AMENDED LIFECYCLE ANALYSIS
OF DIESEL AND LNG POWER PRODUCTION

Prepared For:

Yukon Energy Corporation
#2 Miles Canyon Road
Box 5920, Whitehorse
Yukon
Y1A 6S7

Prepared By

(S&T)^2 Consultants Inc.
11657 Summit Crescent
Delta, BC
Canada, V4E 2Z2

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EXECUTIVE SUMMARY

Established in 1987, Yukon Energy is a publicly owned electrical utility that operates as a business, at arm's length from the Yukon government. They are the main generator and transmitter of electrical energy in Yukon and work with their parent company Yukon Development Corporation, to provide a sufficient supply of safe, reliable electricity and related energy services.

Yukon Energy has the capacity to generate approximately 132 megawatts of power. Ninety two megawatts of that are provided by hydro facilities in Whitehorse, Mayo and Aishihik Lake (40 megawatts at Whitehorse, 37 megawatts at Aishihik and 15 megawatts at Mayo), 39 megawatts by diesel generators (which are currently only use as back-up) and 0.8 megawatts by two wind turbines located on Haeckel Hill near Whitehorse.

Yukon Energy is considering the replacement of some the diesel generators with either new diesel generators or natural gas engines fuelled by liquid natural gas (LNG). The LNG would be obtained from suppliers in British Columbia and/or Alberta.

Four power systems are compared in this report, a diesel fueled system and three LNG supply options. The diesel fuel system is based on new diesel generators and the existing diesel fuel supply system. Two of the LNG systems are similar, both are primarily electric drive systems but one (Fortis) is located in BC and the other (Shell) is located in Alberta, the other LNG supply options is fuelled by natural gas. The carbon intensity of the power grids in the two provinces is quite different and this accounts for most of the difference in GHG emissions for the two electric drive LNG systems. The lifecycle GHG emissions for the four systems are shown in the following table.

Table ES- 1 Comparison of GHG Emissions

Stage	Diesel	Fortis LNG	Shell LNG	Dresser Rand
	GHG Emissions, g CO_2eq/kWh			
Emissions from Operation	701	561	561	561
Fuel dispensing (liquefaction)	2	7	88	147
Fuel distribution and storage	35	75	73	26
Fuel production	90	22	22	23
Feedstock transmission	16	0	0	0
Feedstock recovery	69	24	24	26
Feedstock upgrading	3	0	0	0
Land-use changes, cultivation	0	0	0	0
Fertilizer manufacture	0	0	0	0
Gas leaks and flares	40	10	10	9
CO_2, H_2S removed from NG	0	9	9	39
Emissions displaced	0	0	0	0
Total	957	708	786	831
% Change		-26	-18	-13

The fuel use stage has a significant impact on most of the gases and the quality of data available on these emissions could be better. The CAC emissions from the engines are estimates based on literature and not on information from these specific engines. Care must therefore be taken when interpreting the CAC emissions for the four supply chain options. In a few cases the differences are large enough that conclusions can be drawn but in other cases, the engine specific information could be significantly different than used here in the modelling.

The comparison of the NOx emissions is shown in the following table.

Table ES- 2 Comparison of Lifecycle NOx Emissions

Stage	Diesel	Fortis LNG	Shell LNG	Dresser Rand
	NOx Emissions, g NOx/kWh			
Emissions from Operation	3.646	1.844	1.844	1.844
Fuel dispensing (liquefaction)	0.003	0.012	0.259	0.155
Fuel distribution and storage	0.390	0.057	0.059	0.018
Fuel production	0.148	0.046	0.047	0.048
Feedstock transmission	0.142	0.000	0.000	0.000
Feedstock recovery	0.116	0.075	0.075	0.078
Feedstock upgrading	0.009	0.000	0.000	0.000
Land-use changes, cultivation	0.000	0.000	0.000	0.000
Fertilizer manufacture	0.000	0.000	0.000	0.000
Gas leaks and flares	0.004	0.000	0.000	0.000
CO_2, H_2S removed from NG	0.000	0.000	0.000	0.000
Emissions displaced	0.000	0.000	0.000	0.000
Total	4.459	2.035	2.285	2.142
% Change		-54	-49	-52

The engine exhaust emissions dominate the lifecycle NOx emissions. With the adjustment made to GHGenius for the NOx emissions for a Jenbacher engine, these emissions are lower than the diesel fuel. NOx emissions can be reduced with exhaust system controls.

The Shell supply system has higher NOx than the Fortis system due to the NOx emissions from electric power production in Alberta, where thermal generating systems dominate the grid.

The lifecycle SOx emissions are compared in the following table. For this contaminant the engine is not the major source. In all cases it is the fuel supply chain that has the higher emissions. The marine fuels are in the process of lowering their sulphur content and this will have an impact on these emissions for the diesel fuel system after 2015. The sulphur emissions from power production in Alberta are also a significant source of emissions.

Table ES- 3 Comparison of Lifecycle SOx Emissions

Stage	Diesel	Fortis LNG	Shell LNG	Dresser Rand
	SOx Emissions, g SOx/kWh			
Emissions from Operation	0.006	0.002	0.002	0.002
Fuel dispensing (liquefaction)	0.004	0.008	0.291	0.014
Fuel distribution and storage	0.022	0.042	0.051	0.015
Fuel production	0.284	0.012	0.013	0.012
Feedstock transmission	0.017	0.000	0.000	0.000
Feedstock recovery	0.057	0.002	0.003	0.003
Feedstock upgrading	0.007	0.000	0.000	0.000
Land-use changes, cultivation	0.000	0.000	0.000	0.000
Fertilizer manufacture	0.000	0.000	0.000	0.000
Gas leaks and flares	0.106	0.000	0.000	0.000
CO_2, H_2S removed from NG	0.000	0.035	0.035	0.035
Emissions displaced	0.000	0.000	0.000	0.000
Total	0.502	0.101	0.396	0.082
% Change		-80	-21	-84

The PM emissions are compared in the following table. The engine out emissions for the diesel engine is the largest source. These emissions can be addressed with exhaust emission control systems. The natural gas engines have very low PM emissions.

Table ES- 4 Comparison of Lifecycle PM Emissions

Stage	Diesel	Fortis LNG	Shell LNG	Dresser Rand
	PM Emissions, g PM/kWh			
Emissions from Operation	0.719	0.000	0.000	0.000
Fuel dispensing (liquefaction)	0.000	0.003	0.016	0.007
Fuel distribution and storage	0.017	0.005	0.005	0.002
Fuel production	0.033	0.001	0.001	0.001
Feedstock transmission	0.006	0.000	0.000	0.000
Feedstock recovery	0.015	0.001	0.001	0.001
Feedstock upgrading	0.000	0.000	0.000	0.000
Land-use changes, cultivation	0.000	0.000	0.000	0.000
Fertilizer manufacture	0.000	0.000	0.000	0.000
Gas leaks and flares	0.180	0.000	0.000	0.000
CO_2, H_2S removed from NG	0.000	0.000	0.000	0.000
Emissions displaced	0.000	0.000	0.000	0.000
Total	0.972	0.009	0.023	0.011
% Change		-99	-98	-99

The CO emissions are summarized in the following table. The CO emissions from diesel engines are relatively low. The CO emissions from the rest of the supply chains are also very low.

Table ES- 5 Comparison of Lifecycle CO Emissions

Stage	Diesel	Fortis LNG	Shell LNG	Dresser Rand
	CO Emissions, g CO/kWh			
Emissions from Operation	1.543	0.727	0.727	0.727
Fuel dispensing (liquefaction)	0.001	0.021	0.036	0.043
Fuel distribution and storage	0.049	0.022	0.020	0.007
Fuel production	0.047	0.014	0.015	0.015
Feedstock transmission	0.018	0.000	0.000	0.000
Feedstock recovery	0.117	0.030	0.030	0.031
Feedstock upgrading	0.001	0.000	0.000	0.000
Land-use changes, cultivation	0.000	0.000	0.000	0.000
Fertilizer manufacture	0.000	0.000	0.000	0.000
Gas leaks and flares	0.018	0.000	0.000	0.000
CO_2, H_2S removed from NG	0.000	0.000	0.000	0.000
Emissions displaced	0.000	0.000	0.000	0.000
Total	1.794	0.814	0.827	0.823
% Change		-55	-54	-54

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1. INTRODUCTION

Established in 1987, Yukon Energy is a publicly owned electrical utility that operates as a business, at arm's length from the Yukon government. They are the main generator and transmitter of electrical energy in Yukon and work with their parent company Yukon Development Corporation, to provide a sufficient supply of safe, reliable electricity and related energy services.

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Yukon energy is considering the replacement of some the diesel generators with either new diesel generators or natural gas engines fuelled by liquid natural gas (LNG). The LNG would be obtained from suppliers in British Columbia and/or Alberta.

The environmental attributes of the various supply options will play a role in the final decision of which option to pursue for new power supply.

1.1 LIFECYCLE ASSESSMENT

The concept of life cycle assessment (LCA) emerged in the late 1980's from competition among manufacturers attempting to persuade users about the superiority of one product choice over another. As more comparative studies were released with conflicting claims, it became evident that different approaches were being taken related to the key elements in the LCA analysis:

- Boundary conditions (the "reach" or "extent" of the product system);
- Data sources (actual vs. modeled); and
- Definition of the functional unit.

1.1.1 ISO 14040

In order to address these issues and to standardize LCA methodologies and streamline the international marketplace, the International Standards Organization (ISO) has developed a series of international LCA standards, specifications, and technical reports under its ISO 14000 Environmental Management series. In 1997-2000, ISO developed a set of four standards that established the principles and framework for LCA (ISO 14040:1997) and the requirements for the different phases of LCA (ISO 14041-14043). The main contribution of these ISO standards was the establishment of the LCA framework that involves the four phases in an iterative process:

- Phase 1 - Goal and Scope Definition;
- Phase 2 - Inventory Analysis;
- Phase 3 - Impact Assessment; and
- Phase 4 - Interpretation

By 2006, these LCA standards were consolidated and replaced by two current standards: one for LCA principles (ISO 14040:2006); and one for LCA requirements and guidelines (ISO 14044:2006). Additionally, ISO has published guidance documents and technical reports (ISO 14047-14049) to help illustrate good practice in applying LCA concepts.

The ISO 14040:2006 standard describes the principles and framework for life cycle assessment including: definition of the goal and scope of the LCA, the life cycle inventory analysis (LCI) phase, the life cycle impact assessment (LCIA) phase, the life cycle interpretation phase, reporting and critical review of the LCA, limitations of the LCA, the relationship between the LCA phases, and conditions for use of value choices and optional elements. ISO 14040:2006 covers life cycle assessment (LCA) studies and life cycle inventory (LCI) studies. It does not describe the LCA technique in detail, nor does it specify methodologies for the individual phases of the LCA. The intended application of LCA or LCI results is considered during definition of the goal and scope, but the application itself is outside the scope of this International Standard.

1.1.2 ISO Principles

It is useful to consider seven basic principles in the design and development of life cycle assessments as a measure of environmental performance. The seven principles outlined below are the basis of ISO Standard 14040:2006:

- Life Cycle Perspective (the entire stages of a product or service);
- Environmental Focus (addresses environmental aspects);
- Relative Approach and Functional Unit (analysis is relative to a functional unit);
- Iterative Approach (phased approach with continuous improvement)
- Transparency (clarity is key to properly interpret results)
- Comprehensiveness (considers all attributes and aspects)
- Priority of Scientific Approach (preference for scientific-based decisions)

1.2 GHGENIUS

The GHGenius model has been developed for Natural Resources Canada over the past thirteen years. GHGenius is capable of analyzing the energy balance and emissions of many contaminants associated with the production and use of traditional and alternative transportation fuels.

GHGenius is capable of estimating life cycle emissions of the primary greenhouse gases and the criteria pollutants from combustion sources. The specific gases that are included in the model include:

- Carbon dioxide (CO_2),
- Methane (CH_4),
- Nitrous oxide (N_2O),
- Chlorofluorocarbons (CFC-12),
- Hydro fluorocarbons (HFC-134a),
- The CO_2-equivalent of all of the contaminants above.
- Carbon monoxide (CO),
- Nitrogen oxides (NOx),
- Non-methane organic compounds (NMOCs), weighted by their ozone forming potential,
- Sulphur dioxide (SO_2),
- Total particulate matter.

The model is capable of analyzing the emissions from conventional and alternative fuelled internal combustion engines or fuel cells for light duty vehicles, for class 3-7 medium-duty trucks, for class 8 heavy-duty trucks, for urban buses and for a combination of buses and trucks, and for light duty battery powered electric vehicles. There are over 200 vehicle and fuel combinations possible with the model. The model is also capable of analyzing the emissions from electricity production from a wide variety of fuel and processes.

GHGenius can predict emissions for past, present and future years through to 2050 using historical data or correlations for changes in energy and process parameters with time that are stored in the model. The fuel cycle segments considered in the model are as follows:

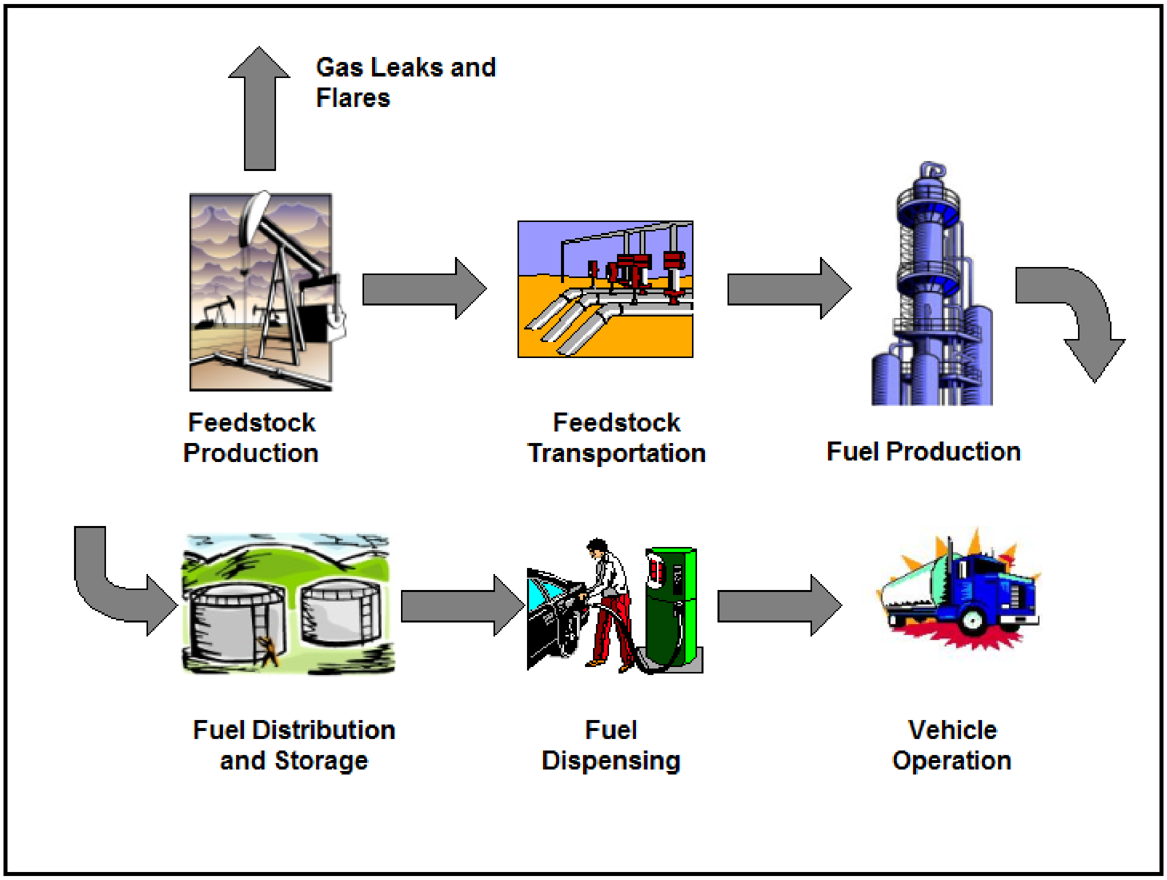
- Vehicle Operation
  Emissions associated with the use of the fuel in the vehicle. Includes all greenhouse gases.
- Fuel Dispensing at the Retail Level
  Emissions associated with the transfer of the fuel at a service station from storage into the vehicles. Includes electricity for pumping, fugitive emissions and spills. For the CNG and LNG pathways this stage includes the compression and liquefaction emissions.
- Fuel Storage and Distribution at all Stages
  Emissions associated with storage and handling of fuel products at terminals, bulk plants and service stations. Includes storage emissions, electricity for pumping, space heating, and lighting.
- Fuel Production (as in production from raw materials)
  Direct and indirect emissions associated with conversion of the feedstock into a saleable fuel product. Includes process emissions, combustion emissions for process heat/steam, electricity generation, fugitive emissions, and emissions from the life cycle of chemicals used for fuel production cycles.
- Feedstock Transport
  Direct and indirect emissions from transport of feedstock, including pumping, compression, leaks, fugitive emissions, and transportation from point of origin to the fuel refining plant. Import/export, transport distances, and the modes of transport are considered. Includes energy and emissions associated with the transportation infrastructure construction and maintenance (trucks, trains, ships, pipelines, etc.).
- Feedstock Production and Recovery
  Direct and indirect emissions from recovery and processing of the raw feedstock, including fugitive emissions from storage, handling, upstream processing prior to transmission, and mining.
- Feedstock Upgrading
  Direct and indirect emissions from the upgrading of bitumen to synthetic crude oil at a standalone facility, including fugitive emissions.
- Fertilizer Manufacture
  Direct and indirect life cycle emissions from fertilizers, and pesticides used for feedstock production, including raw material recovery, transport, and manufacturing of chemicals. This is not included if there is no fertilizer associated with the fuel pathway.
- Land use changes and cultivation associated with biomass derived fuels
  Emissions associated with the change in the land use in cultivation of crops, including N_2O from application of fertilizer, changes in soil carbon and biomass, methane emissions from soil and energy used for land cultivation.
- Carbon in Fuel from Air
  Carbon dioxide emissions credit arising from use of a renewable carbon source that obtains carbon from the air.
- Leaks and flaring of greenhouse gases associated with production of oil and gas

  Fugitive hydrocarbon emissions and flaring emissions associated with oil and gas production.

- Emissions displaced by co-products of alternative fuels
  Emissions displaced by co-products of various pathways. System expansion is used to determine displacement ratios for co-products from biomass pathways.
- Vehicle assembly and transport
  Emissions associated with the manufacture and transport of the vehicle to the point of sale, amortized over the life of the vehicle.
- Materials used in the vehicles
  Emissions from the manufacture of the materials used to manufacture the vehicle, amortized over the life of the vehicle. Includes lube oil production and losses from air conditioning systems.

The main lifecycle stages for crude oil based gasoline or diesel fuel are shown in the following figure.

Figure 1-1 Lifecycle Stages



There are no ISO standards for LCA models but GHGenius allows LCA practitioners to develop an LCA report that is compliant with the ISO LCA principles and requirements. The model has a full lifecycle perspective, it is comprehensive and fully transparent. It reports on the emissions of GHGs and CACs at every stage of the lifecycle. It allows relevant comparisons to be made between various alternatives using the same model and dataset and reported using a variety of functional units.

The GHGenius model is fully documented ((S&T)^2, 2013a and 2013b).

1.3 MODELLING FRAMEWORK

A modified version of GHGenius 4.03 has been used for this work. This version has updated emission factors for US natural gas production and it has the latest IPCC GWPs from the 5th Assessment report which can be used as an option. There are other minor updates in some other pathways that don't have an impact on this work.

The model has been set to 2014 and it uses the 100 year GWPs from the 4th Assessment Report. It has been assumed that carbon monoxide (CO) and non-methane hydrocarbon (NMHC) emissions are ultimately oxidized to CO_2 and the CO_2 emissions are calculated using the carbon weighted emissions of CO and NMOC. The GWP's are summarized in the following table.

Table 1-1 GWPs Used

Contaminant	GWP
CO_2	1
CH_4	25
N_2O	298
CFC-12	10,900
HFC-134a	1,430
SF_6	22,800
CO	1.57
NMOC	2.99

Some sensitivity analyses will be undertaken using alternative GWPs, including those from the 5th Assessment Report and some 20 year values.

Four power systems are compared in this report, a diesel fueled system and three LNG supply options. The diesel fuel system is based on new diesel generators and the existing diesel fuel supply system. Two of the LNG systems are similar, both are primarily electric drive systems but one (Fortis) is located in BC and the other (Shell) is located in Alberta, the third system is a gas fired (Horn River) system processing shale gas.

2. DIESEL FUEL

The diesel fuel used in the Yukon is refined in Washington State and shipped to Skagway, Alaska and then trucked to Whitehorse. The specific modelling parameters for this pathway are presented below.

2.1 DIESEL FUEL PRODUCTION AND DISTRIBUTION

The GHGenius model has been set to the US West region. This selects the crude oil slate used in the US PADD's 4 and 5, which includes Washington State. The crude oil that is refined is a combination of Alaska North Slope oil, oil from Western Canada and offshore imports.

The refinery energy use is specific to the region and the crude oils refined and is from the US Energy Information Administration. Other than selecting the year and region, the only changes that must be made to the model are the modes and distances for the transportation of the refined petroleum products. These are shown in the following table (U.S. Department of Commerce, 2012 and Google Maps).

Table 2-1 Transportation of Refined Petroleum Products

Mode	Distance, kilometres
Marine Vessel	1,735
Truck	354

2.2 POWER PRODUCTION

The electric power production will be produced from a Caterpillar diesel engine. It has reported electric efficiency of 41.6%. This input is a key driver of the lifecycle emissions for power production. Caterpillar (2014) reports their power production efficiency using the lower heating value of the fuel. GHGenius uses higher heating values so the efficiency used for modelling is 39.5% on a higher heating value basis.

The in service exhaust emissions are not available from Caterpillar. GHGenius use emissions from the US EPA Nonroad model for large diesel engines for the emissions from the use stage.

2.3 EMISSIONS

The lifecycle emissions for both the GHG emissions and the CAC emissions are reported and discussed below.

2.3.1 GHG Emissions

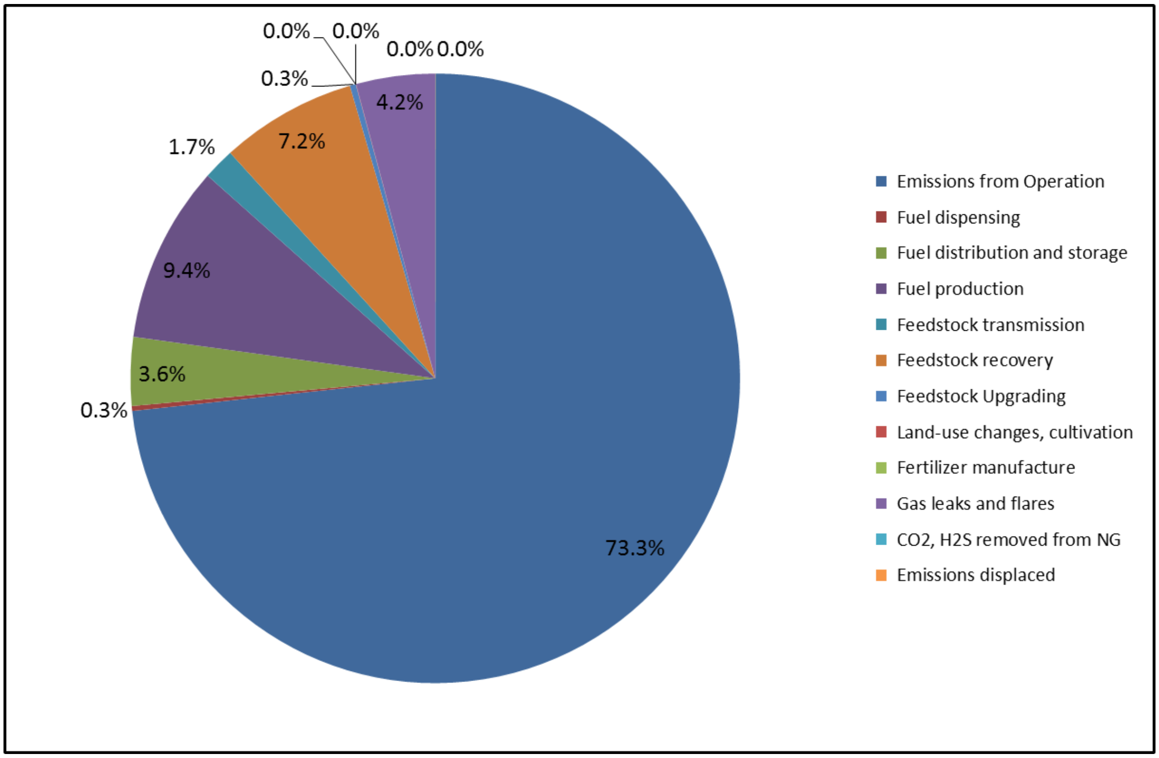
The GHG emissions for each stage of the lifecycle are shown in the following table.

Table 2-2 Diesel Power GHG Emissions

Stage	GHG Emissions, g CO_2eq/kWh
Emissions from Operation	701
Fuel dispensing	2
Fuel distribution and storage	35
Fuel production	90
Feedstock transmission	16
Feedstock recovery	69
Feedstock upgrading	3
Land-use changes, cultivation	0
Fertilizer manufacture	0
Gas leaks and flares	40
CO_2, H_2S removed from NG	0
Emissions displaced	0
Total	957

Over 73% of the lifecycle GHG emissions are from the fuel use stage. The distribution of the emissions by stage is shown in the following figure.

Figure 2-1 Distribution of the GHG Emissions by Stage



2.3.2 CAC Emissions

The CAC emissions for the primary contaminants of interest are shown in the following table. The NOx, SOx, and CO emissions are dominated by the emissions from operation; however the SOx emissions are dominated by the oil production, refining, and fuel transportation stages.

Table 2-3 Diesel Power CAC Emissions

Stage	NOx	SOx	PM	CO
	g/kWh			
Emissions from Operation	3.646	0.006	0.719	1.543
Fuel dispensing	0.003	0.004	0.000	0.001
Fuel distribution and storage	0.390	0.022	0.017	0.049
Fuel production	0.148	0.284	0.033	0.047
Feedstock transmission	0.142	0.017	0.006	0.018
Feedstock recovery	0.116	0.057	0.015	0.117
Feedstock upgrading	0.009	0.007	0.000	0.001
Land-use changes, cultivation	0.000	0.000	0.000	0.000
Fertilizer manufacture	0.000	0.000	0.000	0.000
Gas leaks and flares	0.004	0.106	0.180	0.018
CO_2, H_2S removed from NG	0.000	0.000	0.000	0.000
Emissions displaced	0.000	0.000	0.000	0.000
Total	4.459	0.502	0.972	1.794

3. FORTIS LNG

One of the LNG supply options that is being considered if from the Fortis BC LNG facility at Tilbury Island in Delta, BC. This is an electric drive peak shaving plant that constructed in the early 1970's. It is also now being used to supply LNG for transportation and other applications. Fortis has plans to increase the size of the facility.

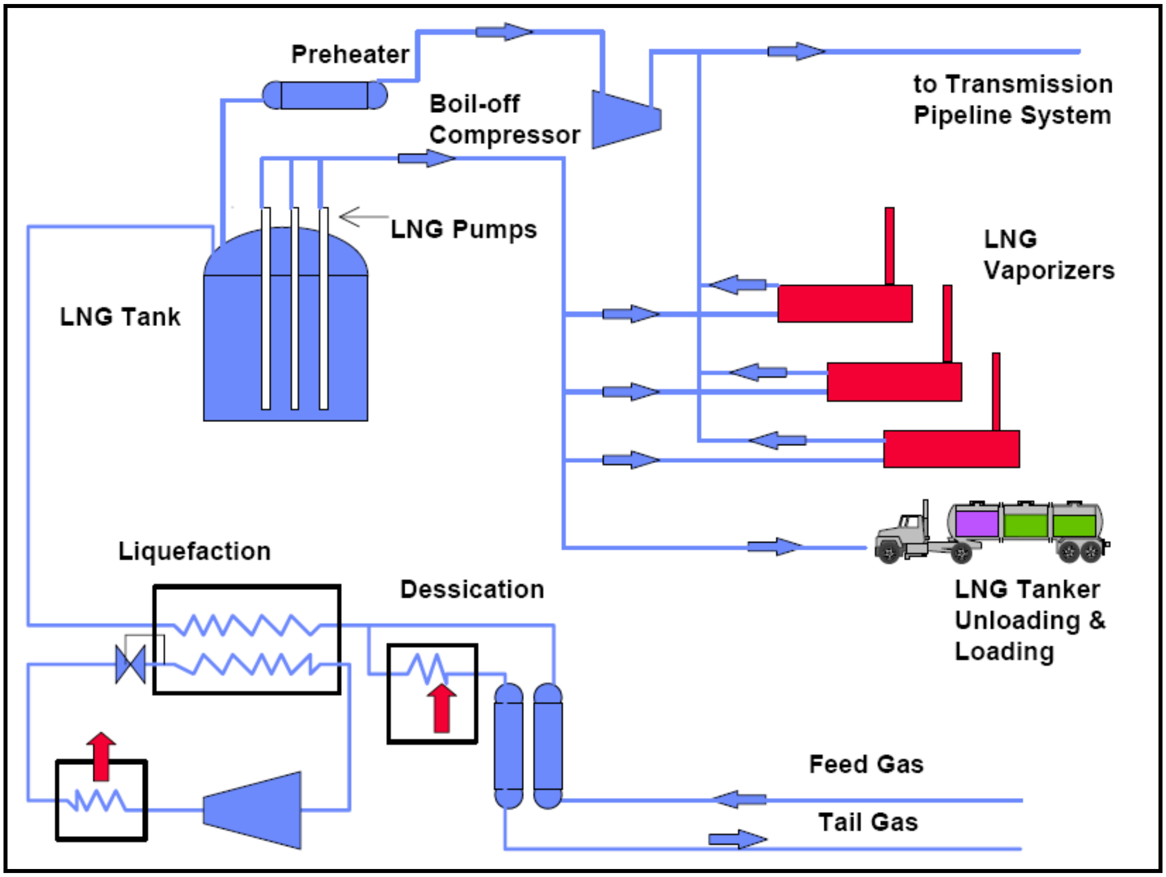
3.1 LNG SUPPLY AND DISTRIBUTION

Fortis operate two LNG peak shaving facilities, one in Delta (Tilbury) and one at Mt. Hayes on Vancouver Island. Peak shavings facilities both liquefy and re-gasify the natural gas. For LNG applications the vaporization is not required since the LNG leaves the facility as a cryogenic liquid and not as a gas in the pipeline system.

Tilbury has operated since 1971 and can liquefy 120,000 cubic metres (4,500 GJ) of natural gas per day. The Mt. Hayes facility is new and can liquefy 8,100 GJ/day.

Both facilities use electricity to drive the LNG process. The process schematic is shown in the following figure.

Figure 3-1 Peak Shaving Process



The energy requirements for both facilities are 0.5 kWh/kg of LNG (Terasen, 2007, Fortis, 2012). In GHGenius this is entered into the model as joules consumed per joule delivered. The equivalent value is 0.039 joules of power per joule of LNG.

At the Fortis facility boil-off gas from the transfer of LNG from the main storage tank to the tanker is captured and re-used as feed gas or enters the gas distribution system. Losses are non-existent. We have also assumed that boil off gas at the Whitehorse facility would follow best practices and be utilized to supply natural gas for the engines or other applications.

We have also assumed that waste heat from the engines could be used to supply the vaporization energy at the Whitehorse facility.

The transportation distance from Tilbury to Whitehorse is between 2,400 and 2,550 km, depending on the route taken. We have assumed the conservative value of 2,550 km for modelling.

3.2 POWER PRODUCTION

The natural gas will be used in a Jenbacher gas fired engine-generator set. The reported efficiency is 46.3% but this is based on the lower heating value of the natural gas. The equivalent efficiency on a higher heating value basis is 40.4%.

The in service exhaust emissions are not available from Jenbacher. GHGenius uses the emissions for a large natural gas engine from the EPA Nonroad model. These engines are characterized by relatively large "methane slip". Jenbacher states that up to 2.5% of the methane entering the engine may be present in the exhaust emissions but the Nonroad emission model uses a methane slip factor of approximately 2.8%.

The Jenbacher engines are promoted as low NOx engines. Kristensen et al of the Danish Gas Technology Centre undertook emission tests on new gas fired engines used in combined heat and power plants. The Jenbacher engines had lower NOx emissions than used in GHGenius. For this work we have reduced the NOx emission factor for gas fired engines from 640 g NOx/GJ to 200 g/GJ by accelerating the rate of emission reduction in the model.

3.3 EMISSIONS

The model is set to the BC region for this modelling. This sets the power used in the liquefaction process to the BC grid.

3.3.1 GHG Emissions

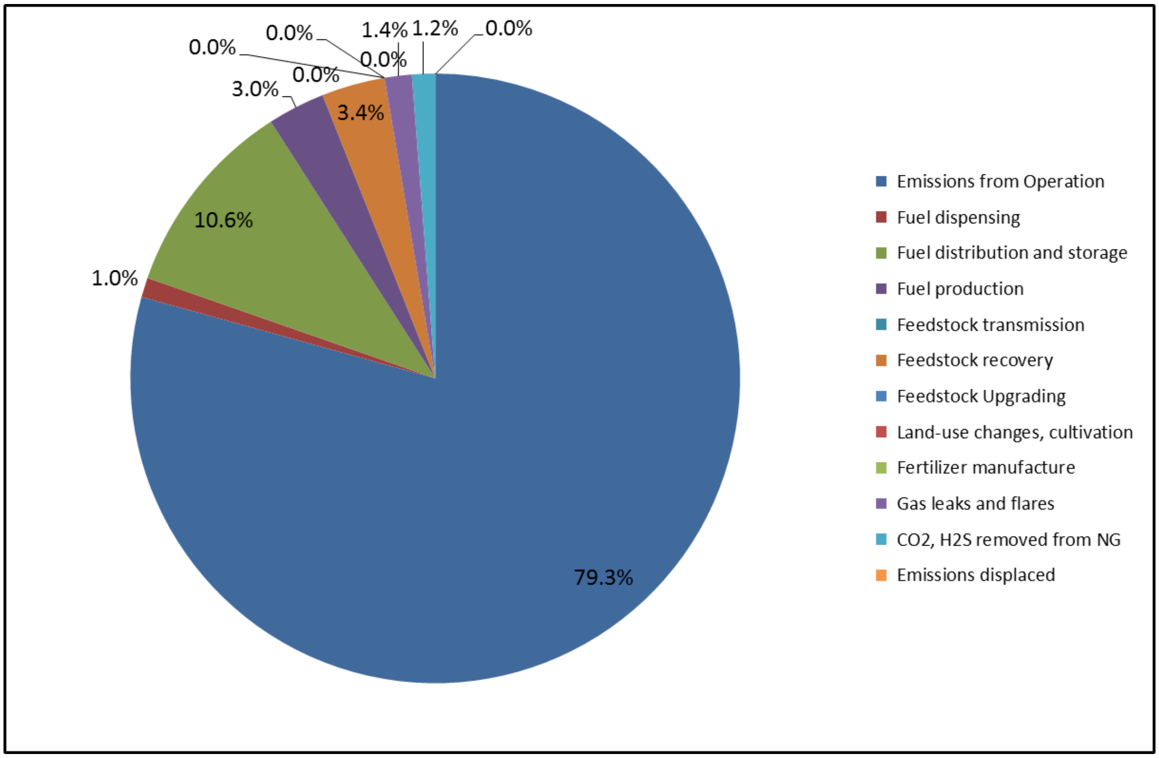
The GHG emissions for each stage of the lifecycle are shown in the following table.

Table 3-1 Fortis LNG Power GHG Emissions

Stage	GHG Emissions, g CO_2eq/kWh
Emissions from Operation	561
Fuel dispensing (liquefaction)	7
Fuel distribution and storage	75
Fuel production	22
Feedstock transmission	0
Feedstock recovery	24
Feedstock upgrading	0
Land-use changes, cultivation	0
Fertilizer manufacture	0
Gas leaks and flares	10
CO_2, H_2S removed from NG	9
Emissions displaced	0
Total	708

Almost 80% of the lifecycle GHG emissions are from the fuel use stage. The distribution of the emissions by stage is shown in the following figure.

Figure 3-2 Distribution of the GHG Emissions by Stage



3.3.2 CAC Emissions

The CAC emissions for the primary contaminants of interest are shown in the following table. The NOx and CO emissions are dominated by the emissions from operation; however the

SOx emissions are dominated by the oil production, refining, and fuel transportation stages. The PM emissions are very low.

Table 3-2 Fortis LNG Power CAC Emissions

Stage	NOx	SOx	PM	CO
	g/kWh			
Emissions from Operation	1.844	0.002	0.000	0.727
Fuel dispensing (liquefaction)	0.012	0.008	0.003	0.021
Fuel distribution and storage	0.057	0.042	0.005	0.022
Fuel production	0.046	0.012	0.001	0.014
Feedstock transmission	0.000	0.000	0.000	0.000
Feedstock recovery	0.075	0.002	0.001	0.030
Feedstock upgrading	0.000	0.000	0.000	0.000
Land-use changes, cultivation	0.000	0.000	0.000	0.000
Fertilizer manufacture	0.000	0.000	0.000	0.000
Gas leaks and flares	0.000	0.000	0.000	0.000
CO_2, H_2S removed from NG	0.000	0.035	0.000	0.000
Emissions displaced	0.000	0.000	0.000	0.000
Total	2.035	0.101	0.009	0.814

4. SHELL LNG

Shell is building a “Moveable Modular Liquefaction System” at their Jumping Pound gas processing plant in Cochrane Alberta. This system is mostly driven by grid electric power but some natural gas is used for systems that need heat.

4.1 LNG SUPPLY AND DISTRIBUTION

The assumptions for the energy requirements will be that 90% of the energy is supplied by electricity and 10% by natural gas. The total energy requirement will be assumed to be 10% higher than the Fortis plant due to its small size. The other assumptions remain the same as the Fortis system.

The transportation distance from the Shell plant to Whitehorse is 2,230 km (Google Maps).

4.2 POWER PRODUCTION

The modelling of the power plant is the same as it was for the Fortis case.

4.3 EMISSIONS

The model is set to the Alberta region for this modelling. This sets the power used in the liquefaction process to the Alberta grid.

4.3.1 GHG Emissions

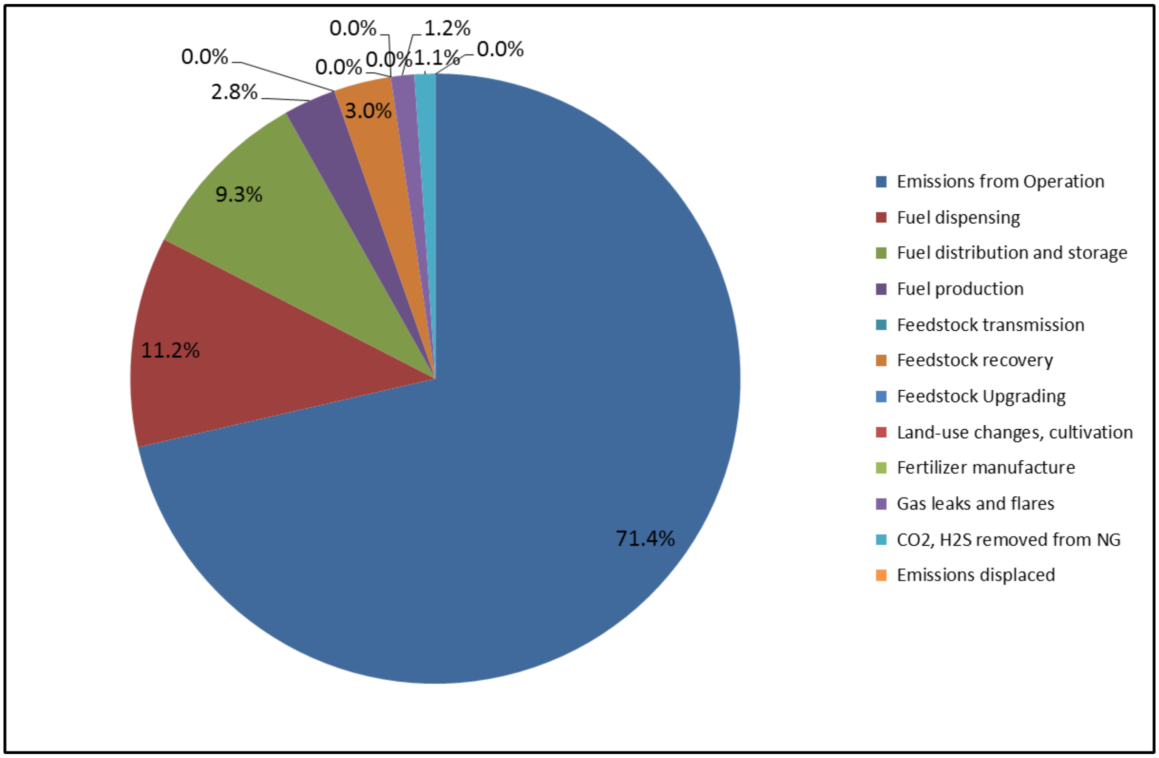
The GHG emissions for each stage of the lifecycle are shown in the following table.

Table 4-1 Shell LNG Power GHG Emissions

Stage	GHG Emissions, g CO_2eq/kWh
Emissions from Operation	561
Fuel dispensing (liquefaction)	88
Fuel distribution and storage	73
Fuel production	22
Feedstock transmission	0
Feedstock recovery	24
Feedstock upgrading	0
Land-use changes, cultivation	0
Fertilizer manufacture	0
Gas leaks and flares	10
CO_2, H_2S removed from NG	9
Emissions displaced	0
Total	786

In this case just over 70% of the lifecycle GHG emissions are from the fuel use stage. The distribution of the emissions by stage is shown in the following figure.

Figure 4-1 Distribution of the GHG Emissions by Stage



4.3.2 CAC Emissions

The CAC emissions for the primary contaminants of interest are shown in the following table. The NOx, and CO emissions are dominated by the emissions from operation; however the SOx emissions are dominated by the emissions from the power plants used to produce the electricity for liquefaction. The PM emissions are very low.

Table 4-2 Shell LNG Power CAC Emissions

Stage	NOx	SOx	PM	CO
	g/kWh			
Emissions from Operation	1.844	0.002	0.000	0.727
Fuel dispensing (liquefaction)	0.259	0.291	0.016	0.036
Fuel distribution and storage	0.059	0.051	0.005	0.020
Fuel production	0.047	0.013	0.001	0.015
Feedstock transmission	0.000	0.000	0.000	0.000
Feedstock recovery	0.075	0.003	0.001	0.030
Feedstock upgrading	0.000	0.000	0.000	0.000
Land-use changes, cultivation	0.000	0.000	0.000	0.000
Fertilizer manufacture	0.000	0.000	0.000	0.000
Gas leaks and flares	0.000	0.000	0.000	0.000
CO_2, H_2S removed from NG	0.000	0.035	0.000	0.000
Emissions displaced	0.000	0.000	0.000	0.000
Total	2.285	0.396	0.023	0.827

5. HORN RIVER LNG

The third option investigated is located closer to Whitehorse and uses a natural gas fired system rather than primarily an electrical drive system.

5.1 GAS SUPPLY

The Horn River Basin is a large-scale, commercial shale gas operation. It is located in the Fort Nelson area of British Columbia. The National Energy Board (2011) estimates that the basin contains 78 TCF of marketable natural gas. One of the characteristics of this field is that it has a relatively high CO_2 content of 12% (National Energy Board, 2009). This gas must be stripped from the natural gas before it can be moved through the pipeline system or before it can be converted to LNG.

To model this source of gas in GHGenius three changes from the default values are required on the Natural Gas supply sheet and one on the Input sheet. The changes are summarized in the following table.

Table 5-1 Modelling Horn River Gas

Sheet	Cell	Old Value	New Value	Comment
Nat Gas	F202	6.5	12.0	Horn River CO_2 level
Nat Gas	AR192	0.0	1.0	Shale gas
Nat Gas	AS186	By Year	User Input	To model just Shale gas
Input	B72	1200	100	Gas transportation distance by pipeline

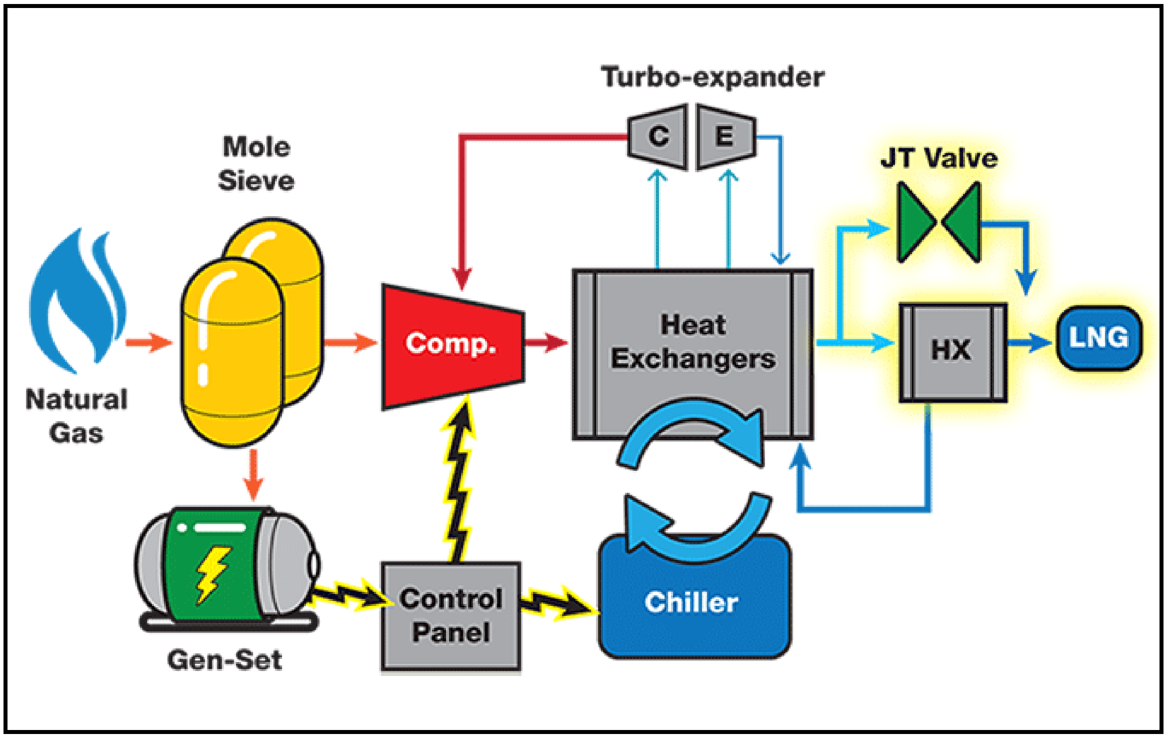
The selection of shale gas has relatively little impact on the results but the CO_2 content does increase the emissions and these are partially offset by a reduction in the natural gas transmission emissions.

5.2 LNG SUPPLY AND DISTRIBUTION

Dresser Rand is developing a modularized, portable natural gas liquefaction plant capable of producing 6,000 gallons of LNG per day. This point-of-use production plant is a standardized product made up of four packaged skids: a power module, compressor module, process module and a conditioning module. The natural gas consumed powers the unit and is also used as the process refrigerant to eliminate complexity and maintenance.

The process schematic is shown in the following figure.

Figure 5-1 Dresser Rand LNG System



Twenty one percent of the natural gas that enters the system is consumed by the system. Thus to produce one unit of LNG requires 0.266 units of natural gas. This is a relatively low efficiency.

The transportation distance from Fort Nelson to Whitehorse is 950 km (Google Maps). All of the other modelling parameters remain the same as the other cases.

5.3 EMISSIONS

The model is set to BC for this scenario, but since there is little electricity consumed in the pathway, the region will not have a large impact.

5.3.1 GHG Emissions

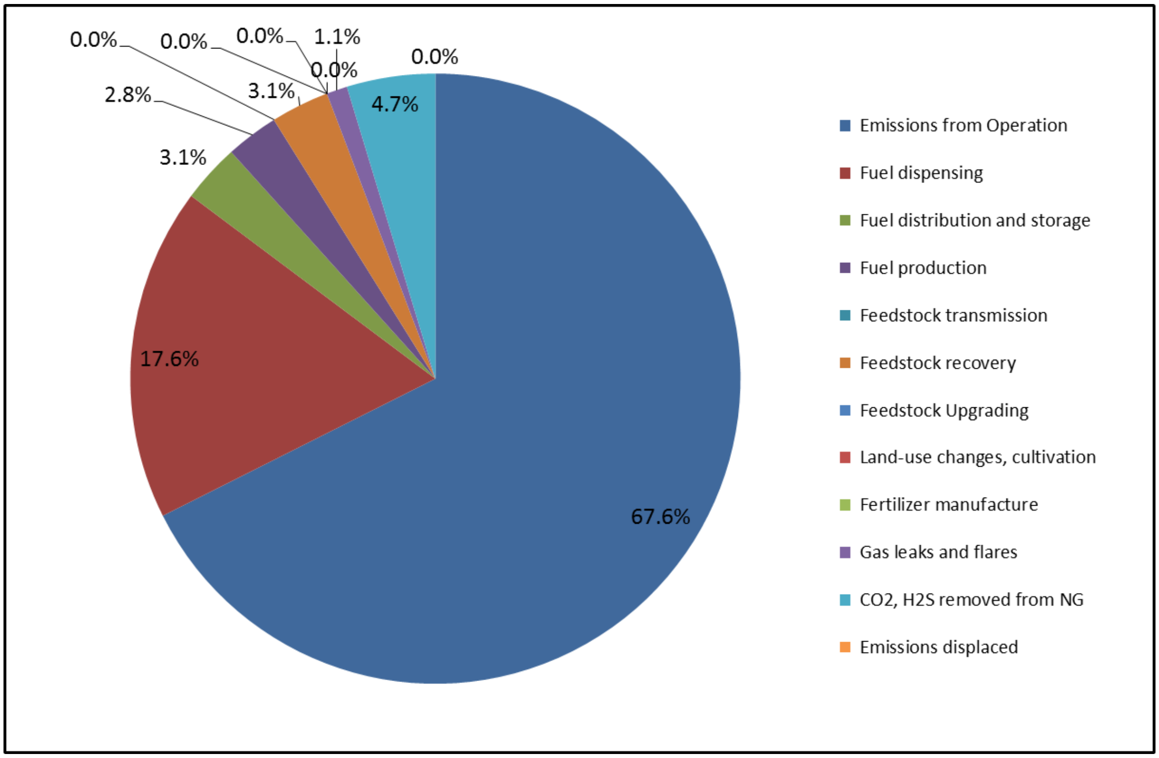
The GHG emissions for each stage of the lifecycle are shown in the following table.

Table 5-2 Dresser Rand LNG Power GHG Emissions

Stage	GHG Emissions, g CO_2eq/kWh
Emissions from Operation	561
Fuel dispensing (liquefaction)	147
Fuel distribution and storage	26
Fuel production	23
Feedstock transmission	0
Feedstock recovery	26
Feedstock upgrading	0
Land-use changes, cultivation	0
Fertilizer manufacture	0
Gas leaks and flares	9
CO_2, H_2S removed from NG	39
Emissions displaced	0
Total	831

In this case just over 67% of the lifecycle GHG emissions are from the fuel use stage. The distribution of the emissions by stage is shown in the following figure.

Figure 5-2 Distribution of the GHG Emissions by Stage



5.3.2 CAC Emissions

The CAC emissions for the primary contaminants of interest are shown in the following table. The NOx, and CO emissions are dominated by the emissions from operation; however the

SOx emissions are dominated by the emissions from the power plants used to produce the electricity for liquefaction. The PM emissions are very low.

Table 5-3 Dresser Rand LNG Power CAC Emissions

Stage	NOx	SOx	PM	CO
	g/kWh			
Emissions from Operation	1.844	0.002	0.000	0.727
Fuel dispensing (liquefaction)	0.155	0.014	0.007	0.043
Fuel distribution and storage	0.018	0.015	0.002	0.007
Fuel production	0.048	0.012	0.001	0.015
Feedstock transmission	0.000	0.000	0.000	0.000
Feedstock recovery	0.078	0.003	0.001	0.031
Feedstock upgrading	0.000	0.000	0.000	0.000
Land-use changes, cultivation	0.000	0.000	0.000	0.000
Fertilizer manufacture	0.000	0.000	0.000	0.000
Gas leaks and flares	0.000	0.000	0.000	0.000
CO_2, H_2S removed from NG	0.000	0.035	0.000	0.000
Emissions displaced	0.000	0.000	0.000	0.000
Total	2.142	0.082	0.011	0.823

6. COMPARISON OF OPTIONS

The lifecycle emissions for each of the four pathways considered have been reported. In this section the results are compared and discussed. Some sensitivity of the results to a few parameters is investigated.

6.1 GHG EMISSIONS

The GHG emissions for each of the four pathways are shown in the following table.

Table 6-1 Comparison of GHG Emissions

Stage	Diesel	Fortis LNG	Shell LNG	Dresser Rand
	GHG Emissions, g CO_2eq/kWh			
Emissions from Operation	701	561	561	561
Fuel dispensing (liquefaction)	2	7	88	147
Fuel distribution and storage	35	75	73	26
Fuel production	90	22	22	23
Feedstock transmission	16	0	0	0
Feedstock recovery	69	24	24	26
Feedstock upgrading	3	0	0	0
Land-use changes, cultivation	0	0	0	0
Fertilizer manufacture	0	0	0	0
Gas leaks and flares	40	10	10	9
CO_2, H_2S removed from NG	0	9	9	39
Emissions displaced	0	0	0	0
Total	957	708	786	831
% Change		-26	-18	-13

All of the LNG systems offer GHG emissions reductions compared to the diesel system. The lower carbon content of natural gas is single largest contributing factor. The low emission pathway is the Fortis system. This system benefits from the low carbon intensity of the BC power grid. There is only about a 10% difference in the transportation distance between Whitehorse and Vancouver or Calgary, so this has a minor impact on the lifecycle emissions.

The Dresser Rand LNG system has the highest emissions of the LNG system due to the high CO_2 content of the natural gas (39 vs. 9 g/kWh) and the fact that natural gas is used to drive the LNG process.

6.1.1 Sensitivity to Variables

The primary variable that impacts the two LNG results is the carbon intensity of the electric grids. The BC grid is one of the lowest carbon intensity grids in Canada and the Alberta grid is one of the highest, so the results already bracket the expected range for this technology.

The GWPs of the various gases are regularly reviewed and updated by the IPCC. The latest review (5^{th} Assessment Report) was released in October 2013. The 5^{th} Assessment report deviated from the earlier reports in that it provided two values for each gas, one with climate carbon feedback and one without. Feedback increases the GWPs for three of the five non CO_2 gases.

Table 6-2 GWP Factors – 100 Year 5th Assessment Report

	Without Feedback	With Feedback
Year	2013	2013
CO_2	1	1
CH_4	28	34
N_2O	265	298
CFC-12	10,200	10,200
HFC-134a	1,300	1,550
SF_6	23,500	23,500

It is not yet clear if the scientific community will move to the 5th Assessment report values without feedback (to be consistent with the earlier reports) or adopt the values that include the feedback mechanisms. Both options are in the GHGenius model.

There have been a number of reports produced that used the 20 year GWP factors. There is no scientific argument for selecting 100 years compared with other choices, the choice of time horizon is a value judgement since it depends on the relative weight assigned to effects at different times. Gases with an atmospheric lifetime of less than 100 years will have higher 20 year GWPs. The gas with the largest change between the 100 year and 20 year time horizon is methane. Twenty year GWPs were first presented in the 3rd Assessment report as shown below.

Table 6-3 GWP Factors – 20 Year

	2nd Assessment Report	3rd Assessment Report	4th Assessment Report
Year	1995	2001	2007
CO_2	Not presented	1	1
CH_4	Not presented	62	72
N_2O	Not presented	275	289
CFC-12	Not presented	10,200	11,000
HFC-134a	Not presented	3,300	3,830
SF_6	Not presented	15,100	16,300

The 5th Assessment report twenty year values are shown in the following table.

Table 6-4 GWP Factors – 20 Year 5th Assessment Report

	Without Feedback	With Feedback
Year	2013	2013
CO_2	1	1
CH_4	84	86
N_2O	264	268
CFC-12	10,800	10,800
HFC-134a	3,710	3,790
SF_6	17,500	17,500

The importance of methane as a source of climate change has increased with the latest assessment report. This is particularly important when the 20 year time frame is selected.

In the following table the GHG emissions using the 5th Assessment report with feedback are shown.

Table 6-5 Comparison of GHG Emissions – 5th Assessment Report

Stage	Diesel	Fortis LNG	Shell LNG	Dresser Rand
	GHG Emissions, g CO_2eq/kWh			
Emissions from Operation	702	605	605	605
Fuel dispensing (liquefaction)	3	8	88	149
Fuel distribution and storage	35	76	74	26
Fuel production	92	22	23	24
Feedstock transmission	16	0	0	0
Feedstock recovery	70	26	26	28
Feedstock upgrading	3	0	0	0
Land-use changes, cultivation	0	0	0	0
Fertilizer manufacture	0	0	0	0
Gas leaks and flares	52	14	13	12
CO_2, H_2S removed from NG	0	9	9	39
Emissions displaced	0	0	0	0
Total	974	760	838	883
% Change		-22	-14	-9

The emission reduction with the LNG fuel is slightly lower with the new GWPs but still significant. The Fortis supply chain is still the low GHG option.

The next table uses the 20 year GWPs from the 5th Assessment report with feedback.

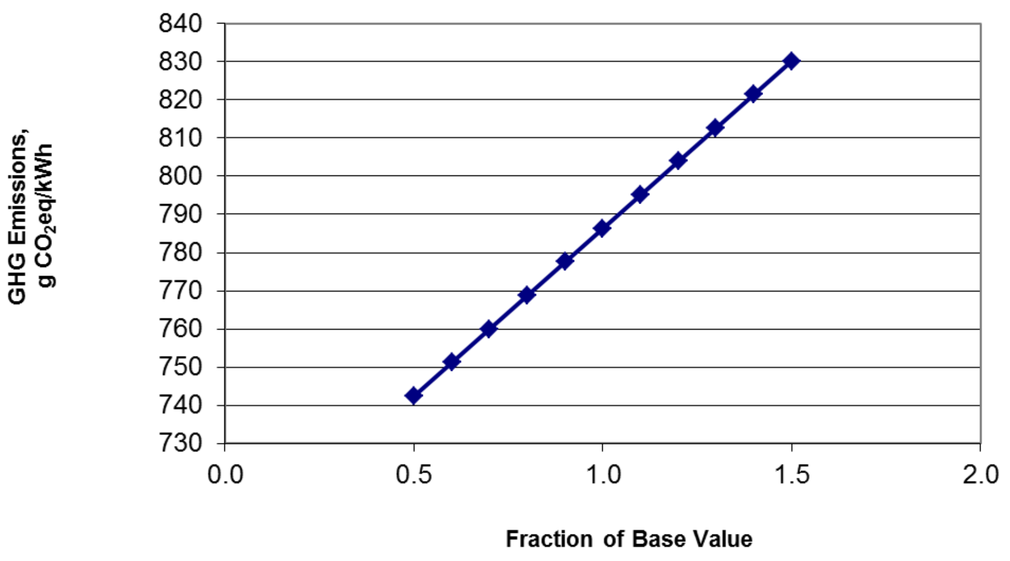
Table 6-6 Comparison of GHG Emissions – 5th Assessment Report 20 Year GWP

Stage	Diesel	Fortis LNG	Shell LNG	Dresser Rand
	GHG Emissions, g CO_2eq/kWh			
Emissions from Operation	696	858	858	858
Fuel dispensing (liquefaction)	3	12	91	161
Fuel distribution and storage	39	82	79	28
Fuel production	106	27	27	29
Feedstock transmission	18	0	0	0
Feedstock recovery	78	36	36	38
Feedstock upgrading	4	0	0	0
Land-use changes, cultivation	0	0	0	0
Fertilizer manufacture	0	0	0	0
Gas leaks and flares	123	35	34	31
CO_2, H_2S removed from NG	0	9	9	39
Emissions displaced	0	0	0	0
Total	1,066	1,059	1,133	1,183
% Change		-0.6	+6.3	+11

The natural gas GHG benefits disappear with the latest 20 year GWPs. Using this metric the Fortis supply chain is essentially equal to diesel fuel and the Shell and Dresser Rand supply chains have higher GHG emissions.

The Shell system is not yet in operation and thus there is some uncertainty with respect to the energy requirements of this system. The GHG emissions as a function of the energy requirements for this system are shown in the following figure. A range of +/- 50% has been used for illustration. Even with 50% more energy use in liquefaction, the supply chain would still have lower GHG emissions than the diesel supply chain.

Figure 6-1 Impact of Energy Use on Shell Supply Chain GHG Emissions



6.2 CAC EMISSIONS

The fuel use stage has a significant impact on most of the gases and the quality of data available on these emissions could be better. The CAC emissions from the engines are estimates based on literature and not on information from these specific engines. Care must therefore be taken when interpreting the CAC emissions for the three supply chain options. In a few cases the differences are large enough that conclusions can be drawn but in other cases, the engine specific information could be significantly different than used here in the modelling.

The comparison of the NOx emissions is shown in the following table.

Table 6-7 Comparison of Lifecycle NOx Emissions

Stage	Diesel	Fortis LNG	Shell LNG	Dresser Rand
	NOx Emissions, g NOx/kWh			
Emissions from Operation	3.646	1.844	1.844	1.844
Fuel dispensing (liquefaction)	0.003	0.012	0.259	0.155
Fuel distribution and storage	0.390	0.057	0.059	0.018
Fuel production	0.148	0.046	0.047	0.048
Feedstock transmission	0.142	0.000	0.000	0.000
Feedstock recovery	0.116	0.075	0.075	0.078
Feedstock upgrading	0.009	0.000	0.000	0.000
Land-use changes, cultivation	0.000	0.000	0.000	0.000
Fertilizer manufacture	0.000	0.000	0.000	0.000
Gas leaks and flares	0.004	0.000	0.000	0.000
CO_2, H_2S removed from NG	0.000	0.000	0.000	0.000
Emissions displaced	0.000	0.000	0.000	0.000
Total	4.459	2.035	2.285	2.142
% Change		-54	-49	-52

The engine exhaust emissions dominate the lifecycle NOx emissions. With the adjustment made to GHGenius for the NOx emissions for a Jenbacher engine, these emissions are lower than the diesel fuel. NOx emissions can be reduced with exhaust system controls.

The Shell supply system has higher NOx than the Fortis system due to the NOx emissions from electric power production in Alberta, where thermal generating systems dominate the grid.

The lifecycle SOx emissions are compared in the following table. For this contaminant the engine is not the major source. In all cases it is the fuel supply chain that has the higher emissions. The marine fuels are in the process of lowering their sulphur content and this will have an impact on these emissions for the diesel fuel system after 2015. The sulphur emissions from power production in Alberta are also a significant source of emissions.

Table 6-8 Comparison of Lifecycle SOx Emissions

Stage	Diesel	Fortis LNG	Shell LNG	Dresser Rand
	SOx Emissions, g SOx/kWh			
Emissions from Operation	0.006	0.002	0.002	0.002
Fuel dispensing (liquefaction)	0.004	0.008	0.291	0.014
Fuel distribution and storage	0.022	0.042	0.051	0.015
Fuel production	0.284	0.012	0.013	0.012
Feedstock transmission	0.017	0.000	0.000	0.000
Feedstock recovery	0.057	0.002	0.003	0.003
Feedstock upgrading	0.007	0.000	0.000	0.000
Land-use changes, cultivation	0.000	0.000	0.000	0.000
Fertilizer manufacture	0.000	0.000	0.000	0.000
Gas leaks and flares	0.106	0.000	0.000	0.000
CO_2, H_2S removed from NG	0.000	0.035	0.035	0.035
Emissions displaced	0.000	0.000	0.000	0.000
Total	0.502	0.101	0.396	0.082
% Change		-80	-21	-84

The PM emissions are compared in the following table. The engine out emissions for the diesel engine is the largest source. These emissions can be addressed with exhaust emission control systems. The natural gas engines have very low PM emissions.

Table 6-9 Comparison of Lifecycle PM Emissions

Stage	Diesel	Fortis LNG	Shell LNG	Dresser Rand
	PM Emissions, g PM/kWh			
Emissions from Operation	0.719	0.000	0.000	0.000
Fuel dispensing (liquefaction)	0.000	0.003	0.016	0.007
Fuel distribution and storage	0.017	0.005	0.005	0.002
Fuel production	0.033	0.001	0.001	0.001
Feedstock transmission	0.006	0.000	0.000	0.000
Feedstock recovery	0.015	0.001	0.001	0.001
Feedstock upgrading	0.000	0.000	0.000	0.000
Land-use changes, cultivation	0.000	0.000	0.000	0.000
Fertilizer manufacture	0.000	0.000	0.000	0.000
Gas leaks and flares	0.180	0.000	0.000	0.000
CO_2, H_2S removed from NG	0.000	0.000	0.000	0.000
Emissions displaced	0.000	0.000	0.000	0.000
Total	0.972	0.009	0.023	0.011
% Change		-99	-98	-99

The CO emissions are summarized in the following table. The CO emissions from diesel engines are relatively low. The CO emissions from the rest of the supply chains are also very low.

Table 6-10 Comparison of Lifecycle CO Emissions

Stage	Diesel	Fortis LNG	Shell LNG	Dresser Rand
	CO Emissions, g CO/kWh			
Emissions from Operation	1.543	0.727	0.727	0.727
Fuel dispensing (liquefaction)	0.001	0.021	0.036	0.043
Fuel distribution and storage	0.049	0.022	0.020	0.007
Fuel production	0.047	0.014	0.015	0.015
Feedstock transmission	0.018	0.000	0.000	0.000
Feedstock recovery	0.117	0.030	0.030	0.031
Feedstock upgrading	0.001	0.000	0.000	0.000
Land-use changes, cultivation	0.000	0.000	0.000	0.000
Fertilizer manufacture	0.000	0.000	0.000	0.000
Gas leaks and flares	0.018	0.000	0.000	0.000
CO_2, H_2S removed from NG	0.000	0.000	0.000	0.000
Emissions displaced	0.000	0.000	0.000	0.000
Total	1.794	0.814	0.827	0.823
% Change		-55	-54	-54

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