include NGL facilities? If not, please provide the emissions, including a breakdown of how they are calculated.

GHG Emissions from Future Expansion

Reference: EIS Volume 1, Section 2.1.2 and Section 2.2.3

Rationale: No information is included for GHG emissions resulting from possible future expansion. Future expansion includes the installation of up to 10 additional compressor stations, 2 NGL pumping stations and increased capacity of associated facilities.

9. Please provide emissions calculations for the expansion scenario at 49 Mm3/d (V1 p2-2), including emissions associated with NGL facilities. Please show all calculations.

Well Testing Frequency

Reference: Response to JRP Intervenor Request for Information No.1, Table JRP DGMA 1.02-2, March 31, 2005

Rationale: The GHG emissions are presented on a per test basis, but the total amount of tests is not given. It is also unclear if the flaring rate for full production well testing refers to the total amount of flaring or if it is per test.

10. Please confirm that ‘full production’ well testing includes all flared gas. If not, please provide total number of tests per field and total associated GHG emissions.

Blowdown Frequency

Reference: ‘Response to JRP Intervenor Request for Information No.1’, Table JRP DGMA 1.02-3, March 31, 2005

Rationale: Blowdown venting is considered an isolated occurrence and emissions are presented on a per event basis for three different situations. There is no information given for the frequency of these events so that annual emissions can be determined.

11. For compressor facility blowdown and blowdown for maintenance, please provide information and context to understand how frequent these events occur. What is the total associated estimated annual emissions?

Total Annual GHG Emissions

Reference: EIS Volume 5, Section 2.4 and all ‘Response to JRP Intervenor Request No.1’

Rationale: Total annual GHG emissions are not provided using the additional information from the ‘Response to JRP Intervenor Request No.1.’

12. What are the total annual GHG emissions when accounting for the GHG emissions noted in the ‘Response to JRP Intervenor Request for Information No.1’ (include NGL facilities and total annual emissions from blowdown)?

Total GHG Emissions over Project Life

Reference: EIS Volume 5, Section 2.4 and all ‘Response to JRP Intervenor Request No.1’

Rationale: Emissions are indicated on a per year basis. Total emissions for the life of the project are not provided.

13. Please provide the total emissions over the life of the project, including all emissions provided in the ‘Response to JRP Intervenor Request for Information No.1’.

Downstream Emissions

Rationale: The impact of this project beyond the MGP is not provided.

14. Please provide downstream emissions associated with this project, including NGL transmission. In particular, emissions associated with transmission through Alberta and

beyond, and end-use consumption. How many more compressor stations would be required prior to end use consumption? What would the downstream GHG emissions be under the 49 Mm3/d scenario?

3.0 MGP GHG Emissions Scenarios

The following section illustrates all annual GHG emissions, and cumulative GHG emissions, directly related to the Mackenzie Gas Project using information from the GLJ report[1] (commissioned by Imperial Oil Ventures Ltd.), the MGP EIS, and intervenor request for information responses. These calculations are provided because the EIS only provides a single annual GHG emission amount for the base case at the point of maximum flow rate (34 Mm^3/day). No profile of GHG emissions or total cumulative amount is provided in the EIS. Also absent from the EIS is a GHG emission amount for a maximum flow rate case (51 Mm^3/day) and other potential reservoir development scenarios. As such, this section provides a more complete picture of the level of GHG emissions that may be expected from the MGP.

Table 1, below, shows the different scenarios, the associated gas flow rates, and the fields considered. The assumptions used to develop the emissions for each of the scenarios are in Appendix A.

Table 1 below shows the different scenarios, the associated gas flow rates, and the fields considered.

Table 1. Description of Scenarios

Scenario	Flow Rate	Description
EIS Scenario	34 Mm^3/day	As per EIS information, plus GHG data from intervenor request responses. Considers the following reservoirs: Taglu, Parsons Lake, Niglingtgak, 'Other Mackenzie Delta Discovered', Colville Hills Discovered.
Maximum Capacity Scenario	51 Mm^3/day	As per the maximum capacity Case described in the EIS, considering additional facilities (ie. compressors) required. Plant based and fugitive GHG emissions based on EIS scenario, increased proportional to increase in capacity.
Onshore Only Scenario	34 Mm^3/day	As per EIS, plus the following fields: Basin Margin Undiscovered, Colville Hills Undiscovered, and Listric Onshore Undiscovered.
Onshore & Offshore Scenario	34 Mm^3/day	As per Onshore Only Scenario, plus Beaufort Sea Discovered and Beaufort Sea Undiscovered.
NEB P50 Estimate Scenario	34 Mm^3/day	As per Onshore and Offshore Scenario, using a reduced plateau rate production 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.

[1] "Mackenzie Gas Project, Gas Resource and Supply Study – A Study Prepared for Imperial Oil Resources Ventures Limited" May 1, 2004.

Figure 1 below shows the annual emissions for the five different scenarios over the life of the project. Figure 2 provides cumulative emissions for each of the different scenarios. As both figures are based off the development scenarios in the GLJ report, the profile shape exactly matches that of the reservoir development rate graphs in that report.

3.1 Annual Emissions

The annual emissions for the five scenarios are shown in Figure 1 below.

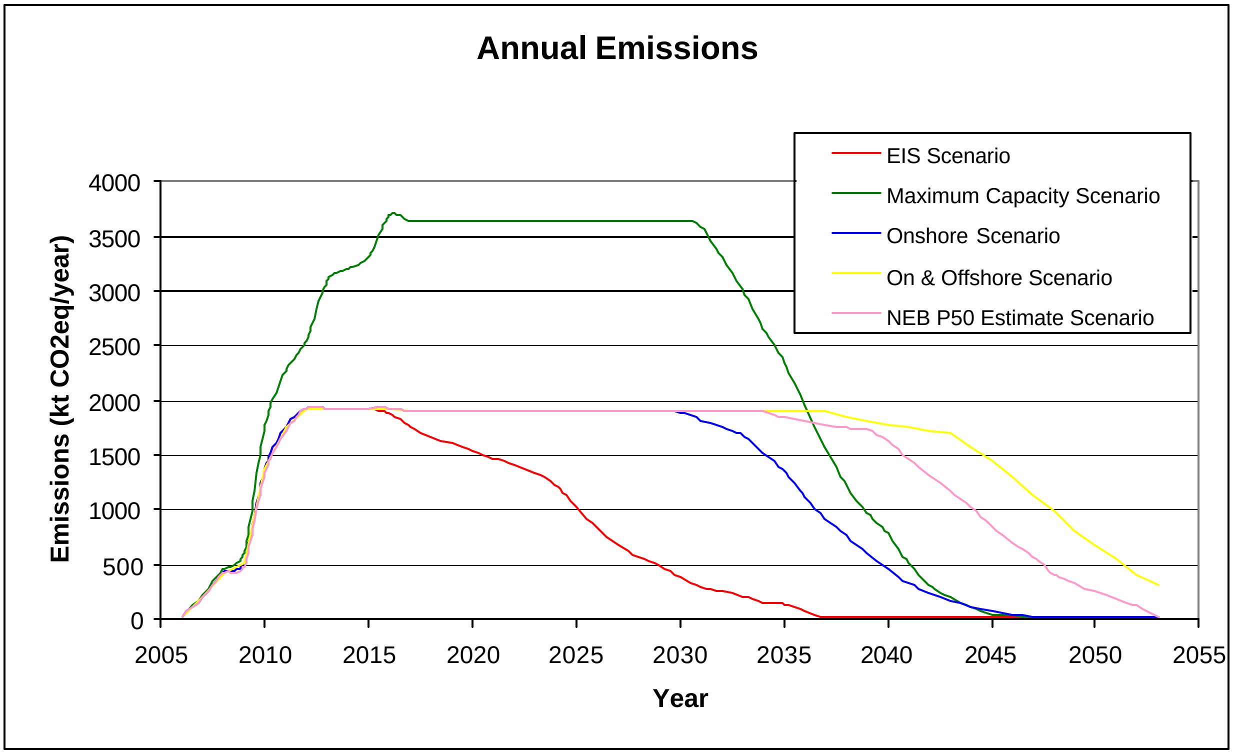

Figure 1. Annual emissions from the MGP over the project lifespan

The results shown in Figure 1 indicate that the "Maximum Capacity" scenario produces the highest annual emissions of 3,050 kt of CO2eq/year, based on the requirement of additional compressor stations and other associated infrastructure. All the other scenarios use the design capacity of 34 Mm3/d and have maximum yearly emissions of 1,925 kt of CO2eq/year. Note that this amount is higher than in the EIS as it includes fugitive emissions that were stated in the initial responses. For the EIS Scenario, maximum design capacity is reached for only four years until emissions decline as contingent resources are depleted and less natural gas is transmitted. Both Onshore Only and Onshore & Offshore Scenarios use contingent and prospective resources to extend the pipeline lifespan, with the NEB P_{50} Scenario being a conservative estimate of the Onshore & Offshore Scenario.

The main conclusion from this figure is that the EIS Scenario can be considered the most conservative, as all other scenarios emit GHGs for an extended period of time. For example, the NEB P_{50} Scenario emits a maximum amount (ie. at 34 Mm^3/d) of GHGs for approximately 20 years longer than the EIS case.

The assumptions used to develop the emissions for each of the scenarios are in Appendix A.

3.2 Cumulative Emissions

The cumulative emissions for the five scenarios are shown in Figure 2 below.

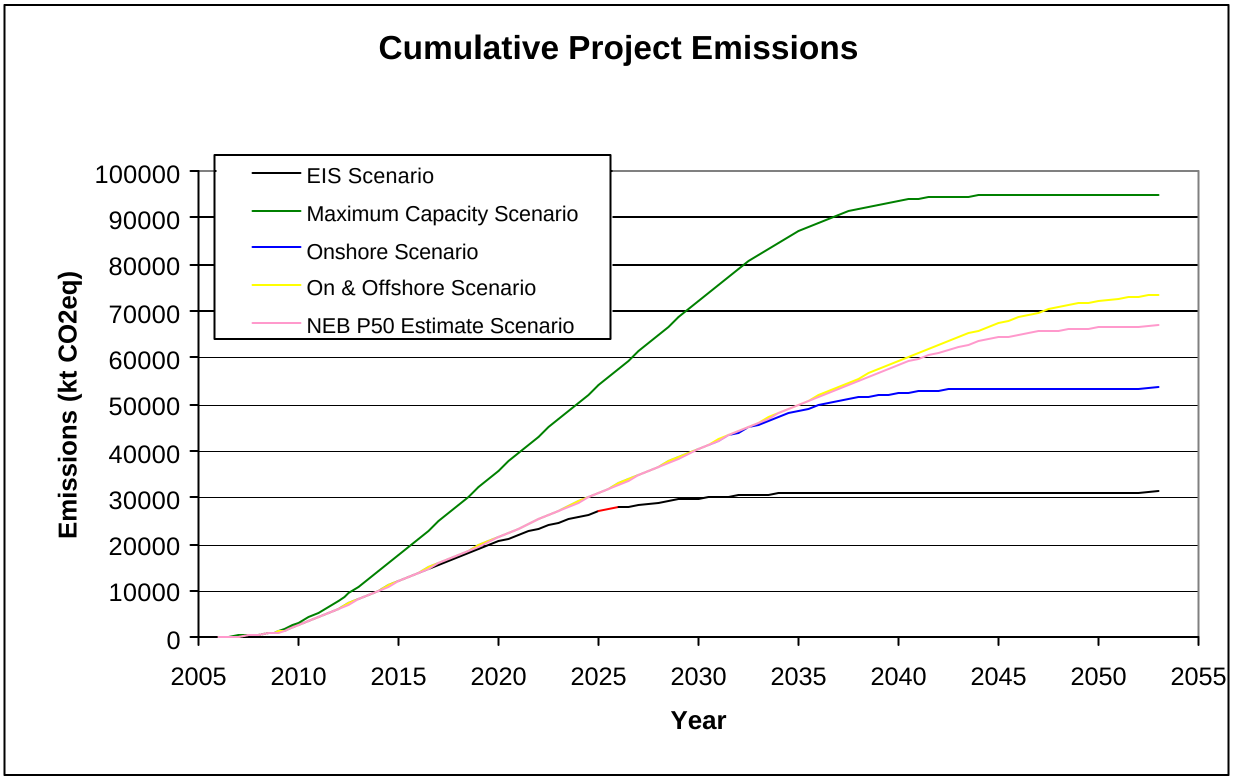

Figure 2. Cumulative emissions from the MGP over the project lifespan

The results shown in Figure 2 indicate that the Maximum Capacity Scenario produces the highest total cumulative emissions at 78,500 kt, which is 2.5 times the amount generated in the EIS Scenario at 31,100 kt. The Onshore Only Scenario generates the second highest amount of GHG's, and is 70% above the EIS Scenario.

Table 2 below provides the maximum annual emissions and total cumulative emissions for each of the scenarios. The total GHG emissions are also broken out for the first three Kyoto commitment periods for further context.

Table 2. GHG Emissions for MGP Scenarios

	Maximum Annual GHG Emissions	Total Cumulative Emissions	Total Emissions for 1st Kyoto Commitment (2008-2012)	Total Emissions for 2nd Kyoto Commitment (2013-2017)	Total Emissions for 3rd Kyoto Commitment (2018-2022)
	(kt CO2eq/year)	*(Mt CO2eq)*	*(Mt CO2eq)*	*(Mt CO2eq)*	*(Mt CO2eq)*
EIS Scenario	1,925	31	6	9.4	8
Maximum Capacity Scenario	3,050	78	6.5	14	15
All Onshore Scenario	1,925	53	6	9.6	9.5
On & Offshore Scenario	1,925	73	6	9.6	9.5
NEB P50 Estimates Scenario	1,925	67	5.9	9.6	9.5

Note that Canada has committed to a reduction of 238 Mt of CO2eq below the business-as-usual by the end of the first commitment period. While the MGP's potential contribution of approximately 6 Mt is relatively small, it should still be a very important consideration in meeting our targets. GHG emissions from the MGP will be even higher for future commitment periods, where targets are likely to be more stringent.

4.0 Fuel Cycle GHG Emissions Related to the Oil Sands

Natural gas from the MGP will be transmitted through the Alberta-based NOVA (TransCanada) network. At least a portion of this gas is likely to supply oil sands operations in the Wood Buffalo Region. This section indicates the life-cycle (i.e., 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 that the MGP may be contributing to, should it supply the oil sands.

The life-cycle GHG emissions provided are based on an estimate of 10 Mm^3/day, or 3,650 Mm^3/year, of natural gas delivered throughout the life-cycle of oil sands fuel production. This estimate was selected as a conservative volume based on the maximum flow rate of 34 Mm^3/day. It also could be considered an average amount of supply over the life of the project.

Figure 3 below shows the 'activities' or processes involved in the life-cycle of natural gas supply and use through the oil sands. Note that emissions for construction activities are included for the MGP project only.[2]

The ratio of in-situ bitumen production and bitumen mining was calculated based on remaining established reserves.[3] 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).

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[2] GHGs from construction activities are typically a small percentage of total GHGs from energy production projects over their life. These were quantified for natural gas and coal fired power generation projects in the report "Life-cycle Evaluation of GHG Emissions and Land Change Related to Selected Power Generation Options in Manitoba", June 16 2003, Pembina Institute, and found to be less than 0.05%.

[3] "Treasure in the Sand, An Overview of Alberta's Oil Sands Resources", April 2005, Canada West Foundation.

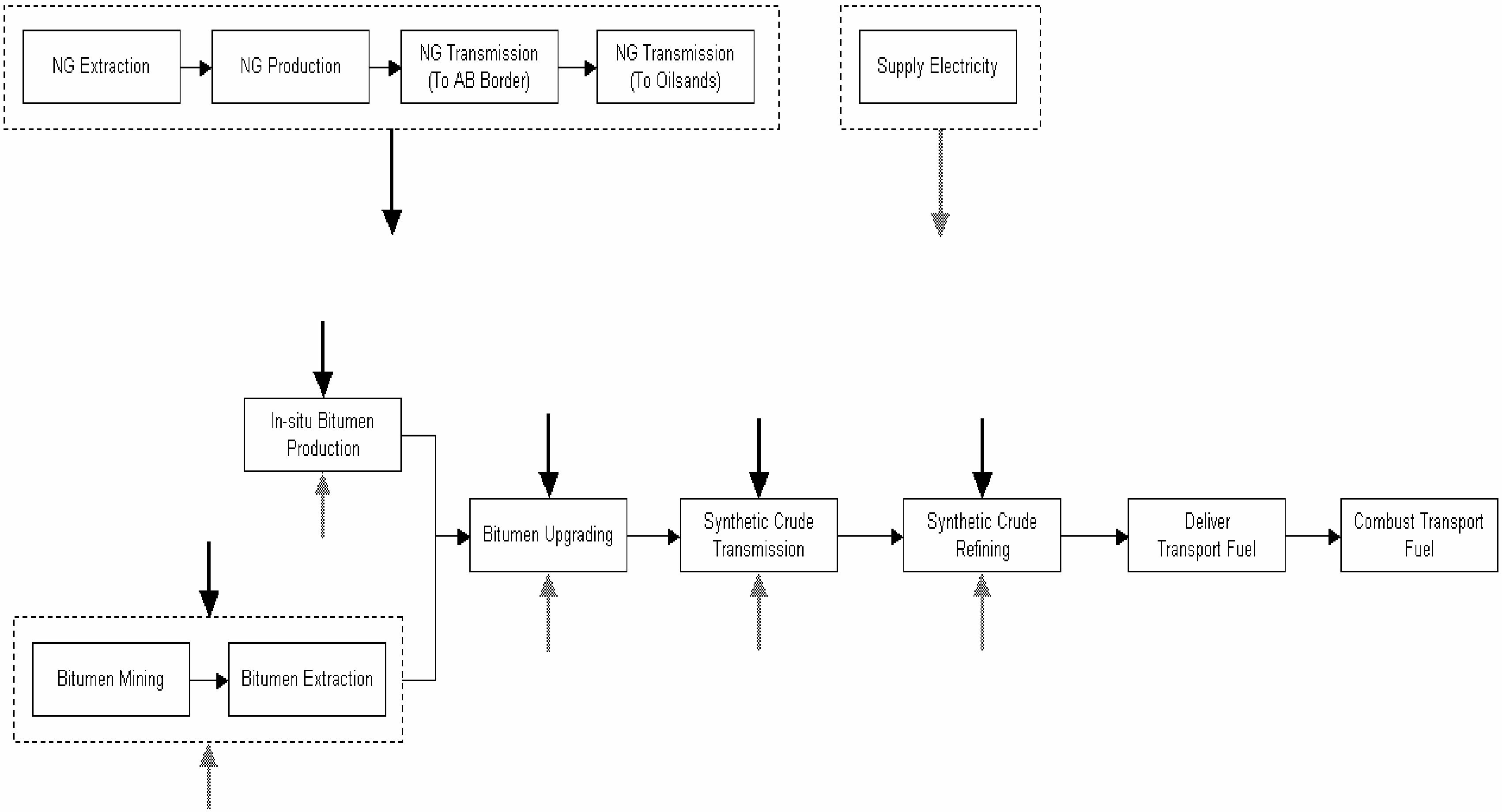

Figure 3. Life Cycle Activity Map of Natural Gas Delivered to the Life-

Emissions resulting from the delivery of natural gas to the oil sands are shown in Figure 4. 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 C1 in Appendix C provides the GHG data for each of the activities.

Note that it is assumed the synthetic crude is refined in Edmonton, and used in Calgary.

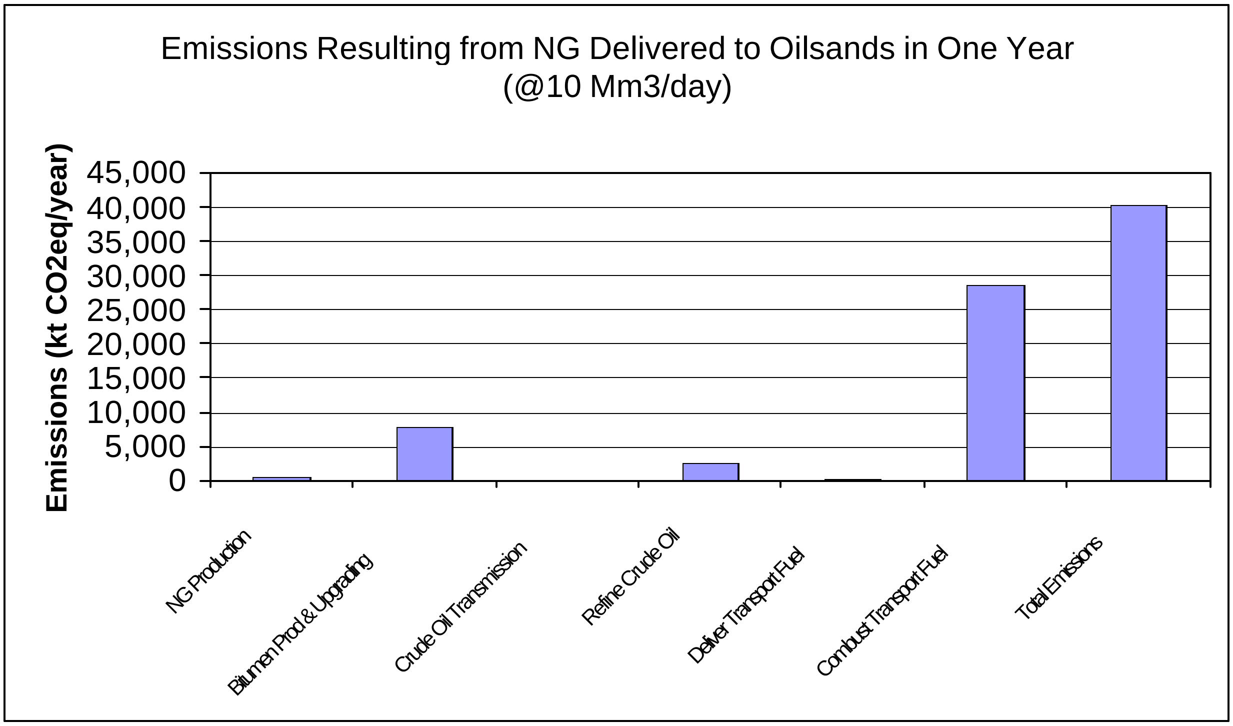

Figure 4. Fuel Cycle Emissions from the delivery of natural gas to the Oil sands

The total GHG emissions produced in one year from the supply of 10 Mm3/day to the oil sands are 40 Mt. The largest contributor to the total emissions is the combustion of transport fuels produced from oil sands crude oil, at 70% of the total. However, bitumen production and upgrading contribute almost 8,000 kt to the total or 20%, while refining the synthetic crude contributes 2,600 kt, or just over 6% to the total emissions.

Figure 4 clearly indicates that production and transmission of natural gas, at 1.65% of the total GHG emissions, contributes to 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 through 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.

Comparison to Compressed Natural Gas (CNG) Vehicle

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 CNG Honda Civic.

As per the analysis in Appendix B, for every $1m^3$ of natural gas delivered to the oil sands, a total of 3 litres of gasoline and diesel are produced. Given an efficiency of 6.85 L / 100 km on average[4] for a gasoline based 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.[5] 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 considering the CNG vehicles fuel cycle.[6] 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 when compared to directly using the natural gas in a CNG vehicle.

On a per kilometer basis, the oil sands based vehicle would generate 0.25 kg CO2eq per km traveled, whereas the CNG vehicle would generate 48% less GHG emissions at 0.13 kg CO2eq per km.

[4] 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.

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

[6] 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

5.0 Conclusions

Key conclusions for each of the specific objectives of this report are provided below:

i. *To comment on the validity of the GHG data included in the EIS report, including associated initial responses to intervenor requests for information. Further questions were also generated as part of Ecology North's and the Sierra Club's second round of intervenor requests for information from the project proponents to better understand the completeness and nature of certain data..*

- Generally, the data used in the EIS and its application is considered reasonable.
- There is a lack of transparency in how GHG emissions from power generation and compression were calculated.
- Information provided in the initial responses around well testing and blowdown events are incomplete.
- Overall, the total maximum annual GHG emissions, based on the base case maximum of 34 Mm^3/d, appears to be an acceptable estimate (pending review of compression and power generation GHG calculations).

ii. *To quantify annual and cumulative GHG emissions for different reservoir development scenarios over the life of the Mackenzie Gas Project. The scenarios considered were: the EIS Scenario, a Maximum Capacity Scenario, Onshore Only, Oonshore & Offshore, and NEB P_{50}.*

The GHG emissions for the five different scenarios were profiled. The lowest maximum annual emissions and cumulative emissions are for the EIS scenario, at 1,925 kt CO2eq/yr and 31 Mt CO2eq per year respectively. The next lowest cumulative emissions are 53 Mt CO2eq, for the All Onshore scenario. Maximum annual emissions for the Maximum Capacity scenario are 3,050 kt CO2eq/yr.

An average of 6 Mt CO2eq/yr are generated during the first Kyoto commitment period. For the two following commitment periods emissions are at least 2 Mt higher, with the likelihood of having more stringent domestic targets.

iii. *To quantify and demonstrate the GHG emissions associated with oil sands development in Northern Alberta, as a result of natural gas supply from the Mackenzie Gas Project.*

At a natural gas delivery rate of 10 Mm^3/d to the fuel supply system, total life-cycle GHG emissions (including end-use combustion) would equal 40 Mt per year. The MGP, plus transmission to the oil sands, account for less than 2% of these emissions.

The use of conventional fuel generated through the oil sands for transportation purposes was compared to using MGP gas directly in a compressed natural gas vehicle. While direct use of 1 m^3 of natural gas in a CNG vehicle could only provide a third the distance in mobility for a light duty vehicle over gasoline and/or diesel; the gasoline/diesel vehicle would generate over five times more GHG emissions on a life-cycle basis.

On a per kilometer basis, the oil sands based (ie. gasoline/diesel) vehicle would generate 0.25 kg CO2eq per km traveled, whereas the CNG vehicle would on generate 48% less GHG emissions at 0.13 kg CO2eq per km.

Appendix A: Emission Scenario Development and Assumptions

EIS Scenario

The 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 (kt/a)[7]	Full Load (Mm3/d)[8]	Fugitive Emissions (kt/a)[9]	Total Yearly Emissions (kt/a)
1,830	34	50.87	1,880.87

In Table A1 the annual operations emissions is 1830 kt/a, which includes the emissions from the production area, Inuvik area facility and the pipeline corridor. The total yearly emissions are calculated to be 1880 kt/a and include fugitive emissions from operation of the system.

Table A2. Total Yearly and Cumulative Emissions for EIS Scenario.

		Emissions (kt/year)						
Year	Total Sales Gas[10]	Operations Emissions	Emissions from Changes in Land Use[11]	Construction Emissions[12]	Well Testing Emissions	Blowdown Venting Emissions	Total Yearly Emissions	Cumulative Yearly Emissions
2006	0	0	0	24.9	0	0	25	25
2007	0	0	43.7	153.5	0	0	197	222
2008	0	0	56.6	363.2	0	0	420	642
2009	3.8	210.2	56.6	246.2	0	0	513	1,155

[7] The total GHG emissions from the combine project are 1830 kt/a is taken from Section 2.4.10.8, pg 2-106 in Environmental Impact Statement for the Mackenzie Gas Project, Volume 5 – Biophysical Impact Assessment, 2004.

[8] Full load of the MGP is 34 Mm3/d is taken from Section 1.1.1.2, pg 1-2 in Application for Approval of the Mackenzie Valley Pipeline, Volume 1 – Pipeline Project Overview, August 2004

[9] 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 Intervenor Information Request Response, March 31, 2005.

[10] GLJ Report, Table 11, Pg 66

[11] The emissions from changes in land use are taken from Table SCC 1.02-1, pg. 4 of Mackenzie Gas Project, Joint Review Panel Intervenor Information Request Response, March 31, 2005.

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

2010	23.5	1,300.0	44.6	32.1	0	0	0	1,377	2,532
2011	31.0	1,714.9	44.6	0	0	0	0	1,760	4,291
2012	34.0	1,880.9	44.6	0	0	0	0	1,925	6,216
2013	34.0	1,880.9	44.6	0	0	0	0	1,925	8,142
2014	34.0	1,880.9	44.6	0	0	0	0	1,925	10,067
2015	33.8	1,869.8	44.6	0	0	0	0	1,914	11,982
2016	33.2	1,836.6	44.6	0	0	0	0	1,881	13,863
2017	31.5	1,742.6	13.1	0	0	0	0	1,756	15,619
2018	29.9	1,654.1	13.1	0	0	0	0	1,667	17,286
2019	28.7	1,587.7	13.1	0	0	0	0	1,601	18,887
2020	27.6	1,526.8	13.1	0	0	0	0	1,540	20,427
2021	26.3	1,454.9	13.1	0	0	0	0	1,468	21,895
2022	25.2	1,394.1	13.1	0	0	0	0	1,407	23,302
2023	23.8	1,316.6	13.1	0	0	0	0	1,330	24,631
2024	22.0	1,217.0	13.1	0	0	0	0	1,230	25,862
2025	18.1	1,001.3	13.1	0	0	0	0	1,014	26,876
2026	14.8	818.7	13.1	0	0	0	0	832	27,708
2027	12.1	669.4	13.1	0	0	0	0	682	28,390
2028	9.9	547.7	13.1	0	0	0	0	561	28,951
2029	8.5	470.2	13.1	0	0	0	0	483	29,434
2030	6.6	365.1	13.1	0	0	0	0	378	29,813
2031	5.1	282.1	13.1	0	0	0	0	295	30,108
2032	4.3	237.9	13.1	0	0	0	0	251	30,359
2033	3.5	193.6	13.1	0	0	0	0	207	30,565
2034	2.5	138.3	13.1	0	0	0	0	151	30,717
2035	2.2	121.7	13.1	0	0	0	0	135	30,852
2036	0.9	49.8	13.1	0	0	0	0	63	30,915
2037	0	0	13.1	0	0	0	0	13	30,928
2038	0	0	13.1	0	0	0	0	13	30,941
2039	0	0	13.1	0	0	0	0	13	30,954
2040	0	0	13.1	0	0	0	0	13	30,967
2041	0	0	13.1	0	0	0	0	13	30,980
2042	0	0	13.1	0	0	0	0	13	30,993
2043	0	0	13.1	0	0	0	0	13	31,006
2044	0	0	13.1	0	0	0	0	13	31,019
2045	0	0	13.1	0	0	0	0	13	31,032
2046	0	0	13.1	0	0	0	0	13	31,046
2047	0	0	13.1	0	0	0	0	13	31,059
2048	0	0	13.1	0	0	0	0	13	31,072
2049	0	0	13.1	0	0	0	0	13	31,085
2050	0	0	13.1	0	0	0	0	13	31,098
2051	0	0	13.1	0	0	0	0	13	31,111
2052	0	0	13.1	0	0	0	0	13	31,124
2053	0	0	13.1	0	0	0	0	13	31,137

The total sales gas for each year in Table A2 is used to calculate the operations emissions, assuming that a decrease in sales gas results in a linear decrease in emissions. The ratio of yearly sales gas to the transmission at full load was multiplied to the maximum total yearly emissions. A sample calculation for the year 2009 is shown below;

Operations emissions = (3.8 Mm3/d ÷ 34 Mm3/d) × 1880 kt/a = 210.2 kt/a

The total yearly 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.

Emissions from well testing and blowdown venting were not included since the only information available was on a "per event" basis with no indication of how many events occur per year. These emissions will increase the total yearly emissions but it is not known by how much. Emissions from well testing and blowdown venting are not included for all of the scenarios developed.

Maximum Capacity Scenario

The emissions for the Maximum Capacity Scenario are calculated in Table A3 and Table A4. A list of assumptions and explanations used to calculate the emissions follows each table.

Table A3. Maximum Annual Operations Emissions for Maximum Capacity Scenario

Annual Operations Emissions at Full Load (kt/a)	Full Load[13] (Mm3/d)	Fugitive Emissions (kt/a)	Extra Compressor Stations	Extra Compressor Station Emissions (kt/a)	Extra NGL Pumping Stations	Extra Pumping Station Emissions	Total Yearly Emissions (kt/a)
2,468	51	76.31	10	107.64	2	0	3,621.19

Full load capacity of 51 Mm3/d is 50% more than the original design capacity of 34 Mm3/d. The annual operations emissions from the production areas (Niglintgak, Taglu and Parsons Lake) and at the Inuvik Facility are increased proportional (50%) to the increase in capacity. This increased the annual operations emissions from 1,830 kt/a to 2,468 kt/a.

Fugitive emissions were also increased by 50% to account for the increased capacity, increasing from 50.87 kt/a to 76.31 kt/a.

Ten extra compressor stations are required for operation at maximum capacity[14]. The GHG emissions from currently planned compressor stations are 107.64 kt/a[15]. This number was used for the expected emissions from future compressor stations for the maximum capacity case.

Two extra NGL pumping stations are required for operation at maximum capacity[16]. The GHG emissions for a pumping station are unknown and not included in this analysis.

The total yearly emissions from operation at maximum capacity are calculated to be 3621 kt/a.

[13] "The estimated annual average capability for the fully expanded system is 55 Mm3/d" taken from Section 1.3.3, pg 1-13 in Application for Approval of the Mackenzie Valley Pipeline, Volume 1 – Pipeline Project Overview, August 2004. The GLJ report uses 51 Mm3/d for the annual average capability of the fully expanded system.

[14] 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

[15] 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.

[16] 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

Table A4. Total Yearly and Cumulative Emissions for Maximum Capacity Scenario.

Year	Total Sales Gas[17]	Emissions (kt/a)						
		Operations Emissions	Emissions from Changes in Land Use	Construction Emissions	Well Testing Emissions	Blowdown Venting Emissions	Total Yearly Emissions	Cumulative Yearly Emissions
2006	0	0	0	24.85	0	0	25	25
2007	0	0	65.55	153.45	0	0	219	244
2008	0	0	84.9	363.22	0	0	448	692
2009	3.8	270	84.9	246.17	0	0	601	1,293
2010	23.5	1,669	66.9	32.09	0	0	1,768	3,060
2011	31.0	2,201	66.9	0	0	0	2,268	5,328
2012	34.9	2,478	66.9	0	0	0	2,545	7,873
2013	42.5	3,018	66.9	0	0	0	3,085	10,958
2014	44.2	3,138	66.9	0	0	0	3,205	14,163
2015	45.7	3,245	66.9	0	0	0	3,312	17,475
2016	51.0	3,621	66.9	0	0	0	3,688	21,163
2017	51.0	3,621	19.65	0	0	0	3,641	24,804
2018	51.0	3,621	19.65	0	0	0	3,641	28,445
2019	51.0	3,621	19.65	0	0	0	3,641	32,086
2020	51.0	3,621	19.65	0	0	0	3,641	35,726
2021	51.0	3,621	19.65	0	0	0	3,641	39,367
2022	51.0	3,621	19.65	0	0	0	3,641	43,008
2023	51.0	3,621	19.65	0	0	0	3,641	46,649
2024	51.0	3,621	19.65	0	0	0	3,641	50,290
2025	51.0	3,621	19.65	0	0	0	3,641	53,931
2026	51.0	3,621	19.65	0	0	0	3,641	57,571
2027	51.0	3,621	19.65	0	0	0	3,641	61,212
2028	51.0	3,621	19.65	0	0	0	3,641	64,853
2029	51.0	3,621	19.65	0	0	0	3,641	68,494
2030	51.0	3,621	19.65	0	0	0	3,641	72,135
2031	50.3	3,571	19.65	0	0	0	3,591	75,726
2032	46.2	3,280	19.65	0	0	0	3,300	79,026
2033	42.1	2,989	19.65	0	0	0	3,009	82,035
2034	37.1	2,634	19.65	0	0	0	2,654	84,689
2035	32.7	2,322	19.65	0	0	0	2,341	87,030
2036	27.2	1,931	19.65	0	0	0	1,951	88,981
2037	21.9	1,555	19.65	0	0	0	1,575	90,556
2038	16.9	1,200	19.65	0	0	0	1,220	91,775
2039	13.4	951	19.65	0	0	0	971	92,747
2040	10.7	760	19.65	0	0	0	779	93,526

[17] GLJ Report, Table 36, Pg 82

2041	6.9	490	19.65	0	0	0	510	94,036
2042	4.0	284	19.65	0	0	0	304	94,339
2043	2.5	178	19.65	0	0	0	197	94,536
2044	1.2	85	19.65	0	0	0	105	94,641
2045	0.3	21	19.65	0	0	0	41	94,682
2046	0.1	7	19.65	0	0	0	27	94,709
2047	0.0	0	19.65	0	0	0	20	94,729
2048	0.0	0	19.65	0	0	0	20	94,748
2049	0.0	0	19.65	0	0	0	20	94,768
2050	0.0	0	19.65	0	0	0	20	94,787
2051	0.0	0	19.65	0	0	0	20	94,807
2052	0.0	0	19.65	0	0	0	20	94,827
2053	0.0	0	19.65	0	0	0	20	94,846

The total sales gas for each year in Table A4 is used to calculate the operations emissions, assuming that a decrease in sales gas results in a linear decrease in emissions. The ratio of yearly sales gas to the transmission at full load was multiplied to the maximum total yearly emissions. A sample calculation for the year 2009 is shown below;

Operations emissions = (3.8 Mm3/d ÷ 51 Mm3/d) × 3621 kt/a = 270 kt/a

Emissions from the changes in land use were scaled up using the same method for emissions in Table A3. Emissions from land change are 50% higher than for the original design capacity of 34 Mm3/day. The assumption for the increase in emissions was that an increase in capacity would require more pipeline infrastructure in the production area to supply the MGP with sufficient gas.

The total yearly emissions in Table A4 include operations emissions, emissions resulting from land disturbance and construction emissions.

Onshore Scenario

The emissions for the Onshore Scenario are calculated in Table A5 and Table A6.All assumptions are the same as the EIS Scenario explained earlier in this appendix.

Table A5. Maximum Annual Operations Emissions for Onshore Scenario.

Annual Operations Emissions at Full Load (kt/a)	Full Load (Mm3/d)	Fugitive Emissions (kt/a)	Total Yearly Emissions (kt/a)
1,830	34	50.87	1,880.87

Table A6. Total Yearly and Cumulative Emissions for Onshore Scenario.

		Emissions (kt/a)						

Year	Total Sales Gas[18]	Operations Emissions	Emissions from Changes in Land Use	Construction Emissions	Well Testing Emissions	Blowdown Venting Emissions	Total Yearly Emissions	Cumulative Yearly Emissions
2006	0	0	0	24.85	0	0	25	25
2007	0	0	43.7	153.45	0	0	197	222
2008	0	0	56.6	363.22	0	0	420	642
2009	3.8	210	56.6	246.17	0	0	513	1,155
2010	23.5	1,300	44.6	32.09	0	0	1,377	2,532
2011	31.0	1,715	44.6	0	0	0	1,760	4,291
2012	34.0	1,881	44.6	0	0	0	1,925	6,216
2013	34.0	1,881	44.6	0	0	0	1,925	8,142
2014	34.0	1,881	44.6	0	0	0	1,925	10,067
2015	34.0	1,881	44.6	0	0	0	1,925	11,993
2016	34.0	1,881	44.6	0	0	0	1,925	13,918
2017	34.0	1,881	13.1	0	0	0	1,894	15,812
2018	34.0	1,881	13.1	0	0	0	1,894	17,706
2019	34.0	1,881	13.1	0	0	0	1,894	19,600
2020	34.0	1,881	13.1	0	0	0	1,894	21,494
2021	34.0	1,881	13.1	0	0	0	1,894	23,388
2022	34.0	1,881	13.1	0	0	0	1,894	25,282
2023	34.0	1,881	13.1	0	0	0	1,894	27,176
2024	34.0	1,881	13.1	0	0	0	1,894	29,070
2025	34.0	1,881	13.1	0	0	0	1,894	30,964
2026	34.0	1,881	13.1	0	0	0	1,894	32,858
2027	34.0	1,881	13.1	0	0	0	1,894	34,752
2028	34.0	1,881	13.1	0	0	0	1,894	36,646
2029	34.0	1,881	13.1	0	0	0	1,894	38,540
2030	33.9	1,875	13.1	0	0	0	1,888	40,428
2031	32.6	1,803	13.1	0	0	0	1,817	42,245
2032	31.4	1,737	13.1	0	0	0	1,750	43,995
2033	30.2	1,671	13.1	0	0	0	1,684	45,679
2034	27.1	1,499	13.1	0	0	0	1,512	47,191
2035	24.2	1,339	13.1	0	0	0	1,352	48,543
2036	19.9	1,101	13.1	0	0	0	1,114	49,657
2037	16.3	902	13.1	0	0	0	915	50,572
2038	13.5	747	13.1	0	0	0	760	51,332
2039	10.5	581	13.1	0	0	0	594	51,926
2040	7.9	437	13.1	0	0	0	450	52,376
2041	5.7	315	13.1	0	0	0	328	52,704
2042	4.1	227	13.1	0	0	0	240	52,944
2043	2.8	155	13.1	0	0	0	168	53,112

[18] GLJ Report, Table 24, Pg 70

2044	1.8	100	13.1	0	0	0	113	53,225
2045	1.1	61	13.1	0	0	0	74	53,299
2046	0.5	28	13.1	0	0	0	41	53,339
2047	0.1	6	13.1	0	0	0	19	53,358
2048	0.0	0	13.1	0	0	0	13	53,371
2049	0.0	0	13.1	0	0	0	13	53,384
2050	0.0	0	13.1	0	0	0	13	53,397
2051	0.0	0	13.1	0	0	0	13	53,410
2052	0.0	0	13.1	0	0	0	13	53,424
2053	0.0	0	13.1	0	0	0	13	53,437

Onshore and Offshore Scenario

The emissions for the Onshore and Offshore Scenario are calculated in Table A7 and Table A8.All assumptions are the same as the EIS Scenario explained earlier in this appendix.

Table A7. Maximum Annual Operations Emissi ons for Onshore and Offshore Scenario.

Annual Operations Emissions at Full Load (kt/a)	Full Load (Mm3/d)	Fugitive Emissions (kt/a)	Total Yearly Emissions (kt/a)
1,830	34	50.87	1,880.87

Table A8. Total Yearly and Cumulative Emissions for Onshore and Offsh ore Scenario.

		Emissions (kt/a)						
Year	Total Sales Gas[19]	Operations Emissions	Emissions from Changes in Land Use	Construction Emissions	Well Testing Emissions	Blowdown Venting Emissions	Total Yearly Emissions	Cumulative Yearly Emissions
2006	0	0	0	24.85	0	0	25	25
2007	0	0	43.7	153.45	0	0	197	222
2008	0	0	56.6	363.22	0	0	420	642
2009	3.8	210	56.6	246.17	0	0	513	1,155
2010	23.5	1,300	44.6	32.09	0	0	1,377	2,532
2011	31.0	1,715	44.6	0	0	0	1,760	4,291
2012	34.0	1,881	44.6	0	0	0	1,925	6,216
2013	34.0	1,881	44.6	0	0	0	1,925	8,142
2014	34.0	1,881	44.6	0	0	0	1,925	10,067
2015	34.0	1,881	44.6	0	0	0	1,925	11,993
2016	34.0	1,881	44.6	0	0	0	1,925	13,918
2017	34.0	1,881	13.1	0	0	0	1,894	15,812
2018	34.0	1,881	13.1	0	0	0	1,894	17,706
2019	34.0	1,881	13.1	0	0	0	1,894	19,600
2020	34.0	1,881	13.1	0	0	0	1,894	21,494

[19] GLJ Report, Table 32, Pg 78

2021	34.0	1,881	13.1	0	0	0	1,894	23,388
2022	34.0	1,881	13.1	0	0	0	1,894	25,282
2023	34.0	1,881	13.1	0	0	0	1,894	27,176
2024	34.0	1,881	13.1	0	0	0	1,894	29,070
2025	34.0	1,881	13.1	0	0	0	1,894	30,964
2026	34.0	1,881	13.1	0	0	0	1,894	32,858
2027	34.0	1,881	13.1	0	0	0	1,894	34,752
2028	34.0	1,881	13.1	0	0	0	1,894	36,646
2029	34.0	1,881	13.1	0	0	0	1,894	38,540
2030	34.0	1,881	13.1	0	0	0	1,894	40,434
2031	34.0	1,881	13.1	0	0	0	1,894	42,328
2032	34.0	1,881	13.1	0	0	0	1,894	44,222
2033	34.0	1,881	13.1	0	0	0	1,894	46,116
2034	34.0	1,881	13.1	0	0	0	1,894	48,010
2035	34.0	1,881	13.1	0	0	0	1,894	49,904
2036	34.0	1,881	13.1	0	0	0	1,894	51,798
2037	34.0	1,881	13.1	0	0	0	1,894	53,692
2038	33.2	1,837	13.1	0	0	0	1,850	55,541
2039	32.4	1,792	13.1	0	0	0	1,805	57,347
2040	31.8	1,759	13.1	0	0	0	1,772	59,119
2041	31.3	1,732	13.1	0	0	0	1,745	60,864
2042	30.9	1,709	13.1	0	0	0	1,722	62,586
2043	30.6	1,693	13.1	0	0	0	1,706	64,292
2044	28.3	1,566	13.1	0	0	0	1,579	65,871
2045	25.7	1,422	13.1	0	0	0	1,435	67,306
2046	23.1	1,278	13.1	0	0	0	1,291	68,597
2047	20.4	1,129	13.1	0	0	0	1,142	69,738
2048	17.6	974	13.1	0	0	0	987	70,725
2049	14.3	791	13.1	0	0	0	804	71,529
2050	11.9	658	13.1	0	0	0	671	72,201
2051	9.8	542	13.1	0	0	0	555	72,756
2052	7.0	387	13.1	0	0	0	400	73,156
2053	5.3	293	13.1	0	0	0	306	73,462

NEB P50 Estimate Scenario

The emissions for the NEB P50 Estimate Scenario are calculated in Table A9 and Table A10.All assumptions are the same as the EIS Scenario explained earlier in this appendix.

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

Annual Operations Emissions at Full Load (kt/a)	Full Load (Mm3/d)	Fugitive Emissions (kt/a)	Total Yearly Emissions (kt/a)
1,830	34	50.87	1,880.87

Table A10. Total Yearly and Cumulative Emissions for NEB P50 Estimate Scenario.

		Emissions (kt/a)						
Year	Total Sales Gas[20]	Operations Emissions	Emissions from Changes in Land Use	Construction Emissions	Well Testing Emissions	Blowdown Venting Emissions	Total Yearly Emissions	Cumulative Yearly Emissions
2006	0	0	0	24.85	0	0	25	25
2007	0	0	43.7	153.45	0	0	197	222
2008	0	0	56.6	363.22	0	0	420	642
2009	3.2	177	56.6	246.17	0	0	480	1,122
2010	22.7	1,256	44.6	32.09	0	0	1,332	2,454
2011	30.2	1,671	44.6	0	0	0	1,715	4,169
2012	34.0	1,881	44.6	0	0	0	1,925	6,095
2013	34.0	1,881	44.6	0	0	0	1,925	8,020
2014	34.0	1,881	44.6	0	0	0	1,925	9,946
2015	34.0	1,881	44.6	0	0	0	1,925	11,871
2016	34.0	1,881	44.6	0	0	0	1,925	13,797
2017	34.0	1,881	13.1	0	0	0	1,894	15,691
2018	34.0	1,881	13.1	0	0	0	1,894	17,585
2019	34.0	1,881	13.1	0	0	0	1,894	19,479
2020	34.0	1,881	13.1	0	0	0	1,894	21,373
2021	34.0	1,881	13.1	0	0	0	1,894	23,267
2022	34.0	1,881	13.1	0	0	0	1,894	25,160
2023	34.0	1,881	13.1	0	0	0	1,894	27,054
2024	34.0	1,881	13.1	0	0	0	1,894	28,948
2025	34.0	1,881	13.1	0	0	0	1,894	30,842
2026	34.0	1,881	13.1	0	0	0	1,894	32,736
2027	34.0	1,881	13.1	0	0	0	1,894	34,630
2028	34.0	1,881	13.1	0	0	0	1,894	36,524
2029	34.0	1,881	13.1	0	0	0	1,894	38,418
2030	34.0	1,881	13.1	0	0	0	1,894	40,312
2031	34.0	1,881	13.1	0	0	0	1,894	42,206
2032	34.0	1,881	13.1	0	0	0	1,894	44,100
2033	34.0	1,881	13.1	0	0	0	1,894	45,994
2034	34.0	1,881	13.1	0	0	0	1,894	47,888
2035	33.0	1,826	13.1	0	0	0	1,839	49,727
2036	32.3	1,787	13.1	0	0	0	1,800	51,527

[20] GLJ Report, Table 40, Pg 86

2037	31.7	1,754	13.1	0	0	0	1,767	53,293
2038	31.3	1,732	13.1	0	0	0	1,745	55,038
2039	31.0	1,715	13.1	0	0	0	1,728	56,766
2040	29.1	1,610	13.1	0	0	0	1,623	58,389
2041	26.2	1,449	13.1	0	0	0	1,462	59,851
2042	23.6	1,306	13.1	0	0	0	1,319	61,170
2043	20.9	1,156	13.1	0	0	0	1,169	62,339
2044	18.3	1,012	13.1	0	0	0	1,025	63,365
2045	15.0	830	13.1	0	0	0	843	64,208
2046	12.3	680	13.1	0	0	0	694	64,901
2047	10.1	559	13.1	0	0	0	572	65,473
2048	7.1	393	13.1	0	0	0	406	65,879
2049	5.5	304	13.1	0	0	0	317	66,196
2050	4.2	232	13.1	0	0	0	245	66,442
2051	3.1	171	13.1	0	0	0	185	66,626
2052	1.9	105	13.1	0	0	0	118	66,745
2053	0.2	11	13.1	0	0	0	24	66,769

Appendix B: Assumptions and Calculations of Life-cycle Oil Sands-based Emissions

GHG emissions associated with the specific life-cycle activities from the supply of one cubic metre of natural gas for the production of transport fuel from the oil sands is shown in Figure B1.

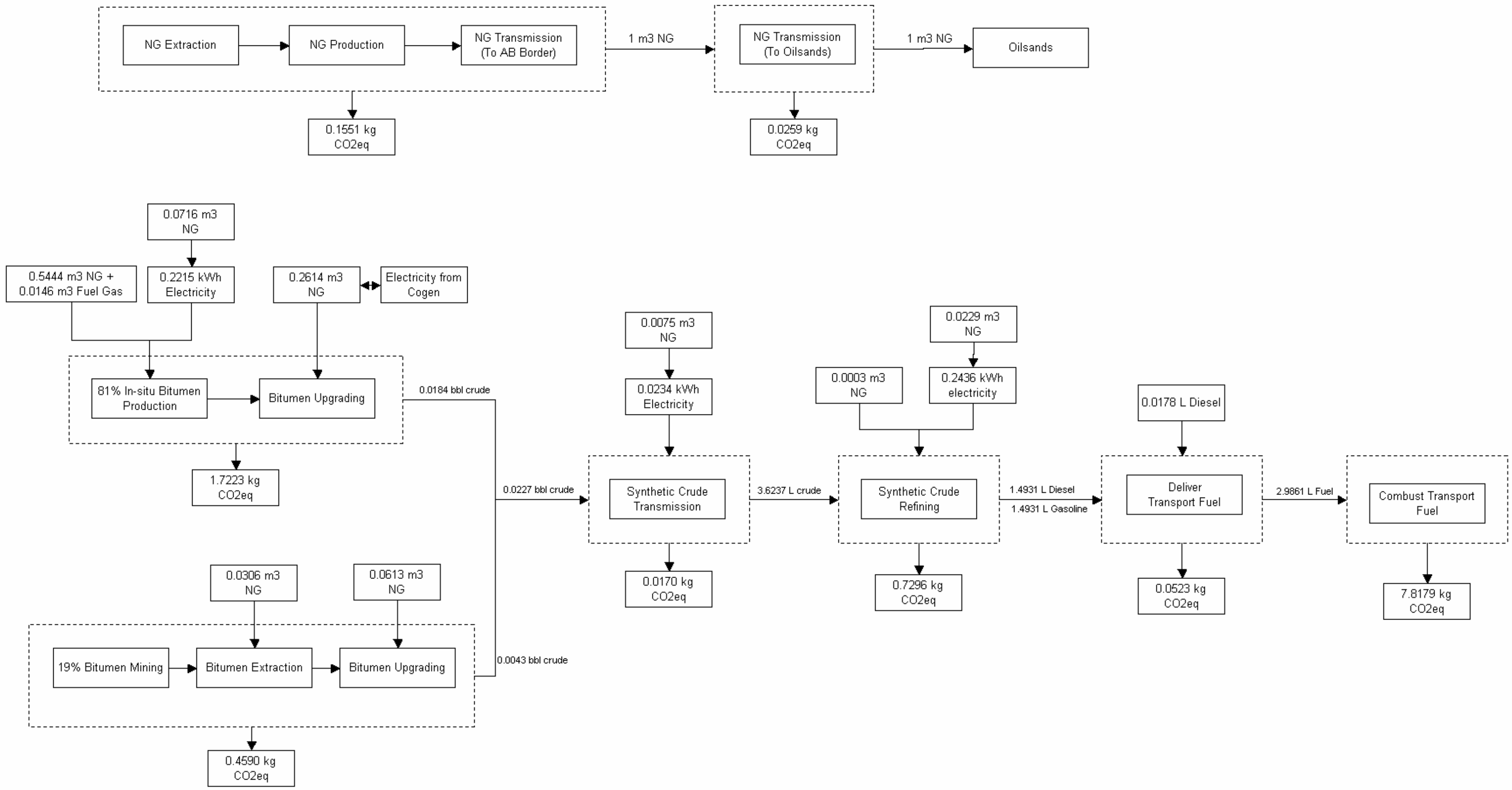

Figure B1. Life Cycle Activity Map of 1m3 of Natural Gas Delivered to the Oil sands

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/yr (see Table 1). Thus, the resulting emissions per cubic metre of natural gas delivered to the Alberta border are:

$$\frac{1925 ? 10^6 kgCO2eq}{34Mm3/d ? 365d/y} ? 0.1551kgCO2eq/m3$$

Natural Gas Transmission from Alberta Border to Oilsands

The length of pipeline from the Alberta border to the Oilsands is approximately 830 km , using 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[21] and requires 4 compressor stations[22], 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/a[23]. The resulting emissions per cubic metre of natural gas are;

$$\frac{107.64 ? 10^6 kgCO2eq ? 3}{34Mm3/d ? 365d/y} ? 0.0259kgCO2eq/m3$$

Bitumen Production and Upgrading

The ratio of in-situ bitumen production and bitumen mining was calculated based on remaining established reserves noted in Table B1. 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 B1. Bitumen Resources in Alberta[24] (Billions of Barrels)

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

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

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

[23] 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.

[24] 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 m3/d of natural gas, 5 m3/d of produced gas and 3.1 kW of electricity to produce 1 m3/d of bitumen[25]. Thus the allocated amount of natural gas required for in-situ production is 0.54 m3. The volume of produced gas required 0.015 m3 of produced gas as indicated in Figure B1.

Electricity is assumed to come from natural gas power production. 0.072 m3 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 m3/kWh[26] was used to calculate the required natural gas.

Upgrading of bitumen requires 14.2 m3 of natural gas per barrel of bitumen produced[27]. 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 B2. 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 B2. Emissions Factor for the Combustion of Natural Gas[28]

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 cubic metres of natural gas and the upgrading of bitumen requires 14.2 cubic metres of natural gas[29]. The normalized amount of natural gas required for mining is 0.031 m3 and upgrading requires 0.061 m3 of natural gas (see Figure B1).

Emissions for bitumen mining were calculated using an emission factor of 0.106 tonne CO2eq/bbl of crude[30], 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[31]. 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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[25] 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.

[26] 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.

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

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

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

[30] 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.

[31] 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[32]. 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 m3 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/m3 of natural gas[33].

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[34]. 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 m3 of natural gas and 0.24 kWh of electricity (see Figure B1)[38]. To produce 0.24 kWh of electricity, 0.023 m3 of natural gas supplied from the MGP is required assuming that 29% of electricity in Alberta[35] 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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[32] "Emission of Greenhouse Gases from the Use of Transportation Fuels and Electricity", Volume 2, Appendix A, US Dept. of Energy, M.Deluchi, 1991.

[33] 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.

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

[35] 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[36], 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[37].

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 B3. Emissions Factor for the Combustion of Natural Gas[38]

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.

[36] 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.

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

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

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

Table C1 considers the total GHG emissions based on one cubic metre of natural gas delivered to the oil sands-based fuel cycle as provided in Appendix B. The emissions are scaled up using a supply of 10 Mm3/d over one year for a total of 3,650 Mm^3/year.

Table C1: 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
CO2 Emissions (kt/year)	661	7,962	62	2,663	191	28,535	40,074