SHALE GAS UPDATE FOR GHGENIUS

Prepared For:

Natural Resources Canada
Office of Energy Efficiency
580 Booth Street
Ottawa, Ontario
K1A 0E4

Prepared By

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

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EXECUTIVE SUMMARY

The GHGenius model has been developed for Natural Resources Canada over the past eleven 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.

In 2010, GHGenius was updated to include unconventional natural gas sources as part of the model. One of the new sources that was added to the model was shale gas. Since that time, the interest in the GHG emissions of shale gas has continued to increase, as the potential of the resource becomes better understood across North America. In the 2010 report, it was found that very little information was available concerning the emissions of the well drilling, “hydraulic fracturing”, and production stages of a shale gas well.

New information has been supplied to Natural Resources Canada by the Canadian Association of Petroleum Producers (CAPP) on the energy and materials consumed during the well drilling, hydraulic fracturing, and production stages. Additional information has recently been released by the US EPA, although that was focussed on updating their National Inventory Report and not on LCA work.

This work has reviewed the data supplied, compared the results between companies and reached some conclusions with respect to the data that has been made available.

To properly model shale gas the structure of the natural gas sheet in GHGenius needed to be changed to have more emphasis on the well drilling emissions. This new structure has been developed and integrated into the model.

The revised model has been used to compare the GHG emissions for shale gas with other types of gas in the model. The upstream emissions are presented in the following table.

Table ES- 1 Comparison of Upstream GHG Emissions

	Solution	Non Associated	Tight	Coalbed Methane	Shale	Frontier	East Coast Offshore	Weighted Average
	g CO_2eq/GJ at Burner							
Fuel dispensing	0	0	0	0	0	0	0	0
Fuel distribution and storage	1,314	1,314	1,326	1,318	1,363	3,490	1,317	1,318
Fuel production	1,174	1,174	1,453	0	1,492	1,159	1,303	1,122
Feedstock transmission	0	0	0	0	0	0	0	0
Feedstock recovery	1,691	1,691	1,988	3,403	2,025	1,678	1,694	1,898
Feedstock Upgrading	0	0	0	0	0	0	0	0
Land-use changes, cultivation	0	0	0	0	0	0	0	0
Fertilizer manufacture	0	0	0	0	0	0	0	0
Gas leaks and flares	2,082	2,082	2,082	1,655	2,082	2,093	2,082	2,054
CO_2, H_2S removed from NG	824	824	824	824	2,473	0	824	863
Emissions displaced	0	0	0	0	0	0	0	0
Total	7,086	7,086	7,674	7,201	9,436	8,421	7,220	7,254

The lifecycle GHG emissions would be the upstream emissions shown in the table above and the emissions from the combustion of the fuel, which are 50,589 g CO_2eq/GJ. The lifecycle emissions therefore range from 57,675 to 60,025 g CO_2eq/GJ, with a weighted average of 57,843. The shale gas lifecycle GHG emissions are 3.8% higher than the weighted average.

The primary difference in the shale gas emissions is the increased quantity of CO_2 that is found in one of the fields. An average CO_2 level of 6.4% was used for modelling. The other difference is that the gas production emissions (feed recovery) are about 5% higher than the weighted average and this is driven by the higher well drilling emissions due to the depth of the deposits and the energy used for hydraulic fracturing.

The GHG emissions for shale gas calculated by this revised version of GHGenius are not significantly different than those previously calculated in version 3.18, when unconventional gas sources were added to the model except that the CO2 content of the field can be modelled separately. There is an increase in emissions attributed to higher drilling emissions. The comparison of shale gas emissions from the two model versions is shown in the following table.

Table ES- 2 Upstream GHG Emissions Shale Gas

	GHGenius 3.18	GHGenius 3.20sg	
		1% CO_2	12% CO_2
	g CO_2eq/GJ		
Fuel dispensing	0	0	0
Fuel distribution and storage	1,340	1,308	1,444
Fuel production	1,414	1,434	1,577
Feedstock transmission	0	0	0
Feedstock recovery	1,742	1,969	2,106
Feedstock Upgrading	0	0	0
Land-use changes, cultivation	0	0	0
Fertilizer manufacture	0	0	0
Gas leaks and flares	1,369	2,082	2,082
CO_2, H_2S removed from NG	2,473	0	6,072
Emissions displaced	0	0	0
Total	8,338	6,793	13,280

The higher emissions are due to the increased energy use in drilling and an increase in the methane loss rate that applies to all types of natural gas in the Canada. The gas content of the shale gas fields makes a larger impact on the overall GHG emissions than does the increase in emissions from drilling and hydraulic fracturing.

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

1. INTRODUCTION

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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:

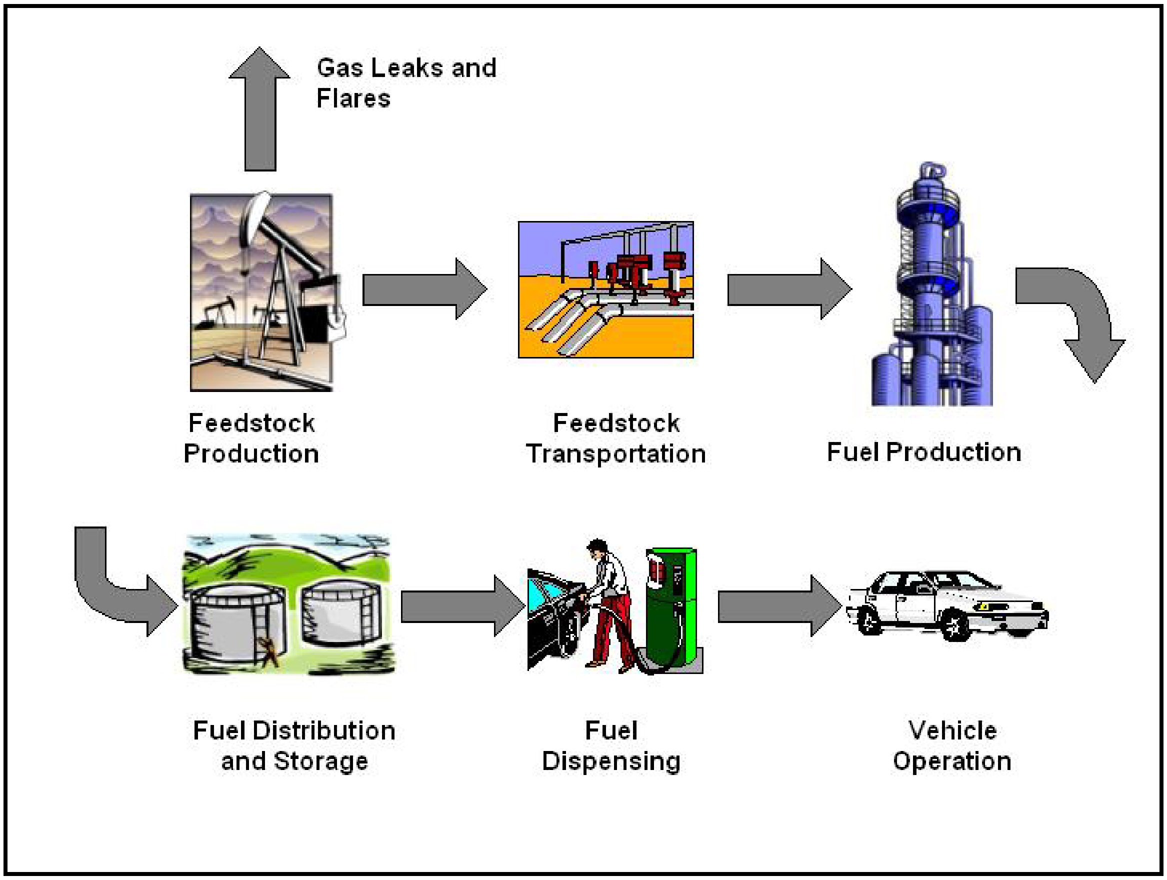
- Vehicle Operation
  Emissions associated with the use of the fuel in the vehicle. Includes all greenhouse gases.
- Fuel Dispensing at the Retail Level
  Emissions associated with the transfer of the fuel at a service station from storage into the vehicles. Includes electricity for pumping, fugitive emissions and spills.
- 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.
- 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



1.1 SCOPE OF WORK

In 2010, GHGenius was updated to include unconventional natural gas sources as part of the model. One of the new sources that was added to the model was shale gas. Since that time, the interest in the GHG emissions of shale gas has continued to increase, as the potential of the resource becomes better understood across North America. In the 2010 report, it was found that very little information was available concerning the emissions of the well drilling, "hydraulic fracturing", and production stages of a shale gas well.

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This work has reviewed the data supplied, compared the results between companies and reached some conclusions with respect to the data that has been made available.

To properly model shale gas the structure of the natural gas sheet in GHGenius needed to be changed to have more emphasis on the well drilling emissions. This new structure has been developed and integrated into the model.

The work has been documented in this report. As it is anticipated that there will be a complete review of the natural gas pathway undertaken this year in conjunction with

Environment Canada, it was not appropriate to release a new complete GHGenius update as part of this work. Nevertheless, an updated model 3.20asg has been made available to NRCan as a result of this work.

2. NATURAL GAS PRODUCTION

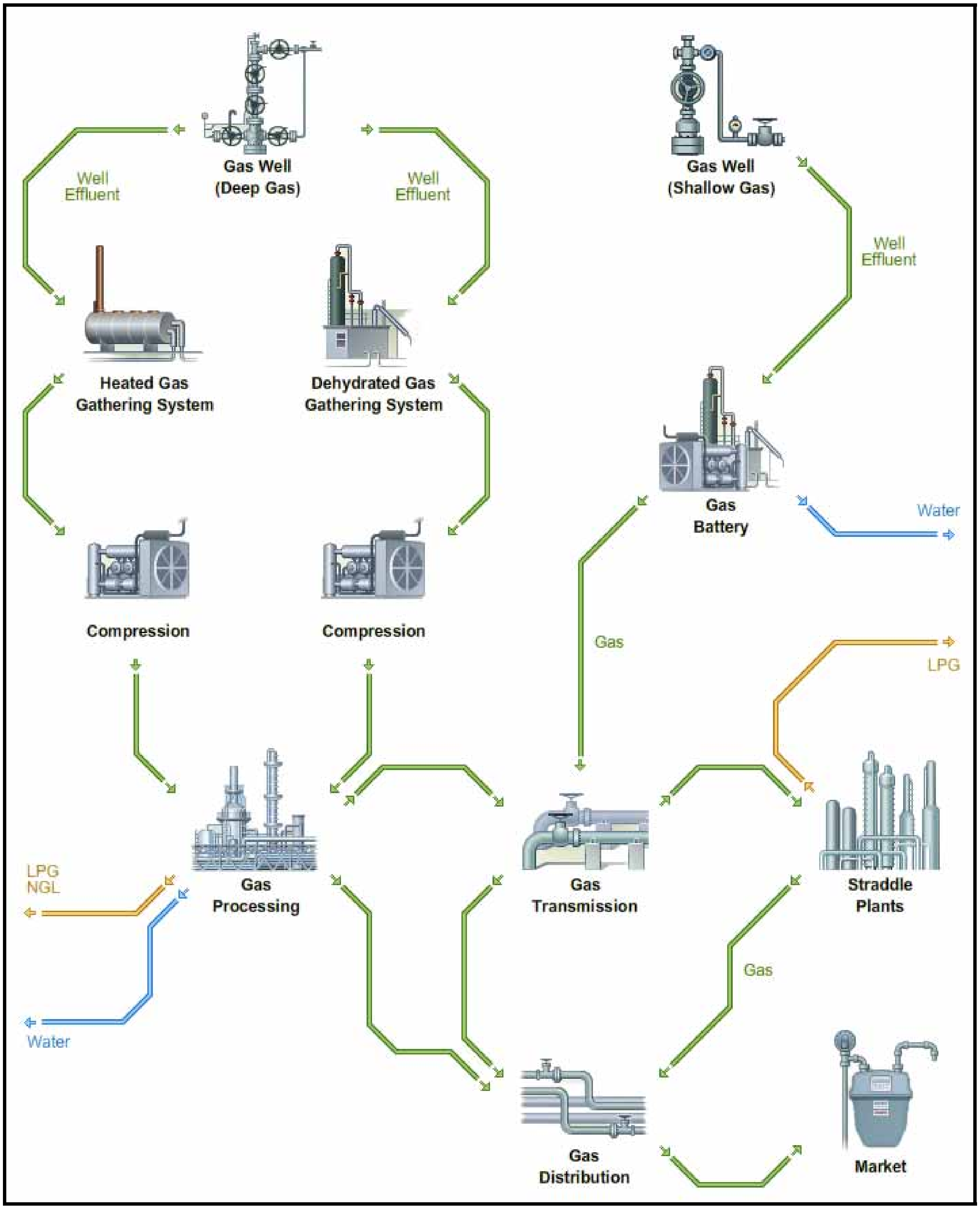
Oil and natural gas systems encompass wells, gas gathering and processing facilities, storage, and transmission and distribution pipelines. These components are all important aspects of the natural gas cycle—the process of getting natural gas out of the ground and to the end user, which can generally be broken out into four sectors. Each sector is defined as follows:

- Production focuses on taking raw natural gas from underground formations.
- Processing focuses on stripping out impurities and other hydrocarbons and fluids to produce pipeline grade natural gas that meets specified tariffs (pipeline quality natural gas is 95-98 percent methane).
- Transmission and Storage focuses on delivery of natural gas from the wellhead and processing plant to city gate stations or industrial end users. Transmission occurs through a network of high-pressure pipelines. Natural gas storage also falls within this sector. Natural gas is typically stored in depleted underground reservoirs, aquifers, and salt caverns.
- Distribution focuses on the delivery of natural gas from the major pipelines to the end users (e.g., residential, commercial and industrial).

In the oil industry, some underground crude contains natural gas that is entrained in the oil at high reservoir pressures. When oil is removed from the reservoir, associated or solution natural gas is produced. Both associated and non-associated gases are considered conventional natural gas as part of this work.

All of these sectors are currently accounted for in GHGenius. The following figure shows the flow of gas from the well to the end market.

Figure 2-1 Natural Gas Production System



Source: Methane to Markets. Sponsored by NRCan.

It is apparent from the figure that the emissions from different gas fields could be quite different, as the processing of the gas that is required will be a function of the impurities in the gas. Dry shallow wells may receive minimal processing prior to compression, transmission and distribution, whereas deep wet gas may require significantly more processing to achieve the same composition that is suitable for downstream use. In GHGenius, these different sources of gas have not previously been segregated.

2.1 GHGENIUS STRUCTURE

GHGenius has four stages for the natural gas production, recovery, processing, transmission and distribution. For each of the stages, the energy consumption and fugitive emissions are specified to allow the model to calculate the lifecycle emissions at the point of dispensing or utilization in an industrial process.

While this structure has been adequate for identifying the emissions of the natural gas production system as a whole, it has limitations with respect to being able to model individual types of gas production systems. Some expansion of the structure was undertaken in 2010 but that maintained the same stages but allowed for different types of gas production:

- Solution gas (or associated gas) is that which is dissolved in crude oil under pressure and is produced at the same time as crude oil is produced.
- Non associated gas (or conventional gas) is gas that is produced independently of crude oil production.
- Tight gas is gas stored in low-permeability rock. Tight gas reservoirs require artificial fracturing to enable the gas to flow.
- Coalbed methane (CBM) is a form of natural gas extracted from coalbeds. Coalbed methane is distinct from typical sandstone or other conventional gas reservoir, as the methane is stored within the coal by a process called adsorption.
- Shale gas is natural gas stored in organic rich rocks such as dark-coloured shale, interbedded with layers of shaley siltstone and sandstone. Shale can be the source, reservoir and the seal for the gas.
- Frontier gas in Canada is the gas from regions that the National Energy Board has authority over. It includes gas in the artic and offshore areas in the Pacific and Atlantic oceans.

For this work we have expanded the production stage so that different energy requirements and fugitive emissions can be modelled for each of the six types of gas. This work focuses on establishing the data for conventional gas and for shale gas.

2.2 CONVENTIONAL GAS DATA

Natural gas production emissions are those associated with drilling the wells, producing and processing the gas. The main emission sources are from the use of energy for drilling, the heating and compressing the gas, and from leaks and flares from equipment. These emissions are found in the feedstock recovery stage and the gas leaks and flares stages in GHGenius.

In many fields, natural gas is also used to drive pneumatic devices, as compressed air is not available. This gas is usually exhausted to the atmosphere as a component of the gas leaks and flares in GHGenius. There is an opportunity to reduce these emissions, through the use of compressed air, particularly in larger fields.

2.2.1 Well Drilling

Good quality data on the energy expended in drilling wells is not often reported. CAPP (2004) has reported the emissions for well drilling, well servicing and well testing on a per well basis for the year 2000. This information is summarized in the following table.

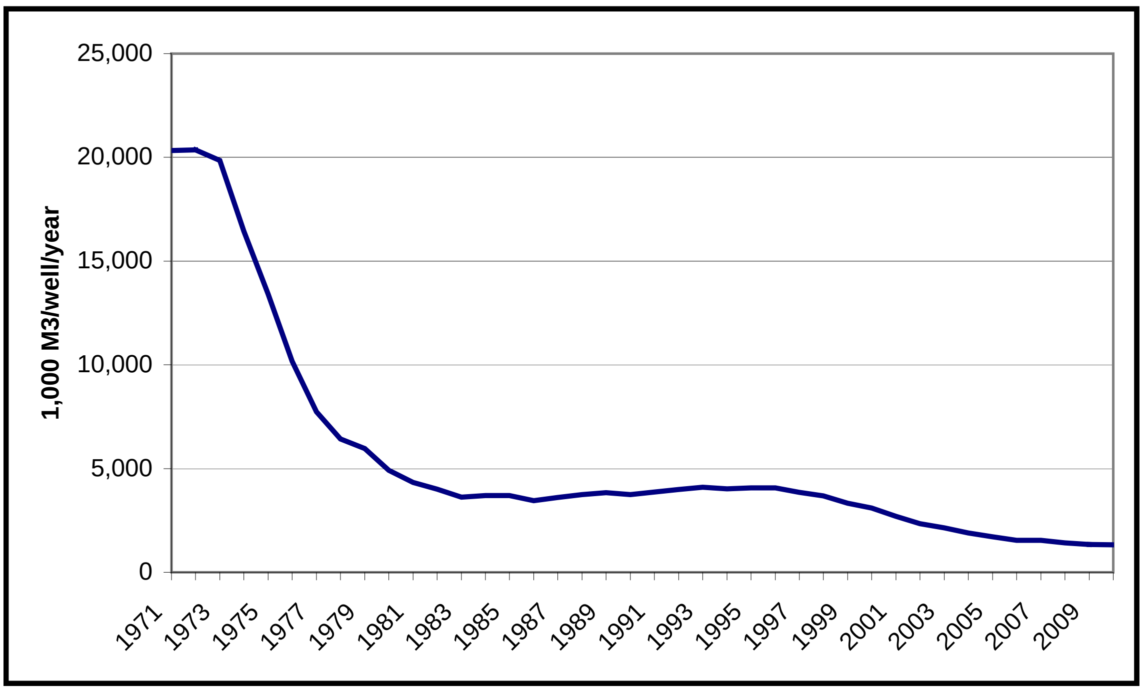
Table 2-1 GHG Emissions – Well Drilling, Testing, and Servicing

	Tonnes/well			
	CO_2	CH_4	N_2O	CO_2eq
Well Drilling	61.1	0.023	0.0055	63.3
Well Servicing	15.0	0.51	0.0018	28.3
Well Testing	42.7	0.24	0.0	48.7
Total	118.8	0.773	0.0073	140.3

While this information is suitable for emission inventory perspective it needs some additional information on the quantity of gas produced per well to be useful for LCA work.

In the following figure the gas production per well in Western Canada has been calculated from data in the CAPP Statistical Handbook. In 2000, the production rate was 3,104,000 m^3/well per year. If a well has a lifetime of 30 years then the lifetime production would be 93 million m^3/well. By 2010 this had dropped to 40 million m^3/well.

Figure 2-2 Western Canada Gas Production



The production rates vary by Province as well as by time and the rates in BC are about three times higher than the rate for western Canada.

The other issue is that GHGenius requires the energy consumption for calculating the emissions, so the well drilling information from CAPP needs to be in the form of energy consumption plus fugitive emissions. CAPP provides a breakdown of these emissions for each of the three stages, the well drilling information is shown in the following table. There were 20,566 wells drilled.

Table 2-2 GHG Emissions – Well Drilling

	kt CO_2eq			
	Fuel Combustion	Flaring	Venting	Total
Drilling	1,285	0	0	1,285
Drill Stem Testing	0	10	7	17
Total	0	0	0	1,301

The diesel fuel emission rate used in the CAPP work was 2.87 kg CO_2eq/litre. Assuming that all of the emissions were from diesel fuel consumption, we can then calculate that the fuel consumption was 21,770 litres/well. With the average well producing 93 million m^3, or 66,600 tonnes of gas over it's lifetime. The diesel fuel consumption is therefore 12,633 kJ/tonne of gas produced.

When the target zone is reached, a drill-stem test may be performed to determine the production potential. During a test, the zone is produced through the centre of the drill stem. At the surface, the gas and liquid phases are separated and measured. If it is a sour well, the gas phase is flared; otherwise, the gas is often vented to the atmosphere. Furthermore, before a drill-stem test is conducted, a clean-up operation is performed. This consists of producing the well overnight to allow any drilling fluid and debris that may have penetrated the zone to be removed.

To assess the emissions from reported drill stem tests CAPP assumed that:

- The average gas flow rate during the test is equal to the average of the maximum and minimum flows reported for the test.
- The average flow during clean-up is equal to the minimum flow reported for the test.
- The duration of the test is as reported.
- The duration of the clean-up operation and preliminary flow test is twelve hours.
- Based on information supplied by several operators, approximately 88.4 percent of drill stem test gas is flared and the remainder is vented.

The reported methane emissions are 23 kg/well. This is equivalent to 0.000035% loss rate over the lifetime of the well. The gas that is flared is 198 kg, or 160 kJ/tonne of gas produced over the lifetime.

2.2.2 Well Tests

The flaring and venting estimates calculated from the CAPP report are 12,670 kJ/tonne of gas for flaring and a 0.00066% gas loss rate.

2.2.3 Well Servicing

This component of well-related activities comprises well completions, workovers and abandonments. The emissions produced by these activities are perhaps evaluated best in terms of the fuel consumption by the major types of equipment that are employed (service rigs, pumping units and wireline units) and specific venting that occurs.

The emissions reported by CAPP are shown in the following table.

Table 2-3 GHG Emissions – Well Servicing

	kt CO_2eq			
	Fuel Combustion	Flaring	Venting	Total
Service Rigs	144	0	0	144
Pumping Units	177	0	0	177
Blowdown treatments	0	220	0	220
Total	321	220	0	541

Converting the fuel combustion emissions to diesel fuel equivalents produces a rate of 5,438 litres/well (3,160 kJ/tonne of gas).

Some natural gas wells must be blown down periodically to remove water that has accumulated in the production tubing. This gas is flared. The flaring rate is 3,170 kJ/tonne of gas over the lifetime of the well. Venting was reported as insignificant.

2.2.4 Gas Production

There are four categories of emissions for natural gas production in the CAPP inventory: wells, gathering systems, batteries, and disposal.

Natural gas wells are primarily sources of fugitive emissions due to leaking seals and fittings on the well head. Additional sources are introduced if pump jacks are used on the well (i.e., leaking pump seals and combustion emissions where a gas-driven engine is used to drive the pump jack). Most of the emissions are fugitive.

CAPP identified the emissions from three types of gathering systems, low pressure, heated, and dehydrated. Gathering systems can involve compressors, venting, and fugitive emissions. For our purposes it will be assumed that all of the combustions emissions are from natural gas combustion.

A natural gas battery is a production unit that is used when natural gas processing is not required. The basic functions of a natural gas battery are to separate the effluent from one or more natural gas wells into natural gas and water, measure the flow rate of each of these phases from each well, and provide any treating and compression that may be required. The water is then disposed of and the marketable natural gas is sent to market. Only compression and treating (e.g., dehydration or sweetening) may be needed to upgrade raw natural gas to market specifications. Typically, this type of natural gas comes from low-pressure, shallow natural gas wells. It is characterized by low concentrations of non-methane hydrocarbons and is called "dry gas." It is assumed that natural gas is the combustion fuel.

There are minimal fugitive emissions associated with the injection of waste gases and water. All of these emissions are summarized in the following table. The total quantity of natural gas produced was reported to be 217,558 million m^3, or 155.7 million tonnes of gas.

Table 2-4 Natural Gas Production Emissions

	Combustion	Flaring	Venting	Total
	Kt CO_2eq			
Wells	65	0	487	552
Gathering Systems	7,225	153	3,171	10,549
Batteries	2,401	102	6,670	9,173
Disposal			1	1
Total	9,690	255	10,331	20,276

The total quantity of natural gas produced was reported to be 217,558 million m^3, or 155.8 million tonnes of gas. The previous table is converted to energy units per tonne in the following table. We will assume that a mixture of internal and external combustion devices are used and that the exhaust GHG emissions are 55,000 g CO_2eq/GJ.

Table 2-5 Natural Gas Production Combustion Emissions

	Combustion	Flaring	Total
	KJ/tonne		
Wells	7,585	0	7,585
Gathering Systems	843,156	17,855	861,011
Batteries	280,196	11,903	292,099
Disposal	0	0	0
Total	1,130,820	29,758	1,160,579

The venting emissions amount to 0.316% of the gas production. This value is higher than was previously in GHGenius. The previous value was 0.13% and was based on the 2002 CGA VCR report. Since all of the other data on well drilling and production energy use and emissions is based on CAPP data, the CAPP estimate for methane losses is used here. This higher loss rate will increase the GHG emissions for natural gas production and use and it will impact all of the production systems that utilize natural gas.

2.2.5 Summary Gas Production

The fuel combustion and venting rates for conventional gas wells are summarized in the following table. These rates are sensitive to the total lifetime production of the well. Using the 2010 production rate per well instead of the 2000 rate essentially double these emissions on a per tonne of gas basis.

Table 2-6 Summary of Energy Consumption and Venting

	Diesel	Natural Gas	Venting
	kJ/tonne gas		% loss rate
Well Drilling	12,633	160	0.000035
Well Servicing	3,160	3,170	0.0
Well Tests	0	12,670	0.000660
Gas Production	0	1,161,579	0.316
Total	15,793	1,177,579	0.316695

There was an update of the emissions for the upstream oil and gas industry undertaken for NRCan in 2009 by a group lead by Clearstone Engineering (2009), using data for 2006. The GHG emission rate was identical to the earlier 2000 data. From the above table it is evident that, for conventional gas, the gas production emissions dominate the well drilling and servicing emissions.

The US EPA has recently published a support document for GHG emission reporting for the Petroleum and Natural gas Industry (2010). This report focuses on the non-combustion emissions. It does have separate estimates of emissions for conventional and non-conventional natural gas production systems. In a number of cases they significantly increased their emission estimates for particular steps in the gas production process. In the following table their emission factors are compared to the CAPP estimated emissions.

Table 2-7 US EPA Emission Factors

Activity	EPA Emission Factor	CAPP equivalent
	kg CH_4/well	
Well venting for liquids unloading	11,000	656
Well completion	710	213
Well workover	50	flared

The largest difference is in the venting during liquids unloading. These emissions are a function of the type of field and it is possible that both estimates are correct.

2.2.6 Gas Processing

Natural gas, as it is produced, can contain varying levels of impurities that must be removed before it can be moved to market. These impurities can include water, carbon dioxide, higher hydrocarbons, and hydrogen sulphides. The level of impurities will vary from field to field.

A natural gas processing plant is a facility for extracting condensable hydrocarbons from natural gas, and for upgrading the quality of the natural gas to market specifications. Some compression may also be required. Each facility may comprise a variety of treatment and extraction processes, and for each of these there is often a range of technologies that may be used.

There are basically five types of natural gas processing facilities: sweet plants, sour plants that flare acid gas, sour plants that re-inject acid gas, sour plants that extract the elemental sulphur from acid gas, and straddle plants. The first four types are fed by natural gas gathering systems and prepare natural gas for transmission to market. The last type is located on major natural gas transmission lines and is used to extract residual ethane and heavier hydrocarbons from the natural gas in the pipeline.

2.2.6.1 Energy Consumption

It will be assumed that all of the energy is supplied by natural gas, LPG, and electricity. The electricity can't be obtained from the CAPP inventory but the natural gas consumption can be. This works out to 1.575 GJ/tonne and would include the LPG energy use. The electric power consumption for this sector was reported in the 2006 Energy Outlook 2020 document published by NRCan as 94,500 kJ/tonne of gas. The total energy consumption would be1.67 GJ/tonne of gas.

2.2.6.2 Methane Losses

The methane losses from the gas processing in the CAPP inventory was 0.027% of the gas throughput. This is lower than the previous value of 0.09% based n the 2002 CGA VCR report. This will offset some of the increased methane losses in the gas production stage.

2.2.6.3 Carbon Dioxide Removal

Data from CAPP (2004) would indicate that these emissions in Canada (identified as formation gas) are 930 g CO_2/GJ of gas produced. This is 29% higher than the US value in the model. The structure of GHGenius has allowed this value to be regionalized since version 3.18.

3. SHALE GAS DATA

The GHG and CAC emissions from shale gas production have been generating some concern in local communities and in the media over the past several years. Very little detailed information has been available. Recently, the US EPA (2010) has released some emission estimates for some stages of the conventional and shale gas industries.

Some field data for Canadian operations has been supplied by CAPP to NRCan. These two new sources of data are described below and, where possible, developed into the same performance indicators developed for conventional gas in the previous section.

3.1 US EPA

The US EPA updated the emission factors that they use for their national GHG Inventory report recently (US EPA, 2010). For the first time they provided emission factors for both conventional and unconventional wells. These emission factors focussed on methane emissions and not on energy use. The emission factors developed for unconventional wells are summarized in the following table.

Table 3-1 EPA Emission Factors – Unconventional Gas Wells

Activity	Emission factor
Gas well venting during completions	177,000 kg CH_4/well
Gas well venting during workovers	177,000 kg CH_4/well

These emission factors are very high compared to those for conventional wells. Reviewing the source data for the EPA emission factors indicates that they were derived from the EPA's interpretation of presentations given in 2004 and 2007. There were a total of four data sources. The data sources varied significantly from 700 to 20,000 MCF/completion (a 30 fold range) and in addition one study represented three wells and another 1,000 wells, yet the EPA took the arithmetic average of the four sources.

EPA's estimates have been criticized recently (CERA, 2011). The two primary concerns are:

- EPA's current methodology for estimating gas field methane emissions is not based on methane emitted during well completions, but paradoxically is based on a data sample of methane captured during well completions.
- EPA assumes that gas produced during completion is vented, rather than flared, unless flaring is required by state regulation. This assumption is at odds with industry practice and with safe operation of drilling sites.

The recent paper by Howarth (2011) relied mostly on the same set of presentations that the EPA used and reached similar conclusions by assuming that all of the methane that was reported to be released in the presentations was neither captured nor flared.

The EPA emission factors do not appear to represent current practices and are not appropriate for use in GHGenius, either for Canadian or American gas production.

For example, the industry procedure in the Horn River shale gas area in British Columbia regarding hydraulic fracturing, well completions and workovers are as follows:

- Hydraulic fracturing is done in intervals starting from toe to heal, once the first section is perforated and fractured it is isolated with bridge plugs before the next section is perforated and fractured. This process is repeated until all the intervals are perforated, fractured and isolated with bridge plugs. During this process there is no flowback.

- Coil tubing is used for milling all bridge plugs, any flowback during this process is captured and directed first to a high pressure (HP) vessel then to a low pressure (LP) vessel and the gas captured at HP and LP vessels are sent to a flare unless it is sent to the processing facility.
- A flare that has a continuous flame is also used during an emergency situation.

There is no venting during well completions in the Horn River area, if there is any gas in the flowback, it is captured and flared if not directed to the processing facility. In addition, there is no open-pit flowback or cold venting practices in the Horn River area. This is a very different scenario than the EPA has developed emission factors for.

3.2 Canada

For this work some actual energy and emission data was received for two drilling operations. This is a very small sample and the two operations each provided partial information, but the data can be compared to the average natural gas emission information described in the previous section.

The wells that provide information had much higher production rate than the average production used in the previous section. Lifetime gas production is expected to be 725 million m^3 of gas, eight times higher than the 2000 production rate and eighteen times higher than the average 2010 production rate.

3.2.1 Well Drilling

Very detailed information on well drilling was received for one field from a CAPP producing member. This is a deep field, with the total length of drilling (vertical and horizontal) of 6,000 m. Energy information was received for the drilling, the logistics of moving material to the drill site, hydraulic fracturing, and production and disposal of the drilling fluids. The information is summarized in the following table.

Table 3-2 Energy Consumption Well Drilling

Stage	Natural Gas (m^3)	Gasoline (litres)	Diesel Fuel (litres)
Logistics	0	0	61,875
Drilling	386,000	2,800	116,250
Fluids Prod & Disposal	375,000	0	
Hydraulic fracturing	0	0	520,000
Total	761,000	2,800	698,125
Total (kj/tonne gas)	57,067	192	53,458

No information was provided on flaring or venting emissions drilling well drilling that would suggest that these emissions are different from a conventional well. These emissions are very low for conventional wells and there is no evidence that the situation is different for these shale gas wells.

The second drilling operation that provided data did not provide as comprehensive a set of data, but it was in broad agreement with the information shown in the table above. The second data set used less drilling energy but the drill depth was lower and the expected lifetime production rate was also lower.

Given the uncertainty in well to well variation, the information shown in Table 3-2 will be used for modelling.

3.2.2 Well Testing and Servicing

No new information on the emissions from well testing and serving were provided for the two operations that supplied data. For modelling we have assumed that the gas lost is the same fraction as is used for conventional gas.

3.2.3 Gas Production

Gas production involves dehydrating the gas, some process energy, electrical power (often self generated), compression, and the use of some gas for instrumentation and pneumatic devices. These processes are generally the same ones that are involved in conventional gas production. The energy required for gas dehydration will vary with the moisture content of the field. Some new fields use compressed air for pneumatic devices and instrumentation and thus have a lower gas loss.

The energy use for conventional gas production is 2.2% of the gas processed. One operation provided an estimate of 2.0% of the gas consumed for production. The other operation provided an estimate of 4% of the gas consumed for production. Since both of these were estimates, the modelling is based on the same gas consumption as conventional gas.

3.2.4 Summary Gas Production

Table 3-3 Summary of Energy Consumption and Venting- Shale Gas

	Diesel	Natural Gas	Gasoline	Total	Venting
	kJ/tonne gas				% loss rate
Well Drilling	53,458	57,067	192	110,717	0.000035
Well Servicing	3,160	3,170	0	6,330	0.00
Well Tests	0	12,670	0	12,670	0.00066
Gas Production	0	1,161,579	0	1,161,579	0.316
Total	56,618	1,234,486	192	1,291,296	0.317

It can be seen from the table that the gas used during the production process for dehydration, compression and other uses dominates the energy used and thus the GHG emissions for natural gas production. The most detailed information for shale gas was received for the drilling stage, and while the energy used here is higher than it is for conventional gas, it is still less than 10% of the emissions from the drilling, testing, servicing, and gas production stages.

3.2.4.1 Gas Processing

Unconventional gas will be transported to a gas processing plant to remove the non methane gases from the stream. These gases will vary from field to field. Some shale gas, the Horn River fields for example, have high levels of CO_2 that must be removed. Other fields, such as the Montney fields have low levels of CO_2 and the gas composition is not significantly different than conventional gas. The CO_2 levels of shale gas reservoirs are shown in the following table.

Table 3-4 Comparison of Canadian Gas Shales

	Horn River	Montney	Colorado	Utica	Horton Bluff
Depth (m)	2,500 to 3,000	1,700 to 4,000	300	500 to 3,300	1,120 to 2,000+
Thickness (m)	150	Up to 300	17 to 350	90 to 300	150+
Published estimate of natural gas (Tm^3)	4 to 14+	2 to 20+	> 3	> 4	> 4
CO_2 Levels, %	12	1	-	< 1	5

There is no data available on the average CO_2 content of the shale gas being produced in Canada. The calculation of the CO_2 emissions from gas plants in GHGenius is overly complex providing and increased precision and will be simplified in a future model update. For this work it is assumed that the average CO_2 content is 6.4%, approximately the average of the Horn River and Montney fields.

The total energy consumption for gas processing for conventional gas is 3.16% with a gas loss rate of 0.027%.

The two estimates received for unconventional gas were 1% to 4%. The higher value is associated with the gas with a high CO_2 content. Since it is well established that energy is required to capture CO_2, it is reasonable that the gas with the highest CO_2 level would have the highest energy content. The energy consumption at the gas plant will also vary with the level of LPG that is removed.

Since the shale gas that is produced in Canada does have a higher CO_2 level, it is reasonable that the processing energy should be higher than is used for conventional gas. On the other hand, the LPG levels will also impact the processing energy.

The one estimate that was received for venting losses for a gas processing plant was 0.17%. This is higher than the average value used for conventional gas.

For this modelling it will be assumed that the energy consumption for gas processing will be 3.5% of the gas produced (1.85 GJ/tonne of gas) and that the loss rate is 0.027%.

4. NEW STRUCTURE FOR GHGENIUS

To be able to better understand the difference in the emission profile for shale gas compared to conventional natural gas the structure of the model has been modified for this work. All of the changes are confined to sheet R in the model. These changes are briefly described below.

4.1 PRODUCTION STAGE

The focus of this work has been on the production of natural gas. In earlier versions of GHGenius the various stages of natural gas production, well drilling, testing, and gas production were combined into a single stage, which covers a variety of activities and time horizons. For this work these stages were disaggregated for each type of gas production in GHGenius.

4.1.1 Well Drilling

The well drilling activity obviously precedes gas production and it occurs once in the lifetime of the well. These emissions need to be amortized over the entire production of the well. The emissions primarily are derived from the combustion of fossil fuels to power the drill rig and associated activities. There can be some losses of methane associated with leaks during drilling, although like all fugitive sources it is difficult to quantify these emissions. There can also be emissions from the trucking activities that are associated with mobilizing the drill rig and the movement of drilling materials to the well site.

In this version of GHGenius, the inputs for the well drilling stage were amortized over the total well production and entered for each of the six types of natural gas production in GHGenius. The structure allows for the use of crude oil, diesel fuel, residual fuel, natural gas, coal, electricity, gasoline and coke. The gas lost, or methane emissions, as a percentage of production are also included as an input.

All of the fuel consumption is entered as kJ of energy per tonne of gas produced.

4.1.2 Well Testing

Well testing is also a unique stage in gas production in the new structure. The energy inputs are the same as those for well drilling and are entered in the same manner, kJ/tonne of gas produced.

4.1.3 Well Servicing

Well servicing energy and emission data is added as a separate sub category of gas production in a similar manner to the well drilling. Well servicing may happen more than once in its lifetime. The energy inputs are the same as those for well drilling and are entered in the same manner, kJ/tonne of gas produced.

4.1.4 Gas Production

The energy and emissions associated with the ongoing production as entered as a unique sub category. The energy inputs are the same as those for well drilling and are entered in the same manner, kJ/tonne of gas produced.

Each of the four stages are then summed so that the total energy and gas lost per tonne of production can be input to the existing structure of the model. Gas production emissions in Canada were previously in the model as a fraction of the US energy consumption and gas lost. This will be changed in future versions of the model but a temporary step has been undertaken with this update in that the fraction is calculated based on the Canadian energy and US energy requirements.

4.2 GAS PROCESSING STAGE

The energy consumed and gas losses during the processing stage is entered into the model and the model calculates the percentage of this energy as a fraction of the energy consumed in the US.

4.3 GAS TYPE

With all of the detailed information on energy consumed and gas loss for each type of gas production, a sumproduct calculation is done to get the average data for either all gas produced in Canada or for a specific scenario that the user designs.

5. SHALE GAS RESULTS

The revised model has been used to compare the GHG emissions for shale gas with other types of gas in the model. The upstream emissions are presented in the following table.

Table 5-1 Comparison of Upstream GHG Emissions

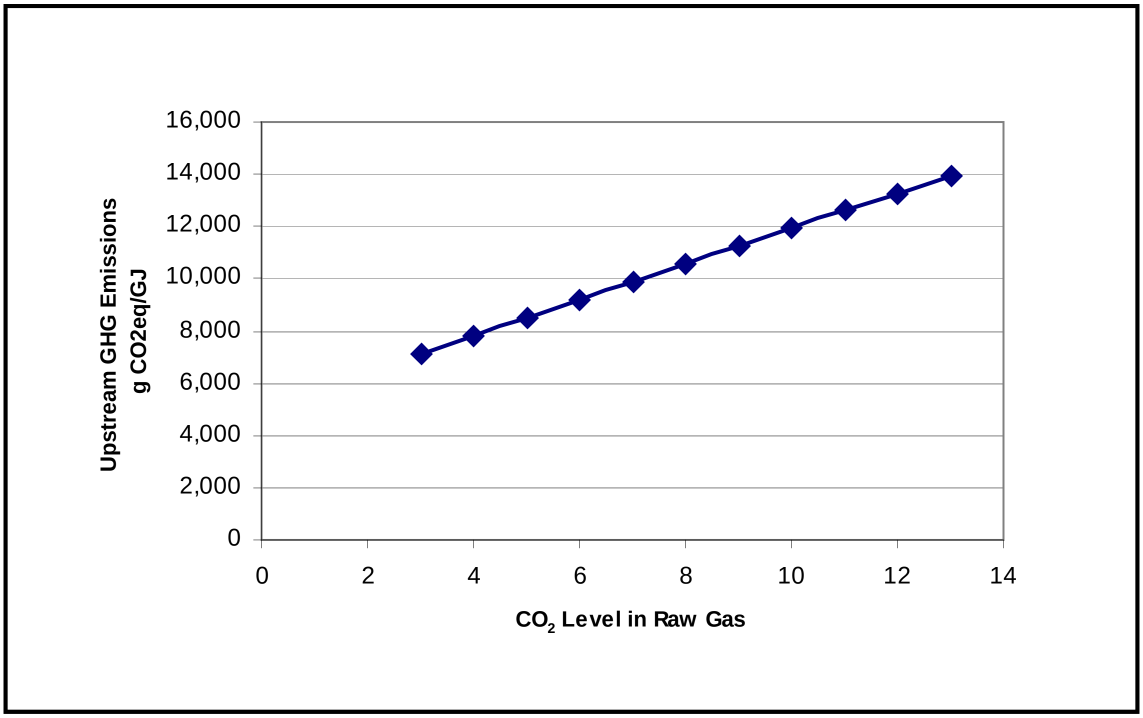
	Solution	Non Associated	Tight	Coalbed Methane	Shale	Frontier	East Coast Offshore	Weighted Average
	g CO_2eq/GJ at Burner							
Fuel dispensing	0	0	0	0	0	0	0	0
Fuel distribution and storage	1,314	1,314	1,326	1,318	1,363	3,490	1,317	1,318
Fuel production	1,174	1,174	1,453	0	1,492	1,159	1,303	1,122
Feedstock transmission	0	0	0	0	0	0	0	0
Feedstock recovery	1,691	1,691	1,988	3,403	2,025	1,678	1,694	1,898
Feedstock Upgrading	0	0	0	0	0	0	0	0
Land-use changes, cultivation	0	0	0	0	0	0	0	0
Fertilizer manufacture	0	0	0	0	0	0	0	0
Gas leaks and flares	2,082	2,082	2,082	1,655	2,082	2,093	2,082	2,054
CO_2, H_2S removed from NG	824	824	824	824	2,473	0	824	863
Emissions displaced	0	0	0	0	0	0	0	0
Total	7,086	7,086	7,674	7,201	9,436	8,421	7,220	7,254

The lifecycle GHG emissions would be the upstream emissions shown in the table above and the emissions from the combustion of the fuel, which are 50,589 g CO_2eq/GJ. The lifecycle emissions therefore range from 57,675 to 60,025 g CO_2eq/GJ, with a weighted average of 57,843. The shale gas lifecycle GHG emissions are 3.8% higher than the weighted average. Coal bed methane is assumed to be dry, sweet gas that can bypass the gas processing stage and go directly to the pipeline, which is why the processing emissions are 0 in the above table.

The primary difference in the shale gas emissions is the increased quantity of CO_2 that is found in one of the fields. An average CO_2 level of 6.4% was used for modelling. The other difference is that the gas production emissions (feed recovery) are about 5% higher than the weighted average and this is driven by the higher well drilling emissions due to the depth of the deposits and the energy used for hydraulic fracturing.

The Upstream GHG emissions for shale gas as a function of CO_2 levels in the raw gas are shown in the following figure. The handling of the emissions of this gas in GHGenius dates back to the original LEM model and it could be improved to make the modelling of different gas fields more responsive.

Figure 5-1 Shale Gas Upstream Emissions vs. Field CO_2 Levels



While some good quality information has been obtained for shale gas production systems, particularly well drilling, there are still other stages in the production cycle where the analysis is assuming that the emissions are the same as they are for conventional natural systems. Based on the current understanding of the production system, this is a reasonable assumption.

6. DISCUSSION AND CONCLUSIONS

The modelling work done here using an enhanced version of GHGenius finds that lifecycle GHG emissions of natural gas produced from shale resources are only slightly higher than those of natural gas produced from more conventional sources. The increase is strongly influenced by the CO_2 level in the raw gas. One field in Canada has about 12% CO_2, whereas other fields are very low in CO2 and will have lower lifecycle GHG emissions as a result. There have been some other analyses of the GHG emissions of shale gas published in the past year and the conclusions of those studies and possible reasons for the differences from these findings are discussed below.

6.1 TYNDALL CENTRE FOR CLIMATE CHANGE RESEARCH

The Tyndall Centre for Climate Change Research is part of the University of Manchester in the UK. They published a report on the environmental impact of shale gas in January 2011 (Wood et al. 2011). The overall objective of this study was to draw on available information (in particular from the US) to consider the potential risks and benefits of shale gas and reflect on development of shale reserves that may be found in the UK. The study considered the lifecycle GHG impacts as well as other environmental attributes.

The study findings and approach were described by the authors as:

> *There is limited publicly available information that is suitable for carrying out an in-depth life cycle assessment of shale gas compared to conventional gas extraction. As in the case of conventional gas sources, the size of the emissions associated with extraction is dependent on the attributes of the reservoir. Due to these variations and inconsistent information a direct comparison between shale versus a conventional well is not recommended.*
>
> *It is assumed that the combustion of natural gas emits the same amount of CO_2 whether it comes from shale or conventional sources. In the UK, natural gas extracted from gas shales is also likely to use the same distribution methods as that from conventional sources, and is therefore subject to the same distribution losses.*
>
> *The main point of difference between the GHG emissions associated with shale compared to conventionally sourced gas lie in the extraction and production processes.*
>
> *The purpose of this section is therefore to quantify the amount of greenhouse gases released during the main stages of the extraction process per well, which are unique to shale gas sites.*
>
> *Emissions during extractions can be divided into three main sources:*
>
> *1) Combustion of fossil fuels to drive the engines of the drills, pumps and compressors, etc, required to extract natural gas onsite, and to transport equipment, resources and waste on and off the well site;*
>
> *2) Fugitive emissions are emissions of natural gas that escape unintentionally during the well construction and production stages; and*
>
> *3) Vented emissions result from natural gas that is collected and combusted onsite or vented directly to the atmosphere in a controlled way.*

This section focuses on the first of these, as this is the primary difference between shale and conventional sources. Fugitive and vented emissions of methane will depend on the control measures and operational procedures employed at each site.

The report finds that shale gas wells are likely to involve more drilling and could contribute an additional 15 to 75 tonnes of CO_2eq/well. The hydraulic fracturing process consumes 110,000 litres of diesel fuel and contributes 295 tonnes CO_2eq/well according to the authors. The authors were unable to determine if there were any differences in fugitive emissions between conventional wells and shale gas wells.

The authors then considered the lifetime production rates of a number of US shale gas fields, assumed that 50% of the wells would require refracturing once in their lifetime, and arrived at a range of emission increases from 140 to 1,630 g CO_2eq /GJ. They conclude that, while emissions from shale gas extraction may be higher than for conventional gas extraction, they are unlikely to be markedly so.

The data that was collected for this work have both higher drilling and hydraulic fracturing emissions and higher production rates and so the calculated GHG emission increase compared to conventional wells was at the low end of the range identified in the Tyndall report.

6.2 WORLDWATCH INSTITUTE

Worldwatch Institute and Deutsche Bank Climate Change Advisors recently released a report “Comparing Lifecycle Greenhouse Gas Emissions from Natural Gas and Coal” (Fulton et al, 2011). This report does not analyze in detail the components of the lifecycle GHG emissions in detail but rather relies on the analyses undertaken by other authors. The concludes that natural gas offers greenhouse gas advantages over coal despite higher EPA estimates of methane emissions from natural gas systems.

The report found that by applying the EPA's new estimates, the life-cycle greenhouse gas footprint of natural gas-fired electricity increased roughly 11 percent. The authors reported that despite the substantial increase in the methane assumed to be emitted during natural gas production, U.S. natural gas-fired electricity generation still released 47 percent fewer greenhouse gases than coal from source to use.

The study points out that regulatory and technological tools to reduce methane emissions are being demonstrated in some U.S. states and by some companies. Although reducing methane emissions has been largely voluntary to date in the United States, new EPA rules could require the natural gas industry to measure and report its greenhouse gas emissions and to use control technologies that will significantly reduce associated methane emissions as early as 2012.

Further highlights from the study:

- The EPA's recent upward revisions of methane emissions from natural gas are related largely to the production share of the gas value chain, especially during the unloading of liquids and (in the case of hydraulically fractured wells) during flowback.

- The life-cycle greenhouse gas footprint of natural gas is lower than coal under all "global warming potentials" tested, with the smallest difference calculated using a GWP for methane of 105, where the emissions are 27 percent less than those of coal-fired generation.

- Methane emissions during natural gas production, processing, transport, storage, and distribution can be mitigated now at moderately low cost using existing technologies and best practices. Such capture potential presents a commercial and investment opportunity that would further improve the life-cycle greenhouse gas footprint of natural gas.

6.3 HOWARTH, SANTORO AND INGRAFFEA

The Howarth et al paper (2011) has claimed that the GHG emissions for shale gas are 20% higher than the emissions from coal when considered over a 20 year time frame and equivalent when considered over a 100 year time frame. These emissions are significantly higher than those found here. While the paper purports to be a lifecycle analysis of shale gas, the focus of the paper is on methane emissions. The paper reports the methane emissions for conventional gas and for shale gas as shown in the following table.

Table 6-1 Fugitive Methane Emissions – Howarth et al

	Conventional gas	Shale gas
		% Loss
Well Completion	0.01	1.9
Venting and Leaks in Operation	0.3-1.9	0.3-1.9
Emissions during Liquid Unloading	0-0.26	0-0.26
Emissions during Gas Processing	0-0.19	0-0.19
Emissions during Transport, Storage, and Distribution	1.4-3.6	1.4-3.6
Total Emissions	1.7-6.0	3.6-7.9

Howarth believes that the major difference in emissions between conventional and shale gas is in the well completion stage. For all of the other stages he assumes that the emissions are the same for the two different sources.

Howarth et al use a variety of secondary sources to estimate the methane losses during the various stages. In all cases they ignore the possibility that the fugitives could be flared rather than vented. The losses in the well completion category are based mostly on the same PowerPoint presentations that the EPA used in their 2010 emission factor update and misinterprets the data to assume that all of the gas is released to the environment.

The gas lost during routine operation is from a US GAO study undertaken in 2010. This report estimated gas that was vented or flared from federally owned land (both onshore and offshore). The GAO report does not generally differentiate between gas that is vented and gas that is flared. Howarth assumes that it is all vented, an unreasonable assumption.

The estimate of gas loss during well liquid unloading is also based on the GAO study. The GAO reports gas flared or vented, Howarth assumes it is vented.

The estimate of gas loss during process is based on an EPA emission factor. It is similar to the emission factor used in GHGenius. Gas processing methane emissions in Canada are reported to be much lower.

The emissions during transport, storage and distribution are based on a number of sources, including gas "lost and unaccounted for". Thus metering differences are assumed to be methane losses in the Howarth study. The information in the Howarth report is not suitable as a data source for modelling, it uses secondary data sources and there are clearly interpretation errors.

6.4 Conclusions

The GHG emissions for shale gas calculated by this revised version of GHGenius are not significantly different than those previously calculated in version 3.18, when unconventional gas sources were added to the model except that the CO2 content of the field can be modelled separately. There is an increase in emissions attributed to higher drilling emissions. The comparison of shale gas emissions from the two model versions is shown in the following table.

Table 6-2 Upstream GHG Emissions Shale Gas

	GHGenius 3.18	GHGenius 3.20sg	
		1% CO_2	12% CO_2
	g CO_2eq/GJ		
Fuel dispensing	0	0	0
Fuel distribution and storage	1,340	1,308	1,444
Fuel production	1,414	1,434	1,577
Feedstock transmission	0	0	0
Feedstock recovery	1,742	1,969	2,106
Feedstock Upgrading	0	0	0
Land-use changes, cultivation	0	0	0
Fertilizer manufacture	0	0	0
Gas leaks and flares	1,369	2,082	2,082
CO_2, H_2S removed from NG	2,473	0	6,072
Emissions displaced	0	0	0
Total	8,338	6,793	13,280

The higher emissions are due to the increased energy use in drilling and an increase in the methane loss rate that applies to all types of natural gas in the Canada. The gas content of the shale gas fields makes a larger impact on the overall GHG emissions than does the increase in emissions from drilling and hydraulic fracturing.

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