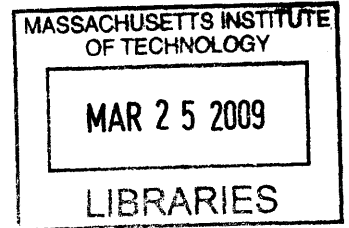# Life-cycle Assessment of Greenhouse Gas Emissions from Alternative Jet Fuels

by

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Submitted to the Engineering Systems Division
in Partial Fulfillment of the Requirements for the Degree of

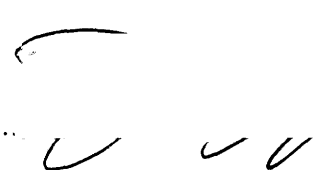Master of Science in Technology and Policy

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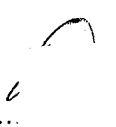
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Life-cycle Assessment of Greenhouse Gas Emissions from Alternative Jet Fuels

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Hsin Min Wong

Submitted to the Engineering Systems Division on August 8, 2008 in Partial Fulfillment of the Requirements for the Degree of Master of Science in Technology and Policy

Abstract

The key motivation for this work was the potential impact of alternative jet fuel use on emissions that contribute to global climate change. This work focused on one specific aspect in examining the feasibility of using alternative jet fuels – their life-cycle Greenhouse Gas (GHG) emissions relative to conventional jet fuel. This involved the quantification of the overall GHG emissions of potential alternative jet fuels, from feedstock recovery and transportation, to the production, transportation and utilization of the fuels. The fuels examined in this work included jet fuel and ultra-low sulfur jet fuel from conventional crude, jet fuel from oil sands and oil shale, Fischer-Tropsch jet fuel from natural gas, coal and biomass, and biojet from soy oil and palm oil. By identifying and varying important input parameters, a range of life-cycle GHG emissions for each fuel pathway was derived.

From the analyses in this work, only alternative jet fuels from biomass offer substantial life-cycle GHG emissions reductions compared to conventional jet fuel, and that is true only if land use change emissions were negligible. Direct or indirect land use changes from the use of biomass feedstocks (particularly food crops) could potentially increase life-cycle GHG emissions to levels several times above that of conventional jet fuel.

A scenario analysis was conducted to examine the amount of biofuel needed to displace conventional jet fuel in 2025 to maintain U.S. aviation GHG emissions at baseline 2006 levels. It was found that the large-scale deployment of biofuels to achieve carbon-neutral U.S. aviation growth through 2025 was limited by feedstock and land availability if current generation biofuels (particularly those made from food crops) were used. Hence, it is important to explore the use of next generation non-food, high yield feedstocks (e.g. algae) that use little land and result in little or no land use change emissions for large-scale biofuel production.

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Acronyms and Abbreviations

AAPG	American Association of Petroleum Geologists
ACR	Alberta Chamber of Resources
AEO	Annual Energy Outlook
AEUB	Alberta Energy and Utilities Board
ATA	Air Transport Association
ATP	Alberta Taciuk Processor
BPD	Barrels Per Day
BTL	Biomass-to-Liquids
CAPP	Canadian Association of Petroleum Producers
CCS	Carbon Capture and Storage
CH_4	Methane
CO_2	Carbon Dioxide
CTL	Coal-to-Liquids
DEFRA	Department for Environment, Food and Rural Affairs
DESC	Defense Energy Support Center
DOE	United States Department of Energy
DTI	Department of Trade and Industry
EIA	Energy Information Administration
EPA	Environmental Protection Agency
ERS	Economic Research Service
FAA	Federal Aviation Administration
FAPRI	Food and Agricultural Policy Research Institute
F-T	Fischer-Tropsch
GDP	Gross Domestic Product
GHG	Greenhouse Gases
GREET	Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation
GTL	Gas-to-Liquids
GWP	Global Warming Potential
HHV	Higher Heating Value
IBCC	International Boreal Conservation Campaign
ICP	In-situ Conversion Process
IGCC	Integrated Gasification and Combined Cycle
IPCC	Intergovernmental Panel for Climate Change
LCA	Life-Cycle Assessment
LHV	Lower Heating Value
LPG	Liquefied Petroleum Gas
mmBtu	Million British Thermal Units
N_2O	Nitrous Oxides
NEB	Canadian National Energy Board
NG	Natural Gas
NO_x	Nitrogen Oxides
OAGC	Office of the Auditor General of Canada

OMAFRA	Ontario Ministry of Agriculture, Food & Rural Affairs
OTPEISIC	Oil shale and Tar sands Programmatic Environmental Impact Statement Information Center
OTS	Oilfield Technical Society
PKE	Palm Kernel Expeller
PKO	Palm Kernel Oil
POME	Palm Oil Mill Effluent
PPM	Parts Per Million
SAGD	Steam Assisted Gravity Drainage
SCF	Standard Cubic Feet
SCO	Synthetic Crude Oil
SO_X	Sulfur Oxides
SSEB	Southern States Energy Board
Ton	Short Ton (2000 pounds)
ULS	Ultra Low Sulfur
USAF	United States Air Force
USDA	United States Department of Agriculture
WNN	World Nuclear News
WTI	West Texas Intermediate
WTT	Well-to-Tank
WTW	Well-to-Wake

Chapter 1: Introduction

1.1 Background

Conventional petroleum-based fuels have been the jet fuel of choice for decades due to their "best combination of energy content, performance, availability, ease of handling and price". (Hemighaus et al., 2006a) However, climate change concerns associated with the use of traditional petroleum-based jet fuels, coupled with steep increases in the price of petroleum over the past few years, with oil prices rising over $140/barrel, have intensified the urgency in the search for alternative jet fuels. If produced in sufficiently large quantities to displace a significant portion of conventional jet fuels, alternative fuels offer the potential to reduce price and environmental impacts of aviation, as well as contributing to energy security through diversification of fuel sources.

This work focused on one specific aspect in examining the feasibility of using alternative jet fuels – their life-cycle Greenhouse Gas (GHG) emissions. This involved the quantification of the overall GHG emissions of potential alternative jet fuels, from feedstocks recovery and transportation, to the production, transportation and utilization of fuels.

1.2 Motivation I – Exploring Alternative Jet Fuels

1.2.1 Climate Change

The key motivation for this work is the impact of aviation on global climate change. Though aviation only contributes about 2% of global CO_2 emissions (IPCC, 1999) and 2.7% of U.S. GHG emissions (DOT, 2008), there is considerable pressure on aviation to take actions to reduce its carbon footprint, just like the larger land transportation sector.

Air travel has grown rapidly over the past several decades, fueled by growth in population, labor force and Gross Domestic Product (GDP). In particular, aviation growth has outpaced other modes of transportation. (FAA, 2005) The continued trend in the growth in demand for air transportation means that its contribution to global GHG emissions will increase. The Intergovernmental Panel on Climate Change (IPCC) estimates that increased air transport over the next 50 years could result in a tripling of aircraft CO_2 emissions; the Federal Aviation Administration (FAA) projects that GHG emissions from domestic aircraft could increase 60% by 2025. (IPCC, 1999; FAA, 2005) These forecasts are further fueling concerns about aviation emissions and are driving actions to curb them.

In Europe, though aviation only accounts for about 3% of the EU's total GHG emissions, aviation CO_2 emissions have increased by 87% since 1990 and are expected to more than double by 2020. (EUbusiness, 2008) Driven by concerns over aviation's impact on

climate change, plans to build additional runways at UK Stansted and Healthrow airports have been put on hold. (Hileman et al., 2008 and references therein) In July 2008, in a bid to curb aviation's fast-rising GHG emissions, the EU finalized a deal with governments to include aviation in the EU's Emission Trading Scheme from 2012. Airlines will be required to cut CO_2 emissions by 3 percent in the first year, and by 5 percent in subsequent years or buy carbon dioxide credits from industries with surpluses. (Harrison, 2008)

In the U.S., actions to curb global warming from aviation are less intense but nonetheless rising. The proposed Lieberman-Warner Climate Security Act of 2008, which would aim to reduce U.S. GHG emissions through a cap-and-trade GHG emissions trading scheme, included the aviation sector. Though the bill was eventually rejected in June 2008 due to concerns over its adverse impacts on the U.S. economy, it underscored rising U.S. awareness of the need to curb GHG emissions, including those from aviation. (ATA, 2007a; Sheppard, 2008) For instance, California, together with four other states (Connecticut, New Jersey, New Mexico and Pennsylvania) and some environmental groups, filed a petition with the U.S. Environmental Protection Agency in December 2007 to curb rising aircraft emissions that contribute to global climate change. In particular, the use of alternative fuels was one of the suggested measures in the petition to reduce GHG emissions from aviation. (Earth Justice, 2007) In addition, the use of alternative fuels also offer the potential to substantially reduce emissions of airborne particulate matter, an EPA criteria pollutant, reducing aviation's impact on air quality. (Hileman et al., 2008)

1.2.2 Price

The high price and price volatility of conventional jet fuels is another key driver in the search for alternative jet fuels. Since the start of this research work almost two years ago, the price of crude oil has doubled to over $140/barrel. Fuel cost overtook labor cost as the top airline operating expense for first time in 2006 (ATA, 2007b). Jet fuel now constitutes between 30 to 50 percent of the airline industry's expense. In 2008, U.S. airlines' expenditure on fuels is expected to increase by almost 50% over the amount spent the previous year. (May, 2008) The availability of cost-competitive alternative fuels (either through technological advancements or government incentives), in sufficient amount to displace a significant amount of conventional jet fuel, could foreseeably increase the market supply of jet fuel, resulting in a lower price for jet fuel.

1.2.3 Energy Security

In 2006, the U.S. imported more than 60% of its crude oil needs. Almost 49% of crude oil imports came from countries in the Western Hemisphere (e.g. North, South and Central America) and 16% came from the Persian Gulf. (EIA, 2008a) The use of alternative jet fuel, particularly those made domestically or from other regions of the world, could diversify energy sources, diminish potential impacts of supply disruptions, reduce reliance on foreign imported crude oil from any one region, and thereby contribute to enhanced energy security. In particular, the U.S. has increasingly turned to its neighbor

and ally Canada for crude oil, particularly synthetic crude made from Canadian oil sands. Canada is currently the U.S.'s top supplier of crude oil, overtaking Saudi Arabia and Mexico in 2004. Crude oil imports from Canada have increased by almost 50% over the past decade and are expected to increase further in the coming years with expansion of oil sands production in Canada. (EIA, 2008b) In addition, to promote greater domestic liquid fuels production, the new Renewable Fuel Standard (RFS) increases the required renewable fuel production in 2008 from 5.4 billion gallons to 9 billion gallons. This will rise to 36 billion gallons by 2022. (Sissine, 2007)

1.3 Motivation II – Quantifying Life-Cycle GHG Emissions

Arising from climate change concerns, government policies in both the U.S. and Europe are linking support for alternative fuels to the potential reduction in life-cycle GHG emissions over conventional fuels. In Europe, biofuels must provide GHG emission reductions of at least 35% compared to conventional fossil fuels in order to count towards EU's proposed target that 10% of transport fuels be made up of biofuels by 2020 and to receive financial subsidies. (de Dominicis, 2008) In the U.S., under the Energy Independence and Security Act of 2007, the expanded Renewable Fuel Standard includes the requirement that renewable fuels produced in new facilities must have life-cycle GHG emissions that are at least 20% below that of gasoline. In addition, section 526 "prohibits federal agencies from procuring synfuel unless its life-cycle GHG emissions are less than those for conventional petroleum resources." (Sissine, 2007) These legislative actions highlight the importance of the quantification of life-cycle GHG emissions as one measure of environmental feasibility, which can in turn guide policy-making and investment decisions. Other sustainability criteria like impacts on land, water, biodiversity, etc. while not specifically considered in this work, are also important factors in evaluating the overall feasibility in the use of an alternative fuel (these are discussed further in Chapter 7).

In addition, much of the existing work on life-cycle analysis has focused on emissions of land transportation fuels and their potential alternatives. Little, if any, work has been devoted to aviation fuels. This work is an effort to contribute to the limited literature on the quantification of the life-cycle GHG emissions of jet fuels.

1.4 Research Questions

In the investigation of the life-cycle GHG emissions of alternative jet fuels, the first and foremost task was to identify the list of potential candidate fuels. The list used in this study was based on previous work (Hileman et al., 2008) and is summarized below. Thereafter, this work quantifies the life-cycle GHG emissions of conventional jet fuel and select alternative jet fuels. Comparisons between the GHG emissions of these alternative fuels are given relative to the baseline conventional jet fuel.

Hence, the key research question in this thesis is:

"What are the life-cycle GHG emissions of potential alternative jet fuels and how do they compare to the emissions of conventional jet fuel?"

As curbing GHG emissions from aviation was a key motivation in this work, a natural follow-up question is:

"Are there alternatives to conventional jet fuel which offer the potential to reduce GHG emissions of aviation?"

Though not explored at length in this work, some key implications (e.g. feedstock requirements, sustainability issues) related to the use of these alternative fuels are also discussed.

1.4.1 Identification of Potential Alternative Jet Fuels

Some potential fuels which have been discussed in the context of aviation include alcohols, biodiesel blends, synthetic paraffinic kerosene-type jet fuels (Fischer-Tropsch fuels and biojet[1]) made from various feedstocks, Jet A and ultra-low sulfur (ULS) Jet A made from unconventional resources like oil sands and oil shale, and cryogenic fuels like liquid hydrogen and liquid methane (see Table 1). The short-listed candidates for further evaluation in this work (also see Table 1) were chosen mainly based on considerations of their energy content and their potential availability in the relative near-term (within a decade). To be readily deployed within the short term, they have to be "drop-in" capable, (i.e. they can be used without major modifications to existing aircraft and transportation infrastructure).

Cryogenic fuels like liquid hydrogen or liquid methane were not considered in this work as they are incompatible with existing aircraft and pipeline infrastructure, necessitate complete aircraft re-design, and are highly unlikely to be available for commercial aviation within the next decade. Alcohols and bio-diesels, which are oxygenated compounds, unlike Jet A, were not evaluated in this work. This was mainly due to their unfavorable energy content relative to Jet A. However, there are also concerns regarding incompatibility with current pipeline infrastructure and performance characteristics which render them non-ideal for use in aviation. These fuels are more appropriate for land transportation. (Hileman et al., 2008)

The potential and short-listed alternative jet fuels discussed above are shown in Table 1.

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[1] Biojet in this work refers to a synthetic paraffinic kerosene-based jet fuel (with similar chemical composition and distillation range of conventional jet fuel) made from the hydrotreatment of plant, animal or waste oils.

Table 1: Potential and Short-listed Alternative Jet Fuels

Potential fuels	Chemical composition	Potential feedstocks
Jet A	C_mH_n	*Conventional crude, unconventional crude (e.g. oil sands, oil shale)*
ULS Jet A	C_mH_n	*Conventional crude, unconventional crude (e.g. oil sands, oil shale)*
Fischer-Tropsch synthetic fuels	C_mH_n	*Natural gas, coal, biomass*
Biojet	C_mH_n	*Oil from biomass, animal fat or waste grease*
Bio-diesel	$C_mH_nO_2CH_3$	Oil from biomass, animal fat or waste grease
Alcohols	C_mH_nOH	Biomass
Liquid hydrogen	H_2	Natural gas, coal, biomass
Liquid methane	CH_4	Natural gas, coal, biomass
Note: The short-listed alternative fuels are italicized.		

1.5 Thesis Roadmap

This work quantifies the GHG emissions of potential alternative jet fuels, compares these emissions with those of baseline jet fuel, and thereby identifies promising alternative fuels which could reduce GHG emissions for aviation. Overall, only alternative fuels made from biomass feedstocks (e.g. Fischer-Tropsch fuel from biomass, biojet) provide appreciable GHG emissions compared to conventional jet fuel, and this is true *if* potential land use change emissions associated with the cultivation of biomass feedstocks were avoided.

This thesis is organized into 8 chapters. Chapter 2 details the methodological approach used in conducting the life-cycle assessment of the GHG emissions of alternative jet fuels short-listed in this chapter. In particular, the GREET (Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation) framework created by Argonne National Laboratory was the key framework used in the calculation of life-cycle GHG emissions. Key assumptions (e.g. time period of analysis, fuel properties, method of allocating emissions to co-products, land use change emission issues associated with the use of biofuels, dealing with uncertainties) made in deriving the results of this work are also discussed.

Chapters 3 to 6 provide detailed analysis of the life-cycle GHG emissions of baseline jet fuel and each alternative jet fuel pathway. Specifically, Chapter 3 focuses on baseline Jet A and ULS Jet A made from conventional crude oil; Chapter 4 discusses jet fuel made from unconventional petroleum resources, namely oil sands and oil shale; Chapter 5

explores Fischer-Tropsch jet fuels from natural gas, coal and biomass feedstocks; while Chapter 6 elaborates on the production of biojet from soy oil and palm oil. For each pathway, the steps involved and key assumptions made from the recovery of the feedstock to final fuel utilization are stated. Key sources of uncertainties are highlighted and sensitivity studies were conducted to determine the impact of these parameters on the overall GHG emissions of the pathway where necessary. In addition, three potential scenarios (low emissions case, baseline case and high emissions case) were identified for each pathway and life-cycle GHG emissions were calculated for each of these scenarios. Hence, a range of possible GHG emissions rather than a single value is provided for each pathway.

Chapter 7 presents the key results of this work and compares the relative merits and implications of the use of each alternative fuel (e.g. feedstock and land use requirement, sustainability issues). A scenario analysis was also conducted and presented in this chapter. Scenarios were created to examine the amount of biofuel needed to displace conventional jet fuel in 2025 to maintain U.S. aviation GHG emissions at baseline 2006 levels. The implications on resource requirements are also discussed. Specifically, it was found that the large-scale deployment of biofuels (e.g. to displace a significant amount of conventional jet fuel to maintain 2006 baseline GHG emission levels) would be severely limited by feedstock and land availability if current generation biofuels (particularly those made from food crops) were used.

Chapter 8 summarizes the main findings of this work and provides recommendations for future work. A key recommendation is to explore the use of non-food, high yield crops (e.g. algae) or waste products, which do not require the use of large areas of arable land or contribute to the creation of land use emissions. Food-based feedstocks appear to be undesirable for large-scale fuel production due to the potential for adverse land use change impacts.

Chapter 2: Methodology

2.1 Well-to-Wake (WTW) Analysis

The main objective of this work was to quantify the life-cycle or "well-to-wake" GHG emissions in the production and utilization of jet fuel and alternative jet fuels. This involved analyzing the GHG emissions in the whole fuel production process (well-to-tank), as well as the CO_2 emissions during the combustion of the fuel in an aircraft (tank-to-wake). The work behind this thesis focused on deriving the well-to-tank GHG emissions of jet fuel and various alternative fuel pathways, while CO_2 emissions from fuel combustion were obtained from Hileman et al., 2008.

Specifically, the well-to-tank (WTT) fuel production analysis incorporated the entire fuel life-cycle from extraction and upgrading of raw materials or production of feedstock (e.g. recovery of crude oil, cultivation of biomass), transportation of these materials to the production facility, processing of the feedstock to final fuel (e.g. through gasification, refining), and the subsequent transportation and distribution of this fuel to the aircraft (see Figure 1). The analysis provided a quantification of the GHG emissions of this whole fuel cycle per unit energy of fuel delivered to the aircraft tank.
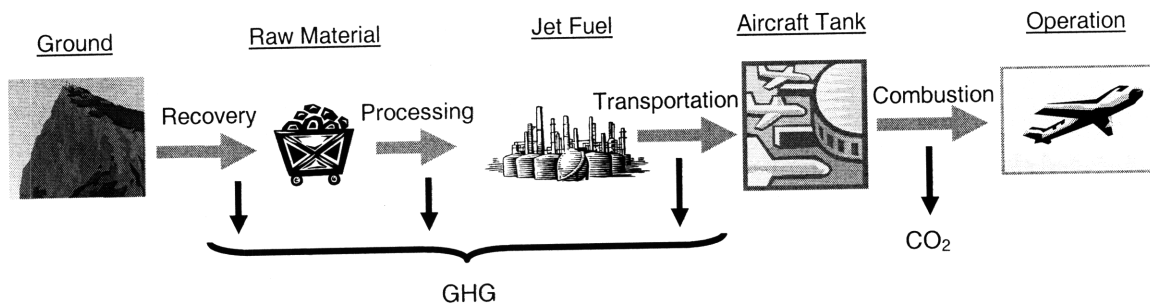
Figure 1: Steps Involved in the Well-to-Wake Analysis

This study did not consider energy or GHG emissions associated with the creation of infrastructure such as extraction equipment, transportation vehicles, farming machinery, processing facilities, etc. The impact of such emissions on the total life-cycle GHG emissions of the pathway is usually relatively small, and within the uncertainty range of the analysis. (Hill et al., 2006, Edwards et al., 2007)

2.2 Fuel Pathways Analyzed

As discussed in Chapter 1, this work explored the life-cycle GHG emissions of potential alternative jet fuels which could be available in the near term, with a focus on those which could be derived from North American resources (exceptions will be noted) Specifically, the fuels analyzed in this work were jet fuel and ULS jet fuel from conventional crude oil, jet fuel from unconventional petroleum resources (Canadian oil

sands and oil shale), Fischer-Tropsch jet fuel (from natural gas, coal and biomass), and biojet (from soy oil and palm oil). The fuel pathways are summarized in Table 2.

Table 2: Fuel Pathways Investigated

Source	Feedstock	Recovery	Processing	Final product
Petroleum	Conventional crude	Crude extraction	Crude refining	Jet fuel
	Conventional crude	Crude extraction	Crude refining	ULS jet fuel
	Canadian oil sands	Bitumen mining/ extraction and upgrading	Syncrude refining	Jet fuel
	Oil shale	In-situ conversion	Shale oil refining	Jet fuel
Coal	Coal	Coal mining	Gasification, F-T reaction and upgrading (with and without carbon capture)	F-T Jet fuel
Natural gas	Natural gas	Natural gas extraction and processing	Gasification, F-T reaction and upgrading	F-T jet fuel
Biomass	Biomass	Biomass cultivation	Gasification, F-T reaction and upgrading	F-T jet fuel
	Renewable oil (soy oil)	Biomass cultivation and extraction of plant oils	Hydrotreating	Biojet
	Renewable oil (palm oil – from South-east Asia)	Biomass cultivation and extraction of plant oils	Hydrotreating	Biojet

2.3 Life-cycle Analysis Tool – GREET Framework

The *G*reenhouse gases *R*egulated *E*missions and *E*nergy use in *T*ransportation (GREET) framework developed by Argonne National Laboratory was the key tool used in the well-to-tank analysis of the GHG emissions of the various fuel pathways. GREET was first developed in 1996 under funding from DOE and had been continually expanded and updated. The latest version of GREET for fuel-cycle analysis (GREET 1.8b) was updated in May 2008 and incorporates more than 100 fuel production pathways. GREET's data are based mainly on U.S. conditions (e.g. U.S. electricity generation mix, U.S. industry statistics, U.S. transportation modes and distances).

Besides GREET, other life-cycle assessment (LCA) models are available, e.g. Canadian GHGenius, E3 database and Ecobalance by Price Waterhouse Coopers in Europe and Life-cycle Emission (LEM) model by University of California, Davis. However, GREET was chosen as the key framework in this analysis as its data is U.S.-centric, which was the focus of this work, and it is widely accepted as an established framework for the evaluation of energy and environmental impact of fuel production pathways and land vehicle systems. The Society of Automotive Engineers have accredited GREET as the "gold standard" for well-to-wheel analyses of vehicle/fuel systems. Since its inception, GREET has been used by both the government (e.g. U.S. Department of Energy) and industry (e.g. General Motors) and currently has more than 5,000 registered users in North America, Europe and Asia. (Wang, 2007)

However, a key limitation of the GREET framework is that it is designed for land transportation fuels and vehicle systems and does not include jet fuel production pathways. Also, not all pathways analyzed in this work are available in GREET (e.g. jet fuel from oil shale). Hence, this work utilized data from the literature on jet fuel and jet fuel alternatives where available (e.g. fuel properties, refining efficiency) and incorporated them into the GREET framework in order to derive life-cycle GHG emissions. Where data specific to alternative jet fuels were not available, diesel fuel was used as a surrogate for jet fuel due to similarities in chemical composition. (Hileman et al., 2008)

In this work, the GREET framework was primarily used as a database and calculation platform where the quality of output energy and emission numbers obtained depended on the quality of input assumptions such as energy efficiencies, fuel properties, type and share of process fuels, and emission allocation method for co-products. Hence, a de novo approach was taken in identifying and reviewing key inputs and assumptions for each pathway. Default GREET values for these key parameters were updated wherever necessary through reviews of recent information available in the literature. Where a specific pathway was not available in GREET, the pathway was built from scratch within the GREET framework with all relevant input parameters gathered from the open literature.

Though the latest version of GREET is version 1.8b released in May 2008, the analysis in this work was carried out using GREET version 1.8a (August 2007) as this was the latest version available when the bulk of the analytical work was being conducted. One key update made in GREET version 1.8b over 1.8a was the refining efficiencies of petroleum products like gasoline, diesel, naphtha, liquefied petroleum gases (LPG) and residual oil. The new refining efficiencies of these products were applied to this work.

2.4 Time Horizon of Analysis

The analysis in this work was on a near-term basis, with the time horizon of study within roughly the next decade. The fuel pathways and technologies considered were those

which were expected to be available within this time frame. To address technological improvements over time, the GREET model provides data up to 2020, in 5-year intervals. The year 2015 was used for this analysis.

2.5 Uncertainties

As mentioned before, GREET is an LCA tool and the robustness of the results depend on the quality of input parameters. Unfortunately, considerable uncertainties exist in some key assumptions (e.g. energy efficiencies, fuel properties), particularly for new, emerging processes, where forecast or modeled results, rather than actual performance parameters are used. Uncertainties also exist because different technologies and feedstocks may be used for the same process, resulting in different process energy requirement or product slate. In particular, for pathways involving biomass feedstocks, data on biomass farming energy and yields, nitrous oxide (N_2O) emissions from nitrogen fertilizer use and land use change emissions, etc. can vary greatly from site to site and these all depend on the type of cultivation process applied (e.g. tillage or no tillage). In general, industry-wide average values, where available, were applied in this analysis. In addition, the method used for accounting for energy and emissions of co-products can also have a significant impact on the final outcome. Some of these sources of uncertainty are examined in the following subsections.

2.5.1 Nitrous Oxide (N_2O) Emissions

N_2O emissions arise from the cultivation of agricultural crops mainly because of fertilizer application and the decomposition of biomass both above and below the ground. Direct N_2O emissions arise from the microbial processes of nitrification (oxidation of ammonia to nitrates, $NO3^-$) and denitrification (reduction of nitrates or nitrites, $NO2^-$) to gaseous nitrogen) in the soil, while indirect N_2O emissions occur through "volatilization of nitrate from the soil" and through "leaching and runoff of nitrate into water streams". (Huo et al., 2008) Estimates of N_2O emissions from the cultivation of crops usually have large uncertainties as they are affected by numerous factors such as "soil type, climate, crop, tillage method, and fertilizer and manure application rates". (Larson, 2005) In addition, the large global warming potential of N_2O (298 times that of CO_2) means that even small changes N_2O emissions can imply potentially large CO_2 equivalent GHG emissions, thus exacerbating the effect of uncertainties in determining N_2O emissions. As an illustration, N_2O emissions could potentially contribute 20 to 30% of the life-cycle GHG emissions of a biofuel pathway, but these emissions could also have an uncertainty range of ±200%. (Larivé, 2008)

In this work, N_2O emissions data were taken from the literature which primarily derived the values based on IPCC guidelines for N_2O emissions from managed soil.

2.5.2 Land Use Change Emissions

Land use change refers to the "conversion of one type of land to another" (Wicke, et al., 2007), for example the conversion of forests to cropland for growing soybeans. In such a conversion, the carbon content of the land changes due to changes in biomass (both above and below ground), soil and organic waste. The net result is sequestration or emission of carbon dioxide, called "land use change emissions." Specifically, in the context of biofuels production, direct land use change emissions occur when existing non-croplands like forests and grasslands are converted to cropland for the cultivation of crops for fuel production. Indirect land use changes, on the other hand, arise when existing cropland (particularly those use for food production) are diverted for fuel production, resulting in the conversion of non-croplands in other areas to cropland for the cultivation of food crops to replace the displaced crops.

Large uncertainties exist in determining land use change emissions. The carbon storage capacity associated with a particular type of land use is "site-specific and highly dependent on former and current agronomic practices, climate and soil characteristics". The estimation is further complicated by the slow time-frame over which carbon storage changes, which makes accurate measurements difficult. (Larson, 2005) In addition, to adequately account for potential indirect land use change impacts, in-depth analyses using general global equilibrium models that consider various factors such as "supply and demand of agricultural commodities, land use patterns, and land availability" are needed. (Wang and Haq, 2008) This is outside the scope of this work.

Rather than totally ignore the effect of land use change emissions, which is potentially an important contributor to life-cycle GHG emissions of biofuel production pathways, this work adopted existing literature data on potential land use change impacts (e.g. Fargione et al., 2008; Searchinger et al., 2008). The objective is to provide an illustrative rather than definitive example of the potential impacts of land use change emissions on the GHG footprint of using certain biomass feedstocks (e.g. soybeans, palm) for fuel production.

2.5.3 Allocation of Co-product Credits

Many fuel production pathways result in products in addition to the desired fuel. Four methods have generally been used to allocate life-cycle emissions among co-products of a process:

- Mass allocation
- Energy allocation
- Market-value allocation
- Displacement (or substitution, or system extension)

The method of choice can potentially lead to significantly different LCA results, particularly in the production of biofuels, where large quantities of co-products are created (e.g. extraction of soy oil from soybeans results in greater than four times more soybean meal being produced as compared to soy oil on a mass basis).

In general, the mass allocation approach is easy to apply as it allocates emissions based on co-product mass. It is sometimes a preferred technique if its application minimizes the contribution of co-products (e.g. when co-products are formed in small quantities relative to desired products), which is the desired outcome of a fuel production process design. (King, 2008) It is also favored by some analysts when the displacement method is not feasible as a suitable substitute for the co-product cannot be identified. (Hill et al., 2006) Other analysts are of the view that the mass allocation method has little logical meaning or physical relevance for co-products unless they can displace other products on a mass basis. (Wang, 1999)

The energy allocation approach allocates emissions based on energy content. Like the mass allocation approach, it has the advantage of ease of application; as one would expect, it is appropriate when apportioning emissions between energy products. In this work, it was used to allocate energy and emissions between co-products of the Fischer-Tropsch process as well as those in the hydroprocessing of renewable oils to make biojet as the co-products all have uses as energy sources.

Unlike the mass or energy allocation approach, the market value allocation could change with time. This is because it allocates emissions based on the market prices of the co-products. The sensitivity to market forces could be particularly meaningful for co-products of biofuel production as it appropriately allocates the larger share of energy and emissions to the key contributor to the biofuel production based on the economic forces driving the production. For example, when demand for biofuels increases biofuel production, the price of biofuel is expected to rise due to higher demand, while the price of co-products are likely to fall as their supply increases, resulting in more emissions being allocated to the main biofuel product and less to the co-products. This appropriately raises the importance of the main biofuel product as the key driver of the biofuel production pathway and its resultant emissions. (Fargione et al., 2008) Nonetheless, the unpredictability over time of the market value allocation is considered by some as a disadvantage as it adds a dimension of uncertainty to the calculation of the life-cycle GHG emissions of the biofuel pathway.

The displacement method is widely favored as the most appropriate and logical method to allocate energy and emissions among co-products as it "seeks to identify benefits from co-products and credit them to the desired fuel product." (Larivé, 2008) It assumes that the production of the incidental co-product displaces the production of a substitute product and hence gains the emission credit from the non-production of this displaced product. However, difficulties arise in identifying a suitable product to be displaced, calculating the life-cycle GHG emissions of that displaced product and determining the displacement ratio. (Huo et al., 2008) In the case of biofuels, the issue of how to appropriately allocate land use change emissions further complicates the application of the displacement method.

In addition, when a large amount of co-product is produced relative to the main product, the displacement method could "generate distorted results for the primary product" (Huo

et al., 2008). For example, it could result in net negative emissions for the pathway should the product being displaced have large life-cycle GHG emissions. This can potentially skew comparisons with other pathways where lesser co-products are formed. A case in point is that of electricity co-production in biofuel plants (e.g. ethanol plants). Where surplus power production in an ethanol plant has a lower GHG footprint than the marginal grid power it displaces (e.g. using natural gas combined heat and power production to displace coal-generated electricity), an emission credit for each kWh exported is apportioned to the ethanol produced. This means that for two ethanol plants using similar processes and process energy source for ethanol production, the one configured to produce greater surplus power for export would result in a lower GHG emissions footprint per MJ of fuel than the one which produces just enough power to be self-sufficient. Since the focus is to analyze GHG emissions of ethanol production rather than electricity production, an allocation method which minimizes the electricity impact might be more appropriate in this case. (Larson, 2005; Wu et al., 2006; Larivé, 2008)

Though there is no one "correct" method that applies to all cases, there are preferred methods being employed by different LCA experts. In particular, LCA experts from the European Union favor the energy allocation method for biofuel pathways as it is "easy to apply, predictable over time, minimizes counter-productive incentives and gives results that are generally comparable with the range of results given by the substitution method". (Friedrich, 2008; de Dominicis, 2008) On the other hand, experts from the Roundtable on Sustainable Biofuels, an international multi-stakeholder initiative focused on developing principles for sustainable biofuels production, recommends the displacement method as the preferred approach, with the energy allocation method being used for energy co-products, and the market value allocation method being applied if the displacement method is not feasible. (Opal, 2008)

The use of different approaches can potentially result in significantly different results, particularly in regards to biofuel pathways where significant quantities of co-products are being produced. The appropriate method may depend to a large extent on the type of question one seeks to answer in the analysis. Regardless of which method was applied, it is important that those conducting LCA emission analyses clearly state the allocation approach that was adopted.

2.5.4 Dealing with Uncertainties

Sensitivity studies were conducted to explore the impact of these uncertainties on the overall GHG emissions of the pathway. In addition, key input parameters were varied across three different scenarios (low emissions, baseline, and high emissions) for each pathway, and the corresponding life-cycle GHG emissions were determined for each scenario. Hence, a range of GHG emissions, rather than a single value, was derived for each pathway. Overall, this report aims to be transparent about assumptions used in arriving at the final results so that the reader can view the results in the context of the author such that they can amend assumptions as necessary for their own purposes.

2.6 Energy Ratio

Though this work focused on quantifying life-cycle greenhouse gas emissions, the overall energy efficiency of a pathway was also of interest in characterizing the merits of a fuel pathway. Hence, the well-to-tank energy efficiency of each pathway was also estimated. This was expressed as an overall energy ratio, defined as:

$$Overall\ Energy\ Ratio = \frac{Total\ Energy\ Out}{Total\ Energy\ In} \qquad (1)$$

The overall energy ratio was estimated from determining the amount of energy that would be needed to create 1 MJ of fuel, the "total energy out". The "total energy in" encompassed input feedstock energy and all primary process energy requirements (including energy from renewable sources like biomass). In this study, it was assumed that 1 MJ of input feedstock energy yielded 1 MJ of fuel energy, and all other energy inputs that were needed for this conversion (including energy for feedstock extraction/cultivation, processing and transportation) were accounted for as "process energy." In addition, this process energy was on a life-cycle basis (i.e. it not only took into account the actual amount of energy, for example natural gas to power a process, but also the energy needed to recover and transport this fuel to the process facility. Hence, the overall energy ratio can also be expressed as:

$Overall\ Energy\ Ratio$

$$= \frac{1\ MJ\ Fuel\ Output}{\left(1\ MJ\ Feedstock\ Input + Total\ Process\ Energy\ Input\ on\ a\ Life\text{-}cycle\ Basis\right)} \qquad (2)$$

Unlike many studies, this study chose not to differentiate between different types of process fuels (e.g. coal, natural gas or biomass) and included renewable energy sources when determining the overall energy ratio. The inclusion of all types of energy sources (including renewable energy from biomass) in the energy ratio calculation was intended to provide a straightforward approach in comparing the relative efficiency of various fuel creation processes.

2.7 General Assumptions

2.7.1 Functional Units

The well-to-tank GHG emissions for all pathways were determined in terms of grams of CO_2 equivalent per MJ of fuel delivered to the aircraft tank, and tank-to-wake (combustion) CO_2 emissions are expressed as grams of CO_2 per MJ of fuel utilized or burnt. All results are given relative to the life-cycle GHG emissions of baseline jet fuel (85 gCO_2e/MJ, derived in Chapter 3).

2.7.2 Global Warming Potential of GHGs

Jet fuel combustion results in other emissions that affect global climate change (e.g. NO_X, SO_X, particulate matter, water vapor, etc.). However, the focus here was on well-to-tank emissions and non-CO_2 combustion emissions were ignored. Future work should combine the well-to-tank emissions presented here with the full combustion emissions to estimate the overall climate impact. Therefore, the greenhouse gases considered in this study were carbon dioxide, methane and nitrous oxide.

Global Warming Potential (GWP) provides a measure of the relative radiative effect of a particular greenhouse gas relative to carbon dioxide and was used to place N_2O, CH_4 and CO_2 on equal footing. The GWP values of greenhouse gases assumed in this study were based on a 100-year horizon using data from the IPCC fourth assessment report. (IPCC, 2007) The GWP for the various greenhouse gases are given Table 3.

Table 3: Global Warming Potential of Greenhouse Gases

Greenhouse Gas	GWP over 100 years
Carbon dioxide	1
Methane	25
Nitrous oxide	298

2.7.3 Energy Content

The energy content of fuels is generally given either in terms of higher heating value (HHV) or lower heating value (LHV). HHV is the energy released during fuel combustion with the combustion products cooled to 25°C, i.e. water released during the process is in liquid form. On the other hand, LHV is the energy released during fuel combustion when the combustion products remain in gaseous form, i.e. water is released as water vapor. Hence, the difference between LHV and HHV is the heat released during the condensation of water vapor. Because aircraft exhaust, like that of ground transportation engines, has water in vapor form and not liquid form, this study used LHV for energy contents of feedstocks and fuels unless otherwise specified.

2.7.4 Coal-based Electricity Generation Efficiency

In this work, the efficiency of conventional coal-fired electricity plants and the newer coal integrated gasification and combined cycle (IGCC) plants used in the GREET framework were based on estimates from Deutch and Moniz, 2007. Specifically, the average generating efficiency of U.S. coal plants is about 33%, with newer units exceeding 36% (HHV basis), while the efficiency of coal IGCC plants is estimated to be 38.4% (HHV basis). The average difference in efficiency on a HHV basis versus LHV basis is about 3%. Hence, in this work, the efficiency of general coal-fired electricity

plants was assumed to be 36% and the efficiency of coal IGCC plants was assumed to be 41.5% (LHV basis). (Deutch and Moniz, 2007)

2.7.5 Feedstock and Fuel Specifications

The properties of the main feedstocks and fuels used in this analysis are given in Table 4. Default GREET (version 1.8a and 1.8b) fuel specifications were used, except where other sources are explicitly cited.

Table 4: Feedstock and Fuel Properties

Feedstock or Fuel	LHV (MJ/kg)	Density (kg/L)	Carbon content (wt %)	Sulfur content (wt ppm)	Source(s)
Crude oil or syncrude	41.3[1]	0.874	84.8[1]	14,100	EIA, 2008c
Conventional Jet A	43.2	0.804	86.2	600	Hileman et al., 2008
ULS Jet A	43.2	0.796	86.0	15	Hileman et al., 2008
Fischer-Tropsch jet fuel / Biojet	44.1	0.764	84.7	0	Hileman et al., 2008
Renewable diesel[2]	44.0	0.78	87.1	0	GREET, 2008
Coal (U.S. average)[3]	22.7	-	59.0	11,100	GREET 2007; EIA, 2006a
Bituminous coal[4]	24.4	-	61.2[5]	32,500	Deutch and Moniz, 2007
Petroleum coke[6]	33.2	-	92.3	68,000	EIA, 2006a; GREET, 2008
Asphaltenes[7]	36.9	-	81.0	82,000	Synenco Energy, 2006a; OTS, 2008
Biomass (forest residue)[8]	16.3	-	51.7	0	Baitz et al., 2004; GREET, 2007
Natural gas	47.1	0.00078	72.4	6	GREET, 2007
Hydrogen	120	0.00009	0	0	GREET, 2007

Notes:
(1) Energy content of crude oil assumed to be 5.8 million Btu per barrel (HHV); carbon content calculated from formula: percent carbon = 76.99 + (10.19×Specific Gravity) + (-0.76×Sulfur Content). (EIA, 1999)
(2) Used as surrogate for biojet in estimation of energy and emissions in hydrotreating of renewable oils to synthetic paraffinic fuels.
(3) As source of process energy (e.g. electricity generation). LHV and sulfur content from GREET, 2007; carbon content derived from coal HHV and U.S. average coal carbon emission factor of 26.0 million metric tons per quadrillion Btu for the electric power sector in 2004. (EIA, 2006a)
(4) For Coal-To-Liquids (CTL) process.
(5) The carbon emission factor for this coal is 25.5 million metric tons per quadrillion Btu, same as the average value of 25.5 for bituminous coal used in the U.S. reported in 2004. (EIA, 2006a)
(6) Used as a source of process energy in the refining of jet fuel. LHV and carbon content from EIA, 2006a, sulfur content from GREET, 2008.
(7) LHV and sulfur content from Synenco Energy, 2006a; carbon content calculated from general chemical formula of asphaltene ($C_{200}H_{246}N_2S_7O_4$) given in OTS, 2008.
(8) For Biomass-To-Liquids (BTL) process. LHV from Baitz et al., 2004 and carbon content from GREET, 2007.

Chapter 3: Jet A and Ultra-Low Sulfur Jet A from Conventional Petroleum

3.1 Introduction

Jet A, a kerosene-based fuel, has been the dominant commercial jet fuel used in the United States since the 1960s. It is largely produced from the refining of conventional crude oil. The sulfur content of jet fuel is limited to a maximum of 3,000 ppm under current specifications. Actual sulfur content of jet fuel can range from as low as below 10 ppm to over 2000 ppm. (Analysis of DESC data (1999-2006) in Hileman et al., 2008) There is a great disparity between jet fuel sulfur specifications and the current sulfur content restriction in road diesel fuels, which is capped at 15 ppm. This ultra-low sulfur (ULS) content restriction would be extended to fuels used by non-road, diesel engines in 2010, and locomotives and marine engines in 2012. (DieselNet, 2004) There is increasing interest in expanding the use of ULS fuel to aviation because of the potential benefit in reducing air pollutant emissions and reducing aviation's impact on air quality. (Sequeira, 2008; Hileman et al., 2008) This study analyzed the life-cycle GHG emissions in the production and use of both Jet A and ULS Jet A from conventional crude oil. The sulfur contents for Jet A and ULS Jet A in this study were assumed to be 600ppm and 15ppm, respectively.

3.2 Overall Analysis Approach

The jet fuel production pathway is not available in GREET, and this work attempted to derive the jet fuel production (from conventional crude) pathway using the GREET framework. This pathway would form the baseline for the analysis of life-cycle GHG emissions of alternative jet fuel. The key parameter needed to analyze the jet fuel production pathway was jet fuel refining efficiency, the estimation of which is described further below. The ULS jet fuel production pathway was derived in a similar manner as that for jet fuel.

The key processes involved in the production of jet fuel / ULS jet fuel from conventional crude oil and the key assumptions used are summarized in Table 5.

Table 5: Key Processes in the Production of Jet Fuel and ULS Jet Fuel from Conventional Crude Oil

Process	Key assumptions / Source
Recovery of Crude oil	Default GREET assumptions
Transportation of crude oil to refineries	Default GREET assumptions
Refining of jet fuel / ULS jet fuel	Derived using various sources in literature
Transportation and distribution of jet fuel / ULS jet fuel to final users	Default GREET assumptions for diesel fuel, assuming that the transportation and distribution of jet fuel require the same distances and transportation modes and shares as diesel.

3.3 Analysis of Jet fuel / ULS Jet Fuel Refining Efficiency

Two methods were employed in the derivation of jet fuel / ULS jet fuel refining efficiency. The first method was a top-down approach which derived jet fuel refining energy efficiency from the overall U.S. refining energy efficiency. The ULS jet fuel refining efficiency was in turn estimated from the jet fuel refining efficiency. The second method was a bottom-up approach which estimated jet fuel / ULS jet fuel refining efficiency by summing the energy required for the various refining processes needed to produce jet fuel / ULS jet fuel from crude oil.

3.3.1 Estimating Jet Fuel / ULS Jet Fuel Refining Efficiency from Overall Refinery Efficiency (Top-down Approach)

The overall U.S. refinery efficiency used in this study was 90.1%, estimated by Wang, 2008[2], based on statistics on process fuel use in U.S. refineries, and refinery fuel inputs and outputs in 2006 provided by the EIA. Overall refinery efficiency is defined as (Wang, 2008):

$$\eta_o = \frac{E_{products}}{E_{inputs}};$$ (3)

where η_o = petroleum refinery energy efficiency,
$E_{products}$ = energy in all petroleum products,
E_{inputs} = energy in crude input, other feedstock inputs, and process fuels used.

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[2] This work was used to update the refining efficiency of gasoline, diesel, LPG, residual oil and naphtha in the latest version of GREET (version 1.8b released in March 2008). (GREET, 2008)

The jet fuel-specific refining efficiency was derived from the overall refinery efficiency using the kerosene relative energy intensity estimated by Wang et al., 2004. Relative energy intensity was defined as "the ratio of total energy use share to the mass share of a given fuel." It provides a measure of how energy intensive the production of a particular fuel is relative to the mass share of that fuel produced. A relative energy intensity of more than 100% for a particular fuel means that the production of that fuel uses up a greater share of overall process energy than the mass share of that fuel produced. The energy intensity of the overall refinery is 100%. The relative energy intensity of the production of kerosene (jet fuel), X_s, based on an energy-content process allocation method calculated by Wang et al., 2004 is 62.4%.

The refining energy efficiency of jet fuel (η_s) was calculated from the overall refining efficiency, $\eta_o = 90.1\%$, and relative energy intensity of kerosene, $X_s = 62.4\%$, using the equation given by Wang et al., 2004:

$$\eta_s = \frac{1}{1 + X_s\left(1/\eta_o - 1\right)} \tag{4}$$

From equation (4), the refining energy efficiency of jet fuel is about 93.5%. This refining efficiency was used in the baseline case for the life-cycle analysis of GHG emissions in the production of jet fuel from conventional petroleum.

General Motors et al., 2001 provides an estimate of a 2% energy penalty for sulfur reduction in gasoline and diesel fuel from 350ppm to 5ppm. This work assumed that the same 2% energy penalty applies for the production of ULS jet fuel compared to jet fuel. Hence, the refining energy efficiency of ULS jet fuel was assumed to be 2% less than that of jet fuel, i.e. about 91.5%. As in the case of jet fuel, this refining efficiency was used in the baseline case for the life-cycle analysis of GHG emissions in the production of ULS jet fuel from conventional petroleum.

Based on 2006 U.S. refinery data published by the EIA, Wang, 2008 calculated the shares of process fuel used in U.S. petroleum refineries. This work adapted the process fuel shares given in Wang, 2008 as inputs to the GREET model for the production of jet fuel and ULS jet fuel (baseline cases). The process fuel shares assumed in the refining of jet fuel / ULS jet fuel used in the GREET model are shown in Table 6.

Table 6: Type of Process Fuel and Fuel Share in the Refining of Jet Fuel and ULS Jet Fuel

Type of process fuel	Process fuel share (%)
Electricity	3.5
Natural Gas	41.3
Refinery Gas	39.6
Coke	14.3
Residual Oil	1.3
Total	100

3.3.2 Estimating Jet Fuel Refining Efficiency from Individual Refining Processes (Bottom-up Approach)

The jet fuel produced by a refinery may be straight-run, or produced from cracked stocks that are hydroprocessed, or a blend or both (see Figure 2). (Hemighaus et al., 2006b) This work derived a refining efficiency by estimating the process energy needed to produce straight-run jet fuel as well as jet fuel produced through hydroprocessing. These two cases formed the low and high emissions scenarios, respectively, for the life-cycle analysis of GHG emissions in the production of jet fuel from conventional petroleum. The "top-down" estimate from Section 3.3.1 provided the baseline estimate.

The energy needed in the various processes involved in the refining of jet fuel were taken from a DOE-sponsored report by Pellegrino et al., 2007. A range of refining process energy use, as well as the average energy use were provided in this report. The average energy use data for the relevant refining processes were used to calculate the jet fuel refining efficiency in this work.
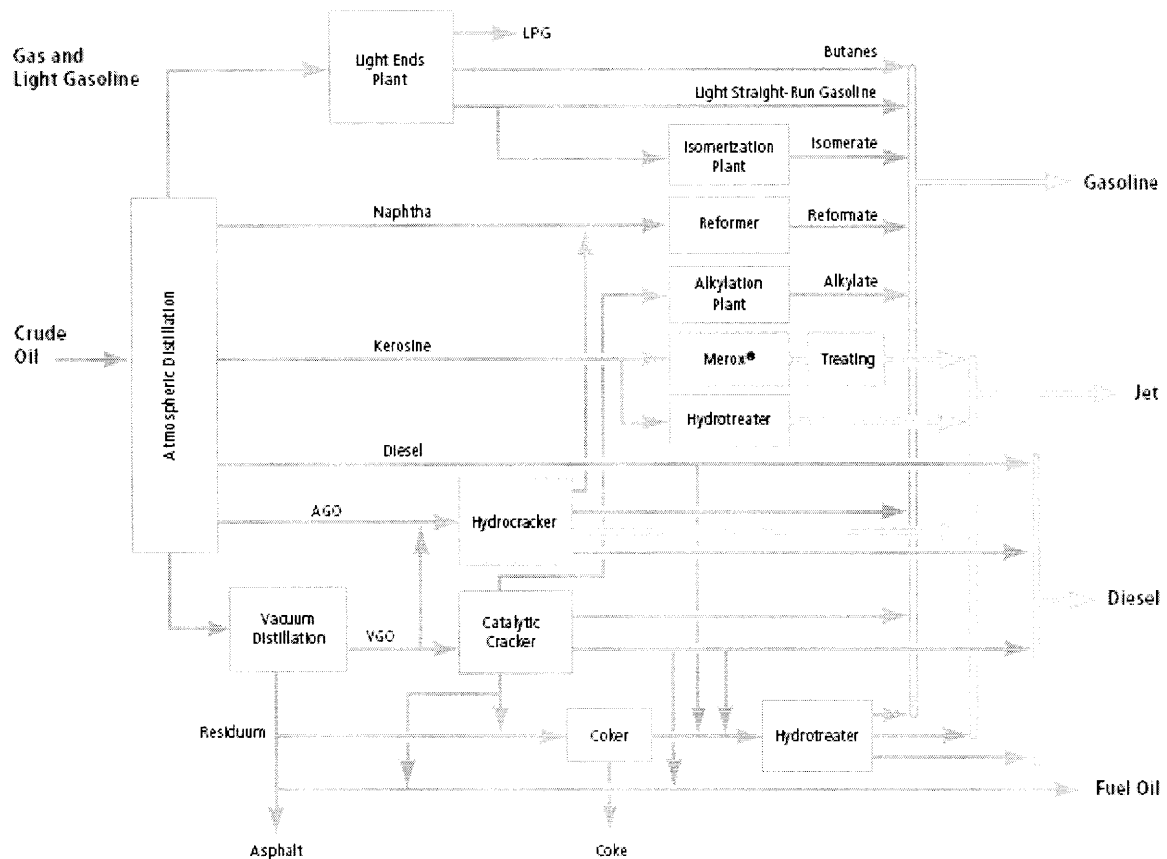
Figure 2: Typical Refinery Processes for Production of Jet Fuel (Hemighaus et al., 2006b)

3.3.2.1 Production of Straight-run Jet Fuel

The main processes involved in the production of straight-run jet fuel are crude desalting and atmospheric distillation, followed by chemical treatments (such as the Merox process)

to remove contaminants like mercaptans and organic acids, etc. The estimated process energy in crude desalting and atmospheric distillation is shown in Table 7 (see Appendix A for detailed calculations). As no data was found in the literature regarding the energy needed for chemical treatment, it was assumed that the energy needed for this process was negligible compared to the energy needed for atmospheric distillation.

Table 7: Energy Requirement in the Production of Straight-run Jet Fuel

Refining process	Energy required (Btu/mmBtu product)
Crude desalting and atmospheric distillation	20,055
Chemical treatment (remove mercaptans / organic acids, etc.)	No data available, assume to be very low compared to distillation
Total	20,055
Overall refining efficiency	98%

With these assumptions, the overall process energy requirement for the production of straight-run jet fuel is about 20,000 Btu/mmBtu of jet fuel produced. From this, the refining efficiency of jet fuel is about 98%. This refining efficiency likely represented the maximum efficiency for the production of jet fuel from conventional crude and was used in the low emissions scenario of this study.

The corresponding process fuel and fuel shares for the production of straight-run jet fuel is shown in Table 8 (derivation provided in Appendix A).

Table 8: Process Fuel and Fuel Shares for the Production of Straight-run Jet Fuel

Type of process fuel	Btu/mmBtu of jet fuel	Process fuel share (%)
Electricity	423	2.1
Natural Gas	5,772	28.8
Refinery Gas	9,669	48.2
Coke	3,548	17.7
Residual Oil	643	3.2
Total	20,055	100

3.3.2.2 Production of Straight-run ULS Jet Fuel

The production of straight-run ULS jet fuel requires crude desalting and atmospheric distillation followed by hydrotreatment to remove sulfur and other impurities. The estimated energy for these processes is shown in Table 9 (see Appendix A for detailed calculations).

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Table 9: Energy Requirement in the Production of Straight-run ULS Jet Fuel

Refining process	Energy required (Btu/mmBtu product)
Crude desalting and atmospheric distillation	20,055
Hydrotreatment (to S content of ~5ppm)	48,184
Total	68,239
Overall refining efficiency	93.5%

Hence, the overall process energy requirement for the production of straight-run ULS jet fuel is about 68,200 Btu/mmBtu of jet fuel produced. From this, the refining efficiency of ULS jet fuel is about 93.5%. This refining efficiency was used in the ULS jet fuel low emissions scenario of this study.

The corresponding process fuel shares for the production of straight-run ULS jet fuel are shown in Table 10 (derivation provided in Appendix A).

Table 10: Process Fuel and Fuel Shares for the Production of Straight-run Jet ULS Fuel

Type of process fuel	Btu/mmBtu of jet fuel	Process fuel share (%)
Electricity	3,806	5.6
Natural Gas	42,570	62.4
Refinery Gas	15,235	22.3
Coke	5,603	8.2
Residual Oil	1,025	1.5
Total	68,239	100

3.3.2.3 Production of Jet Fuel from Hydroprocessing

The refining processes that could be involved in producing jet fuel from hydroprocessing include crude desalting, atmospheric and vacuum distillation, and hydrotreating and/or hydrocracking. Since the production of this hydroprocessed jet fuel was treated as the high emissions scenario in this analysis, it was assumed that all the processes mentioned above (including both hydrotreating and hydrocracking) were required. The energy needed for the various refining processes to produce hydroprocessed jet fuel is shown in Table 11 (see Appendix A for detailed calculations).

Table 11: Energy Requirement in the Production of Jet Fuel from Hydroprocessing

Refining process	Energy required (Btu/ mmBtu product)
Crude desalting and atmospheric distillation	20,055
Vacuum distillation	16,379
Hydrotreating (to S content of ~500ppm)	24,368
Hydrocracking	75,092
Total	135,894
Overall refining efficiency	88%

The overall process energy requirement for the production of hydroprocessed jet fuel is about 136000 Btu/mmBtu of jet fuel produced. From this, the refining efficiency of jet fuel is about 88%. As mentioned earlier, this refining efficiency was assumed in the high emissions scenario of this study.

The corresponding process fuel shares for the production of hydroprocessed jet fuel are shown in Table 12 (derivation provided in Appendix A).

Table 12: Process Fuel and Fuel Shares for the Production of Jet Fuel from Hydroprocessing

Type of process fuel	Btu/mmBtu of jet fuel	Process fuel share (%)
Electricity	9,137	6.7
Natural Gas	82,683	60.9
Refinery Gas	30,713	22.6
Coke	11,294	8.3
Residual Oil	2,067	1.5
Total	135,894	100

3.3.2.4 Production of ULS Jet Fuel from Hydroprocessing

The calculation of the process energy required in the production of ULS jet fuel from hyprocessing is similar to that of jet fuel, except that additional hydrotreating is required to further reduce the sulfur content of jet fuel from about 500ppm to 5ppm. The energy needed for the various refining processes to produce hydroprocessed ULS jet fuel is shown in Table 13 (see Appendix A for detailed calculations).

Table 13: Energy Requirement in the Production of ULS Jet Fuel from Hydroprocessing

Refining process	Energy required (Btu/mmBtu product)
Crude desalting and atmospheric distillation	20,055
Vacuum distillation	16,379
Hydrotreating (to S content of ~5ppm)	47,578
Hydrocracking	75,092
Total	159,104
Overall refining efficiency	86%

The overall process energy requirement for the production of hydroprocessed ULS jet fuel is about 159000 Btu/mmBtu of jet fuel produced. From this, the refining efficiency of ULS jet fuel is about 86%. This refining efficiency was assumed in the "high" emissions scenario for the production of ULS jet fuel from conventional crude oil.

The corresponding process fuel shares for the production of hydroprocessed ULS jet fuel are shown in Table 14 (derivation provided in Appendix A).

Table 14: Process Fuel and Fuel Shares for the Production of ULS Jet Fuel from Hydroprocessing

Type of process fuel	Btu/mmBtu of jet fuel	Process fuel share (%)
Electricity	10767	6.8
Natural Gas	100408	63.1
Refinery Gas	33394	21.0
Coke	12284	7.7
Residual Oil	2251	1.4
Total	159104	100

3.4 Sensitivity Study on Crude Oil Quality

The quality of the average crude oil arriving at U.S. refineries has varied (generally decreasing) over time. This work investigated the effect of varying crude oil quality – in terms of sulfur content and density – on the life-cycle GHG emissions of the jet fuel and ULS jet fuel production pathways. Specifically, the quality of the average crude oil received by U.S. refineries in 1995, 2006 and 2015 (forecasted) formed the low, baseline, and high emission cases in this study. Information on the crude oil quality (sulfur content and specific gravity) received by U.S. refineries were obtained from the EIA. (EIA, 2008c) The corresponding carbon content of the crude oil was calculated from its sulfur content and specific gravity based on the following formula (EIA, 1999):

$$Percent\ Carbon = 76.99 + (10.19 \times Specific\ Gravity) + (-0.76 \times Sulfur\ Content) \qquad (5)$$

The variation in *average* crude oil property received by U.S. refineries from 1995 to 2015 is shown in Table 15.[3] It was assumed that the energy content of the different crude oils remained the same (EIA, 1999), and that the relatively small variations in sulfur content, carbon content and specific gravity did not affect the refining efficiency of jet fuel / ULS jet from these crude oils.

Table 15: Variation in Crude Oil Properties (1995 – 2015)

Year	1995	2006	2015
Specific Gravity	0.869	0.874	0.878
Sulfur content (weight %)	1.13	1.41	1.69
Carbon content (weight %)	85.0	84.8	84.6

3.5 Results

Through the variation of refining efficiency and crude oil quality, the life-cycle GHG emissions of the production of jet fuel from conventional crude for the low emissions, baseline and high emissions cases were estimated. The combustion CO_2 emissions data were obtained from Hileman et al., 2008. The results are shown in Table 16.

Table 16: Summary of Inputs and Results for Jet Fuel from Conventional Crude Pathway

	Low	Baseline	High
Refining efficiency	98.0%	93.5%	88.0%
Crude specific gravity	0.869	0.874	0.878
Crude carbon content (weight)	85.0%	84.8%	84.6%
Crude sulfur content (weight)	1.13%	1.41%	1.69%
WTT CO_2 emissions (gCO_2/MJ)	5.6	9.5	15.0
WTT CH_4 emissions (gCO_2e/MJ)	2.2	2.3	2.6
WTT N_2O emissions (gCO_2e/MJ)	0.03	0.05	0.08
WTT GHG emissions (gCO_2e/MJ)	7.9	11.9	17.7
Combustion CO_2 (gCO_2/MJ)	72.4	73.2	74.5
Total WTW GHG emissions (gCO_2e/MJ)	80.3	85.0	92.2
Total WTW GHG emissions relative to baseline conventional jet fuel	0.94	1.00	1.08
Overall energy ratio	0.94	0.89	0.83

Similarly, the low, baseline, and high emission cases for the production of ULS jet fuel from conventional crude were estimated, as shown in Table 17.

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[3] As a comparison, the specific gravity of heavy oil is at least 0.933 (<20 °API), the specific gravity of extra heavy oil, e.g. from Venezuela Orinoco belt, is > 1, or < 10 °API (Meyer and Attanasi, 2003), and the specific gravity of the benchmark light sweet crude, West Texas Intermediate (WTI), is around 0.827 (sulfur content of 0.24 weight %). (EIA, 2006b)

Table 17: Summary of Inputs and Results for ULS Jet Fuel from Conventional Crude Pathway

	Low	Baseline	High
Refining efficiency	93.5%	91.5%	86%
Crude specific gravity	0.869	0.874	0.878
Crude carbon content (weight)	85.0%	84.8%	84.6%
Crude sulfur content (weight)	1.13%	1.41%	1.69%
WTT CO_2 emissions (gCO_2/MJ)	9.5	11.3	17.1
WTT CH_4 emissions (gCO_2e/MJ)	2.4	2.4	2.7
WTT N_2O emissions (gCO_2e/MJ)	0.05	0.06	0.09
WTT GHG emissions (gCO_2e/MJ)	12.0	13.7	19.9
Combustion CO_2 (gCO_2/MJ)	72.9	72.9	72.9
Total WTW GHG emissions (gCO_2e/MJ)	84.9	86.7	92.8
Total WTW GHG emissions relative to corresponding conventional jet fuel	1.06	1.02	1.01
Overall energy ratio	0.89	0.87	0.81

The GHG emissions for the various steps in the production and use of jet fuel and ULS jet fuel (baseline cases) are shown in Table 18.

Table 18: GHG Emissions for Various Stages in Jet Fuel and ULS Jet Fuel from Conventional Crude Pathways

Stage emissions	Jet fuel	ULS jet fuel
Recovery (gCO_2/MJ)	2.8	2.8
Processing (gCO_2/MJ)	5.5	7.3
Transportation (gCO_2/MJ)	1.2	1.2
Well-To-Tank CH_4 and N_2O emissions (gCO_2e/MJ)	2.4	2.4
Combustion (gCO_2/MJ)	73.2	72.9
Total (gCO_2e/MJ)	85.0	86.7

3.6 Discussion

In the baseline case, where a refining energy efficiency penalty of 2% was assumed in the production of ULS jet fuel relative to conventional jet fuel, the production of ULS jet fuel results in life-cycle GHG emissions of about 2% greater than those of conventional jet fuel. In the low emissions case, the increase in life-cycle GHG emissions in the production of ULS jet fuel relative to conventional jet fuel is almost 6%. This is because the production of straight-run ULS jet fuel assumed in this case required an additional energy-intensive hydrotreating step compared to the production of straight-run conventional jet fuel. In the high emissions case, the difference in life-cycle GHG emissions between ULS jet fuel and conventional jet fuel is less than 1%. The energy

penalty in this case is that required to further hydrotreat jet fuel from about 500ppm to 15 ppm (~2% difference in refining efficiency). The increase in GHG emissions that result is partially offset by the lower CO_2 combustion emissions of ULS jet fuel compared to conventional jet fuel assumed in the high emissions case.

Even though the production and use of ULS jet fuel generally results in greater GHG emissions compared to conventional jet fuel, the former can provide important air quality benefits. For example, sulfur oxide emissions could be reduced by more than 95% while primary particulate matter emissions could be reduced by almost 15%. (Hileman et al., 2008) Hence, it is possible that the benefits from the improvement in air quality may outweigh the environmental burden resulting from the greater life-cycle GHG emissions that result from the use of ULS Jet A over conventional Jet A. A comprehensive environmental cost-benefit study in future follow-on work could verify this hypothesis. Overall, the use of ULS jet fuel in place of jet fuel merits further consideration and analysis (e.g. cost assessment, in-depth analysis of environmental impacts including air quality and global climate change).

Chapter 4: Jet Fuel from Unconventional Crude

4.1 Jet Fuel from Canadian Oil Sands

4.1.1 Introduction

Almost all of Canada's vast oil sands resources are concentrated in the Alberta region. Alberta's oil sands resources constitute one of the world's largest proven oil reserves, second only to Saudi Arabia. (Lacombe and Parsons, 2007) Bitumen production from oil sands takes place primarily by two methods, depending on the depth of the oil sand deposits. Relatively shallow deposits (75m or less) are recovered through surface-mining, which involves the removal of overburden, mining of the oil sands ore and extraction of bitumen from oil sands using hot water. For deeper deposits, in-situ production methods, which typically inject steam underground to reduce the viscosity of the bitumen and allow it to be extracted from the oil sands and pumped to the surface, are employed. (AEUB, 2007) The bitumen produced (usually from surface mining processes) can be upgraded to lighter synthetic crude oil (syncrude) through hydrogen-addition processes (e.g. ebullated bed hydroprocessing, hydrocracking) and/or carbon-subtraction processes (e.g. delayed coking).

In 2007, the total crude bitumen production from Alberta was about 1.32 million barrels per day, with about 59% being surface-mined, and the remaining 41% from in-situ production. (AAPG, 2008) Crude bitumen production is expected to more than double to about 3.1 million barrels per day in 2016 (AEUB, 2007), and reach between 3.8 to 4.4 million barrels per day by 2020. (CAPP, 2007) While bitumen production from surface mining projects form the majority of total production currently, the future of the oil sands industry lies in in-situ production. Oil sands reserves which are shallow enough for surface mining constitute only about 20% of the total remaining established reserves, the rest of which have to be recovered through in-situ technologies. (Lacombe and Parsons, 2007; NEB, 2006) The Alberta Energy and Utilities Board (AEUB) forecast that 57% of crude bitumen production in 2016 will come from surface mining and 43% from in-situ production. (AEUB, 2007)[4]

The U.S. is the largest market for Canada's oil production, absorbing 99% of its oil exports. Canada is also the top supplier of U.S.'s oil imports, providing 18.5% of total U.S. imported crude oil and petroleum products in 2007 (~2.4 million barrels a day). In 2007, oil sands production made up approximately 50% of Canada's total crude oil production. (EIA, 2008d) Currently, about 5% (~1 million barrels/day) of total oil

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[4] The Canadian National Energy Board (NEB), in a 2006 assessment, predicted that 52% of total bitumen production in 2015 would be surface-mined and remaining 48% recovered from in-situ production (NEB, 2006). The Energy Information Administration, in its Annual Energy Outlook 2004 publication, estimated the proportion of bitumen production of surface mining in 2015 to be 55%, and 45% from in-situ production. It also forecast 3.3 million per day of oil sand production in 2025, 57% of which was expected to be surface-mined, and 43% from in-situ production. (EIA, 2004)

consumption in the U.S. are from Canadian oil sands, and this is expected to increase in the future as the U.S. looks to reduce its dependence on middle-eastern oil. (Humphries, 2008; Snyder, 2008) Speculations of future oil sands imports from Canada found in the literature range from 2 million bpd in 2025 (Doggett, 2006) to 3 million bpd in 2015 (Perry, 2008).

Synthetic crude oil from Canadian oil sands has very low sulfur and produces very little heavy fuel oil compared to its conventional crude counterpart. However, it is also lower in hydrogen content which results in lower quality distillate output, requiring additional processing in refineries to produce transportation-quality fuels. (AEUB, 2007; EIA, 2006c) In the U.S., about 75% of the oil from Canadian oil sands is refined into transportation fuels. (Woynillowicz, 2007a)

Oil sands projects have traditionally been heavily dependent on natural gas as the main source of process energy for bitumen extraction and upgrading, as well as to produce hydrogen required for the upgrading process. This stems from the era when natural gas was cheap and abundant. However, this practice is not sustainable as bitumen production expands and natural gas prices rise steeply as reserves dwindle. To reduce the dependence on natural gas, alternative process energy and hydrogen sources are being explored. These include coal combustion, coal gasification, use of nuclear energy, and the use of internally generated fuels such as bitumen residues. (ACR, 2004)

4.1.2 Overall Analysis Approach

This work analyzed the life-cycle GHG emissions of the extraction of bitumen by both surface mining and in-situ technologies. In particular, steam assisted gravity drainage (SAGD) is the main in-situ technology in that it has proven to be "technically feasible and economically attractive" for the extraction of bitumen from deep oil sands deposits (Isaacs, 2007a). Hence, it was the main technology assumed for the in-situ production of oil sands in this work. In addition, it was assumed that the bitumen was upgraded in both cases to a light synthetic crude oil (syncrude). About 1600–1800 standard cubic feet of hydrogen was assumed to be used per barrel of syncrude produced through bitumen upgrading. The quality of syncrude produced (~35-49 °API) is generally lighter than the average crude oil received by U.S. refineries (~30 °API). However, as mentioned earlier, syncrude tends to produce lower quality distillate oil due to its low hydrogen content and requires more complex refining operations to produce transportation fuels. This report assumed that the refining efficiency of jet fuel (93.5% for the baseline case, as derived in Chapter 3) from the lighter, but lower hydrogen content syncrude was the same as that from using heavier crude oil with higher hydrogen content. This work also explored the use of various energy sources (e.g. natural gas, coal, bitumen residue) for the production of process fuel and hydrogen required in the bitumen extraction and upgrading processes.

The pathway for the production of syncrude from Canadian oil sands is available in GREET. This work updated the default GREET inputs to this pathway with recent data

from literature, namely publications from the Canadian government publications and proposed oil sands projects by the industry.

The key processes and assumptions involved in the production of jet fuel from Canadian oil sands are summarized in Table 19.

Table 19: Key Processes in the Production of Jet Fuel from Canadian Oil Sands

Process	Key assumptions / Source
Recovery of bitumen from oil sands	Updated default GREET inputs using various sources in literature
Upgrading of bitumen to syncrude	Updated default GREET inputs using various sources in literature
Transportation of syncrude from Canada to U.S. refineries	Default GREET assumptions
Refining of jet fuel fuel from syncrude	Derived in this work using various sources in literature (see Chapter 3)
Transportation and distribution of jet fuel to final users	Default GREET assumptions for diesel fuel, assuming that the transportation and distribution of jet fuel require the same distances and transportation modes and shares as diesel.

4.1.3 Analysis of Key Parameters in the Production and Upgrading of Bitumen from Oil Sands

4.1.3.1 Production of Bitumen through Surface Mining

The GHG emissions of bitumen production through surface mining are largely dependent on the amount and source of energy required for this process. Specifically, this work explored the use of natural gas and coal combustion to generate the steam and electrical power required for bitumen extraction. The use of different sources to generate the required process energy was assumed in the three different scenarios (low, baseline and high emissions cases). In addition, energy was also provided by diesel, gasoline and grid electricity. The total process energy data used (for the low, baseline and high emissions cases) were average values of individual industry surface mining projects (Deer Creek Energy, 2006; Synenco Energy, 2006; Shell Canada, 2007a). The process energy sources and values for the production of bitumen through surface mining for the three scenarios are summarized in Table 20.

Table 20: Process Energy Assumptions for the Production of Bitumen through Surface Mining for Low Emissions, Baseline and High Emissions Cases

Parameter	Low	Baseline	High
Process energy required for steam and power generation (Btu/mmBtu bitumen)	52058	26029 (NG) 26029 (coal)	52058
Source of process energy	NG	NG and coal	Coal
Grid electricity (Btu/mmBtu bit)	3213	3213	3213
Diesel (Btu/mmBtu bit)	10723	10723	10723
Gasoline (Btu/mmBtu bit)	319	319	319
Total process energy required (Btu/mmBtu bitumen)	66313	66313	66313

4.1.3.2 Production of Bitumen through In-situ Production

Similar to the case of surface-mining, the process energy used in in-situ production of bitumen from oil sands was the main parameter analyzed in quantifying the life-cycle GHG emissions of this pathway. For in-situ production, the process efficiency is characterized by the steam-to-oil ratio (SOR), which measures the volume of steam required to extract a unit volume of bitumen. As mentioned earlier, this work assumed that steam assisted gravity drainage (SAGD) was the main in-situ technology employed. The SOR of SAGD technology ranges from 2.0 to greater than 3.0. (Nieuwenburg, 2006; Lacombe and Parsons, 2007).

According to Canada's National Energy Board (NEB, 2006), the average SOR of in-situ production projects was about 2.5 in 2006. This number was adopted for the baseline case in this analysis. A SOR of 2.0 was assumed in the low emissions case to represent very efficient projects using high-quality oil sand reservoirs or the average SOR expected with technological improvements in the future. In the high emissions case, a SOR of 3.5 was assumed to reflect the higher range of SOR values found in the literature (e.g. Petro-Canada, 2005; Nexen and OPTI, 2006). From the SOR value, the process energy required for steam production can be calculated assuming that 420 standard cubic feet of natural gas (or equivalent energy of coal) is needed to make a barrel of steam. (Lacombe and Parsons, 2007) In the low and baseline cases, it was assumed that the process energy for steam generation was provided by natural gas; and in the high case, by coal. In addition, electricity was also used in the in-situ production of bitumen, and the average value assumed in all three cases was based on that provided in NEB, 2006. The process energy values for the production of bitumen through in-situ production for the three scenarios are summarized in Table 21.

Table 21: Process Energy Assumptions for the Production of Bitumen through In-situ Production for Low Emissions, Baseline and High Emissions Cases

Parameter	Low	Baseline	High
SOR (steam-to-oil ratio)	2.0	2.5	3.5
Process energy needed to make steam (Btu/mmBtu bitumen)	138544	173180	242451
Source of steam energy	NG	NG	Coal
Grid electricity (Btu/mmBtu bit)	5700	5700	5700

4.1.3.3 Upgrading of Bitumen to Syncrude

The parameters analyzed in the upgrading of bitumen to syncrude included the yield of syncrude, amount of hydrogen used for the upgrading process, the source of hydrogen and the process energy required.

The yield of syncrude from bitumen upgrading can vary depending on the upgrading processes employed. The average volumetric yield is about 1 barrel of syncrude per 1.16 barrel of bitumen input, or about 1.27 MJ bitumen input for every 1 MJ of syncrude produced in energy terms. (EIA, 2006c)[5] This yield formed the baseline base in the upgrading analysis of this work. In the low case, it was assumed that 1.1 MJ of bitumen input is required per MJ of syncrude produced, based on the Shell Scotford upgrading project which used a combination of hydroprocessing and solvent deasphalting. (Shell Canada, 2007b) For the high case, this work assumed that 1 MJ of syncrude was produced from 1.36 MJ of bitumen input. This case was based on the Synenco Energy Northern Lights Upgrading project which used hydroprocessing, and gasification of asphaltenes to provide all the hydrogen needed, with excess hydrogen available for export. (Synenco Energy, 2006b)

In the low and baseline cases, it was assumed that 1600 scf of hydrogen was needed per barrel of syncrude produced (Isaacs, 2007b, ACR, 2004)[6] and that natural gas was the source of the hydrogen. In the high case, 1800 scf of hydrogen was assumed to be used per barrel of syncrude produced, as predicted by the Aberta Chamber of Resources as the amount needed to produce high quality light syncrude in the future. (ACR, 2004) It was further assumed that this hydrogen was produced from the gasification of asphaltene, a by-product of the bitumen upgrading process with no carbon capture.[7] For the high emissions cases, carbon capture of the CO2 that resulted from gasification was also analyzed.[8]

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[5] Assuming that the LHV of bitumen is 39.5 MJ/L (Shell Canada, 2007b), and the LHV of syncrude is 36.1 MJ/L (from Table 4).

[6] From ACR, 2004, ~0.4 volume units of natural gas are needed to produce a volume unit of hydrogen.

[7] It is assumed that there are no energy use or emissions associated with the production of asphaltene, which is a by-product of bitumen upgrading. The efficiency of asphaltene gasification is also assumed to be the same as that of coal gasification (default GREET value of 62%).

[8] A 90% efficiency in the capture of carbon emitted from the gasification of asphaltene and carbon capture energy requirement of 250 kwh/ton C are assumed.

The main process energy required in the upgrading processes are assumed to be provided by natural gas and electricity. The range of values used for the low to high cases is based on data from the Alberta Chamber of Resources (baseline case) and individual industry upgrading projects (Sturgeon upgrader (low case) and Northern Lights upgrader[9] (high case)). (ACR, 2004; Petro-Canada, 2006; Synenco Energy, 2006a) The parameters analyzed in the upgrading of bitumen to syncrude and their assumed values for the three scenarios are summarized in Table 22.

Table 22: Assumed Parameters in the Upgrading of Bitumen to Syncrude

Parameter	Low	Baseline	High
Yield of SCO (MJ bitumen used per MJ of SCO produced)	1.1	1.27	1.36
Amount of H_2 needed (Btu/mmBtu SCO)	86468	86468	98780
Source of H_2	NG	NG	asphaltene gasification
Process energy (NG) (Btu/mmBtu SCO)	4747	14400	25207
Electricity (Btu/mmBtu SCO)	8323	4200	34846
Jet fuel refining efficiency from syncrude (%)	93.5	93.5	93.5

4.1.4 Results

The parameter inputs for the upstream production of bitumen (through surface-mining or in-situ production) and downstream upgrading of bitumen to syncrude for the three cases were combined to determine the life-cycle GHG emissions in the production and combustion of jet fuel from oil sands. The combustion CO_2 emissions data were obtained from Hileman et al., 2008. The inputs and results using surface-mining and in-situ technologies are summarized in Table 23 and Table 24, respectively.

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[9] In addition to syncrude, the Northern Lights upgrader project also produces butane and excess hydrogen for export. The emission credit for the butane co-product is ignored in this analysis as it is very small compared to the overall WTT emissions (~1%). It is also assumed that the emissions associated with asphaltene gasification to produce the excess hydrogen are offset by the emissions credit given when this hydrogen displaces conventional hydrogen production in the market. The net effect is to ignore the excess hydrogen produced in the process. Such assumptions are deemed appropriate for the high emissions scenario.

Table 23: Summary of Inputs and Analysis Results for Jet Fuel from Canadian Oil Sands via Surface Mining

		Low	Baseline	High
Surface mining	Process energy required for steam and power generation (Btu/mmBtu bitumen)	52058	26029 (NG) 26029 (coal)	52058
	Source of process energy	NG	NG and coal	Coal
	Grid electricity (Btu/mmBtu bit)	3213	3213	3213
	Diesel (Btu/mmBtu bit)	10723	10723	10723
	Gasoline (Btu/mmBtu bit)	319	319	319
Upgrading	Yield of SCO (MJ bitumen used per MJ of SCO produced)	1.10	1.27	1.36
	Amount of H_2 needed (Btu/mmBtu SCO)	86468	86468	98780
	Source of H_2	NG	NG	asphaltene gasification w/o capture (w capture[1])
	Process energy (NG) (Btu/mmBtu)	4747	14400	25207
	Electricity (Btu/mmBtu)	8323	4200	34846
	Jet fuel refining efficiency from SCO (%)	93.5	93.5	93.5
Overall	WTT CO_2 emissions (gCO_2/MJ)	21.6	23.8	37.6 (26.7)
	WTT CH_4 emissions (gCO_2e/MJ)	2.7	2.7	2.5. (2.6)
	WTT N_2O emissions (gCO_2e/MJ)	0.09	0.09	0.11 (0.12)
	WTT GHG emissions (gCO_2e/MJ)	24.3	26.6	40.3 (29.4)
	Combustion CO_2 (gCO_2/MJ)	72.4	73.2	74.5
	Total WTW GHG emissions (gCO_2e/MJ)	96.8	99.7	114.8 (103.9)
	Total WTW GHG emissions relative to baseline conventional jet fuel	1.14	1.17	1.35 (1.22)
	Overall energy ratio	0.74	0.73	0.67 (0.66)

Note:

(1) The results for the high case with carbon capture in the asphaltene gasification process are shown in parenthesis.

Table 24: Summary of Inputs and Analysis Results for Jet Fuel from Canadian Oil Sands via In-situ Production

		Low	Baseline	High
In-situ extraction	SOR (steam-to-oil ratio)	2.0	2.5	3.5
	Process energy needed to make steam (Btu/mmBtu bitumen)	138544	173180	242451
	Source of steam energy	NG	NG	Coal
	Grid electricity (Btu/mmBtu bit)	5700	5700	5700
Upgrading	Yield of SCO (MJ bitumen used per MJ of SCO produced)	1.1	1.27	1.36
	Amount of H_2 needed (Btu/mmBtu SCO)	86468	86468	98780
	Source of H_2	NG	NG	asphaltene gasification w/o capture (w capture[1])
	Process energy (NG)	4747	14400	25207
	Electricity	8323	4200	34846
	Jet fuel refining efficiency from SCO (%)	93.5	93.5	93.5
Overall	WTT CO_2 emissions (gCO_2/MJ)	27.1.	31.4	62.3 (51.5)
	WTT CH_4 emissions (gCO_2e/MJ)	3.2	3.5	3.3 (3.3)
	WTT N_2O emissions (gCO_2e/MJ)	0.11	0.14	0.18 (0.19)
	WTT GHG emissions (gCO_2e/MJ)	30.4	35.0	65.8 (55.0)
	Combustion CO_2 (gCO_2/MJ)	72.4	73.2	74.5
	Total WTW GHG emissions (gCO_2e/MJ)	102.9	108.2	140.3 (129.5)
	Total WTW GHG emissions relative to baseline conventional jet fuel	1.21	1.27	1.65 (1.52)
	Overall energy ratio	0.69	0.65	0.57 (0.56)

Note:
  (1) The results for the high case with carbon capture in the asphaltene gasification process are shown in parenthesis.

The GHG emissions for the various steps in the production and use of jet fuel from Canadian oil sands using surface-mining and in-situ technologies (baseline cases) are shown in Table 25.

Table 25: GHG Emissions for Various Stages in Jet Fuel from Canadian Oil Sands Pathways

Stage emissions	Surface-mining	In-situ production
Recovery (gCO$_2$/MJ)	16.5	23.9
Processing (gCO$_2$/MJ)	5.5	5.5
Transportation (gCO$_2$/MJ)	1.8	1.9
Well-To-Tank CH$_4$ and N$_2$O emissions (gCO$_2$e/MJ)	2.8	3.6
Combustion (gCO$_2$/MJ)	73.2	73.2
Total (gCO$_2$e/MJ)	99.7	108.2

4.1.5 Discussion

The life-cycle GHG emissions of the production and use of jet fuel from Canadian oil sands range from about 1.1 to 1.7 times higher than those that result from the production and use of conventional jet fuel. Though the carbon intensity of oil sand operations has generally declined over the years as technological improvements have increased energy efficiency, several factors could lead to the opposite trend. For instance, surface-mining is generally a less carbon-intensive process than in-situ production, and it provides the majority of bitumen production today. However, as discussed earlier, Canadian oil sands reserves recoverable using the surface-mining process only form about 20% of the total reserves. In the future, bitumen production through in-situ production technologies will likely over-take those from surface-mining production and worsen the carbon footprint of this pathway. The problem of high GHG emissions in the production of jet fuel from oil sands is further exacerbated by the decline in the availability of cleaner natural gas resources. As natural gas reserves dwindle and prices rise, producers may be forced to turn to dirtier resources like coal and bitumen upgrading by-products (e.g. asphaltene, coke) to provide both the process fuel and hydrogen needed. Even with the capture of carbon emissions from asphaltene gasification for hydrogen production, the overall GHG emissions are still considerably higher than those of conventional jet fuel. It should be noted that GHG emissions could potentially be further reduced by also capturing the carbon emitted during process energy consumption in the extraction and upgrading steps, e.g. gasification of coal to provide steam and electrical power.

As Canada accelerates its expansion of oil sands production, it finds itself further away from its commitment under the Kyoto Protocol to reduce GHG emissions to 6% below 1990 levels. In 2004, Canada's GHG emissions were about 27% above 1990 levels. (OAGC, 2007) In an effort to curb rising GHG emissions and respond to increasing pressure from environmental groups, the Alberta government recently embarked on a series of "green" initiatives. From July 2007, new climate change regulations mandate Alberta facilities that emit more than 100,000 metric tons of GHG annually to reduce emission intensity by 12% through energy efficiency improvements, purchase of carbon credits or contribution of $15/tonne of carbon to the Climate Change and Emissions Management Fund. (Alberta, 2008a) Alberta also announced in July 2008 its plan to

invest $2 billion to support carbon capture and storage projects at facilities including oil sands extraction and upgrading plants and coal-fired electricity plants. (Alberta, 2008b) Canada is also looking into the use of nuclear power in oil sands operations, but there has been no firm commitment to do so until the "repercussions of this process are fully known and understood." (WNN, 2007)

Other environmental and ecological issues related to oil sands operations also have to be addressed. For example, the large water requirement for bitumen extraction poses a major environmental concern for oil sands operations, particularly for surface-mining projects. About 2 to 4.5 barrels of water are typically used to produce 1 barrel of syncrude using surface-mining, compared to 0.2 barrel of fresh water per barrel of bitumen extracted in SAGD in-situ operations (about 90-95% of water used for steam generation is recycled). The water is primarily withdrawn from the Athabasca River and there are concerns about the water supply from this resource being insufficient to maintain both a healthy aquatic ecosystem and to support the requirements of future oil sand operations. (NEB, 2006) Because of the large water requirement in oil sand operations, producing enough oil sand derived jet fuel to power a large airport (~25,000 barrels a day) would require water volumes of up to eight Olympic-sized swimming pools[10] a day.

Oil sand operations also produce substantial waste streams. Surface-mining operations produce six barrels of waste in the form of mine tailings (slurry of water, sand, fine clay and residual bitumen) per barrel of bitumen extracted. These wastes are stored in reservoirs known as "tailing ponds." Currently, these tailing ponds collectively cover more than 50 square kilometers (>12,000 acres). These waste ponds are toxic and threaten the environment through contamination of soil and water supply. The waste streams from in-situ processes, on the other hand, are less threatening and can be disposed of in landfills or injected underground. (Woynillowicz, 2007b)

Land impacts associated with oil sand operations, such as deforestation, also have to be considered. Oil sand reserves are found beneath more than 140,000 square kilometers (~size of Florida) of the Boreal forest in Alberta (about 2.5% of the total size of Canada's Boreal forest), and this forest is being cleared to access these reserves in surface-mining operations. Each mine ranges from 150 to 200 square kilometers and the currently planned expansion of oil sand production could result in the deforestation of about 3000 square kilometers of the Boreal forest. In-situ production does not require excavation and perturbs less land area. However, together with surface mining operations, in-situ production causes forest disruption from the construction of infrastructure (e.g., wells, roads, and pipelines) over the rest of the region. Such industrial development could lead to irreversible damage to the Boreal's forest rich ecological system and loss of biodiversity. Only a small proportion of the area affected by oil sand operations has been reclaimed thus far. Even when reclamation takes place, the new landscape is likely to be different from the original forest ecosystem. (NEB, 2006; IBCC, 2008; Woynillowicz, 2007b)

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[10] The volume of an Olympic-sized swimming pool is about 600,000 gallons.

It is noteworthy that even though the recovery of bitumen through in-situ processes are more GHG intensive than surface mining, its other environmental impacts (land, water and ecological systems) are less pronounced compared to surface mining. This underscores the importance of a comprehensive assessment of all potential impacts on the environment (including, but no limited to GHG emissions) in evaluating the merits of a particular alternative fuel production pathway.

In summary, though the production of jet fuel from oil sands is a technologically mature process, with a large resource base and production capacity, it is not an ideal alternative for conventional jet fuel from the GHG emissions perspective unless a clean energy source for process fuel and hydrogen production can be found and effectively implemented (e.g. nuclear energy). Other environmental and ecological impacts of oil sands operations need to be closely examined as well.

4.2 Jet Fuel from Oil Shale

4.2.1 Introduction

The U.S. has the largest oil shale reserves in the world, estimated to be more than three times the proven petroleum reserves of Saudi Arabia. The U.S. oil shale reserves are mainly concentrated in the Green River Formation, which consists of parts of Colorado, Utah and Wyoming. (Bartis et al., 2005) Oil and gas can be produced from oil shale by a process called "retorting" which involves heating the oil shale to convert the kerogen in it to liquid and gaseous hydrocarbons. There are 2 main types of retorting processes: surface retorting and in-situ retorting. Surface mining involves the mining of oil shale, crushing it and retorting it in an above-ground facility. In-situ processes heat the oil shale while it remains underground to extract oil which is then pumped to the surface. The Alberta Taciuk Processor (ATP) is viewed as the "most advanced above-ground retort design;" it has lower water needs and produces less wasted shale than previous designs. (Brandt, 2007a) However, surface retorting is generally a more carbon-intensive process than in-situ retorting because the former takes place at higher temperatures (up to 750°C) where carbonate minerals in the oil shale could decompose, releasing carbon dioxide.[11] The production of oil from shale using the ATP surface-retorting process could result in GHG emissions of between 1.2 times to about 3 times those from the production of shale oil using the Shell in-situ conversion process (ICP) (discussed below). (Brandt, 2007a; Brandt, 2007b) In addition, surface retorting also results in negative surface impacts to the mined areas. Surface retorting has not been successfully applied at a "commercially viable level" in the U.S.. (OTPEISIC, 2008)

This work focused on analyzing the life-cycle GHG emissions of the extraction of oil from oil shale using an in-situ process, specifically the Shell In-situ Conversion Process. Research on the Shell ICP commenced more than 25 years ago and the technology has been undergoing research demonstration at Shell's Mahogany test plot in Colorado since 1996. The process involves heating oil shale in-situ to about 340-400°C for a prolonged period (three to four years) through electrically heated wells drilled 1000 to 2000 feet into the ground to generate oil and gas from the kerogen in the oil shale. These products, estimated to comprise about two-thirds oil and one-third gas (natural gas, propane, butane) on an energy basis, are brought to the surface through conventional well technology. The shale oil produced is much lighter than traditional crude oil and contains practically no heavy ends, and hence requires less refining energy compared to traditional crude. The area around the extraction site is frozen to form an impermeable barrier, preventing groundwater from disturbing the heating process and to keep products from escaping and contaminating the groundwater. (Mut, 2005) About 1,700 barrels of light shale oil have been recovered from the small 30 foot by 40 foot test plot. (Shell U.S., 2008) Though Shell's ICP has not been proven to be viable at a commercial scale, it is regarded by the

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[11] Typical oil shale from the Green River Formation comprised 23% dolomite (calcium-magnesium bicarbonate), and 16% calcite (calcium carbonate). The decomposition temperature of calcite is about 620-675°C, while dolomite decomposes at around 565°C. (Brandt, 2007a)

DOE as a "very promising technology." It may also reduce surface impacts "by up to a factor of ten" compared to surface-retorting processes. (OTPEISIC, 2008)

4.2.2 Overall Analysis Approach

As mentioned earlier, the analysis of the life-cycle GHG emissions for the production and use of jet fuel from oil shale was based on the Shell ICP. The pathway for the extraction of oil from oil shale is not available in GREET and was analyzed based on information available from the literature which was incorporated into the GREET framework. Specifically, the process energy for the production of shale oil from oil shale, as well as the yield of oil and gas products using the Shell ICP, were adopted from Brandt's analysis (Brandt, 2007b). Only the major sources of process energy, namely in-situ retorting energy and energy to maintain the freeze wall (which is about one order of magnitude less than the retorting energy) were considered.[12] Energy and emission credits were given to the natural gas co-produced in the process using the displacement method.[13] As a large amount of electrical energy is needed to provide in-situ heating for the Shell ICP, it was assumed that this electricity was provided by dedicated electric power plants constructed near the extraction site, reducing transmission losses. Hence, electricity transmission losses were assumed to be 5% instead of GREET's default 8%. In addition, as the produced shale oil is much lighter and contains almost no heavy ends compared to traditional crude oil, the refining efficiency for the processing of shale oil to jet fuel was assumed to be higher (~2-3%) than that of refining traditional crude oil (Bartis, 2007a). Specifically, a jet fuel refining efficiency of 96% was assumed in this analysis (2.5% higher than the baseline jet fuel efficiency of 93.5%) for all scenarios (low emission, baseline and high emission cases).

The key processes and assumptions involved in the production of jet fuel from oil shale using the Shell ICP are summarized in Table 26.

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[12] Other minor process energy requirements like drilling and pumping energy (< 1% of retorting energy), as well as energy needed for infrastructural construction, are ignored in this study.

[13] The displacement (substitution) method was used to account for energy and emission credits to natural gas, i.e., the natural gas produced was assumed to displace the recovery and processing of natural gas in a separate, independent facility.

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Table 26: Key Processes in the Production of Jet Fuel from Oil Shale

Process	Key assumptions / Source
Production of shale oil from in-situ heating (retorting) of oil shale based on the Shell ICP	Derived in this work mainly using process energy data from Brandt, 2007b.
Transportation of shale oil to U.S. refineries	Assume 100% by pipeline with distance of 750 miles (assumed mode same as oil sands operation, assumed distance same as crude oil transportation)
Refining of jet fuel from shale oil	Assume higher refining efficiency (~2.5% greater) than in the case of refining from conventional crude oil due to superior quality of shale oil
Transportation and distribution of jet fuel to final users	Default GREET assumptions for diesel fuel, assuming that the transportation and distribution of jet fuel require the same distances and transportation modes and shares as diesel.

4.2.3 Analysis of Key Parameters in the In-situ Extraction of Oil from Oil Shale

The amount and source of retorting energy required in the Shell ICP are key factors contributing to the GHG emissions in the in-situ production of oil from oil shale. As mentioned earlier, the refrigeration energy needed to maintain the freeze wall is a secondary energy requirement compared to the retorting energy needed. The effects of the use of different amounts of retorting energy and source of this energy on the overall GHG emissions of this pathway were explored through three scenarios (low, baseline and high emissions cases). In the low and baseline cases, it was assumed that 25% of the retorting energy needed was provided through the recycling of waste heat (as also assumed in the low carbon case in Brandt's analysis, Brandt, 2007b), while no recycling of waste heat was assumed in the high case. In addition, it was assumed that retorting energy was provided by coal-generated electricity in all three cases due to the large amount of electrical power needed and the vast abundance of coal resources in the Green River Formation region. For the low case, the use of coal IGCC electricity with carbon capture (90% efficiency) was assumed;[14] while for the baseline and high cases, traditional pulverized coal-fired electricity without carbon was assumed to provide the retorting energy. Brandt, 2007b provided estimates of low and high values for the electrical energy required for retorting, amount of shale oil output and amount of gas co-produced. The low value for retorting and high values for shale oil and gas outputs were adopted in the low case; mean values in the baseline case; and high value for retorting and low values for shale oil and gas outputs in the high case. The assumed inputs for the three scenarios are summarized in Table 27.

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[14] From Deutch and Moniz, 2007, the estimated efficiency of an IGCC plant with 90% carbon capture is 31.2% (HHV) or about 34% (31.2+3) on a LHV basis. The efficiency of 34% (LHV) was adopted in this study.

Table 27: Input Assumptions for the Production of Jet Fuel from Oil Shale for Low Emissions, Baseline and High Emissions Cases

	Low	Baseline	High
Process conditions	Use of 25% recycled heat for retorting; use of coal IGCC electricity with CCS; capture efficiency of 90%	Use of 25% recycled heat for retorting; use of 100% coal-fired electricity; no carbon capture	No recycled heat used; use of 100% coal-fired electricity; no carbon capture
Electrical energy input (Btu/mmBtu shale oil produced)	134600	148100	211900
Natural gas co-produced (Btu/mmBtu shale oil produced) (LHV)	223700	189600	152500

4.2.4 Results

The key assumed inputs and corresponding life-cycle GHG emissions from the production and use of jet fuel from oil shale using the Shell ICP for the three scenarios are shown in Table 28. The combustion CO_2 emissions data were obtained from Hileman et al., 2008.

Table 28: Summary of Inputs and Results for Jet Fuel from Oil Shale Pathway

	Low	Baseline	High
Process conditions	Use of 25% recycled heat for retorting; use of coal IGCC electricity with CCS; capture efficiency of 90%	Use of 25% recycled heat for retorting; use of 100% coal-fired electricity; no carbon capture	No recycled heat; use of 100% coal-fired electricity; no carbon capture
Electrical energy input (Btu/mmBtu shale oil produced)	134600	148100	211900
Natural gas co-produced (Btu/mmBtu shale oil produced) (LHV)	223700	189600	152500
Refining efficiency	96%	96%	96%
WTT CO_2 emissions (gCO_2/MJ)	7.8	45.8	64.4
WTT CH_4 emissions (gCO_2e/MJ)	2.4	2.5	3.2
WTT N_2O emissions (gCO_2e/MJ)	0.6	0.2	0.2
WTT GHG emissions (gCO_2e/MJ)	10.9	48.4	67.8
Combustion CO_2 (gCO_2/MJ)	72.4	73.2	74.5
WTW GHG emissions (gCO_2e/MJ)	83.3	121.6	142.2
Total WTW GHG emissions relative to baseline conventional jet fuel	0.98	1.43	1.67
Overall energy ratio	0.67	0.67	0.59

The GHG emissions for the various steps in the production and use of jet fuel from oil shale using the Shell ICP (baseline cases) are shown in Table 29.

Table 29: GHG Emissions for Various Stages in Jet Fuel from Oil Shale Pathway

Stage	Emissions
Recovery (gCO_2/MJ)	41.2
Processing (gCO_2/MJ)	3.3
Transportation (gCO_2/MJ)	1.3
Well-To-Tank CH_4 and N_2O emissions (gCO_2e/MJ)	2.7
Combustion (gCO_2/MJ)	73.2
Total (gCO_2e/MJ)	121.6

4.2.5 Discussion

Without the capture of carbon dioxide from coal-based electricity plants which provide the retorting energy, the production of jet fuel from oil shale produces life-cycle GHG emissions about 43% to almost 70% greater than the baseline jet fuel case. The increase is largely due to the high retort energy required and the use of coal electricity to provide this energy. Hence, this process is not viable from the carbon-footprint perspective unless carbon capture is used (as in the low emissions case); this reduces emissions to about the same level as conventional jet fuel production and combustion. This analysis is based on the use of coal as the main source of retorting energy. The use of natural gas or nuclear energy to power the retorting process could foreseeably provide a significant decrease in the GHG emissions of this pathway. However, the availability of these resources is likely to be limited (compared to coal) in the Green River Formation region.

In addition to increased GHG emissions, oil shale development also presents other adverse impacts to the environment. One is negative impacts to land in the region. Though less intrusive to the surface topography than surface-retorting processes and not requiring the disposal of spent shale, in-situ retorting will still cause displacement of all other land uses in the area and disruptions to the local ecological community. (Bartis et al., 2005) In-situ methods can also potentially cause ground water contamination. In Shell's ICP, though the freeze wall protects groundwater during production, contamination may occur post-production. As the Green River formation lies within the Colorado River drainage basin, water contamination could impact millions of downstream users. (Gruenwald, 2006) Oil shale production is also a water-intensive process, requiring about 3 barrels of water per barrel of shale oil produced using mining and surface-retorting operations, a major constraint in the arid Green River Formation region. Though in-situ processes eliminate the need for shale mining, crushing and reclamation of spent shale and the water requirement in these areas, considerable amounts of water may still be required for product extraction, post-extraction cooling, etc. As the Shell ICP is still in development, reliable water use data is currently not available. (Bartis et al., 2005)

As in the case of oil sands, the production of jet fuel from oil shale to displace conventional jet fuel production is not an ideal measure when trying to control aviation's impact on the climate, despite the vast oil shale reserves in the U.S.. This is due to the high GHG emissions and other negative environmental impacts imposed by this pathway. The availability of carbon capture and storage technology could mitigate the GHG emissions but other environmental and ecological implications should be explored and taken into consideration before this technology is used on a large-scale.

Chapter 5: Fischer-Tropsch Jet Fuel from Natural Gas, Coal and Biomass

5.1 Introduction

Fischer-Tropsch (F-T) synthesis was developed by German scientists in the 1920s and was used as a technology to make liquid fuels from coal during the Second World War. The F-T process is an established technology and is currently applied on a commercial scale. However, the high risks involved in building an F-T plant have hampered its widespread application. These risks include high capital, operation and maintenance costs, price and volatility of crude oil, and local politics. (Dry, 2002)

The F-T process first involves the steam reforming or gasification of any carbon-containing feedstock (e.g. natural gas, coal or biomass) to synthesis gas (syngas), which is a mixture of hydrogen and carbon monoxide; followed by the conversion of syngas in the presence of a catalyst (Fischer-Tropsch synthesis) to form a slate of paraffinic hydrocarbon products. A third upgrading step cracks the longer hydrocarbon chains to maximize the production of synthetic paraffinic liquid fuels like diesel and jet fuel. Syngas has to be cleaned before the Fischer-Tropsch synthesis step to remove contaminants, particularly sulfur, to avoid poisoning the catalyst. Hence, the resultant Fischer-Tropsch liquid fuels are virtually free of contaminants (e.g. sulfur) and burn more cleanly than conventional jet fuel. In particular, studies have shown that the combustion of sulfur-free F-T jet fuels results in lower airborne particulate matter and sulfur oxides (SO_X) emissions compared to conventional jet fuel, providing potential air quality benefits.[15] (Hileman et al., 2008 and references therein)

This chapter explores the life-cycle GHG emissions of the production of Fischer-Tropsch jet fuel from three types of raw materials: natural gas, coal and biomass. Gas-to-liquid (GTL) plants utilizing natural gas as the feedstock are the most common type of F-T plant in commercial operation today, mainly due to the relative technological ease of steam reforming or partial oxidation process for the conversion of natural gas to syngas compared to solid feedstocks like coal and biomass. GTL plants are also generally more efficient compared to F-T plants using coal or biomass as feedstocks. In addition, stranded natural gas in remote locations provides a widely abundant and relatively cheap source of feedstock for the GTL plants. (Edwards et al., 2007) Shell has been operating a GTL plant in Malaysia since 1993 which has a production capacity of 14,700 barrels a day. It is planning to build a new GTL plant almost 10 times larger in Qatar towards the end of the decade, producing about 140,000 barrels a day of liquid products. (Shell, 2008) Sasol, in a joint venture with Qatar Petroleum, is currently operating the Oryx GTL plant

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[15] Airborne particulate matter can cause respiratory disease and aggravate cardiovascular conditions. Sulfur oxides (SO_X) can cause acid rain and are associated with secondary particular matter formation. (Hileman et al., 2008 and references therein)

in Qatar. The plant is designed to produce 34,000 barrels a day of liquid fuels. (Green Car Congress, 2007a)

Comparatively, coal-to-liquid (CTL) plants are technologically more complex, less efficient and therefore more costly than GTL plants. Biomass-to-liquid (BTL) plants are even more complex and costly as compared to CTL plants. According to EIA (EIA, 2006d), capital investment costs range from $25,000 to $40,000 per daily barrel of capacity for GTL plants, $50,000 to $70,000 for CTL plants, and $103,000 to $145,000 for BTL plants (all costs in 2004 dollars). One source of cost increase and complexity in BTL plants stems from the general non-homogeneous nature of the biomass feedstock resulting in difficulties in maintaining a "reliable biomass handling, storage, and feeding system". (Ciferno and Marano, 2002) BTL plants also suffer from issues of feedstock availability, limiting scale and the achievement of optimal energy efficiency. While commercial CTL plants have been operating in South Africa since the 1950s, producing about 150,000 barrels of liquid fuels a day; the first commercial BTL plant, built by CHOREN in Germany, is only coming online this year. Its production capacity is about 300 barrels of liquid fuels per day. The CHOREN plant employs a complex three-stage gasification process (termed "Carbo-V" technology) to convert biomass feedstock to synthesis gas. (CHOREN, 2008) In addition, Solena Group, in partnership with Rentech Inc., has plans to construct a BTL facility in California in 2009 that would produce 1,800 barrels per day of fuel from waste resources in northern and central California. (Environmental Protection Online, 2008)

As most of the data that are available in the literature (e.g. process efficiency) focus on the production of F-T diesel rather than jet fuel, F-T diesel processing was used as a surrogate for F-T jet fuel processing in this analysis, (i.e. it was assumed that the production of F-T jet fuel resulted in similar life-cycle GHG emissions as the production of F-T diesel).

5.2 Fischer-Tropsch Jet Fuel from Natural Gas

5.2.1 Overall Analysis Approach

This work analyzed the life-cycle GHG emissions of the production of F-T fuels using natural gas sourced from North America. This pathway is available in GREET and well-documented based on current industry data, (e.g., Shell Middle Distillate Synthesis plant in Malaysia). (Wang, 1999; Wang and Huang, 1999; Wang, 2002) Specifically, this analysis assumed a stand-alone F-T liquid fuels plant designed to maximize liquid fuels production (e.g. through recycling of tail gas from F-T reactors). It produced sufficient electrical energy to fuel its internal processes, with little or no excess electricity produced for export. In addition, the process included the upgrading / hydroprocessing of long-chain liquid products to desired fuels like diesel, jet fuel and naphtha. The energy allocation method was adopted for assigning energy and emissions to various liquid fuels produced as each product essentially went through the same processes.

The key processes and assumptions involved in the production of F-T jet fuel from natural gas are summarized in Table 30.

Table 30: Key Processes in the Production of F-T Jet Fuel from Natural Gas

Process	Key assumptions / Source
Recovery and processing of North America natural gas	Default GREET assumptions
Transportation of natural gas to F-T facilities in the U.S.	Default GREET assumptions
Processing of natural gas to F-T jet fuel	Default GREET assumptions (using F-T diesel as a surrogate for F-T jet fuel)
Transportation and distribution of F-T jet fuel to final users	Default GREET assumptions for F-T diesel fuel, assuming that the transportation and distribution of F-T jet fuel require the same distances and transportation modes and shares as F-T diesel.

5.2.2 Analysis of Key Parameters in the Production of F-T Jet Fuel from Natural Gas

The F-T process efficiency is a key parameter affecting the life-cycle GHG emissions of the production of F-T jet fuel from natural gas. The range of F-T process efficiencies estimated from literature is 60-65%. (Edwards et al., 2007; Green Car Congress, 2006a; Wang, 2002) These were adopted as the range of values for the low, baseline and high emission scenarios in this study. Specifically, the baseline and high emission scenarios assumed process efficiencies of 63% and 60%, respectively.

As a concentrated stream of CO_2 is produced and separated from the syngas upstream of the F-T synthesis step, there is an opportunity for capture and storage of this CO_2. Unlike coal-to-liquids (CTL) plants, there is little literature data available on gas-to-liquids (GTL) plants with CO_2 capture. One reason could be due to the lower amounts of CO_2 produced, lower capture efficiency and hence possibly higher capture cost per ton of carbon in GTL plants compared to CTL plants. Nonetheless, this work explored the effect of capturing CO_2 produced from GTL plants in the low emissions scenario, assuming a pre-capture process efficiency of 65%. From Edwards et al., 2007, it was assumed that the energy efficiency penalty for carbon capture was 3%, and that the capture efficiency was 75%.[16] Hence, the net process efficiency in the low emissions scenario with carbon capture was assumed to be 62%. In addition, it was assumed that the energy penalty for the carbon capture only accounted for the separation of CO_2 (through physical absorption processes or chemical scrubbing processes) from the syngas and its subsequent compression to about 15 MPa, which should be sufficient to transport it via pipelines to storage sites.

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[16] Within the GREET framework, 75% capture efficiency refers to the capture of 75% of all carbon present in the feedstock (natural gas in this case) which are not converted to carbon in products. Carbon emitted in the combustion of process fuels are not captured.

(Edwards et al., 2007) The analysis did not include the actual transportation and injection of CO_2 into storage sites.

The assumed inputs for the three scenarios are summarized in Table 31.

Table 31: Input Assumptions for the Production of F-T Jet Fuel from Natural Gas for Low Emissions, Baseline and High Emissions Cases

	Low	Baseline	High
Process efficiency	62% (65% without carbon capture)	63%	60%
Carbon capture efficiency	75%	No carbon capture	No carbon capture

5.2.3 Results

The key assumptions and corresponding life-cycle GHG emissions in the production and use of F-T diesel / jet fuel from natural gas for the three scenarios are shown in Table 32. The combustion CO_2 emissions data were obtained from Hileman et al., 2008.

Table 32: Summary of Inputs and Results for F-T Jet Fuel from Natural Gas Pathway

	Low	Baseline	High
Process efficiency	62% (65% without carbon capture)	63%	60%
Carbon capture efficiency	75%	No carbon capture	No carbon capture
WTT CO_2 emissions (gCO$_2$/MJ)	12.6	25.5	26.7
WTT CH_4 emissions (gCO$_2$e/MJ)	4.6	4.6	4.8
WTT N_2O emissions (gCO$_2$e/MJ)	0.04	0.04	0.04
WTT GHG emissions (gCO$_2$e/MJ)	17.3	30.1	31.5
Combustion CO_2 (gCO$_2$/MJ)	70.0	70.4	70.9
Total WTW GHG emissions (gCO$_2$e/MJ)	87.3	100.4	102.5
Total WTW GHG emissions relative to baseline conventional jet fuel	1.03	1.18	1.21
Overall energy ratio	0.58	0.59	0.56

The GHG emissions for the various steps in the production and use of F-T diesel / jet fuel from natural gas in the baseline case are shown in Table 33.

Table 33: GHG Emissions for Various Stages in F-T Jet Fuel from Natural Gas Pathway

Stage	Emissions
Recovery (gCO$_2$/MJ)	4.6
Processing (gCO$_2$/MJ)	20.2
Transportation (gCO$_2$/MJ)	0.7
Well-To-Tank CH$_4$ and N$_2$O emissions (gCO$_2$e/MJ)	4.6
Combustion (gCO$_2$/MJ)	70.4
Total (gCO$_2$e/MJ)	100.4

5.2.4 Discussion

The life-cycle GHG emissions of the production and use of F-T diesel / jet fuel made from natural gas are about 20% higher than those from conventional jet fuel in the baseline and high emissions cases. Where carbon capture is applied (as in the low emissions case), life-cycle GHG emissions could be reduced to a level close to that of conventional jet fuel. As highlighted earlier, carbon capture and storage technologies are currently not being applied to GTL plants and the energy penalty and capture efficiency involved in the application of this technology to GTL plants have not been studied at length. Hence, the numbers provided in the low emissions scenario were more for illustrative purposes rather than to provide a definitive result. Nonetheless, carbon capture and storage technologies are critical enabling technologies for the use of F-T jet fuel made from natural gas in place of conventional jet fuel if the life-cycle carbon footprint is to remain unchanged.

It must also be noted that natural gas is the cleanest-burning fossil fuel and its supply is limited. The use of natural gas as a feedstock for GTL plants is most viable when stranded sources of natural gas are used. For remote sources far from consumer markets, it is inefficient to transport the gas for long distances through conventional natural gas pipelines. The conversion of such sources of natural gas to high-value liquid products offers an alternative to the traditional option of direct liquefaction of remote natural gas. (Edwards et al., 2007)

In summary, the use of F-T jet fuel produced from natural gas is not a desirable alternative to conventional jet fuel from a carbon standpoint unless carbon capture technologies are applied and stranded sources of natural gas are utilized.

5.3 Fischer-Tropsch Jet Fuel from Coal

5.3.1 Overall Analysis Approach

This work examined the life-cycle GHG emissions of the production of F-T fuels from coal for the case without capture of carbon dioxide and the case with capture. As in the case of GTL plants, this analysis assumed a stand-alone F-T liquid fuels plant designed to maximize liquid fuels production with no excess electricity produced for export and included the upgrading / hydroprocessing of long-chain liquid products to desired fuel products. The energy allocation method was adopted for assigning energy and emissions to various liquid fuels produced.

In the case of a coal-to-liquids (CTL) plant with carbon capture, this work assumed that the energy needed for the separation and compression of carbon dioxide was provided by the electrical power generated in the F-T process, instead of from the grid. This resulted in a reduction of the overall process efficiency. The amount of electrical power needed for the carbon capture was based on literature review and GREET assumptions (assumed to be ~250 kWh/ton carbon captured).

The key processes and assumptions involved in the production of F-T jet fuel from coal are summarized in Table 34.

Table 34: Key Processes in the Production of F-T Jet Fuel from Coal

Process	Key assumptions / Source
Mining and cleaning of coal	Default GREET assumptions
Transportation of coal to F-T facilities in the U.S.	Default GREET assumptions
Processing of coal to F-T jet fuel (with and without carbon capture)	Data based on literature review, which are in line with default GREET assumptions in the latest version of GREET (using F-T diesel as a surrogate for F-T jet fuel)
Transportation and distribution of F-T jet fuel to final users	Default GREET assumptions for F-T diesel fuel, assuming that the transportation and distribution of F-T jet fuel require the same distances and transportation modes and shares as F-T diesel.

5.3.2 Analysis of Key Parameters in the Production of F-T Jet Fuel from Coal

In this work, the effect of varying F-T process efficiencies, coal properties and carbon capture efficiencies on the overall life-cycle GHG emissions of the CTL pathway was specifically analyzed in sensitivity studies due to the relatively high level of uncertainty

associated with these parameters and their potential significant influence on the overall GHG emissions of the pathway.

5.3.2.1 Process Efficiency

A relatively large range of values for process efficiency can be found in the literature, ranging from below 40% to about 60%, for plants utilizing different technologies, feedstocks, scale, and configurations (e.g. whether designed for maximizing liquid fuels production or with substantial electricity production for export). For example, the first Sasol CTL plant built in the 1950s had process efficiencies lower than 40% while large-scale CTL plants with co-electricity generation are estimated to have process efficiencies topping 60%. (UK DTI, 1999; Gray and Tomlinson, 2001) Hence, a sensitivity study was carried out to examine the effect of varying process efficiency on the overall GHG emissions of the CTL pathway. As shown in Table 35, varying process energy efficiency could result in overall GHG emissions ranging from less than 2 times those of conventional jet fuel to almost 3 times higher.

Table 35: Variation of Life-cycle GHG Emissions with Fischer-Tropsch Process Energy Efficiency

Process energy efficiency (%)	Life-cycle GHG emissions (gCO$_2$e/MJ)	Compared to baseline conventional jet fuel
40	243	2.9
50	195	2.3
60	162	1.9

For the scenario analysis, process efficiencies of 60%, 50% and 40% were assumed for the low, baseline and high emission cases for a CTL plant without carbon capture, respectively. For the case of a CTL plant with carbon capture, as in the case of the GTL plant with carbon capture, it was assumed that the energy needed to separate and compress the carbon dioxide for subsequent transportation and sequestration was provided by electrical energy by internal processes instead of the grid. This resulted in a reduction in the overall process efficiency. Assuming a 90% carbon capture efficiency and capture power of about 250 kWh/ton C, the process efficiencies for the low, baseline and high cases for a CTL plant with carbon capture were reduced to 58.1%, 48.3% and 38.5%, respectively.

5.3.2.2 Coal Property

The type of coal used, specifically its carbon emission factor, can have a significant impact on the overall GHG emissions of the pathway. A coal's carbon emission factor is a function of its heating content and carbon content.[17] The carbon emission factor for various types of coal can range from 24.9 million metric tons per quadrillion Btu for

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[17] The formula for calculating carbon emission factor (lb CO$_2$/million Btu) = carbon weight percent (%) / higher heating value (Btu/lb) * 36,670. To convert emission factor from lb CO$_2$/million Btu to million metric tons of carbon per quadrillion Btu, multiply by 0.1237 (EIA, 1994).

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bituminous coal to 28.1 million metric tons per quadrillion Btu for lignite coal (see Table 36). (Deutch and Moniz, 2007; SSEB, 2005)

Table 36: Properties of Different Types of Coal

Type of coal	Higher heating value (Btu/lb)	Carbon content (weight %)	Carbon emission factor (Million metric ton per quadrillion Btu)	Source
Bituminous coal	11800	64.8	24.9	SSEB, 2005
Illinois #6 bituminous coal	10900	61.2	25.5	Deutch and Moniz, 2007
Typical sub-bituminous coal	8599	49	25.9	Deutch and Moniz, 2007
Typical lignite coal	6449	40	28.1	Deutch and Moniz, 2007

Table 37 shows the effect of varying the type of coal (specifically their carbon emission factor) on the life-cycle GHG emissions of the CTL pathway, assuming process efficiency of 50% in all cases.[18] The type of coal used in the F-T process can have an appreciable impact on the overall GHG emissions of the CTL pathway.

Table 37: Variation of Life-cycle GHG Emissions with Coal Carbon Emission Factor

Carbon emission factor (Million metric tons per quadrillion Btu)	Life-cycle GHG emissions (gCO2e/MJ)	Compared to baseline conventional jet fuel
24.9	191	2.2
25.5	195	2.3
28.1	215	2.5
Note: Process energy efficiency of 50% was used in all cases.		

For the scenario analysis, bituminous coal was assumed to be used in the low and baseline cases, and lignite coal in the high emissions case. The average carbon emission factor for bituminous coal used in the U.S. is about 25.5 million metric tons per quadrillion Btu (EIA, 2006a), similar to the carbon emission factor of Illinois #6 coal reported by Deutch and Moniz, 2007. This factor and the corresponding coal properties were assumed for the bituminous coal in the baseline case. For the low case, a smaller carbon emission factor of 24.9 for bituminous coal was assumed. For the high case, the carbon emission factor of 28.1, typical of lignite coal as reported by Deutch and Moniz,

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[18] Petroleum coke is another possible feedstock in CTL plants. The carbon emission factor of petroleum coke is about 27.9 million metric tons of carbon per quadrillion Btu (EIA, 2006a), slightly lower than that of typical lignite coal. Assuming that the recovery emissions of pet coke are comparable to those of coal, and 50% efficiency for the CTL process, the life-cycle GHG emissions of the CTL pathway using pet coke as a feedstock will likely fall within the range shown in Table 37 (close to those of typical lignite).

2007, was used in this study.[19] These coal properties were adopted in both the cases of a CTL plant with carbon capture and without carbon capture.

5.3.2.3 Carbon Capture Efficiency

In this analysis, carbon capture efficiency was defined as the percentage capture of all carbon present in the feedstock (coal in this case) which was not converted to carbon in the final products. Carbon emitted during the combustion of process fuels was not captured.

The range of carbon capture efficiency explored in the sensitivity analysis was from 75% to 95%, representing the worst to best case scenarios found in the literature. (SSEB, 2005) Assuming a pre-carbon capture process efficiency of 50%, which was correspondingly reduced, depending on the extent of carbon capture; and an energy requirement of about 250 kWh/ton of carbon captured, the resultant life-cycle GHG emissions from varying carbon capture efficiency are shown in Table 38. Carbon capture efficiency has a significant impact on the life-cycle GHG emissions of the CTL pathway. Using bituminous coal with a carbon emission factor of 25.5 metric ton per quadrillion Btu and assuming pre-capture process efficiency of 50%, capture efficiencies higher than 95% are needed to achieve overall GHG emissions levels that are lower than those of conventional jet fuel.

Table 38: Variation of Life-cycle GHG Emissions with Carbon-Capture Efficiency

Capture efficiency (%)	Process efficiency	Life-cycle GHG emissions (gCO_2e/MJ)	Compared to baseline conventional jet fuel
75	48.6	109	1.28
85	48.4	97	1.14
90	48.3	91	1.07
95	48.2	85	1.00

For the scenario analysis of a CTL plant with carbon capture, a carbon capture efficiency of 75% was assumed for the high emissions case. A carbon capture efficiency of 90%, which was a typical value found in the literature (e.g. Deutch and Moniz, 2007; Edwards et al., 2007; GREET, 2008; Marano and Ciferno, 2001), was assumed for the baseline case. An efficiency of 95%, representing a high-end value that may be achieved with technological advancements, was adopted for the low emissions case.

5.3.3 Results

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[19] EIA, 2006a reports that the average CO_2 emission factor for lignite coal is 26.3, and 26.5 for sub-bituminous coal. However, to illustrate the effect of CO_2 emission factor on the overall GHG emissions in the *high* emissions case, this analysis chooses to use the higher factor of 28.1 for typical lignite coal reported by Deutch and Moniz, 2007.

The cumulative effects of the various parameters analyzed in the sensitivity studies above on the overall GHG emission of the production of F-T diesel / jet fuel from coal with and without carbon capture are explored using the three scenarios (low, baseline and high cases). The results are shown in Table 39 and Table 40. As before, the combustion CO_2 emissions data were obtained from Hileman et al., 2008.

Table 39: Summary of Inputs and Results for F-T Jet Fuel from Coal Pathway (without carbon capture)

	Low	Baseline	High
Process efficiency	60 %	50 %	40 %
Coal carbon emission factor (million metric ton per quadrillion Btu)	24.9	25.5	28.1
WTT CO_2 emissions (gCO_2/MJ)	84.0	118.8	190.6
WTT CH_4 emissions (gCO_2e/MJ)	4.7	5.6	7.0
WTT N_2O emissions (gCO_2e/MJ)	0.01	0.01	0.02
WTT GHG emissions (gCO_2e/MJ)	88.7	124.5	197.6
Combustion CO_2 (gCO_2/MJ)	70.0	70.4	70.9
Total WTW GHG emissions (gCO_2e/MJ)	158.7	194.8	268.6
Total WTW GHG emissions relative to baseline conventional jet fuel	1.87	2.29	3.16
Overall energy ratio	0.59	0.49	0.39

Table 40: Summary of Inputs and Results for F-T Jet Fuel from Coal Pathway (with carbon capture)

	Low	Baseline	High
Process efficiency (including energy needed for CCS)	58.1% (60% w/o CCS)	48.3% (50% w/o CCS)	38.5% (40% w/o CCS)
Coal carbon emission factor (million metric ton per quadrillion Btu)	24.9	25.5	28.1
CO_2 capture efficiency	95%	90%	75%
WTT CO_2 emissions (gCO_2/MJ)	6.5	14.8	52.5
WTT CH_4 emissions (gCO_2e/MJ)	4.9	5.8	7.3
WTT N_2O emissions (gCO_2e/MJ)	0.01	0.01	0.02
WTT GHG emissions (gCO_2e/MJ)	11.4	20.6	59.8
Combustion CO_2 (gCO_2/MJ)	70.0	70.4	70.9
Total WTW GHG emissions (gCO_2e/MJ)	81.3	91.0	130.8
Total WTW GHG emissions relative to baseline conventional jet fuel	0.96	1.07	1.54
Overall energy ratio	0.57	0.48	0.38

The GHG emissions for the various steps in the production and use of F-T diesel / jet fuel from coal for both the CTL pathway with carbon capture and that without carbon capture (baseline cases) are shown in Table 41.

Table 41: GHG Emissions for Various Stages in F-T Jet Fuel from Coal Pathways (with and without carbon capture)

Stage emissions	CTL pathway without carbon capture	CTL pathway with carbon capture
Recovery (gCO_2/MJ)	0.8	0.8
Processing (gCO_2/MJ)	117.3	13.3
Transportation (gCO_2/MJ)	0.7	0.7
Well-To-Tank CH_4 and N_2O emissions (gCO_2e/MJ)	5.7	5.9
Combustion (gCO_2/MJ)	70.4	70.4
Total (gCO_2e/MJ)	194.8	91.0

5.3.4 Discussion

In the case of the CTL pathway without carbon capture, the life-cycle GHG emissions of the production and combustion of F-T diesel / jet fuel range from 1.9 times to 3.2 times greater than those of conventional jet fuel for the low to high emissions cases. When carbon capture is employed, the overall GHG emissions of the CTL pathway are reduced to slightly less than 1.0 times to 1.5 times those of conventional jet fuel, depending on the process efficiency, coal type and carbon capture efficiency assumed in the process.

Though coal is an abundant and cheap resource in the U.S., its use in the production of liquid fuels through the F-T process could generate large GHG emissions (~2-3 times) compared to conventional jet fuel, making its use unacceptable from the environmental perspective. However, if reliable and efficient (e.g., in terms of carbon capture efficiency) carbon capture and storage (CCS) technologies become available, GHG emissions can possibly be reduced to levels close to or lower than those of conventional jet fuel, allowing the use of large coal reserves in a cleaner and more environmentally-responsible manner.

It is noteworthy that the use of CCS in CTL plants incurs substantially lower cost and energy penalties compared to its use in coal integrated gasification and combined cycle (IGCC) power plants. This is mainly because the air separation unit (to provide oxygen), the CO_2 separation process units and the high operating pressures are integral parts of the F-T process and are considered "sunk costs," and this is not the case for the IGCC plant. Relatively pure CO_2 at moderately high pressure is produced as a by-product of the F-T process which makes carbon capture easier and less energy intensive as compared to an IGCC plant. Specifically, Deutch and Moniz, 2007, estimate that CCS would increase the cost of a CTL plant by about 10%, which is about one-third the "CO_2 avoided cost" for IGCC plants. (Deutch and Moniz, 2007) Given this disparity, it would be interesting to

further examine the relative merits of using coal gasification in IGCC plants versus CTL plants, particularly when CCS is required.

In addition, water use in CTL plants could be an important consideration in the environmental sustainability of such plants, especially in arid regions. It is estimated that about 1.5 to 7 barrels of water would be consumed for every barrel of F-T liquid fuels produced, depending on the "cost, availability, and quality of local water supplies." (Bartis, 2007b) This means that water volumes of up to 12 Olympic-sized swimming pools a day of water could be required to produce enough CTL jet fuel to power a large airport (~25,000 barrels per day).

5.4 Fischer-Tropsch Jet Fuel from Biomass

5.4.1 Overall Analysis Approach

This work investigated the life-cycle GHG emissions of the production of F-T fuels from biomass. The data used for this pathway was mainly based on the CHOREN process, producing "Sun Diesel" (F-T diesel) via the only commercial biomass-to-liquids (BTL) plant in the world today. It was assumed that the BTL plant was self-sufficient, using biomass feedstock to provide its internal process energy needs, with little or no excess electricity produced for export. Similar to the other F-T plants analyzed above, the BTL plant was assumed to produce commercial quality liquid fuels like diesel and jet fuel, and the energy allocation method was adopted for assigning energy and emissions to various liquid fuels produced.

It was also assumed that the biomass feedstock used in this pathway were waste biomass (e.g. forest residue) or non-food energy crops (e.g. herbaceous biomass) grown on idle, abandoned cropland or pastureland which did not contribute to adverse direct or indirect land use change emissions. Specifically, this work adopted default GREET assumptions for land use change emissions in the use of waste biomass and herbaceous biomass (discussed further below). In addition, the energy content of the forest residue feedstock used in the GREET analysis was derived from the CHOREN process, which assumed a biomass feedstock to F-T diesel mass ratio of 6:1 for a process efficiency of 45% (refer to Table 44 below). (Baitz et al., 2004)

The key processes and assumptions involved in the production of F-T jet fuel from biomass are summarized in Table 42.

Table 42: Key Processes in the Production of F-T Jet Fuel from Biomass

Process	Key assumptions / Source
Cultivation / collection of biomass feedstock	Default GREET assumptions
Transportation of biomass feedstock to F-T facilities in the U.S.	Default GREET assumptions
Processing of biomass to F-T jet fuel	Data based on literature review (CHOREN Industries), using F-T diesel as a surrogate for F-T jet fuel
Transportation and distribution of F-T jet fuel to final users	Default GREET assumptions for F-T diesel fuel, assuming that the transportation and distribution of F-T jet fuel require the same distances and transportation modes and shares as F-T diesel.

5.4.2 Analysis of Key Parameters in the Production of F-T Jet Fuel from Biomass

Similar to the CTL pathway, considerable uncertainties exist in the parameters assumed in the BTL pathway. Specifically, sensitivity studies were conducted to examine the effect of varying F-T process efficiencies and type of biomass feedstock on the overall life-cycle GHG emissions of the BTL pathway.

5.4.2.1 Process Efficiency

Process efficiencies ranging from 40% to 60% were used in the sensitivity analysis, representative of the range of values found in the literature. For example, process efficiencies ranging from 37% to 55% for BTL plants were reported by EU, 2005; while 58% efficiency was estimated by Wu, 2005 for relatively large-scale liquid fuels production with co-electricity generation. In the sensitivity study, it was assumed that forest residue was used as the feedstock (similar to the CHOREN process, which used wood waste) As can be seen in Table 43, varying process energy efficiency from 40% to 60% can result in overall GHG emissions reductions of 85% to 90% compared to conventional jet fuel.

Table 43: Variation of Life-cycle GHG Emissions with Fischer-Tropsch Process Efficiency

Process efficiency (%)	Mass ratio of feedstock to F-T Fuel	Life-cycle GHG emissions (gCO_2e/MJ)	Compared to baseline conventional jet fuel
40	6.8:1	13	0.15
45	6.8:1	12	0.14
50	6.8:1	11	0.12
55	6.8:1	10	0.11
60	6.8:1	9	0.10
Note: Forest residue was used as the biomass feedstock in this analysis.			

For the scenario analysis, process efficiencies of 60%, 45% and 40% were assumed for the low, baseline and high emission cases of the BTL pathway. The process efficiencies assumed for the low and high emission cases represent the range of values found in the literature, while the process efficiency of 45% for the baseline case is that reported by the CHOREN process based on the "self-sufficient basis scenario" (i.e. energy required for the process entirely provided by biomass feedstock, with no purchase of energy from the grid).

5.4.2.2 Type of Feedstock

This work also investigated the effect of varying feedstock type to the overall life-cycle GHG emissions of the BTL pathway. Specifically, this study only considered feedstock types which did not result in undesirable CO_2 emissions from land use changes, e.g. waste biomass and non-food, dedicated energy crops grown on idle land or pastureland. In particular, three types of biomass feedstocks were considered: forest residue, herbaceous crops and corn stover. All three feedstocks are available in GREET and default GREET assumptions for the energy and emissions associated with the cultivation (including fertilizer use) / collection and transportation of these feedstocks were adopted. Default GREET assumptions on the energy content and carbon content of the feedstocks were also assumed, except for the energy content of forest residue, which was derived from the CHOREN process (see Table 44). In addition, default GREET assumptions were used for nitrogen fertilizer use and land use change emissions associated with the use of these feedstocks (see Table 44). Nitrogen fertilizer use can contribute to GHG emissions through the energy and emissions needed in their manufacture, as well as nitrous oxide (N_2O) emissions from nitrogen compounds released into the soil. There is no nitrogen fertilizer use associated with forest residue. In the case of corn stover, it is usually retained in the corn field to provide soil nutrients. The nitrogen fertilizer use allocated to corn stover represents the incremental amount of nitrogen fertilizer which needs to be applied to corn cultivation when corn stover is removed from the field (GREET, 2007). There is no land use change emission associated with the use of forest residue or corn stover as they are considered waste crops. However, GREET assumes a net sequestration

of 48,500 g CO2/dry ton of herbaceous biomass used, arising from the increase in the carbon content of the soil from the conversion of idle land or pastureland to grasslands.

Table 44: Input Assumptions for Different Feedstocks

Feedstock	Lower heating value (Million Btu/ton)	Carbon content (mass %)	Nitrogen fertilizer use (g N/dry ton)	CO_2 emissions from land use change (g/ dry ton)
Forest residue	14.0	51.7	0	0
Herbaceous biomass	14.8	42.6	10,635	-48,500
Corn stover	14.1	44.5	3,175	0

For this sensitivity study, a process energy efficiency of 45% was assumed in all the cases. As shown in Table 45, the life-cycle GHG emissions of the BTL pathway show the greatest reduction compared to conventional jet fuel when corn stover is used as the biomass feedstock, and the least when herbaceous biomass is used.

Table 45: Variation of Life-cycle GHG Emissions with Type of Feedstock

Feedstock	Mass ratio of feedstock to F-T fuel	Life-cycle CO_2 emissions (gCO_2/MJ)	Life-cycle N_2O emissions (gCO_2e/MJ)	Life-cycle GHG emissions (gCO_2e/MJ)	Compared to baseline conventional jet fuel
Forest residue	6.0:1	11.2	0.1	11.6	0.14
Herbaceous biomass	5.7:1	2.3	10.1	12.7	0.15
Corn stover	6.0:1	7.1	-0.3	6.9	0.08
Note: Process efficiency of 45% was assumed in all cases.					

From the sensitivity study, the life-cycle CO_2 emissions from the use of herbaceous biomass are lower compared to those from the use of forest residue and corn stover. This is mainly due to the net CO_2 sequestration (credit) from the growth of these crops on idle lands or pastureland. In addition, the life-cycle CO_2 emissions of the BTL pathway using forest residue are higher compared to those using corn stover mainly due to the higher energy required for the collection of forest residue.

In terms of GHG emissions, there is a large increase in life-cycle GHG emissions compared to just life-cycle CO_2 emissions in the case of herbaceous biomass (increase from 2.3 gCO_2/MJ to 12.7 gCO_2e/MJ). This is largely due to the large N_2O emissions (10.1 gCO_2e/MJ) from the use of nitrogen fertilizers in the cultivation of the herbaceous biomass. On the other hand, the difference between life-cycle GHG emissions and CO_2 emissions for the use of forest residue as a feedstock is lower as no nitrogen fertilizer is used in the case of forest residue. In the case of corn stover, incremental fertilizer use (including nitrogen fertilizer) is accounted for to make up for the loss in soil nutrients from the removal of corn stover from the field. On the other hand, if left on the field, a

fraction of the nitrogen in corn stover will be converted to N_2O and emitted from the soil. Hence, this N_2O emission is avoided when corn stover is removed from the field. In this case, the N_2O credit from the removal of corn stover slightly outweighs the N_2O emissions resulting from the incremental application of nitrogen fertilizers, resulting in net negative N_2O emissions. Hence, the life-cycle GHG emissions of the BTL pathway using corn stover are slightly lower than its life-cycle CO_2 emissions.

Large uncertainties exist in the calculation of N_2O emissions from the use of nitrogen fertilizers. In some cases, N_2O emissions can contribute substantially to the overall GHG emissions of the biofuel production pathway (e.g. ignoring the N_2O emissions associated with herbaceous biomass nitrogen fertilizer use would increase GHG reductions of the BTL pathway relative to jet fuel from 85% to 97%). Default GREET assumptions were applied in this analysis. It would be worthwhile to conduct detailed analyses and sensitivity studies of N_2O emissions in the production of biofuels in future work.

Overall, the use of all three types of feedstocks in the BTL pathway results in significant reduction of life-cycle GHG emissions compared to conventional jet fuel.
For the analysis, corn stover was used in the low emissions case and herbaceous biomass in the high emissions case. Since the baseline case was based on the CHOREN process which used wood waste as the main biomass feedstock, forest residue was used in this case.

5.4.3 Results

The cumulative effects of the parameters analyzed in the sensitivity studies above on the overall GHG emission of the production of F-T diesel / jet fuel from biomass were explored using the three scenarios (low, baseline and high cases). The results are shown in Table 46. It was assumed that the CO_2 emitted during the combustion of the F-T fuel was equal to the CO_2 that was absorbed from the atmosphere during the growth of the biomass feedstock. Therefore, combustion CO_2 was set to zero in the BTL pathway.

Table 46: Summary of Inputs and Results for F-T Jet Fuel from Biomass Pathway

	Low	Baseline	High
Type of feedstock	Corn stover	Forest residue	Herbaceous biomass
Process efficiency (%)	60	45	40
WTT CO_2 emissions (gCO_2/MJ)	5.5	11.2	2.6
WTT CH_4 emissions (gCO_2e/MJ)	0.15	0.32	0.27
WTT N_2O emissions (gCO_2e/MJ)	-0.2	0.1	11.4
WTT GHG emissions (gCO_2e/MJ)	5.4	11.6	14.2
Combustion CO_2 (gCO_2/MJ)	0	0	0
Total WTW GHG emissions (gCO_2e/MJ)	5.4	11.6	14.2
Total WTW GHG emissions relative to baseline conventional jet fuel	0.06	0.14	0.17
Overall energy ratio	0.57	0.42	0.38

The GHG emissions for the various steps in the production and use of F-T diesel / jet fuel from biomass in the baseline case are shown in Table 47.

Table 47: GHG Emissions for Various Stages in F-T Jet Fuel from Biomass Pathway

Stage	Emissions
Recovery (gCO_2/MJ)	3.0
Processing (gCO_2/MJ)	5.8
Transportation (gCO_2/MJ)	2.3
Well-To-Tank CH_4 and N_2O emissions (gCO_2e/MJ)	0.4
Combustion (gCO_2/MJ)	0
Total (gCO_2e/MJ)	11.6

5.4.4 Discussion

The life-cycle GHG emissions of the BTL pathway range from 94% to 83% lower than those of conventional jet fuel. Hence, the use of F-T fuel from biomass is an attractive alternative to conventional jet fuel from the GHG emissions perspective. F-T fuels also burn more cleanly than conventional jet fuel and could help to reduce aviation's impact on air quality. (Hileman et al., 2008 and references therein) However, it is important to keep in mind that high levels of reduction in GHG emissions can only be achieved with the use of biomass feedstocks which do not contribute adversely to CO_2 emissions from land use changes, as was assumed in this analysis of this fuel pathway. The use of waste products such as forest residues or crop residues is an obvious way to circumvent the possible negative effects of land use change emissions. However, the use of waste products is limited by their availability, both within a reasonable distance from the BTL plant and arising from seasonal and behavioral fluctuations, which in turn limits the scale of BTL production. This resource limitation is further exacerbated by the large biomass feedstock requirement per mass of fuel produced. For example, assuming that 6 tons of forest residue feedstock is required to produce each ton of F-T fuel (as discussed earlier), about 0.02 ton of feedstock would be required per gallon of F-T fuel. This means that in order to produce about 25,000 barrels a day of F-T jet fuel (enough to meet the needs of a large airport), about 20,000 tons of forest residue would be required a day, about 5% of current forest biomass consumption.[20] Biomass feedstock requirements for large-scale BTL production are further explored in Chapter 7.

The use of dedicated energy crops could ensure a steadier and higher level of feedstock supply, as opposed to the use of waste products, but land use change emission considerations could come into play as production expands to a level which could not be met with the use of idle land or pastureland (see discussion on land use change emissions in Chapter 2). Grasslands or forests may need to be converted for the cultivation of energy crops, possibly resulting in adverse direct land use change emissions. Though not

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[20] According to a US biomass resource assessment study by the USDA (Perlack et al., 2005), current forest biomass consumption in the US is about 142 million tons a year, or almost 400,000 tons a day.

specifically investigated in this work, such negative land use change impacts are likely to be less pronounced than in the case of the use of food crops like soybeans (e.g., conversion of grasslands to lands for the growth of herbaceous crops like switchgrass or conversion of forests to lands for the cultivation of farmed trees would likely result in less carbon being emitted compared to the conversion of grassland or forest for the growth of soybeans or corn).

In addition to issues of feedstock availability and possible land use change impacts, the high cost of BTL production and the complexity of BTL plants (compared to GTL and CTL plants) could also restrict the widespread commercial production of F-T fuels from biomass. (Edwards et al., 2007) Nonetheless, F-T fuels from biomass remain an attractive option in reducing GHG emissions. However, for large-scale BTL production sufficient to replace a significant portion of conventional jet fuel consumption and reduce aviation GHG emission, the right policies and economic incentives need to be put in place to allow a greater adoption of commercial BTL production. The potential water, ecological and other sustainability issues associated with the use of biomass in fuel production also need to be examined in greater detail.

Chapter 6: Biojet from Renewable Oils

6.1 Introduction

In this work, biojet referred to a synthetic paraffinic kerosene fuel with similar physical properties as F-T fuels that is produced from the hydrotreatment of plant or animal oils. Unlike oxygenated fuels like alcohols and biodiesel, biojet is composed of hydrocarbons (non-oxygenated) with similar physical and chemical properties as conventional jet fuels. In particular, it displays the typical distillation range of Jet A. As such, it could be used without modifications in existing aircraft and fuel delivery infrastructure. Similar to F-T fuels, biojet has negligible sulfur content and its combustion should result in reduced particulate matter emissions compared to conventional jet fuel, lessening aviation's air quality impact.

Several production facilities are being (or have been) constructed to create synthetic fuels through the hydroprocessing of plant, animal, or waste oils. Most of these plants focus on the production of synthetic diesel. These synthetic fuels are named differently by different firms. Neste oil has four commercial plants (one in Austria, two in Finland, and one in Singapore) which can produce a total of about 25,000 barrels per day of synthetic fuels, termed "NexBTL". (Green Car Congress, 2006b, 2006c, 2007) Syntroleum, in cooperation with Tyson Foods, is constructing a facility that will produce 4,900 barrels per day of synthetic fuels, expected to be operational in 2010. Their synthetic fuels are termed "bio-synfining" diesel and jet fuel. (Syntroleum, 2008) UOP developed processes for the conversion of oils to fuels based on conventional hydroprocessing technologies employed in typical petroleum refineries. The synthetic diesel produced is termed "green diesel". (UOP, 2005) UOP, together with Eni, is planning a 6,500 bpd synthetic fuel facility in Italy which is expected to come online in 2009 (Huo et al., 2008). As of now, there is no conventionally accepted name for synthetic non-oxygenated fuels produced from the hydrotreatment of plant or animal oils. As highlighted above, such synthetic jet fuels were termed "biojet" in this study.

This chapter examined the life-cycle GHG emissions of the production of biojet from soy oil and palm oil. Soy oil is of interest as it is the main feedstock used in the U.S. for the production of biodiesel. Palm oil, on the other hand, has grown to become the largest produced oil in the world. Its production has increased rapidly in the past 20 years and the production of palm oil surpassed soy oil for the first time in 2006. (Rupilius and Ahmad, 2007) However, both soybeans and palm are edible food crops requiring fertile cropland for cultivation. The use of these crops in fuel production could result in direct and/or indirect land use change emissions (as discussed in Section 2.5.2). This analysis attempted to include the impact of land use change emissions in analyzing the life-cycle GHG emissions in the production of biojet from soy oil and palm oil by using existing data from the literature (e.g. Fargione et al., 2008 and Searchinger et al., 2008).

The hydrotreatment process for the production of biojet from soy oil and palm oil examined in this work was based on the process by UOP, which primarily produces "green diesel." Detailed process data on the production of biojet from renewable oils were not available in the literature. Hence, renewable diesel was used as a surrogate for biojet in this analysis.

6.2 Biojet from Soybean Oil

6.2.1 Overall Analysis Approach

This work examined the life-cycle GHG emissions of the production of biojet from soybean oil. This pathway is available in GREET and default assumptions on farming energy, fertilizer use, yield, etc. were updated where necessary using available data from the literature. In particular, the effect of indirect land use change emissions, not considered in GREET, was investigated in this analysis. Various allocation methods (e.g. displacement, energy, mass, market value, as discussed in Section 2.5.3) were examined in the partitioning of emissions between soy oil and the co-product of soy oil extraction, soybean meal. In analyzing the GHG emissions of the hydrotreatment of soy oil to biojet / renewable diesel via the UOP process, the energy allocation method was adopted for assigning energy and emissions to the various fuels produced (e.g. propane).

The key processes and assumptions involved in the production of biojet from soy oil are summarized in Table 48.

Table 48: Key Processes in the Production of Biojet from Soy Oil

Process	Key assumptions / Source
Cultivation of soybeans	Data from literature, GREET assumptions
Transportation of soybeans to oil extraction facilities	Default GREET assumptions
Extraction of soy oil from soybeans	Default GREET assumptions
Transportation of soy oil to biojet production facilities	Default GREET assumptions
Processing of soy oil to biojet	Data from the UOP process and GREET assumptions, with renewable diesel as a surrogate for biojet
Transportation and distribution of biojet to final users	Default GREET assumptions for conventional diesel, assuming that the transportation and distribution of biojet require the same distances and transportation modes and shares as diesel.

6.2.2 Analysis of Key Parameters in the Production of Biojet from Soy Oil

6.2.2.1 Cultivation of Soybeans

In this work, the parameters examined in the cultivation of soybeans included soybean yield, farming energy, fertilizer and pesticide use, N_2O emissions, lime use, and indirect land use change emissions. The data for these parameters came mainly from the U.S. Department of Agriculture (USDA), Hill et al., 2006, Sheehan et al., 1998 and default GREET assumptions as documented in Huo et al., 2008.

Soybean Yield

Soybean yield is the basic parameter that determines the life-cycle GHG emissions associated with the cultivation of soybeans as it affects the farming energy, fertilizer and other inputs, as well as emissions (e.g. N_2O, CO_2 from land use changes) (which are calculated on a per land area basis) per bushel of soybeans produced. Soybean yield statistics in recent years from the USDA as well as the projected soybean yield in 2016 are shown in Table 49.

Table 49: U.S. Soybeans Production and Yield (2002-2016)

Year	Planted acreage (million acres)	Production (billion bu)	Yield per planted acre (bu)	Yield per ha (bu)
2002	74.0	2.76	37.3	92.0
2003	73.4	2.45	33.4	82.5
2004	75.2	3.12	41.5	102.5
2005	72.0	3.06	42.5	105.0
2006	75.5	3.19	42.2	104.2
2007	63.6	2.59	40.6	100.3
2016	70.1	3.11	44.4	109.6
Notes:				

Notes:
  (1) Soybean production and yield data from 2002 and 2007 were obtained from USDA, 2008a.
  (2) Soybean production and yield projection in 2016 was obtained from FAPRI, 2007 based on average of projections in the years 2015/16 and 2016/17.

For the baseline case, the average soybean yield over the last 3 years (2005-2007) (41.8 bu/acre; 103 bu/ha) was assumed. For the high emissions case, the average soybean yield over the past 6 years (2002-2007) (39.6 bu/acre; 98 bu/ha) was assumed; while the projected soybean yield in 2016 (44.4 bu/acre; 110 bu/ha) was adopted for the low emissions case.

Farming Energy

The latest available farming energy use data for soybean cultivation was collected by the USDA's Economic Research Service (ERS) in 2002 and is shown in Table 50. This information is no longer available on the USDA website and was obtained through e-mail request. From the farming energy information and the assumed soybean yield in the low, baseline and high cases, the required farming energy per bushel of soybean can be derived for the three cases (see Table 51). For the high case, the energy used in growing and processing the soybean seed (i.e. seeding energy) was considered. This is estimated by Hill et al., 2006 to be an additional ~4.5% of total energy inputs (including farming and fertilizer energy).

Table 50: Farming Energy of U.S. Soybeans

Fuel type	Farming energy (gal/acre)	LHV of fuels (Btu/gal)[2]	Farming energy (Btu/acre)	Fuel share (%)
Diesel	4.8[1]	128,450	616,560	70.1
Gasoline	1.3	116,090	150,917	17.1
LPG	0.4	84,950	33,980	3.9
Electricity	7.8 (kWh/acre)	3,413 (Btu/kwh)	26,621	3.0
NG	52.5 (cubic ft/acre)	983 (Btu/scf)	51,608	5.9
Total			879,686	100
Notes:				
(1) Diesel use included custom work of 0.7 gal/acre (Hill et al., 2006; Sheehan et al., 1998).				
(2) LHV values of fuels (except electricity) were obtained from GREET (GREET, 2007).				

Table 51: Farming Energy of U.S. Soybeans for High Emissions, Baseline and Low Emissions Cases

Farming fuel energy (Btu/bu)	Soybean yield (bu/acre)		
	39.6 (high)[1]	41.8 (baseline)	44.4 (low)
Diesel	16,270	14,750	13,886
Gasoline	3,983	3,610	3,399
LPG	897	813	765
Electricity	703	637	600
NG	1,362	1,235	1,162
Total	23,214	21,045	19,813
Notes:			
(1) Includes an additional 4.5% energy due to seeding energy.			

Fertilizer and Pesticide Use

The data on fertilizer (nitrogen, phosphorus and potash), herbicide and insecticide use in the cultivation of soybeans in recent years was obtained from the USDA website (USDA, 2008b). Specifically, USDA provides information on total planted acreage for soybeans and total agricultural chemical use for different years. Using these statistics and soybean yield information, the agrichemical use in terms of grams of chemical per bushel of soybean can be derived for a particular year (see Table 52). The latest available data for soybeans is for the year 2006. No data were available for 2003 and 2005.

Glyphosate was the most commonly applied herbicide in soybean cultivation. The energy data for the manufacture of glyphosate is not available in GREET, so the estimated energy requirement provided by Hill et al., 2006 (475 MJ/kg) was used in this study. The percentage of glyphosate in overall herbicide use for each year was calculated and default GREET assumptions for herbicide energy use was applied for the remaining proportion of non-glyphosate herbicide use. Insecticide and fungicide are also applied in soybean cultivation, but in negligible amounts (e.g. 0.4 g/bu of insecticide and 0.1 g/bu of fungicide were applied in 2006) compared to fertilizer and herbicide application. Hence, these were not considered here.

Table 52: U.S. Soybeans Agrichemical Use

Agrichemical use (g/bu)	Year			
	2002	2004[1]	2006	Average
Nitrogen	52	64 [67]	31	49
Phosphorus	154	196 [205]	114	155
Potash	311	310 [324]	214	278
Herbicide (Percentage of glyphosate in herbicide use)	15 (73.6%)	13 [13] (83.1%)	15 (88.8%)	14 (81.8%)
Notes: (1) Numbers in square brackets represent the total amount after taking into account an additional 4.5% for seeding needs in the high emissions case.				

Fertilizer use (nitrogen, phosphorus and potash) in 2006 shows a significant decrease compared to 2002 and 2004. The year 2004, in particular, shows a spike in the use of nitrogen and phosphorus fertilizers. Hence, the agrichemical use data in 2006 was used in the low emissions case, while the data in 2004 was assumed for the high emissions case. As in the case of farming energy use, an additional 4.5% was applied to the default agrichemical use to account for seeding needs in the high emissions case. For the baseline case, the average agrichemical use data of 2002, 2004 and 2006 was adopted.

Land Use Change Emissions

As discussed earlier, the use of food crops in the production of renewable oils for fuels production may lead to emissions from land use change. The magnitude of land use change emissions can depend on the type of land being converted to cropland, the type of crops being grown, etc. Land use change scenarios were analyzed in the low, baseline and high cases using available data from the literature to illustrate the possible range of magnitudes of land use change emissions when soybeans are used to produce soy oil for biojet production.

In the low case, indirect land use change emissions were assumed to arise from the conversion of Cerrado grassland in Brazil to cropland for the growth of soybeans to replace those diverted for fuel production (data from Fargione et al., 2008). For the baseline case, land use change emissions data (from the conversion of non-crop lands worldwide to cropland) estimated by Searchinger et al., 2008 due to the diversion of U.S. corn to large-scale ethanol production were adopted, assuming that they also broadly apply in the case of soybeans diverted for biojet production. For the high case, land use change emissions were assumed to result from the conversion of tropical rainforests in Brazil to cropland for soybean cultivation (data from Fargione et al., 2008). In all scenarios, the total land use change emissions were assumed to be amortized over 30 years. From land use emissions data given in Mg CO_2/ha and assumed yield of soybeans for each of the low, baseline and high cases, the resultant land use change emissions per bushel of soybeans were estimated (see Table 53).

Table 53: Land Use Change Emissions Arising from Soybean Production

Scenario	Land use change emissions (Mg CO_2/ha)	Assumed soybean yield (bu/ha)	Land use change emissions (g CO_2/bu)[3]
Grassland conversion (low emissions case)	85[1]	110	25,836
World wide conversion of non-cropland (baseline case)	351[2]	103	113,322
Rainforest conversion (high emissions case)	737[1]	98	251,162
Notes:			
(1) From Fargione et al., 2008 (2) From Searchinger et al., 2008 based on diversion of corn production for large-scale ethanol production (3) Assumed to be amortized over 30 years			

Nitrous Oxide Emissions

Nitrous oxides emissions arising from the cultivation of agricultural crops were broadly discussed in Section 2.5.1. In this work, default N_2O emissions assumptions in GREET (documented in Huo et al., 2008) and N_2O emissions estimated by Hill et al., 2006 in soybean farming were used. Specifically, GREET calculated the total amount of nitrogen in soybean biomass left on the field as 200.7 g/bushel of soybeans harvested. The conversion rate for nitrogen to both direct and indirect N_2O emissions was estimated at 1.325%. Hence, the formula for calculating N_2O emissions in GREET is given by:

$$Total \ N_2O \ emissions \ (g/bu)$$
$$= (grams \ of \ nitrogen \ fertilizer \ used/bu + 200.7) \times 0.01325 \times \frac{44}{28} \qquad (6)$$

Assuming nitrogen fertilizer application rate of about 50 g/bu, total N_2O emissions are about 5.2 g/bu.

Hill et al. 2006 assumed N_2O emissions to be an all encompassing number of about 1760 g/ha based on conventional tillage on a corn, soybean and wheat rotation farm. Assuming a soybean yield of about 100 bu/ha, N_2O emissions would work out to be about 17.6 g/bu, more than 3 times the figure estimated by GREET.

For the scenario analysis, N_2O emissions estimated by GREET were assumed in the low and baseline cases, while the N_2O emissions adopted by Hill et al., 2006 were used in the high emissions case. The assumed nitrogen fertilizer use in the low and baseline cases was 31g/bu and 49g/bu, respectively. Hence, the corresponding N_2O emissions in the low and baseline cases were 4.8g/bu and 5.2g/bu, respectively. Using the assumed soybean yield of 98 bu/ha in the high case, the resultant N_2O emissions in this case were 18.0 g/bu.

Liming Emissions

Lime (composed primarily of calcium carbonate) can be added to soil to reduce soil acidity and increase nutrient uptake by crops. However, the use of lime can lead to CO_2 emissions which have to be taken into account in the overall life-cycle analysis of soybean farming emissions. GREET does not account for lime use in soybean cultivation. Hill et al., 2006 estimates 230 kg/ha of CO_2 emissions from liming based on conventional tillage on a farm that annually rotates among corn, soybean and wheat. This is about 2300 g CO_2/bu assuming a soybean yield of about 100 bu/ha. The full CO_2 emissions from liming (230 kg/ha) were assumed in the high emissions case, half the emissions (115 kg/ha) in the baseline case, and no lime use (hence no emissions) in the low case. Using the assumed soybean yield of 103 bu/ha in the baseline case and 98 bu/ha in the high case, the corresponding liming emissions were 1117 g/bu and 2347g/bu, respectively.

The energy and emissions associated with the manufacture of lime were ignored in this analysis as the specific lime application rate was not known. The errors introduced are likely to be small as the energy and emissions in the manufacture of lime are small

compared to those of other fertilizers and herbicides (e.g nitrogen fertilizer manufacture energy and CO_2 emissions are 42 mmBtu/ton and 2.5 Mg/ton, respectively, compared to 7 mmBtu/ton and 0.5 Mg/ton for lime).

Summary

A summary of the assumed parameters in the cultivation of soybeans for the low, baseline and high cases discussed above is given in Table 54.

Table 54: Input Assumptions for the Cultivation of Soybeans for the Low Emissions, Baseline and High Emissions Cases

Input parameter	Low	Baseline	High
Soybean yield (bu/ha)	110	103	98
Farming energy (Btu/bu)	19,813	21,045	23,214
Fertilizer inputs (g/bu)			
Nitrogen	31	49	67
Phosphorus	114	155	205
Potash	214	278	324
Herbicide (g/bu)	15	14	13
Percentage of glyphosate in herbicide use (%)	88.8	81.8	83.1
CO_2 emissions from land use changes (g/bu)	25,836 (Cerrado grassland conversion)	113,322 (average world non-cropland conversion)	251,162 (Tropical rainforest conversion)
N_2O emissions (g N_2O/bu)	4.8	5.2	18.0
Liming emissions (g/bu)	0	1,117	2,347

6.2.2.2 Extraction of Oil from Soybeans

The energy needed for the crushing and extraction of oil from soybeans was based on GREET default assumptions (~5,900 Btu/lb soy oil produced). GREET data is based on the study by Sheehan et al., 1998, but adjusted to reflect potential technological improvements (about 10% less total process energy than the value estimated by Sheehan et al., 1998). The inputs, outputs and process energy needed per lb of soy oil output are summarized in Table 55. (GREET, 2007)

Table 55: Input, Output and Process Energy for Extraction of Oil from Soybeans

Input (lb)	
Soybean	5.70
Output (lb)	
Soy oil	1
Soy bean meal	4.48
Process energy (Btu)	
Electricity	551
Natural Gas	5134
N-hexane	182
Total	5867

Allocation Approach between Co-products

In the extraction of soy oil from soybeans, soy bean meal is produced in large quantities (by mass relative to soy oil) as a co-product. Four methods were explored in this work to allocate the energy and emissions of soybean farming and soy oil extraction between soy oil and soy bean meal. These were allocation by mass, energy, market value, and the displacement (or substitution) method (as discussed in Section 2.5.3). The resultant allocation of GHG emissions between soy oil and soybean meal based on the four methods are given in Table 56 further below. More discussion on the application of the displacement method follows.

Soybean meal is primarily used as an animal feed. In this work, three potential products which soybean meal can potentially displace were explored: barley, corn, and soybean. The amount of product soybean meal would displace was calculated on a protein equivalence basis (i.e. matching of protein content). It was assumed that soybean meal had a protein content of ~48%. (Ahmed et al., 1994) The avoidance of land use change emissions potentially associated with the cultivation of the displaced crops was taken into account in the analysis.

Displacement of Barley

The protein content of barley was assumed to be 12% (USDA, 2008c; OMAFRA, 2003; Kennelly et al., 1995). Hence, 1 lb of soymeal displaced 4 lbs of barley on a protein equivalence basis. As 0.27 lbs of soymeal was produced per MJ of fuel, about 1.1 lbs of barley was displaced per MJ of fuel. From the life-cycle assessment of GHG emissions of barley cultivation conducted by Lechón et al., 2005, the CO_2 credit was 71.5 g/lb of barley displaced (76.3 g CO_2/MJ fuel) and N_2O credit was 0.36 g/lb of barley displaced (114 gCO_2e/MJ fuel). Lechón et al., 2005 did not include land use change emissions associated with the farming of barley. In this work, it was assumed that the land use change credit associated with the displaced barley was the avoidance of the conversion of Brazilian Cerrado grassland to cropland (~2,833,333 g CO_2/ha when emissions were amortized over 30 years, Fargione et al, 2008). Assuming a barley yield of 5940 lb/ha

(Lechón et al., 2005), the resultant land use change credit was 477 g CO_2/lb of barley displaced (508 g CO_2/MJ).

Displacement of Corn

Corn is also a widely used animal feed and can potentially be displaced by soybean meal. The protein content of corn is about 9%. (OMAFRA, 2003; Parish, 2007; Kennelly et al., 1995) Hence, 1 lb of soybean meal displaced 5.3 lbs of corn on a protein equivalence basis. As 0.27 lbs of soybean meal was produced per MJ of fuel, about 1.4 lbs of corn was displaced per MJ of fuel. The life-cycle GHG emissions for corn farming was analyzed in GREET and default GREET values (version 1.8b, GREET, 2008) were used in this work. Specifically, the CO_2, CH_4 and N_2O credits per lb of corn displaced were 100.6 g/lb (143.1 gCO_2/MJ fuel), 0.15 g/lb (5.0 gCO_2e/MJ fuel) and 0.22 g/lb (93.5 gCO_2e/MJ fuel), respectively. In the case of corn displacement, it was assumed that the land use change credit resulted from the avoidance of world wide conversion of non-cropland to cropland for corn cultivation as simulated by Searchinger et al., 2008 (11.7 Mg CO_2/ha when emissions were spread over 30 years). Assuming a corn yield of 150 bu/acre (average yield from 2003-2007, USDA, 2008a), the land use change credit was estimated to be 1393 g/lb of corn displaced (1982 gCO_2/MJ fuel).

Displacement of Soybeans

Soybean is the default product assumed to be displaced by soybean meal in GREET. (GREET, 2008) The protein content of soybeans was assumed to be 40%. (GREET, 2008) Hence, 1 lb of soybean meal displaced 1.2 lbs of soybean on a protein equivalence basis. As 0.27 lbs of soybean meal was produced per MJ of fuel, 0.32 lbs of soybean was displaced per MJ of fuel produced. The life-cycle GHG emissions for soybean farming were analyzed in this work and applied in this case. Specifically, based on the assumptions in the baseline scenario, the CO_2, CH_4 and N_2O credits per lb of soybeans displaced were 74.6 g/lb (23.9 gCO_2/MJ fuel), 0.08 g/lb (0.59 gCO_2e/MJ fuel) and 0.09 g/lb (8.4 gCO_2e/MJ fuel), respectively. In considering land use change emissions, it was assumed that the land use change credit was due to the avoidance of world wide conversion of non-cropland to cropland for corn cultivation as simulated by Searchinger et al., 2008 (11.7 Mg CO_2/ha when emissions were spread over 30 years). It was assumed that this scenario broadly applied to the case of soybean farming. Assuming a soybean yield of 105 bu/acre (as in baseline case described above), the land use change credit was estimated to be 1893 g/lb of soybean displaced (606 gCO_2/MJ fuel).

Results

Table 56 shows the allocation of emissions between soy oil and soybean meal using the four methods: mass allocation, energy allocation, market value allocation and displacement method. In particular, the displacement method considered three potential displaced products. Hence, six different approaches are shown in Table 56. The corresponding life-cycle GHG emissions of the production of biojet from soy oil using the different allocation approaches are shown in Table 57.

Table 56: Allocation of Emissions between Co-products of Soy Oil Extraction Using Various Allocation Approaches

Allocation approach	Soy oil (%)	Soybean meal (%)
Mass	18.2	81.8
Energy[1]	45.6	54.4
Market value[2]	41.8	58.2
Displacement[3] (barley)	-5 [668 - 700 = -32 gCO_2e/MJ]	105 [Displacement credit: 191 (production) + 509 (land use) = 700 gCO_2e/MJ]
Displacement[3] (corn)	-233 [668 - 2223 = -1555 gCO_2e/MJ]	333 [Displacement credit 242 (production) + 1982 (land use) = 2223 g gCO_2e/MJ]
Displacement[3] (soybean)	4.3 (45.3 without land use change emissions) [668 - 639 = 29 gCO_2e/MJ]	95.7 (54.7 without land use change emissions) [Displacement credit: 33 (production) + 606 (land use) = 639 g gCO_2e/MJ]

Notes:

(1) Energy content of soy oil: 37.2 MJ/kg (UOP, 2005); energy content of soybean meal: 9.88 MJ/kg (GREET, 2008)

(2) Market value of soy oil: $0.84/kg (GREET, 2008); market value of soy meal: $0.26/kg (GREET, 2008)

(3) The life-cycle GHG emissions of soybean farming and soyoil extraction (excluding land use change emissions) were 60.3 gCO_2e/MJ, and land use change emissions were 607.3 gCO_2/MJ. Total GHG emissions were 668 gCO_2e/MJ. These values were based on the assumptions of the baseline case as described above.

Table 57: Life-Cycle GHG Emissions in the Production of Biojet from Soy Oil Using Different Allocation Approaches

GHG emissions	Mass allocation	Energy allocation	Market value allocation	Displacement (soybean)
Soy oil recovery (soybeans farming and extraction of soy oil) (gCO_2e/MJ)	11.0	27.5	25.2	27.3
WTW GHG emissions (gCO_2e/MJ) (without land use change)	21.0	37.5	35.2	37.3
WTW GHG emissions relative to baseline conventional jet fuel (without land use change)	0.25	0.44	0.41	0.44
Land use change emissions (gCO_2/MJ)	110.5	276.9	253.8	1.2
WTW GHG emissions (gCO_2e/MJ) (with land use change)	131.5	314.4	289.0	38.5
WTW GHG emissions relative to baseline conventional jet fuel (with land use change)	1.5	3.7	3.4	0.45
Note: The calculation of the GHG emissions was based on assumptions of the baseline scenarios for soybean cultivation, land use change emissions and hydrotreating of soy oil to biojet (described in Section 6.2.2.3).				

Discussion

The displacement approaches where soybean meal was assumed to displace corn and barley produced net negative emissions for the biojet pathway (>100% allocation of GHG emissions to soybean meal). This is due to the large amount of soybean meal co-product produced relative to soy oil, and the low protein content of barley and corn compared to soybean meal (48% protein content of soybean meal versus 9% for corn and 12% for barley), resulting in a high protein-equivalence displacement ratio. This large discrepancy in protein content between soybean meal and corn / barley implies that these products may not be the most appropriate or likely products to be displaced by soybean meal production. Hence, they were not further considered in the analysis. Soybeans, on the other hand, have a protein content of about 40%, more comparable to that of soybean meal.

When land use change emissions are not considered, the energy, market value and displacement methods produce similar results due to their similar emissions allocation ratios to soy oil (42-46%). The mass allocation method, on the other hand, results in substantially lower GHG emissions as most of the emissions are allocated to the soybean meal co-product which is produced in larger quantities than soy oil.

When land use emissions are taken into account, the displacement method results in the lowest GHG emissions among the four approaches. This is because the land use change emissions credit given to the displacement of soybeans production by soybean meal (606 gCO_2/MJ) practically offsets the total land use change emissions of the biojet pathway (607 gCO_2/MJ). As before, the energy and market value approaches produce similar results due to their similar allocation ratios; while the mass allocation approach produces lower GHG emissions than the other two allocation approaches as a result of its lower allocation ratio of emissions to soy oil.

The use of different co-product allocation approaches can result in substantially different results, particularly when significant amount of co-products are being produced. The consideration of land use change emissions further complicates the analysis. Different allocation approaches are appropriate in different scenarios and pathways.

In this case, the mass or energy allocation method may not be most appropriate as soybean meal is not valued based on its mass, or sold as a commercial energy product due to its low energy content. Rather, its high protein content means that it has commercial value in the animal feed market. As discussed in Chapter 2, a general shortcoming in the displacement approach may arise when a large quantity of co-product is generated relative to the desired product, potentially resulting in an overestimation of credits for the co-product and even leading to net negative emissions. (Huo et al., 2008) In this case, the large proportion of soybean meal formed results in a majority of emissions being allocated to soybean meal (96%) compared to soy oil (4%) when soybean meal is assumed to displace soybeans. This is mainly due to the large land use emissions credit given to the displaced soybeans production, which may be an over-estimation due to the large amount of soybean meal produced. In addition, soybean, which is the feedstock from which soybean meal is produced, may not be the most likely product which would be displaced by soybean meal. In fact, some studies have adopted the mass allocation approach for simplicity as a suitable product to be substituted by soybean meal cannot be identified for the application of the displacement method. (Hill et al., 2006)

Hence, the method of choice in this work was the market value allocation approach, even though uncertainties arising from temporal fluctuations in the market prices of co-products could cause temporal changes in the allocation values. In fact, the sensitivity to market forces is apt in this case as it appropriately allocates the larger share of energy and emissions to the key contributor to the biofuel production based on the economic forces driving the production. For example, when biojet production increases due to higher demand, the price of soy oil is expected to rise, while the price of soybean meal will likely fall due to increased supply. The increase in relative price difference between soy

oil and soybean meal will result in greater emissions being allocated to soy oil, which as the desired feedstock driving biojet production, should aptly assume a major share of the resultant GHG emissions. (Fargione et al., 2008) For the aforementioned reasons, the market value approach was applied in determining the life-cycle GHG emissions of the production of biojet from soy oil in the low emissions, baseline and high emissions scenarios in Section 6.2.3.

6.2.2.3 Processing of Soy Oil to Biojet

The process energy input, hydrogen required and product slate in the production of biojet from soy oil were based on the UOP hydrotreating process. (UOP, 2005; Huo et al., 2008) In particular, this process produced a synthetic diesel termed "green diesel". As no detailed information was available on the hydroprocessing of renewable oils to synthetic jet fuel per se, diesel was used as a surrogate for jet fuel for this study .

The feedstocks, key products and process energy needed per 100 lb of oil feed are summarized in Table 58 (based on data from Appendix 2 of Huo et al., 2008).

Table 58: Input, Output and Process Energy for Processing of Soy Oil to Biojet

Feedstock (lb)	
Oil	100
H$_2$	2.72
Key Products (lb)	
Renewable diesel	84.19
Propane mix gas	4.75
Process Energy (Btu)	
Electricity	11570
Natural Gas[1]	8950
Notes: (1) Assume that steam is produced from natural gas at 80% efficiency.	

The effect of varying hydrogen input and product yield on the life-cycle GHG emissions of the soy oil to biojet pathway was investigated in this work. From UOP, 2005, the hydrogen input per 100 lb of oil can vary between 1.5 to 3.8 lbs, with the amount of renewable diesel and propane mix varying between 83-86 lbs and 2-5 lbs, respectively. For the baseline case, the hydrogen input and product yield given in Table 58 were assumed. In the low case, it was assumed that 1.5 lbs of hydrogen input was required per 100 lbs of oil feed to give 83 lbs of diesel and 2 lbs of propane gas mix. In the high case, it was assumed that 3.8 lbs of hydrogen input was required per 100 lbs of oil feed to give 86 lbs of diesel and 5 lbs of propane gas mix. The electricity and natural gas requirement for all 3 cases were assumed to be the same. This assumption is unlikely to introduce significant errors as the required hydrogen energy input is much larger than the electricity and natural gas energy inputs. In addition, the energy allocation method was used to

partition the energy and emissions of the whole process between diesel and the propane gas mix co-product as both were considered energy products.

A summary of key assumptions, inputs and outputs (based on 1 lb of product) for the three scenarios in the hydroprocessing of soy oil based on the UOP process is given in Table 59.

Table 59: Assumptions in the Hydroprocessing of Soy Oil to Biojet

Basis: per lb product	Hydrogen input (lb)	Hydrogen input (Btu)[1]	Electricity use (Btu)	NG use (Btu)	Total Energy	Propane output (lb)	Allocation to Diesel (Energy)[2]
Low	0.018	932 (80.5%)	139 (15%)	108 (4.5%)	1179	0.024	97.7%
Baseline	0.032	1667 (88.2%)	137 (8.2%)	106 (3.5%)	1910	0.056	94.8%
High	0.044	2279 (91.3%)	135 (5.9%)	104 (2.8%)	2518	0.058	94.6%

Notes:
(1) Assuming hydrogen LHV of 51,586 Btu/lb (GREET, 2007)
(2) Assuming renewable diesel LHV of 18,925 Btu/lb and propane gas mix LHV of 18,568 Btu/lb (Huo et al., 2008)

6.2.3 Results

The key assumptions and corresponding life-cycle GHG emissions in the production and use of biojet from soy oil for the low, baseline and high emission cases are shown in Table 60. It was assumed that the CO_2 emitted during the combustion of biojet was equivalent to the CO_2 that was absorbed from the atmosphere during the growth of the soybean feedstock. Therefore, combustion CO_2 was set to zero. The market value allocation approach was assumed for the allocation of emissions between soy oil and soybean meal (see discussion in Section 6.2.2.2), while the energy allocation approach was adopted for apportioning of emissions between biojet and propane gas (assuming hydroprocessing of soy oil to renewable diesel as a surrogate for the production of biojet).

Table 60: Summary of Inputs and Results for Biojet from Soy Oil Pathway

	Low	Baseline	High
Soybean yield (bu/ha)	110	103	98
Farming energy (Btu/bu)	19,813	21,045	23,214
N_2O emissions (gN_2O/bu)	4.82	5.20	17.96
Liming emissions (gCO_2/bu)	0	1,117	2,347
Soy oil extraction energy (Btu/lb soy oil)	5,800	5,800	5,800
Hydrotreatment energy (Btu/lb fuel)	1179	1910	2518
Hydrogen input (lb/lb fuel)	0.018	0.032	0.044
WTT CO_2 emissions (gCO_2/MJ) (without land use change)	25.1	30.1	37.2
WTT CH_4 emissions (gCO_2e/MJ)	1.3	1.4	1.7
WTT N_2O emissions (gCO_2e/MJ)	3.5	3.6	11.9
WTW GHG emissions (gCO_2e/MJ) (without land use change)	29.9	35.2	50.8
WTW GHG emissions relative to baseline conventional jet fuel (without land use change)	0.35	0.41	0.60
Land use change emissions (gCO_2/MJ)	60.5	253.8	549.6
WTW GHG emissions (gCO_2e/MJ) (with land use change)	90.4	289.0	600.3
WTW GHG emissions relative to baseline conventional jet fuel (with land use change)	1.1	3.4	7.1
Overall energy ratio	0.72	0.70	0.66

The GHG emissions for the various steps in the production of biojet from soy oil (assuming hydroprocessing of soy oil to renewable diesel as a surrogate for the production of biojet) in the baseline case are shown in Table 61.

Table 61: GHG Emissions for Various Stages in Biojet from Soy Oil Pathway

Stage	Emissions
Recovery (soy oil) (gCO_2/MJ)	19.5
Processing (gCO_2/MJ)	8.9
Transportation (gCO_2/MJ)	1.7
Land Use Change Emissions (gCO_2/MJ)	253.8
Well-To-Tank CH_4 and N_2O emissions (gCO_2e/MJ)	5.1
Combustion (gCO_2/MJ)	0
Total (gCO_2e/MJ)	289.0

6.2.4 Discussion

Without the effect of land use change emissions (e.g. use of excess/idle cropland or excess soybean production), the life-cycle GHG emissions of the production of biojet from soy oil are 0.35 to 0.60 times those of conventional jet fuel, making biojet a viable alternative to jet fuel from the perspective of curbing GHG emissions.

About 0.7 bushels of soybeans are needed to produce one gallon of biojet fuel. This means that to produce the amount of biojet needed to fuel a large airport (25,000 bpd) would require about 281 million bushels of soybeans a year, almost 10% of current U.S. soybean production. About 6.7 million acres of land would be required to grow this volume of soybean crops. Hence, with the large-scale biojet production needed to make a significant impact in the displacement of conventional jet fuel, it is likely that the amount of diverted soy oil to fuel production would result in conversion of non-cropland to cropland to replace the diverted soy oil for food purposes. This would result in indirect land use change emissions which could dramatically increase the overall GHG emissions of the biojet pathway to up to seven times more than those of conventional jet fuel, depending on the land use change that results, rendering the use of biojet undesirable in terms of its GHG footprint.

As mentioned earlier, these results are based on land use change emissions which were adopted from existing data in the literature and as such may not directly or exactly reflect the land use change emissions in the scenarios analyzed in this work. They are meant to illustrate the impact of different land use change scenarios on the overall GHG emissions of the pathway and are not intended to be definitive. Further modeling work and land use data would be required to derive more exact land use change emissions information. These are outside the scope of this work but should be explored in further studies due to the importance of land use change emissions and their large contribution to the overall GHG emissions. In addition, other sustainability issues related to the use of biomass feedstock for fuel production, such as water, ecological, biodiversity, soil erosion issues, etc. while not specifically considered in this study, remain important factors to consider when evaluating the overall feasibility in the use of biomass (e.g. soybeans) for fuel production.

In summary, food-based feedstocks are usually not appropriate from a carbon perspective when large-scale production of fuel is desired due to potential land use change emissions, the negative impacts of which are likely to be exacerbated when production volume expands and higher carbon storage lands (e.g. rainforests, peatland) are converted to croplands. However, without the effect of land use change emissions, life-cycle GHG emissions in the production of biojet from renewable oils are favorable. Hence, it is important to investigate use of renewable oil which would not result in large land use change emissions (e.g. waste products, non-food crops, algae) for fuel production.

6.3 Biojet from Palm Oil

6.3.1 Overall Analysis Approach

This section analyzes the life-cycle GHG emissions of the production of biojet from palm oil. This pathway is not available in GREET. Information on farming energy, fertilizer use, yield, oil extraction energy, etc. were obtained from the literature, the main source of which was the work by Wicke et al., 2007. As in the case of soy oil analysis, the effect of land use change emissions was investigated in this analysis, based on existing data in the literature. (Wicke et al., 2007; Fargione et al., 2008) In the extraction of oil from palm fresh fruit bunches (FFB), two types of oil, palm oil and palm kernel oil, are produced. Palm kernel oil, in particular, has carbon numbers ranging from 6-20, with peak distribution at C12, similar to that of jet fuel. (Ranken et al., 1997) Hence, both palm oil and palm kernel oil were assumed to be main products in the FFB extraction process, to be used in the production of biojet. This is in contrast to other studies where diesel is the desired product from renewable oil processing and palm kernel oil, whose carbon number distribution is not in the diesel range, is considered a by-product instead of a main product in the FFB extraction process. Palm kernel expeller, which can be used as an animal feed, is also formed in this process.

This work also examined various allocation methods (displacement, energy, mass, market value) in the apportitioning of emissions between palm oil, palm kernel oil and palm kernel expeller. The approach and assumptions in analyzing the GHG emissions in the hydroprocessing of palm oil and palm kernel oil to biojet were similar to those in the case of using soy oil as the feedstock (i.e. based on the UOP process, using the energy allocation method for assigning energy and emissions between co-products, and using diesel as a surrogate for jet fuel in the process).

The key processes and assumptions involved in the production of biojet from palm oil and palm kernel oil are summarized in Table 62.

Table 62: Processes in the Production of Biojet from Palm Oil and Palm Kernel Oil

Process	Key assumptions / Source
Cultivation of palm fresh fruit bunches in South-East Asia	Data from literature
Transportation of palm fresh fruit bunches (FFB) to oil extraction facilities	Default GREET assumptions (assuming similar transportation distance and mode as the transportation of soybeans to oil extraction plants)
Extraction of palm and palm kernel oil from palm FFB	Data from literature
Transportation of palm and palm kernel oil from South-East Asia to biojet production facilities in the U.S.	Data from literature
Processing of palm oil and palm kernel oil to biojet	Using data from the UOP process and GREET assumptions, with renewable diesel as a surrogate for biojet
Transportation and distribution of biojet to final users	Default GREET assumptions for conventional diesel, assuming that the transportation and distribution of biojet require the same distances and transportation modes and shares as diesel.

6.3.2 Analysis of Key Parameters in the Production of Biojet from Palm Oils

6.3.2.1 Cultivation of Palm Fresh Fruit Bunches (FFB)

The parameters examined in the cultivation of palm fresh fruit bunches (FFB) included FFB yield, farming energy, fertilizer use, N_2O emissions, and indirect land use change emissions. The data on these parameters were mainly obtained from Wicke et al., 2007 (based primarily on a case study of palm plantation operations in Malaysia) and Reijnders and Huijbregts, 2008.

FFB Yield

The average FFB yield reported in literature ranges from 21.6-27.5 ton FFB/ha. (Reijnders and Huijbregts, 2008; Wicke et al., 2007) Hence, the yield of 21.6 ton FFB/ha was assumed in the high case, while the yield of 27.5 ton FFB/ha was assumed in the low case. For the baseline case, the average of the high and low values, 24.6 ton FFB/ha was assumed.

Farming Energy

In South-East Asia oil plantations, most of the cultivation and harvest of the palm FFB are done manually and with the help of animals. The main fossil energy used is diesel

fuel for powering farm machinery and equipment. In this work, it was assumed that 3.0mmBtu/ha of diesel was consumed in the low emissions and baseline cases, while 4.9 mmBtu/ha was used in the high emissions case. (Wicke et al., 2007) Using the assumed FFB yield in the three scenarios as described above, the corresponding farming energy per ton of FFB harvested was estimated. The results are shown in Table 63.

Table 63: Farming Energy of Palm Fresh Fruit Bunches

	Low	Baseline	High
Yield (ton FFB/ha)	27.5	24.6	21.6
Farming energy (Btu/ton FFB)	110,300	123,300	228,200

Fertilizer Application

Only nitrogen fertilizer application was considered in the cultivation of palm FFB in this study as the GHG emissions contributions from the production of phosphate and potash fertilizers, as well as herbicides, were negligible compared to those of nitrogen fertilizers. (Wicke et al., 2007) In addition, the application of organic fertilizers (e.g. empty fruit bunches) were not considered as their emissions were carbon-neutral, i.e. the CO_2 emitted were equivalent to the CO_2 absorbed during their growth. The assumed nitrogen fertilizer in all three cases (low, baseline and high) was 139 kg/ha. (Wicke et al., 2007) The corresponding nitrogen fertilizer application in terms of grams of nitrogen per ton of FFB is shown in Table 64.

Table 64: Nitrogen Fertilizer Use in the Cultivation of Palm Fresh Fruit Bunches

	Low	Baseline	High
Yield (ton FFB/ha)	27.5	24.6	21.6
Nitrogen fertilizer application (g/ton FFB)	5055	5650	6435

Land Use Change Emissions

Like soy oil, palm oil is also a source of food and its use in fuel production may lead to land use change emissions. As in the case of soy oil, three land use change scenarios were analyzed using available data in the literature to illustrate the possible range of magnitudes of land use change emissions when palm oil and palm kernel oil were used for biojet production.

In the low emissions case, direct land use change emissions were assumed to occur from the conversion of previously logged over forest to palm plantations (data from Wicke et al., 2007). For the baseline and high cases, it was assumed that land use change emissions resulted from the conversion of tropical rainforest and peatland rainforest in South-East Asia, respectively, to palm plantations (data from Fargione et al., 2008). In all scenarios, the total land use change emissions were assumed to be allocated over 30 years, roughly

the life-span of a palm plantation. From land use emissions data given in Mg CO_2/ha and assumed yield of palm FFB for each of the low emissions, baseline and high emissions case, the resultant land use change emissions per ton of FFB were determined (see Table 65).

Table 65: Land Use Change Emissions in the Cultivation of Palm Fresh Fruit Bunches

Scenario	Land use change Emissions (Mg CO_2/ha)	Assumed palm FFB yield (ton/ha)	Land use change emissions (g CO_2/ton FFB)[1]
Conversion of previously logged over forest (low case)	-	27.5	82,300[2]
Conversion of tropical rainforest (baseline case)	702[2]	24.6	951,200
Conversion of peatland rainforest (high case)	3452[3]	21.6	5,327,200
Notes:			
(1) Assumed to be amortized over 30 years (2) Derived from data in Wicke et al., 2007, assuming crude palm oil energy content of 36 MJ/kg and that 1 lb of FFB produces 0.21 lbs of crude palm oil. (3) From Fargione et al., 2008			

Nitrous Oxide Emissions

In this section, N_2O emissions from nitrogen fertilizer application were estimated based on IPCC guidelines as applied by Wicke et al., 2007. Due to the lack of data, N_2O emissions from nitrogen in above and belowground crop residues were not accounted for in this analysis. Specifically, it was assumed that 1% of nitrogen applied to the soil was emitted to the atmosphere as nitrogen in N_2O.

Hence, the amount of N_2O emissions from nitrogen fertilizer use (g/ton FFB) was given by:

$$N_2O \ emissions = (g \ nitrogen \ fertilizer \ / \ ton \ FFB) \times 0.01 \times \frac{44}{28} \qquad (7)$$

The corresponding N_2O emissions per ton of FFB harvested for the low emissions, baseline and high emissions cases are shown in Table 66.

Table 66: N_2O Emissions from Cultivation of Palm Fresh Fruit Bunches

	Low	Baseline	High
Nitrogen fertilizer application (g/ton FFB)	5055	5650	6435
N_2O emissions (g N_2O/ton FFB)	79.4	88.8	101.1

Summary

A summary of the assumed parameters in the cultivation of palm FFB for the low, baseline and high cases discussed above is given in Table 67.

Table 67: Assumptions in the Cultivation of Palm Fresh Fruit Bunches for the Low Emissions, Baseline and High Emissions Cases

Input parameter	Low	Baseline	High
FFB yield (ton/ha)	27.5	24.6	21.6
Farming energy (Btu/ton FFB)	110,300	123,300	228,200
Nitrogen fertilizer inputs (g/ton FFB)	5055	5650	6435
CO_2 emissions from land use changes (g/ton FFB)	82,300 (conversion of logged over forest)	951,200 (conversion of tropical rainforest)	5,327,200 (Conversion of peatland rainforest)
N_2O emissions (g N_2O/ton FFB)	79.4	88.8	101.1

6.3.2.2 Extraction of Oil from Palm FFB

Palm oil and palm kernel oil are produced from palm FFB at a processing plant called the mill. In the extraction of palm oil from FFB, palm kernel shells (PKS), fibre, empty fruit bunches (EFB) and kernels are also produced. PKE and fiber are burnt to generate electricity to fuel mill processes, while EFB are used as organic fertilizers. Palm kernels can be further processed to produce palm kernel oil and palm kernel expeller, which can be used as an animal feed. In addition, a waste stream called palm oil mill effluent (POME) is produced from the extraction of oil from FFB. POME treatment (through anaerobic digestion) results in the emission of CH_4.

The energy needed for the crushing and extraction of oil from palm FFB and from palm kernels were obtained from Wicke et al., 2007. The input parameters used to calculate the extraction energy and yield of oils from palm FFB and the resultant energy consumption and product yield data are shown in Table 68. (Wicke et al., 2007) The total process

energy of 191.4 Btu/lb oil was used in all the three scenarios (low emissions, baseline and high emissions cases).

Table 68: Inputs, Outputs and Process Energy in the Extraction of Palm Oil and Palm Kernel Oil

Extraction of palm oil from FFB	
Palm oil extraction rate (ton palm oil/ton FFB)	0.21
Amount of kernels produced (ton kernels/ton palm oil)	0.24
Energy input Diesel (litre/ton FFB)[1]	1.36
Extraction of palm kernel oil from kernels	
Palm kernel oil extraction rate (ton PKO/ton kernel)	0.45
Palm kernel expeller extraction rate (ton PKE/ton kernel)	0.53
Energy input Electricity (kWh/ton kernel) Diesel (litres/ton kernel)	77.3 17.3
Overall energy use and product yields	
Input FFB (lb)	4.3
Output Palm oil and palm kernel oil (lb) Palm kernel expeller (lb)	1 0.11
Process energy Electricity (Btu/lb oil) Diesel (Btu/lb oil)	28.5 162.9
Notes: (1) The amount of diesel energy needed for electricity generation is reduced by the use of palm kernel shell and fiber (by-products of palm oil extraction) for electricity production.	

Methane Emissions from POME Treatment

As mentioned earlier, the treatment of palm oil mill effluent results in the production of methane. For every ton of FFB that is processed, between 1.5 to 2.2 kg of CH_4 is emitted from POME that is treated in an open digesting tank system. (Reijnders and Huijbregts, 2008) In this work, it was assumed that 1.5 kg CH_4/ton FFB was emitted in the low emissions case, 1.85kg CH_4/ton FFB (average value) in the baseline case, and 2.2 kg CH_4/ton FFB in the high emissions case. The resultant CH_4 emissions on a per lb of oil basis are given in Table 69.

Table 69: Methane Emissions from POME Treatment

	Low	Baseline	High
CH$_4$ emissions from POME treatment (g CH$_4$/lb oil)	3.18	3.97	4.77

Allocation Approach between Co-products

As discussed above, in the extraction of palm oil from FFB and palm kernel oil from kernels, co-products such as palm kernel shell, fibre, empty fruit bunches and palm kernel expeller are also formed. As palm kernel shell and fibre are used for electricity production in the mill and empty fruit bunches as fertilizers in palm FFB cultivation to reduce energy requirement and fertilizer input, respectively, they are considered "inputs" to the process rather than specific co-products. In addition, the emissions generated by the use of these products are considered carbon-neutral as they were previously absorbed from the atmosphere during growth. Hence, palm kernel expeller is the only co-product considered in the allocation of process energy and emissions.

As in the case of soy oil production, allocation of mass, energy, market value and the displacement method were explored in this work to allocate the energy and emissions of palm FFB cultivation and oil extraction between palm oil, palm kernel oil (PKO) and palm kernel expeller (PKE). The resultant allocation of GHG emissions between palm oil, PKO and PKE based on the four approaches are given in Table 70 below.

In the application of the displacement method, it is necessary to identify potential product(s) which PKE can displace. PKE is primarily used as an animal feed and two potential products which PKE can potentially displace, barley and corn, were examined. As in the case of soybean meal, the amount of product that PKE would displace was calculated on a protein equivalence basis. It was assumed that PKE had an average protein content of 14.4%. (Tang, undated) Emission credit arising from the avoidance of land use change emissions potentially associated with the displaced product was considered in this analysis.

Displacement of Barley

As before, barley was assumed to have a protein content of about 12%. Hence, 1 lb of PKE displaced about 1.2 lbs of barley on a protein equivalence basis. As 0.0068 lbs of PKE was produced per MJ of fuel, 0.0082 lbs of barley was displaced per MJ of fuel. As in the case of soybean meal, the GHG emissions credit associated with the cultivation of barley was taken from the work by Lechón et al., 2005. Specifically, the CO$_2$ credit was 71.5 g/lb of barley displaced (0.59 g CO$_2$/MJ fuel) and N$_2$O credit was 0.36 g/lb of barley displaced (0.88 gCO$_2$e/MJ fuel). Similar to the soybean meal analysis, it was assumed that the land use change credit associated with the displaced barley was the avoidance of the conversion of Brazilian Cerrado grassland to cropland (~2,833,333 g CO$_2$/ha when emissions were amortized over 30 years, Fargione et al, 2008). Assuming a barley yield

of 5940 lb/ha (Lechón et al., 2005), the resultant land use change credit was 477 g CO_2/lb of barley displaced (3.9 g CO_2/MJ).

Displacement of Corn

The protein content of corn was assumed to be about 9%. Hence, 1 lb of PKE displaced 1.6 lbs of corn on a protein equivalence basis. As 0.0068 lbs of soybean meal was produced per MJ of fuel, about 0.011 lbs of corn was displaced per MJ of fuel. As in the case of soybean meal, default GREET values for the life-cycle GHG emissions of corn farming were used in this work. Specifically, the CO_2, CH_4 and N_2O credits per lb of corn displaced were 100.6 g/lb (1.10 gCO_2/MJ fuel), 0.15 g/lb (0.04 gCO_2e/MJ fuel) and 0.22 g/lb (0.72 gCO_2e/MJ fuel), respectively. In addition, it was assumed that the land use change credit resulting from the avoidance of world wide conversion of non-cropland to cropland for corn cultivation was estimated from Searchinger et al., 2008 (11.7 Mg CO_2/ha when emissions were spread over 30 years). Assuming a corn yield of 150 bu/acre, the land use change credit was estimated to be 1393 g/lb of corn displaced (15.2 gCO_2/MJ fuel).

Results

Table 70 shows the allocation of emissions between palm oil, palm kernel oil and palm kernel expeller using the four approaches: mass allocation, energy allocation, market value allocation and displacement method. Specifically, the displacement method considered two potential displaced products. Hence, five different approaches are shown in Table 70. The corresponding life-cycle GHG emissions for the production of biojet from palm oil using the various methods are shown in Table 71.

Table 70: Allocation of Emissions between Co-products of Palm Oil and Palm Kernel Oil Extraction Using Various Allocation Approaches

Allocation approach	Palm oil and palm kernel oil (%)	Palm kernel expeller (%)
Mass	89.7	10.3
Energy[1]	98.1	1.9
Market value[2]	97.9	2.1
Displacement[3] (barley)	95.8 (89.4 without land use change emissions) [129.0 – 5.4 = 123.6 gCO_2e/MJ]	4.2 (10.6 without land use change emissions) [Displacement credit: 1.46 (production) + 3.91 (land use) = 5.4 gCO_2e/MJ]
Displacement[3] (corn)	86.7 (86.6 without land use change emissions) [129.0 – 17.1 = 111.9 gCO_2e/MJ]	13.3 (13.4 without land use change emissions) [Displacement credit 1.85 (production) + 15.21 (land use) = 17.1 gCO_2e/MJ]

Notes:
(1) Energy content of palm oil and PKO: 36 MJ/kg (Wicke et al., 2007; Reijnders and Huijbregts, 2008); energy content of PKE: 6.2 MJ/kg (Tang, undated).
(2) Market value of palm oil: $0.78/kg; market value of PKO: $0.89/kg; market value of PKE: $0.15/kg (Fargione et al., 2008).
(3) The life-cycle GHG emissions of palm FFB cultivation and oil extraction (excluding land use change emissions) were 13.8 gCO_2e/MJ, and land use change emissions were 115.3 gCO_2/MJ. Total GHG emissions are 129.0 gCO_2e/MJ. These values were based on the assumptions of the baseline case as described above.

Table 71: Life-Cycle GHG Emissions in the Production of Biojet from Palm Oil and Palm Kernel Oil Using Different Allocation Approaches

GHG emissions	Mass allocation	Energy allocation	Market value allocation	Displace-ment (barley)	Displace-ment (corn)
Palm oils recovery (palm FFB farming and extraction of palm oil and PKE) (gCO$_2$e/MJ)	12.3	13.5	13.5	12.3	11.9
WTW GHG emissions (gCO$_2$e/MJ) (without land use change)	24.8	26.2	26.2	25.1	24.7
WTW GHG emissions relative to baseline conventional jet fuel (without land use change)	0.29	0.31	0.31	0.30	0.29
Land use change emissions (gCO$_2$/MJ)	103.4	113.1	112.8	111.3	100.4
WTW GHG emissions (gCO$_2$e/MJ) (with land use change)	128.2	139.3	139.0	136.4	124.7
WTW GHG emissions relative to baseline conventional jet fuel (with land use change)	1.51	1.64	1.64	1.60	1.47
Note: The calculation of the GHG emissions was based on assumptions of the baseline scenarios for palm FFB cultivation, land use change emissions and hydroprocessing of palm oil and palm kernel oil to biojet (similar to those of soy oil to biojet). These are discussed in subsequent sections.					

Discussion

Unlike the case of soy oil, different allocation methods produce similar results in the distribution of emissions among palm oil, PKO and PKE. This is true in both the cases where land use change emissions were considered and not considered. This is largely due to the small quantity of PKE produced relative to the main products. In particular, the displacement method using corn or barley did not result in net negative emissions in the pathway unlike the case of soy oil. The protein content of PKE was closer to those of corn and barley compared to soybean meal. Hence the displacement ratio based on protein equivalence was smaller than in the case of soybean meal. As mentioned, PKE was also produced in smaller quantities relative to the palm oils, while the amount of soybean meal formed was more than four times the amount of soy oil formed. Hence, the

displacement method using either corn or barley, as well as the market value allocation approach, appeared to be appropriate in this case. As in the case of soy oil, the mass or energy allocation methods were less appropriate as PKE was not valued based on its mass or energy content. Nonetheless, since all four approaches produced similar results, the market value method was adopted in presenting the overall GHG emissions of this pathway for the three scenarios (low emissions, baseline, high emissions) to be consistent with the approach taken in the soy oil pathway.

6.3.2.3 Transportation of Palm Oil and Palm Kernel Oil to Biojet Production Facilities

In this work, it was assumed that palm oil and palm kernel oil were produced in facilities near palm plantations in South-east Asia, and then transported to U.S. hydroprocessing facilities to produce biojet. This transportation pathway is not available in GREET. The key assumptions used in this work are summarized in Table 72.

Table 72: Assumptions in the Transportation of Palm Oil and Palm Kernel Oil from South-east Asia to the U.S.

Transportation of palm oil and PKO from mill to harbor in South-east Asia	
Mode (%)	
Truck	100
Distance (miles)	63[1]
Transportation of palm oil and PKO from harbor in South-east Asia to ports in the U.S.[2]	
Mode (%)	
Ocean tanker	100
Distance (miles)	
Gulf Coast (50%)	13500
East Coast (25%)	12300
West Coast (25%)	7700
Average	11750
Transportation of palm oil and PKO from U.S. ports to biojet production facilities[3]	
Mode (%)	
Truck	50
Rail	50
Distance (miles)	
By truck	100
By rail	500
Notes:	
(1) From Wicke et al., 2007.	
(2) Derived from shipping distances found in http://www.asaim.org.tw/Ocean%20Shipping%20Distances.pdf	
(3) Author's own estimates.	

6.3.2.4 Processing of Palm oil and Palm Kernel Oil to Biojet

The process energy input, hydrogen required and product slate in the production of biojet from palm oil and palm kernel for the low, baseline and high emission scenarios were assumed to be similar to those in the case of using soy oil as a feedstock, as described in Section 6.2.2.3. As in the case of soy oil processing, diesel was used as a surrogate for jet fuel in this case. The energy allocation method was used in apportioning emissions among the co-products formed.

6.3.3 Results

The key assumptions and corresponding life-cycle GHG emissions in the production and use of biojet from palm oil and PKO for the low, baseline and high emission cases are summarized in Table 73. Combustion CO_2 was set to zero in this pathway as it was assumed to be equal to the CO_2 absorbed from the atmosphere during the growth of palm FFB. As in the case of soy oil and soybeans, the market value allocation approach was assumed for the allocation of emissions between palm oil, PKO and PKE. The energy allocation approach was adopted for dividing emissions between biojet (renewable diesel was used as a surrogate for biojet in the hydroprocessing of palm oils) and propane gas.

Table 73: Summary of Inputs and Results for Biojet from Palm Oil and Palm Kernel Oil Pathway

	Low	Baseline	High
Palm FFB yield (ton/ha)	27.5	24.6	21.6
Farming energy (Btu/ton FFB)	110,300	123,300	228,200
Nitrogen fertilizer application (g/ton FFB)	5055	5650	6435
N_2O emissions (g N_2O/ton FFB)	79.4	88.8	101.1
Palm oil and PKO extraction energy (Btu/lb oil)	191.4	191.4	191.4
CH_4 emissions from POME treatment (gCH_4/lb oil)	3.2	4.0	4.8
Hydrotreatment energy (Btu/lb fuel)	1179	1910	2518
Hydrogen input (lb/lb fuel)	0.018	0.032	0.044
WTT CO_2 emissions (gCO_2/MJ) (without land use change)	13.8	16.8	20.7
WTT CH_4 emissions (gCO_2e/MJ)	5.1	6.2	7.3
WTT N_2O emissions (gCO_2e/MJ)	3.0	3.2	3.6
WTW GHG emissions (gCO_2e/MJ) (without land use change)	21.9	26.2	31.5
WTW GHG emissions relative to baseline conventional jet fuel (without land use change)	0.25	0.31	0.37
Land use change emissions (gCO_2/MJ)	10.2	112.8	617.3
WTW GHG emissions (gCO_2e/MJ) (with land use change)	32.1	139.0	648.8
WTW GHG emissions relative to baseline conventional jet fuel (with land use change)	0.4	1.6	7.6
Overall energy ratio	0.83	0.79	0.75

The GHG emissions for the various steps in the production of biojet from palm oil and PKO (assuming diesel as a surrogate for jet fuel) in the baseline case are shown in Table 74.

Table 74: GHG Emissions for Various Stages in Biojet from Palm Oil and Palm Kernel Oil Pathway

Stage	Emissions
Recovery (palm oils) (gCO_2/MJ)	4.2
Processing (gCO_2/MJ)	8.9
Transportation (gCO_2/MJ)	3.7
Land Use Change Emissions (gCO_2/MJ)	112.8
Well-To-Tank CH_4 and N_2O emissions (gCO_2e/MJ)	9.4
Combustion (gCO_2/MJ)	0
Total (gCO_2e/MJ)	139.0

6.3.4 Discussion

Excluding the potential impact of land use change emissions, the life-cycle GHG emissions of the production of biojet from palm oil and PKO are about 0.3 to 0.4 times those of conventional jet fuel. These emissions are also lower compared to the overall GHG emissions when using soy oil as a feedstock (0.4 to 0.6 times those of jet fuel). This is largely due to the lower oil yields, higher farming energy, fertilizer inputs and extraction energy in the production of soy oil compared to palm oil and PKO.

About 60 gallons of biojet can be produced from one ton of palm FFB. Hence, to produce 25,000 bpd of fuel (roughly the amount needed to fuel a large airport), about 6.4 million tons of FFB would be required a year, using a total of 0.64 million acres of land. This means that the use of palm oil and palm kernel oil to produce biojet requires about 25% less biomass feedstock (by mass) and 90% less crop land compared to the use of soy oil. The use of palm oils appears to be a more attractive option compared to soy oil in terms of GHG emissions reduction, feedstock and land use requirement.

Nonetheless, like soy oil, palm oil is also a food source and its diversion towards large-scale fuel production could potentially lead to the adverse land use change impacts arising from the conversion of carbon-rich non-croplands (e.g. rainforests, peatlands) to palm plantations. When such land use change emissions are taken into account, the life-cycle GHG emissions in the production of biojet from palm oils range from a low of 0.4 times to as high as 7.6 times those of conventional jet fuel.

As discussed earlier, the land use change emissions data are obtained from existing data in literature and are for illustrative purposes, rather than to provide absolute results.

Further work in determining more accurate land use change impacts, as well as in other issues related to the sustainable use of palm for fuel production, such as water use, ecological, biodiversity, economic issues, etc. should be conducted when evaluating the overall attractiveness of the use of palm biomass for fuel production.

In summary, the production of biojet from palm oils appears to be a more attractive option compared to the use of soy oil due to lower GHG emissions, feedstock and land use requirements, particularly when land use change emissions do not come into play (e.g. use of idle cropland). However, as a food-based feedstock, the use of palm oil in large-scale fuel production is likely to lead to undesirable land use change impacts, rendering the pathway unsustainable from the GHG emissions perspective. Hence, it is worthwhile to look into the use of non-food biomass feedstocks which would not result in land use change emissions for large-scale fuel production (e.g. waste biomass, algae).

Chapter 7: Results and Discussion

7.1 Introduction

In the preceding four chapters, the life-cycle GHG emissions of jet fuel and ULS jet fuel from conventional crude, as well as the life-cycle GHG emissions of alternative jet fuels from unconventional crude (oil sands and oil shale), the F-T process, and renewable oils were determined. For each pathway, three potential scenarios (low emissions case, baseline case and high emissions case) were identified and life-cycle GHG emissions were calculated for each of these scenarios. This chapter presents the life-cycle GHG emissions for all fuel pathways and discusses the key policy issues associated with the use of the various alternative jet fuels. In addition, a scenario analysis was carried out to investigate the amount of renewable jet fuel needed to displace conventional jet fuel use in order to achieve carbon-neutral aviation growth in the U.S. to 2025, relative to a baseline year of 2006.

7.2 Results

The life-cycle GHG emissions for all fuel pathways for the baseline case are compiled in Table 75 and shown graphically in Figure 3. Figure 4 illustrates the range of life-cycle GHG emissions for each fuel pathway, using the low emissions, baseline and high emissions scenarios.

Table 75: Life-Cycle GHG Emissions for All Fuel Pathways Studied

| Fuel pathway	Emissions (g CO_2e/MJ)							
	Recovery	Process-ing	Transport-ation	Combust-ion	WTT N_2O	WTT CH_4	Land use change	Total
Crude to conventional jet fuel	2.8	5.5	1.2	73.2	0.05	2.3	0	85.0
Crude to ULS jet fuel	2.8	7.3	1.2	72.9	0.06	2.4	0	86.7
Oil sands to jet fuel (surface)	16.5	5.5	1.8	73.2	0.09	2.7	0	99.7
Oil sands to jet fuel (in-situ)	23.9	5.5	1.9	73.2	0.1	3.5	0	108.2
Oil shale to jet fuel	41.2	3.3	1.3	73.2	0.2	2.5	0	121.6
Natural gas to F-T fuel	4.6	20.2	0.7	70.4	0.04	4.6	0	100.4
Coal to F-T fuel (no carbon capture)	0.8	117.3	0.7	70.4	0.01	5.6	0	194.8
Coal to F-T fuel (with carbon capture)	0.8	13.3	0.7	70.4	0.01	5.8	0	91.0
Biomass to F-T fuel	3.0	5.8	2.3	0	0.10	0.3	0	11.6
Soy oil to biojet	19.5	8.9	1.7	0	3.6	1.4	253.8	289.0
Palm oils to biojet	4.2	8.9	3.7	0	3.2	6.2	112.8	139.0
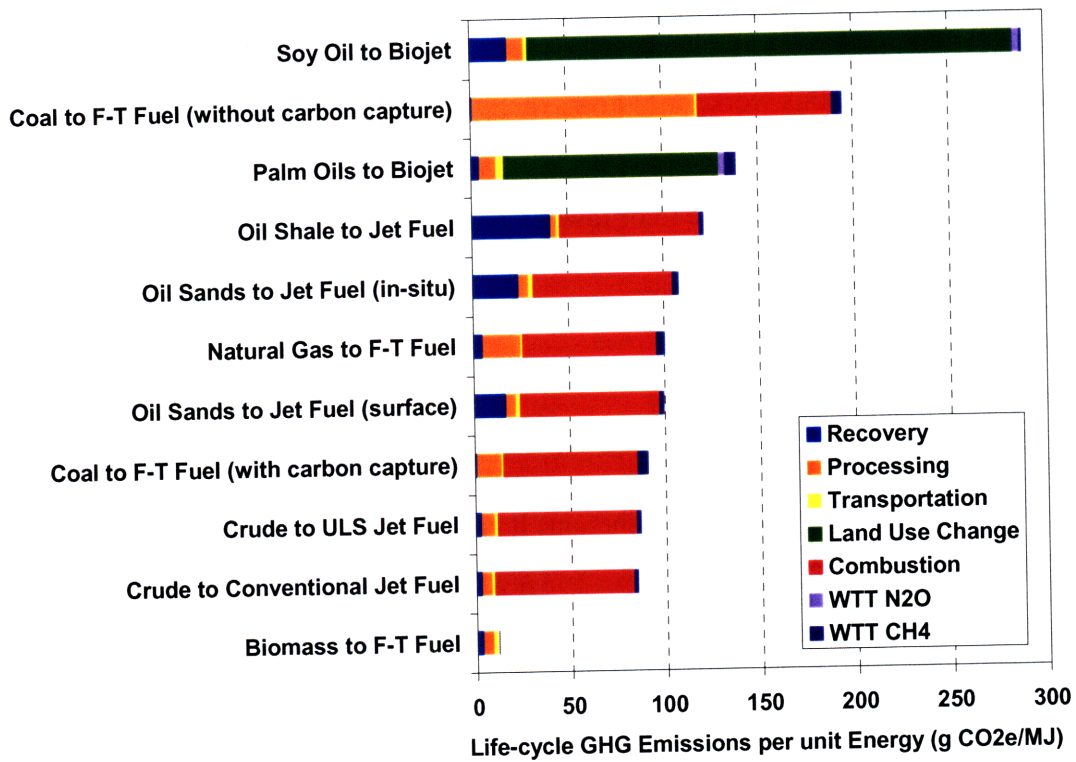
Figure 3: Life-Cycle GHG Emissions for the Fuel Pathways Considered in this Study
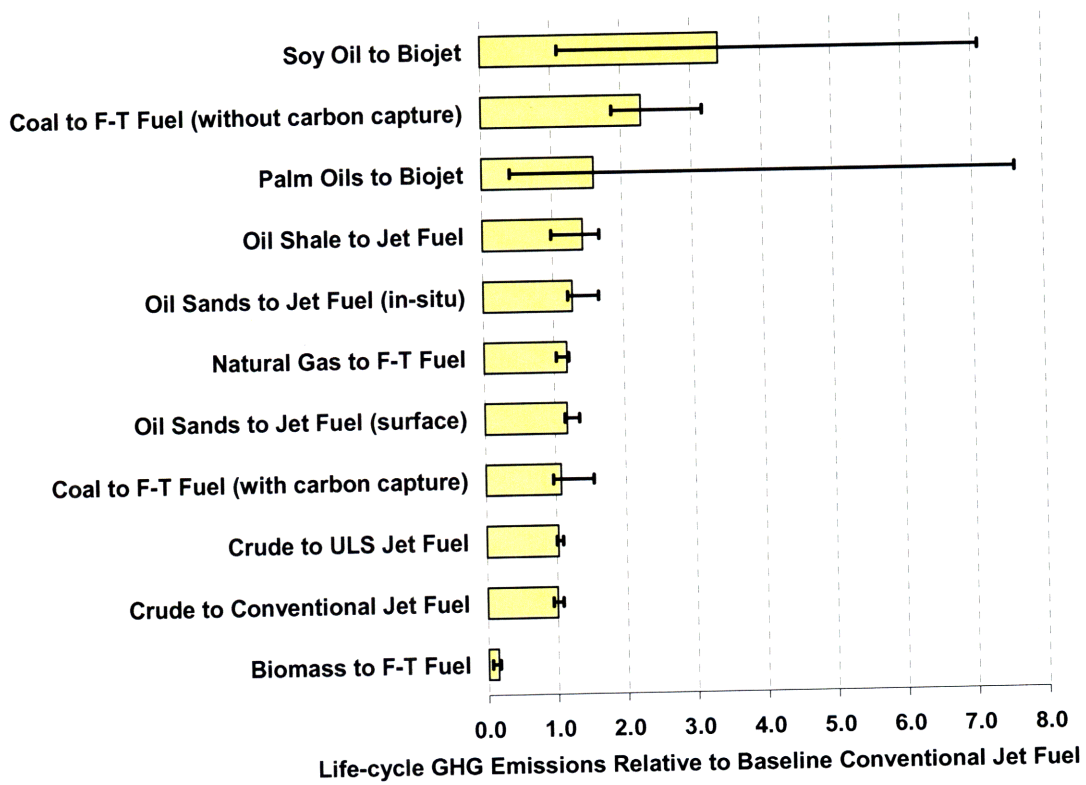

Figure 4: Life-Cycle GHG Emissions for All Fuel Pathways Relative to Baseline Conventional Jet Fuel (Low Emissions, Baseline and High Emissions Cases)

7.3 Discussion

From the analyses in this work, only fossil fuel pathways assuming high process efficiencies and/or adopting carbon capture (e.g. CTL, GTL, jet fuel from oil shale) and biofuel pathways assuming no land use change impacts result in life-cycle GHG emissions which are comparable to or lower than those of baseline conventional jet fuel. Out of these, only alternative fuels made from biomass feedstocks show significant GHG emissions reductions of 60% or more.

7.3.1 ULS Jet Fuel

ULS jet fuel is not an alternative fuel per se, but shows potential in reducing health impacts of jet fuel combustion through reductions in particulate matter emissions. (Hileman et al., 2008 and references therein) It can be produced quickly and in large quantities through an additional hydrotreatment step in most refineries, and would have minimal impact on operational performance.[21] However, the large-scale use of ULS jet fuel would result in greater GHG emissions (between 1% to 6% higher) compared to the use of conventional higher-sulfur jet fuel due to larger energy requirements in the production of the former.

7.3.2 Jet Fuel from Oil Sands and Oil Shale

The production potential for jet fuel from oil sands is large due to the enormous oil sands reserves in Canada. However, its life-cycle GHG emissions are about 1.2 to 1.3 times greater than those of conventional jet fuel. Nonetheless, the U.S. has been increasing its oil imports from Canada such that Canada is now the U.S.'s top supplier. Currently, about half of this oil is from oil sands. This proportion is set to rise as the projected increase in oil sands production is expected to more than offset the decline in Canada's conventional oil production in coming years. (EIA, 2008d) Though oil sand production may provide energy security benefits, it exacerbates the problem of climate change and also causes other adverse environmental impacts (e.g. deforestation, water pollution, disruption of ecological systems). Alberta is currently investing in CCS technologies with the hope of reducing its GHG footprint. The extent to which CCS would be successful in reducing the overall GHG emissions from oil sand operations remains to be seen; this is complicated by the fact that many existing processes in bitumen production and upgrading are not capture-ready.

Oil shale is another unconventional petroleum resource that is available in enormous quantities, with the U.S. holding the largest reserves. However, the life-cycle GHG emissions in the production of jet fuel from oil shales are even greater than those from oil sands – about 1.4 times greater than those of conventional jet fuel. Unlike oil sands, oil production from oil shale has not been carried out on a commercial scale. This is largely due to prohibitive capital costs, potential environmental disruptions and the inefficiency

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[21] The hydroprocessing required to achieve low sulfur contents could reduce the fuel's ability to provide lubrication causing stress on the engine's moving parts. However, it is thought that such lubricity problems could be largely solved using additives.

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of traditional mining and surface retorting processes. Though the Shell ICP is less disruptive to the extraction landscape, it is an energy-intensive process and results in an unfavorable carbon footprint compared to the use of conventional jet fuel. The Shell ICP technology has also yet to be proven on a commercial scale.

Despite potential adverse environmental impacts, high costs and low energy efficiency of oil recovery from oil shale, interest in oil shale development in the U.S. has revived in recent years, fueled by high energy prices and energy security considerations. The Energy Policy Act of 2005 directed the Department of Energy to look into ways to "advance the commercialization of the United States' strategic unconventional fuel resources, including oil shale." (DOE, 2007) However, opponents to oil shale development view the near-term pursuit of oil shale commercialization as being too aggressive because of the current lack of technology readiness for large-scale shale oil extraction and the absence of a thorough understanding of its environmental impacts. They are also cautious to avoid the "boom-and-bust" of the last oil shale commercialization efforts in the 1970s and 80s. These opponents have successfully sought a moratorium on the commercial leasing of land for oil shale development to allow more time for deeper research into the technology and impacts of oil shale commercialization. (Mulkern, 2008; Udall, 2008)

7.3.3 Fischer-Tropsch Jet Fuel

The production and use of synthetic jet fuel from finite fossil resources like natural gas and coal generally results in life-cycle GHG emissions greater than those from conventional jet fuel. With the application of carbon capture, GHG emissions are reduced to levels comparable to those from baseline jet fuel (-5% to +7%).[22] The use of biomass feedstocks, on the other hand, could potentially provide GHG emission reductions of up to 94% compared to conventional jet fuel.

There is particular interest in co-firing coal and biomass in an F-T facility to produce liquid fuels. The intent is to lower the carbon footprint of coal gasification through the use of biomass, and to overcome the feedstock availability issue of biomass-gasification plants through the combined use of widely available coal feedstock. The use of CCS in the coal-biomass-to-liquids (CBTL) plant could further reduce the GHG footprint of the pathway, potentially to levels below those of conventional jet fuel, depending on the proportion of biomass feed and efficiency of carbon capture. A recent study conducted by NETL shows that a 20% reduction in life-cycle carbon emissions compared to conventional low-sulfur diesel can be achieved by co-firing coal with a "relatively modest amount of biomass" (10% to 18% by weight) and capturing 88% of carbon dioxide emissions from the coal gasification. (NETL, 2007) However, technical challenges related to the efficient and effective co-firing of coal and biomass, though not insurmountable, remain to be overcome.

Currently, the U.S. Air Force (USAF) is the key proponent of the use of synthetic fuels among U.S. federal agencies. The Air Force uses more than half of all fuel consumed by the U.S. government, and is the largest user of aviation fuel within the U.S. government.

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[22] Ignoring the high emissions case in the CTL pathway with carbon capture.

It costs the USAF an additional $600 million for fuel for each $10 increase per barrel in the price of oil. The USAF aims to power half its domestic fleet with a synthetic fuel blend by 2016. To that end, it plans to test and certify all of its aircraft to fly on synthetic fuel blend by 2011. Arising from economic and natural security interests, the USAF wants the synfuel to be made from domestic resources. Though most of the flight tests have been conducted using synfuel from natural gas, natural gas resources in the U.S. are too scarce and expensive to be used for liquid fuel production. Instead, the USAF is looking for "clean" ways of using the U.S.'s vast coal resources (27% of the world's supply) as the key feedstock for synfuel production. To encourage greater investments in the development of a domestic CTL industry, the USAF plans to lease property in Montana for the construction for a CTL plant. (Montgomery, 2008; Layer 8, 2008; Neo Natura, 2008) It is also seeking legislation authorizing the Department of Defense to engage in long term contracts (up to 25 years) for unconventional fuel acquisition.[23] (Blackwell, 2007)

However, current U.S. government plans to develop and expand the use of fuels from unconventional resources like oil sands and oil shale, as well as from GTL or CTL processes, are restricted by recent legislation. This arises from Section 526 of the Energy and Independence Act of 2007, which prohibits the federal government from procuring alternative fuels whose life-cycle greenhouse gas emissions are higher than those of conventional fuels. This provision was to ensure that taxpayers' money would not be invested in fuels which worsen global climate change, and was largely drawn up to stifle the USAF's efforts to procure CTL fuel. Besides CTL, it also applies to fuels from oil sands, oil shale and other "dirty" alternative fuels, sparking attempts from the USAF and the Canadian Government to repeal it. Though efforts are being made to reword Section 526 such that it "does not apply to generally available products that are predominantly made from conventional sources" (e.g., products from oil sand syncrude which are refined in U.S. refineries and are indistinguishable from those from conventional crude), the broad language of Section 526 could allow varied legal interpretations, causing uncertainties in multi-billion dollar investments in oil sands, oil shale and CTL development. (Kosich, 2008; McKenna and Parkinson, 2008)

7.3.4 Jet fuel from biomass

Jet fuel made from biomass feedstocks like BTL and biojet from palm oil and soy oil are the only pathways which offer substantial life-cycle GHG emissions reduction compared to conventional jet fuel, but that is true only if land use change emissions are negligible (e.g. use of excess production, idle cropland, etc.). However, large-scale biofuel production would be required to displace sufficient jet fuel to result in substantial impacts in aviation GHG reductions (see scenario analysis in Section 7.4), and this could lead to substantial land use change emissions.

In addition to the GHG footprint of biofuels, other environmental and socio-economic issues are important considerations in ensuring that any large-scale use of biofuels is implemented in a sustainable manner. These issues were not explored in depth in this

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[23] Currently, DoD may only engage in fuel acquisition contracts for up to 5 years. (Blackwell, 2007)

work but are briefly touched upon here. Specifically, ensuring the sustainability of a biofuel requires careful assessment of all environmental impacts including GHG emissions, air quality, land use and land erosion, water use, fertilizer use and potential run-off impacts, biodiversity, etc. as well as socio-economic issues like impacts on food prices, displacement of indigenous people from land, environmental justice, labor law violation, etc. (Kammen, 2008)

In Europe, the EU's current target that 10% of transport fuels be made up of biofuels by 2020 has raised concerns about whether this goal can be achieved in an environmentally sustainable manner. For example, as will be discussed below, the diversion of food crops to fuel production has been cited by the International Monetary Fund and the Asian Development Bank as one of the reasons for the drastic increase in staple food prices. Proponents for a moratorium on this target felt that there were "insufficient standards and safeguards" to ensure the sustainable production of biofuels, particularly those which take place in developing countries. Going ahead with the target before "adequate and enforceable" sustainability standards could be put in place would lead to further environmental destruction, unintended or otherwise. (Schnoneveld, 2008)

To address these concerns, the EU has drafted a set of sustainability criteria which a biofuel producer has to comply with to qualify for financial incentives and to meet national targets and obligations, as well as potential means of ensuring compliance. These criteria include a minimum 35% reduction in GHG emissions compared to conventional fuels, non-use of land with high biodiversity value or high carbon stocks, and growing of crops in accordance with "EU rules on minimum requirements for good agricultural and environmental conditions." (Schnoneveld, 2008; de Dominicis, 2008) Though these criteria addressed concerns of direct land use conversion impacts, they did not take into account potential indirect land use impacts such as those arising from the diversion of food crops to energy production, which could result in the clearing of rainforests or grasslands elsewhere to grow food crops to replace those that had been displaced. However, the European Commission is required to monitor and report every 2 years on commodity price changes, availability of food in exporting countries, affordability of food in developing countries and other sustainability and developmental issues associated with the EU biofuel policy, with corrective actions to be taken if appropriate. (Schnoneveld, 2008; de Dominicis, 2008)

Compared to direct land use change emissions, indirect land use change impacts are considerably harder to quantify. In-depth analysis is required for each potential land use change scenario to assess what types of land are converted, how much land is affected, GHG emissions from those land conversions, etc. These factors in turn depend on the time-frame and scale of biofuel production. (Larson, 2008) In addition, questions such as how many crops are actually diverted for fuel production, how much of these crops would actually be replaced, and whether new crop production elsewhere are meant to replace diverted crops or are motivated from higher food prices may not have easy answers. Equity issues also arise: is it fair, on the grounds of reducing GHG emissions, to discourage the conversion of non-cropland (e.g. forests) in developing countries to cropland for agricultural production which would improve the income and quality of life

of the poor there? Such issues underscore the multi-faceted problem of ensuring sustainability, of which GHG footprint comprises one element.

The potential impact of biofuel production on food prices remains an unresolved issue in the biofuel sustainability debate. Though some studies have concluded that "even moderate increases in use of land for biofuels may have significant effect on land and food prices," others have estimated less substantial impacts of biofuel production on food prices, attributing price increase to other factors like growing world population, rising wealth, greater meat consumption in Asia, poor crop harvests, weak U.S. dollar and even speculation in agricultural commodity markets. (Schnoneveld, 2008) Yet others have pointed to the advantage of higher crop prices in allowing farmers in poor countries to afford more sophisticated methods of agriculture, which increases yield and results in more efficient land use. The development and use of non-food biomass feedstocks in biofuel production would provide a giant step towards putting an end to the food versus fuel debate.

7.4 Scenario Analysis – Renewable Jet Fuel Requirement for Carbon-neutral Growth

For an alternative fuel to be able to reduce aviation's GHG emissions, it not only should have life-cycle GHG emissions substantially lower than those of conventional jet fuel, but should also be available in sufficient quantities to displace a substantial amount of conventional jet fuel use. From the analyses carried out in this work, only jet fuel made from biomass feedstocks, not taking into account potential land use change emissions, provides significant reduction in life-cycle GHG emissions compared to baseline jet fuel. In this section, a scenario analysis was carried out to investigate the amount of various renewable jet fuels that would be needed to displace conventional jet fuel use in order to maintain carbon-neutral aviation growth in the U.S. to 2025, relative to the baseline year of 2006.

7.4.1 Analysis Approach and Assumptions

In conducting the scenario analysis for carbon-neutral U.S. aviation growth from 2006 to 2025, the key input parameters required were U.S. jet fuel consumption in 2006 and 2025, as well as life-cycle GHG emission factors for conventional jet fuel and biofuels.

The projection of jet fuel consumption in 2025 was taken from EIA Annual Energy Outlook (AEO) 2008 report, based on the reference scenario. (EIA, 2008e) Four other scenarios were modeled in the AEO 2008 report, namely high economic growth, low economic growth, high price, and low price.[24] Out of these, only the low growth and low price scenarios show different projections of jet fuel consumption in 2025 (2.11 million barrels/day for low growth; 2.17 million barrels/day for low price) compared to the

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[24] The reference case assumes world crude oil price of $70/barrel in 2030, while the low and high price cases assume world crude oil price of $119/barrel in 2030, and $42/barrel in 2030, respectively (all prices in terms of 2006 dollars).

reference case (2.16 million barrels/day) which was used in this analysis. According to EIA's projection, future jet fuel demand is largely independent of crude oil price.

The resources (feedstock and land) needed for the production of these biofuels were also estimated. The biofuels examined in this analysis include BTL from forest residue, corn stover and herbaceous biomass; as well as biojet from soy oil and palm oil. The life-cycle GHG emissions of jet fuel in the baseline year 2006 and future year 2025 took into account the proportion of syncrude from oil sands that U.S. refineries received in the production of jet fuel. For simplicity, it was assumed that the proportion of all jet fuel used in the U.S. made from syncrude derived from oil sands was the same as the proportion of syncrude in the total crude received by U.S. refineries.[25] The life-cycle GHG emissions of the fuels were taken from the analyses in this work, using the baseline cases. These emissions (particularly those of conventional jet fuel) were assumed to apply to all of the years investigated, unless otherwise specified. Specifically, the GHG emissions of the biofuels used in this analysis did not include emissions from potential land use change impacts (e.g. use of excess crop production, idle cropland). This assumption was made for the purpose of this analysis; it is unlikely to hold true for food-based feedstocks and dedicated energy crops due to the large biofuel quantities required, potentially resulting in diversion of food crops to fuel production and conversion of non-cropland to cropland to meet higher production demand.

The input parameters assumed in the scenario analysis and their sources are summarized in Table 76.

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[25] This assumption may be incorrect. However, it was made for simplicity as no information was available on the exact proportion of jet fuel consumed in the US that came from Canadian oil sands.

Table 76: Assumptions and Input Parameters in Scenario Analysis

1) Fuel energy content[1]

Fuel	MJ/kg	MJ/L
Jet A	43.2	34.8
BTL	44.1	33.7
Biojet	44.1	33.7

2) Jet fuel use

Year	Million barrels/day	MJ/year ($\times 10^{12}$)	Sources(s)
1990	1.52	3.07	EIA, 2008f
1995	1.51	3.06	EIA, 2008f
2000	1.73	3.48	EIA, 2008f
2006	1.63	3.29	EIA, 2008e
2025	2.16 (2.11-2.17)	4.36 (4.26-4.38)	Reference scenario in EIA, 2008e (ranges from other EIA scenarios)

3) Oil sands use in U.S.

Year	Percent of syncrude from oil sands in total crude in U.S. (%)	Source(s)
2006/07	5	Snyder, 2008
2025	11	See note (2)

4) Oil sands technology mix

Year	Surface mining (%)	In-situ production (%)	Source(s)
2006/07	59	41	AAPG, 2008
2016	57	43	AEUB, 2007
2025	50	50	Author's assumption

5) Life-cycle GHG emissions of fuels[3]

Fuel	Life-cycle GHG emissions (g CO_2e/MJ)
Conventional jet fuel (1990)[4,5]	85.3
Conventional jet fuel (1995)[4,5]	85.0
Conventional jet fuel (2000-2025)[5]	85.0
Jet fuel from oil sands (surface mining)	99.7
Jet fuel from oil sands (in-situ production)	108.2
BTL (forest residue)	11.6
BTL (corn stover)	12.7
BTL (herbaceous biomass)	6.9
Biojet (soy)	35.2
Biojet (palm)	26.2
Jet fuel (2006) (conventional + oil sands)	85.9
Jet fuel (2025) (conventional + oil sands)	87.1

Notes:

(1) From Table 4 of this report.

(2) Total oil consumption in 2025 is projected to be 22.3 million barrels a day in 2025 (EIA, 2008e); and estimates in literature on oil sands use in the U.S. within the next one to two decades range from 2 to 3 million barrels a day. (Doggett, 2006; Perry, 2008) Assuming oil sands use of 2.5 million barrels a day in 2025, the proportion of oil sands in total petroleum consumption in the U.S. is about 11%.

(3) From baseline-case values derived in this work

(4) Until 1993, both kerosene- and naphtha-based jet fuels were widely used in the U.S.. The combustion CO_2 emission for naphtha-based jet fuel was about 3% higher than that for kerosene-based jet fuel. The proportion of kerosene-based jet fuel used in 1990 was about 88%, and about 99% in 1995. (EIA, 1999; EIA, 2008f; EIA, 2008g)

(5) Assume no jet fuel production from Canadian oil sands from 1990 to 2000.

7.4.2 Results

From jet fuel consumption data and life-cycle GHG emissions of jet fuel production and use, the total annual GHG emissions from aviation (combustion emissions are limited to CO_2) between 1990 and 2025 were derived and are shown in Table 77 and Figure 5. GHG emissions factors in the baseline case of this work had been applied. However, to address uncertainties, this work also examined GHG emissions of the fuel pathways in the low and high emissions scenarios. To illustrate the potential variation in annual aviation GHG emissions arising from these uncertainties, the possible ranges of annual GHG emissions for aviation in the baseline 2006 case and the projected 2025 case were estimated using GHG emission factors for jet fuel (from conventional crude and oil sands) derived in the low to high emissions cases. The results are also shown in Table 77.

Table 77: Estimated Total Annual U.S. Aviation Life-cycle GHG Emissions (1990-2025)

Year	Jet fuel consumption (Million barrels/day)	Life-cycle GHG emission index for jet fuel (g CO_2e/MJ)[1]	Total aviation GHG emissions (Tg CO_2e/year)[1]
1990[2]	1.52	85.3	262
1995[2]	1.51	85.0	260
2000[2]	1.73	85.0	296
2006[2]	1.63	85.0	280
2006[3]	1.63	85.9 (81.3 – 93.8)	283 (267 – 309)
2025[3]	2.16	87.1 (82.5 – 96.1)	380 (360 – 419)

Notes:
(1) Values are based on baseline GHG emission numbers derived in this work; values in brackets provide the range using GHG emission estimated from the low and high emissions cases of this work. Combustion emissions are limited to CO_2.
(2) Assuming no oil sands use.
(3) Assuming 5% oil sands use in 2006 and 11% oil sands use in 2025.
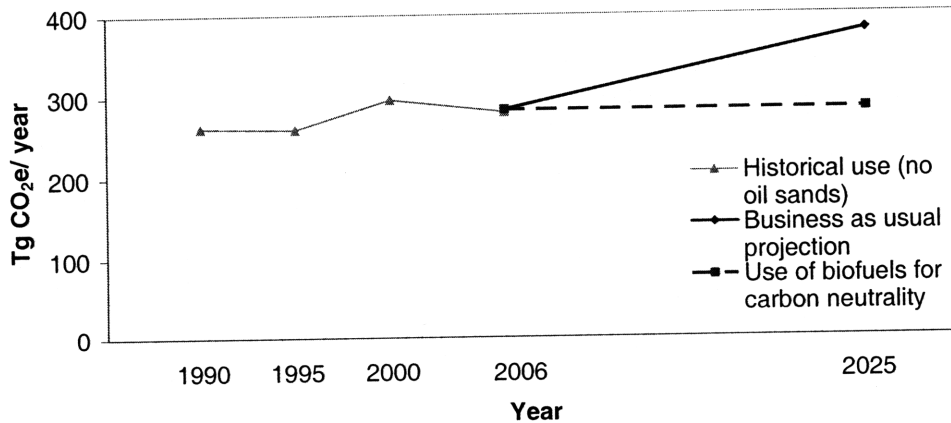
Figure 5: Estimated U.S. Total Annual Aviation Life-cycle GHG Emissions (1990-2025). Combustion Emissions are Limited to CO_2.

The amount of baseline jet fuel and various biofuel that would be needed in 2025 to achieve carbon-neutral aviation growth are shown in Table 78. This scenario definition is graphically shown in Figure 5 by the dashed line. The resource requirement (feedstock and land) for the production of the specified quantities of biofuels were also estimated and these are summarized in Table 78.

Table 78: Amount of Biofuel (BTL and Biojet) and Resources Required to Achieve Carbon-neutral Growth in 2025

2025 Scenario	Baseline jet fuel		Biofuel			Biomass feedstock/ land needed
	Emissions (TgCO$_2$e/ year)	Fuel use (Million bbl/day)	Emissions (TgCO$_2$e/ year)	Fuel use (Million bbl/day)	%	
1) Jet fuel only	380	2.16	0	0	0	-
2) Jet fuel + BTL from forest residue	268	1.52	15	0.66	30	193 million tons/yr[1]; ~136% of current U.S. forest biomass consumption[2]; ~52% of total available U.S. forest biomass resource[3]
3) Jet fuel + BTL from corn stover	266	1.51	17	0.67	31	196 million tons/yr[4]; ~261% of current U.S. corn stover resources[5]; ~76% of future potential corn stover resources[6]
4) Jet fuel + BTL from herbaceous biomass	274	1.56	8	0.62	28	173 million tons/yr[7]; 35 million acres of land[8]; ~46% of total available perennial crops[9]; ~8% of U.S. cropland[10]
5) Jet fuel + biojet from soy oil	217	1.23	66	0.96	44	10.7 billion bushels soybeans/year[11]; 256 million acres of land[12]; >4 times current U.S. soybean production[13]; ~56% of U.S. cropland[10]
6) Jet fuel + biojet from palm oils	241	1.37	42	0.82	37	48 million tons palm oil/yr[14]; 21 million acres of land[15]; 104% of current global palm oil production[16]; ~25% size of Malaysia

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Notes:
  (1) Forest residue feedstock requirement of about 0.019 ton/gal BTL.
  (2) Current U.S. forest biomass (includes wood residues, biomass from fuel treatment and fuelwood) consumption is estimated to be 142 million tons/year. (Perlack et al., 2005)
  (3) Total potentially available forest biomass resources in U.S. is estimated to be 368 million tons/year. (Perlack et al., 2005)
  (4) Corn stover feedstock requirement of about 0.019 ton/gal BTL.
  (5) Total current available corn stover resource is estimated to be 75 million tons/year. (Perlack et al., 2005)
  (6) Total potentially available corn stover resource in future (assuming higher crop yields and collection rates) is estimated to be 256 million tons/year. (Perlack et al., 2005)
  (7) Herbaceous biomass feedstock requirement of about 0.018 ton/gal BTL.
  (8) Assuming average yield of 5 tons/acre/year. (Wu et al., 2006)
  (9) Total available perennial crops (trees or grasses) (assuming high yield increase) is estimated to be 377 million tons/year. (Perlack et al., 2005)
  (10) Total cropland available in the U.S. is estimated to be 452.6 million acres (Perlack et al., 2005)
  (11) Soybean feedstock requirement of about 0.73 bushels/gal biojet.
  (12) Assuming yield of 42 bu/acre.
  (13) Current U.S. soybean production is about 2.6 billion bu/year, projected to increase to 3.1 billion bu/year in 2016 (from Table 49).
  (14) Palm FFB feedstock requirement of about 0.017 tons/gal biojet; palm oil requirement of about 7.7 lb/gal biojet.
  (15) Assuming palm FFB yield of 9.96 tons/acre; palm oil yield of 2.3 tons/acre.
  (16) Global palm oil production in 2007/2008 is about 46.2 million tons. (Flexnews, 2008)

7.4.3 Discussion

From Table 77, varying the life-cycle GHG emissions index for jet fuel (using values from low to high emissions scenarios in this work) results in an uncertainty range of -6% to +10% for the total annual aviation GHG emissions in 2006 and 2025. It is noteworthy that jet fuel consumption has only increased by about 7% over 16 years (from 1990 to 2006), though EIA projects that it will grow by more than 30% over the next two decades. In addition, there are concerns that the use of Canadian oil sands in the U.S. fuel supply is contributing to greater GHG emissions. From the analyses in this work, the life-cycle GHG emissions of jet fuel from oil sands are about 1.2 to 1.3 times greater than those of conventional jet fuel (baseline scenario). However, from Table 77,[26] it appears that with a relatively low level of oil sands use (5% of total oil consumption), annual aviation GHG emissions have increased by about 1%.

From Table 78, the production of sufficient biojet from either soybeans or palm to achieve carbon-neutral aviation growth in 2025 appears to require resources that cannot be supported by current levels of production. The required dramatic increase in feedstock production would likely result in adverse land use change impacts from the conversion of non-cropland to cropland for feedstock production (either directly for fuel production, or indirectly to replace food crops diverted for fuel production). In particular, the required four-fold increase in soybean production by 2025 may not even be physically possible due to land constraints. As shown in Chapter 6, with the inclusion of large land use change impacts, the production of biojet from soybeans or palm would no longer offer savings of GHG emissions compared to baseline jet fuel, but result in GHG emissions up to several times more than those of jet fuel. Hence, food-based feedstocks like palm or soybeans do not appear to be suitable feedstocks for the large-scale production of biojet to curb aviation GHG emissions.

The use of waste products and dedicated energy crops in the large-scale production of biofuels appears to be more attainable than food-based crops in terms of feedstock resource demand, even though a sizable proportion (46-76%) of total (future) available resources still needs to be dedicated to this production. Specifically, large-scale production of perennial crops like herbaceous biomass would require land conversion to perennial crop production. Depending on the type of land use change,[27] net carbon emissions may result, which would increase the GHG footprint of this particular pathway. Specifically, the diversion of cropland for dedicated energy crop production is undesirable as it could lead to indirect land use change emissions. The use of waste products generally does not impose land constraints and does not lead to any adverse land use change emissions. However, though available, waste resources, particularly wood

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[26] The total aviation GHG emissions in 2006 with 5% oil sands use are estimated to be 280 Tg CO_2e/year, compared to 283 Tg CO_2e/year for the case without any oil sands use.

[27] For example, the cultivation of switchgrass on converted cropland can result in net carbon sequestration due to increase in soil organic carbon. However, the conversion of forests or grasslands to switchgrass production could potentially result in net carbon emissions from a decrease in soil organic carbon. (Larson, 2005)

wastes, could be highly dispersed, making their collection and transportation to central facilities costly. Seasonality of residue generation can be another factor affecting the availability of this resource. In addition, removal of large portions of crop residues from cropland could result in undesirable environmental impacts like reduction in soil quality, soil erosion and loss of soil carbon, leading to lower crop yields. (Perlack et al., 2005)

In general, biomass production potential is limited due to constraints on land availability. The dedication of limited biomass resources to large-scale biofuel production introduces concerns of ensuring that such resources are being effectively utilized. Besides fuel production, biomass can also be used to generate heat and power. The processes of converting biomass to fuels are generally less energetically efficient than generating heat and/or power from biomass. For example, the process efficiency of producing BTL ranges from about 40% to 60%, while combined heat and power production from biomass have typical efficiencies of 60% to 80%, and the generation of heat from biomass combustion is about 80% to 85% efficient. (U.S. EPA, 2008; UK DEFRA, 2007)

Nonetheless, energy efficiency is only one factor of consideration in the optimization of biomass resource utilization. Other factors include the extent of GHG emissions abatement, availability of other renewable or low carbon options, and economics. For example, the displacement of coal-fired electricity and oil heating with combined heat and power generation from biomass may generate more GHG emissions savings per ton of biomass used than the displacement of jet fuel by BTL. The converse may be true if other fossil energy systems were being displaced. In addition, while there exists a range of other renewable or low carbon options to produce heat and power (e.g. wind, solar, geothermal, nuclear), the alternatives for producing low carbon liquid fuels to displace conventional transportation fuels are more limited, particularly for the aviation sector. Through policies, financial incentives and/or subsidies, governments often determine how fossil, biomass, and other energy resources are utilized.

In addition to waste biomass and dedicated energy crops, desired next generation feedstocks for biofuel productions are those which are not used as food, require little use of land (e.g. high energy yield per unit land area), or can grow on degraded or marginal land with little energy, water or fertilizer inputs. Potential next generation feedstocks include algae, halophytes, and jatropha. To examine the potential volume and resource requirements of such next generation feedstocks in maintaining a carbon-neutral aviation growth, this work examined four hypothetical advanced biomass feedstocks with oil yields of 10,000 and 50,000 liters per hectare, and life-cycle GHG emissions of 0.1 to 0.3 times those of conventional jet fuel. As a reference, palm oil yield is >5000 liters/ha, with life-cycle GHG emissions about 0.3 times those of conventional Jet A (assuming no land use change emissions). Oil yields from algae could potentially be higher than 100,000 liters/ha. (Sheehan et al., 1998) The characteristics of the four hypothetical feedstocks are shown in Table 79. It must be emphasized that these feedstocks do not represent any existing feedstock; they are simply meant to place context on what may be possible with next generation feedstocks.

Table 79: Characteristics of Four Hypothetical Feedstocks for the Production of Biojet

Feedstock	Oil yield (liters per hectare)	Life-cycle GHG emissions relative to baseline conventional jet fuel
A	10,000	0.1
B	10,000	0.3
C	50,000	0.1
D	50,000	0.3

The amount of baseline jet fuel and biofuel needed in 2025 to maintain a carbon-neutral aviation growth using the four hypothetic feedstocks, as well as the associated resource requirements are shown in Table 80.

Table 80: Amount of Biofuel (From Four Hypothetical Feedstocks) and Resources Required to Achieve Carbon-neutral Growth in 2025

2025 Scenario	Baseline jet fuel		Biofuel			Biomass feedstock/ land needed
	Emissions ($TgCO_2e$/ year)	Fuel use (Million bbl/day)	Emissions ($TgCO_2e$/ year)	Fuel use (Million bbl/day)	%	
1) Jet fuel only	380	2.16	0	0	0	-
2) Jet fuel + Biojet from feedstock A	272	1.55	11	0.63	29	37 mil tons oil/yr[1]; 9.1 million acres[2,3]
3) Jet fuel + Biojet from feedstock B	243	1.38	40	0.81	37	48 mil tons oil/yr[1]; 11.6 million acres[2,3]
4) Jet fuel + Biojet from feedstock C	272	1.55	11	0.63	29	37 mil tons oil/yr[1]; 1.8 million acres[2,3]
5) Jet fuel + Biojet from feedstock D	243	1.38	40	0.81	37	48 mil tons oil/yr[1]; 2.3 million acres[2,3]

Notes:

(1) Assume renewable oil requirement of 7.7 lb per gal biojet.

(2) Calculated from oil yield (liters per hectare) assuming oil density to be 920g/liters.

(3) For reference, the land areas of the two smallest U.S. States, Rhode Island and Delaware, are about 1 million acres and 1.6 million acres, respectively. Further, the land areas of New Hampshire, New Jersey and Connecticut are about 6.0 million acres, 5.6 million acres and 3.5 million acres, respectively.

To put the results of Table 78 and Table 80 in perspective, Figure 6 illustrates the land use requirement to maintain aviation carbon-neutral growth in 2025 relative to 2006 using soy oil, palm oil, feedstock B and feedstock D, as well as herbaceous biomass for biofuel production. The results show that the use of high oil yield crops can result in substantial reductions in land use requirements (a land mass equal to 0.4-2.6% of U.S.

cropland), making these feedstocks potentially viable for large-scale biojet production. This underscores the importance of investing in the development of non-food biomass feedstocks which can achieve high oil yields (e.g. algae), combined with significant reduction in life-cycle GHG emissions relative to conventional jet fuel.

It is important to keep in mind that the scenario analysis conducted in this study to achieve carbon-neutral aviation growth in the U.S. examined just one specific solution – the use of low carbon fuels. In each scenario, the case where one particular type of feedstock was used to curb GHG emissions was explored. The intent was to illustrate the potential feasibility of each feedstock for large-scale biofuel production by demonstrating the extent of feedstock and/or land resources required, as well as to allow cross-comparisons with other feedstock options. In reality, the approach to carbon-neutral or even carbon-negative aviation growth would likely comprise a myriad of strategies, from aircraft operational improvements to more efficient aircraft designs. The use of alternative low carbon fuels provides just one wedge of the solution pie. In addition, low carbon fuels would likely be produced from a variety of suitable feedstocks, based on their availability and sustainability characteristics. Also, this study has focused on the U.S.. Most of the feedstock options (except palm oil) were explored in terms of their availability in the U.S.. Climate change is a global problem requiring a global solution. Future work should explore potential solutions to curb world-wide aviation GHG emissions through identification of the best feedstock options in different regions of the world (e.g. jatropha, babassu, halophytes, algae).

Legend:
- ▧ Soy oil (oil yield~550L/ha)
- ▧ Herbaceous biomass (using F-T process with ~11,000 kg biomass/ha)
- ▧ Palm oil (oil yield ~5600 L/ha)
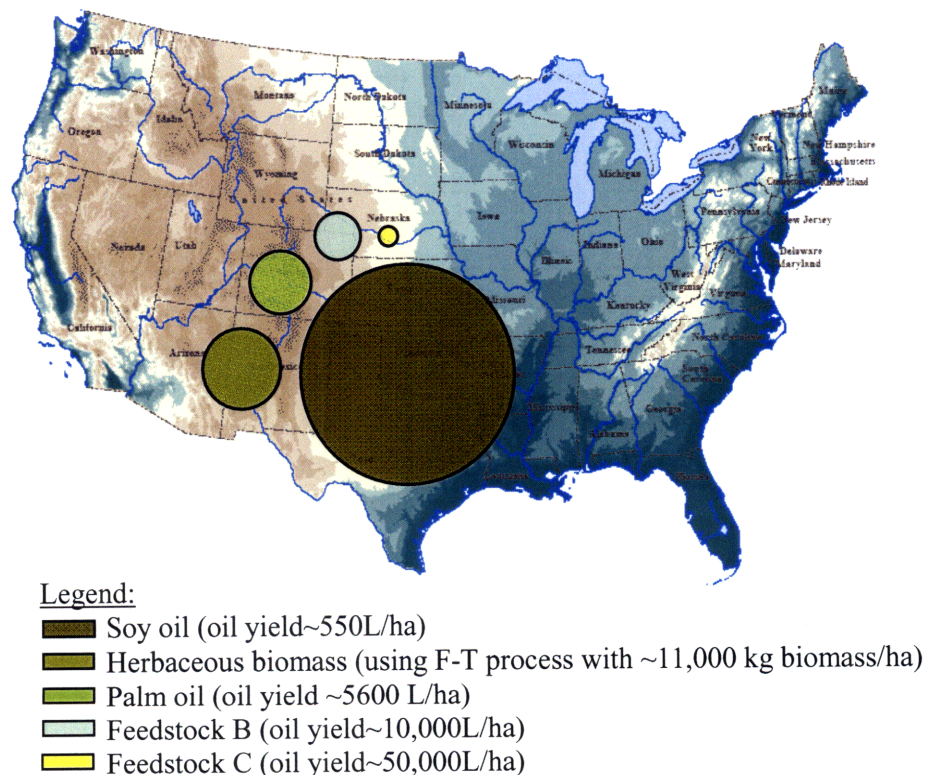- ▧ Feedstock B (oil yield~10,000L/ha)
- ▧ Feedstock C (oil yield~50,000L/ha)

Figure 6: Land Requirement to Maintain Carbon-neutral Aviation Growth in 2025 Using Varied Feedstocks (Map taken from http://www.united-states-map.com/us402112.htm)

Chapter 8: Conclusions and Recommendations

8.1 Conclusions

The key motivation of this work was to address the impact of aviation on climate change through the use of alternative jet fuels. This work focused on one specific aspect in examining the feasibility of using alternative jet fuels – their life-cycle Greenhouse Gas (GHG) emissions. This involved the quantification of the overall GHG emissions of potential alternative jet fuels, from feedstock recovery and transportation, to the production, transportation and utilization of the fuels. The fuels examined in this work included jet fuel and ULS jet fuel from conventional crude, jet fuel from oil sands and oil shale, F-T jet fuel from natural gas, coal and biomass, and biojet from soy oil and palm oil. By identifying and varying important input parameters, a range of life-cycle GHG emissions for each fuel pathway was derived (see Table 81).

Table 81: Life-Cycle GHG Emissions for the Fuel Pathways Considered in this Thesis. Values are Relative to Baseline Conventional Jet Fuel (Low Emissions, Baseline and High Emissions Cases)

Fuel pathway	Life-cycle GHG emissions relative to baseline conventional jet fuel		
	Low	Baseline	High
Crude to jet fuel	0.9	1.0	1.1
Crude to ULS jet fuel	1.0	1.0	1.1
Oil sands to jet fuel (surface mining)	1.1	1.2	1.4
Oil sands to jet fuel (in-situ production)	1.2	1.3	1.7
Oil shale to jet fuel	1.0	1.4	1.7
Natural gas to F-T jet fuel	1.0	1.2	1.2
Coal to F-T jet fuel (without carbon capture)	1.9	2.3	3.2
Coal to F-T jet fuel (with carbon capture)	1.0	1.1	1.5
Biomass to F-T jet fuel	0.1	0.1	0.2
Soy oil to biojet (without land use change)	0.4	0.4	0.6
Soy oil to biojet (with land use change)	1.1	3.4	7.1
Palm oil to biojet (without land use change)	0.3	0.3	0.4
Palm oil to biojet (with land use change)	0.4	1.6	7.6

Specifically, the key research question this thesis sought to answer was:

"Are there alternatives to conventional jet fuel which offer the potential to reduce GHG emissions of aviation?"

An answer to this question based on the analyses in this work and other key conclusions are outlined in the following paragraphs.

Only alternative jet fuels from biomass offer substantial life-cycle GHG emissions reductions compared to conventional jet fuel.

From the analyses in this work, only fossil fuel pathways achieving high process efficiencies and/or adopting carbon capture (e.g. CTL, GTL, jet fuel from oil shale) and biofuel pathways assuming no land use change impacts result in life-cycle GHG emissions which are comparable or slightly lower than those of baseline conventional jet fuel. Out of these, only alternative jet fuels made from biomass feedstocks show substantial GHG emissions reductions of 60% or more.[28]

Current production of food-based feedstocks like soy oil and palm oil is insufficient to support the level of biofuel production needed to achieve carbon-neutral U.S. aviation growth through 2025.

A scenario analysis was conducted to examine the amount of biofuel, as well as the corresponding resource requirement (feedstock and/or land), needed to attain carbon-neutral aviation growth through 2025. The analysis showed that the production of sufficient biojet from either soy oil or palm oil to maintain carbon-neutral aviation growth requires resources that cannot be supported by current levels of production. In particular, more than 100% of global palm oil production is required. In addition, the required four-fold increase in soybean production by 2025 may not be physically possible due to land constraints.

Land use change impacts from the use of biomass feedstocks (particularly food crops) could potentially increase life-cycle GHG emissions to levels several times above that of conventional jet fuel.

When potential land use change impacts are considered, particularly arising from the large-scale production of biofuels from food-based feedstocks, the production of biojet from soybeans or palm may no longer offer savings of GHG emissions compared to baseline jet fuel. Instead, depending on the type of land conversion, the overall GHG emissions of these food-based biojet pathways could potentially be more than seven times greater than the life-cycle GHG emissions for conventional jet fuel. Hence, food-based feedstocks like palm or soybeans do not appear to be suitable feedstocks for the large-scale production of biojet.

The use of waste products and dedicated energy crops in the large-scale production of renewable jet fuel appears to be more feasible than food-based crops in terms of feedstock requirements.

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[28] Considering baseline cases without land use change emissions.

Achieving carbon-neutral U.S. aviation growth through 2025 appears to be possible with potentially available U.S. biomass resources, (e.g., waste products such as forest residues and agricultural residues as well as dedicated energy crops such as herbaceous biomass like switchgrass). However, a sizable portion of this resource (46-76%) needs to be dedicated to this production, which introduces concerns of ensuring resources are being effectively utilized (e.g. biomass for fuel production versus biomass for heat and power production). In addition, the large-scale production of perennial crops like herbaceous biomass could potentially result in land use change emissions, which depends on the type of land use conversion employed in the cultivation of these crops.

Next generation biomass feedstocks with high oil yields can provide substantial reductions in land use requirements over conventional food-based feedstocks. Carbon-neutral U.S. aviation growth could be achieved through 2025 with biojet created from high oil yield crops (>10,000 L/ha) on a landmass that would be less than 3% of total U.S. cropland. In addition to high oil yields, it would be desirable for next generation feedstocks to be able to grow on non-arable lands like marginal land and even desert land with little to no fresh water. This would eliminate competition with food crops for the use of prime cropland. Hence, it is important to invest in the development of non-food biomass feedstocks which can achieve high oil yields and can be grown on non-cropland (e.g. algae), and at the same time be able to attain substantial reductions in life-cycle GHG emissions relative to conventional jet fuel.

8.2 Life-Cycle Assessment Key Issues and Limitations

In this thesis, the life-cycle assessment of GHG emissions from conventional jet fuel and various potential alternative jet fuels was conducted. Some issues pertinent to life-cycle assessment studies and the key limitations of this work are summarized below.

Transparency in Assumptions and Results

Various factors such as system boundaries, fuel properties, methodologies for co-product allocation, sources of inputs and other key assumptions contribute to the results obtained, and are the key reasons for the variation in results of different LCA studies. This work aimed to achieve transparency in the methodological approach and key assumptions undertaken in this analysis.

Input Assumptions and Uncertainty Management

In this work, the GREET framework was primarily used as an LCA tool and the robustness of the results depended strongly on the quality of the input parameters. Most of the input assumptions were based on estimates available in the literature. Unfortunately, considerable uncertainties exist in some key assumptions (e.g. energy efficiencies, fuel properties), particularly for new, emerging processes, where forecast or modeled results, rather than actual performance parameters are used. Key sources of uncertainty were identified and sensitivity studies and scenario analysis (low emissions,

baseline and high emissions cases) were conducted to explore the effect of these uncertainties on the overall GHG emissions of the fuel pathways. A range of GHG emissions, rather than a single value, was estimated for each fuel pathway to help to mitigate the impact of uncertainties.

Methodology for Co-product Credit Allocation

The application of different co-product allocation methods can have substantial impact on the overall results, particularly when co-products are produced in large quantities compared to the desired product. Regardless of which method was applied, it is important to clearly state the allocation approach that was adopted. This work explored the impact of different co-product allocation methodologies in the biojet production pathways. The soy oil-to-biojet pathway showed a greater variation in results when different allocation approaches were applied compared to the palm-oil-to-biojet pathway in part due to a large quantity of co-product being produced in the former case.

Study Limitations

This study focused specifically on quantifying GHG emissions of potential alternative fuel pathways and then compared them to those of baseline convention jet fuel. The life-cycle GHG footprint of a fuel pathway is important but by no means is sufficient on its own to determine the overall merits and feasibility of a particular alternative fuel. It should be considered in conjunction with other factors such as cost, feedstock availability, water and land use, ecological impacts such as soil erosion, biodiversity, etc. All these factors have an important role to play in assessing the overall sustainability and viability of a potential alternative fuel. These were not considered at length in this study but should be explored in future work.

This work utilized data from the literature on jet fuel and jet fuel alternatives where available. However, such information are usually limited as most data in the literature focused on the larger land transportation sector and the production of land-based transportation fuels (e.g. diesel, gasoline). Where data specific to alternative jet fuel production were not available, diesel fuel was used as a surrogate for jet fuel due to their similar chemical composition.

Large uncertainties exist in determining land use change emissions. The in-depth analyses required to adequately and specifically account for potential land use change impacts in the various fuel pathways examined were outside the scope of this work. Instead, existing data from the literature on potential land use change emissions were adopted to provide an illustrative example rather than definitive indication of such impacts on the life-cycle GHG emissions of biojet production.

8.3 Recommendations and Future Work

The key recommendations and areas of future research are outlined in the following paragraphs.

Explore the use of non-food, high yield crops (e.g. algae) or waste products, which do not require the use of larges areas of arable land, as biofuel feedstocks.
Such feedstocks would minimize land use requirements and the adverse impacts of land use change emissions, which could potentially be a significant contributor to overall GHG emissions.

Examine the overall sustainability of a potential alternative jet fuel pathway, in addition to life-cycle GHG emissions, in assessing its viability for large-scale production.
Sustainability factors like socio-economic impacts, water and land use, ecological impacts such as soil erosion, biodiversity, etc. have to be assessed in conjunction with life-cycle GHG emissions to determine the overall merit of an alternative jet fuel.

Conduct more detailed, specific analysis of land use change impacts in the use of biomass feedstocks for alternative jet fuel production.
The assessment of potential land use change impacts is an integral part of determining the sustainability of a biofuel pathway. In particular, the magnitude of land use change emissions could potentially be of the order of several times above the well-to-tank emissions of a biofuel pathway, rendering it unfeasible from the carbon perspective. Hence, it is essential to obtain information on specific land use change emission impacts of a potential biofuel pathway (e.g. through the use of general equilibrium models) to enable a more accurate assessment of the life-cycle GHG emissions of this pathway.

Develop an aviation-specific life-cycle analysis framework (including aircraft operation emissions analysis) to provide a more detailed and accurate assessment of life-cycle emissions of jet fuel and alternative jet fuels.
The life-cycle assessments models currently available do not include aviation. An aviation-specific life-cycle analysis framework that can capture greenhouse gases due to fuel production as well as aviation specific combustion emissions that affect global climate change needs to be developed. Such a framework would provide aviation with a consistent method for greenhouse gas accounting that includes operational details of aviation.

Appendix A: Calculation of Process Energy Needed in the Refining of Jet Fuel / ULS Jet Fuel

A.1 Production of Straight-run Jet Fuel

The main processes involved in the production of straight-run jet fuel are crude desalting and atmospheric distillation, followed by chemical treatments (such as the Merox process) to remove contaminants like mercaptans and organic acids, etc.

The analysis presented here is based on the process energy data given by Pellegrino et al., 2007, which are in terms of energy per barrel of feed. Such data were converted to process energy per unit energy of feed or product in our calculations.

Table 82 provides a summary of the data used to derive the process energy needed in the crude desalting and atmospheric distillation processes to produce a million Btu of straight-run jet fuel.

Table 82: Process Energy in Crude Desalting and Atmospheric Distillation Processes for the Production of Straight-run Jet Fuel

Type of process fuel	Process energy (Btu/barrel of crude[1])	Process energy (Btu/mmBtu of jet fuel[2])
Electricity	2,300	423
Natural gas	29,300	5,386
Refinery gas	52,600	9,669
Coke	19,300	3,545
Oils (includes crude oil, distillate and residual fuel oil)	3,500	643
Others (includes LPG, coal and purchased steam)	2,100	386
Total	109,100	20,055

Notes:
(1) Based on average energy use given by Pellegrino et al., 2007.
(2) Assumes that 1 barrel of crude oil = 5.44 mmBtu (LHV); and that 1 mmBtu of crude oil input produces 1 mmBtu of products (including jet fuel). Assuming energy allocation of input process energy among all products, energy required per mmBtu of products = energy required per mmBtu of jet fuel.
(3) Electricity losses were not accounted for in this calculation as it was already accounted for in the GREET calculations.

As no data was found in the literature regarding the energy needed for chemical treatment, it was assumed that the energy needed was negligible compared to the energy needed for atmospheric distillation and was ignored in this analysis.

Hence, the overall process energy requirement for the production of straight-run jet fuel was about 20,000 Btu/mmBtu of jet fuel produced.

The process fuel shares for the production of straight-run jet fuel were calculated from Table 82, assuming that "oils" were provided by residual oil, and "others" were provided by natural gas. The results (shown in Table 83) formed the process fuel shares input in the GREET model for the jet fuel production pathway (low emissions case).

Table 83: Process Fuel Shares for the Production of Straight-run Jet Fuel

Type of process fuel	Process energy (Btu/mmBtu of jet fuel)	Process fuel share (%)
Electricity	423	2.1
Natural gas	5,772	28.8
Refinery gas	9,669	48.2
Coke	3,548	17.7
Residual oil	643	3.2
Total	20,055	100

A.2 Production of Straight-run ULS Jet Fuel

The production of straight-run ULS jet fuel requires crude desalting and atmospheric distillation followed by hydrotreatment to remove sulfur and other impurities. Table 84 provides a summary of the process energy data needed in the production of straight-run ULS jet fuel.

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Table 84: Refining Processes and Process Energy for the Production of Straight-run ULS Jet Fuel

Refining process	Type of process fuel	Process energy (Btu/barrel of feed[1])	Process energy (Btu/mmBtu of feed[2])	Process energy (Btu/mmBtu of output[3])
Crude desalting and atmospheric distillation	Total (from Table 82)	109,100	20,055	20,055
Hydrotreating[4]	Electricity	18,600	3,556	3,383
	Natural Gas[5]	201,125	38,456	36,580
	Refinery Gas	30,600	5,851	5,565
	Coke	11,300	2,161	2,05
	Oils (includes crude oil, distillate and residual fuel oil)	2,100	402	382
	Others (includes LPG, coal and purchased steam)	1,200	229	218
	Total	264,925	50,654.9	· 48,184
Total for all processes				**68,239**

Notes:

(1) Based on average energy use given by Pellegrino et al., 2007.

(2) Assumed that the input to the atmospheric distillation processes was crude oil (5.44 mmBtu/barrel) and the input to the hydrotreating unit was jet fuel (5.23 mmBtu/barrel). All energy contents are given on a lower heating value (LHV) basis.

(3) Assumed that 1 mmBtu of input (plus process energy) produced 1 mmBtu of output for the atmospheric distillation processes. For the hydrotreating process: 1 mmBtu of feed + X mmBtu of hydrogen (plus Y Btu of process fuel) gave (1+X) mmBtu of product. Hence, the amount of process fuel used per mmBtu of product = $[1/(1+X)] \times Y$ Btu. For hydrotreating, the amount of hydrogen used per mmBtu of feed was 25,645 Btu (calculated from values given in Pellegrino et al., 2007).

(4) It was assumed that the hydrotreating process reduced sulfur content in jet fuel from about 4500ppm to about 5ppm.

(5) Included energy needed to produce hydrogen and energy credit from the steam production (assuming that energy efficiency of steam production from natural gas was 80%).

(6) Electricity losses were not accounted for in this set of calculations as it was already accounted for in the GREET model calculations.

Hence, the overall process energy requirement for the production of straight-run ULS jet fuel was about 68200 Btu/mmBtu of jet fuel produced.

The process fuel shares for the production of straight-run ULS jet fuel were calculated from Table 84, assuming that "oils" were provided by residual oil, and "others" were provided by natural gas. The results (shown in Table 85) formed the process fuel shares input in the GREET model for the ULS jet fuel production pathway (low emissions case).

Table 85: Process Fuel Shares for the Production of ULS Straight-run Jet Fuel

Type of process fuel	Process energy (Btu/mmBtu of jet fuel)	Process fuel share (%)
Electricity	3,806	5.6
Natural gas	42,570	62.4
Refinery gas	15,235	22.3
Coke	5,603	8.2
Residual oil	1,025	1.5
Total	68,239	100

A.3 Production of Jet Fuel from Hydroprocessing

The refining processes that could be involved in producing jet fuel from hydroprocessing include crude desalting, atmospheric and vacuum distillation, and hydrotreating and/or hydrocracking. Since the production of this hydroprocessed jet fuel was treated as the "high emissions" scenario in this analysis, it was assumed that all the processes mentioned above (including both hydrotreating and hydrocracking) were included in its production.

Table 86 provides a summary of the data used to derive the process energy needed in the various refining processes to produce a million Btu of hydroprocessed jet fuel from the refining of conventional crude oil.

Table 86: Refining Processes and Process Energy for the Production of Jet Fuel from Hydroprocessing

Refining process	Type of process fuel	Process energy (Btu/barrel of feed[1])	Process energy (Btu/mmBtu of feed[2])	Process energy (Btu/mmBtu of output[3])
Crude desalting and atmospheric distillation	Total (from Table 82)	109,100	20,055	20,055
Vacuum distillation	Electricity	1,200	221	221
	Natural Gas	24,100	4,430	4,430
	Refinery Gas	43,200	7,941	7,941
	Coke	15,900	2,923	2,923
	Oils[4]	2,900	533	533
	Others[5]	1,800	331	331
	Total	89,100	16,379	16,379
Hydrotreating[6]	Electricity	9,300	1,755	1,711
	Natural Gas[7]	100,563	18,974	18,500
	Refinery Gas	15,300	2,887	2,815
	Coke	3,300	1,066	1,039
	Oils[4]	1,050	198	193
	Others[5]	600	113	110
	Total	132,463	24,993	24,368
Catalytic hydrocracking	Electricity	38,900	7,340	6,783
	Natural Gas[7]	304,650	57,481	53,121
	Refinery Gas	59,000	11,132	10,288
	Coke	21,700	4,094	3,784
	Oils[4]	4,000	755	698
	Others[5]	2,400	453	418
	Total	430,650	81,255	75,092
Total for all processes				**135,894**

Notes:

(1) Based on average energy use given by Pellegrino et al., 2007.

(2) Assumed that the input to the atmospheric and vacuum distillation processes was crude oil (5.44 mmBtu/barrel) and the input to the hydrotreating and hydrocracking units was vaccum gas oil (5.3 mmBtu/barrel). All energy contents were given on a lower heating value (LHV) basis.

(3) Assumed that 1 mmBtu of input (plus process energy) produced 1 mmBtu of output for the atmospheric and vacuum distillation processes. For the hydrotreating and hydrocracking processes: 1 mmBtu of feed + X mmBtu of hydrogen (plus Y Btu of process fuel) gave (1+X) mmBtu of product. Hence, the amount of process fuel used per mmBtu of product = [1/(1+X)]×Y Btu. For hydrotreating and hydrocracking, the amount of hydrogen used per mmBtu of feed were 82,075 Btu and 25,645 Btu (calculated from values given in Pellegrino et al., 2007), respectively.

(4) Included crude oil, distillated and residual oil.

(5) Included LPG, coal and purchased steam.

(6) From Parkash, 2003, about 48000 Btu of process energy (calculated) was required per mmBtu of output in the hydrotreating process to reduce sulfur content from 4500ppm to 4ppm. It was assumed that half that process energy was required to reduce sulfur content from 4500ppm to about 500 ppm for conventional jet fuel production. The process energy information for hydrotreating given in Pellegrino et al., 2007 gave similar results to those based on the Parkash, 2003 and was applied in this case for consistency (energy inputs were halved for the higher sulfur content allowed in the production of conventional jet fuel).

(7) Included energy needed to produce hydrogen and energy credit from the steam production (assuming that energy efficiency of steam production from natural gas was 80%).

(8) Electricity losses were not accounted for in this set of calculations as it was already accounted for in the GREET model calculations.

Hence, the overall process energy requirement for the production of hydroprocessed jet fuel was about 135,900 Btu/mmBtu of jet fuel.

The process fuel shares for the production of hydroprocessed jet fuel were calculated from Table 86, assuming that "oils" were provided by residual oil, and "others" were provided by natural gas. The results (shown in Table 87) formed the process fuel shares input in the GREET model for the jet fuel production pathway (high emissions case).

Table 87: Process Fuel Shares for the Production of Jet Fuel from Hydroprocessing

Type of process fuel	Process energy (Btu/mmBtu of jet fuel)	Process fuel share (%)
Electricity	9,137	6.7
Natural gas	82,683	60.9
Refinery gas	30,713	22.6
Coke	11,294	8.3
Residual oil	2,067	1.5
Total	135,894	100

A.4 Production of ULS Jet Fuel from Hydroprocessing

The calculation of the process energy required in the production of ULS jet fuel from hyprocessing was similar to that of jet fuel, except that additional energy was required in the hydrotreating step to further reduce the sulfur content of jet fuel from about 500ppm to 5ppm.

Table 88 provides a summary of the data used to derive the process energy needed in the various refining processes to produce a million Btu of ULS jet fuel from hydroprocessing.

Table 88: Refining Processes and Process Energy for the Production of ULS Jet Fuel from Hydroprocessing

Refining process	Type of process fuel	Process energy (Btu/barrel of feed)[1]	Process energy (Btu/mmBtu of feed)[2]	Process energy (Btu/mmBtu of output)[3]
Crude desalting and atmospheric distillation	Total (from Table 82)	109,100	20,055	20,055
Vacuum distillation	Total (from Table 86)	89,100	16,379	16,379
Hydrotreating[4]	Electricity	18,600	3,509	3,340
	Natural Gas[5]	201,125	37,948	36,120
	Refinery Gas	30,600	5,774	5,495
	Coke	11,300	2,132	2,029
	Oils[6]	2,100	396	377
	Others[7]	1,200	226	216
	Total	264,925	49,986	47,578
Catalytic hydrocracking	Total (from Table 86)	430,650	81,255	75,092
Total for all processes				**159,104**

Notes:

(1) Based on average energy use given by Pellegrino et al., 2007.

(2) Assumed that the input to the atmospheric and vacuum distillation processes was crude oil (5.44 mmBtu/barrel) and the input to the hydrotreating and hydrocracking units was vaccum gas oil (5.3 mmBtu/barrel). All energy contents were given on a lower heating value (LHV) basis.

(3) Assumed that 1 mmBtu of input (plus process energy) produced 1 mmBtu of output for the atmospheric and vacuum distillation processes. For the hydrotreating and hydrocracking processes: 1 mmBtu of feed + X mmBtu of hydrogen (plus Y Btu of process fuel) gave (1+X) mmBtu of product. Hence, the amount of process fuel used per mmBtu of product = [1/(1+X)]×Y Btu. For hydrotreating and hydrocracking, the amount of hydrogen used per mmBtu of feed were 82,075 Btu and 51,291 Btu (calculated from values given in Pellegrino et al., 2007), respectively.

(4) It was assumed that the hydrotreating process reduced sulfur content in jet fuel from about 4500ppm to about 5ppm.

(5) Included energy needed to produce hydrogen and energy credit from the steam production (assuming that energy efficiency of steam production from natural gas was 80%).

(6) Included crude oil, distillate and residual fuel oil.

(7) Included LPG, coal and purchased steam.

(8) Electricity losses were not accounted for in this set of calculations as it was already accounted for in the GREET model calculations.

Hence, the overall process energy requirement for the production of hydroprocessed ULS jet fuel was about 159,100 Btu/mmBtu of jet fuel.

The process fuel shares for the production of hydroprocessed jet fuel were calculated from Table 88, assuming that "oils" were provided by residual oil, and "others" were provided by natural gas. The results (shown in Table 89) formed the process fuel shares input in the GREET model for the ULS jet fuel production pathway (high emissions case).

Table 89: Process Fuel Shares for the Production of ULS Jet Fuel from Hydroprocessing

Type of process fuel	Process energy (Btu/mmBtu of jet fuel)	Process fuel share (%)
Electricity	10,767	6.8
Natural gas	100,408	63.1
Refinery gas	33,394	21.0
Coke	12,284	7.7
Residual oil	2,251	1.4
Total	159,104	100

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