FULL FUEL CYCLE ASSESSMENT WELL TO TANK ENERGY INPUTS, EMISSIONS, AND WATER IMPACTS

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ABSTRACT

Pursuant to AB1007, the California Energy Commission and California Air Resources Board are developing a “State Plan to Increase the Use of Alternative Transportation Fuels”. The plan is to set goals for increased use of alternative transportation fuels without material increases in air or water pollution. To ensure that fair comparisons are made between the various alternative fuels, emissions from the full fuel cycle need to be considered. The full fuel cycle analysis can be divided into two parts:

- Well-to-Tank (WTT)
  Feedstock extraction, transport, storage, processing, distribution, transport, and storage

- Tank-to-Wheels (TTW)
  Refueling, consumption and evaporation

The full fuel cycle is the combination of the WTT and TTW, which is also commonly referred to as a Well-to-Wheels (WTW) analysis. TIAX has performed a WTW emissions analysis for a wide variety of alternative transportation fuels, considering criteria and greenhouse gas pollutants, as well as air toxic contaminants and multimedia impacts. The alternative fuels considered include gasoline and diesel baselines compared to liquefied petroleum gas (LPG), natural gas, hydrogen, ethanol, biodiesel, synthetic diesel, and electricity. For many of these fuels a number of different feedstocks and production methods were evaluated. The WTT emissions were quantified for 2012, 2017, 2022, and 2030.

The results of the full fuel cycle analysis are reported in three different volumes. This volume presents the results of the WTT portion of the full fuel cycle.

KEYWORDS

Full Fuel Cycle Analysis, Well to Tank, Criteria Pollutants, Multi-media impacts, EMFAC

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SECTION 1. INTRODUCTION

In response to Assembly Bill 2076[1], the California Energy Commission and California Air Resources Board analyzed the economic and environmental impacts of technology and alternative fuel options that could reduce California's dependence on petroleum as a transportation fuel[2]. The agencies concluded that not only could on-road gasoline and diesel consumption be reduced to 15 percent below 2003 levels by 2015 it could be done with net cost benefits. The agencies recommended that the reduction goal be achieved by doubling the federal fuel economy standard for new vehicles, and increasing the use of non-petroleum fuels to 20 percent of on-road demand by 2020.

To achieve the alternative fuel portion of the AB 2076 goals, Governor Schwarzenegger signed AB 1007[3] in September 2005. AB1007 requires the California Energy Commission and Air Resources Board to prepare a "State Plan to Increase the Use of Alternative Transportation Fuels" by June 30, 2007. This plan is referred to here as the Alternative Fuels Plan. In developing the Alternative Fuels Plan, the Agencies must perform three tasks:

1. Evaluate the alternative fuels on a full fuel cycle basis

2. Set goals for 2012, 2017, and 2022 ensuring no net material increase in air pollution, water pollution or other substances known to damage human health

3. Recommend policies that ensure the alternative fuel goals will be met.

In support of AB 1007 policy making, TIAX has performed a California specific full fuel cycle analysis for a variety of alternative transportation fuels. This analysis is one of several ongoing work efforts that provide a foundation for Energy Commission activities in response to AB 1007. This report is part of a three volume set of reports describing the full fuel cycle analysis assumptions and results. The intention has been to clearly present all important assumptions that have been made in the quantification of fuel cycle emissions so that stakeholders may understand how the final emission estimates were determined. The following sections describe full fuel cycle analysis, the scope of the present analysis, and organization of this volume of the report.

[1] AB 2076, Shelley, Chapter 936 Statutes of 2000

[2] *Reducing California's Petroleum Dependence,* California Energy Commission, California Air Resources Board Joint Agency Report, August 2003.

[3] AB 1007, Pavley, Chapter 371 Statutes of 2005

1.1 What is a Full Fuel Cycle Analysis?

To fairly compare the relative merits of alternative transportation fuels to gasoline and diesel, the environmental impacts of the entire fuel cycle need to be accounted for. The components of a full fuel cycle analysis are shown schematically in Figure 1-1.

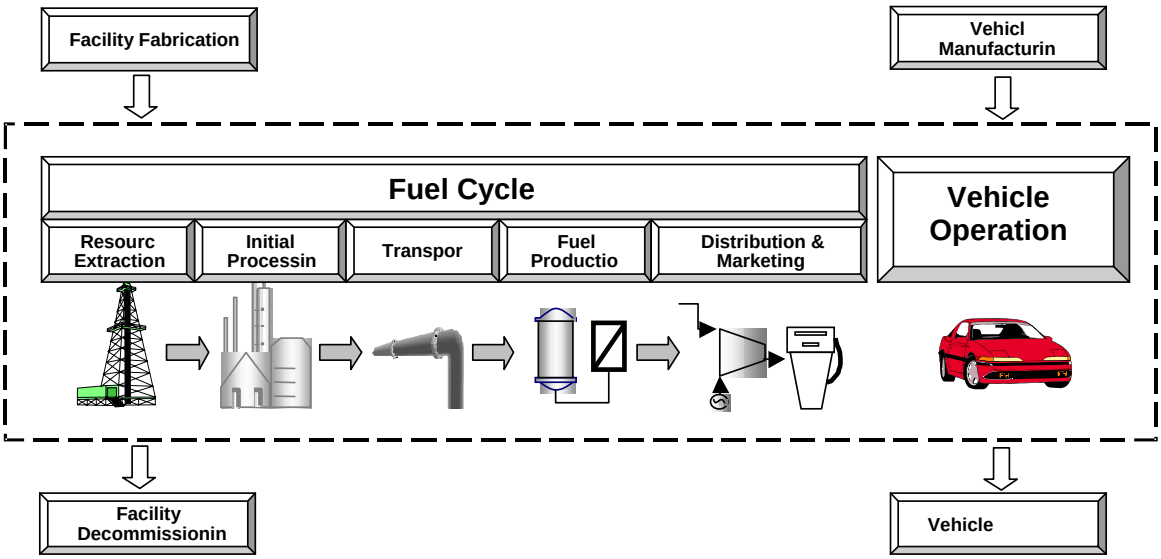

Figure 1-1. Total Vehicle Energy Cycle

The boundaries of the cycle can include the production and burning of the fuel as well as the production and final fate of the fuel production facilities and vehicle. The idea of quantifying total fuel cycle emissions is not new. Fuel cycle analyses have been used for many years to support the analysis of energy use and vehicle impacts, including the following:

- Benefits of Reducing Demand for Gasoline and Diesel (CEC 2001)
- Comparison of fuel cell and other vehicle options (Knight, Choudhury, GM 2001, Brinkman, Lasher, Wang 1999, Delucchi 1993, Unnasch (1989, 2001, 2005), Weiss 2000, Thomas 2000)
- Develop R&D Goals for Technology Development (Lasher 2002)
- Evaluate energy efficiency of vehicle options (Unnasch 2000, EPRI 2001)
- Compare fuel cycle emissions with ARB PZEV requirements (ARB 2000, Unnasch 2001)
- Emission factors for a GHG registry (WRI, California Climate Action Registry)

Most of these analyses aim to compare the sum of vehicle and fuel cycle emissions on a per mile driven basis. Some also include discussions of the emissions associated with material processing.

A full fuel cycle analysis includes the following components:

1. Feedstock extraction, transport, and storage
2. Fuel production, distribution, transport, and storage
3. Vehicle operation including refueling, consumption, and evaporation

The first two items track the fuel cycle up to storage at retail and these emissions are commonly referred to as Well-to-Tank (WTT) emissions. Emissions from vehicle refueling and operation are referred to as Tank-to-Wheels (TTW) emissions. The combination of the WTT and TTW emissions represent the emissions associated with the full fuel cycle, and are referred to here as the Well-to-Wheels (WTW) emissions. The primary purpose of this study has been to develop emission factors that reflect the analysis of petroleum displacement in California.

The assumptions and results of the present analysis have been organized into three volumes that are conceptually consistent with the fuel cycle components:

- Well to Tank Energy Inputs, Emissions, and Multimedia Impacts
- Tank to Wheels Energy Inputs, Emissions, and Multimedia Impacts
- Well to Wheels Comparison of Alternative Transportation Fuels

This document provides the assumptions and results for the WTT portion of the fuel cycle.

1.2 Scope of Wheel to Tank Analysis

AB 1007 defined an alternative fuel as

> *…a nonpetroleum fuel, including electricity, ethanol, biodiesel, hydrogen, methanol, or natural gas that, when used in vehicles, has demonstrated to the satisfaction of the state board, to have the ability to meet applicable vehicular emission standards. For the purpose of this section, alternative fuel may also include petroleum fuel blended with nonpetroleum constituents, such as E85 or B20.*

Table 1-1 shows the fuel and feedstock combinations analyzed in this study. The fuels can be loosely grouped by feedstock, which follows their organization in this report. The alternative fuels have been grouped into eight pathways as follows: petroleum fuels, LPG, natural gas fuels, synthetic fuels, ethanol and ethanol blends, biodiesel, electricity and hydrogen. A wide variety of feedstocks utilized to produce these fuels are analyzed including various biomass sources and coal. Please refer to Section 2 for a more detailed analysis matrix.

Table 1-1. Fuel and Feedstock Combinations

Fuels	Primary Feedstock	Other Feedstocks
RFG — E0 RFG — E5.7 RFG — E10 Diesel	Petroleum	
LPG		Natural Gas
CNG LNG	Natural Gas	Landfill Gas Remote NG
Methanol DME FT blends	Remote Natural Gas	Coal Biomass
Ethanol — E85 E-diesel	Corn	Sugar Cane Biomass
Biodiesel (vegetable)	Soybean Oil	Palm Oil
Electricity	Various	
Hydrogen	Various	

1.3 Report Organization

This report describes the energy consumption and emission factor assumptions used to estimate WTT emissions. The information is organized as follows:

Section 2 — Fuel Cycle Analysis Methodology. This section presents the analysis methodology and describes key overarching assumptions of the analysis including geographic boundaries, emission sources considered, and fuel property assumptions. The analysis tools are also described.

Section 3 — Fuel Production Processes. For each fuel, the various feedstocks, transportation modes, and other parameters that affect fuel cycle emissions are discussed. For each of the fuel production process, the energy inputs and emission factors are provided.

Section 4 — Transportation and Distribution. Assumptions about transportation modes (ship, rail, truck, and pipeline) and distances for each feedstock and fuel that affect fuel cycle emissions are discussed.

Section 5 — Emissions from Fuel Production and Distribution. Emission factors for new alternative fuel production facilities in California are discussed along with emission factors assumed for fuel and feedstock transportation.

Section 6 — Multimedia Impacts. This section analyzes permit requirements for discharges to media other than air and estimates associated emissions for each alternative fuel.

Section 7 — Finished Fuels. This section provides WTT results for the base case and each of the seven alternative fuel groupings.

Section 8 — Fuel Cycle Conclusions. This section draws key conclusions from the finished fuel results presented in Section 7.

SECTION 2. FUEL CYCLE ANALYSIS METHODOLOGY

The analysis presented in this report quantifies the WTT impacts for each of the fuel options in the WTW analysis. The WTT component corresponds to the energy impacts and emissions associated with feedstock extraction, fuel production, transport, storage, and local distribution. This section identifies the boundaries and approach to the fuel cycle or WTT analysis.

2.1 Fuel Cycle Boundaries

2.1.1 Global GHG Emissions

Fuel production and distribution processes can occur throughout the world depending on the type of fuel and where the energy resources are available. Because the impact of GHG are global, they are counted on a global basis.

2.1.2 Local Criteria Pollutant and Air Toxics Emissions

This report determines fuel cycle emissions for fuels consumed in California. Stringent stationary source emission standards in California limit the emissions associated with power production, fuel transport through marine terminals, power generation, and other large stationary emission sources.

Criteria pollutant and air toxics emissions are grouped by emissions in California non attainment areas and emissions occurring outside California. California specific emission factors provide the basis for estimating emissions from equipment in California, while a composite of U.S. emission factors provides the basis for emissions outside of California as described in Section 5.

2.1.3 Marginal Emissions

This study evaluates global GHG and local emissions from marginal fuel production. In the view of the authors, production capacity in California and many other regions involved in the logistics of fuel supply are well enough understood that a first order estimate of the marginal sources provides a good basis for the study assumptions. In order to meet California and worldwide demand for most of the fuels considered in this study, new growth in production capacity will be required. Any increases in fuel production or power generation due to a reduction in petroleum use were assumed to come from new, more efficient plants built to meet growing demand.

Petroleum Fuels

The emphasis on marginal emissions by industry groups was a key outcome of the 1996 ARB Fuel Cycle study (Unnasch 1996). Industry groups and State agencies

ultimately agreed that a marginal approach was relevant in the context of a moderate usage of alternative fuels. Another point of view is that a very substantial use of alternative fuels could result in a reduction in refinery capacity. Given the limited refinery capacity and substantial growth in gasoline demand, this outcome is unexpected.

The emission impact of displacing a very large fraction of refinery capacity with alternative fuels is not analyzed here. Even if such a scenario were to occur, average emission rates would not reflect the impact on emissions, as the disposition of emission permits and offsets would need to be taken into account.

A more rigorous economic analysis could provide more detail on marginal energy production impacts. An economic analysis would take into account the supply and demand elasticities where reductions in the usage of one fuel would affect its supply, price, and other aspects of the economy. Comments from industry experts indicated that future marginal gasoline supplies would clearly come from out of State sources[4].

Some environmental groups and researchers consider the results of the marginal analysis in this study as optimistically low for gasoline production emissions in California. However, in the authors' view, marginal emissions represent the contribution to the air that we breathe. The analysis could also go through the exercise of calculating average emissions and then estimating secondary impacts due to offsetting, emission caps, and other regulatory constraints.

Electric Power Production

The study looks at local emissions from the perspective of exposure to an individual in California. Although the total emissions from global fuel production and transportation are important, policy makers outside California can also address air quality goals with a variety of measures. Another consequence of a marginal analysis is that no hydroelectric or nuclear power is included in the electric generation mix. Reducing gasoline demand by increasing electric power demand for various hydrogen production or other electric transportation options does not increase the output from these types of generation facilities. The marginal source of electric power was assumed to be natural gas and renewable power that complies with the California's RPS.

Gaseous Fuels

Substantial transportation distances were assumed for the natural gas used to produce hydrogen. Some analysts argue that natural gas resources in the U.S. are limited, and if hydrogen vehicles are used on a large-scale basis, additional natural gas would need to come from foreign sources of LNG. In this analysis, energy inputs and emissions and GHG emissions are consistent with long range, pipeline transportation distances (from

[4] The marginal source of gasoline was extensively reviewed with oil industry participants in prior ARB fuel cycle studies (Unnasch 1996, 2001)

Canada). Foreign sources of LNG were also analyzed as a source of pipeline natural gas. This pipeline transportation results in greater energy inputs and GHG emissions for natural gas or natural-gas-derived fuels than those derived from California natural gas.

Summary of Marginal Considerations

The principal assumptions that relate to these considerations include the following:

- Import liquid fuels to California
- Produce marginal electric power from fossil fuels projected to be natural gas with 20 percent of the power from new renewables
- Emissions from vehicles and stationary sources, such as fueling stations, are consistent with ARB rules
- Marginal natural gas originates outside California
- RECLAIM and other offset requirements limit NO_x and PM from power plants and large hydrogen production facilities (and oil refineries but reducing gasoline demand displaces imported gasoline, so the impact on refinery emissions is minimal, at least in 2010)
- Changes in land use for agriculture are to be addressed separately from the WTT analysis.

2.2 Fuel Cycle Analysis Approach (WTT)

In the study, local and regional emissions of criteria pollutants are calculated using in-use and rule-based emissions factors for the steps in the fuel cycle. Because the rules primarily govern fuel and vapor transfers on a volumetric basis, the local emissions are also tracked per unit of volume. GHG emissions, on the other hand, are calculated using energy efficiency factors for the fuel cycle, which are inputs to the GREET model, which was developed by Argonne National Laboratory (Wang 1999, 2007). A composite of several results from GREET provide the GHG emission factor values for hydrogen.

Determining fuel cycle emissions requires a detailed tracing of the steps involved in the production and distribution of fuels. This includes the following:

- Energy consumption is determined for all steps in the fuel cycle. Energy consumption and related combustion emissions are the principal source of GHG and criteria pollutant emissions in the fuel cycle

- The energy consumption in the full fuel cycle includes, not only the direct energy consumption of fuel production and transport equipment, but also the energy required to produce the fuel in the fuel cycle

- CO_2 emissions for combustion or fuel conversion are calculated from the carbon content of the fuel or feedstock[5]

- CH_4 and N_2O emissions depend on the type of equipment and are based on emission factors or fuel combustion

Key assumptions that affect the fuel cycle energy and GHG emissions include feedstock extraction and refining efficiency, energy requirements for feedstock and fuel transport, and the feedstock resource mix and related carbon content. These input assumptions were modified in the baseline GREET model to reflect the assumptions discussed in the following section. The details of the fuel cycle analysis are considered in the GREET 1.7 model. This model was used to determine energy inputs and GHG emissions for the fuel cycle. The outputs of the GREET model were used to develop the results presented in this study.

Some enhancements to the analysis and presentation of the results in the GREET 1.7 model were included in this study. These include the following:

- In addition to fuel cycle emissions, vehicle GHG emissions are determined on a g_{GHG}/MJ_{Fuel} basis. This approach prevents an inadvertent decoupling of the vehicle and fuel cycle results by readers of this study. The fuel cycle results for a particular fuel often correspond to the fuel properties, which affect the vehicle GHG emissions.

- Results from GREET 1.7 were determined for several "primary fuels." The fuel cycle results for the primary fuels were used to determine the energy inputs and GHG emissions for fuels such as CNG, where multiple feedstocks are required from different regions. For example CNG would be produced from natural gas distributed throughout the U.S. and electric power produced both inside and outside California[6].

- Detailed calculations of local fuel distribution emissions were used to determine emissions in California. This analysis allowed for a better tracking of the vapor pressure of blending components and delivered fuel products. The effect of ARB emission regulations was also tracked for each of the fuel distribution processes.

[5] In the case of fuel processes that involve a conversion of one feedstock to a fuel, the fuel cycle CO_2 emissions are typically determined using a carbon balance method. Carbon emissions = carbon in feedstock – carbon in product fuel – carbon in plant emissions. The carbon in the product fuel is converted to CO_2 in the vehicle. Vehicle CO_2 emissions = carbon in the product fuel – carbon in the form of CH_4, CO, or hydrocarbons. In the case of hydrogen, all of the carbon is used in the fuel cycle.

[6] GREET17 does allow for fuels and feedstocks from different regions to be used in the analysis. However, combining the results off model provided for better transparency and also eliminated a calculation issue when both electric power and natural gas power were assumed for hydrogen liquefaction facilities. Off-model calculations also allow for a simple analysis of different hydrogen production scenarios.

2.2.1 WTT Analysis Approach

In general, fuel cycle energy inputs and emissions can be calculated by tracking the energy inputs to a fuel production process from steps including:

- Feedstock extraction
- Feedstock processing
- Feedstock transport
- Feedstock conversion to product fuel
- Product fuel transport
- Product fuel storage
- Local delivery
- Retail storage and dispensing

Figure 2-1 illustrates the WTT accounting for CNG production as an example. The amount of energy corresponding to 1 J of CNG is illustrated. In the transportation and distribution step, electricity and natural gas are energy inputs. Natural gas and a small amount of petroleum are used in the extraction and production of natural gas used. These upstream fuel cycle components contribute to the WTT analysis in two ways. First, the energy used to extract and process natural gas is part of the fuel chain for CNG. However, the second order energy and natural gas used to produce the natural

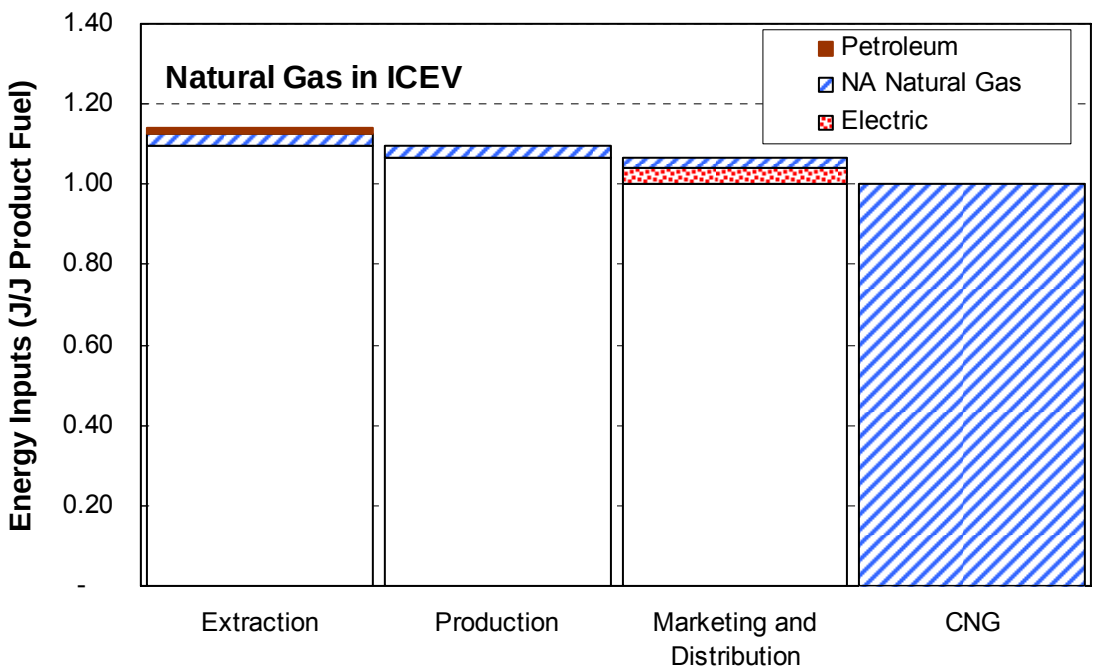

Figure 2-1. Energy Inputs in the Production of Compressed Natural Gas

gas in the fuel cycle must also be included in the analysis. These second order fuel cycle impacts are determined through recursive calculations in WTT models. GREET for example, operates in circular reference mode where the cumulative effect of second order fuel cycle inputs is calculated through repeated iterations.

A variety of analytical tools provided the basis for the WTT analysis. Energy inputs, GHG emissions, and criteria pollutant emissions were calculated using GREET 1.7 with significant modifications to the assumptions reflecting the transportation distances, fuel mix, and location of emissions. The process energy inputs used in the GREET model are generally reasonable. The energy inputs and emissions for some pathways were calculated using the WTT post processor tool either because the pathway was not supported in GREET, or because the modification to the pathway was so simple it did not warrant the effort to develop the input assumptions and extract the results for the model. For example, the WTT for night time weighted EV charging was estimated as 99.1 percent of the 24 hour average. The results for power generation were simply adjusted by 99.1 percent.

Toxic air contaminants and water impacts were calculated using the WTT post processor tool. With this approach, the WTT inputs for several primary fuels (electricity, diesel, and natural gas) were calculated. These energy inputs provided the primary source of toxic air contaminants in California through transportation or delivery equipment or plant process emissions. The process energy required to make a fuel (specific energy) was then determined for each fuel. (for example CNG from pipeline gas requires 1.00001 J of natural gas per J of CNG and 0.02 J of electric power. The WTT post processor calculates the weighted result using a spreadsheet database approach. The database method has significant advantages for fuel chains like hydrogen that are composed of a variety of primary energy carriers. In principal a database approach could also be applied to the full fuel cycle analysis as has been done in other fuel cycle studies (Unnasch 1996, Choudhury 2002, EUCAR 2006).

The approach for determining energy inputs and GHG emission corresponds to the following steps:

1. Calculate WTT energy, GHG emissions, and criteria pollutants using GREET
2. Verify California specific process assumptions and transportation distances
3. Determine water impacts and toxics for primary energy inputs for fuel production and transportation
4. Calculate water impacts and toxics using WTT post processor

2.2.2 GREET Model Inputs

The approach for determining the model inputs and performing the calculations are described below.

Process Energy

Process energy inputs represent the energy used in feedstock extraction, fuel production, gas compression and liquefaction, and fuel transportation. For example, the amount of energy required to produce a J of FT Diesel is expressed as an efficiency input (63 percent for today's plants). The baseline process energy inputs in the GREET model are reasonable estimates of the process performance of equipment in the fuel cycle. TIAX modified some of the inputs as described in Sections 3 and 5 to represent different fuel production scenarios or to provide a revision to the baseline estimate where additional information was available.

Geographic Regions

The GREET model was configured to analyze fuel production in the U.S., California, and outside the U.S. where fossil fuels such as petroleum, LNG, or synthetic fuels might be produced (Chile, Maylasia, Saudi Arabia). Transportation distances and electric generation mix were coded into the GREET model to correspond to these regional scenarios. The electricity mix for each region is shown below:

- U.S. Fuel Production (case 1) – U.S. Generation Mix
- CA Fuel Production (case 3) – Natural Gas combined cycle and renewable mix
- Rest of World (ROW) Fuel Production (case 4) – 85 percent natural gas based power, no coal or nuclear power

Criteria Pollutants

Emission factors representing new facilities in California were entered into GREET. The California based emission factors are used when case 3 is invoked. Other modifications to the GREET model include:

- Heavy-duty truck emission factors corresponding to EMFAC by scenario year
- California off-road emissions for agricultural equipment and stationary engines
- Zero sulfur from power plants as this pollutant must be offset.
- Zero NO_x and HC emissions from new large California facilities in non attainment areas as these emissions must be offset (the offset emissions can also be tracked
- Fuel spillage and fugitive losses consistent with fuel vapor pressure and ARB regulations for vapor recovery and fuel spillage
- Revised emission factors for hydrogen and synthetic fuel plants based on source test data
- Adjusted marine vessel and rail emissions to reflect additional emissions from in-port and rail yard activity

Transportation Distance

Fuel transportation distances for California are described in Section 4. The transportation distances are inputs to the GREET model. The distances that the vessel operates in a California non attainment area was incorporated into the urban shares inputs.

Urban Shares

The urban shares inputs to GREET were modified to correspond to the fraction of the transportation in California. Tanker ship emissions are counted for 100 nautical miles (kn) of travel. The pathways for delivering liquid fuels are similar, with the primary differences in local emissions resulting from the fuels vapor pressure and related fuel transfer emissions. Emissions associated with the rail transport of ethanol, a component of gasoline, as well as imported LPG and biodiesel are counted for a distance of 178 miles. Emissions from pipelines were estimated for energy inputs corresponding to 160 miles of natural gas transport to California and 50 miles of petroleum product transport. Criteria pollutant emissions were counted for all fuel storage terminals and fueling stations in urban areas.

Fuel Properties

The project team reviewed fuel property data from a wide range of sources. Consistency checks were also completed for the fuel density, carbon content, and heating value and compared with those in the GREET model. With few exceptions described in Section 1.3, the fuel property values in GREET were left unchanged. Table 2-1 summarizes the fuel production scenarios evaluated.

Table 2-1. Fuel Production Scenarios

Fuel	Feedstock	Production Location	WTT Data				
			US_Base	CA	Blended	ROW	Other
CARBOB/ E5.7	Crude Oil, SE Asia	Singapore	x				
	Crude Oil, CA Mix	CA		x			
	Crude Oil, VZ	CA					x
	Crude Oil, Iraq	CA					x
CA RFG0	Crude Oil, SE Asia	Singapore					x
CA RFG - E10	Crude Oil, SE Asia	Singapore					x
Diesel, ULSD, 10 ppm S	Crude Oil	Singapore	x				
LPG	Crude Oil	CA Mix	x				
	NA Natural Gas	U.S. Mix		x			
CNG	NA Natural Gas	Texas, Canada	x				
	LNG	Chile				x	
	Landfill Gas	CA		x			
LNG	Natural Gas	Chile				x	
	Stranded NG	CA					
Methanol	Natural Gas	Chile				x	
DME	Natural Gas	Chile				x	
Fischer Tropsh Diesel	Natural Gas	Malaysia			x	x	
	Poplar	CA			x		
Biodiesel (vegetable oil)	Palm Oil	Malaysia			x		
	Soy Bean Oil	Midwest/ CA	x				
E-Diesel	Corn, Midwest	Midwest	x				
Ethanol, E85	Marginal Corn	Midwest					x
	Corn, Midwest	CA	x				
	Corn, Midwest, Digester Gas	CA			x		
	Sugar Cane	CA			x		
	Poplar	CA		x	x		
	Switch Grass	CA			x		
	Forest Residue	CA			x		
	Agricultural Residue	CA			x		
	Waste Paper	CA			x		

2.2.3 Air Toxic Pollutant Calculations

This study analyzes the air toxic emissions associated with alternative and conventional fuel extraction, transportation, production/processing, and final distribution to consumers. Fuel cycle sources of air toxic emissions range from internal combustion engines at natural gas compressor stations to petroleum refineries. Each source in the well to tank cycle for each fuel/feedstock is considered; specific air toxic emission

factors for each source are shown along with the criteria pollutant emission factors in Section 3 (for fuel production processes) and Section 5 (for transportation and distribution). Air toxic emissions from sources located within California are rigorously quantified while sources located overseas (such as petroleum refining in Africa) are estimated.

In 1983, the California Legislature passed AB1807, creating a comprehensive program to address adverse public health impacts from emissions of toxic substances to ambient air. In 1993, the Legislature amended AB1807, stipulating that the 189 hazardous air pollutants formally identified by the federal EPA be identified as Toxic Air Contaminants (TACs) in California. Toxic air contaminants are defined as an air pollutant that may cause or contribute to an increase in mortality or an increase in serious illness. This study only considers those TACs which present an increased risk of developing cancer. A recent list developed by ARB and the Office of Environmental Health Hazard Assessment (OEHHA) of toxic air contaminants and their associated inhalation unit risk factors for cancer can be obtained from the ARB website[7].

TACs with cancer unit risk factors that have been identified as being emitted from well to tank alternative fuel production processes are shown in Table 2-2. Their unit risk

Table 2-2. Common Toxic Air Contaminants from WTT Sources

Toxic Compound	Inhalation Unit Cancer Risk $(\mu g/m^3)^{-1}$	Unit Risk Normalized to Formaldehyde
Acetaldehyde	2.70E-06	0.45
Benzene	2.90E-05	4.8
1,3-Butadiene	1.70E-04	28
Chromium Compounds	1.50E-01	25,000
Ethylene Dibromide	7.10E-05	12
Formaldehyde	6.00E-06	1.0
Lead & Lead Compounds	1.20E-05	2.0
Methyl Tertiary-Butyl Ether	2.60E-07	0.043
Nickel and Nickel Compounds	2.60E-04	43
Tetrachloroethylene	5.90E-06	1.0
Dioxins (PCDD)	3.80E+01	6,300,000
PAH	1.10E-03	180
Napthalene	3.40E-05	5.7
Diesel Particulate Matter	3.00E-04	50

[7] Consolidated Table of OEHHA/ARB Approved Risk Assessment Health Values, can be obtained from www.arb.ca.gov/toxics/healthval/healthval/htm, April 2005.

factors are also given. The unit risk factors are also shown normalized to the formaldehyde risk factor to provide a sense of relative toxicity. For example, dioxin (PCDD) is typically emitted in very small quantities, if at all, but it is much more carcinogenic than formaldehyde. So, low level emissions may pose some significant risk.

For each fuel/feedstock pathway, the total amount of each TAC (gms) per energy unit (GJ) of fuel/feedstock produced will be determined using the emission factors specified in Sections 3 and 5. To facilitate quantification of air toxic risk, a composite air toxic value will also be calculated by multiplying each g/GJ by the normalized unit risk factor and summing.

2.2.4 Multimedia Impacts

Multi-media impacts include a wide range of potential discharges to the environment including surface water, ground water, and soil. The potential impacts are discussed in Section 6. Water impacts, such as oil tanker spills or chemical run-off from farming, are discussed qualitatively for each fuel option. The WTT analysis proceeds with the calculation of fuel spills, as these impacts affect all of the fuel options to some extent, and a calculation of the effects of fuel spills was possible on a WTT basis.

Fuel spills were calculated for each fuel option based on the fuel delivery modes described in Section 5. Most of the spilled fuel is associated with vehicle fueling. The fraction of the fuel spilled was assumed to be 99 percent for gasoline and alcohol fuels and 10 percent for diesel fuels.

Spilled fuel losses were attributed to each fuel during its transport and delivery. The primary source of spilled fuel in the fuel cycle was diesel used to transport fuels. Typically, the amount of diesel used to transport fuel corresponds to less than 5 percent of the energy in the product fuel. Consequently, the second order fuel cycle effects are only a minor part of the fuel spillage. These second order impacts were calculated using the WTT post processor.

Of course, fuel production processes can result in a wide variety of multi-media impacts that are not calculated here. These impacts do not lend themselves to a comparison on a per unit fuel basis. The wide range of regulatory constraints and environmental review requirements makes attributing impacts, such as underground tank leaks and farming run off, too challenging to attempt within the scope of this project if a meaningful comparison among fuel options is desired.

2.2.5 Fuel and Feedstock Combinations

Fuel feedstock combinations assessed in the evaluations are shown in Table 2-3.

Table 2-3. Fuel/Feedstock Scenarios for Electricity and Hydrogen Fuel Production and Use

Fuel	Feedstock	Production Location	WTT Data				
			US-Base	CA	Blended	ROW	Other
Electricity	CA Average Mix	Various	x				
	CA Marginal, 20% RPS	CA Marginal Mix		x			
	Dedicated Renewable	CA					x
	Petroleum Coke	CA					x
Hydrogen	NG SR, LH2, 20% RP	CA		x	x		
	NG SR, LH2, 100% RP	CA			x		
	NG SR, Tube Trailer	CA			x		
	NG SR, Pipeline	CA			x		
	Pet Coke, Gasification	CA			x		
	Biomass, Gasification	CA			x		
	On Site NG SR, 20% RP	CA		x			
	On Site NG SR, 700 bar, 20% RP	CA			x		
	On Site NG SR, 100% RP	CA			x		
	On-Site Electrolysis, CA Marginal	CA			x		
	On-Site Electrolysis, Renewable Power	CA			x		

2.3 Fuel Properties

Table 2-4 shows fuel properties that provide inputs for the analysis in this study. The values represent typical compositions. Some fuels such as gasoline, diesel, LPG, FTD, natural gas, and residual oil vary in composition while methanol, hydrogen, and ethanol are pure compounds. Variations in fuel properties for these pure compound fuels are only due to contaminants.

Both conventional and future hydrocarbon fuels are shown in Table 2-4. California RFG3 is blended with ethanol to meet oxygenate, benzene, vapor pressure, and other requirements. Ultra low sulfur diesel (ULSD) contains 10 ppm sulfur which is achieved through additional hydrotreating. The hydrotreating results in a higher H/C ratio, which also affects the heating value and density.

Table 2-4. Fuel Properties — Metric Units

Fuel[a]	H/C	MW (g/mole)	Density [b] (kg/m³)	RVP (kPa)	HHV[a] (MJ/kg)	LHV[a] (MJ/kg)	HH[a]V (MJ/L)	LHV[a] (MJ/L)	Carbon Content		
									Mass Fraction	Energy Specific[c]	
										(gC/MJ)	(gCO_2/MJ)
Gasoline[d]	2.02	92.0	719	58	48.4	44.7	34.8	32.1	85.5%	19.1	70.2
CARFG3[d]	2.07	89.7	722	47	47.2	43.5	34.1	31.4	84.2%	19.3	70.9
CARBOB[d]	2.02	96.0	719	47	47.9	44.2	34.5	31.8	85.5%	19.3	70.9
Diesel, No. 2	1.71	170.2	863	0.15	46.5	42.6	40.2	36.7	87.5%	20.5	75.3
ULSD[e]	1.80	154.8	830	0.15	44.7	42.8	37.1	35.5	86.9%	20.3	74.4
Residual oil	1.60	177.1	971	0	45.0	42.0	43.7	40.8	88.2%	21.0	77.0
LPG	2.63	44.0	504	930[f]	50.2	46.0	25.3	23.2	81.9%	17.8	65.3
Propane	2.67	44.1	510	930[f]	50.4	46.4	25.7	23.7	81.7%	17.6	64.6
Natural Gas	3.85	16.6	0.81	—	52.3	47.2	0.042	0.038	74.1%	15.7	57.6
LNG	3.89	16.3	420	414[f]	53.8	48.5	22.6	20.3	75.4%	16.0	58.5
Methane	4.00	16.0	0.78	—	55.6	50.0	0.043	0.039	74.9%	15.0	54.9
Methanol	4.00	32.0	792	32	22.8	20.0	18.1	15.8	37.5%	18.7	68.7
DME, fuel grade	3.16	42.28	740	900	—	26.75	—	—	49.1%	18.4	67.4
FT, Diesel Oil	2.14	127.5	780	0.15	47.2	43.9	36.8	34.2	84.8%	19.3	70.6
FT, Naphtha	2.26	100.0	703	0.15	47.8	44.5	33.6	31.3	84.1%	18.9	69.3
Ethanol	3.00	46.1	785	15.9	29.8	27.0	23.4	21.2	52.1%	19.3	70.8
Biodiesel BD100	1.88	292.2	884	0.07	40.5	36.9	35.8	32.6	78.0%	21.1	77.5
LH2	—	2.0	69	160[f]	142.1	119.9	9.8	8.2	0.0%	0.0	0.0
Hydrogen	—	2.0	0.10	—	142.1	119.9	0.014	0.012	0.0%	0.0	0.0

[a] Heating values are for liquids except for natural gas, methane, and hydrogen.

[b] Density for natural gas, methane, and hydrogen are for gases at 1 atm, 25°C.

[c] Carbon per MJ, LHV basis. Includes total carbon in fuel. Actual CO_2 from combustion will be lower due to CO, HC, and CH_4 emissions and vehicle evaporative losses.

[d] Gasoline without oxygenate, available in California before 1990. RFG3 based on meeting 2% oxygen by mass with 5.7wt% ethanol (5.3vol%). CARBOB (California Reformulated Gasoline Blendstocks for Oxygenate Blending) is the blending component for RFG3.

[e] Ultra low sulfur diesel, 10 ppm sulfur.

[f] Represents storage pressure. For LPG, pressure at 25°C. For LNG and LH2, maximum storage pressures. Note the lower estimated storage pressure for LH2. At elevated pressure, equilibrium storage temperature would be higher and density would decrease, which would be impractical for most storage systems.

Sources: DOE, Glassman, Heywood, Kanury, North American, Schmidt, Unnasch 1996, Weast 1979. GREET 1.7, biodiesel.org

LPG is a mixture of various hydrocarbons primarily propane and butane, which are gases at atmospheric pressure and temperature but are stored as liquids at elevated pressure. Propane is the major constituent in LPG. LPG is a by-product of both natural gas processing and oil refining. In the United States, approximately 30 percent of the LPG is produced from oil refining and 70 percent is from natural gas processing. In California, 90 percent of LPG production comes from refineries and the remainder from natural gas processing plants. LPG from oil refineries contains propene, while LPG

from natural gas does not. The propene content of LPG is limited to 5 percent for vehicle use (the HD-5 specification).

Natural gas contains primarily methane, some higher saturated hydrocarbons, nitrogen, and CO_2. GRI and others have reported data on pipeline gas compositions (Liss 1991). LNG is produced from the liquefaction of natural gas and is stored at -260°C. Liquefaction removes almost all of the nitrogen, CO_2, and higher hydrocarbons, except for ethane.

Fischer Tropsch synthesis produces a variety of products ranging in density from naphtha to diesel to waxes. Low temperature FT products are pure straight chain hydrocarbons.

Several plant oils are the primary component of biodiesel. Soybean oil was the basis for the analysis in this study. A reaction with methanol produces an ester, which stabilizes the vegetable oil. Biodiesel is often blended with conventional diesel with the aim to reduce emissions.

Fuel properties have an important impact on fuel cycle and vehicle emissions. The composition of fuels determines their combustion properties including heating value. The elemental composition relates to CO_2 and SO_2 emissions. Almost all of the carbon in fuel is converted to CO_2, and similarly almost all sulfur in fuel is converted to SO_2. The hydrogen content of fuels relates directly to the amount of water vapor produced during combustion. The difference between higher and lower heating values is the heat of vaporization of water vapor produced during combustion. For many hydrocarbons a relationship occurs between hydrogen to carbon ratio (H/C) and density, as well as between H/C and heating value (Schmidt 1969, North American 1965, Unnasch 1996).

Fuel density directly affects the cargo capacity of delivery trucks. Similarly, the energy required for tanker ship transport depends on the weight of the fuel. The fuel density also relates the heating value per unit mass to the heating value per unit volume. The density of gaseous fuels in Table 2-4 is shown at atmospheric pressure. Since gaseous fuels can be stored at various pressure and temperatures, the values are not shown for vehicle storage conditions.

The lower heating value (LHV) provides a basis for comparing fuel economy among fuel choices. The comparison of vehicle fuel efficiency on an LHV basis for internal combustion engines and fuel cells is industry practice. Both higher and lower heating value comparisons are typically used in industry for stationary fuel combustion. For the fuel cycle analysis, all of the efficiency inputs and calculations are performed on an LHV basis. Any HHV-based data was converted to an LHV basis.

Vapor pressure and fuel molecular weights are also shown in Table 2-4. These properties are important in determining hydrocarbon emissions from storage and transport of these liquid fuels. The vapor density depends on vapor molecular weight and vapor pressure. ARB completed an extensive evaluation of the composition of vapors from vehicle fuel tanks and storage containers. Several gasoline compositions

and alcohol blends were tested. These data were supplemented with model calculations and reported in an ARB study (Unnasch 1996). The vapor pressure of liquid fuels affects their evaporative emissions, with the density of fuel vapors being proportional to the molecular weight of the vapors and vapor pressure.[8] For liquefied gases, the storage pressure affects the vapor mass from fueling nozzle disconnects and venting.

Table 2-5 shows the most widely used fuel properties in English units. This tabulation facilitates comparison with other studies and is helpful for calculation checks. Most of the fuel properties agree closely with those reported in the GREET 1.7 model (Wang 2007) and the values that differ have little impact on the outcome of the analysis.[9]

Several fuels analyzed in this study are blends. The composition of the blended fuels is shown in Table 2-6 on a volumetric basis, which is typically used to describe fuel composition, particularly of alternative fuel blends. RFG3 requires 2 percent oxygen, which corresponds to 5.7 percent ethanol on a mass basis or 5.3 percent for volumetric blending. Fuel cycle energy and GHG calculations track the steps on an energy basis. The energy-weighted fraction of the blended fuels is shown in Table 2-7. The lower heating value, which is typically used to compare the energy consumption for vehicles, is shown for the blended fuels.

[8] For multi-component liquid fuels, the composition of fuel vapors differs from the liquid. In addition, the composition differs with temperature.

[9] One notable exception is the carbon content of FTD fuel. The carbon content of FTD shown in Tables 2-4 and 2-5 was compared with various published values and reviewed with FTD developers. From a practical viewpoint, the carbon content of FTD fuels does not impact the final WTW fuel cycle analysis on a g/mi basis. CO_2 emissions from the fuel production process are calculated by a carbon balance method combining the efficiency of fuel production with the carbon content of the feedstock and fuel.

Table 2-5. Fuel Properties — English Units

Fuel[a]	HHV[a] (Btu/lb)	LHV[a] (Btu/lb)	HHV[a] (Btu/gal)	LHV[a] (Btu/gal)	Density[b] (lb/gal)	RVP (psi)	CO_2 Factor (lb/MMBtu)	
							(HHV)	(LHV)
Gasoline	20,800	19,200	124,790	115,190	6.00	8.4	150.7	163.2
CARFG3	20,400	18,820	122,960	113,430	6.03	6.8	151.3	164.1
CARBOB	20,600	19,000	123,600	114,000	6.00	6.8	152.2	165.0
Diesel, No. 2	20,010	18,300	144,060	131,750	7.20	0.02	160.3	175.3
ULSD[c]	19,210	18,400	133,080	127,460	6.93	0.02	165.8	173.1
Residual oil	19,350	18,060	156,720	146,270	8.10	0.03	167.1	179.0
LPG	21,570	19,770	90,800	83,230	4.21	135	139.3	152.0
Propane	21,669	19,950	92,230	84,910	4.26	135	138.3	150.2
Natural Gas	22,500	20,300	152	137	4.58[b]	—	120.8	133.9
LNG	23,100	20,300	80,850	71,050	3.50	60	119.7	136.2
Methane	23,900	21,500	156	140	4.31[b]	—	114.9	127.7
Methanol	9,800	8,600	64,770	56,840	6.61	4.6	140.2	159.8
DME, fuel grade	—	—	—	—	—	135	—	—
FT Diesel Oil	20,638	18,918	134,340	123,140	6.51	0.02	150.6	164.3
FT Naphtha	20,853	19,133	122,340	112,250	5.87	0.02	147.8	161.1
Ethanol	12,800	11,600	83,850	75,990	6.55	2.3	149.4	164.8
Biodiesel BD100	17,420	15,870	128,520	117,090	7.38	0.01	164.2	180.2
LH2	61,100	51,550	35,040	29,570	0.57	23	0.0	0.0
Hydrogen	61,100	51,550	50.1	42.3	0.54[b]	—	0.0	0.0

[a] Heating values are for liquids except for natural gas, methane, and hydrogen.
[b] Density for natural gas, methane, and hydrogen are in lb/100 scf. Reference temperature = 60°F.
[c] Ultra low sulfur diesel, 10 ppm sulfur.

Fuelprop.xls

Table 2-6. Fuel Mixtures for Volumetric Blending

Component Blend (Vol %)	CA RFG			E10	E25	E85	BD20	FTD33
	E0	E5.7	E10					
CARBOB	100%	94.7%	90%	90%	75%	15%	—	—
E100[a]	0	5.3%	10%	10%	25%	85%	—	—
Biodiesel	—	—	—	—	—	—	20%	
FTD	—	—	—	—	—	—	—	33%
Diesel	—	—	—	—	—	—	80%	67%

[a]Contains 5% gasoline denaturant.

Table 2-7. Energy Fraction for Calculating GHG and Energy (LHV Basis)

Component Blend (J/J)[a]	RFG3	E10	E25	E85	BD20	FTD33
CARBOB	96.4%	93.1%	78%	20.9%	—	—
E100	3.6%	6.9%	22%	79.1%	—	—
Biodiesel	—	—		—	19.3%	—
FTD	—	—		—	—	32.3%
Diesel	—	—		—	80.7%	67.7%
Blend LHV (MJ/L)	31.4	30.7	27	22.8	35.1	35.0

[a] Indicates proportion of each blending component as a ratio of mass fraction x LHV (g/MJ) divided by total mass fraction x LHV (g/MJ)

emissions.xls

SECTION 3. FUEL PRODUCTION PROCESS

This section discusses the energy consumption and emissions associated with production of the fuels included in the present analysis. The following sections discuss energy consumption and emissions from production of petroleum, natural gas, LNG, synthetic fuels, hydrogen, coal, biomass, ethanol, biodiesel, and electricity.

3.1 Petroleum Fuels

Although a significant fraction of crude oil for California refineries is produced in the state, California production is estimated to remain constant for any change in diesel or gasoline consumption[10]. Furthermore, with limited refinery capacity, additional refined product may be imported to California, or refinery operations may be modified. As a result, increased or decreased diesel or gasoline use does not lead to a change in local emissions from California oil production and refining. With extensive analysis of the supply/demand elasticity of future petroleum products in California, the projections of oil industry experts and the consensus of energy industry stakeholders has been that gasoline would be imported to California on the margin (Unnasch 1996, Unnasch 2001, Jackson 2001).

As a first order estimate, local emissions from refineries are independent of diesel, gasoline, or LPG demand[11]. If gasoline demand were reduced, it is likely that imports of finished gasoline would simply be reduced while operations remain constant at local refineries. Increased diesel demand at the expense of gasoline sales could be met by increasing the mix of diesel products that are importing to California or by adjusting refinery operations to produce more diesel. Analyzing the effect of changing the shift in refinery products ideally would be accomplished by a linear programming (LP) model that optimizes all of the refinery streams for an optimal economic and fuel specification output.

A variety of petroleum products are produced from crude oil. Refineries produce gasoline, diesel, kerosene/jet fuel, LPG, residual oil, asphalt, and other products. A variety of co-feedstocks, including natural gas, electricity, hydrocarbons from other refineries, and MTBE and other oxygenates, complicates the analysis of fuel-cycle emissions. Different crude oil feedstocks, gasoline specifications, and product mixes also complicates the picture for refineries.

Crude oil is refined into a variety of products including primarily gasoline or CARBOB, kerosene, diesel, LPG, residual oil, waxes, sulfur, and coke. The crude oil production

[10] California oil production responds to world oil prices, which are affected by California demand. California production is either at full capacity when prices are above a threshold of roughly $15/bbl, or it tapers of depending on each well's parameters. This report does not attempt to analyze the effect of changes in California production.

[11] The analysis in this report is based on imported gasoline and diesel. However, some shift in refinery mix might also be contemplated as a way of producing diesel.

and processing steps apply to all of the petroleum products because the feedstock is the same. Various refinery units produce a mix of products. Energy consumption for each refinery unit was allocated to the products to determine the efficiency of each fuel production.

In addition to gasoline, distillate fuel, and LPG, oil refineries produce products such as residual oil, coke, sulfur, and asphalt[12]. The fate of the byproducts, especially residual oil can effect the GHG emissions associated with fuel production (gasoline, diesel, and LPG). Residual oil is used as fuel for marine vessels and power plants. Additional residual oil supply would have an impact on prices and demand for marine vessel fuel, but much of the additional fuel could be used for power plant fuel where it would displace coal or natural gas. Displacing coal-based power with residual oil reduces GHG emissions, while displacing natural gas based power increases GHG emissions. Residual oil might also be attributed to displacing nuclear or other non-fossil power where the GHG emissions from residual oil would be higher.

3.1.1 Petroleum Production and Refining Outside of California

Refinery Energy Inputs

The output from a refinery model was used to determine the energy inputs required to produce different gasoline, diesel, and other petroleum products (MathPro 1998). Refinery combustion emissions were allocated to gasoline, diesel, and LPG in proportion to the energy requirements for refinery units. An energy allocation model was also used to determine changes in refinery energy needed to produce diesel and LPG. This approach results in the average emissions from refineries.

Emissions from refinery units in the model were allocated to the petroleum products produced by each refinery unit. For example, all of the combustion emissions associated with the diesel hydrodesulfurization unit are attributed to diesel fuel. Table 3-1 shows the allocation of crude oil energy input and imported energy to diesel, ULSD, and LPG.

Petroleum fuels analyzed in this study include CARBOB, the blending component for RFG3, ULSD, and LPG. Energy inputs and emissions associated with residual oil production were also analyzed, as residual oil is used for marine vessel transport. Residual oil is also a byproduct of refining and the fate of residual oil is also considered.

[12] Not all refineries produce asphalt but it is an interesting product as it sequesters carbon in a form that is not combusted.

Table 3-1. Allocation of Product Output and Energy Consumption for Refineries: Mathpro Results

Product	Crude Oil (gal/gal)	Natural Gas (100 scf/gal)	Electric Power (kWh/gal)	Energy[a] (Btu/gal)
RFG[b]	0.94	0.18	0.27	157,000
Diesel	1.04	0.09	0.13	163,000
ULSD	1.04	0.12	0.25	178,500
LPG	0.71	0.05	0.05	111,400

[a] Energy inputs based on allocation of energy inputs for MathPro refinery model. 103,000 Btu/100 scf natural gas and 9,000 Btu/kWh power.
[b] Includes 5.7% ethanol.

Source: A. D. Little

Effect of Ethanol Blends

The allocation of refinery energy consumption to different products determines their associated emissions. The refinery energy is allocated to the production of gasoline, or in the case of California, CARBOB. An estimate of the refinery operations associated with all of the refinery products is segregated by product slate. Energy inputs that are only associated with gasoline production (like alkylation) are assigned to gasoline, while crude oil distillation is assigned to all refinery products. The energy input for refining is based on a refinery modeling study performed by MathPro (MathPro1999). The energy inputs for all of the refinery units in this study were segregated by product stream and output. This breakdown allows for the calculation that reflects the refining efficiency for diesel alone.

The energy inputs for CARBOB production are assumed to correspond to a refinery efficiency of 84.5 percent. An allocation of energy inputs based on the MathPro study result in a refinery efficiency of 83.9 percent. The baseline GREET estimate for California RFG is 85.5 percent. Note that the exercise of attributing energy inputs to refinery operations is not straightforward and requires some interpretation of what energy inputs should be assigned to gasoline. More detailed discussions of refinery energy allocation are discussed in studies by Acurex, Argonne National Laboratory, and NREL (Unnasch 1996, Wang 1999, Kadam 1999). Other energy allocation schemes can result in a lower allocation of energy to gasoline production (EC 2003).

The principal assumptions affecting the WTT_f energy and emission inputs are shown in Table 3-2.

Table 3-2. Energy and GHG Assumptions for Fuels Imported to California

Parameter	Value
Petroleum Processes	
Petroleum Recovery Efficiency	97.7%
Refining Assumptions	
CARBOB refining efficiency	84.5%
Supplemental Hydrogen	150 scf/bbl
Sulfur content	10 ppm
Oxygenate, Ethanol	5.7 wt%
Diesel, 10 ppm S refining efficiency	88.5%
Supplemental Hydrogen	100 scf/bbl
LPG refining efficiency	93.5%
Petroleum coke refining efficiency	95.0%

3.1.2 California Petroleum Production and Refining

As mentioned in Section 2, this WTT analysis is a marginal analysis. Because California refineries are operating at capacity, the marginal gallons of finished product are assumed to be imported. Even though California crude oil production and refining emissions are not used in this analysis, they are still of interest and are documented here.

California's crude oil production has been steadily declining since its peak in the late 1980s. Table 3-3 provides 2005 emissions from oil and gas production operations within California. Most of the emissions are from combustion equipment and fugitive emissions of ROG. The emissions are shown in tons/day and tons/gallon of crude oil processed.

Table 3-3. Criteria Pollutants Emissions from Oil & Gas Production

	2005 California Statewide Emissions, tons/day					
	ROG	CO	NOx	SOx	PM_{10}	$PM_{2.5}$
Oil & Gas Production						
Combustion	14.9	21.3	22.1	1.8	1.4	1.4
Tank Losses	0.8	0.0	0.0	0.0	0.0	0.0
Flares	0.1	0.8	0.4	0.3	0.1	0.1
Fugitives	21.3	0.5	2.2	0.0	0.0	0.0
Other	21.9	0.1	0.0	0.0	0.0	0.0
Production Totals						
tons/day	59.1	22.6	24.8	2.1	1.4	1.5
gm/gal crude	0.7	0.3	0.3	0.0	0.0	0.0

California's petroleum refining industry converts domestic and imported crude oil into more than 2,500 refined products, including LPG, gasoline, kerosene, aviation fuel, diesel fuel, fuel oils, lubricating oils, and other feedstocks for the petroleum industry. In the past 20 years, approximately 40 percent of its refineries were retired due to changing fuel specifications and the associated capital investment required. In 2004, there were 21 petroleum refineries operating in California – the larger refineries and their locations are provided in Table 3-4. Seven of these refineries are located in the South Coast Air Basin, five are located in the Bay Area, one on the Central Coast, and one in the San Joaquin Valley. All are located in ozone nonattainment areas.

Table 3-4. Major Refineries Operating in California

Company	City
British Petroleum West Coast	Carson
Chevron	El Segundo
Chevron	Richmond
ConocoPhillips	Wilmington
ConocoPhillips	Carson
ConocoPhillips	Rodeo
ConocoPhillips	Arroyo Grande
ExxonMobil	Torrance
Shell	Bakersfield
Shell	Wilmington
Shell	Martinez
Tesoro	Martinez
Ultramar	Wilmington
Valero	Benicia

Despite the reduction in number of refineries, the remaining refineries have managed to increase their capacity through debottlenecking efforts such that crude oil input levels are within approximately 7 percent of their high in 1989 (~712 million bbls). Figure 3-1 shows crude oil input levels and total gasoline and distillate production in California over the past 10 years. Crude input and gasoline/diesel output values for 2005 are indicated on the plot. California refineries essentially operate at maximum capacity factor and will continue to do so into the foreseeable future. While no new refineries will be built in California, further capacity increases at existing refineries are anticipated.[13]

[13] Shell Bakersfield may double its diesel and gasoline output and Paramount Petroleum will produce 7,500 and 8,500 bbl/day of RFG and diesel, respectively. "Petroleum Infrastructure Environmental Performance Report", June 2005, CEC-700-2005-012.

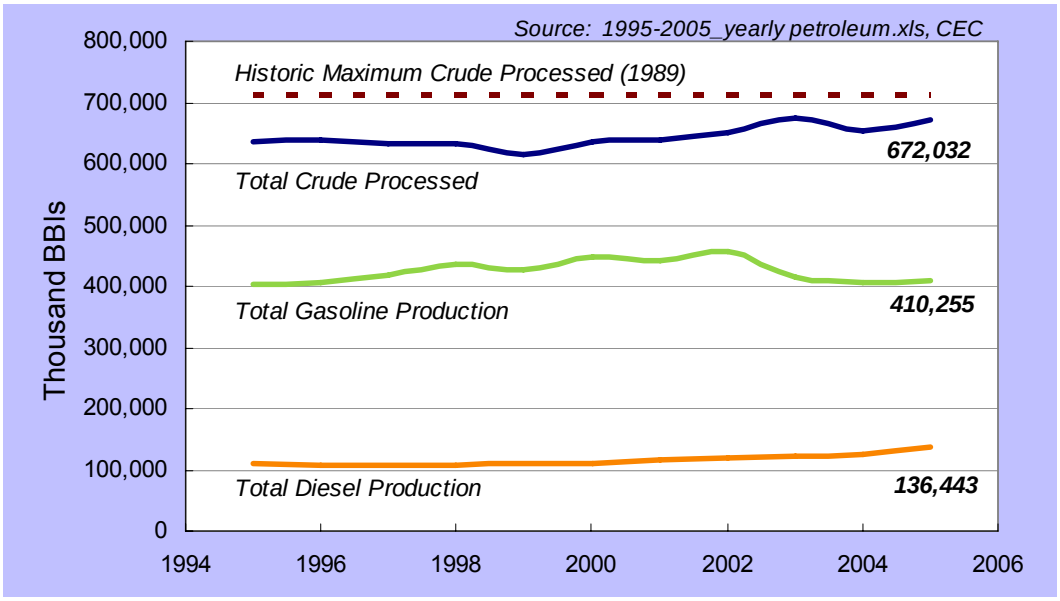

Figure 3-1. Historic Levels of Crude Input and Diesel/ Gasoline Output from California Refineries

Criteria pollutant emissions from California refineries were obtained from CARB's Emission Almanac for 2004 and are shown in Table 3-5. As can be seen, the bulk of the emissions come from combustion sources with the exception of ROG and CO. A significant portion of the ROG inventory comes from "other" sources. The main ROG sources in the "other" category are wastewater treatment and cooling tower emissions. Flares account for approximately 40 percent of the total CO emissions. The total refinery emissions are shown in tons/day currency as well as grams per gallon of crude processed in California.

Table 3-5. 2005 California Petroleum Refining Criteria Pollutant Emissions

	2005 California Statewide Emissions, tons/day					
	ROG	CO	NOx	SOx	PM_{10}	$PM_{2.5}$
Petroleum Refining						
Combustion	2.0	19.1	24.8	12.2	3.3	3.2
Tank Losses	2.7	0.0	0.0	0.0	0.5	0.4
Flares	1.4	14.3	1.0	2.0	0.1	0.1
Fugitives	3.2	0.0	0.0	0.0	0.0	0.0
Other	8.4	6.6	5.0	43.7	1.4	1.2
Totals						
tons/day	17.7	39.9	30.7	57.9	5.3	4.9
gm/gal crude	0.2	0.5	0.4	0.7	0.1	0.1

Source: CARB Emission Almanac

To estimate air toxic emissions associated with petroleum refinery operations in California, the EPA Toxic Release Inventory (TRI) Database for 2004 was utilized. Table 3-6 provides the total onsite fugitive and point source air toxic contaminant emissions from refineries in California in 2004.

Table 3-6. Air Toxic Emissions from California Refineries (2004)

Air Toxic Contaminant	2004 Emissions (lbs)	Air Toxic Contaminant	2004 Emissions (lbs)
1,2,4-Trimethylbenzene	22,262	Hydrogen Fluoride	1,042
1,2-Dibromomethane	3	Lead	9
1,3-Butadiene	3,543	Lead Compounds	1,007
2,4-Dimetholphenol	516	Manganese Compounds	289
Ammonia	5,003,163	Mercury	1
Anthracene	4	Mercury Compounds	450
Benzene	43,907	Methanol	444,881
Benzo(g,h,i)perylene	5	Methyl Tert-Butyl Ether	16,198
Carbon Disulfide	3,213	Molybdenum Trioxide	356
Carbonyl Sulfide	46,742	N-Hexane	83,226
Chromium Compounds*	151	N-Methyl-2-Pyrrolidine	136,932
Cobalt Compounds	38	Naphthalene	8,247
Copper Compounds	1,174	Nickel Compounds	2,994
Cresol (Mixed Isomers)	440	Phenanthrene	717
Cumene	1,725	Phenol	4,107
Cyanide Compounds	54	Polycyclic Aromatic Compounds	164
Cyclohexane	36,027	Propylene	161,088
Diethanolamine	31,420	Silver Compounds	11,005
Dioxin and Dioxin-Like Compounds	1.4	Styrene	729
Ethylbenzene	32,582	Sulfuric Acid Aerosols	646,333
Ethylene	48,641	Tetracholoroethylene	5,072
Ethylene Glycol	257	Toluene	127,179
Formaldehyde	24,647	Vanadium Compounds	477
Hydrocholoric Acid Aerosols	189,256	Xylene	125,768
Hydrogen Cyanide	1,843	Zinc Compounds	20,978

* TRI database does not indicate whether this is hexavalent chromium.

Although this is an impressive list of toxic air contaminants, only the contaminants that pose a cancer risk were considered in this study. The refinery air toxics that pose a cancer risk are shown in Table 3-7. The table provides the inhalation unit cancer risk and annual California refinery emissions. The unit cancer risk is also shown normalized by the formaldehyde cancer risk to indicate cancer potency relative to formaldehyde. Annual emissions have also been divided by the annual gallons of crude oil refined in the state. The normalized risk factor is multiplied by the per gallon emission level to provide a qualitative comparison of cancer threat. As can be seen, the toxic compounds from refineries of real concern are: benzene, 1,3-Butadiene, formaldehyde, nickel, dioxins, polycyclic aromatic hydrocarbons, and naphthalene.

Refined petroleum products are generally transported by pipeline from the refineries to the bulk terminals for distribution. Air toxic emissions from bulk terminals are due to evaporation. There are approximately 38 main bulk terminals in California. The on-site fugitive and point source air toxic emissions from these terminals, as reported to the TRI database in 2004, are provided in Table 3-8.

Table 3-7. Refinery Air Toxic Emissions that Pose a Cancer Risk

Toxic Compound	Inhalation Unit Cancer Risk $(\mu g/m^3)^{-1}$	Unit Risk Normalized to Formaldehyde	Refinery Emissions		lb/million gal * Normalized Risk Factor
			lb/yr	lb/million gals Crude Oil	
Benzene	2.90E-05	5	43,907	1.60	8
1,3-Butadiene	1.70E-04	28	3,543	0.13	4
Chromium Compounds*	1.50E-01	25,000	151	0.01	137
Ethylene Dibromide	7.10E-05	12	3	0.00	0
Formaldehyde	6.00E-06	1	24,647	0.90	1
Lead & Lead Compounds	1.20E-05	2	1,016	0.04	0
Methyl Tertiary-Butyl Ether	2.60E-07	0	16,198	0.59	0
Nickel	2.60E-04	43	2,994	0.11	5
Tetrachloroethylene	5.90E-06	1	5,072	0.18	0
Dioxins (PCDD)	3.80E+01	6,333,333	1.417284	0.00	327
PAH	1.10E-03	183	164	0.01	1
Napthalene	3.40E-05	6	8,247	0.30	2

* Emissions are "unspecified chromium compounds". Unit risk factor is for hexavalent chromium, barium chromate, calcium chromate, lead chromate, sodium dichromate, strontium chromate, chromium trioxide. Since exact chromium compounds are unknown, actual risk is unclear.

Table 3-8. Air Toxic Emissions from California Bulk Terminals (2004)

Air Toxic Contaminant	2004 Emissions (lbs)	Air Toxic Contaminant	2004 Emissions (lbs)
1,2,4-Trimethylbenzene	4,565	Methanol	750
1,3-Butadiene	10	Methyl Isobutyl Ketone	1,000
Benzene	9,157	N-Hexane	69,590
Biphenyl	36	Naphthalene	1,491
Glycol Ethers	500	Nickel	2
Chlorine	4	Phenanthrene	104
Cresol	3	Phenol	95
Cumene	306	Polycyclic Aromatic Compounds	328
Cyclohexane	7,840	Propylene	1,713
Ethylbenzene	4,789	Sec-Butyl Alcohol	500
Ethylene Glycol	255	Styrene	12
Lead	206	Toluene	21,951
Mercury	2	Xylenes	16,598

3.1.3 LPG from Petroleum

Because LPG from overseas refineries is not likely to be imported to California, the fuel cycle for LPG represents imported crude oil with production in California refineries. This production pathway is different than that for gasoline or diesel; however, it is consistent with the modest amounts of LPG used in a future petroleum displacement strategy. In addition, LPG could also be available from natural gas sources. At present, normally some petro-LPG comes from outside California, typically during the winter when the state is a net importer. Directly importing LPG from petroleum sources to California was not analyzed.

An important consideration is the fuel that the refinery LPG displaces. The analysis presented for LPG is a first order approximation since it appears unlikely that California refineries will increase their LPG production to meet vehicle demand. Refinery LPG could displace LPG from natural gas. Alternatively, natural gas fuel could displace LPG sold from refineries.

Important factors that affect LPG fuel cycle emissions include the mode for local transportation and the extent of vapor control during storage and vehicle tank fills. Improved vapor controls were assumed for LPG transfers.

3.2 Natural Gas Fuels

Many of the finished fuels considered in this study are produced from natural gas. These include LPG, CNG, LNG, methanol, DME, GTL, hydrogen, and electricity. This section discusses the energy inputs for extraction and processing of natural gas. Because the WTT portion of the LPG and CNG pathways is minimally removed from the natural gas production process, a discussion of these finished fuels is included in sections 3.2.2 and 3.2.3. The other finished fuels that utilize natural gas as a feedstock are simply listed in Section 3.2.4 with a reference to the Section in which they are discussed. Section 3.2.5 provides a description of the landfill gas (LFG) production process.

3.2.1 Natural Gas Production

Natural gas production can be divided into the following parts:

- Exploration and production
- Field gathering and pipeline transport to processing plant
- Natural gas processing
- Pipeline transport to storage/distribution
- Storage
- Pipeline distribution to end-users

California currently produces approximately 15 percent of the natural gas consumed in the state. In-state production peaked in 1985 at approximately 7 trillion cubic feet and subsequently reached a historic low of 290 billion cubic feet in 1996. Production in recent years has been in the 350 billion cubic feet range. While peak California production levels are not expected to return, in-state production is an on-going activity with 1,200 producing wells. Most (75 percent) of the in-state natural gas comes from Southern California and is associated gas (comes from a crude oil well), while the remainder is non-associated gas produced in Northern California from large gas fields.

Before the raw gas is sent to a nearby processing plant through gathering pipelines, the oil and condensates (including water) are removed at the wellhead. At the processing plant, the gas is transformed into pipeline quality natural gas. The process includes: dehydration (removing water vapor in solution), separation of natural gas liquids, removal of sulfur, and venting of carbon dioxide. LPG, discussed in Section 3.2.2 is derived from the recovered natural gas liquids.

From the processing plant, the gas enters the transmission pipeline system and either flows to storage fields or through distribution pipelines to the end user. Because only 15 percent of the natural gas consumed in California is produced in-state, the dominant natural gas activities in California are transmission, storage and distribution to end users.

Most of the imported natural gas is delivered to the PG&E and SoCalGas intrastate transmission pipeline system, commonly referred to as the "backbone pipeline system." PG&E and SoCalGas are not allowed to own natural gas production facilities – they are required by law to purchase natural gas from producers and marketers. From there, it is either delivered directly to large non-core customers, into the local transmission and distribution pipeline systems, or to storage fields. Some of the imported natural gas goes directly to large consumers, bypassing the backbone system.

The natural gas transmission and distribution loss factors have a large impact on WTT greenhouse gas emissions. A 1991 study[14] of unaccounted for (UAF) natural gas indicated that the total UAF losses are 0.94 percent and 1.61 percent for SoCalGas and PG&E, respectively. Of this, a large percentage is attributed to measurement error. The data indicate that leakage in the transmission and distribution systems are 0.083 percent for SoCalGas and 0.078 percent for PG&E. In this analysis we therefore assume 0.08 percent T&D loss for North American natural gas. The GREET default value is used for remote natural gas loss. Table 3-9 presents the key assumptions for natural production used in this analysis.

Table 3-9. Summary of Assumptions for Natural Gas Based Fuels

Parameter	Value
Natural Gas Processing, Overseas	
Natural Gas Recovery	97.2%
Natural Gas Processing	97.2%
CO_2 Venting	1,237 g/MMBtu
NG Recovery Losses	0.35%
NG Processing Losses	0.15%
NG Transmission Losses	0.49%
Natural Gas Processing, North America	
Natural Gas Recovery	97.2%
Natural Gas Processing	97.2%
CO_2 Venting	1,237 g/MMBtu
LPG production	96.5%
NG Transmission & Distribution Losses, U.S.	0.08%

[14] "A study of the 1991 Unaccounted for Gas Volume at the Southern California Gas Company" GRI-93/0115.1

3.2.2 Liquid Petroleum Gas (LPG)

LPG is derived from the natural gas liquids (NGLs) that are separated out in the natural gas production process. Once the NGLs are separated out, the pentanes are distilled off leaving a mixture of propanes and butanes. This mixture is pressurized and sold as LPG.

3.2.3 Compressed Natural Gas (CNG)

As mentioned above, the WTT pathway for CNG is a simple extension of the natural gas production process. In most CNG fueling facilities, electric motors power compressors, which compress pipeline gas. Several fuel storage and dispensing strategies are used. These approaches differ with the type of vehicle application, fuel throughput, and other requirements. The infrastructure for the extraction, processing, and distribution of natural gas is available for most potential CNG users where a compression facility might be installed. Please refer to Section 5.2.5 in this report for CNG WTT emission factors.

3.2.4 Other Natural Gas Based Pathways

In addition to LPG and CNG, there are six other finished fuels that utilize natural gas as a feedstock. These fuels and the sections in which they are discussed as follows:

Section 3.3 – LNG
Section 3.4 – Synthetic Fuels (Methanol, DME and GTL)
Section 3.5 – Hydrogen
Section 3.10 – Electricity

3.2.5 Landfill Gas Production

Landfill gas is produced when organic material decomposes in a landfill. The organic material converts to methane and CO_2 through biological decomposition. Traces of sulfur containing compounds and chlorinated compounds occur in landfill gas. Air can also be entrained in landfill gas. Most large landfills in California are required to collect and combust their landfill gas. A portion of the landfills utilize the LFG in engines and combustion turbines to produce electricity. Many landfills simply flare the gas. Landfill gas and digester gas represent limited resources for fuel production. Landfill gas is a relatively cost effective feedstock although it represents a small fraction of the total potential synfuels production market.

3.3 Liquefied Natural Gas (LNG)

As demand for natural gas continues to increase, California can expect to begin importing LNG to supplement the traditional out-of-state supplies. The analysis of LNG from remote natural gas was based on fuel production overseas and transport to a

future marine terminal in California where it would be stored. The LNG would be re-gasified and transferred to the utility transmission pipeline system as needed.

An LNG terminal could also be built in Mexico where the fuel could be distributed by rail to Southern California. The California emission results would be similar to those for LNG from domestic natural gas. Since no clear plan exists for an LNG production facility, the analysis was based on a new LNG terminal in the California. While this scenario is remote, the comparison of emissions with domestic or North American LNG is more revealing than a scenario in which LNG is imported to Mexico and transported by rail to California. This is so because many of the local distribution steps would be the same as LNG from domestic natural gas.

LNG is produced from natural gas in liquefaction facilities. Natural gas is compressed and cooled and expanded in a multi-stage operation. Energy for compression in the United States is assumed to come from natural gas fired combustion turbines. Energy for compression in remote locations is assumed to come from electric motor driven compressors.

LNG is stored as a cryogenic liquid in insulated storage vessels. When stored near atmospheric pressure the LNG temperature is -260°C. While LNG tanks are thermally insulated, some heat enters the tank, which results in the boil-off of liquid to gas. The pressure in the tank increases and after several days, the gas must be vented. The gas can be vented to the atmosphere, recovered as CNG, or burned to generate heat.

Another source of losses is during transfer operations. LNG absorbs heat during transfer operations and some liquid is vaporized. Tank truck fuel transfer to a storage facility usually involves passing a small amount of LNG into a heat exchanger to generate gaseous natural gas. This process increases the pressure in the tank truck and forces the liquid into the receiver tank. After transferring the vapors, the gas in the truck is purged.

Table 3-10 shows the analysis assumptions for LNG production and distribution from U.S. domestic and remote natural gas.

Table 3-10. Summary of Assumptions for LNG Production

Parameter	Value
LNG Production, Overseas	
LNG Production Efficiency	91.0%
LNG Production Energy Consumption	2.4 kWh/100 scf
LNG Storage Losses	0.79%
LNG Power Source	Gas Turbine
LNG Production, North America	
LNG Production Efficiency	90.0%
LNG Production Energy Consumption	2.7 kWh/100 scf
LNG Storage Losses	0.49%
LNG Power Source	Electric motor

3.4 Synthetic Fuels

Synthetic fuels are liquid fuels made from coal, natural gas, or biomass. The synthetic fuels are generally utilized in vehicles with compression ignition (diesel) engines. This analysis considers three different synfuels: methanol, dimethyl ether (DME), and natural gas to liquid GTL or Fischer Tropsch Diesel). In this study it is assumed that all synfuels are produced from natural gas in Indonesia and shipped to California in marine tankers. Although there are other feedstocks of interest, such as coal, biomass and landfill gas, these are not considered commercially viable and are not analyzed here.

Important parameters affecting the WTT energy inputs and emissions for synthetic fuels include the efficiency of the conversion to syngas and emissions from the production facilities. The general approach for determining CO_2 and other pollutant emissions based on the feedstock conversion efficiency is described for methanol and not elaborated for other synthetic fuel production options. A wide range of fuel conversion efficiencies can be expected with different process configurations and uses of waste heat. The following paragraphs describe the synthesis gas production step and the synfuel production processes. The energy assumptions used in the GREET model for each synfuel are also provided.

3.4.1 Synthesis Gas Production

The first production step for each synfuel considered here is production of synthesis gas (syngas). Syngas is produced by steam reforming, partial oxidation or a combination of the two. The process is similar for methanol, DME, and FT diesel with differences in the final syngas conversion step. Natural gas is the simplest feedstock to convert to synthesis gas, mainly because it does not have to be converted from solid to gas phase. There are two main syngas production methods: steam reforming and partial oxidation.

Steam reforming of natural gas yields synthesis gas through the following chemical reaction:

$$CH_4 + H_2O \rightarrow CO + 3H_2$$

The product syngas is over 90 percent CO and H2 with traces of CO_2, CH_4, and light hydrocarbons.

The partial oxidation (POX) process produces a more stoichiometrically optimum synthesis gas. In this process, oxygen reacts with methane to produce two moles of hydrogen per mole of CO. Because oxygen is used rather than air, NO_x emissions are negligible. However an oxygen plant is required. The POX reactor is exothermic, so combining a POX plant with a steam reformer allows the exothermic heat from the POX unit to be used as energy for the steam reformer. Combined POX and steam reformer systems are referred to as autothermal reformers (ATRs).

3.4.2 Methanol Production

Methanol was first produced by heating wood in the absence of air (destructive distillation of wood) and distilling the products. In 1913, methanol was produced by passing CO and H_2 over an iron catalyst. Today, most of the methanol in the world is made from syngas produced by natural gas reforming. The methanol is produced by catalyzing the reaction of CO and CO_2 with H_2 as follows:

$$CO_2 + 3H_2 \rightarrow CH_3OH + H_2O$$

$$CO + 2H_2 \rightarrow CH_3OH$$

The catalyst is typically copper-nickel, and reactor conditions are 10 to 30 atm and 260°C. Crude methanol produced by the reactor is then refined into chemical grade methanol. The opportunity to produce fuel grade methanol rather than chemical grade methanol results in a process with less energy input required for the final distillation step. The fuel grade methanol would have about 2 percent water and traces of other alcohols. Process energy requirements for methanol production from natural gas are shown in Table 3-11.

When available, adding CO_2 can enhance the efficiency of methanol production. In remote locations, CO_2, which is about 5 percent of natural gas, is not removed from methanol feedstock (Allard 2000).

Table 3-11. Methanol Processing from Natural Gas

Process	Steam Reforming						Combined POX		
	Current			Advanced					
Fuel Processing									
Electricity use (kWh/gal)	-0.04			-0.09			0.25		
Energy ratio (%)	66.8			68.3			72.3		
NG[a] feed (Btu/gal) (100 scf/gal)	96,970 0.941			94,840 0.921			89,591 0.870		
Combustion (Btu/gal)	32,190			30,060			24,820		
Emission Source	**P.V.[b]**	**D.V.[c]**	**Reformer[d]**	**P.V.**	**D.V.**	**Reformer**	**P.V.**	**D.V.**	**Vent**
Emissions (g/gal)									
NO_x	0	0	2.94	0	0	1.36	0	0	0.28
CO	0	0	0.50	0	0	0.46	0	1	0.09
CO_2	5	1	1,135	1	1	1,023	1	1	737
CH_4	2.9	0	0.04	0.29	0	0.04	0.29	0	0.01
NMOG[e]	0.4	1.2	0.04	0.04	0.12	0.04	0.04	0.12	0.01

[a]NG = Natural gas.
[b]P.V. = Purge vent. Uncontrolled emissions.
[c]D.V. = Distillation vent. Uncontrolled emissions.
[d]Reformer emissions based on 0.216 NO_x/MMBtu. CO_2 from carbon balance.
[e]NMOG = Non-methane organic gases.

Source: Bechtel, Methanex 1998[15], Stratton, (S&T)[16]

Co-producing methanol and electricity provides an opportunity to balance the load from coal gasification systems. With this process, synthesis gas from the gasifier is passes over a methanol catalyst and the unreacted gas burned in a power plant. The Air Products liquid-phase methanol (LPMEOH) process is particularly suited for once-through-type operations since a high methanol conversion can be achieved in a single pass through the catalyst.

Methanol plants can be either importers or exporters of electricity. Power generation emissions associated with net electric power were included with the fuel production emissions. Electricity demand for the POX process includes required energy for an oxygen plant. The energy input for methanol production only affects global CO_2 emissions. The technology for methanol production facilities does not affect criteria pollutant or air toxic emissions in California because it is assumed that the methanol is produced in Indonesia and imported by tanker ship.

[15] Methanex 1998 Annual Report, 1998.

[16] Stratton, A., "Methanol Production from Natural Gas or Coal, December 1982.

3.4.3 DME Production

DME is produced from methanol and is considered an emerging fuel because it has high volatility (desired for cold starts) and high cetane number. Like other syngas based fuels, natural gas, coal bed methane, coal, and biomass are all potential feedstocks for DME production. Only the natural gas route is analyzed here in order to provide a basis for comparison with other natural gas based synthetic fuels.

Today's DME production is based on the indirect synthesis using the dehydration reaction of methanol. Ongoing research and development of DME production technology includes pilot plant projects in Japan (ref). Methanol dehydration heats and evaporates liquid methanol so that it is converted to DME in a dehydration reactor. The energy consumed in DME refining is very high at about 20% of the calorific value of the DME product, which makes the dehydration process a less desirable option for a fuel pathway.

Larger methanol synthesis plants are built at a scale of 2,000 tons/day and larger. A similar scale would be needed for direct conversion to DME. For large scale fuel production, the direct synthesis route would be similar to that for methanol. Several developers including Haldor Topsoe and Air Products are examining large scale DME processes. With direct conversion, natural gas is converted to CO and H_2 in a reformer and then processed in a synthesis reactor via the following reactions:

$$3CO + 3H_2 \rightarrow CH_3OCH_3 + CO_2 + 246.0 \text{ kJ/DME-moll}$$

$$2CO + 4H_2 \rightarrow CH_3OCH_3 + H_2O + 205.0 \text{ kJ/DME-mol}$$

A key difference between DME and methanol is that methanol is soluble in water. The additional energy required for water separation, combined with the thermodynamics of DME conversion result in a higher than predicted conversion efficiency for similar production technologies (EUCAR 2006).

3.4.4 Gas to Liquid (GTL)

The Fischer Tropsch (FT) process was originally developed in Germany in the 1920s to produce diesel from coal. Synthetic diesel and FT Diesel are categorized together as all approaches for producing synthetic diesel are conceptually similar and result in the same emissions impact in California. These synthetic diesels are referred to here as gas-to-liquid (GTL) fuels.

In recent years, developments in catalysts have allowed for the production of fuels in the diesel boiling point range. Major oil companies are supporting the development of GTL products since they own significant natural gas resources. Shell, BP, ExxonMobil, and ChevronTexaco have built or are planning to build production facilities. Exxon included an article describing its GTL technology in their 1998 publication for shareholders which illustrates their interest in the technology (Weeden, GTL Progress

2001). GTL fuels are attractive to oil companies because they improve the quality of diesel and make use of their natural gas resources.

Another benefit is that GTL fuels can be used in existing vehicles. The GTL fuels contain saturated hydrocarbons and no aromatics. GTL fuels will likely be blended to produce high cetane, low aromatic diesel before they are sold as pure clean fuel alternatives. The blending approach allows for a build up of production and bulk storage capacity.

The FT Process has three principal steps. The first, already discussed above, consists of converting natural gas into syngas. In the second step, a catalytic reactor (iron or cobalt) converts the syngas to a mixture of light hydrocarbons and heavier waxes. In the third step, hydrocarbons are converted to final products such as synthetic diesel fuel. Most developers are working on “low temperature” cobalt based catalysts. Higher temperature processes may produce a product that contains aromatics and was not considered in this study.

The efficiency of the GTL plant has the most significant impact on fuel cycle energy and GHG emissions. Efficiency depends on the plant configuration, which varies with each potential location and facility. Parameters such as production technology, feedstock costs, and construction costs affect the configuration of the plant. Efficiencies in the range of 61 to 63 percent (HHV) can be expected with Shell’s SMDS technology, where the synthesis gas is produced with partial oxidation and pure oxygen feed. Efficiencies closer to 55 percent (HHV) are achieved with air blown systems; however additional waste heat can be recovered and exported from the plant as steam. This study does not analyze air blown or small-scale FTD technologies.

Most fuel cycle studies show similar results for oxygen and air-blown systems because of credits associated with “steam export”. In principle, exported steam can be used in other industrial processes and potentially can displace fossil energy. Baseline GREET inputs assume that export steam displaces natural gas energy inputs. The fuel cycle GHG emissions with these assumptions are similar to those for higher efficiency GTL processes.

Understanding the configuration of synthetic fuels plants helps illustrate the fate of carbon and net CO_2, as well as combustion and compressor engine emissions. A synthetic fuels plant with a steam reformer and POX reactor is illustrated in Figure 3-2. A steam reformer converts steam and CH_4 to CO and hydrogen. An excess of hydrogen is produced with a steam reformer. The CO and hydrogen mixture flows over a catalyst where methanol or other fuels are produced. This reaction occurs at high pressure (30 atm), as thermodynamics do not favor synthesizing methanol or hydrocarbons at low pressure. The synthesis gas may be recirculated several times over the catalyst or flow over the catalyst in a single pass (once through process). Recirculating the synthesis gas results in a higher fuel conversion rate. The power required to compress and circulate the synthesis gas is a significant energy demand.

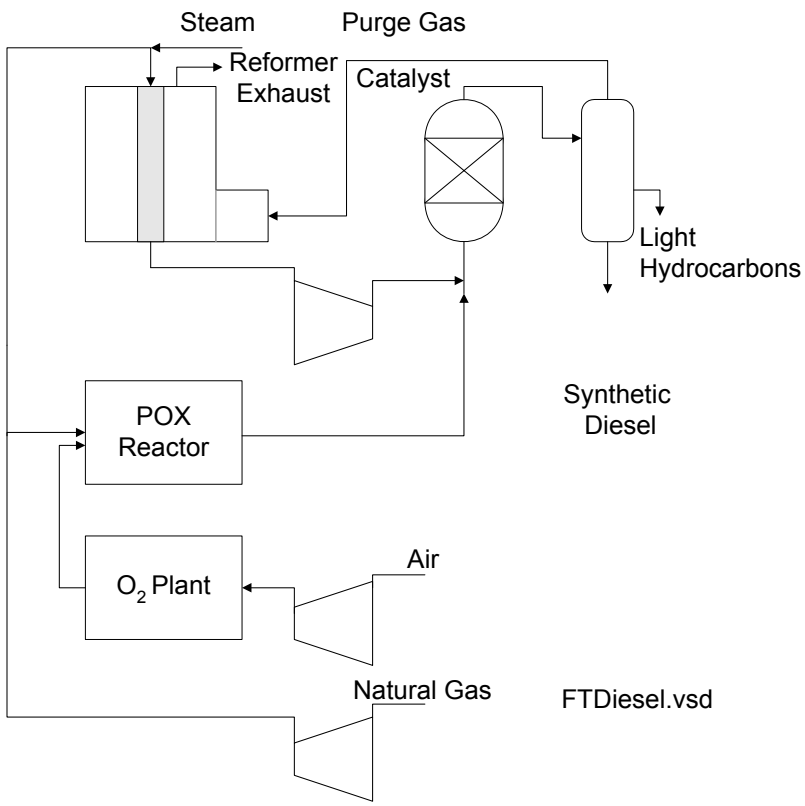

Figure 3-2. Process Components for Synthetic Fuel Production

This power is provided by natural gas engines, electric motors powered by energy created at the plant, or steam-driven turbines. Excess synthesis gas contains hydrogen (because there is a stoichiometric excess), unreacted CO and CO_2, and CH_4 that was not converted in the reformer.

Producing methanol or FTD from natural gas results in a fuel with reduced hydrogen content (H/C) compared to CH_4. (While methanol has four hydrogens per carbon, it can be considered a combination of CH_2 and H_2O for this discussion.) Because the composition of the feedstock and fuel differ, a carbon balance must be used to determine the amount of CO_2 emitted from synthetic fuel production. This can be illustrated by the overall reactions for a steam reforming methanol plant.

$$CH_4 + H_2O \rightarrow CO + 3\ H_2 \quad \text{Reforming}$$

$$CO + 3H_2 \rightarrow CH_3OH + H_2 \quad \text{Methanol synthesis}$$

In practice, equilibrium and reactor volume considerations prevent complete conversion of CO to methanol. In addition, some of the methane is not converted to CO and hydrogen. Converting CH_4 to fuels does, however, convert a significant fraction of the

carbon in methane to liquid fuel. A process is thus characterized by its energy efficiency, energy ratio, and carbon efficiency. The energy efficiency is the ratio of product output to all energy inputs to the facility (natural gas for reforming, natural gas for compressor engines, and electric power). The product output can include fuel, electricity, or steam that is exported to other facilities. The energy ratio is simply the fuel output divided by the natural gas input. The carbon efficiency (HHV basis) is the carbon in the fuel output divided by the carbon in the feedstock (not counting natural gas for compressors).

Combustion emissions from GTL and methanol plants consist of purged syngas. Because the purge gas consists primarily of hydrogen, CO_2, and CO, with low levels of CH_4, NMOG emissions from reformers are extremely low.

Steam reforming results in an excess of hydrogen for each mole of carbon. In steam reforming systems, the purge gas provides fuel to the reformer. Purge gas input to the reformer exceeds the energy requirements of the reformer for generating steam and the reforming reaction. Excess steam energy can be used to power compressors or generate electric power.

The subject of steam export and credits for steam exports is a key issue for fuel-cycle studies. Credit for steam production or electric power generation can be given for export steam. Several approaches exist for providing credits for excess process energy. The energy required to generate steam in a boiler from natural gas can be determined and used as a credit, primarily for process energy and CO_2. Also, the credit can be calculated in terms of energy required to generate electric power. In this study, power requirements were matched with energy inputs within the fuel production facility, thus, no export energy credits are generated.

3.4.5 Synthetic Fuel Energy Requirements

The key assumption for WTT analysis of synfuels is the feedstock conversion efficiency, shown in Table 3-11. The analysis shows the expected range for new plants that are or could be built today with projections for future technology improvements. Methanol and hydrogen from natural gas are the most established technologies.

Significant developments with GTL technologies are expected. Shell projects that improvements in thermal integration, catalyst yields, and reduced recycle energy would result in an efficiency of 68 percent on a lower heating value basis. The carbon conversion efificiency ranges from 78 percent to 81percent for plants with a thermal efficiency of 63 to 68 percent, respectively.

Table 3-12. Comparison of Feedstock Conversion Efficiency for Synthetic Fuel Processes

Process	Analysis Input		EUCAR 2005, Other References	
	2012	2022		
Natural Gas Reforming				
Methanol	67.5%	71.3%	68.2%	Stratton, 1982
DME	70.0%	72.0%	71.3%	—
FTD (GTL)	63.0%	68.0%	63.0%	Shell
H_2 Central	78.0%	78.0%	72-79	Simbeck 1998
H_2 Central, Steam Export	—	—	76.0%	Contadini, Simbeck 1998
H_2 On Site	72.0%	74.0%		H_2A, Thomas 2000, Lasher 2002
Biomass Gasification				
Methanol	—	—	58.0%	GREET
DME	—	—	54.9%	GREET
FTD (BTL)	—	—	57.7%	GREET
Hydrogen	51.0%	60.0%		Simbeck 1998
Coal Gasification				
Methanol	—	—	59.7%	Stratton 1982, GREET
DME	—	—	59.7%	GREET
FTD (CTL)	—	—	40.5%	GREET
Hydrogen	61.0%	63.0%	50.8%	Simbeck 2002, DOE 1985

3.5 Hydrogen Production

Hydrogen can be produced from numerous primary energy sources and through a variety of production pathways. These energy inputs include fossils fuels, renewable biomass feedstocks, as well as electric power derived from both fossil fuels and renewable/non-fossil resources. Potential feedstocks are shown in Figure 3-3[17]. The most common hydrogen production methods involve the conversion of hydrocarbons or the electrolysis of water. On an industrial scale, hydrogen is currently produced primarily through the steam reforming of natural gas.

[17] See California Hydrogen Highway Network, Roll Out Team, Production Report.

	Feedstock	Energy Carrier
Non Fossil	Nuclear Solar	High temperature heat Electricity
	Geothermal Hydroelectric Wind	Electricity
	Renewable contract Grid Power Mix	
Renewables	Biomass	
	Corn Waste sugar Sugar crops	Sugar, starch to ethanol or hydrogen
	Energy crops Switchgrass Forest residue Manure	Cellulose to ethanol, methanol or hydrogen
	Algae Sewage	Methane
Fossil Fuels	Coal	Coal
	Shale oil Tar sands Crude Oil	Petroleum coke LPG Naphtha Gasoline
	Pipeline natural gas LNG	Natural gas
	Remote natural gas	Methanol

California grid power is produced from a variety of energy resources. On the margin, the grid mix is assumed to be from natural gas fired combined cycle power plants plus renewables consistent with the RPS standard for the given year.

Figure 3-3. Potential Hydrogen Feedstocks

While natural gas is the most prevalent hydrocarbon feedstock used for hydrogen production, a variety of other feedstocks are available, including LPG, methanol, ethanol, biomass, coal, and petroleum coke. The electrolysis pathway can draw from grid-power for small applications or from dedicated power plants for larger production capacities. The environmental impact of producing hydrogen through electrolysis depends on the source of the electric power (fossil, nuclear, or renewable). Emerging technologies for hydrogen production include photolysis[18] and nuclear power in conjunction with thermochemical water splitting[19].

[18] California Hydrogen Highway Economic Report

[19] DOE Hydrogen Program Plan

Figure 3-4 shows some of the numerous feedstock and existing production technologies that could be used to produce hydrogen. Combinations of energy carriers and production technologies are referred to as "production pathways." The solid lines represent the more common uses of primary energy and pathways for hydrogen production. The pathway combined with the vehicle affects the overall energy inputs, GHG emissions, criteria pollutant emissions, and other impacts of hydrogen use.

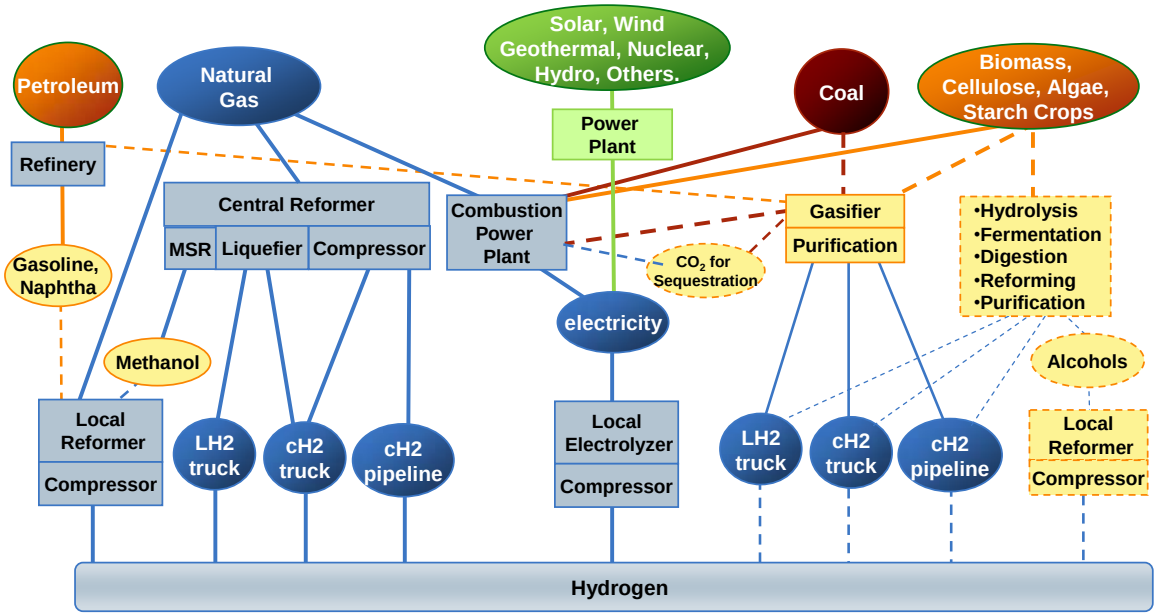

Figure 3-4. Potential Hydrogen Production Pathways

As Figure 3-4 illustrates, a large number of pathways exist for the production of hydrogen. Recognizing that there are hundreds of pathways, it is not tenable to evaluate them all. Certain pathways were chosen, and these selected pathways provide a broad range of hydrogen production options and focus on those that are more viable in the near-term for commercial production. The production pathways selected for analysis include: natural gas reforming, solids reforming (biomass, coal, coke), and water electrolysis. Pathways not considered are reforming of other gaseous fuels, other reformer technologies (autothermal, partial oxidation), and thermal electrolysis.

In this study we consider hydrogen production from three main technologies: natural gas reforming, solid fuel gasification and electrolysis of water. The most prevalent technology today is steam reforming of natural gas. Methane is reformed into CO and hydrogen. The CO is reacted with steam to form additional hydrogen via water-gas shift reactions. While there are a number of different reforming techniques, steam reforming is the only pathway considered here. Gasification of solid fuels is essentially combustion under very reducing conditions to generate hydrogen and CO. Electrolysis separates water into hydrogen and oxygen by passing current through an electrochemical cell. Each of these production processes is described below.

3.5.1 Hydrogen Production from Natural Gas Steam Reforming

Technologies that enable production of hydrogen from natural gas or other hydrocarbon feedstocks are typically called reformers because they *reform* the hydrocarbons into carbon monoxide (CO) and hydrogen. Natural gas steam reforming is the most well known, commercially available process for hydrogen production. In the United States, nearly 90 percent of the hydrogen produced is manufactured through the steam reformation of natural gas[20].

Figure 3-5 is a schematic of a hydrogen fueling station with an on-site steam methane reformer (SMR). The principle elements of the hydrogen production system are the natural gas and air supply, reformer, and purification system. Hydrogen and other gases are produced in the reformer, a pressure swing adsorption system is used to purify the hydrogen product stream, and the purified hydrogen is compressed and stored. If liquefied hydrogen is the delivery mechanism, the hydrogen will be liquefied and stored after production and purification.

SMRs are best operated under steady-state conditions and therefore require a relatively constant demand for hydrogen. The advantages of steam reforming are that it is an efficient process and the product gas is not diluted by nitrogen. The main disadvantages of steam reforming are that it requires steam for initial operation, and requires sophisticated equipment design and high-grade metallurgies.

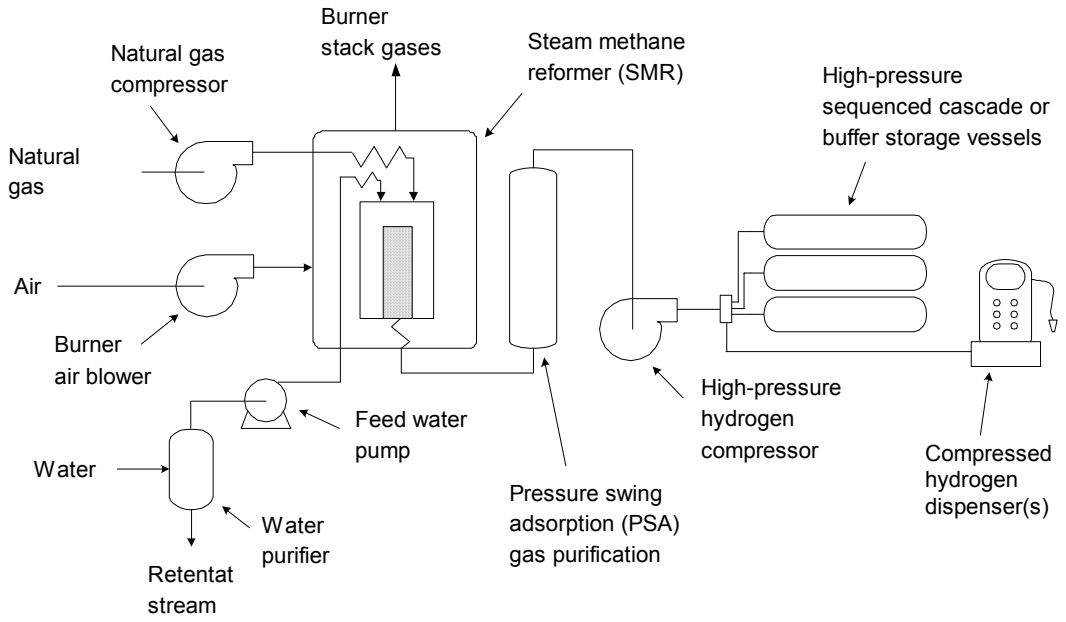

Figure 3-5. Simplified Process Flow Schematic for a Hydrogen Fueling Station with an On-site Reformer

[20] "California Hydrogen Fueling Station Guidelines," TIAX Report No. TR-03-163a for the California Energy Commission, November 2003.

Hydrogen production is accomplished in several steps: a steam reforming step followed by a water gas shift reaction and hydrogen purification. Steam reforming involves the reaction of natural gas (or other hydrocarbon feedstocks) with steam to produce CO and hydrogen. This reforming reaction is represented as:

$$CH_4 + H_2O \rightarrow CO + 3\,H_2$$

The steam reforming reaction requires external heat input. Economics favor reactor operation at pressures of 3 to 25 atmospheres and temperatures of 1,300 to 1,550^{o}F. The external heat needed to drive the reaction is often provided by the combustion of waste gases, such as combustion of the purge gas from the hydrogen purification system. Further processing of the gas stream with steam in a shift reactor produces CO_2 and additional hydrogen:

$$CO + H_2O \rightarrow CO_2 + H_2$$

The gas exiting the shift reactor contains mostly H_2 (70 to 80 percent) plus CO_2, CH_4, H_2O and small quantities of CO. Depending on the type of shift reactor, CO concentrations are a few percent by volume or less. Hydrogen is then purified, typically by pressure swing adsorption (PSA) systems, although palladium membranes or other technologies are also options. The product hydrogen can have a purity of up to 99.999 percent. A purity of 98 percent hydrogen is specified in ISO 14687 for fuel cells for transportation and stationary applications. Compared with other reforming approaches, a high temperature steam reformer with methane feedgas can be expected to produce the greatest amount of hydrogen per unit of natural gas. The energy conversion efficiency[21] of large-scale steam methane reformers is between 75 and 80 percent, although 85 percent efficiencies have been achieved with additional waste heat recovery and utilization .

3.5.2 Hydrogen Production through Electrolysis

Electrolysis is another option for on-site production of hydrogen at a refueling station. Electrolysis uses only water and electricity as inputs and has the potential for producing hydrogen from non-fossil sources with zero emissions. Several companies have built electrolysis-based hydrogen production systems with a range of production capacities for both industrial and vehicle fueling applications.

The advantages of electrolysis in the near term include its replacement of the need to store large quantities of liquid or high-pressure gaseous hydrogen on-site at a fueling station, its suitability for smaller scale production, and zero emission operation. Furthermore, there are no truck emissions associated with electrolyzer-based facilities.

[21] Efficiency is defined here as hydrogen product (HHV)/ feedstock energy input (HHV). Efficiency is also sometimes defined as hydrogen product (HHV)/(feedstock energy input (HHV) + electric input), and this is often defined in terms of LHV instead of HHV.

Electrolyzers are considered a reliable, well-developed option compared with other on-site production approaches.

Electrolysis is the process of splitting water into hydrogen and oxygen with electricity by transmitting an electrical current through an electrolyte. Oxygen and hydrogen gases are produced at the anode and the cathode respectively, separated from the electrolyte, and gathered in separate vessels for further processing. The anode is the electrode through which the electrons leave the electrolytic cell and produce gaseous oxygen. Similarly, the cathode is the electrode where electrons enter the electrolytic cell and produce gaseous hydrogen.

The electric power required to produce a given hydrogen output flow can be calculated from thermodynamic energy balance considerations. For hydrogen fueling station application, the electrolyzer efficiency is often defined as the hydrogen output LHV divided by the input electrical energy. A 100 percent efficiency electrolyzer would therefore require approximately 33 kW-hr per kg of hydrogen production. Real electrolyzer efficiencies can range from approximately 60 to 90 percent, depending on various design and operating details. Thus, the overall efficiency of producing hydrogen using a reformer is superior to using the hydrocarbon feedgas to generate electricity to power an electrolyzer. This is why nearly all large-scale hydrogen production in the U.S. is by reforming, and large-scale production by electrolysis is used primarily in areas with low-cost electricity (e.g., due to hydroelectric generating resources).

Alkaline electrolysis is the oldest electrolysis technology, and the one most typically used for large-scale electrolytic hydrogen production. Diluted potassium hydroxide (KOH) or sodium hydroxide (NaOH) are normally used as the electrolytes. Alkaline electrolyzers have been developed to operate at higher pressures and/or higher temperatures. High-temperature alkaline electrolyzers have higher electrical efficiencies (as high as 90 percent, because of various factors including the improved reaction kinetics at the electrodes, which increases the current density), but these designs present more durability-affecting materials challenges.

Solid polymer electrolyte (SPE) membrane electrolyzers operate as reverse proton exchange membrane (PEM) fuel cells, and typically use similar parts and materials. In SPE electrolyzers, a solid-state ion-conducting membrane (the SPE) replaces the liquid electrolyte used in alkaline electrolyzers.

Because of the low internal resistance of SPE membrane assemblies, they can operate at higher efficiencies than alkaline electrolyzers. Efficiencies of 90 percent have been reported in SPE electrolyzers in Japan, and a demonstration unit is being installed in Takamatsu, Japan. These units typically operate at pressures from 100 to 300 psig and at temperatures between 200 and 250ºF. While SPE electrolyzers have the potential for high efficiency, the actual efficiency depends on the load factor. Higher loads result in more power consumption, but they also increase the hydrogen output. Similar load versus efficiency tradeoffs are exhibited with PEM fuel cells, batteries, and other electrochemical devices.

The principal utility requirements for electrolyzers are water and electric power. These utility requirements depend on the application hydrogen demand and the type of electrolyzer used. The performance and efficiency of an electrolyzer varies with each manufacturer and model, depending on the specific technology and configuration. An electrolyzer, which is 75 percent efficient (LHV basis), would require 44 kWh/kg of hydrogen for electrolysis and roughly 4 kWh/kg for compression (depending upon the electrolyzer output pressure).

Estimated utility requirements are shown in Table 3-13 for an example 72 kg/day on-site electrolyzer system. The performance parameters are based on the estimates discussed above. The table also indicates that substantial electric power service is required for a station with an on-site electrolyzer, possibly requiring electric utility upgrades at some facilities.

Table 3-13. Example Utility Requirements for an Electrolysis System

Parameter	Approximate Requirement
Hydrogen Capacity	72 kg/day, 3 kg/hr
Water consumption	8 U.S.gal/hr
Electrolyzer system power	500 amp service at 480 volts
Compressor system power	50 hp

3.5.3 Hydrogen from Gasification of Solid Fuels

Gasification of biomass, coal, or petroleum coke is another hydrogen production pathway. A wide variety of biomass materials have been considered as feedstocks for energy production. In many places in the world, including California, forest materials, agricultural residue, and urban wood waste have been used as fuel for power plants. These and other biomass materials including waste paper and rice straw have also been considered as feedstocks for cellulose based ethanol production processes. Such biomass and other solid materials including petroleum coke, or even tires, could be used as feedstocks for gasifiers that produce hydrogen. While the scale and configuration of gasification systems would vary with different feedstocks, the general principle is similar. Solid material is reacted with steam, oxygen, or air to produce a syngas stream. Components of this gas stream are further processed into pure hydrogen.

Gasification provides an opportunity to convert solid materials with low economic value to hydrogen or other fuels. However, the gasification pathways require more development than reforming and also represent higher capital costs per unit of hydrogen. The feasibility of using solid materials as feedstocks is largely affected by the avoided cost of transporting or disposing of these materials.

The assumed energy ratio for petroleum coke gasification and biomass gasification are 75 and 66 percent respectively. The difference is largely due to biomass being assumed as a supplemental fuel to raise steam for the gasification system. Both of the assumed gasification systems also require oxygen. The energy inputs for the oxygen plant are included in the electric energy requirements for the system. A variety of other reforming and gasification processes are candidates for hydrogen production. The details of these systems will vary, and affect the amount of electricity required to operate the system as well as the energy ratio. For example, some gasification systems require no oxygen but the energy ratio is lower. For all of these thermo-chemical conversion processes, the energy ratio values typically can range from 65 to 80 percent (LHV).

3.5.4 Hydrogen Production Energy Inputs

Table 3-14 shows the primary energy inputs for each of the hydrogen pathways analyzed in this report. The primary energy includes feedstocks such as natural gas, petroleum coke, and biomass. Power for electrolysis can also be considered a feedstock/energy carrier as it is the only source of energy for separating water into hydrogen. Other electric energy inputs include power for the hydrogen plant as well as power for hydrogen compression.

The specific details of the energy inputs for hydrogen production have been evaluated in many studies. These feedstock and electric power energy inputs are shown in Table 3-15. The values used in the California Hydrogen Highway Network analysis by the Economics team and those reported by Simbeck (Simbeck 2002) reflect largely near term technology. Improvements in some technologies such as on-site reforming and electrolysis are expected in the long term. The energy inputs that can be expected with further technology development reflect values presented by DOE and part of their H2A effort as well as studies from Arthur D. Little (Lasher 2002) and the National Academy of Sciences.

The calculation of energy inputs and GHG emissions collapses to the simple multiplication of natural gas consumption by parameters for the fuel cycle and fuel plus similar calculations for power consumption. While no GHG emissions are emitted from hydrogen fuel cell vehicle operation[22], all of the fuel cycle energy inputs and GHG emissions are proportional to vehicle fuel consumption.

The natural gas reformer consumes most of the energy in the fuel cycle. Most of the GHG emissions associated with the use of natural gas are emitted from the reformer. Energy consumption for electric power generation corresponds to 0.24 J/J of hydrogen produced. This value includes the electricity itself and energy inputs for power generation (indicated as a second order fuel cycle). Both the estimates for the reformer and compressor energy consumption reflect optimized future systems.

[22] Hydrogen ICE vehicles would emit low levels of N_2O which would represent less than 1% of GWP weighted fuel cycle GHG emissions.

Table 3-14. Energy Inputs for Hydrogen Production

	Primary Energy, WTT_f (J/J H_2)				
	Natural Gas	Diesel	Petroleum Coke	Biomass	Electric
Central Pet. Coke Gasifier, Mobile Fueler	—	0.114	1.33[a]	—	0.133
Sequestration Petroleum Coke	—	—	—	—	0.112[a]
Central Biomass Gasifier, Mobile Fueler	—	0.114	—	1.51[b]	0.19
Sequestration Biomass	—	—	—	—	0.105[b]
Central Biogas SR, Mobile Fueler	—	0.114	—	1.47	0.160
Central NG SR, LH2 Truck	1.28	0.012	—	—	0.384
Central NG SR, Mobile Fueler	1.28	0.114	—	—	0.096
Sequestration Central NG SR	—	—	—	—	0.054[c]
On-Site NG Steam Reformer	1.43	—	—	—	0.090
On-Site Electrolysis	—	—	—	—	1.80
Central Electrolysis, Wind, Tube Trailer	—	0.095	—	—	1.83

Note: These energy inputs represent the baseline pathways. Many other pathways can be considered. For example, some applications will provide hydrogen on-site and will not require delivery. The information in this table can be used to determine the energy and GHG factors for these and other pathways.

Sources: Unnasch 2005, California Hydrogen Highway Network, Economics Team Report

Electricity input includes power for central plant production and compression and/or forecourt production and compression

Electric power values are for cascade storage at 420 bar.

90 % of concentrated CO_2 is captured for sequestration. This CO_2 is captured in a concentrated stream from the PSA.

[a] 18.7 kg CO_2 available/kg H_2, 4.36 kg O_2/kg H_2 for gasifier. O_2 requirement for gasification and power requirement for air separation unit based on SFA Pacific study (Simbeck 2002). Energy ratio for petroleum coke gasification is 75%. CO and PSA losses are 5%. The PSA off-gas is used to generate steam.

[b] 17.5 kg CO_2 available/kg H_2, 9.0 kg O_2/kg H_2 for gasifier. Energy ratio for biomass gasifier is 80%. 15% additional feedstock is assumed as fuel for fluid bed combustor for biomass drying. CO shift and PSA losses are 5%.

[c] 9.0 kg CO_2 available per kg H_2

Table 3-15. Comparison of Energy Inputs from Hydrogen Studies

Study	Time-frame	Parameter	Central NG SR, Tank Truck	Central NG SR, LH2	On-Site NG Steam Reformer
California Hydrogen Highway Network, 2010 Scenario [a]	2010	Combustion (J/JH_2)	0.27	0.27	0.27
		Natural Gas (J/JH_2)	1.28	1.28	1.43
		Efficiency (LHV,%)	72.5%	61%	66%
		Total Electric (J/JH_2)	0.10	0.36	0.09
		Total Electric (kWh/kg H_2)	3.21	12.0	3.0
Arthur D. Little (Lasher 2002)	Long-Term	Natural Gas (J/J H_2)	1.26	1.26	1.32
		Total Electric (kWh/kg)	1.203	8.6	3.41
Simbeck/SFA Pacific (Simbeck 2002)	2002	Natural Gas (J/J H_2)	1.31	1.31	1.43
		Total Electric (kWh/kg)	3.74	12.0	2.19
DOE H2A	Long-Term plus some Mid-Term	Natural Gas (J/J H_2)	~1.28	~1.28	1.37
		Total Electric (kWh/kg)	3.24	10.5	2.92
		LH2 Boil-off	—	0.07%	—
National Academy of Science	Current Technology	Natural Gas (J/J)	1.31	—	1.42
		Total Electric (kWh/kg)	3.71	—	2.22
National Academy of Science	Future Optimism	Natural Gas (J/J H_2)	1.25	—	1.34
		Total Electric (kWh/kg)	3.57	—	1.70
GM/LBST (Choudhury 2002)	2010	Natural Gas (J/J H_2)	—	1.42	1.44
		Total Electric (kWh/kg H_2)	—	11.6	2.16

Emission factors for hydrogen reformers are difficult to find in the literature and most models assume that the emission factors are the same as a natural gas fired boiler. However, since the carbon content of the reformate is much lower than natural gas, the particulate matter emission factor for natural gas was thought to be too high for the reformer. TIAX identified a hydrogen reformer in the South Coast Air Quality Management District that had performed a source test for all criteria pollutants. The emission factors are indicated in Table 3-16. As suspected, the PM_{10} emission factor is an order of magnitude lower than the value used for natural gas combustion.

Table 3-16. Emission Factors from a Hydrogen Reformer in SCAQMD (HHV Basis)

Criteria Pollutant	lb/MMBtu
NO_x	0.00487
CO	0.00294
PM_{10}	0.00063
SO_2	0.00001
ROG*	0.00597

* As Methane

3.6 Coal Production

Coal is a solid hydrocarbon fossil fuel. There are four general coal classifications, termed ranks, that vary by moisture content and heating value. These are lignite, subbituminous, bituminous and anthracite. Lignite, also referred to as brown coal, has high moisture, ash, and volatile content as well as lower heating value (~7,500 Btu/lb). Subbituminous and bituminous coals have lower moisture contents and higher carbon contents, with heating values in the 8,500 to 11,000 Btu/lb range for subbituminous coals and 11,000 to 14,000 Btu/lb for bituminous coals. Anthracite is very hard and has a fixed carbon content of approximately 97 percent.

The United States has some of the largest deposits of coal in the world. More than half of these reserves are bituminous coal located east of the Mississippi River and concentrated in the Appalachian region. More than one third of the coal reserves are subbituminous, located west of the Mississippi River, with large deposits in Montana and Wyoming. The remaining U.S. reserves consist of lignite, with large deposits in Montana, North Dakota and Texas. Anthracite represents approximately 1 percent of total reserves and is located almost exclusively in Pennsylvania. Anthracite is mainly used for residential and commercial space heating. Most (92 percent) of the coal produced in the United States is used domestically for production of electricity[23].

During the past five years, approximately 1.1 billion short tons of coal have been mined each year. Table 3-17 provides coal production data by major coal producing regions for 2005. In response to the Title IV Acid Rain program SO_2 emission limitations, use of western coals has increased over the past 15 years because they have significantly lower sulfur contents. In particular, demand for Powder River Basin (PRB) coal has been very high. The 2005 passage of the Clean Air Interstate Rule (CAIR) reduces the existing SO_2 cap for utility boilers by a factor of 2 in 2010 and 2.86 in 2015. As a result,

[23] EIA Annual Coal Report, 2005.

there is a surge in demand for SO_2 scrubber installations at coal plants in anticipation of the 2010 compliance date. An increase in the installed scrubber capacity may reduce the importance of lower sulfur PRB coals and provide utilities more flexibility in their coal procurement strategies.

Table 3-17. 2005 Coal Mining Production

Region	Number of Mines, 2005			2005 Production, 1000 short tons		
	Underground	Surface	Total	Underground	Surface	Total
Appalachian	548	682	1,230	247,528	149,139	396,667
Interior	34	72	106	59,645	89,520	149,165
Western	24	38	62	61,438	523,532	584,970
U.S. Total	606	792	1,398	368,611	762,191	1,130,802

Source: EIA Annual Coal Report, 2005

There are two main types of mining processes used to produce coal: surface mining and underground mining. Table 3-16 indicates that 33 percent of the coal mined in 2005 was from underground mines with 67 percent from surface mines. Coal beds deeper than 100 to 200 feet or under hilly terrain are generally mined by underground methods.[24] Deposits closer to the surface generally utilize surface mining techniques. Surface mining is the less expensive mining method and results in removal of up to 95 percent of the coal from the deposit. Underground mining is much more complex and therefore more expensive; only 50 to 80 percent of the coal is recovered depending on the mining method employed. The following sections briefly describe the surface and underground mining methods and the energy requirements per ton of coal for each.

3.6.1 Surface Mining

In surface mining, large bulldozers clear and level the mining site by removing and storing the topsoil. The rock in the overburden is broken through the use of explosives, and the overburden is cleared away with power shovels and draglines. Figure 3-6 shows a dragline excavator. These machines are capable of moving up to 250 tons of overburden at a time with buckets holding up to 2,000 cubic feet. Because of their large power demand, most dragline excavators are connected directly to high voltage lines and run on electricity.

[24] "Energy and Environmental Profile of the U.S. Mining Industry", US DOE Office of Energy Efficiency and Renewable Energy, Dec 2002.

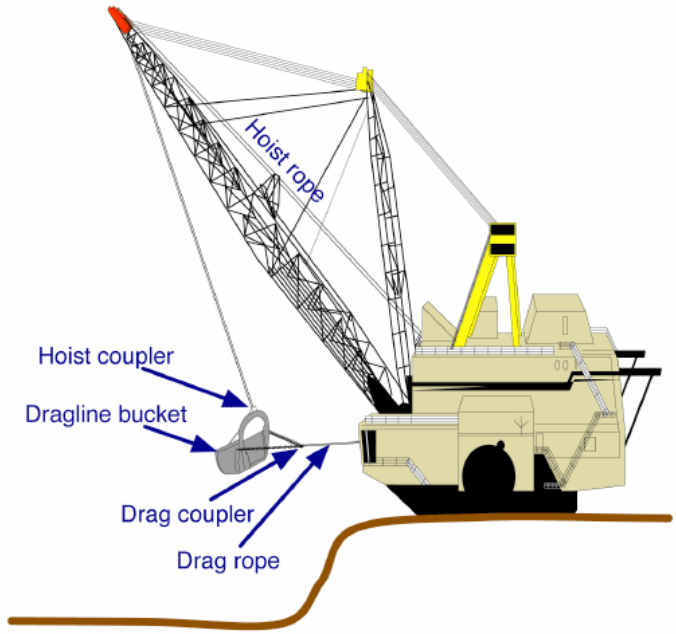

Figure 3-6. Schematic of Dragline Excavator

Once the overburden has been removed, smaller diesel powered shovels scoop up the coal and load it onto trucks that transport it to the coal preparation plant.

3.6.2 Underground Mining

There are a number of different underground coal mining techniques in use. However, most of the underground mines today use either the continuous mining or longwall mining methods. The continuous mining machine is essentially an automation of the "room and pillar" system of mining. In this system, series of rooms are cut out leaving pillars of coal to hold up the roof. The continuous mining machines use electric power. Figure 3-7 is a photograph of an operating continuous mining machine in a coal "room". Because columns of coal need to be left behind, this method of mining leaves behind a significant fraction of the coal. Slightly less than half of underground mine production utilizes the continuous mining method.

Longwall mining was introduced in the 1960s. This method employs an electrically driven cutting head that travels back and forth across the coal seam (up to ~1,000 ft wide). The coal falls onto a conveyor belt for removal. The cutter, shown in Figure 3-8, travels back and forth underneath a hydraulic roof support system that advances along the coal seam as the coal is cut. The roof in the mined out area caves in as the support shields advance. This method of mining is much safer than the room and pillar method and is more productive because coal pillars are not left behind. More than half of the coal from underground mines is produced via longwall mining.

Figure 3-7. An Operating Continuous Mining Machine in a Room and Pillar Mine (www.coalmining.net)

Figure 3-8. A Longwall Cutter Operating under Hydraulically Supported Roof Shields (www.coalmining.net)

3.6.3 Coal Mining Energy Consumption

Data regarding the amount of energy expended in both surface and underground coal mining is available in two US Census Reports[25]. The data are summarized in Table 3-18. As can be seen, most of the energy used is in the form of electricity. In 2002 (the most recent census year) a total of 55.8 million GJ were expended in the mining and preparation of coal.

It is of interest to look at energy consumption on a per unit of coal basis. The total U.S. production of coal by rank for 2002 was obtained from an EIA report[26]. The production values in tons are shown in Table 3-19 along with average higher heating values and corresponding energy value of coal produced. As can be seen, the energy content of all coal produced in the U.S. in 2002 was 24,400 million MMBtu. If we divide the total energy expended by the energy content of total fuel produced, we arrive at an energy intensity of 2,168 Btu per MMBtu coal produced.

Finally, Table 3-20 compares these coal and coal preparation energy consumption values to the values in GREET 1.7. In the GREET methodology, a value for production efficiency (99.3 percent) and relative contribution from each energy type are assumed. As shown in Table 3-20, the production efficiency, from TIAX's analysis is 99.78 percent – resulting in an energy consumption that is only 20 percent of the GREET assumption. Also, the split between fuel types is significantly different. The TIAX analysis indicates that most of the process energy comes from electricity while the GREET model assumes that most comes from diesel.

Table 3-18. 2002 Energy Consumed in Coal Mining and Preparation (HHV Basis)

Energy Type	Units	2002 Census Values		Surface	Underground	Total	
		Surface	Underground	GJ	GJ	GJ	%
Purchased Electricity	MWh	3,698,491	6,287,072	13,314,568	22,633,459	35,948,027	64%
Coal	short tons	1,100	179,800	22,022	4,818,101	4,840,123	9%
Distillate Oils (No. 1,2,4)	bbl	126,800	witheld[2]	779,546	4,032,368	4,811,914	9%
Residual Oil (No. 5,6)	bbl	973,900	178,300	6,462,343	1,183,115	7,645,458	14%
Gasoline	gal	11,800,000	1,500,000	1,127,070	143,272	1,270,341	2%
Natural Gas	billion ft^3	withheld[1]	withheld[3]	753,270	538,050	1,291,320	2%
Total				22,458,819	33,348,364	55,807,183	

Using 1997 numbers where 2002 values have been withheld.
1. *billion ft^3 in 1997 0.7*
2. *bbls in 1997 655,900*
3. *billion ft^3 in 1997 0.5*

[25] "2002 Economic Census: Surface Coal Mining", Dec 2004, EC02-21I-212111 (RV)
"2002 Economic Census: Underground Coal Mining", Dec 2004, EC02-21I-212112 (RV)

[26] "Coal Production in the U.S. – An Overview", EIA, Oct 2004.

Table 3-19. Heat Content of U.S. Coal Production in 2002

	Units	2002 Values
Total Production		
Bituminous	Million Short Tons	572
Sub-Bituminous	Million Short Tons	438
Lignite	Million Short Tons	83
Assumed HHVs*		
Bituminous	Btu/lb	12,700
Sub-Bituminous	Btu/lb	9,900
Lignite	Btu/lb	7,300
Total Heat Content		
Bituminous	Million MMBtu	14,531
Sub-Bituminous	Million MMBtu	8,680
Lignite	Million MMBtu	1,205
TOTAL	**Million MMBtu**	**24,416**

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Table 3-20. Comparison of the GREET Model Coal Mining and Cleaning Energy Consumption Values to this TIAX Analysis

	Coal Mining and Cleaning	
	GREET 1.7	TIAX 2007
Energy efficiency	0.993	0.9978
Shares of process fuels		
Residual oil	7%	14%
Diesel fuel	56%	9%
Gasoline	3%	2%
Natural gas	1%	2%
Coal	9%	9%
Electricity	24%	64%
Energy consumed: Btu/mmBtu of fuel throughput		
Residual oil	493	297
Diesel fuel	3,948	187
Gasoline	211	49
Natural gas	70	50
Coal	634	188
Electricity	1,692	1,396
Total Consumption	10,637	2,167

3.6.4 Coal Bed Methane Emissions

Methane is released from coal beds during coal mining. This methane is referred to as coal mine methane and is a subset of coal bed methane. Table 3-21 summarizes the coal mine methane emissions as estimated by the U.S. EPA in its most recent greenhouse gas inventory. Also shown in the table are total tons of coal produced and its estimated heat content. The emissions are divided by the total heat content to arrive at a g methane/MMBtu coal produced emission factor. As can be seen, the factor ranges from 102 to 110 g/MMBtu. This emission factor for coal mine methane is slightly lower than the value in GREET1.7. The GREET model uses a value of 118 g/MMBtu, based on a 1999 study by Spath and Mann[27].

Table 3-21. Coal Mine Methane Emission Estimate

	Units	2002	2003	2004
Underground Mines				
Liberated	Gg Methane	2,538	2,554	2,512
Recovered	Gg Methane	830	716	661
Net	Gg Methane	1,708	1,838	1,851
Surface Mining	Gg Methane	420	402	444
Post Mining				
Underground	Gg Methane	304	305	315
Surface	Gg Methane	68	65	72
TOTAL	Gg Methane	2,500	2,611	2,682
Coal Produced[1]	10^6 Short Tons	1,094	1,072	1,112
Average HHV[2]	Btu/lb	11,169	11,107	11,107
Emission Factor	g/MMBtu	102	110	109

Emission Data from "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2004, April 2006. EPA#430-R-06-002

1. EIA U.S. Coal Supply and Demand, 2005
2. Weighted average for 2002/2003 by coal rank. Production by rank not available for 2004, assumed 2003 HHV for 2004.

3.7 Biomass Feedstocks

Biomass feedstocks are utilized in the production of a number of alternative fuels including ethanol, hydrogen, biodiesel, and electricity. In the United States, farming has changed dramatically over the last century, mainly due to advances in technology and farming techniques. The average size of a farm has more than doubled from less than 200 acres (80 hectares) to more than 400 (160 hectares), with a corresponding steady

[27] Spath, P.C. and M. K. Mann, "Life Cycle Assessment of Hydrogen Production via Natural Gas Reforming," NREL TP-570-27637, February 2001.

decrease in the number of farmers. Today, farmers make up less than two percent of the labor force. Some of the key advances in farming technology include:

- Precision agriculture combines information technology and agronomy. By using a Global Positioning System, farmers can monitor precise locations in their fields. Data management software maps information such as soil sample anslysis results. On-board computers automatically vary the rate of inputs, allowing growers to apply fertilizers and pesticides more accurately. More careful management practices also reduce fertilizer inputs. Historically farmers have over fertilized in order to assure a maximum crops yield; this is no longer the case.

- No-till, or conservation-till, farming limits soil disturbance, leaving debris from the harvest on the ground and reducing the use of mechanical cultivation. Conservation till prevents erosion and improves soil health. No-till is an important aspect of sustainable agriculture. An example of low till agriculture applies to corn where the seeds are planted with a drill, herbicide is applied several weeks later, and no further farming equipment is required. A no-till farming system might use 2 tractor passes compared with 6 for conventional farming practice. By reducing soil compaction and increasing nutrients from decomposing plant material, it helps preserve the soil moisture and structure. No-till farming also helps lower fossil fuel consumption and related costs, improving efficiency. At the same time, it requires close monitoring to manage potential increases in disease and insect presence.

- Biotechnology has provided new plant varieties that can deliver traits beneficial to the grower, such as resistance to insects, fungi, and herbicides. For example, Bt corn has been modified with a protein from Bacillus thurigiensis to defend itself against attack by the European corn borer. When eaten by the corn borer, the Bt protein in the corn causes the insect to immediately stop feeding and prevents yield loss due to pest damage.

The following subsections describe different types of biomass feedstocks including biomass residues and energy crops. The final section provides the energy input assumptions for feedstock extraction utilized in this analysis.

3.7.1 Biomass Residues

California has substantial waste and residual biomass resources because of its rich agricultural and forestry resources and its large volume of commercial and municipal solid waste materials. Resources reviewed in this section include agricultural residues, forest/chaparral residues, and municipal solid waste. In addition, out of state biomass sources and other potential sources of biomass are briefly discussed. Collectively, California's estimated gross biomass resource potential for waste and residue sources that are convertible to ethanol totals approximately 50 million bone dry tons (bdt). This amount does not include energy crops or out of state resources, which could add significantly to this total.

Agricultural Residues

California has long been the leading agricultural producer in the nation. According to the *1998 California Agricultural Resource Directory*, gross income from agricultural production in 1997 reached $26.8 billion (including dairy, livestock and poultry). California's agricultural sector is considered one of the most diversified in the world, with no one crop dominating the state's farm economy. Some 350 different crops are grown in the state; consequently, residues from this sector are substantial and diverse.

The total acreage devoted to agriculture in California is decreasing slightly over time, a trend that is expected to continue for the foreseeable future. Much of this land is being converted to commercial and residential uses. At the same time, a shift to higher value crops including grape vines, and fruit and nut trees is occurring. Crops such as corn and wheat are expected to decrease over time as water costs and other factors make these crops less attractive to grow in the state.

Currently, much of the residue from California agriculture is incorporated into the soil or used for other purposes. Rice straw and orchard prunings, however, appear to be the principal agricultural residues that are strong candidates for cellulosic ethanol conversion. Rice straw is plentiful in the Sacramento Valley, where approximately 450,000 acres are devoted annually to rice production. Traditional means of disposal is open field burning, which has been largely eliminated due to mandatory reductions in the amount of straw which may be open burned. Rice straw continues to be considered a viable ethanol feedstock.

Forest and Chaparral Residues

To prevent overloading in the forest, mechanical thinning operations and periodic controlled burnings of forest areas can be used to reduce the risks of catastrophic fires. The forest residues generated from thinning and logging has little value for timber or paper products and must be disposed of through burning or other means. Conversion of forest residues to ethanol and/or electricity, with co-products offers an alternative to burning. This conversion has the added benefit of avoided emissions due to both prescribed burns and wildfires. The emission reductions associated with reducing wild fire risk were examined in an Energy Commission study (Perez, 2001).

The United States Forest Service manages approximately one-half of the forestland in the state. At least 250,000 acres per year of the land under U.S. Forest Service jurisdiction would benefit from thinning operations. Through thinning efforts, benefits can be realized in improved forest health, lowered catastrophic wildfire risks and other related areas.

3.7.2 Energy Crops

Energy crops involve a "closed-loop process" in that they are grown specifically for their ability to generate energy. Crops such as poplar, willow, switchgrass, and sugar cane

are being studied by for their ability to serve as energy crops for fuel. One of their great advantages is that they are short rotation crops; they re-grow after each harvest, allowing multiple harvests each year without having to re-plant. Corn and sorghum serve a dual purpose as they can be grown for fuel, with the leftover by-products being used for other purposes, including food.

Cellulosic Energy Crops

Poplar is a tree species that has been examined as a potential energy crop. Some hybrid forms of poplar require minimal agricultural inputs. The trees can be started simply by placing a cutting in the soil. An advantage of wood based energy crops may be their limited handling requirements. Trees can be harvested with standard forest practices, and storage poses less of a rotting and decomposition problem than other types of biomass.

Switchgrass has one of the highest potentials for use as a biofuel crop in the United States, mainly because it grows well under a wide range of conditions. In his January 2007 State of the Economy Speech, President Bush referred to cellulosic ethanol as “a fancy word for saying some day we're going to be able to convert switchgrass into energy that powers your cars”. Switchgrass contains large amounts of sugar that can be refined into ethanol. As a fast growing energy crop, or closed loop biomass, switchgrass can yield over 1,000 gallons of ethanol per acre, more than three times the yield of corn. Switchgrass and sorghum are from the same family; both are short term crops and produce prolifically with limited water, insecticides, or fertilizer needs. Switchgrass prevents soil erosion as it restores vital organic nutrients to the soil, so that it can be cultivated repeatedly in the same enriched soil.

Switchgrass can also be burned in fluidized bed boilers to produce electricity. Many farmers already grow switchgrass, either as forage for livestock or as a ground cover to control erosion, so cultivating it as an energy crop would be an easy switch. The challenge for scientists is in unlocking the sugars held in switchgrass so that it can be converted into cellulosic ethanol. Please refer to Section 3.8 for a discussion of the ethanol process.

Starchy Energy Crops

There are two main starch based energy crops: corn and sugar cane. The following paragraphs describe these two feedstocks. In the United States, approximately 80 million acres of land are dedicated to growing corn. The majority of the crops are grown in the Midwest. Approximately 20 percent of the corn crop is exported. The main domestic use of corn is for livestock feed. One of the key variables in the WTT analysis of ethanol from corn is the crop yield. Table 3-22 provides US corn crop yields per acre.

Table 3-22. Average Corn Yields

5-year Period	Fertilizer Use for Corn Farming: Nitrogen grams/bushel		Corn Yield, bu/Harvest Acre
	Nitrogen	P_2O_5	
1990	612	245	106
1995	529	198	118
2000	490	170	135
2005	441	157	150
2010	420	149	158
2015	399	142	166
2020	380	135	174

Source: Baseline GREET inputs

A corn yield of 120 bushels per acre is consistent with the higher yields that have been achieved in the past decade. These yields represent bushels of corn per acre of corn harvested. Some land that is planted but not harvested is not included in these figures. However, this corn is usually harvested for other purposes such as animal feed (silage).

In the future, the combination of improved farming practices and efforts to minimize inputs to farm land such as fertilizer may result in equal or slightly lower corn yields but less energy consumed per bushel. Expanding corn production significantly beyond current acreage onto more demanding farm land will lower yields and increase irrigation requirements. Such production would result in an increase in the energy requirements for corn production. However, the trend is toward higher crop yields with fewer agricultural inputs. Therefore, no energy or carbon losses were associated with the clearing of land for corn crops. Existing farm land was cleared of carbon-storing vegetation many decades ago. With efforts in soil conservation, existing farm land will continue to be used.

Expanding corn production onto new farm land in the U.S. would not result in the removal of forest land, but the impact on land use feeds to be examined. GREET estimates the impact on carbon in the soil. Corn stover which is plowed back into the soil along with the root mass, contains carbon that was captured from the atmosphere over a short period. This carbon is released back into the atmosphere over a much longer period. Burned stover releases CO_2 immediately, but the root mass remains to decompose slowly. The oxidation of soil organic material can take one to ten years depending on environmental conditions and cultural practices.

Another variable in the energy use for corn production is the energy associated with fertilizer production. Most of the energy associated with fertilizer production for corn is in the form of urea ($(NH_2)_2CO$), and urea is produced from natural gas. Pesticides,

irrigation, harvesting, drying, and transportation make up the remainder of the energy requirements for corn production. Most corn is grown with little irrigation. The energy requirement for irrigation used in this study represents the average for corn production in the United States.

Sugar cane is the primary source of sugar in the world. Estimates for 1996 and 1997 indicate world production of cane sugar was between 40 and 41 million tons. Production in the United States, excluding Puerto Rico, averaged 2.6 million tons during those years - from 592,000 acres of cane in Hawaii, Florida and Louisiana. Sugar production in Puerto Rico averaged nearly 1 million tons for the same period.

The cane plant is a coarse growing member of the grass family with juice or sap high in sugar content. It is tender to cold, the tops being killed by temperatures a little below freezing. In the continental United States, the growing season is limited to 7 or 8 months to avoid freezing. In tropical locations, sugar cane growth is continuous unitl harvest, producing much higher yields per acre. For example, sugar cane yields per acre in Hawaii, are three to four times higher than yields in Louisiana and Florida.

Harvesting of cane in Hawaii and Louisiana is highly mechanized. Machines top the canes at a uniform height, cut them off at ground level, and deposit them in rows. In Florida, cane is mainly cut by hand. Leaves and trash are burned from the cane in the fields. An alternate method is to burn the leaves from the standing cane, after which it is cut and taken directly to the mill. Delay between cutting and milling in either case should be as short as possible because delay results in loss of sugar content and presents spoilage concerns. Machines are under development that will cut, clean, and load the cane so it can be taken directly to the mill.

Sugar cane is being grown in Imperial County to supply feedstock for an ethanol plant. Agriculture in this region uses water from the Colorado River. Some of the water makes its way to the Salton Sea, which was originally formed by a breach in the pipeline carrying water from the Colorado River. Because of the unique circumstances, farming in this area with water intensive crops is considered a necessary element of maintaining the Salton Sea. Therefore the water use from growing sugar cane does not represent a net increase in water consumption.

Vegetable Oils

Vegetable oils are a promising feedstock for biodiesel fuels. Please refer to Section 3.9 for a discussion of the biodiesel production process. Many different seed and nut crops are being considered for use as a fuel. The prominent sources include soybeans, rapeseed, and palm oil with crop yields of 48, 127, and 635 gallons of ethanol per acre, respectively.

Soybeans are in the legume family grown around the world for both oil and protein. The U.S. produces approximately 75 million metric tons of soybeans each year, most of which is exported. Dry soybeans are 20 percent oil by weight. The oils are extracted and the remaining material is converted to soy meal for use in animal feed.

Rapeseed is from the canola family and is cultivated extensively throughout the world. According to the United States Department of Agriculture, rapeseed was the third leading source of vegetable oil produced in the world, second to soybean and palm oil. The rapeseed itself is the valuable harvested component of the crop. The processing byproduct has value as an additive to animal feed.

Palm oil comes from the fruit of the oil palm tree. The oil palm tree is grown for its fruit clusters which weigh up to 20 pounds. Oil is derived from both the fleshy part of the fruit and from the kernel inside. The flesh yields about 10 times the oil of the kernel. The processed byproduct meal is used for livestock. Malaysia is a leading producer of palm oil.

3.7.3 Biomass Feedstock Energy Inputs

Table 3-23 provides the energy assumptions utilized in this analysis for biomass feedstocks. The values are consistent with the GREET model except for the case of forest residue where the scenario analyzed here reflects the collection as part of a forest thinning program to reduce potential wildfire risk.

Table 3-23. Analysis Assumptions for Biomass Feedstocks

Agricultural Input	Corn Farming	Farmed Trees	Biomass Farming	Mustard Seed	Soybeans	Forest Residue
N_2O Emissions: N in N_2O as % of N in fertilizer	2.0%	1.5%	1.5%	0%	1.3%	0%
Farming or Collection Energy Use(Btu)	(per bushel) 22,500	(per dry ton) 234,770	(per dry ton) 217,230	(per acre) 650,000	(per bushel) 28,926	(per dry ton) 67,500
Fertilizer Use						
Grams of Nitrogen	420	709	10,635	0	107	0
Grams of P_2O_5	149	189	142	0	336	0
Grams of K2O	174	331	226	0	572	0
Grams of $CaCO_3$	1,202	0	0	0	0	0

3.8 Ethanol

A variety of materials are potential feedstocks for ethanol production. These include sugars and starches from agricultural products, cellulose from biomass materials, and petrochemicals. Both starches and cellulose can be converted to sugars and fermented to produce CO_2 and ethanol. Ethanol from petrochemical feedstocks is not evaluated in this study because this product is rarely used as a vehicle fuel[28]. Starch and sugar

[28] Only ethanol derived from biomass feedstocks is eligible for the Federal tax credit for ethanol or ethanol blends.

feedstocks comprise most of the global ethanol production capacity. These feedstocks are primarily corn, sugar beets, and sugar cane. Other grains and waste sugar feedstocks are also used for ethanol production on a smaller scale.

Almost all of the ethanol blended with gasoline in the U.S. is derived from corn produced in Iowa, Illinois, Minnesota or Nebraska. This ethanol is transported into California by rail. Approximately 10 percent of the ethanol utilized in California comes from Brazil by marine tanker. Brazil utilizes sugarcane as the ethanol feedstock and is the largest producer in the world.

California's ethanol industry includes the following existing plants and plants planned or under construction:

- Parallel Products operates a 3 million gallon per year facility in Rancho Cucamonga using beverage wastes.

- The Golden Cheese Company in Corona uses waste cheese whey to produce 5 million gallons per year of ethanol.

- Altira Inc. purchased the 25 million gallon per year corn grain ethanol plant in July 2006 from Phoenix Bio Industries. Altira announced plans to increase capacity to 35 million gallons/yr by the end of 2006.

- Pacific Ethanol completed construction of their new 35 million gallon per year ethanol production plant in Madera in October, 2006. This plant produces fuel-grade ethanol from corn. Pacific Ethanol announced plans to build four more facilities on the west coast in the next four years.

- Calgren Renewable Fuels has broken ground on the construction on a 50 million gallon per year facility in Pixley (Tulare County) to convert Midwest corn to ethanol. Construction is anticipated to be complete by mid-2007.

3.8.1 Ethanol Production Processes

Most ethanol is produced by fermentation and distillation. The ethanol feedstock is converted to sugar which is metabolized by yeast in the absence of oxygen to produce carbon dioxide gas and a dilute solution of ethanol in water. Distillation is used to separate the ethanol from the water. The energy requirements for the fermentation and distillation are generally independent of feedstock. However, the energy requirements to convert the feedstock to sugar prior to fermentation and distillation vary by feedstock type. In this analysis fuel ethanol derived from corn, sugar cane and cellulose is considered. The processing required to convert each of these feedstocks into sugar is described in the following paragraphs.

Corn Based Ethanol

Corn kernels can be divided into three parts: the hull, the germ, and the endosperm. The germ contains most of the oil while the endosperm contains the starch. There are two mature processes for producing ethanol from corn: wet milling and dry milling. In the wet milling process, corn kernels are washed and steeped in tanks containing a dilute solution of sulfuric acid for 24 to 48 hours to soften the hull. The steepwater is recovered because it contains significant amounts of protein.

The steeped corn is milled into a pulp that is pumped through cyclones to separate out the germ. The milling residue is combined with the recovered steepwater and sold as animal feed. The germ is recovered and sold as corn oil meal. The slurry is ground and screened to separate the starch from the gluten. The starch is subsequently hydrolyzed (converted to sugar) using mineral acids or enzymes. The sugars are then fermented to produce ethanol solution as described above.

In dry milling, the corn passes through a hammer mill which grinds it into a fine meal. The meal is mixed with water and alpha-amylase, and heated until the starch is liquefied. The resulting mash is cooled and a second enzyme, gluco-amylase is added to convert the liquid starch to sugar, which subsequently goes through the fermentation and distillation processes. Dry milling plants are dedicated ethanol plants that coproduce either wet or dry distillers grains. Dry milling plants achieve higher yields of ethanol per bushel than wet milling, while wet milling provides greater flexibility. Most new ethanol plants, including those in California, are dry mill plants.

Sugar Cane Based Ethanol

Because the sugar in sugar cane is easily accessible, the energy requirements upstream of the fermentation and distillation steps are much lower than for corn based ethanol. The harvested sugar cane is washed, chopped, and shredded in a mill. The shredded cane is then mixed with water and crushed between rollers. The resulting sugar containing juices are used as the feedstock for ethanol production. The leftover fibers (biomass) can be burned in a boiler to either generate process steam or electricity.

Cellulosic Ethanol

With cellulose feedstocks, ethanol is produced from the hydrolysis and fermentation of the feedstock. The biomass feedstock is assumed to be wood materials, either from forest, agricultural, or possibly municipal residues. Ethanol from these woody feedstocks is a long-term option for ethanol production in California. Cellulose is made up of long chains of glucose ($C_6H_{12}O_6$) molecules. Hydrolysis breaks these long chains down into free sugar that can go through the fermentation and distillation processes.

In the traditional hydrolysis process, the cellulose is exposed to an acid solution which breaks the long sugar chains down into single molecules. Before the fermentation step,

the acid must be removed from the product sugar or the yeast will be killed. Again, this process is much less energy intensive than the corn based process. Technologies employing enzymes to break down the cellulose into single sugar molecules rather than acid solutions are the focus of research and are considered emerging technologies at this time.

Biomass Gasification and Fermentation

Another emerging technology for conversion of biomass into ethanol is gasification and fermentation of the synthesis gas. The biomass fuel is partially combusted in a fuel rich gasifier to produce synthesis gas (CO, CO2, and hydrogen). The synthesis gas is digested (fermented) by a microorganism that produces an ethanol in water solution. The ethanol is then distilled off.

3.8.2 Ethanol Energy Input Assumptions

The energy assumptions used in this analysis for producing ethanol from corn, sugar cane and biomass are provided in Table 3-24.

Table 3-24. Summary of Ethanol Assumptions

Parameter	Value
Ethanol Production — Corn	
Corn production yield	2.6 gal/bushel
Energy mix for processing	10% coal/90% NG
Processing energy after allocation to by-products	38,200 Btu/gal (LHV)
Corn farming energy	22,800 Btu/bushel
Power production	Baseline GREET
Ethanol Production — Cellulose	
Dilute Acid Process Yield	77 gal/bdt
Byproduct electric power	0 kWh/gal

3.9 Biodiesel

Biodiesel fuels are defined as monoalkyl esters of long chain fatty acids derived from plant or animal matter. Biodiesel fuel can be utilized in many unmodified diesel engine vehicles. In the United States, ASTM D 6751 is the biodiesel standard. In Europe, the DIN EN 14214 standard is used. Biodiesel fuels can be made from vegetable oils or animal fats. The main vegetable oils that are considered feedstocks for biodiesel production include: soybean oil, rapeseed oil (canola oil is in the rapeseed family), castor oil, corn oil, mustard seed oil, coconut oil, and palm kernel oil. Sources of animal

fats include: tallow, lard, chicken fat, and fish oils. Despite the wide variety of biodiesel feedstocks, it is estimated[29] that 90 percent of the biodiesel produced in the U.S. comes from soybeans.

Biodiesel is produced via three main processes:

- Base catalyzed transesterification of the oil with alcohol (normally methanol)
- Acid catalyzed transesterification of the oil with methanol
- Conversion of the oil to fatty acids and acid catalyzed to alkyl esters

A fourth emerging process, thermal depolymerization, converts plant or animal matter into light crude oil. Because of its emerging commercial status, it is not included in this analysis. This analysis assumes biodiesel production through the base catalyzed transesterification process since it is the most commonly utilized. This process has been the preferred technology because it requires relatively low temperatures and produces very high yields. This process is illustrated schematically in Figure 3-9 and consists of combining methanol with refined oils in the presence of a base that acts as a catalyst. The most commonly used base catalyst is sodium hydroxide. The mixture is heated to approximately 70°C and maintained there for 4 to 8 hours. When the reaction is completed, the crude glycerin sinks to the bottom and is removed, leaving a mixture of biodiesel and methanol behind. The methanol is subsequently distilled off.

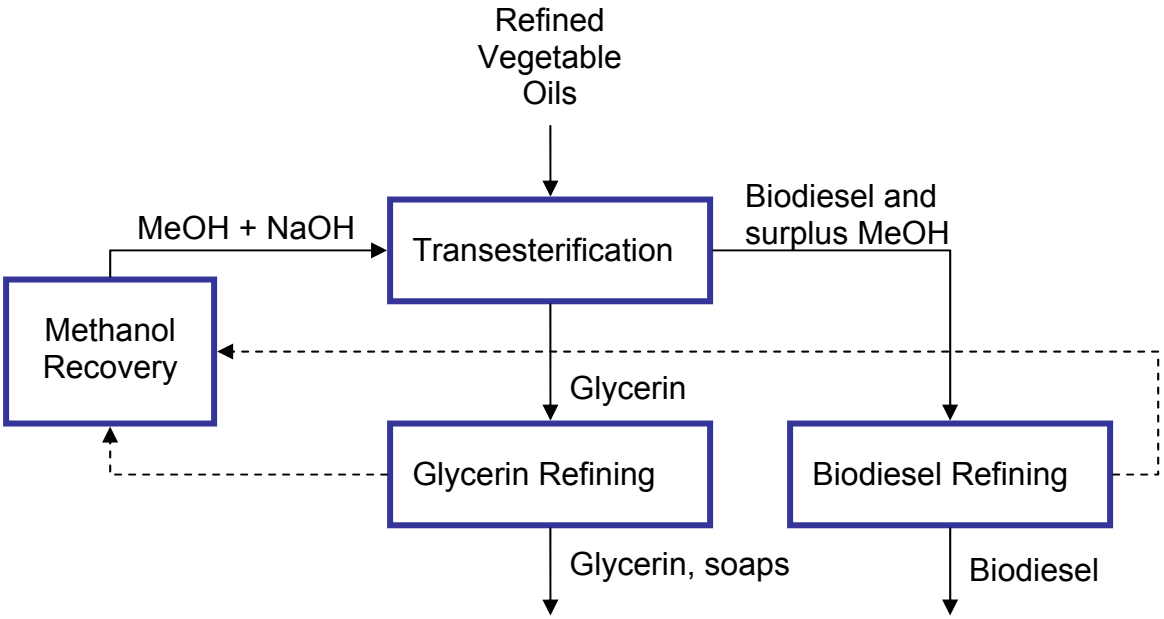


Figure 3-9. Process Schematic of Base Catalyzed Transesterification Process

[29] "Chicken Fat Key Biodiesel Ingredient", Christopher Leonard, Associated Press, January 2, 2007.

To estimate energy consumption in the form of methanol, steam (assumed to come from natural gas fired boilers), and electricity, two reports were consulted. The energy consumption values from these two reports and the default values embedded in GREET are compared in Table 3-25. As can be seen, the GREET and EUCAR values for methanol energy content agree reasonably well – this analysis has used an average of the two (875 Btu/lb biodiesel on an LHV basis). For steam, the two referenced studies are in fairly close agreement, but the GREET value is a factor of three higher. This study uses an average of the NREL and EUCAR values (625). For electricity, the EUCAR and NREL values are again in close agreement with the GREET value approximately a factor of 7 higher. This study uses 46 Btu/lb biodiesel for electricity consumption.

Table 3-25. Summary of Energy Inputs for Transesterification Process

	Energy Inputs (Btu/lb Biodiesel, LHV)			
	Methanol	**Steam (NG)**	**Electricity**	**Total**
GREET 1.7 Values	800	1,864	341	3,005
EUCAR/JRC Analysis[1]	942	660	47	1,649
NREL Biodiesel Study[2]	x	590	45	x
Used In TIAX Analysis	875	625	46	1,546

1. *Well-to-Wheels Analysis of Future Automotive Fuels and Powertrains in the European Context;* Well-to-Tank Report Version 2b, May 2006.

2. *Life Cycle Inventory of Biodiesel and Petroleum Diesel*, NREL/SR-580-24089

3.10 Emissions from Electric Power Generation in California

The WTT analysis of many alternative transportation fuels includes the emissions associated with electric power generation. This section provides the emission factors used in the present analysis for electricity generation within California. Section 5.1.4 provides the emission factors for electricity generation outside of California. Forecasting resource types utilized to generate future electricity consumption within California is a complex subject. A variety of methods could be employed to assign power generation emissions to new loads such as EVs and alternative transportation fuel production plants. As will be seen, this analysis assumes that the marginal electricity generation for EV charging and alternative fuel production will come from natural gas fired combined cycle power plants in conjunction with the current renewable portfolio standard (RPS) goals (33 percent by 2030).

The following sections describe the approach taken by TIAX to reasonably quantify fuel cycle emissions from electric power generation. The first subsection provides estimates of increased demand presented by new EVs and alternative fuel production. Charging scenarios are considered and an upper bound on new capacity required is defined. The second subsection provides background information on the current (2005) characteristics of California's electricity generation. This includes annual average resource mix of California and imported power, hourly demand profiles during peak and non-peak periods, and an estimate of the hourly resource mix serving peak and non-peak loads. The third subsection discusses the future resource mix of electricity consumed in California and what this means for marginal generation to support EV and alternative fuel production demand. The final subsection provides the emission factors used in the analysis consistent with the assumed marginal generation resource mix.

3.10.1 Electric Vehicle and Alternative Fuel Production Demand Scenarios

For the evaluation timeframe of 2012-2030, three different electric vehicle sales penetration cases have been defined as illustrated in Figure 3-10. Case 1 assumes that 10,000 EVs will be sold each year beginning in 2010. Case 2 assumes 10,000 EVs will be sold each year beginning in 2010, ramping up to 40,000 per year in 2020 and remaining at that level until 2030. Case 3 assumes the same EV sales as Case 2 but adds 20,000 PHEVs sold per year beginning in 2010 ramping up to 200,000 per year by 2020 and continuing to increase at this rate until 2030. These penetration scenarios are assumed to bracket the range of actual EV sales.

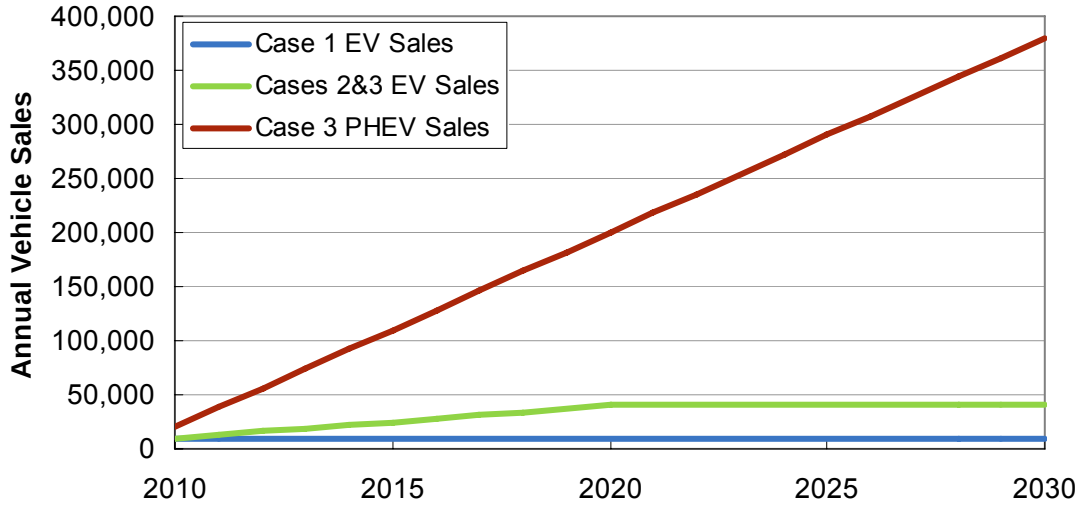


Figure 3-10. EV and PHEV Annual Sales for Cases 1-3

To estimate electricity consumption for each case, mileage accrual rates[30] by vehicle age were determined and applied to the vehicle sales data. We further assumed that 40 percent of the PHEV miles are electric and that the electric fuel economy is 0.33 kWh per mile. Figure 3-11 provides the resulting vehicle electricity consumption for each case. As will be discussed in the following sections, the Energy Commission predicts that California will consume over 313,000 GWh in 2016[31]. If this is extrapolated to 2030, nearly 350,000 GWh of electricity will be consumed in California. The projected electricity consumption for Cases 1-3 represent 0.2 percent, 0.8 percent and 3% of total consumption in 2030, respectively.

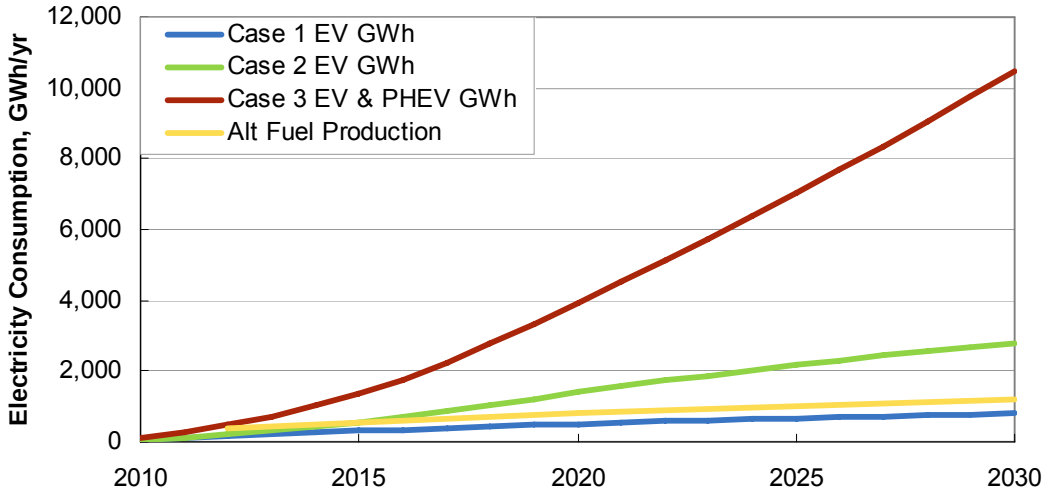


Figure 3-11. Annual Electricity Demand for EVs/PHEVs and Alternative Fuel Production

Also shown in Figure 3-11 is projected electricity demand for ethanol production assuming 200 million gallons of ethanol will be produced (and consumed) in California in 2012, increasing to 600 million gallons per year by 2030. Ethanol is viewed as being the most energy intensive alternative fuel to produce and is being used as an example here to indicate magnitude of electric power needs. Other fuels such as biodiesel, CNG, LFG, and hydrogen have more modest power requirements.

The time of day that EVs are charged affects transmission losses and may affect which generation resources are utilized. Therefore, daytime and nighttime charging scenarios are considered, as shown in Figure 3-12. The nighttime scenario assumes that most of the vehicles will be charged in the evening, with 70 percent of the charging is done off-

[30] Accrual rates of gasoline passenger cars from ARB's on-road model, EMFAC2007 by vehicle age.

[31] "California Energy Demand 2006-2016, Staff Energy Demand Forecast, Revised September 2005", CEC-400-2005-034-SF-ED2.

peak[32]. The daytime scenario assumes that most vehicles are plugged in upon arrival at work and only 6 percent of the charging is done off-peak. The actual charging profile will likely be a blend of the two profiles, perhaps resulting in an even load throughout the day.

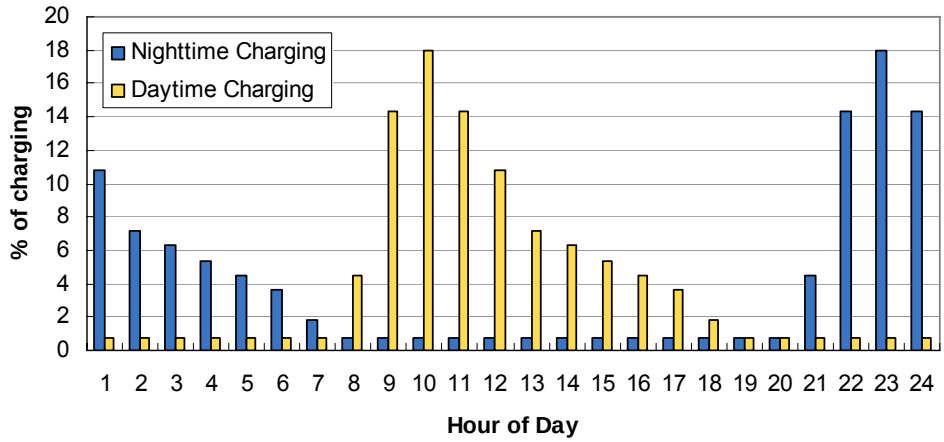


Figure 3-12. Assumed Charging Scenarios

If the daytime and nighttime charging scenarios are applied to the market penetration cases, the new load associated with EV charging can be quantified. Figure 3-13 illustrates the EV hourly demand for Case 3 (the upper bound of new demand) for each analysis year. For perspective, total California generating capacity in 2005 was 63 GW[33]. As can be seen, up to 5 GW of new demand could be seen by 2030. The data for all cases as well as ethanol production are shown in Table 3-26.

[32] Per the California ISO, Off-Peak hours are 11PM through 6AM.

[33] California Energy Commission 2005 Database of California Power Plants.

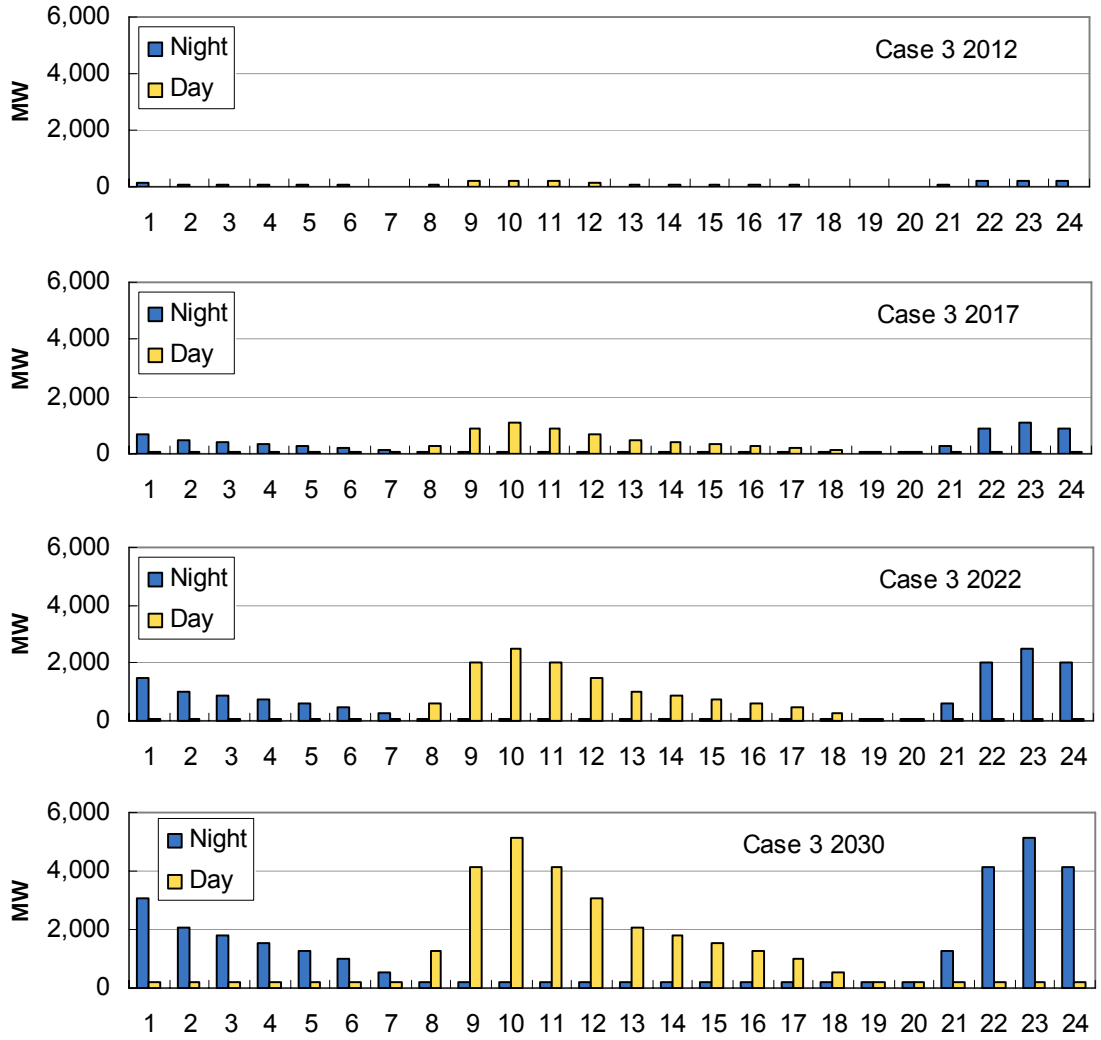


Figure 3-13. EV Charging Demand for Case 3, 2012-2030

Table 3-26. Estimated Maximum Demand (MW) From EV Charging and Alternative Fuel Production

	2012	2017	2022	2030
Case 1: 10,000 EVs per year beginning in 2010	8	20	30	40
Case 2: 10,000 EVs in 2010 ramping to 40,000 per yr in 2020 and constant thereafter	10	40	90	1,400
Case 3: Case 2 EVs plus 20,000 PHEVs per yr in 2010 ramping to 200,000 per yr by 2020 and constant thereafter	23	1,100	2,500	5,000
Ethanol Production: 200 Million gal/yr in 2012 ramping to 600 gal/yr by 2030.	5	7	10	14

3.10.2 California Electricity Supply and Demand in 2005

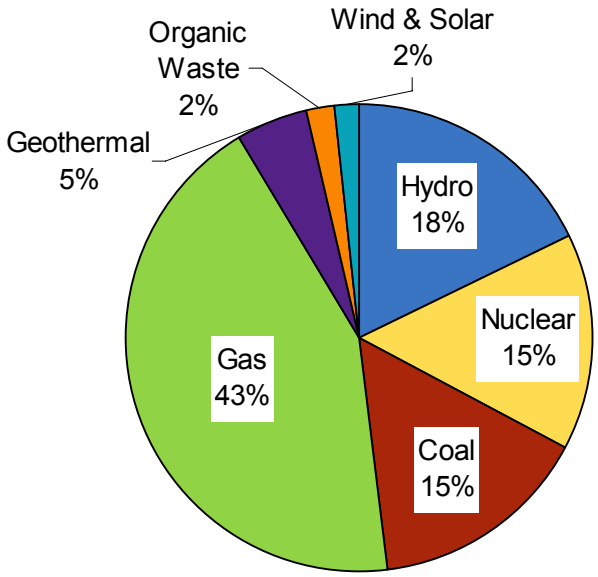
In 2005, California consumed nearly 288,000 GWh of electricity, with net imports representing 22 percent of the total[34]. Figure 3-14 provides a breakdown of electricity consumed in California by fuel type, with imports assigned according to the Energy Commission's revised resource mix accounting methodology[35]. As can be seen, fossil fuels provided nearly 60 percent of the electricity consumed in California. Hydro and nuclear power plants provided approximately one third of the power consumed in California, with other renewables providing slightly less than 10 percent.

Figure 3-15 provides a breakdown of electricity generated (as opposed to consumed in Figure 3-14, which includes imports) in California in 2005 by resource type. The breakdown is very similar to the total consumption values shown in Figure 3-14. Note that most of the coal based electricity that is counted as in-state was generated by the Mohave units in Nevada and the Intermountain units in Utah. These are counted as in-state since they are partially owned by California IOUs. Mohave was retired at the end of 2005, so in-state coal generation will be significantly lower in the future. The similarity between Figures 3-14 and 3-15 highlight the fact that the resource mix for imports is fairly similar to California's generation mix, although coal consumption is higher while nuclear is lower. Figure 3-16 provides the estimated resource mix of imports in 2005.

In addition to the annual average resource mix, the hourly system load, generation and net imports are of interest. Figure 3-17 provides hourly load for the California Independent System Operator (CAISO) area in 2005 for peak and non-peak months. Because the July and August curves were quite similar, these months are shown as average "peak" values. The maximum peak load for the ISO control area in 2005 was 43.7 GW at 3:00 in the afternoon on August 8. Because only average daily values for July and August are shown in Figure 3-17, the maximum peak load indicated is 40 GW. The September through June curves are also quite similar, so these data are averaged and shown as "non-peak" values. It is interesting to note that there is not much difference between peak and off-peak net import levels; this indicates that the difference in peak and non-peak demand is largely supplied by in-state generation.

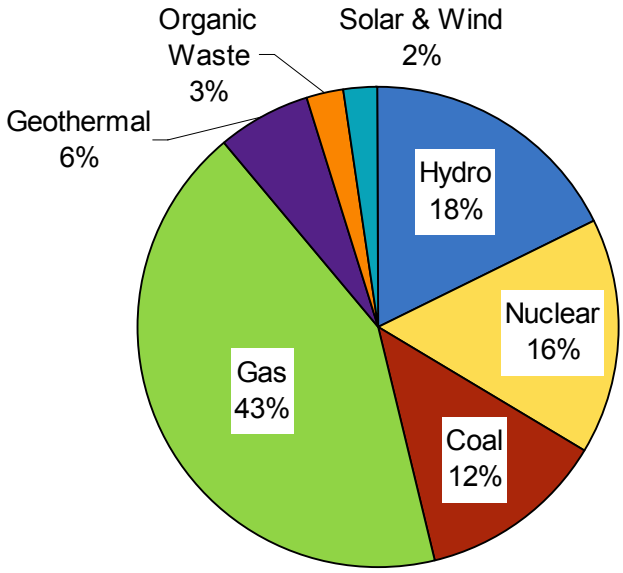
[34] According to the Energy Commission convention, this value counts the owned MWh from Intermountain and Mohave coal fired plants as in-state generation, not imports.

[35] "Proposed Methodology to Estimate the Generation Resource Mix of California Electricity Imports", CEC-700-2006-007.



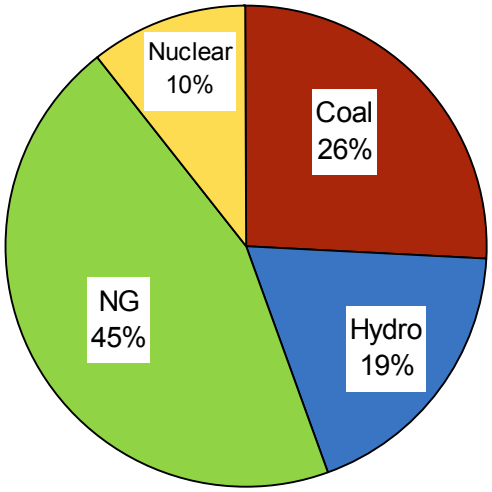
"Electricity Gen 1983-2005.xls", CEC
Imports (22% of total) were asssigned according to "Proposed Methodology to Estimate the Generation Resource Mix of California Electricity imports", CEC 2006.

Figure 3-14. Generation Mix of Electricity Consumed in California, 2005



"Electricity Gen 1983-2005.xls", CEC
In-state Generation Only

Figure 3-15. Generation Mix of Electricity Production in California, 2005



"Electricity Gen 1983-2005.xls", CEC
Imports (22% of total) were asssigned according to "Proposed Methodology to Estimate the Generation Resource Mix of California Electricity imports", CEC 2006.

Figure 3-16. Generation Mix of Imported Power, 2005

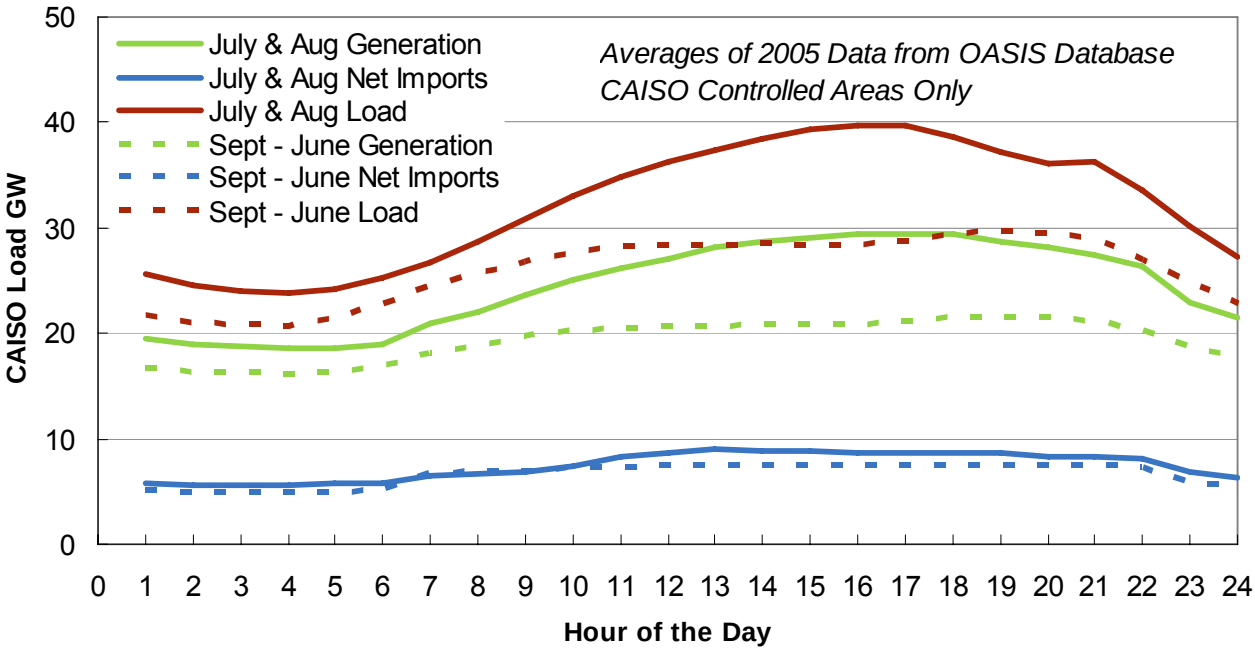


Figure 3-17. Hourly Load, Generation, and Net Imports for the CAISO Area, 2005

Because the emissions associated with electric vehicle charging are dependent on the generation fuel and equipment type, the peak day and non-peak day load profiles were combined with 2005 capacity by resource type to determine the load carried by each fuel type. Because the CAISO represents approximately 80 percent of the state load, the Oasis load was augmented by 5 to 9 GW depending on month and hour to reflect the load in other areas of the state[36]. The split between net imports and in-state generation provided by the Oasis Database was applied to the total state load and the import generation mix provided in Figure 3-16, and was subsequently applied to total imports to estimate hourly imports by resource type in 2005.

The natural gas combustion category was further split by generator type: steam turbine, combined cycle combustion turbine (CCCT), or simple cycle combustion turbine (SCCT). The splits were calculated from the 2005 plant prime mover level generation data from the Energy Information Administration[37]. The result of this analysis is shown in Figures 3-18 and 3-19 for peak and non-peak months, respectively. These figures indicate that the load carried by nuclear, coal, and renewable resources are relatively constant by the hour over the entire year. The increased demand during peak months is served by increased levels of hydro and natural gas generation – base and intermediate loaded CCCTs, load cycling steam generators, and SCCT peaking units.

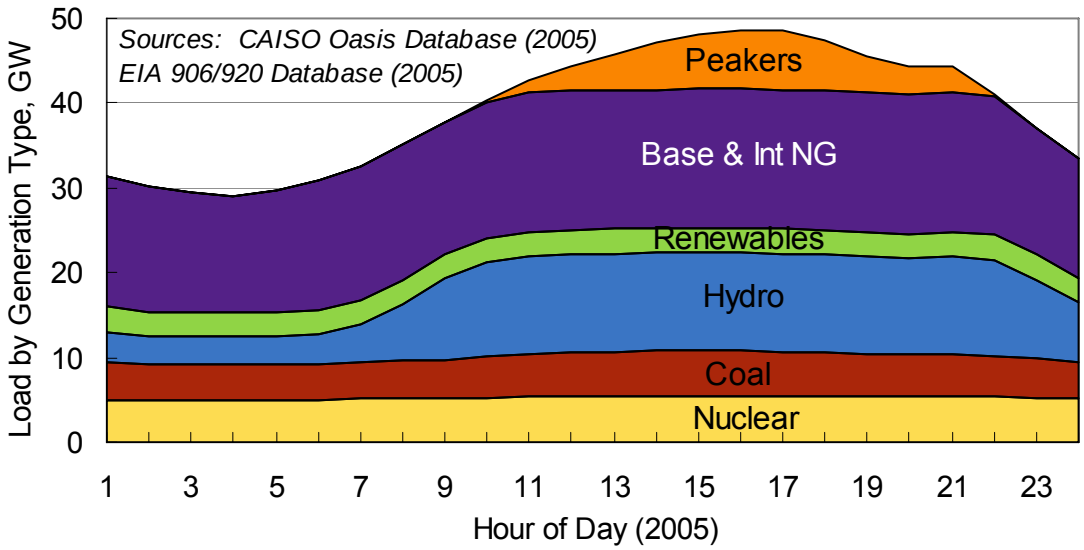


Figure 3-18. Estimate of Resource Mix Serving 2005 Peak Month Loads

[36] SMUD, LADWP, Pacificorp, Imperial Valley, Sierra Pacific, Turlock Irrigation District, and Truckee Donner.

[37] EIA-906/920 Database, 2005.

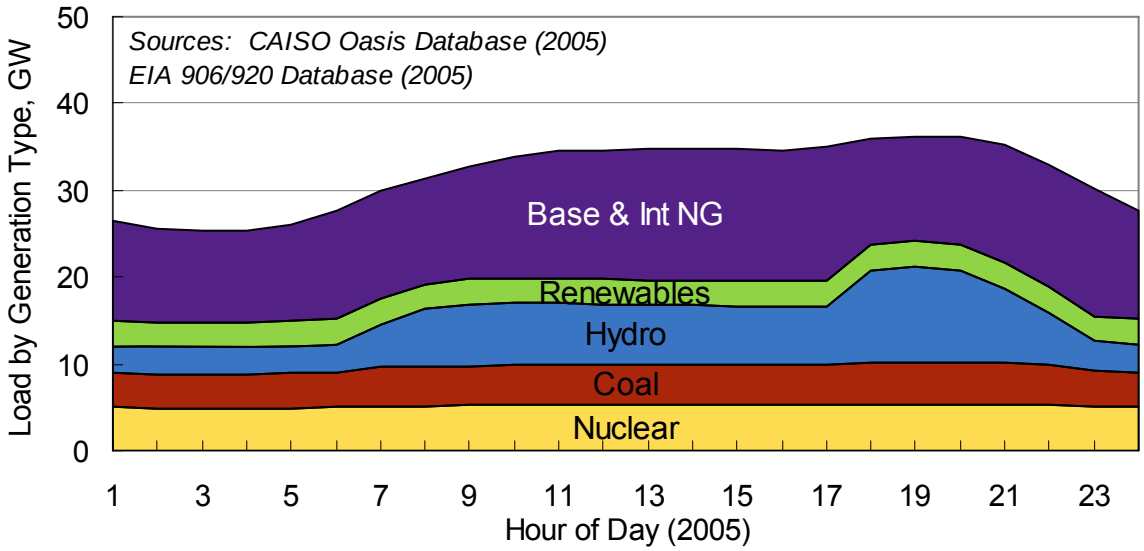


Figure 3-19. Estimate of Resource Mix Serving 2005 Non-Peak Month Loads

3.10.3 Future Electricity Resources for California

What resources will California utilize to meet future electricity demand, including demand from EV charging and alternative fuel production? The Energy Commission has projected[38] that energy consumption will grow between 1.2 and 1.5 percent annually from 271,000 GWh in 2004 to between 310,700 and 323,400 GWh in 2016. Peak demand is expected to grow at a faster rate; 1.4 to 1.75 percent annually from 56,435 MW in 2005 to nearly 70,000 MW in 2016. This growing demand will continue to be supplied by existing in-state and imported electricity from nuclear, coal, hydroelectric, natural gas, and renewable resources.

Many assumptions must be made to project the resource mix for electricity consumed in California for the analysis period of 2012 through 2030. The main assumptions made here are:

- The amount (GWh) of nuclear electricity generated and consumed within California remains constant. The underlying assumption is that either re-licensing efforts will be successful and/or that new nuclear plants will be constructed to replace decommissioned units.

[38] "Integrated Energy Policy Report", November 2005, CEC-100-2005-007CMF

- The amount (GWh) of nuclear electricity imported into California will remain constant. This may not be valid as interest in construction of new nuclear capacity outside of California is on the rise.

- The amount (GWh) of hydroelectric generation within California remains constant. This assumes that all the hydroelectric assets will be successfully re-licensed.

- The amount (GWh) of hydroelectric imports will remain constant. This assumes that Western states will continue to sell this power to California even though the electricity demands within the Pacific Northwest rise.

- The amount (GWh) of "in-state" coal generation will remain at 2005 levels less the contribution from Mohave, which has been retired is replaced.

- The goals set forth in the Renewable Portfolio Standard (RPS) will be met.

- Future long-term contracts for imported power will have emissions consistent with natural gas fired combined cycle combustion turbines (new and emerging California policy statements).

Given the foregoing assumptions, it is evident that the balance between future capacity and demand will be made up of a combination of renewables (both in-state and imported) and natural gas. In other words, the marginal electricity for new load will be met with a combination of natural gas CCCTs and renewable energy. The underlying assumption of this analysis is that generation capacity will expand slightly ahead of demand in an orderly fashion. If, for example California nuclear capacity is not re-licensed and it is not possible to install new nuclear capacity, an unstable period lasting several years would occur until sufficient natural gas CCCTs could be installed.

As mentioned above, this study assumes that the contribution of renewable resources to the total electricity consumption will track with the Renewable Portfolio Standard (RPS). Several years ago, SB1078 established the RPS requiring that 20 percent of all power sold in California must be renewable by the end of 2017. The 2005 Integrated Energy Policy Report and The Energy Action Plan accelerated the 20 percent goal to 2010 and added a 33 percent goal for 2030. These goals have been endorsed by the Governor and are used in this analysis. Figure 3-20 illustrates the projected total electricity consumed in California through 2030 along with the amount of renewables consistent with the RPS. As can be seen, over 115,000 GWh of renewable energy is projected to be produced and consumed by 2030.

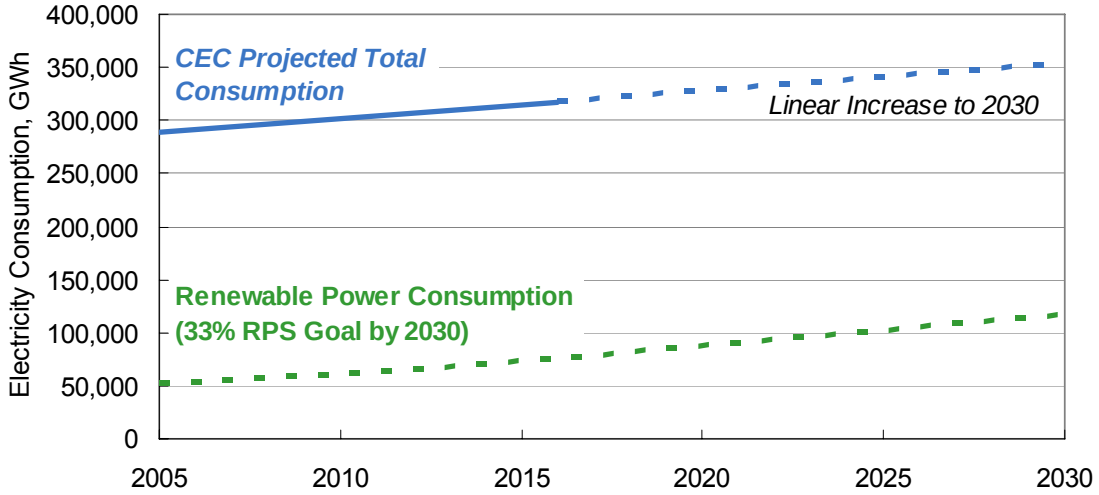


Figure 3-20. Projected Total and Renewable Electricity Consumption, 2005-2030

For the WTT analysis, two different RPS cases are considered. The first RPS case assumes that all renewable generation is from noncombustion sources: hydroelectric, geothermal, wind and solar. The second RPS case (given in Table 3-27) is based on the split of renewable resources utilized in 2005. As can be seen, the analysis assumes that the hydroelectric and geothermal capacity remain constant with time while the wind, solar, wood/biomass, and landfill gas (LFG) generation increases.

Table 3-27. Projected Electricity Generation from Renewable Resources, RPS Case 2

	Electricity Consumed/Sold by Resource Type, GWh				
	2005	2012	2017	2022	2030
Wind	2,594	9,136	15,101	21,453	32,425
Solar	538	1,893	3,129	4,446	6,719
Geothermal	12,014	12,014	12,014	12,014	12,014
Hydroelectric	33,040	33,040	33,040	33,040	33,040
LFG	673	2,369	3,916	5,563	8,408
Wood	1,939	6,827	11,285	16,032	24,231
Total Renewables	50,797	65,280	78,485	92,549	116,837
Total Generation	287,977	306,478	319,693	332,908	354,052
% Renewables	18%	21%	25%	28%	33%

Figures 3-21 and 3-22 show anticipated electricity generation by resource type for peak and non-peak days, assuming nighttime EV charging for the Case 3 market penetration scenario in 2030. The demand from EV charging is indicated in pink and has not been assigned to a resource type. As can be seen, as much as 5 GW may be needed to charge EVs and PHEVs in 2030. In the nighttime charging figures, it appears that the hydroelectric resources drop-off at night and that this power could actually be used for EV charging. However, this hydroelectric power is not being lost or wasted; rather it is being stored for later use. Therefore, hydroelectric power can not be considered a marginal resource for nighttime EV charging. One interesting conclusion that can be drawn from the figures is that the nighttime EV load could level the natural gas load, effectively allowing intermediate load CCCTs to become more base-loaded, reducing the reliance on simple cycle combustion turbines.

Figures 3-22 and 3-24 provide similar data for daytime EV charging. An interesting note is that most of the EV charging is completed by the time the afternoon peaks occur during the summer.

The actual EV and PHEV charging pattern will likely be a blend of the nighttime and daytime scenarios, with Time-of-Use (TOU) metering encouraging nighttime charging. Regardless of the hourly charging pattern, a key conclusion is that EV charging represents load growth each day of the year that will have to be met by adding capacity to the grid. As discussed above, this study assumes that marginal power will come from new natural gas CCCTs combined with the RPS.

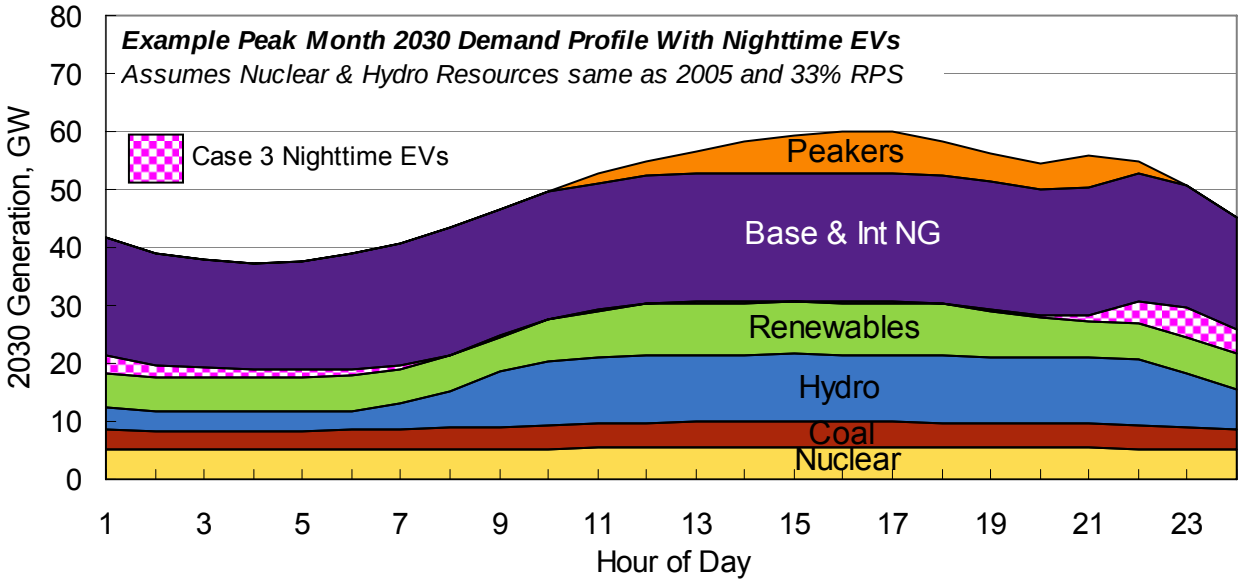


Figure 3-21. Peak Day Hourly Resources with Nighttime EV Charging (Case 3) in 2030

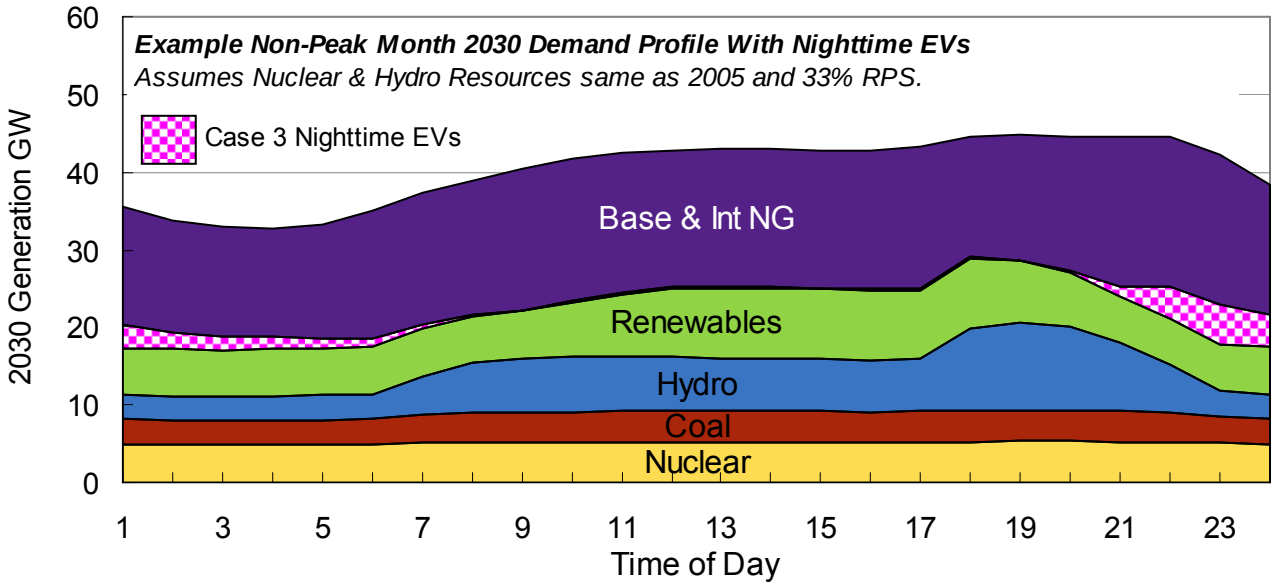


Figure 3-22. Non-Peak Day Hourly Resources with Nighttime EV Charging (Case 3) in 2030

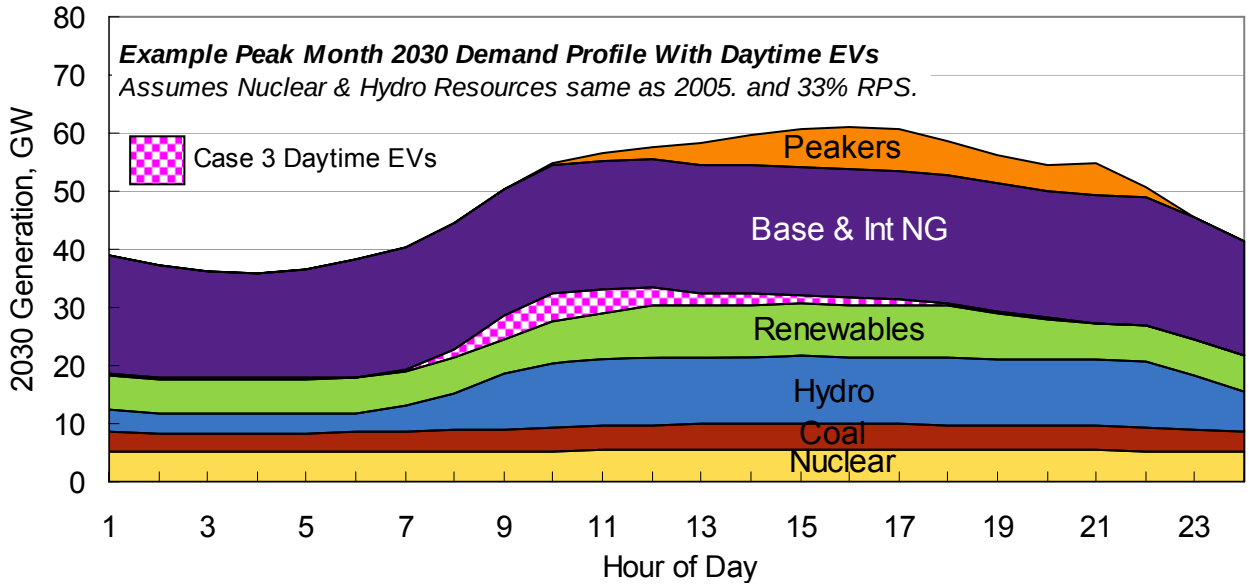


Figure 3-23. Peak Day Hourly Resources with Daytime EV Charging (Case 3) in 2030

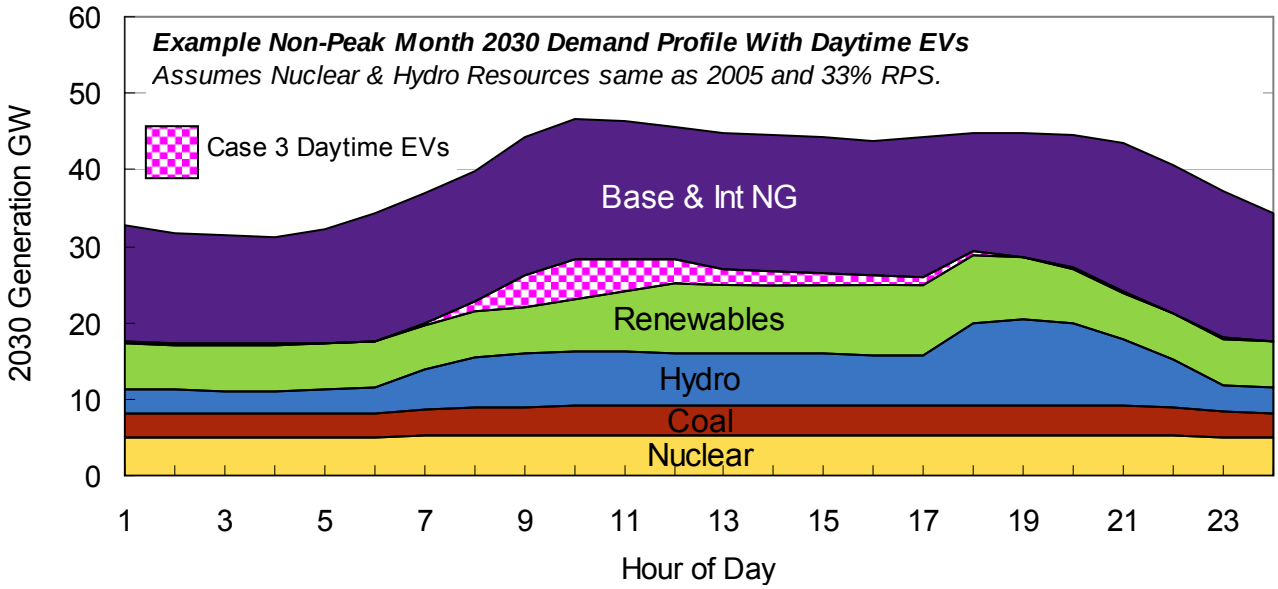


Figure 3-24. Non-Peak Day Hourly Resources with Daytime EV Charging (Case 3) in 2030

3.10.4 Marginal Electricity Emission Factors

The emissions associated with natural gas combustion are dependent on the employed combustion equipment. Table 3-28 indicates the GWh produced in California by natural gas fired steam boilers, CCCTs, and SCCTs in 2005. As can be seen, most of the natural gas based electricity was produced by CCCTs, however steam boilers still contribute a significant amount. California's aging fleet of natural gas fired steam generators has been the subject of considerable debate in recent years. Although these aging boilers are not as efficient as CCCTs (and therefore are more expensive to operate) they remain an active part of California's power mix because utilities are reluctant to enter into long term power purchase agreements with the merchant generators. In turn, the merchant generators are unable/unwilling to invest in projects to repower the boilers with CCCTs without long-term purchase agreements.

This analysis assumes that regulators will set policy allowing for the methodical retirement or repowering of the state's 66 aging steam boilers by 2012. As of 2005, seven of these boilers had been shutdown and six units were repowered with CCCTs. This analysis further assumes that all natural gas combustion during the analysis period of 2012-2030 will be in base and intermediate load CCCTs and peaking SCCTs. We further assume that the reliable daily load represented by EV charging will not be served by SCCTs because these typically operate less than 400 hours per year due to their poor efficiency. In summary, this analysis assumes that the electricity used to charge

Table 3-28. Natural Gas Based Generation by Prime Mover Type in California, 2005

	GWh	%
Steam Boiler	13,661	28%
Combined Cycle Combustion Turbine	32,951	66%
Simple Cycle Combustion Turbine	3,006	6%
Total	49,618	

Source: EIA-906/920

EVs and to produce alternative fuels will come from natural gas fired CCCTs and renewable resources according to the RPS. The primemover/fuel combinations providing electricity to EVs include:

- Natural gas fired CCCTs
- Landfill gas (LFG) fired SCCTs
- Wood/Biomass fired steam generators

To determine the emissions associated with these generation sources, emission factors and efficiency numbers for combinations of equipment and fuels of interest have been compiled. Table 3-29 provides heatrates for California's natural gas fired CCCTs, calculated from 2005 EIA data. As can be seen, the MWh weighted average heatrate (HHV basis) is about 7,500 Btu/kWh.

Emission factors for new natural gas fired CCCTs, LFG SCCTs, and wood/woodwaste, coal and natural gas fired boilers are provided in Table 3-30 on both a HHV and LHV basis.

Table 3-31 provides a comparison of the emission factors (LHV Basis) in the GREET model to the TIAX values for a new NG CCCT sited in California. As can be seen, the NO_x, CO and VOC emission factors are much lower than the default values employed in the GREET model.

Finally, the emission factors and heatrates are combined to show emissions on a gram of pollutant per GJ of electricity produced for each of the scenario years. The two different RPS cases are shown: the one with renewables split per Table 3-27 and the non-combustion RPS scenario. These composite emission factors are provided in Table 3-32.

Table 3-29. Heatrates (HHV Basis) for California's NG fired CCCTs, 2005

Plant Name	Heat Input MBtu	Output Net MWh	Net Heatrate Btu/kWh
Moss Landing	34,778,407	4,863,979	7,150
Coolwater	3,825,163	364,996	10,480
Mountain View	1,132,584	148,559	7,624
El Centro	3,805,460	387,576	9,819
Harbor	2,655,108	268,095	9,904
Haynes	19,384,563	2,277,396	8,512
Valley	18,225,357	2,488,485	7,324
Foster Wheeler Martinez	6,841,961	670,810	10,200
Sutter Energy Center	18,036,357	2,429,452	7,424
Los Medanos	25,975,028	3,594,588	7,226
Blythe Energy Center	6,650,204	830,040	8,012
Delta Energy center	39,273,020	5,359,470	7,328
Metcalf Energy Center	14,404,139	2,020,895	7,128
Elk Hills Power	24,962,020	3,590,648	6,952
High Desert Power	26,896,808	3,656,116	7,357
Totals/weighted average	246,846,179	32,951,106	7,491

Source: 2005 EIA-906/920 Database

Table 3-30. Emission Factors for Utility Generators

		Coal Fired Steam Turbines	NG Fired Steam Turbines	NG Fired Combined Cycle CTs	NG Fired Simple Cycle CTs	LFG Fired Simple Cycle CTs	Wood Fired Boilers
Emission Factors (lb/MMBtu, HHV Basis)	**Criteria Pollutants**						
	NO_x[1]	0.4000	0.0325	0.0024	0.0305	0.0778	0.4900
	VOC	0.00	0.0023	0.0021	0.0021	0.0130	0.0170
	SO_2[2]	0.2100	0.0006	0.0006	0.0006	0.0450	0.0250
	PM_{10}[3]	0.02	0.0075	0.0066	0.0066	0.0230	0.061
	CO[4]	0.02	0.0824	0.013	0.030	0.44	0.60
	Toxic Air Contaminants[5]						
	Benzene	0.0001	0.0000	0.000	0.000	0.00	0.00
	1-3 Butadiene	—	—	0.000	0.000	—	—
	Formaldehyde	0.0000	0.0001	0.001	0.001	—	0.00
	Acetaldehyde	0.0000		0.000	0.000	—	0.00
	Lead	0.0000	0.0000	—	—	—	0.00
	Mercury	0.0000	0.0000	—	—	—	0.00
	Greenhouse Gases						
	Methane[5]	0.0017	0.0054	0.0086	0.0086	—	0.0210
	N_2O[5]	0.0021	0.0006	0.0030	0.0030	—	0.013
	CO_2[6]	200	117	117	117	50	0
Emission Factors (g/MMBtu, LHV Basis)	**Criteria Pollutants**						
	NO_x	189	16	1	15	39	234
	VOC	1.18	1.13	1.06	1.06	6.53	8.12
	SO_2	99.4	0.302	0.302	0.302	22.6	11.9
	PM_{10}	9.47	3.74	3.32	3.32	11.56	29.14
	CO	9.86	41.4	6.5	15.1	221	287
	Toxic Air Contaminants						
	Benzene	0.0256	0.0010	0.0060	0.0060	0.1055	2.0062
	1-3 Butadiene	—	—	0.0002	0.0002	—	—
	Formaldehyde	0.0000	0.0369	0.3568	0.3568	—	2.1017
	Acetaldehyde	0.0112	0.0000	0.0201	0.0201	—	0.3965
	Lead	0.0083	0.0002	—	—	—	0.0229
	Mercury	0.0016	0.0001	—	—	—	0.0017
	Greenhouse Gases						
	Methane	0.79	2.71	4.32	4.32	—	10.03
	N_2O	0.99	0.32	1.51	1.51	—	6.21
	CO_2	94,896	58,771	58,771	58,771	25,125	0

1. Steam turbine NO_x avg of California boilers from 2005 Acid rain database. CCCT NO_x assumes 2 ppm, SCCT & LFG at 25 ppm.
2. 40CFR Part 75 App D default factor for pipeline quality natural gas. LFG and wood from AP-42.
3. From most recent versions of EPA's AP-42. PM_{10} includes condensable and filter catch. Assume wood boiler equipped with an ESP.
4. 5 ppm for NG CCCT, AP-42 for all others.
5. AP-42
6. CO_2 Factor for NG is CCAR reporting protocol value. LFG and wood from AP-42.

Table 3-31. Comparison of GREET and TIAX California NG CCCT Emission Factors

	2010 NG CCCT Emission Factors, g/MMBtu (LHV basis)						
	VOC	CO	NOx	PM10	SO2	CH4	N2O
GREET 1.7	3.43	24.0	114	1.31		4.26	1.50
TIAX Analysis	1.06	6.53	1.23	3.32	0.302	4.32	1.51

Table 3-32. Composite Emission Factors (g per GJ electricity produced) for each RPS Scenario

Renewables (%)[2]		2012 21%	2017 25%	2022 28%	2030 33%
		NG CCCT + Combustion RPS[1]			
Emission Factor, g/GJ Electricity Produced With Transmission & Distribution Loss[3]	Criteria Pollutants				
	NO_x	19	29	39	55
	VOC	2.4	2.8	3.1	3.6
	SO_2	1.8	2.6	3.4	4.6
	PM_{10}	7.6	8.7	9.8	11.6
	CO	49	63	76	98
	Air Toxics				
	Benzene	0.2	0.2	0.3	0.4
	1-3 Butadiene	0.0	0.0	0.0	0.0
	Formaldehyde	0.7	0.8	0.9	1.0
	Acetaldehyde	0.060	0.075	0.089	0.112
	Lead	0.0016	0.0025	0.0035	0.0049
	Mercury	0.0001	0.0002	0.0003	0.0004
	Greenhouse Gases				
	Methane	7.6	7.7	7.9	8.0
	N_2O	2.9	3.1	3.2	3.5
	CO_2	94,604	91,060	87,511	81,826
		NG CCCT + NonCombustion RPS[1]			
Emission Factor, g/GJ Electricity Produced With Transmission & Distribution Loss[3]	Criteria Pollutants				
	NO_x	1.81	1.74	1.66	1.54
	VOC	1.56	1.50	1.43	1.33
	SO_2	0.446	0.428	0.409	0.380
	PM_{10}	4.91	4.71	4.50	4.18
	CO	22.3	21.4	20.5	19.0
	Air Toxics				
	Benzene	0.0089	0.0086	0.0082	0.0076
	1-3 Butadiene	0.0003	0.0003	0.0003	0.0003
	Formaldehyde	0.5280	0.5062	0.4844	0.4495
	Acetaldehyde	0.0297	0.0285	0.0273	0.0253
	Lead	0	0	0	0
	Mercury	0	0	0	0
	Greenhouse Gases				
	Methane	6.4	6.1	5.9	5.4
	N_2O	2.2	2.1	2.0	1.9
	CO_2	86,980	83,388	79,796	74,049

1. Combustion RPS assumes hydroelectric and geothermal GWh remain at 2005 levels. Increases due to solar, wind, LFG and, wood/biomass combustion. Noncombustion RPS assumes all renewables are from noncombustion sources.
2. Assumes linear increase from 2005 levels to 33% of total GWh in 2030.
3. Statewide average T&D loss of 8.1% applied to composite emission factor. "Electricity Use in California" Past Trends and Present Usage Patterns," May 2002, LBNL-47992

SECTION 4. TRANSPORTATION AND DISTRIBUTION

Transportation of feedstocks and fuels is an important component of the overall fuel cycle, significantly impacting local emissions, energy consumption, and GHG emissions. Emissions and energy consumption vary with transportation mode, delivery distance, cargo capacity, and mode specific energy use. Such variables depend on the fuel production scenario including the location of feedstock and fuel production facilities.

This section describes the transportation modes for a variety of alternative fuel options. The modes, distances, and energy consumption are presented for feedstock, wholesale fuels, and finished fuels.

Primary energy inputs for fuel transport and delivery are presented. These values serve as inputs to the WTT energy and emission analysis. The results of this analysis are presented in Section 7. Emission factors for fuel transportation and delivery equipment are discussed in Section 5.

4.1 Fuel Transport

A marginal demand increase for an alternative fuel will increase the energy consumption and emission output of a particular transportation pathway. In addition, it displaces a similar amount of gasoline or diesel fuel, thereby reducing the energy consumption and emission output of that pathway. In order to properly evaluate the energy and emission tradeoffs of various fuels it is necessary to properly identify the transportation pathway or pathways that are used to move feedstocks and fuels from the origin to California and the consumer.

4.1.1 Gasoline & Diesel Transport

The general practice - and the assumption of this study - is that the supply of marginal gasoline and diesel fuel involves the transport of finished fuel to California for distribution to bulk terminals and subsequent truck delivery. While marginal demand will be fulfilled by imported product, it is important to consider the present supply of gasoline and diesel.

California has an extensive infrastructure for refining gasoline, diesel, and jet fuels from crude produced in California, and imported from Alaska and foreign nations (primarily in the Persian Gulf). Crude produced in California is transported to refineries via pipeline; crude arriving by tanker arrives in San Francisco Bay or the Ports of Los Angeles and Long Beach. Crude oil pipelines carry imported crude from the marine terminals to northern and southern California refineries. CARBOB, diesel, and jet fuel are distributed to some 60 terminals located throughout the state by pipelines. The largest pipeline company in California is Kinder Morgan with over 3,400 miles of pipelines, some of which are shown in Figure 4-1.

Figure 4-1 provides an overview of crude oil and refined products transport in California. The figure illustrates the amount of crude shipped into northern and southern California ports. Refined petroleum products are also shipped from Washington to greater Los Angeles, from the Bay Area to Portland and Los Angeles, as well as from foreign refineries to Northern and Southern California. U.S. Gulf Coast products are also brought into the Los Angeles and San Francisco ports.

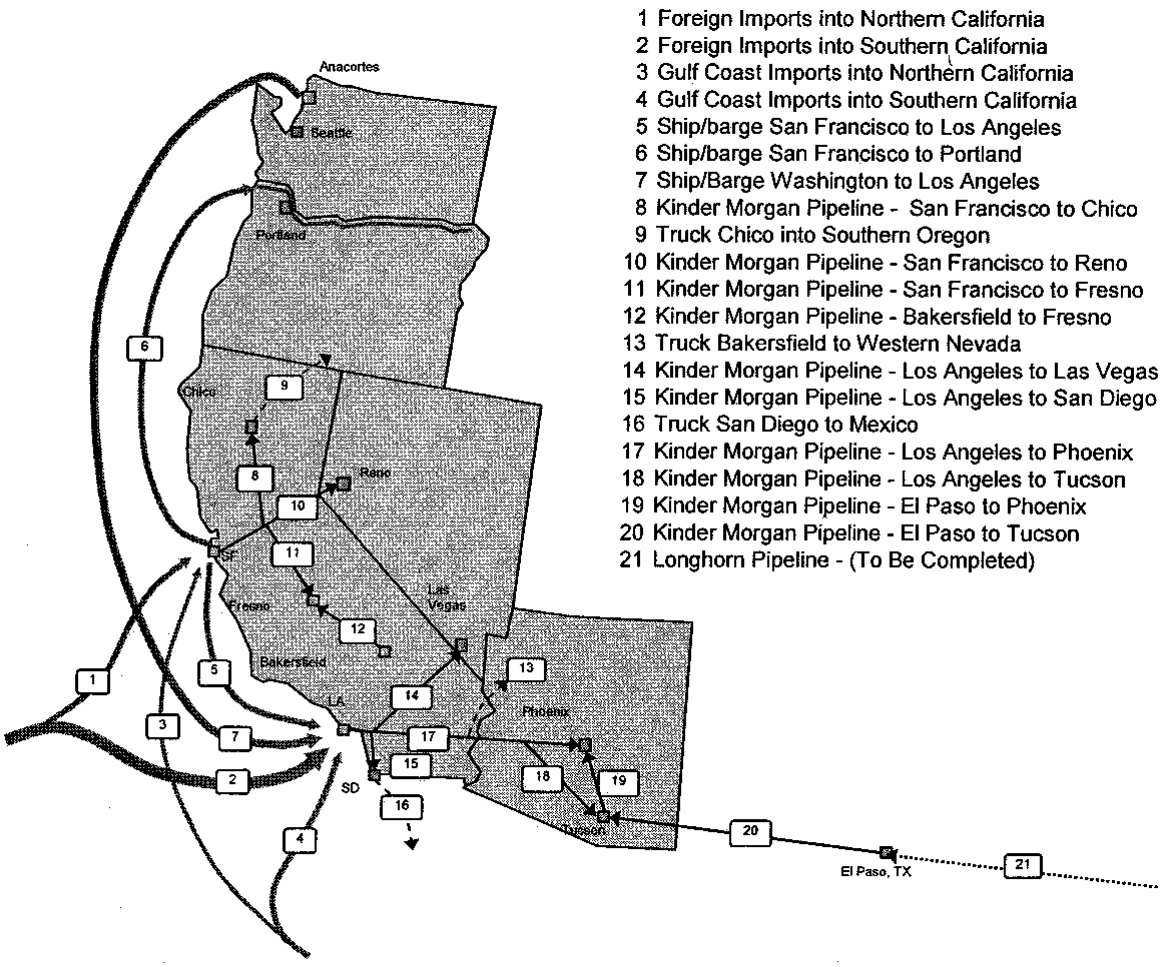


Figure 4-1. California Petroleum Flows and Infrastructure (Source: CEC 2003)

4.1.2 Ethanol Transport

Ethanol may be produced, used, and transported in a variety of ways. Presently, ethanol is used as a low-level blending component in California gasoline. It is likely that future ethanol use in California will dramatically increase either as a stand-alone fuel

(E85) or as a blending component of increasing percentage. This necessitates an analysis of all potential production methods and transport pathways.

In the analysis time frame, a majority of ethanol will likely derive from midwest corn or Brazilian sugarcane. This analysis will evaluate the transportation of ethanol and feedstock for both production scenarios.

At present, ethanol derived from midwest corn is produced near the feedstock source and transported by rail to blending terminals in California. This transportation pathway is not expected to change, as the only alternative is transport on barges down the Mississippi River and through the Panama Canal. This is not a favorable option.

Brazilian ethanol is produced from sugarcane grown in south-central Brazil – the Sao Paulo state in particular. Ethanol production plants are generally in close proximity to the feedstock and the finished fuel is transported by rail to the ports where it is loaded onto tankers and transported to California via the Panama Canal. This ethanol will end up at terminals in the Bay Area or the Ports of LA/Long Beach. Ethanol imported through the Caribbean Initiative is often Brazilian ethanol that has been dehydrated at processing plants in Trinidad. The transportation distance is not substantially different than direct delivery from Brazil, however, the tanker ship must be unloaded and loaded at the reprocessing facilities.

Pathways for producing ethanol in California are also considered. These options fall into two primary categories. First, the ethanol plant is located close to the feedstock source - such as an agricultural region in the Central or Imperial Valley. Feedstocks for ethanol plants are typically located within 25 miles of the plant. The other category involves locating corn based ethanol plants near cattle feedlots and dairy facilities in the Central Valley. For these facilities, corn is transported from the Midwest. To some extent, the byproducts from the corn based ethanol plant displace corn and cattle feed that is imported from the Midwest. While some corn is also grown in California, it is mostly grown for silage and not likely to be considered as a feedstock for ethanol production.

When used as a blending component for gasoline, ethanol is transported by tanker truck to terminals where it is blended into CARBOB with other proprietary additives. Blending ethanol with gasoline requires the removal of some of the lower molecular weight components from gasoline, primarily pentanes, in order to provide a resultant vapor pressure that meets California requirements. During the summer months, pentanes are shipped to Nevada by railcar where they are blended with gasoline. The incremental energy and emissions associated with shipping pentanes to Nevada can be attributed to meeting California RFG requirements with the current E5.7 blend.

Ethanol products are not shipped in petroleum pipelines due to the risk of water or sediment absorption as well as the possibility of ethanol affecting the life of the pipeline by dissolving corroded components. Regardless of the rationale for segregated infrastructure, trucks will remain the near term delivery mode.

4.1.3 Natural Gas Transport

California's natural gas supply includes in-state production as well as imports from the southwest U.S. and western Canada. Natural gas from these locations is transported almost exclusively through a large network of natural gas pipelines. This extensive network makes the transportation of natural gas particularly efficient as there are a minimum number of steps between production and the consumer. The primary energy input is the pipeline natural gas required to run the natural gas compressors throughout the pipeline distribution system.

With demand for natural gas increasing it is evident that, in future, marginal demand growth for natural gas will be supplied from outside California. Some of this demand will be fulfilled by increasing imports from other parts of the U.S. and Canada; in addition much of it will be imported from overseas.

4.1.4 Liquid Natural Gas Transport

Liquid natural gas (LNG) will likely be the primary supplement to North American natural gas. LNG is exported by numerous countries outside of North America, the most prolific of which are Russia, Norway, the Netherlands, Algeria, Indonesia, and Malaysia. Given the geographical factors, it is likely that a large portion of LNG imports will originate in Borneo which is rich in natural gas reserves. LNG is shipped in specially designed tankers that require dedicated terminals for off-loading product. In general, LNG will undergo phase change at the terminal and be transported throughout California in the existing pipeline network. Presently there are no LNG terminals on the West Coast. However, several locations are being considered as sites for LNG terminals. These proposals site terminals in Southern California, Baja, and Coos Bay, Oregon. With the construction of new (potentially off-shore) LNG terminals, natural gas will have to be transported from the terminals to the central distribution network in California.

LNG for vehicle fueling is unlikely to come from import terminals. The leading import terminals proposaled are being configured for off-shore unloading and regasification. Therefore, supplies of LNG considered as the primary case for the analysis are peak shaving and pressure let down facilities. Currently LNG travels over 500 miles from peak shaving facilities to serve vehicle fleets in California.

4.1.5 Natural Gas Derived Fuel Transport

A number of fuels - methanol, DME, FT diesel – are produced from natural gas. Given that domestic natural gas resources are used for a variety of important applications, it is safe to assume that any sizable consumption of NG-derived fuels will be produced from foreign natural gas resources. As with LNG, Borneo is a likely source for these fuels. Constructing production plants in the vicinity of natural gas wells and transporting liquid fuels onboard tankers is the most efficient method for providing NG-derived fuels for use

in California. Upon arrival in California, the fuels will be transferred to blending terminals or retail stations.

4.1.6 Biodiesel Transport

Sources of biodiesel include soybean oil from the midwest, palm oil from Malaysia, and mustard seed grown in California. The assumption of this analysis is that these oils will be shipped via tanker, rail, and truck to the processing plants in California where they will be reacted with an alcohol (generally methanol) and other minor components in an esterification process to produce mono-alkyl esters (methyl-ester when using methanol). Glycerol is a byproduct of this process and is used to make soap. This soap must be transported from the processing facility. Once biodiesel production is complete, tanker trucks will move the finished product to retail locations throughout the state.

4.2 Delivery Distances

Once the general pathways have been laid out, it is important to consider the important variables affecting criteria pollutant and GHG emissions. A primary factor affecting the GHG emissions profile of various fuels is the transport distance of feedstocks and fuels. Some of the fuel pathways have components that are well defined, with known production or harvest locations, defined transport modes and consistent destinations. In these cases defining the delivery distance is relatively straightforward. Other pathways are less defined, thus requiring assumptions to be made about particular pathways. The methodology of this analysis requires quantifying the marginal fuel consumption. As a result, it is necessary to identify the location of the feedstock or production facility for the demand that will occur in the time frame of this analysis. For many of these products there are existing sources that may be at capacity or otherwise unable to meet increased demand. In these cases, care was taken to evaluate fuels with delivery distances that are probable and yield fair comparisons between fuels with equally undefined transportation pathways. Table 4-1 lists the relevant delivery distances for various fuels and transport modes.

When quantifying emissions for those transport pathways that cross the California border, it is important to determine what portion of the emissions for that particular pathway occur in California. Under certain circumstances evenly distributing the emitted pollutants along the pathway would improperly attribute emissions to transport outside of the state. Part of accurately quantifying these emissions is properly defining the delivery distances within California. This is of particular importance in the case of marine vessels and railways.

Table 4-1. Transport Distance Assumptions

Mode	Fuel	Origin	Destination	Shipping Distance (miles)	Notes
Tanker	Crude Oil	Valdez, AK	San Francisco	1,700	
		Saudi Arabia	Long Beach	9,800	Port Fahd Terminal, Saudi Arabia
		Analysis Value		9,800	Assumes marginal supply from Gulf states
	Gasoline (CARBOB)	St. John, NB	Long Beach	5,200	Large Irving Oil refinery produces CARBOB in Eastern Canada
		Dubai	Long Beach	11,100	
		Saudi Arabia	Long Beach	9,800	
		Analysis Value		7,900	Weighted average of Canada, 52%; Dubai, 27%; Saudia Arabia, 22%.
	LNG	Borneo	Long Beach	7,200	Borneo is the largest exporter of LNG and proposed terminals are located in southern California/Baja
	DME	**Analysis Value**		7,200	Appropriate for all NGs derived fuels to have equal delivery distance
	FT Diesel	**Analysis Value**		7,200	Appropriate for all NGs derived fuels to have equal delivery distance
	Methanol	Indonesia/ Malaysia	Long Beach	7,200	Cabo Negro, Chile is the location of the primary producer of imported methanol
		Analysis Value		7,200	Appropriate for all NGs derived fuels to have equal delivery distance
	Ethanol	Brazil	Long Beach	7,300	Santos, Brazi - Assumes the use of Panamax tankers
	Palm Oil	Borneo	Long Beach	7,200	Bontang, Indonesia
	Biodiesel	Borneo	Long Beach	7,200	Bontang, Indonesia
Rail	Ethanol (Sugarcane)	Sao Paulo, Brazil	Santos, Brazil	300	Ethanol is shipped by rail from plants in the center of the Sao Paulo state to the port of Santos
	Ethanol (Corn)	Nebraska	California	1,400	Ethanol is imported into California where it is blended with gasoline
	Corn	Nebraska	California	1,400	Corn is imported into California from the Midwest for use in ethanol production facilities
	Soybean Oil	Nebraska	California	1,400	Soybean oil is imported into CA from the Midwest for use in biodiesel production facilities
	LPG CA Product	**Analysis Value**		50	Transport of LPG from California plant to California terminal
	LPG Import Product	New Mexico	California	900	Transport of LPG from facility in Albuquerque, New Mexico to California terminal
	Pentane	California	Nevada	400	Byproduct of California refineries is transported by rail to salt domes in Nevada
Pipeline	Gasoline (CARBOB)	**Analysis Value**		50	Gasoline piped from California refineries to California terminals
	Diesel	**Analysis Value**		50	Diesel piped from California refineries to California terminals
	Natural Gas	New Mexico	California	650	
		Alberta	California	1,400	
		Analysis Value		1,000	Average delivery distance between Alberta and Albuquerque
	Natural Gas	Baja	California	300	Natural gas from a LNG terminal in Baja is piped to California terminals
	Hydrogen	**Analysis Value**		100	Hydrogen from California plants is piped to California terminals
Truck	LNG	Arizona	California	500	LNG is transferred by truck from a Topak, Arizona pressure let-down facility
		Wyoming	California	1,200	LNG is transferred by truck from a Wyoming nitrogen rejection unit
		Analysis Value		600	Majority of LNG by truck will come from Topak, Arizona
	Ethanol	**Analysis Value**		50	All ethanol arriving at a port or rail yard will be transferred to trucks for transport to a California blending terminal
	Methanol	**Analysis Value**		50	Methanol from port will be transported by truck to the California biodiesel plant

One way transportation distance. Energy required for marine, rail, and truck transport is for twice the distance shown here

4.2.1 Marine Vessel Transport Distance

In the case of marine vessels, it is not clear when the emissions from vessels should be considered to occur in California given that the ships are at sea. For this analysis a California boundary was set at 100 nautical-miles. Within this 100 nautical-mile range all emitted pollutants will be quantified as being emitted inside California. This distance was chosen for two reasons. The first is that it is generally consistent with the boundary of California Coastal Waters (except on part of the South Coast where the distance can get as close as 30 nautical-miles). The second is that emissions emitted at this distance – and farther – have been shown to effect on-shore air quality. The emissions from marine vessels within this boundary include transit, in-port maneuvering, and hotelling (the emissions from the auxiliary engine that occur when the ship is in port). Had these emissions been evenly distributed along the entire delivery pathway it would greatly reduce the effect that this pathway has on air quality in California.

It is assumed for this analysis that there is no intra-state transport of feedstock, fuels or byproduct employing marine vessels.

4.2.2 Railway Transport Distance

Freight trains more obviously cross a state border indicating when they are emitting in California. However, it is more difficult to determine how far these trains travel once inside the state. Marine vessels will generally make a more direct route away from the California shore and are only limited to two general destinations on the coast. Freight trains however, have the potential for a far more varied transport route once inside California. Figure 4-2 illustrates California's major rail networks (not including local commuter or light-rail networks).

As illustrated, there are three main corridors for rail traffic coming into California, from the north and from the east into both the northern and southern regions of the state. Given the assumptions about feedstock and fuel production locations, as well as population centers, four major routes were assumed for inter-state railway traffic:

- Westbound from the Lake Tahoe region to the Bay Area: 185 miles
- Westbound from the Lake Tahoe region to Sacramento: 110 miles
- Westbound from Arizona/southern Nevada to Los Angeles: 285 miles
- Westbound from Arizona/southern Nevada to San Bernadino: 215 miles

These routes were weighted based on each region's overall population to determine the amount of freight being transported to each destination. Table 4-2 lists the assumed transport distances and regional populations that were used to arrive at the average distance of 236 miles for freight trains traveling with product into California. This is the value used in the computational analysis.

Figure 4-2. California Railway Map[39]

Table 4-2. California Petroleum Flows and Infrastructure (Source: CEC 2003)

General Destination	Approximate Population (million)	Miles	Fraction
SF Bay Area	5.8	185	21%
Sacramento Area	2.8	110	10%
Los Angeles Area	14.9	285	54%
San Bernadino Area	4	215	15%
	Weighted Average	**236**	**100%**

[39] Infobase, Ltd.

4.2.3 Pipeline Transport Distance

Pipelines will bring natural gas into California from wells in the southwest and western Canada. Natural gas transport is evaluated at an average distance between the two primary North American supplies. Additional natural gas pipelines will likely transport natural gas from proposed LNG terminals on Mexico's Baja coast. Natural gas imports are evaluated via these two pathways: North American supplies and foreign LNG.

In addition to transporting natural gas, pipelines are used to distribute finished fuels from California refineries to bulk terminals across the state. In order to model the impact of this transportation pathway, it is necessary to make assumptions of the average distance between refineries and terminals as well as the fraction of fuel that is transported via that pathway. To determine the average distance that finished fuels are transported by pipeline, a population-based weighted average of major transport routes was calculated. The major transport routes include the following:

- Transfer from Bay Area refineries to various Bay Area terminals: 30 miles
- Transfer from Bay Area refineries to terminals in the Sacramento area: 52 miles
- Transfer from southern California refineries to terminals in the Los Angeles area: 30 miles
- Transfer from southern California refineries to terminals in the San Bernadino area: 65 miles
- Transfer from southern California refineries to terminals in the San Diego area: 95 miles

Pipeline distances were estimated using straight line-distances with an additional 15 percent for the fact that pipelines will not always take a direct route from refinery to terminal. These distances are reiterated in Table 4-3, which shows the population weighted distance employed in the analyses. This process begets the assumption of a 50-mile delivery distance for gasoline and diesel being transported to terminals. At the terminal additives and blending components are added before finished fuels are loaded onto trucks for distribution to retail outlets.

A certain fraction of refined product will be shipped from the refinery on trucks. Refineries generally have a terminal that distributes finished fuels to local area retailers. For this analysis it is assumed that 70 percent of the refined product leaves the refinery by pipeline en route to terminals, and the remainder is blended on-site and exits the refinery by truck from an on-site terminal.

Table 4-3. Estimated Pipeline Delivery Distance

General Destination	Approximate Population (million)	Miles	Fraction
SF Bay Area	5.8	30	19%
Sacramento Area	2.8	52	9%
Los Angeles Area	14.9	30	49%
San Bernadino Area	4	65	13%
San Diego Area	3.1	95	10%
	Weighted Average*	**50**	**100%**

*Includes additional 15% to account for pipelines not travelling straight line distances

4.2.4 Truck Transport Distance

Tanker trucks, as shown in Figure 4-3, are used for a variety of purposes, including transporting LNG from domestic sources, transporting methanol to biodiesel plants, and transporting ethanol to blending stations. However, the primary application for tanker trucks is the distribution of gasoline and diesel fuels to fueling stations throughout the state. Table 4-4 summarizes the number of stations distributing gasoline in California. There are some 15,500 retail, card lock, and private stations that dispense gasoline in California. There are an additional 4,700 stations owned and operated by government or utility companies that also dispense gasoline. Present assumptions state that 70 percent of these stations are served by trucks coming from bulk terminals, and the other 30 percent by trucks from terminals at the refineries.

Figure 4-3. Typical Gasoline Tractor and Straight Tanker Trucks

Table 4-4. Number of Retail and Other Fueling Stations Located in California in 2001-02[40]

Facility Type/Owner	Number
Retail	9,398
Card lock	157
Private	5,997
Subtotal	15,552
Federal	449
State	508
Local	2,306
Utility	1,500
Subtotal	4,763
Airport	101
Marina	73
Subtotal	174
Bulk plant	190
Pump Station	79
Tank Farms	14
Terminals	135
Refinery	31
Subtotal	449

Using VIUS[41] the number of California tanker trucks was estimated at 1,391 in 2002. VIUS also provides the average annual mileage of these trucks, estimated at 164,000 miles. If these trucks distribute 14.6 billion gallons of gasoline per year at a capacity of 8,000 gallons per truck, then each truck makes on average 1,312 deliveries per year or about 3.6 deliveries per day. Average daily miles per trip is 125 miles at these average deliveries and annual mileages. Gasoline tanker trucks are used to transport the fuel the "relatively" short distance from the terminals to retail stations.

A one-way 50-mile distance was assumed for wholesale fuel delivery from refineries or marine terminals to product terminals in California. This distance reflects the travel in the San Francisco Bay Area and Southern California Area, and is roughly half the VIUS round-trip.

[40] http://www.energy.ca.gov/gasoline/gasoline_stations/index.html

[41] U.S. Census Bureau, U.S. Department of Commerce, "United States 2002, 2002 Economic Census, Vehicle Inventory and Use Survey", EC02TV-US, December 2004.

For alternative liquid fuels including methanol, ethanol, FTD and biodiesel, sufficient bulk terminal capacity was assumed to allow for a 50-mile truck transportation distance.

In the case of LNG, a greater transportation distance was assumed due to the anticipation that there will be a limited number of bulk LNG terminals. LNG tanker trucks were evaluated at a delivery distance of 100 miles. It is probable that LNG would be distributed directly from peak shaving facilities in California[42]. Intermediate product terminals would be unlikely, as the cryogenic fuels cannot readily be transported by pipeline.

4.3 Transportation Modes and Capacity

4.3.1 Marine Vessel

Emissions and energy use occurring during transit depends primarily on two variables: delivery distance and vessel size (DWT). Delivery distance will affect the duration of transit, and the vessel size affects the power output of the main propulsion engine. Table 4-5 lists the assumed capacity for ships carrying particular fuels. As the vessel gets larger the relative size of the main engine will decrease, making for more efficient transportation. The relationship between vessel size (capacity) and main engine power is shown in Figure 5-3.

Table 4-5. Tanker Cargo Capacity

Fuel	Ship Capacity (DWT)	Notes
Crude Oil	185,000	Capacity of BP tankers operating between Valdez, AK and California
Gasoline (CARBOB)	150,000	
LNG	68,000	Conventional LNG tanker carries ~135,000 m^3
Methanol	150,000	
DME	150,000	
FT Diesel	150,000	
Ethanol	80,000	Largest Panamax tanker
Biodiesel	150,000	

As stated earlier, in addition to capacity, delivery distance is the parameter that most effects GHG emissions for a particular fuel cycle. Table 4-1 lists important delivery distances for a variety of fuels. It is important to note that this analysis attempts to

[42] The same rationale would apply to LNG import terminals, however, no proposed projects appear to be configured for LNG fuel distribution.

evaluate the marginal supply. Therefore, the production location of the marginal supply may not coincide with the location of present production. For example, Chile is presently a world leader in methanol production. However, a significant move to methanol as a fuel of choice will undoubtedly lead to production in other locations. Thus for this analysis the distance from Indonesia/Malaysia was assumed for methanol as well as for the other natural gas derived fuels. Indonesia and Malaysia have significant natural gas resources and it is appropriate to compare all of those fuels with the same delivery distance.

4.3.2 Railway

Railroads commonly transport large quantities of various commodities and are one of the most efficient methods for hauling freight. In the context of alternative fuel production and distribution, railroads may serve to move finished fuels, feedstocks, as well as waste products from processing facilities. Quantifying the energy use and pollutant emissions of transporting freight via rail is made difficult by the flexibility associated with the transport mode. Trains are often “built” in railyards in a manner that will most efficiently transport various goods to their required destinations. Freight and tanker cars carrying particular material can be transported in trains carrying like materials or in trains hauling numerous other types of freight. Particularly in the case of trains with various cargo, the number of cars and locomotives can vary throughout a trip as certain cargo reaches intended destinations. The complex dynamics associated with trains hauling multiple cargoes makes quantifying emissions associated with a particular cargo quite difficult.

Commodities shipped in large quantities with a limited distribution network are often carried on trains that haul a single material with a limited number of destinations. Trains of such specifications are commonly referred to as “unit-trains”. Coal is the most prevalent commodity on the railways and is typically hauled on unit trains from mines to electrical power plants. Significant growth in the consumption of alternative fuels requiring transport by train will likely lead to the use of unit-trains, as the quantities will be large and the distribution will likely be limited to refineries, processing plants and bulk terminals. Coal trains typically consist of 100-car trains hauling up to 10,000 tons of material with up to six locomotives providing propulsive power. This analysis assumes that any fuel, feedstock, or material transported by rail moves in 100-car unit trains. Individual tanker cars typically contain 30,000 gallons of liquid product, thus creating 100-car unit trains with overall capacities ranging from 8,000-10,000 tons for typical fuels.

4.3.3 Pipeline

The share of power generation technologies for pipeline compression stations are assumed to be 55 percent turbines, 36 percent current natural gas engines, and 9 percent future (advanced) natural gas engines (the default values for GREET). The energy intensity of pipeline transportation is generally 240 Btu/ton-mile for turbines, 270 Btu/ton-mile for current natural gas engines, and 260 Btu/ton-mile for future natural

gas engines. The exceptions are natural gas pipelines that require 336/355/346 Btu/ton-mile respectively and CO_2 pipelines that require 133/140/137 Btu/ton-mile respectively.

4.3.4 Trucks

The assumed truck cargo carrying capacity is consistent with an 80,000 lb GVW limit for tanker trucks carrying liquid fuels or practical limits on the maximum volume for LNG and hydrogen trucks. Gasoline trucks can carry 9,000 gallons of fuel or a cargo weight of 54,000 lb. The volume of other fuels that can be carried will be less, depending on the density of the fuel. A 50-mile one-way trip was assumed as a transportation distance for all fuels, which reflects the average distance traveled by fuel delivery trucks in California. The assumed value is slightly below the state average to the delivery to urban areas rather than remote regions of California.

4.4 Urban Transport

When quantifying the emissions of criteria pollutants in California, it is necessary to consider the location at which the emissions occur. California has large regions specified as non-attainment areas with elevated levels of some number of criteria pollutants. These non-attainment regions include nearly all urbanized regions in the state. It is therefore necessary to quantify the portion of emissions occurring within the non-attainment regions. In the case of transport emissions, specifying the length of transport in these regions allows for the proper quantification of emissions.

For bulk transport the relevant delivery distances are shown in Table 4-5.

Table 4-5. Urban Bulk Transport Delivery Distances

	Tanker	NG Pipeline	Rail	Truck
Transport Miles inside California	115	160	236	160

For bulk transport, the analysis assumes that all of the transport in California occurs within the non-attainment regions. From both the Bay Area and Los Angeles, the non-attainment regions stretch east to the eastern border of the state. The majority of transport occurs within these corridors. This analysis does not consider emissions resulting from north-south ethanol transport through the Central Valley.

The urban distances for tanker/ships and rail are discussed in Section 4.2.1 (Marine Vessel Transport Distance) and Section 4.2.2 (Railway Transport Distance). For pipelines and trucks the delivery distance is assumed equal to the straight-line distance from Baja, California, Wyoming, or Nevada to either the Bay Area or the South Coast.

In addition to the urban distances for bulk transport, all of the emissions associated with fuel distribution – primarily from trucks – are assumed to occur in the non-attainment

area. The assumed distribution distance is 50 miles and follows a similar logic to that is discussed in Section 4.2.4.

Special distribution cases include LPG transported in trucks from California refineries to fueling stations over an assumed distance of 50 miles and hydrogen shipped by pipeline to fueling stations 50 miles from the production facility. The potential exists for mixed-mode hydrogen distribution, where trucks deliver hydrogen to outlying areas. Nevertheless, this analysis assumes that hydrogen is primarily distributed through distribution pipelines.

SECTION 5. EMISSIONS FROM FUEL PRODUCTION AND DISTRIBUTION

This section describes emissions from feedstock extraction, fuel production, and distribution. The emissions sources are covered roughly in order from extraction through distribution with some overlap. Section 5.1 reviews emission rates from equipment used in transporting feedstocks and fuel and in processing operations. Energy usage rates for transportation equipment are discussed in Section 4.

Fuel production emissions and energy inputs are covered in the following subsections. The allocation of energy use to product fuels is discussed. While fuel production processes have a minor or no effect on marginal NMOG or NO_x emissions in California, they are still analyzed as they affect global CO_2 emissions. Fuel processing is defined as the conversion of feedstock material into end use fuel, or fuel production. Feedstock input requirements also relate to feedstock extraction requirements which are covered in Section 3. Several fuels are processed from a combination of feedstocks and process fuels. Oil refineries and gas treatment plants produce multiple fuel products. Many production facilities import or export electricity, and excess heat energy can be exported to other facilities.

Section 5.3 discusses emissions from fuel storage and distribution. These represent the most significant sources of marginal NMOG emissions. Local fuel cycle emissions are presented in terms of emissions per unit of fuel distributed (i.e. actual gallons of fuel). This approach allows for a more direct comparison with the steps in the fuel cycle.

For example, consider a diesel delivery truck with 7,800 gal of fuel traveling a 50-mi round trip route. A diesel truck fuel consumption of 5 mi/gal is expressed in energy terms as 0.0011 J/J product based on lower heating values. Expressing all of the fuel processing steps in energy terms allows for a convenient comparison amongst different fuel-cycle emission studies. In the case of fuel delivery trucks, a constant mileage is assumed for all fuel types, and emissions are calculated from the g/mi emissions and truck fuel capacity to yield g/gal of delivered fuel. The energy associated with each step in the fuel cycle is also used to calculate GHG emissions.

5.1 Combustion Equipment Emission Factors

In the well to tank portion of the life cycle, the fuels and feedstocks are processed in a variety of combustion devices. These devices include: steam boilers, process heaters, reformers, combustion turbines, and IC engines. The fuels that are typically utilized in these types of equipment are natural gas, distillate, residual oil, coal, LPG, and biomass. The GHG emission factors for these equipment types are independent of location, though the criteria pollutant emissions will largely depend upon location. This section presents an overview of emission regulations, a discussion of local/regional emission caps, the emission factors for equipment located within California, factors for

equipment located outside of California, and a discussion of local/regional emission caps.

5.1.1 Stationary Source Emission Constraints

Stationary sources are utilized in each of the alternative fuel production processes. These sources include power plants, steam boilers, process heaters, refinery boilers and heaters, combustion turbines, and IC engines. The federal EPA sets national ambient air quality standards (NAAQS) for criteria pollutants (ozone, NO_2, CO, VOC, SO_2, $PM_{2.5}$, and lead). At present there are no mandatory constraints on GHG emissions, therefore this discussion will focus on criteria pollutants. As can be seen in Figure 5-1, much of California does not attain the federal 8 hr ambient air quality standard for ozone. The San Joaquin and South Coast basins also fail to attain the federal standard for $PM_{2.5}$. Air districts that do not attain the NAAQS must implement regulations that reduce emissions contributing to the exceedance, and also show that the region will attain the ambient standard by the required date.

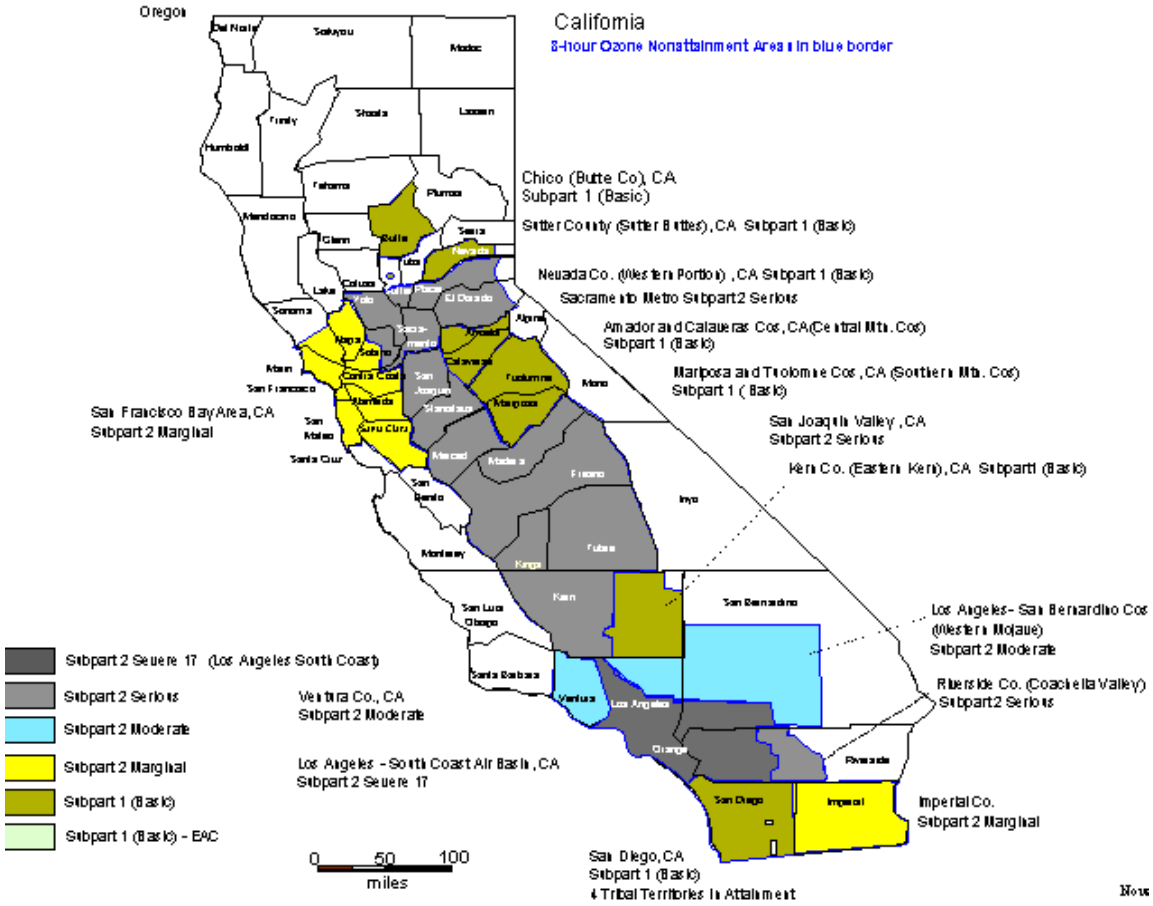


Figure 5-1. California Areas Not Attaining the 8-Hour Federal Ambient Standard for Ozone

Therefore, a combustion source's allowable emission rates are to a large degree dependent on location. Equipment located in an ozone nonattainment area will likely have lower NO_x levels than equipment located in areas that attain the ozone standard. In nonattainment areas, two different types of rules affect stationary sources:

- Existing stationary sources are subject to prohibitory rules mandating retrofit with Reasonably Available Control Technology (RACT)

- New and modified stationary sources are subject to New Source Review (NSR) permitting which requires Best Available Control Technology (BACT)[43] and the surrender of offsets (depending on annual emission thresholds in the particular district that the equipment is located).

The fuel cycle analysis assumes that all alternative fuel production equipment in California will be new installations in populated (ozone nonattainment) areas; therefore the RACT limits are not applicable. The new combustion equipment will be subject to nonattainment NSR permitting. Nonattainment NSR requires both installation of BACT and the surrender of offsets (generally at a ratio greater than 1:1) for the nonattainment pollutants. BACT levels for NO_x emissions generally require installation of selective catalytic reduction (SCR).

Offsets are emission reduction credits (ERCs) in currency of lb/yr into perpetuity. ERCs may be generated by permanently reducing emissions below required levels on-site, or they may be purchased from other entities within the nonattainment area that have permanently reduced their emissions below what is required by current regulations. One might argue that new facilities sited in nonattainment areas to produce alternative transportation fuels would be subject to the offset requirements. As a result, these new facilities would not result in an increase in air emissions in the region.

However, emissions from a new/modified piece of equipment must exceed a certain annual emission threshold before the offset requirements are triggered. In the SCAQMD, the threshold is 4 tons/yr of NO_x, VOC, SO_2, or PM_{10}. In the BAAQMD the threshold is 35 tons/yr of any pollutant. In the SMAQMD, the threshold is 5,000 lb/quarter of NO_x or VOC. In general, small pieces of equipment (engines, boilers < 20 MMBtu/hr, combustion turbines) will not by themselves trigger the offset requirement. But a new facility with equipment collectively emitting more than the threshold will be required to offset their emissions.

5.1.2 Other Local/Regional Emission Caps

As discussed in the previous paragraphs, nonattainment NSR permitting creates a cap on local nonattainment pollutant emissions. This is a leaky cap, though, since pieces of equipment below the emission threshold are exempted from the offset requirements.

[43] Note that in California, BACT is equivalent to the federal definition of Lowest Achievable Emission Rate (LAER)

Another example of a regional cap is SCAQMD's Regional Clean Air Incentive Market (RECLAIM) program. Participation in the RECLAIM program is mandatory for facilities emitting 4 or more tons/yr of NO_x or SO_2. New alternative fuel production facilities emitting more than 4 tons/yr of NO_x would be required to participate in the RECLAIM program.

Probably the best example of a successful cap and trade program is the Acid Rain SO_2 Trading program. In 1980, total SO_2 emissions from utility generators greater than 25 MW was 17.2 million tons. The current emission cap is 8.95 million tons. Because all utility generators in the U.S. are subject to this cap, marginal SO_2 emissions from electricity generation are zero.

Another successful cap and trade program is the NO_x Budget Trading Program. Started in the 1990s, with 11 Northeastern states agreeing to cap and reduce their ozone season NO_x emissions, the program has grown to include 21 Northeastern and Midwestern states plus the District of Columbia. The rule applies to all pieces of equipment that generate 25 MW or more of electricity for sale and requires NO_x controls during the ozone season (May 1-Sept 30). The program allocates allowances to each unit based on historic ozone season heat inputs and an emission rate of 0.15 lb/MMBtu.

The Clean Air Interstate Rule (CAIR), promulgated in 2005, is essentially an extension of the Acid Rain SO_2 and the NO_x Budget Programs. Figure 5-2 illustrates the states a ffected by the CAIR rule. Most states are affected by the particulate requirement, therefore requiring year round control of both SO_2 and NO_x. Three states are only

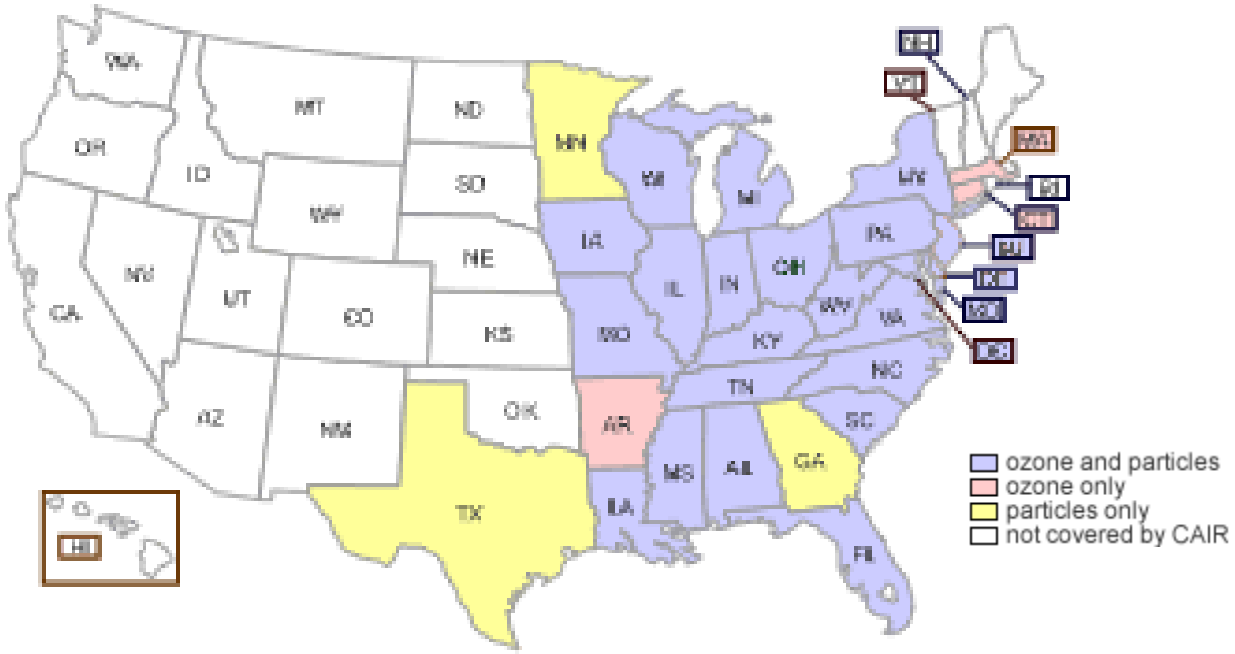


Figure 5-2. States Affected by the Clean Air Interstate Rule

ozone affected and therefore only need to comply with seasonal NO_x limits. For SO_2, affected units must surrender 2 allowances for each ton emitted beginning in 2010 and 2.86 allowances for each ton emitted beginning in 2015. The NO_x allowances will be allocated consistent with historic heat input levels and an emission rate of 0.15 lb/MMBtu.

Coincident with the CAIR program in 2005, EPA also issued its Clean Air Mercury Rule (CAMR). This rule established a cap and trade program for mercury emissions from coal fired utility generators. Emissions are capped and must be reduced by 70 percent from current levels by 2018. Therefore, in marginal WTW analyses, mercury emissions from coal fired utility generators should be set to zero.

5.1.3 Emission Factors for California Equipment

As noted above, the fuel cycle analysis assumes that all alternative fuel production equipment in California will be new installations in populated (ozone nonattainment) areas and therefore the RACT limits are not applicable. The new combustion equipment will be subject to nonattainment NSR permitting and therefore BACT and offsets. Note that the term BACT in California is equivalent to the Federal Lowest Achievable Emission Rate (LAER), and the terms are interchangeable.

Table 5-1 provides a summary of BACT/LAER emission levels for each type of equipment compiled from a survey of the most recent BACT determinations on the SCAQMD website. Note that BACT levels require the use of natural gas, therefore only natural gas fired equipment are considered here. In most areas, only NO_x, CO and VOC are subject to BACT. The other emission factors shown are from AP-42. The emission factor for SO_2 is EPA's default value for pipeline quality natural gas. Table 5-2 provides a comparison between GREET1.7 and the BACT values shown in Table 5-1.

The second component of nonattainment NSR permitting is offsets. Again, we are assuming that all alternative fuel production plants in California will be located in ozone nonattainment areas and therefore emissions of NO_x and VOC fall under nonattainment NSR. Because the offset applicability thresholds (in tons/yr) are very low, it is assumed that all new alternative fuel production facilities sited in California will be required to offset the NO_x and VOC emissions from their facilities. As a result, the plants will not result in an increase in the regional NO_x/VOC emissions and therefore the emission factors for these plants have been set to zero.

Table 5-1. Emission Factors for New Combustion Equipment in California

	Pollutant	BACT/LAER, Natural Gas Fired Equipment				
		Combustion Turbine	Utility Boiler	Industrial Boiler	Process Heater	IC Engine
BACT	NO_x					
	ppm (3% O_2)		5	9	5	
	ppm (15% O_2)	2				7.3
	lb/MMBtu (HHV)	0.010	0.008	0.015	0.008	0.037
	g/MMBtu (LHV)	5.1	4.2	7.6	4.2	18.8
	CO					
	ppm (3% O_2)		5	100	10	
	ppm (15% O_2)	2				36
	lb/MMBtu (HHV)	0.017	0.014	0.277	0.028	0.303
	g/MMBtu (LHV)	8.5	7.0	139.4	13.9	152.2
	VOC[1]					
	lb/10^6 scf			5.5	5.5	
	ppm (3% O_2)		4.2			
	ppm (15% O_2)					11
	lb/MMBtu (HHV)	0.0015	0.0204			0.1620
	g/MMBtu (LHV)	0.7538	10.2436	2.54	2.54	81.4
AP-42	PM_{10}					
	lb/10^6 scf		7.6	7.6	7.6	
	lb/MMBtu (HHV)	0.0066				0.04831
	g/MMBtu (LHV)	3.32	3.51	3.51	3.51	24.28
	CH_4					
	lb/10^6 scf			2.3	2.3	
	lb/MMBtu (HHV)	0.009	0.0023	0.0023	0.0023	0.977
	g/MMBtu (LHV)	4.322	1.133	1.133	1.133	491.0
	N_2O					
	lb/10^6 scf					
	lb/MMBtu (HHV)	0.003	0.00063	0.00063	0.00063	
	g/MMBtu (LHV)	1.51	0.315	0.315	0.315	
EPA	SO_2[2]					
	lb/MMBtu (HHV)	0.0006	0.0006	0.0006	0.0006	0.0006
	g/MMBtu (LHV)	0.3015	0.3015	0.3015	0.3015	0.3015

1. ppm values converted assuming a MW of 16.
2. EPA default value for "pipeline quality" natural gas. 40CFR 75 App D.

Table 5-2. Comparison of BACT values to 2010 values in GREET1.7

	g/MMBtu, LHV Basis						
	VOC	CO	NO_x	PM_{10}	SO_2	CH_4	N_2O
TIAX California Values							
Combustion Turbine	0.75	8.46	5.15	3.32	0.30	4.32	1.51
Utility Boiler	10.24	6.97	4.24	3.51	0.30	1.13	0.32
Industrial Boiler	2.54	139.36	7.63	3.51	0.30	1.13	0.32
Process Heater	2.54	13.94	4.24	3.51	0.30	1.13	0.32
IC Engine	81.39	152.21	18.79	24.28	0.30	490.95	n/a
GREET 1.7 Values (2010)							
Combustion Turbine	1.00	24.00	113.0	3.10		4.26	1.50
Utility Boiler	1.56	16.42	57.61	3.21		1.10	1.10
Industrial Boiler (Small)	2.42	28.82	30.00	2.96		1.10	1.10
IC Engine	41.12	342.45	1200	5.53		368.9	1.50

Values for PM_{10}, CH_4 and N_2O are from AP-42. SO_2 is EPA's default for pipeline quality NG

5.1.4 Emission Factors for Equipment Located Outside of California

For combustion equipment located outside of California, the combustion equipment emission factors in the most recent version of the GREET1.7 model are used. The emission factors have recently been revised[44] by performing a statistical analysis of historic data from EPA's National Emission Inventory (NEI). For utility boilers, the impact of the Clean Air Interstate Rule (CAIR) was projected using a GWh weighted approach rather than a unit by unit average. These updated GREET emission factors are provided in Table 5-3.

Table 5-4 provides comparisons of the GREET, AP-42, and California Climate Action Registry (CCAR) emission factors for CH_4 and N_2O. As can be seen, the GREET N_2O emission factor for natural gas fired boilers (1.1 g/MMBtu) is much higher than both the AP-42 (0.32) and CCAR (0.1) factors. TIAX has elected to use the AP-42 N_2O factor for natural gas boilers in this analysis. Also, the GREET N_2O factor for coal fired IGCC appears to be a typo. Since there is no AP-42 factor for IGCC and because the CCAR values are independent of combustion equipment type, TIAX has elected to use the GREET coal fired utility boiler N_2O factor for coal fired IGCC.

[44] "Well-to-Wheels Analysis of Advanced Fuel/Vehicle Systems", Brinkman, Wang, Weber, Darlington, May 2005, Argonne National Lab, General Motors.

Table 5-3. Emission Factors for Equipment Outside of California (GREET1.7 Defaults) (g/MMBtu LHV)

	2012 Emission Factors Used in Analysis (g/MMBtu, LHV Basis)						
	VOC	CO	NO_x	PM_{10}	SO_x	CH_4	N_2O
Natural Gas							
Utility/Industrial Boiler	1.56	16.4	57.6	3.26		1.100	1.100
Small Industrial Boiler	2.42	28.8	30.0	2.96		1.100	1.100
Combustion Turbines	1.00	24.0	113.0	3.10		4.260	1.500
Combined Cycle Turbines	3.43	24.0	16.0	2.00		4.260	1.500
Reciprocating Engine	41.1	342.4	1200.0	5.53		368.9	1.500
Residual Oil							
Utility Boiler	2.0	15.8	85.0	16.00	202.6	0.9	0.36
Industrial Boiler	0.91	15.76	125.00	44.40	202.6	3.24	0.36
Commercial Boiler	0.91	15.76	125.00	60.00	202.6	1.54	0.36
Diesel Fuel							
Industrial Boiler	1.17	16.69	82.23	42.53		0.184	0.390
Commercial Boiler	1.17	16.69	82.23	42.53		0.760	0.390
Combustion Turbines	1.34	8.71	131.7	16.99		0.844	2.000
Reciprocating Engine	70.44	361.00	681.6	61.86		3.940	2.000
Coal							
Utility Boiler	1.14	100.00	105.7	10.00	228.0	4.000	1.060
Industrial Boiler	2.07	76.19	155.3	100.00	200.0	4.000	1.000
IGCC	1.5	12.3	44.1	6.5	44.1	5.098	5.098

From latest version of GREET1.7 (derived from Argonne/GM Study)

Table 5-4. Comparison of CH_4 and N_2O Emission Factors

	g/MMBtu, LHV Basis					
	CCAR[1]		AP-42		GREET 1.7	
	CH_4	N_2O	CH_4	N_2O	CH_4	N_2O
Natural Gas						
Boilers	6.6	0.1	1.13	0.315	1.10	1.10
Combustion Turbines	6.6	0.1	4.32	1.51	4.26	1.50
Reciprocating Engine	6.6	0.1	491	-	369	1.50
Residual Oil						
Utility Boiler	0.32	0.11	3.99	0.44	0.9	0.36
Industrial Boiler	0.32	0.11	3.99	0.44	3.24	0.36
Commercial Boiler	1.58	0.11	3.99	0.44	1.54	0.36
Diesel Fuel						
Industrial Boiler	0.32	0.11	0.18	0.39	0.18	0.39
Commercial Boiler	1.47	0.11	0.18	0.39	0.76	0.39
Combustion Turbines	0.32	0.11	-	-	0.84	2.00
Reciprocating Engine	1.47	0.11	3.93	-	3.94	2.00
Coal						
Utility Boiler	1.16	1.68	0.81	1.11	4.00	1.06
Industrial Boiler	1.16	1.68	0.81	1.11	4.00	1.00
IGCC	1.16	1.68	-	-	5.10	5.10

1. California Climate Action Registry Values are independent of equipment type.

Finally, as mentioned in Section 5.1, the Acid Rain Program has capped SO_2 emissions from all utility boilers in the United States. Therefore in a marginal analysis, increased electricity generation does not result in an increase in SO_2 emissions. The Clean Air Interstate Rule has capped annual utility emissions of NO_x in many states, but not all, so this analysis does not set marginal electricity NO_x emissions to zero.

5.2 Fuel Extraction, Transportation, and Processing Equipment

Several types of equipment are used repeatedly throughout the estimation of fuel-cycle emissions. For example, diesel powered tanker trucks are used to move gasoline, diesel, LPG, ethanol, LNG, and methanol fuels from storage locations. Natural gas engines and gas turbines compress natural gas and are used in a variety of fuel industry applications. These engines are used to transmit natural gas feedstock to oil refineries, and FT diesel, methanol, and electric power plants. This section summarizes the emissions and estimated usage rates for various types of equipment.

5.2.1 Marine Vessel Emissions

Crude oil and other finished fuels are often transported in tanker ships. Tanker ships generate airborne emissions from two types of engines: main propulsion engines and auxiliary engines. Main engines are generally two-stroke, slow or medium-speed compression ignition engines that burn residual oil (also know as HFO – heavy fuel oil) which typically has higher volumetric energy density and sulfur levels than diesel fuel. Main propulsion engines are used when the vessel is underway and provide propulsion through either a transmission or a generator that runs an electric propulsion system. Main propulsion engines only operate when the vessels are underway and almost exclusively burn residual oil. Auxiliary engines are used in generator-sets to meet onboard electric demand requirements both at sea and in port. Auxiliary engines can also burn residual oil, but may also burn diesel or low-sulfur diesel (especially when in port to reduce local pollutants). In order to quantify emissions from the engines on tanker ships, the operation of the tanker is divided into three distinct segments:

- Transit: the period when the vessel is operating between ports
- Maneuvering: the period when the vessel is operating in and around the port during departure and arrival
- Hotelling: the period when the vessel is in the port without any propulsive load

The main propulsion engines have different emission factors for transit and maneuvering and the auxiliary engines have a set of emission factors dependent on fuel type. The main engine factors are a weighted composite of slow and medium-speed engines, with 95 percent of the population being slow-speed engines. Tables 5-5 and 5-6 show the assumed emission factors for the different engines and operating conditions.

Table 5-5. Main Engine Emission Factors

Type	Fuel	Units	PM	NOx	SO2	HC	CO	CO2
Transit - Slow/Medium Speed Composite	HFO	g/bhp-hr	1.12	13.36	7.91	0.45	1.04	465
Maneuvering - Slow/Medium Speed Composite	HFO	g/bhp-hr	1.12	10.67	8.73	1.34	1.04	511

Table 5-6. Auxiliary Engine Emission Factors

Type	Fuel	Units	PM	NOx	SO2	HC	CO	CO2
All Modes - Medium Speed	HFO	g/bhp-hr	1.12	10.97	9.18	0.30	0.82	539
All Modes - Medium Speed	Marine Distillate	g/bhp-hr	0.22	10.37	1.57	0.30	0.82	515
All Modes - Medium Speed	Marine Distillate @0.1%S	g/bhp-hr	0.19	10.37	0.30	0.30	0.82	515

It is important to add that these emission factors are likely to change in the future. There are a few technologies and/or policies that are likely to have significant effects on these emissions, including:

- Main Engine Fuel Regulation: at present the average sulfur content in bunker fuel is ~2.7 percent. ARB is seeking 0.5 percent by 2015 leading to 75 percent reductions in PM and SO_x and a 6 percent reduction in NO_x.

- Mandatory Speed Reduction: mandating that ships slow down within a certain distance of the port will reduce the emissions of most pollutants

- Cold-Ironing: allowing or mandating that ships in port utilize grid power in place of auxiliary engines and generators

- Clean Vessels: mandating that vessels with new or rebuilt engines achieve a high standard of emission reduction, up to 60 percent of PM and 90 percent of NO_x. ARB sees the potential for 20 percent of ships to be "cleaner vessels" by 2010 and 50 percent by 2015

Of these technologies, only the Fuel Regulations seem to have a high likelihood of implementation before 2010. However the adoption of any additional technologies could significantly alter the emission characteristics of a vessel.

To calculate the emissions from an individual ship, it is necessary to determine the main engine power rating. The power requirement for a ship will vary with capacity, thus it is necessary to determine this relationship – on average – for tankers within the capacity range being considered. Three data sources provided insight into the power-capacity relationship. Figure 5-3 presents estimates by GREET and MAN Diesel, as well as a sampling of existing ship data gathered by TIAX.

As illustrated in Figure 5-3 the GREET estimate falls between the MAN estimate and TIAX data, especially in the range of our analysis (50,000-200,000 DWT). It was thus selected as the method for calculating main engine power output.

Similarly, it is necessary to determine the size of auxiliary engines. To determine this relationship, main and auxiliary engine power data from ARB was used to determine the relative size of the engines. The ARB data indicate that, on average, the auxiliary engine is 21 percent of the main engine rated capacity.

In order to compare the POLA emission factors to those used in the GREET model, it is necessary to determine engine fuel consumption using CO_2 emission data. Fuel properties from the GREET model –shown in Table 5-7 – were used to facilitate this conversion.

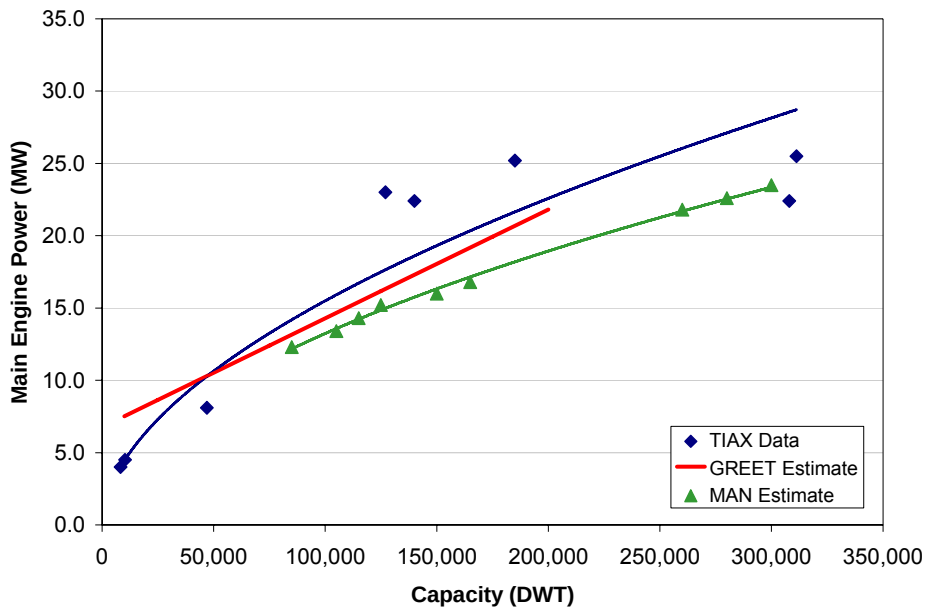


Figure 5-3. Typical Gasoline Tractor and Straight Tanker Trucks

Table 5-7. Residual Fuel Properties[45]

Fuel Property	
LHV (Btu/gal)	140,353
HHV (Btu/gal)	150,110
Density (g/gal)	3,752
C:H ratio (wt.)	0.868

Using the GREET fuel properties and the POLA CO_2 emissions data, it is possible to express the emission factors as a function of the LHV of fuel burned. In addition, the brake specific fuel consumption can be determined with the fuel properties shown in Table 5-7. It is important to note that the GREET model only considers main engine transit emissions when determining the impact of delivery on the overall fuel cycle. Therefore, Table 5-8 compares the POLA main engine, transit mode emission factors with the GREET emission factors for an ocean tanker operating on bunker fuel (in the 2010 time frame).

[45] GREET fuel properties were verified using data on Bunker C (aka: Fuel Oil No. 6, Residual Fuel Oil, Heavy Fuel Oil) from a study by "Analytika" (an independent French laboratory specializing in the analysis of organic chemicals) that verified an API Gravity between 12.3-14.1. The "Fuel Oil Manual" (Schmidt, Paul) states that a fuel oil with an API Gravity equal to 13 will have HHV/LHV of 150,310/142,030 BTU/gal which is consistent with the values in Table 4.7. A report by MAN Diesel, "Operation on Low-Sulfur Fuels: Two Stroke Engines" indicates that the average sulfur content of marine diesel fuels is 2.7%.

Table 5-8. Emission Factor Comparison

Pollutant	Units	POLA	GREET
PM*	g/MMBtu	204.7	73.5
NO_x	g/MMBtu	2,443.1	2,480.5
HC	g/MMBtu	81.9	93.5
CO	g/MMBtu	191.1	430.0

*GREET's emission factor is for PM_{10}

The POLA CO_2 emission levels yield BSFC values for the main and auxiliary engines of 196 g/kW-hr and 227 g/kW-hr. Other studies show BSFC values of 163-171 g/kW-hr for a new Wartsila low-speed marine engine (Wartsila 2006) and 184-188 g/kW-hr for older slow-speed marine engines (Wilbur 1984). The BSFC based on POLA CO_2 emission data would seem to be between 4 and 20 percent too high (more likely on the low end of that range for an older population of vessels). While this may lead to inaccuracies of a certain degree, it was decided that the BSFC was within an acceptable range to allow the POLA emission factors to be verified and accepted. In addition to proper emission factors, the appropriate load factors must be used for each transport mode. As with the emission factors, the load factors from the POLA study were used in this report. Table 5-9 lists the load factors for the various modes of transit.

Table 5-9. Engine Load Factors

Mode	Load Factor
Main Engine — Transit	80%
Main Engine — Maneuvering	2%
Auxiliary Engine — Transit	24%
Auxiliary Engine — Maneuvering	33%
Auxiliary Engine — Hotelling	26^

While the load factors in Table 5-9 were used in the present analysis, certain literature indicates that in transit the main engine can often operate between 85 and 90 percent of capacity (MAN Diesel, "Containership Propulsion).

Verified emissions factors allow for the identification of the overall vessel emissions. Emissions from marine vessels are evaluated in two segments. The first segment is between the origin of the transport leg and a boundary 100-nautical miles (~115 statute miles) from the destination. In this first segment the analysis is primarily concerned with GHG emissions. The second segment is from the 100-nautical mile boundary to the port and includes all of the maneuvering and hotelling loads that occur within the boundary. The 100-nautical mile boundary was selected as it is generally consistent with the

California Coastal Waters boundary (except along the south-central coast) and is the value used by ARB for their ocean-going vessel emission inventory.

Carbon dioxide emitted during the first transport segment depends primarily on two variables, delivery distance and vessel size (DWT). These variables are discussed in depth in Section 4.

Using the data collected, the CO_2 emissions from the transit segment are calculated and shown below in Figure 5-4. In this case the emissions are normalized by the higher heating value of the fuel transported. As a result, the values shown are also a function of fuel density and HHV.

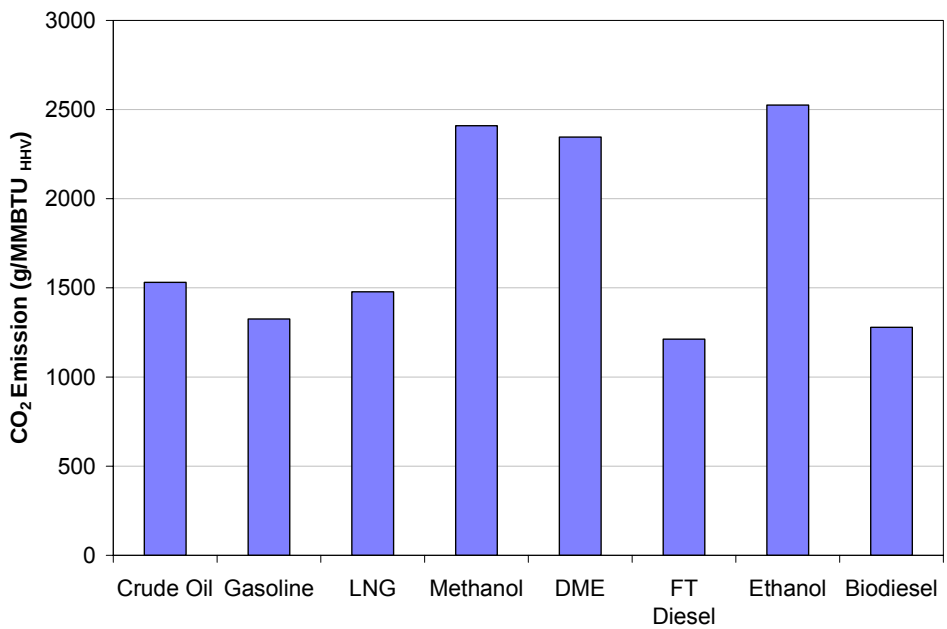


Figure 5-4 CO_2 Emissions for the Transit Segment of Tanker Transport

Three fuels seem to have particularly high levels of CO_2 emissions in the figure: methanol, DME, and ethanol. Methanol and DME are hindered by their low heating value relative to most of the other fuels. This has the consequence of transporting less energy in a ship than another fuel in a ship of similar DWT. Ethanol is hindered by the requirement that it be shipped in a vessel that can access the Panama Canal. The smaller vessel is, generally, a less efficient method of transporting fuel. In addition, ethanol is also hindered by its low heating value relative to comparable fuels such as gasoline.

As stated earlier, the GREET model does not consider maneuvering or hotelling when determining the overall impact on the fuel cycle. The present analysis aims to consider those emissions in addition to the transit emissions.

A primary factor in quantifying maneuvering, and hotelling emissions is determining the amount of time that vessels spend engaged in each mode. For this analysis the data from the POLA-study was used. This data indicate that on average a tanker spends 2 hours maneuvering in port and 38 hours hotelling. During maneuvering both the main engine and auxiliary engines are in use, although the load factor for the main engine is very low: 2 percent. During maneuvering the tankers will likely be assisted by tugboats. Emissions from those vessels are not quantified in this analysis. While hotelling the main engine is not in use, but the auxiliary is continually in use to provide electricity for the ship's systems. It is during this period where the adoption of cold-ironing would aid in the reduction of local emissions.

In order to see the effect that maneuvering and hotelling have on overall emissions, Table 5-10 lists the ratio between the total emissions within the 100-nautical mile boundary and the emissions within that boundary that are solely the result of main engine transit operation.

Table 5-10. Total / Transit Emissions Inside the 100 nautical-mile Boundary

	Crude Oil	Gasoline	LNG	Methanol	DME	FT Diesel	Ethanol	Biodiesel
PM	113%	114%	122%	114%	120%	114%	120%	114%
NOx	110%	112%	118%	112%	116%	112%	116%	112%
SO2	115%	117%	125%	117%	123%	117%	123%	117%
HC	109%	110%	115%	110%	114%	110%	114%	110%
CO	110%	111%	117%	111%	116%	111%	116%	111%
CO2	114%	117%	125%	117%	123%	117%	123%	117%

The data contained in Table 5-10 indicate that maneuvering and hotelling account for an increase of an additional 9-25 percent relative to the transit emissions within the 100-nautical mile boundary. These amounts are not insignificant and should be taken into account in any analysis of the overall fuel cycle.

In order to make this analysis compatible with the GREET structure it was necessary to express the emission factors in terms of fuel energy used, in contrast to power output. This conversion was performed using CO_2 emission data to provide fuel consumption for both the propulsion engine and the auxiliary engines. Two sets of emission factors are provided; those for emissions outside the boundary and those for emissions inside the boundary. The emission factors inside the boundary account for the maneuvering and hotelling emissions by increasing the factors associated with the energy in the transit fuel. This allows for use in the GREET model architecture. When examining the emission factors the values do not indicate the emissions associated with that specific volume of fuel, but the total in-port emissions that will occur following the transit into port. Table 5-11 provides the inputs to the GREET model that incorporate the maneuvering and hotelling emissions.

Table 5-11. Emission Factors for Tankers Inside the 100 Nautical-Mile Boundary (g/MMBtu)

	Crude Oil	Gasoline	LNG	Methanol	DME	FT Diesel	Ethanol	Biodiesel
PM	229.4	233.1	247.8	233.1	244.8	233.1	244.8	233.1
NOx	2,683	2,719	2,863	2,719	2,834	2,719	2,834	2,719
SO2	1,650	1,680	1,801	1,680	1,776	1,680	1,776	1,680
HC	89.1	90.0	94.0	90.0	93.2	90.0	93.2	90.0
CO	209.2	211.8	222.7	211.8	220.4	211.8	220.4	211.8
CO2	96,961	98,702	105,807	98,702	104,339	98,702	104,339	98,702

5.2.2 Locomotive Emissions

Line-haul locomotives (an illustration is shown in Figure 5-5) employing large four-stroke, compression-ignition engines burning diesel fuel typically provide the motive power used to move freight on the railways. Nearly all locomotives hauling freight are of the diesel-electric variety. Diesel-electric locomotives use a diesel engine ranging from 2,000-4,000 hp to generate the electricity that powers electric traction motors. This allows the engine to operate at more efficient operating conditions than would occur if the engine speed was more directly tied to the train speed. Diesel-electric locomotives operate at discrete operating points called “notches,” of which there are generally eight motive notches. In addition to the eight notches used in transit there are also engine states associated with idle and dynamic braking - which occurs when traction motors are employed as generators to assist with deceleration.

Figure 5-5. GE Line Haul Locomotive

To quantify the emissions and energy consumption associated with hauling freight on the railways it is necessary to specify what sources should be included in the overall inventory. The present analysis assumes that the following sources will be included for railway transport:

- Transit: the period between origin and destination. All locomotive emissions and energy use will be quantified under the assumption that unit-trains make uninterrupted transit
- Idle: a defined period of time at the railyard in which the main locomotive engine is operating.
- Switching: “switchers” are low-power locomotives used in the railyard to “build” trains. While unit-trains simplify the process of train building, it is assumed for this analysis that a certain amount of time is spent moving rail cars in the railyard before the train begins its transit

As locomotives generally operate in defined notches, emission factors are often provided for each notch. For this study, locomotive emission data – for both line-haul and switcher – was taken from the Port of Los Angeles emission inventory. Table 5-12 lists the emission factors from the POLA study.

Table 5-12. Locomotive Emission Factors

						Notch						
Source	**Pollutant**	**Units**	**Idle**	**DB**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**
POLA Line-Haul Locomotive	HC	g/kWh	19.72	9.24	1.41	0.63	0.48	0.36	0.34	0.32	0.34	0.34
	NOx	g/kWh	121.55	71.92	18.34	16.06	15.40	15.95	16.15	15.90	15.71	15.17
	CO	g/kWh	37.35	13.27	1.97	1.27	1.25	1.54	1.89	2.10	1.96	1.64
	PM	g/kWh	6.26	3.78	0.60	0.50	0.50	0.35	0.29	0.31	0.27	0.28
Source	**Pollutant**	**Units**	**Idle**	**DB**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**
POLA Switcher Locomotive	HC	g/kWh	9.97	3.59	1.70	0.64	0.44	0.40	0.43	0.44	0.50	0.54
	NOx	g/kWh	99.83	55.60	24.02	16.72	17.96	19.37	20.51	21.51	21.66	21.13
	CO	g/kWh	20.74	9.06	3.35	1.72	1.01	0.72	0.67	0.83	1.68	3.67
	PM	g/kWh	3.08	1.13	0.43	0.44	0.42	0.32	0.31	0.38	0.34	0.38

It is important to note that these emission factors are likely to change in the future. The EPA has passed regulations that will reduce the sulfur content of locomotive diesel fuel in 2007 – to 500 pmm - causing immediate reduction of NO_x and PM emissions. In addition, increasingly stringent emission standards will likely be implemented for new locomotives. By 2015 it may be the case that all new locomotives will meet EPA Tier 4 standards and fuel standards will have reduced the sulfur content of locomotive diesel fuel to 15 ppm. The stricter fuel standards will allow manufacturers to employ aftertreatment options that significantly reduce emissions of not only SO_2, but of NO_x and PM as well.

To quantify the transit emissions, it was necessary to define a number of variables, most importantly: locomotive power, operating states, and train speed. Determining the power required to haul a particular load is necessary, as it is not possible to simply define the average power of line-haul locomotives. The power of a locomotive does not reflect the power potential of a train because any number of locomotives may haul a particular train. To determine the power required to haul a particular load, data from a

1991 Booz-Allen & Hamilton Study, “Report on Locomotive Emission Inventory” was used to create a relationship between tonnage hauled and the locomotive power. Data shown in Figure 5-6 reflects bulk and intermodal trains operating in California’s Bay Area and Southcoast region.

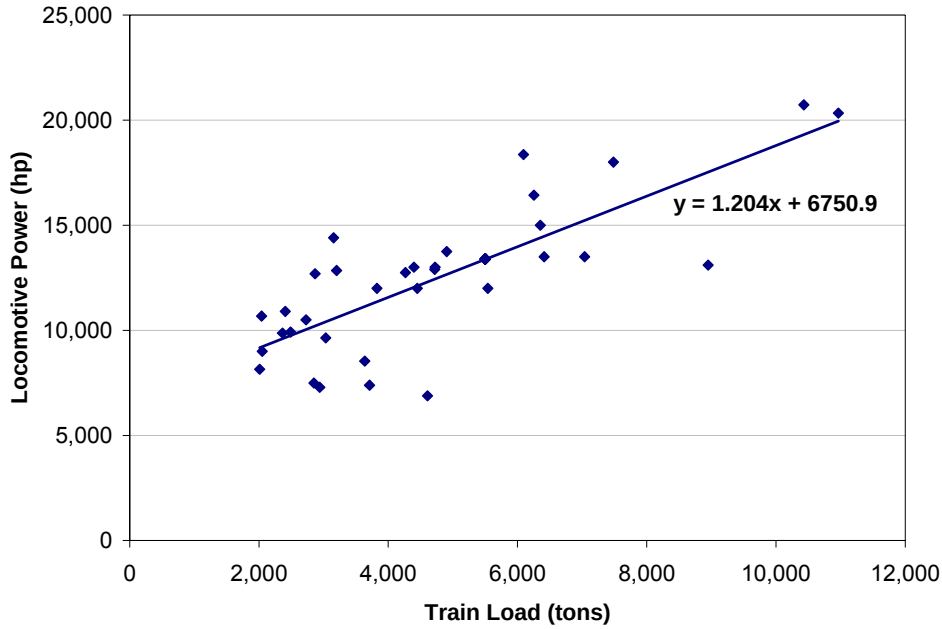


Figure 5-6. Train Load and Locomotive Power Relationship

The linear trendline in Figure 5-6 is used in this analysis to determine the power required to pull the 100-car unit trains. For this analysis, the loads hauled depend on the density of the fuels being carried in the 30,000 gallon tanker cars. For those commodities that are not carried in tanker cars and have densities difficult to quantify – corn, coal, soybeans – the total load assumed is the average of the various liquid fuel options. In the case of switcher trains it was assumed that all of the switcher locomotives have a power output of 1,750 hp. This is a value typical of switcher locomotives.

To create a composite emission factor, it is necessary to determine how much time is spent in each notch during transit and during switching. Additionally, the power output associated with each notch is important to determine overall emission output. Table 5-13 lists the fraction of time spent in each notch and the fraction of power delivered.

The data included in Table 5-13 is used in a harmonic average and in conjunction with notch-specific emission factors to create composite emission factors applicable during transit and switching. Table 5-14 lists those emission factors. These emission factors apply to two of the three phases of rail transport: transit and switching. For the period

Table 5-13. Locomotive Power and Notch Relationship

Power Percentage

Type	Source	Idle	DB	1	2	3	4	5	6	7	8
Line-Haul	POLA	0.4%	2.1%	5.0%	11.4%	23.5%	34.3%	48.1%	64.3%	86.6%	102.5%
Switcher	POLA	0.8%	3.8%	4.7%	14.2%	27.8%	42.0%	57.3%	72.5%	89.7%	105.3%

Time-in-Notch

Type	Source	Idle	DB	1	2	3	4	5	6	7	8
Line-Haul	POLA	38.0%	12.5%	6.5%	6.5%	5.2%	4.4%	3.8%	3.9%	3.0%	16.2%
Switcher	POLA	67.4%	0.0%	5.9%	7.7%	6.7%	5.3%	3.0%	2.0%	0.9%	1.1%

Table 5-14. Composite Transit Emission Factors (g/kWh)

Type	Pollutant	Value
Line-Haul	HC	0.55
	NO_x	16.59
	CO	2.00
	PM	0.37
Switcher	HC	0.96
	NO_x	23.69
	CO	2.28
	PM	0.50

during which the line-haul locomotives are idling, the idle emission factors, listed in Table 5-12, were used to determine the emissions.

Lastly, it is necessary to estimate the average train velocity in order to effectively determine the time spent in transit. Average train speed was estimated using values for locomotive BSFC and the average efficiency of goods movement – expressed in ton-miles/gallon. BSFC values are based on published data for new Caterpillar locomotive engines. For line-haul locomotives 230g/kWh is the assumed BSFC. Figure 5-7 Illustrates the data used to make that estimate.

Estimated BSFC is used with the calculated power – determined with the relationship shown in Figure 5-6 – to determine the fuel consumption in g/hr. Train speed provides the bridge between fuel consumption (g/hr) and transport efficiency (ton-miles/gallon). For this analysis the train speed was set such that the calculated efficiency equaled the values cited by industry groups, shown in Table 5-15.

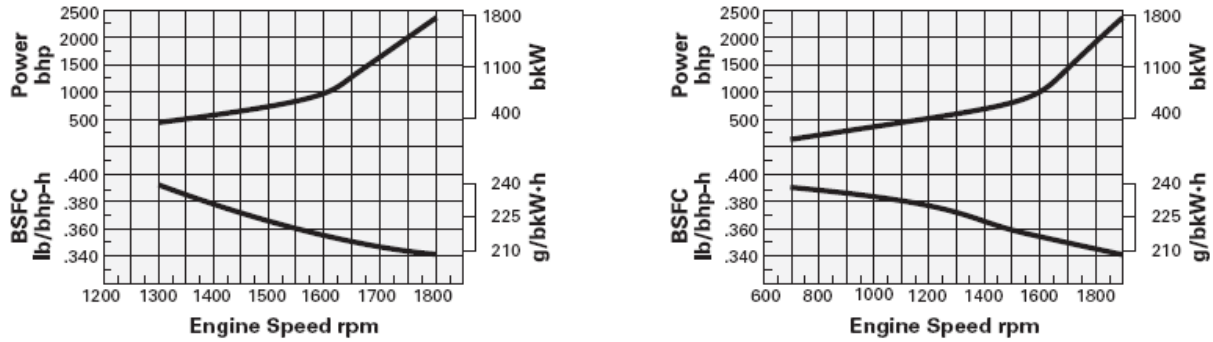


Figure 5-7. Line-Haul BSFC Data[46]

Table 5-15. Railway Transit Efficiency

Source	Efficiency (ton-mile/gallon)
GREET	347
American Association of Railroads	410
Upper Great Plains Transportation Institute	386
Average	381

The estimated BSFC and efficiency values from industry yield an estimated train speed of 24.2 mph. This estimate is somewhat higher than expected given that a 2005 Freight News report indicated that average freight train speed for the nation's largest railroads varies between 19.6-24.6 mph, with heavier freight – grain and corn – expected to fall at the lower end of that range. Nevertheless, the calculated value is within the range and agrees with the average efficiency values specified. While this elevated speed estimate may have an effect on the calculation of criteria pollutant emissions, the methodology should yield the correct fuel consumption for rail transit.

The average train speed is used in conjunction with specific delivery distances to determine the amount of time spent in transit for various scenarios. Discussion of delivery distances is discussed in Section 4. For the activities in the railyard, switching and idling, the amount of time spent was estimated based on data published by the California ARB from their study of the Roseville Railyard. It was estimated that line-haul locomotives spent 4.5 hours idling at either end of the transit trip and switching required 2 switcher-locomotives operating for 2 hours.

[46] Caterpillar 3516C Locomotive Engine, EPA Tier 2

A major addition of this analysis is the quantification of criteria pollutant emissions resulting from idling line-haul locomotives and switchers in the railyard. The GREET model does not account for these contributions. In general, the percentage of total emissions relative to the portion emitted during transit within California is about 103 percent. This confirms that the addition of line-haul idling and switching locomotives does not have a profound affect on California emissions. This results from the operating efficiency of unit-trains, for which the time spent in the railyard is significantly reduced.

In order adapt this analysis to the GREET model structure, the emission factors must be based on the LHV of fuel burned. Accordingly, GREET fuel properties are used to modify the emission factors. Table 5-16 lists the diesel fuel properties used in the analysis.

The GREET compatible emission factors are listed in Table 5-17 and compared to the GREET values. It is important to note that the GREET model only considers line-haul emissions during transit when determining the impact of rail transport on the overall fuel cycle. The emission factors presented here include all emissions in California based on the transit fuel consumption and are compared with the GREET factors in the final column. The emission factors shown in Table 5-17 used in this study are intended to provide an updated and accurate representation of the effects of railway transport on overall fuel cycle emissions.

Table 5-16. Diesel Fuel Properties

Fuel Property	
LHV (Btu/gal)	128,450
HHV (Btu/gal)	137,380
Density (g/gal)	3,167
C:H ratio (wt.)	0.865

Table 5-17. In-state Rail Emission Factors (g/MMBtu)

	This Study	GREET
HC	60	74
NO_x	1,790	1,517
CO	215	213
PM	40	36

5.2.3 Truck Emissions

Emission factors for tanker trucks can be estimate from ARB's emissions inventory code for mobile sources—EMFAC.[47] Figure 5-8 shows tanker truck NO_x and PM emission rates from 2006 to 2030. These emission factors are for the "average California" heavy, heavy duty truck. These emission factors where obtained by running EMFAC2007 for each calendar year to obtain total NO_x and $PM_{2.5}$. These emissions where then normalized by the total vehicle miles traveled in that calendar year for heavy, heavy duty diesel trucks. These factors assume that the "average" California truck weight is 56,000 lbs (laden). EMFAC2007 also includes deterioration for expected aftertreatment devices such as diesel particulate filters and either NO_x absorbers or SCR catalyst systems.[48]

No correction should be made to the EMFAC2007 NO_x and $PM_{2.5}$ emission factors for truck tanker weight or for in-use deterioration of the emission control equipment. As indicated above, tanker trucks leave the terminals full (80,000 lbs) and return empty (33,000 lbs). The average weight is 56,500 lbs, the same as the average truck weight in EMFA2007. Similarly, EMFAC2007 now includes tampering and malmaintenance (T&M) as well as malfunction of the emissions systems on existing and future diesel engines. For example, the increase in NO_x emissions for 2010 technology is 178 percent at 500,000 miles compared to the emission factor at zero miles. For $PM_{2.5}$ the increase is 144 percent.[49]

The EMFAC truck loading provides a reasonable basis for the tanker truck weight for all of the fuels hauled by truck. An 80,000 lb GVWR truck hauls 24.5 metric tons of fuel and returns empty weighing 26,000 lb. In the case of LH2 tucks, the capacity "cubes out" and the truck can hold only 4 metric tons of LH2. However, the fully laden weight of an LH2 truck is less than that of a conventional tanker truck, so the average emission factor is still appropriate. In the case of hydrogen tube trailers, the truck weighs 80,000 lb but hauls only 300 kg of fuel. The low fuel cargo capacity has a dominant effect on the emissions per kg of fuel delivered, and no adjustment to the emission factor was incorporated into the analysis for this delivery mode.

[47] EMFAC2007 was released by ARB on November 1, 2006 see http://www.arb.ca.gov/msei/onroad/latest_version.htm

[48] Zhou, Lei, "Revision of Heavy Heavy-Duty Diesel Truck Emission Factors and Speed Correction Factors", EMFAC Modeling Change Technical Memo, October 20 , 2006. http://www.arb.ca.gov/msei/onroad/techmemo/on-2006-07.pdf

[49] Ibid, pg 9

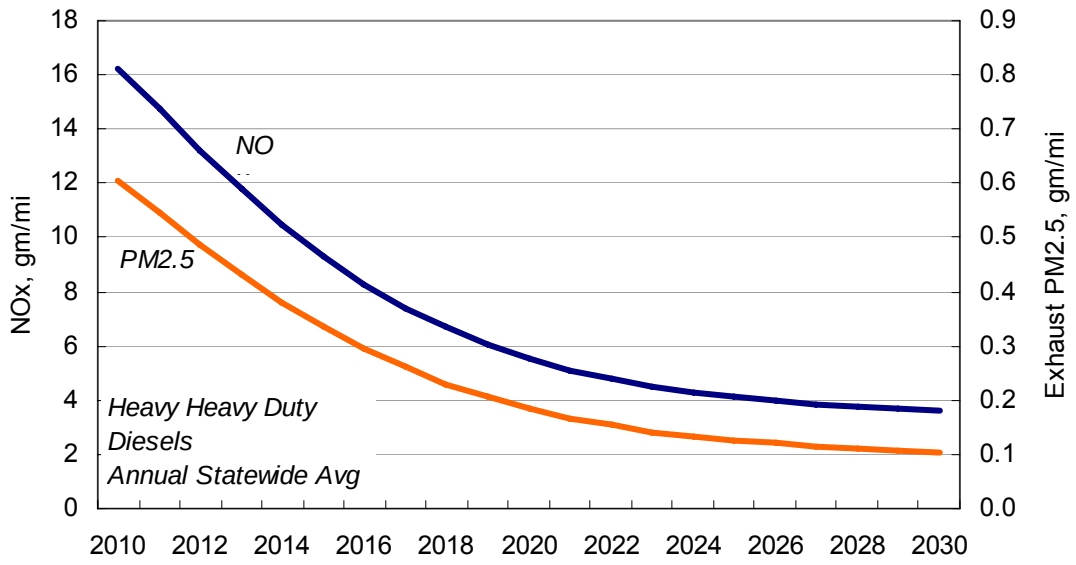


Figure 5-8. EMFAC2007 NO_x and PM Emission Factors for Gasoline and Diesel Fuel Tanker Trucks

5.2.4 Biomass Collection Equipment

Fuels and feedstocks are transported and distributed by a variety of equipment including trucks, trains, and marine vessels. Emissions from fuel or material transport were determined from emission rates and equipment usage factors that take into account distance traveled and cargo load. The emissions and use factors for the relevant fuels are discussed for each transportation mode. Several types of biomass are potential feedstocks for fuel production. Such feedstocks include agricultural residues, forest residues, and purpose grown energy crops. This study focuses on agricultural and wood residues. Feedstock transportation requirements for combustion of agricultural material and forest residue were used to estimate fuel usage in this study. The energy inputs are described in the 2001 ARB fuel cycle study.

While the collection of biomass results in emissions from gasoline and diesel equipment, the overall emissions associated with feedstock collection are likely to be a net negative. Collecting agricultural residue or forest waste results in a reduction in emissions from agricultural burns, prescriptive fires, and possibly wildfires. A report from the Energy Commission assesses the value of these emission reductions (Perez 2001).

5.2.5 Pipeline Transport Emissions

Natural gas-fired internal combustion engines are used in the natural gas industry at pipeline compressor and storage stations. These engines provide power to drive the compressors. At pipeline compressor stations, the engine is used to move natural gas from station to station. It is assumed that all pipeline engines in the South Coast are controlled. The U.S. criteria pollutant emission factors for three different engine designs from AP-42 are provided in Table 5-18. The California BACT emission factors are given in Table 5-1. Table 5-19 provides the AP-42 emission factors for toxic air contaminants that have an inhalation unit cancer risk factor (see the methodology in Section 2.2).

Table 5-20 summarizes the emission and performance characteristics of natural gas reciprocating engines used for natural gas transmission. Engines outside of North America are assumed to emit at the 1990 U.S. level.

Energy consumption is based on a population profile of reciprocating engines prime movers (Huey 1992), and emissions data for individual makes and models of engines. The energy consumption can range from 6,000 to 10,000 Btu/bhp-hr.

Population profiles of reciprocating engine prime movers indicate that the majority of these engines are lean-burn, with relatively few being stoichiometric rich-burn engines. The emission factors assigned to reciprocating engine prime movers are associated with lean-burn engines. Uncontrolled lean burn engines do not operate sufficiently lean to provide significant NO_x reductions. All new lean burn engines sold in North America are configured for low NO_x emissions.

Table 5-18. AP-42 Criteria Pollutant Emission Factors for NG fired IC Engines (lb/MMBtu)[a]

Criteria Pollutant	Lean Burn 2-Stroke	Lean Burn Stroke	Rich Burn Stroke
NO_x	3.17	4.08	2.21
CO	0.386	0.317	3.72
SO_2	5.88E-4	5.88E-4	5.88E-4
VOC	0.12	0.118	0.0296
$PM_{2.5}$ (total)*	0.0483	0.010	0.0194

*Includes both filterable and condensable
[a] U.S. emission factors; California BACT emission factors are given in Table 5-1.

Table 5-19. AP-42 Emission Factors for Toxic Air Contaminants from NG Combustion Equipment (lb/MMBtu)

Toxic Air Contaminant	AP-42 Emission Factors (lb/MMBtu HHV Basis)			
	Natural Gas IC Engines			Natural Gas
	Lean Burn	Lean Burn	Rich Burn	Combustion
	2-Stroke	4-Stroke	4-Stroke	Turbines
Acetaldehyde	7.76E-03	8.36E-03	2.79E-03	4.00E-05
Acrolein	—	—	—	6.40E-06
Benzene	1.94E-03	4.40E-04	1.58E-03	1.20E-05
1,3-Butadiene	8.20E-04	2.67E-04	6.63E-04	4.30E-07
Carbon Tetrachloride	6.07E-05	3.67E-05	1.77E-05	—
Chloroform	4.71E-05	2.85E-05	1.37E-05	—
1,1-Dichloroethane	3.91E-05	2.36E-05	1.13E-05	—
Ethylbenzene	—	—	—-	3.20E-05
Ethylene Dibromide	7.34E-05	4.43E-05	2.13E-05	—
Formaldehyde	5.52E-02	5.28E-02	2.05E-02	7.10E-04
Perchloroethylene	—	2.48E-06	—	—
PAH	1.34E-04	2.69E-05	1.41E-04	2.20E-06
Benzo(a)pyrene	5.68E-09	—	—	—
Benzo(b)fluoranthene	8.51E-09	1.66E-07	—	—
Benzo(k)fluoranthene	4.26E-09	—	—	—
Indeno(1,2,3-c,d)pyrene	9.93E-09	—	—	—
Naphthalene	9.63E-05	7.44E-05	9.71E-05	1.30E-06
1,1,2,2-Tetrachloroethane	6.63E-05	4.00E-05	2.53E-05	—
1,1,2-Trichloroethane	5.27E-05	3.18E-05	1.53E-05	—
Toluene	—	—	—	1.30E-04
Vinyl Chloride	2.47E-05	1.49E-05	7.18E-06	—
Xylenes	—	—	—	6.40E-05

Table 5-20. Natural Gas Reciprocating Engine Emissions

Engine Location	SoCAB		ROW	CA, U.S.	
Year	1996	2020	2020	1996	2020
Energy Consumption (Btu/bhp-hr)	8,000	7,800		8,000	7,800
Emissions (g/bhp-hr)					
NO_x[a]	2	0.48	5	5	2
CO	2.7	2.7	2.7	2.7	2.7
CO_2	438	427	438	438	427
CH_4	4.4	5	5	5	5
NMOG	0.45	0.5	0.5	0.5	0.5

[a] SCAQMD rule 1110.2 requirements are equivalent to 0.34 to 0.61 g/bhp-hr.

NO_x emissions outside California (CA and the U.S.) are estimated to be 5 g/bhp-hr, which is based on an engine prime mover population distribution and emissions profile. NO_x emissions for an uncontrolled lean-burn prime mover range from 10 to 12 g/bhp-hr, whereas the emissions for a controlled lean-burn prime mover are about 1 to 2 g/bhp-hr (Huey 1993). Future NO_x emissions for engines located in California are estimated to be 0.48 g/bhp-hr, based on SCAQMD Rule 1110.2 (Emissions from Stationary Internal Combustion Engines).

CO and HC emissions are based on EPA emission factors and CO_2 is calculated from energy consumption and fuel properties. Similar to gas turbines, the emissions data also show that methane emissions make up over 90 percent of the VOC emissions from an engine.

5.2.6 Fuel Production Outside California

The criteria pollutant emissions associated with methanol, FTD, ethanol, CNG, and LNG all occur outside of California. As discussed in Section 4, they are all produced in and imported from other states or countries. The emissions from these fuels are discussed in detail in the 2001 ARB Fuel Cycle Report (ARB 2001b) and in the 2001 CEC Biomass-to-Ethanol report (Perez, 2001).

5.3 Fuel Storage and Distribution

Table 5-21 shows the emissions from bulk storage tanks calculated by TIAX staff based on the calculation technique employed in AP-42.

According to SCAQMD staff, refinery and bulk storage inspection and permitting teams, floating roof tanks are the most common storage tank type in California and will constitute the majority of storage facilities on the margin. These tanks comply with "SCAQMD Rule 463: Organic Liquid Storage" which regulates the storage of gasoline and several organic compounds in above-ground tanks. Tanks in bulk storage farms and refineries are often used to store more than one type of product such as diesel and other intermediary refinery product.

Vapor controls on floating roof storage tanks are required to be at least 95 percent efficient. Internal and external floating roof tanks must be equipped with liquid mounted primary and secondary seals consistent with the best available technology. Other tanks are outfitted with vapor recovery systems that feed the recovered vapor either into an incinerator or a liquifier. In this study, a 90 percent reduction in emissions is assumed for methanol tanks in California. Such controls were not assumed for diesel because its low vapor pressure does not give rise to evaporative emissions from storage tanks.

Actual NMOG emissions are either capped by BACT requirements in California, or are naturally lower due to low vapor pressure (RVP), as indicated in Table 5-21. Table 5-22 shows the actual values used in this report. Evaporative controls on bulk storage tanks

limit emissions. The actual values used are the BACT factors for gasoline and M100, and the AP-42 values in the table for the other fuels.

Table 5-21. Fugitive Hydrocarbon Emissions from Internal Floating Roof Storage Tanks

Fuel	RFG	Diesel	FTD	E100	M100
RVP (psi)	6.80	0.022	0.030	2.3	4.63
TVP (psi)	6.10	0.015	0.02	1.7	3.50
Temperature (°F)	90	90	90	90	90
MW	76	130	120	46	32
Tank capacity (bbl)	50,000	50,000	50,000	50,000	50,000
Tank diameter (ft)	100	100	100	100	100
Tank height (ft)	36	36	36	36	36
Throughput (bbl/yr)	600,000	600,000	600,000	600,000	600,000
Throughput (gal/day)	69,041	69,041	69,041	69,041	69,041
Turnover (day/tank)	30.42	30.42	30.42	30.42	30.42
Emissions (lb/yr)	6,855	88	94	965	1,663
Emissions (g/gal)	0.1235	0.0016	0.0017	0.0174	0.0300

Source: TIAX

Table 5-22. NMOG Emissions from Bulk Fuel Storage

Fuel	Vapor Without Control (g/gal)	BACT (g/gal)
Gasoline	0.123	0.0246
Diesel	0.0016	—
FTD	0.0017	—
E100	0.0174	—
M100	0.030	0.0246

Source: BAAQMD

5.3.1 Liquid Fuel Storage and Distribution

This section describes the storage and distribution of liquid fuels at local service stations. These emissions consist of the following categories:

- Tank truck unloading spills and working losses: tank trucks unload fuel to storage tanks at fueling stations using Phase I vapor recovery.

- Under ground tank breathing: during the course of fuel storage, the vapor or ullage space in the tank expands and contracts as atmospheric pressure and fuel temperature change, although fuel temperature usually remains nearly constant in underground tanks.

- Vehicle fuel tank filling (working losses): fuel is dispensed to vehicles with vapor recovery hose systems, called Phase II vapor recovery.

Numerous observations of the different stages of fuel distribution were made to support prior studies (Unnasch 2001). There are no significant differences in the unloading techniques for gasoline or alcohol fuels. Unloading is accomplished with appropriate precautions for safety and minimizing emissions. Fuel and vapor transfer hoses are connected from the storage tank to the truck. The truck carries its own fuel transfer hoses and an assortment of fittings for connection to the underground tank. After verifying the remaining tank volume with a dipstick measurement, the truck operator initiates the gravity fed unloading operation. When the fuel transfer is completed, the hoses are returned back to the tank truck. There is still a considerable volume of fuel in the fuel transfer hose (about 4-inch inner diameter). The truck operator disconnects the hose from the truck tank and drains the remaining fuel in the bottom of the hose into the underground storage tank by lifting the hose into the air and moving the elevated section towards the connection at the underground tank. The hose is then disconnected and stored on the truck. During several such fueling operations, about 250 ml of fuel was observed spilling out of the hose as it was placed back into its holding tube on the truck. Based on this observation, it is estimated that spillage is about 180 g for an 8,000 gal fuel load or 0.023 g/gal (0.05 lb/1,000 gal). While this quantity is based on casual observations and interviews with drivers, it provides some quantification of a small source that is not explicitly counted in emission inventories. It is difficult to spill no fuel during hose transfers because the inner wall of the transfer hose is covered with fuel during fuel transfer. An even smaller amount of fuel may remain on the hose surface and evaporate later.

Truck transfer is intended to be a no spill operation while in reality it is not completely so. Drivers are instructed to drain the hose into the tank before placing it back on the truck. Catch drains at the top of underground tanks would capture some spilled fuel if it dripped from the tank connection. However, some wet hose losses are inevitable. The thin layer of fuel in the hose will result in some drips and evaporation. It bears noting that the volumes used in this study are based on rough estimates and do not reflect a large sample suze. Furthermore, liquid spill volumes are difficult to measure. While further quantification of the frequency and quantities of Phase I spillage would be necessary to assure the accuracy of this value, it is significantly smaller than Phase II spillage.

Vehicle Fueling Spillage

While most vehicle fueling operations are successfully performed with little fuel spilled from the nozzle, occasionally a significant quantity of fuel is spilled. Fuels spills from

vehicle refueling were evaluated by ARB in the Enhanced Vapor Recovery Standards and Specifications (ARB 2001). This rulemaking sets standards for spillage, drips, and nozzle retention. These standards are summarized in Table 5-23. For calculation purposes, spillage, liquid retention, and nozzle spitting are lumped together on a g/gal basis. All of these emissions are event related. The amount of fuel spilled per event is assumed to be constant; so, larger fuel tanks or volumes of fuel dispensed result in lower emissions per gallon dispensed. Historically, the emission factor for spillage has been 0.7 lb/1,000 gal. With Phase II vapor recovery systems, this value was adjusted downward to 0.24 lb/1,000 gal. For Phase II systems, spillage plus liquid retention results in 0.40 lb/1,000 gal of gasoline.

Table 5-23. Standards for Gasoline Spillage, Dripping and Nozzle Retention

Source	Standard	Units
Phase II dispensing spillage	0.24	lb/1000 gal
Dripless nozzle	<1	drops/fueling event
Liquid retention	100	ml/1000 gal
Nozzle spitting	1	ml/nozzle

Source: ARB 2001, Unnasch 2001

The liquid retention emissions are based on gasoline evaporating from the nozzle. With methanol, this level of evaporation would be lower, and it would be virtually eliminated with diesel. The ARB standard for diesel spillage is 0.61 lb/1,000 gal. The standard for diesel spillage is higher than that for gasoline for several reasons. Because evaporative emissions from diesel spills are much lower than those from gasoline, a higher spillage rate is allowed in the rules. In addition, because diesel fueling occurs without vapor recovery, higher fueling rates are possible. The potential for spillage is potentially higher with higher fueling rates. Also, spillage volumes per unit fuel transferred could be lower for smaller vehicles having smaller fueling volumes. The trade offs between fuel economy and spillage are analyzed in the 2001 ARB fuel cycle study (Unnasch 2001). Spillage rates of other liquid fuels were estimated. These are summarized in Table 5-24. Gasoline spill limits were assumed for RFG and ethanol blends. Diesel spillage limits were assumed for ULSD, FTD, biodiesel, and blends of these products. Methanol fuel cell vehicles have special fittings to prevent fuel spillage (Heffelfinger 2002).

Table 5-24. Estimated Vehicle Fuel Spillage Rates

Fuel	Spillage Rate (g/gal)
Diesel, Biodiesel, FTD	0.277
LPG	0.090
M100 Fuel Cell	0
RFG3, Ethanol blends with RFG3	0.182

Source: Unnasch 2001

Vapor Space NMOG Losses for Gasoline Vehicles

Vapor emissions in this study are determined from modeled vapor concentrations. The fuel temperature used to determine vapor concentrations was selected to be consistent with ARB's inventory for fueling station emissions.

Vehicles are fueled at fueling stations with dispensing equipment that is regulated by ARB. Fuel is pumped into the vehicle tank and the vapors in the vehicle tank are either collected by the fueling station's Phase II vapor recovery system or the vehicle's on board refueling vapor recovery system (ORVR) as illustrated in Figure 5-9. Starting 2003, passenger cars and light trucks began to be equipped with ORVR with the mix of vehicles changing by model year. In future, the mix of ORVR equipped vehicles will then change as new vehicles are introduced and older vehicles retire. ARB projects an ORVR penetration rate of 90 percent by about 2020.

When fueling vehicles with no ORVR system, saturated vapors from the vehicle are returned back to the underground fuel storage tank. The vapor recovery efficiency of the Phase II systems is assumed to be 95 percent by both ARB and air quality planners. However, the vapor recovery system may not function properly in some fueling systems. A limited number of systems are also not required to have Phase II vapor recovery. In order to account for systems where the vapor recovery system is not functioning, a defect rate is used to develop the air emissions inventory. ARB estimates the defect rate to be 20 percent though 2008 and 10 percent in 2009 and beyond.

When fueling vehicles equipped with ORVR, vapor in the vehicle tank is captured by the ORVR system in a canister on board the vehicle. The efficiency of the ORVR system was also assumed to be 95 percent. Operating ORVR systems with a dispenser Phase II vapor recovery system can pose a challenge for emission control. Instead of returning saturated vapor back to the underground tank, air now displaces the fuel that was pumped from the tank. When the air reaches equilibrium with the fuel, the volume of the vapor is about 50 percent of that of the air (if the fuel has a true gasoline vapor pressure of about 5 psi). ARB requires Phase II fueling systems to be compatible with ORVR systems, so no increase in emissions is assumed.

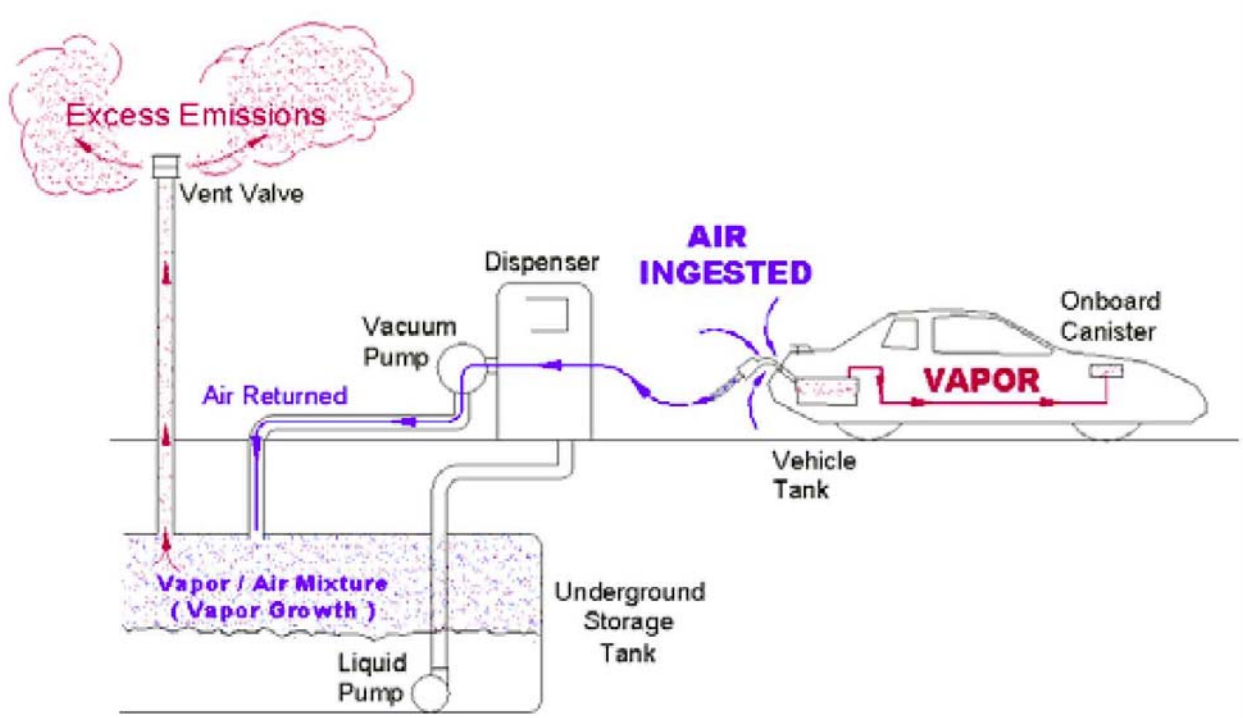


Figure 5-9. Phase II Vapor Recovery and ORVR

The refueling losses from a vehicle are estimated to be:

Refueling loss = (1-ORVR) x VD x SF x [(1-DR)(1-CF) + DR] + ORVR x VDxSF x CF

Where:

VD = vapor density
SF = saturation factor
CF = control factor (95 percent)
DR = defect rate
ORVR = fraction of vehicles with ORVR

The first set of terms in the equation represents the emissions from vehicles that are not equipped with ORVR. The emissions are estimated from the combination of the Phase II control factor plus the defect rate. The final sets of terms represent the emissions from fueling the ORVR equipped vehicles. The mix of vehicles equipped with ORVR was estimated by ARB (Guerrero 2006) and is shown in Figure 5-10.

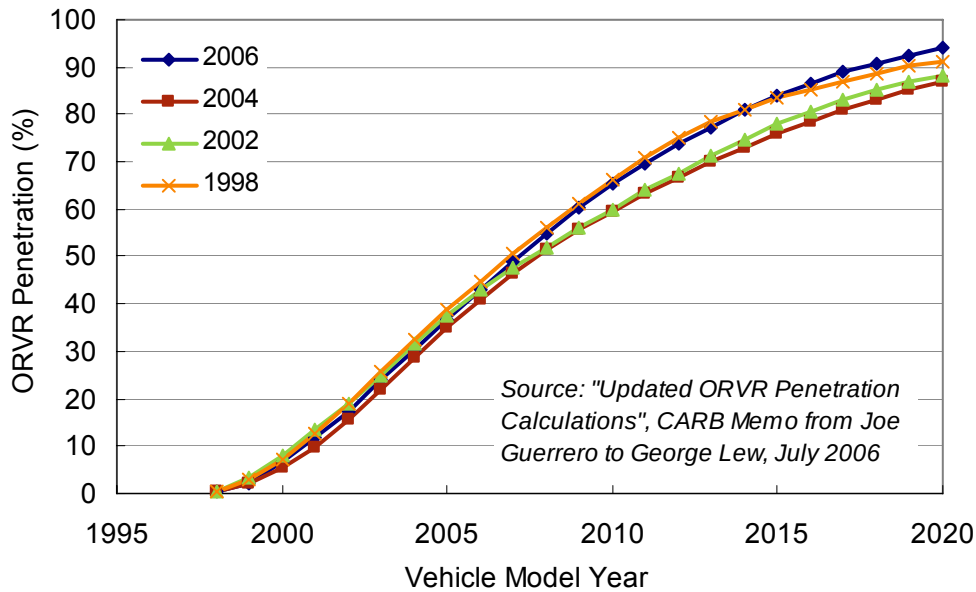


Figure 5-10. Percent ORVR Penetration

The vapor concentration in the tank vapor space is the basis for the fuel transfer emission calculations in AP-42, and provides insight into the temperature conditions for vapor emissions. Vapor space concentrations are modeled from equilibrium vapor pressures. The extent of vapor saturation is reflected by the saturation factor. For vapor recovery systems a saturation factor of 1.0, or completely saturated vapor, is assumed in AP-42. ARB bases vapor space concentration on test data. The vapor space gas concentration represents the uncontrolled emissions from tank truck unloading (underground tank working losses), and vehicle tank working losses.

Vapor space concentrations from liquid fuels were estimated from the ideal gas law. Given a molar volume of 379.6 ft^3/lb mole at 60°F and 1 atmosphere, the equilibrium vapor quantity (V_e) in a tank head space can be calculated from the following equation:

$$V_e \text{ (lb/gal)} = MW\text{(lb/mol)} \times \text{lbmol}/379.6\ ft^3 \times 0.1337\ ft^3/\text{gal} \times TVP/14.7\ \text{psi} \times 520°R/T$$

Where:

T = gas and liquid temperature (°R)
TVP = true vapor pressure (psi) at the equilibrium temperature

The same temperature conditions are associated with emission estimates that are consistent with California inventories. This effectively results in an equivalent equilibrium temperature that reflects the actual range of fuel temperatures and saturation conditions corresponding to test data. The underlying assumption with this approach is that the inventory data is based on a broad range of conditions and reflects

suitable ones. Shown in Table 5-25 are evaporative emissions from out of state fuel storage and transfer for several fuels.

Table 5-25. Evaporative Emissions from Out of State Fuel Storage and Transfer

Emission Category/Fuel	TVP (psi)	MW (g/mol)	Effective Temperature (°F)	Uncontrolled NMOG Vapor Mass		Control Efficiency (%)	Controlled Vapor (g/gal) a
				(g/gal)	(lb/1000gal)		
Marine vessel loading, overseas, Tank Working Loss							
Diesel	0.0092	130	76	0.0126	0.03	0	0.0126
BD2	0.0092	130	76	0.0126	0.0	0	0.0126
BD20	0.0092	130	76	0.0126	0.0	0	0.0126
FTD	0.0092	120	76	0.0116	0.0	0	0.0116
FTD33	0.0092	127	76	0.0123	0.03	0	0.0123
M100	2.35	32	76	0.792	1.7	90	0.0792
E100	1.50	46.05	76	0.73	1.6	90	0.073
E85	4.84	61	76	3.11	6.9	90	0.311
E65	4.84	63	76	3.21	7.1	90	0.321
E10	4.84	68	76	3.45	7.6	90	0.345
Gasoline 7 RVP	4.84	68	76	3.47	7.6	90	0.347
CARBOB	4.84	76	76	3.88	8.5	90	0.388

Vapor concentrations (uncontrolled NMOG vapor mass) for this study were determined from equilibrium vapor densities that correspond to 70°F for underground tank vapors, and 76°F for vehicle fuel tank vapors. Actual vehicle vapor temperatures can be higher. Table 5-26 summarizes the evaporative emissions from in-state liquid fueling station operations for the fuels included in this analysis.

Table 5-26 also shows distribution tank truck emissions for liquid fuels. These emissions take into account vapor recovery effectiveness and a defect rate between 0 and 4 percent for Phase II emission controls. The higher defect rate reflects the potential interaction between ORVR equipment and vapor control equipment or simply a less effective vapor recovery system. Because no methanol powered fuel cell vehicles or any passenger cars that operate on M100 are offered in commercial volumes, emission control requirements can still be developed. Such emission control requirements would address Phase II efficiency requirements, refueling connections that reduce the risk of misfueling, ORVR requirements, and other details of refueling. Table 5-27 summarizes vehicle fueling operation evaporative emissions.

Table 5-26. Evaporative Emissions from Liquid Fuel Station

Emission Category/Fuel	TVP (psi)	MW (g/mol)	Effective Temperature (°F)	Uncontrolled NMOG Vapor Mass (g/gal)	Uncontrolled NMOG Vapor Mass (lb/1000 gal)	Control Efficiency (%)	Controlled Vapor (g/gal)[a]
Truck loading, Tank Working Loss			Limit 0.15 lb/1000 gal				
Diesel	0.0092	130	76	0.0126	0.03	0	0.0126
BD2	0.0092	130	76	0.0126	0.0	0	0.0126
BD20	0.0092	130	76	0.0126	0.0	0	0.0126
FTD	0.0092	120	76	0.0116	0.0	0	0.0116
FTD33	0.0092	127	76	0.0123	0.03	0	0.0123
M100	2.35	32	76	0.792	1.7	98	0.0158
E85	4.84	61	76	3.11	6.9	98	0.062
E65	4.84	63	76	3.21	7.1	98	0.064
E10	4.84	68	76	3.45	7.6	98	0.069
Gasoline 7 RVP	4.84	68	76	3.47	7.6	98	0.069
Truck Unloading, Underground Tank Working Loss			Limit 0.15 lb/1000 gal				
Diesel	0.0090	130	70	0.0125	0.03	0	0.0125
BD2	0.0090	130	70	0.0125	0.0	0	0.0125
BD20	0.0090	130	70	0.0125	0.0	0	0.0125
FTD	0.0090	120	70	0.0115	0.0	0	0.0115
FTD33	0.0090	127	70	0.0122	0.03	0	0.0122
M100	1.95	32	70	0.667	1.5	98	0.0133
E85	4.30	61	70	2.80	6.2	98	0.056
E65	4.30	63	70	2.88	6.3	98	0.058
E10	4.30	68	70	3.10	6.8	98	0.062
Gasoline 7 RVP	4.30	68	70	3.12	6.9	98	0.062
Underground Tank Breathing Loss			All tanks under negative pressure				
Diesel	0.0090	130	70	0.0125	0.03	90	0.001
BD2	0.0090	130	70	0.0125	0.0	90	0.001
BD20	0.0090	130	70	0.0125	0.0	90	0.001
FTD	0.0090	120	70	0.0115	0.0	90	0.001
FTD33	0.0090	127	70	0.0122	0.03	90	0.001
M100	1.95	32	70	0.667	1.5	99	0.007
E85	4.30	61	70	2.80	6.2	99	0.028
E65	4.30	63	70	2.88	6.3	99	0.029
E10	4.30	68	70	3.10	6.8	99	0.031
Gasoline 7 RVP	4.30	68	70	3.12	6.9	99	0.031

[a]AP-42 Sec 7, U.S. EPA, Compilation of Air Pollutant Emission Factors, AP-42, Fifth Edition, Volume I: *Stationary Point and Area Sources,* January 1995.
Methanol TVP from AP-42 Table 7.1-3. Diesel, Gasoline TVP from AP-42 Table 7.1-2.
Molecular weight of E85 based on test data, (Unnasch 1996.)
Molecular weight is weighted average of E85 and E5.7.
Assumed molecular weight of 68 for gasoline with RVP of 7 based on AP-42. Data from gasoline vapor space indicates a higher MW (71), (Unnasch 1996.)

Table 5-27. Evaporative Emissions from Vehicle Fueling

Emission Category/Fuel	TVP (psi)	MW (g/mol)	Effective Temperature (°F)	Uncontrolled NMOG Vapor Mass		Control Efficiency (%)	Controlled Vapor (g/gal)[a]
				(g/gal)	(lb/1000gal)		
Vehicle Working Loss			Limit 0.38 lb/1000 gal				
Diesel	0.0120	130	80	0.0163	0.04	0	0.0163
BD2	0.0120	130	80	0.0163	0.0	0	0.0163
BD20	0.0120	130	80	0.0163	0.0	0	0.0163
FTD	0.0120	120	80	0.0151	0.0	0	0.0151
FTD33	0.0120	127	80	0.0159	0.04	0	0.0159
M100	2.61	32	80	0.875	1.9	95	0.0437
E85	5.20	61	80	3.32	7.3	95	0.166
E65	5.20	63	80	3.42	7.5	95	0.171
E10	5.20	68	80	3.68	8.1	95	0.184
Gasoline 7 RVP	5.20	68	80	3.70	8.2	95	0.185

[a]AP-42 Sec 7, U.S. EPA, Compilation of Air Pollutant Emission Factors, AP-42, Fifth Edition, Volume I: *Stationary Point and Area Sources,* January 1995.

Methanol TVP from AP-42 Table 7.1-3. Diesel, Gasoline TVP from AP-42 Table 7.1.2.

Molecular weight of E85 based on test data, (Unnasch 1996).

Molecular weight is weighted average of E85 and E5.7.

Assumed molecular weight of 68 for gasoline with RVP of 7 based on AP-42. Data from gasoline vapor space indicates a higher MW (71), (Unnasch 1996).

5.3.2 LPG and DME Distribution

LPG is stored and distributed in pressurized tanks. The fuel is stored in a liquid state at ambient temperature with the pressure in the tank at equilibrium. At 70°F the storage pressure is 105 psig. When LPG is transferred from a storage tank to a tank truck, or to a vehicle fuel tank, a transfer pump provides about 50 psi of differential pressure. When fueling vehicle tanks, the fuel enters the tank and the LPG ullage condenses. This process can be accelerated with top loaded tanks where the liquid spray can absorb some of the heat from condensing the vapors.

The tank trucks are filled at refineries using a two hose system with one hose acting as a vapor return. Hoses are evacuated after fuel transfer operations at the refinery. Tank trucks can be filled to a safe fraction of its water capacity by weighing the truck during fueling (Lowi 1994), although this is not the current practice. However, current regulations require the use of an "outage" valve that indicates when the tank is full. Some LPG also enters the atmosphere from the fuel transfer fitting.

Table 5-28 shows the emissions associated with LPG storage and distribution. The LPG emissions correspond to the volume of liquid that escapes from the fuel transfer fitting divided by the amount of fuel transferred. Currently, LPG vehicles in California are equipped with an “outage” valve that indicates the 80 percent fill level by spilling LPG to the atmosphere. During vehicle fueling, the outage valve is opened and vapors pass through a 0.060-inch orifice and through the valve. When LPG reaches the 80 percent level in the vehicle tank, liquid enters the fill level line and exits into the atmosphere. A puff of white liquid is visible to the fueler that provides an additional signal that the tank is full. California's vehicle code requires use of the outage valve. As indicated in Table 5-28 emissions from vehicle fueling are several grams per gallon.

Table 5-28. Fuel Emissions from LPG Fuel Delivery Operations

Emission Source	Tank Volume (gal)	Liquid Spill Volume		LPG Loss (g/gal)
		(ml/fill)	(ml/gal)	
Transfer tank outage[a]	10,000	—	—	1
Bulk tank outage	30,000	—	—	0.2-0.5
Truck fill outage[a]	—	—	—	2
Truck fill hose	3,000	1,391	0.139	0.070
Local tank hose	1,000	17.4	0.0017	0.0008
Local tank outage[a]	—	—	—	5
Vehicle tank outage	—	—	—	0

[a]Better vapor management could eliminate this emissions source by the year 2010.

Many LPG tanks are already equipped with automatic stop-fill devices that could eliminate fuel tank vapor venting; however, Titles 8 and 13 of the California Administrative Code require the use of the outage valve. Other countries, including the Netherlands where many LPG vehicles operate, do not use the outage valve for fueling. One might expect that many LPG vehicles in California are fueled without using the outage valve if they are equipped with automatic stop fill devices.

A committee of NFPA, CHP, NPGA, and WLPGA representatives are working to set standards that will allow LPG vehicles to be fueled without leaking LPG to the atmosphere. Equipment that will minimize the fuel released from transfer fittings is also being approved (Wheeler 1994) with the potential to reduce disconnect losses to below 0.002 g/gal. EPA regulations on evaporative emissions from vehicles will also eliminate vehicle outage valve emissions.

Emission estimates for LPG fueling are based on the following conditions:

- 1,391 ml loss from fuel couplings on 10,000 gal delivery trucks. Fluid loss is equivalent to 18 in of 1.25-in (inner diameter) hose (Lowi 1992)
- Current vehicle hose coupling liquid losses are 7.57 ml (Lowi 1992) for a 12 gallon fuel transfer. Dry-break couplings would have less than 5 percent of the trapped volume of current LPG nozzles of the same capacity.
- Current fuel tank vapor displacement is based on sonic flow through a 1.5 mm orifice, with 70°F tank temperature and a fuel pressure of 105 psig. Assuming an orifice discharge coefficient of 0.5 results in 2 g/s of vapor flow. With an 8 gal/min flow rate, vapor displacement is 15 g/gal.
- Vapor displacement from current tank truck filling assumes a 100 gal/min fill rate with an outage loss of 2 g/s

5.3.3 Natural Gas Distribution

LNG Distribution

The losses associated with LNG fuel transfers are summarized in Table 5-29. Fuel losses occur from hose disconnect events and from tank venting. These losses were assumed to be controlled by 90 percent by 2020.

Table 5-29. Fuel Emissions from LNG Fuel Delivery Operations

Emission Source[a]	LNG loss (g/gal)
Boil Off Losses	10
Truck fill hose	0.070
Truck venting	2.2
Local tank hose	1
Vehicle hot tank venting	0.5

[a] Better vapor management could eliminate this emissions source by the year 2020.

CNG Distribution

Energy inputs for CNG compression are based on process modeling results assuming optimized compressor systems. CNG fueling will continue to be accomplished with electric compressors. Some natural gas engine compressor systems have been tried, however the issues associated with emissions permitting favor electric compressors. The method for gas storage and compression, type of gas, as well as final storage pressure affects the energy inputs for compression.

Slow fill (or time fill) systems compress the gas and directly fill the vehicle over an extended period of time (usually overnight). The compressor output is only slightly higher than the vehicle storage pressure.

Fast fill fueling requires slightly more energy as the gas stored at higher pressure prior to vehicle fueling. For cascade fast fill, natural gas is compressed and stored in several sets of storage cylinders (typically three). The cascade storage pressure is about 3,600 psi for a 3,000 psi vehicle storage system.

Fast fill fueling results in rapid compression and corresponding temperature rise of the gas in the vehicle. If the vehicle is fueled to 3000 psi, its final fill pressure will drop after the temperature in the vehicle tank equilibrates with ambient air. Sophisticated fueling systems that compensate for the ambient temperature and gas within the vehicle have been designed. Such systems would allow the vehicle to be filled to an effective pressure of 3,000 psi. Therefore, after compression to 3,600 psi and the fuel heating effect are taken into account, fast fill fueling requires about 22 percent more energy than slow fill fueling.

Actual data on CNG fueling compressor systems is not widely available[50]. Compression energy ranging from 0.6 to 1.7 kWh/100 scf has been measured in real world fast-fill systems (Wang 1999, Unnasch 1993). Calculations of energy requirements, mechanical losses, and motor efficiencies with more optimized designs indicate electricity consumption below 0.8 kWh/100 scf (Lasher 2001). An improvement in compressor system efficiency resulting in a power consumption of 0.9 kWh/100scf was assumed for future systems. PG&E estimates a power consumption of 0.7 kWh/100 scf for systems that are supplied by high pressure natural gas (40 to 200 psia).

Fuel-cycle emissions, including CO_2, correspond largely to the total volume of fuel produced. Thus, fuel consumption is a strong driver in determining total fuel-cycle emissions. In general, as more fuel is produced, more feedstocks are extracted and transported, production facilities operate with greater throughput, and trucks and pipelines move more fuel to fueling stations. This section reviews the data inputs used in this study, methods for estimating fuel economy, and the sets of fuel economy assumptions that were used for the fuel-cycle analysis.

5.3.4 Hydrogen Delivery

A variety of methods exist for transporting hydrogen from a central plant to a fueling station. The primary methods of transport include compressed hydrogen tube trailers, liquid hydrogen trailers, and pipeline delivery.

Fuel cycle CO_2 and other GHG emissions depend on energy inputs within the fuel cycle. Calculations of energy efficiency for fuel cycle steps combined with transportation

[50] Many CNG systems are not equipped with a dedicated electric meter for the compressor. Determining power consumption per scf also requires an alert data collection effort.

distances were used as inputs the GREET model to determine fuel cycle GHG emissions.

The type of hydrogen delivery option also affects the energy inputs and emissions for hydrogen production. The baseline pathways analyzed in this report represent some of the combinations of production and delivery options. Table 5-30 provides a comparison of the energy inputs and GHG emissions for various hydrogen delivery optioins. These values are proportional to distance traveled and the amount of hydrogen carried by the delivery truck. The transportation energy can become a significant portion of the overall energy input for delivered compressed hydrogen. The economics of delivering compressed hydrogen will likely limit the practical driving range. The values in Table 5-30 can be used to determine the GHG emissions for other pathways that are not analyzed in this report.

Table 5-30. Energy Inputs for Hydrogen Delivery Options

Delivery Option	Fuel	Capacity (kg H_2)	H_2 Used (kg H_2)	Distance (mi)	Energy (J/J H_2)	GHG Emissions (g/kg H_2)
Pipeline	Natural Gas	various	various	0.5 - 3	0.01 – 0.05	100-500
Tube Trailer	Diesel	300	240	50	0.095	1,060
Mobile Fueler	Diesel	100	50	20	0.114	1,280
LH2 Truck	Diesel	3,700	3,700	100	0.012	135

One-way transportation distance; energy and GHG based on round trip.

Pipeline distance for hydrogen fueling stations built in 2010. Future hydrogen pipeline networks could be much longer.

GHG emissions based on WTT_f GHG factor, 93.4 g/MJ, for diesel fuel. Diesel GHG factor (g/kg Hg) = J/JH_2 x 120 MJ/kg H_2 x 93.4 g/MJ

SECTION 6. MULTIMEDIA IMPACTS

Each step in the production and marketing of transportation fuels potentially impacts the environment and public health. Marine environments and coastal beaches are impacted by marine tanker spills. Soil, surface and groundwater are affected by releases from pipelines. Discharge from refineries, ethanol and biodiesel plants, and synthetic fuel production facilities impact the environment. In the event of a rollover and spill, transportation by tanker trucks can cause soil, surface water, and groundwater contamination. Leaks from underground tanks at dispensing facilities can compromise the quality of drinking water supplies. The combined effect on water, soil, and air are known as multimedia impacts. This section focuses on specifically on water impacts.

While considerable effort has been devoted to characterizing the impact of various fuels on air quality, comparatively less work has gone to assessing the production, refining, and use of transportation fuels on water quality in California. In contrast to air emissions, which tend to be a shared set of chemical species with relatively predictable impacts, water emissions vary widely in terms of chemical composition and impact on the environment between fuels. Impacts are likely to be location-specific, with the rate and direction of surface water flow, subsurface conditions, and proximity to urban water supplies all influencing the degree to which discharges directly impact human health and vulnerable ecosystems. Finally, the impact of the release of a given fuel into the environment may be secondary, as with the case of ethanol, which may aid the transport of other, more toxic, chemicals also found in petroleum fuels.

A variety of multimedia impacts are anticipated, including but not limited to:

1. Water consumption during crude oil production: Significant volumes of water are used in secondary production methods such as steam injection, commonly applied to extract low-gravity crude oils in California's Central Valley.
2. Wastewater discharge from crude oil production: Crude oil pumped in California contains a significant water fraction, often contaminated with high levels of heavy metals. The disposal of that fraction is a significant environmental concern.
3. Crude oil spills: Oil spills on the ground (from pipelines) and in marine environments (from tankers) are commonplace and have significant impacts on the quality of surface and groundwater in California.
4. Refinery/production facility wastewater discharge: Refinery wastewater streams often contain significant levels of heavy metals and organic materials. Those waste streams typically require significant treatment prior to discharge into surface waters.
5. Agricultural water use and runoff: Significant quantities of water are used in the production of the primary biofuel feedstocks of corn and soybeans. In addition, agricultural runoff contaminated by fertilizers and pesticides can impact surface and groundwater reserves. In extreme cases, such as the "dead zone" in the Gulf of Mexico caused by the long-range transport of agricultural chemicals from the

Midwest, agricultural runoff may be associated with ecosystem-scale water quality impacts.

6. Spills during distribution/storage: Spills from pipelines and tanker trucks during distribution, along with leaking underground storage tanks (LUSTs), are an additional source of water impacts. Depending upon a given fuel's chemical composition, toxicity, and amenability to biological degradation, those impacts can range from minimal to serious.

In this chapter, data from various sources are compiled to estimate the full lifecycle water impacts of producing, refining, and distributing key fuels in California. Table 6-1 shows the key indicators of multimedia impacts that are investigated: water consumption and wastewater production, both measured in terms of (gallons/gallon fuel); and hydrocarbons spilled or discharged into surface or groundwater.

Table 6-1. Significant Water Impacts Analyzed

Water Pollutant	Sources		
	Fuels	Engines	Facilities
Hydrocarbons	●	■	■
Alcohols	●	■	■
Toxics		■	■
Water use			■
Wastewater Generation			■

6.1 The State of Knowledge

While the impacts of energy use on California's water are difficult to deny, efforts to assess those impacts are plagued by significant methodological challenges. The large number of chemical species emitted, the lack of clear emissions standards for most equipment regarding water releases, and difficulties in monitoring non-point source water releases make quantifying emissions difficult.

There have been several notable attempts to estimate the impact of different transportation fuels on water quality, several of which explicitly addressed lifecycle impacts. The first, a *Health and Environmental Assessment of the Use of Ethanol as a Fuel Oxygenate* by the University of California and Lawrence Livermore National Laboratory in 1999 (LLNL 1999), conducted a comprehensive review of the potential environmental impacts associated with the introduction of ethanol as an oxygenate to California's gasoline supply. The report, which included detailed modeling of the movement of contaminant plumes from leaking underground storage tanks, concluded that the introduction of ethanol as an oxygenate could be associated with a 20 percent elevated risk of contamination of California's drinking water wells with benzene as

ethanol is preferentially biodegraded in subsurface environments. This elevated risk actually represents a reduction over the baseline risks of continuing the use of MTBE as an oxygenate, which was expected to impact substantially larger numbers of wells.

A later effort in 2006, headlined by academics at the University of California at Berkeley, UC-Davis, and Lawrence Livermore National Laboratory, produced the "Guidance Document and Recommendations on the Types of Scientific Information to be Submitted by Applicants for California Fuels Environmental Multimedia Evaluations" (UCB 2006). That document details data necessary for and the protocols to be adopted in assessing the impacts of fuels likely to be released into California's water supplies. It also recommends the adoption of a multi-tiered, collaborative, and flexible approach in assessing the probable impacts of fuel production and use in California.

Two separate studies by the National Renewable Energy Laboratory (NREL) similarly broached the water quality impacts of fuels, this time explicitly through the lens of lifecycle analysis. The first, a 1998 study entitled "Life Cycle Inventory of Biodiesel and Petroleum Diesel for Use in an Urban Bus" (NREL 1998), provided a highly detailed analysis of the inputs, outputs, and environmental impacts associated with the production and distribution of biodiesel relative to petroleum-based distillate fuels. The second, NREL's 1999 "Environmental Life Cycle Implications of Fuel Oxygenate Production from California Biomass – Technical Report" (NREL 1999), similarly estimated the lifecycle costs and impacts of in-state ethanol production from three feedstocks – rice straw, forest residue, and chaparral – converted to ethanol through both enzyme and acid dominated processes. Both of these studies are referenced heavily in this analysis.

6.2 Analysis Methodology

Given the state of knowledge regarding the water impacts of transportation fuel production, refining, and distribution, TIAX adopted the following methodology in conducting this preliminary analysis of water impacts:

- Three indicators of water impacts – water consumed, wastewater produced, and hydrocarbons/alcohols discharged into water – were estimated for the lifecycle of each transportation fuel included in this study.
- Data for refining/production facilities was estimated by reference to previous NREL work, or via to National Pollution Discharge Elimination System (NPDES) permit data for representative facilities. Facilities were assumed to discharge continuously at monthly permit maximums in this analysis. This analysis also assumes that California produces 72 percent of PAD V production volumes, as presented in DOE's EIA data (EIA 2000).
- Information regarding the release of fuels via spills and accidents at various stages in the production and/or distribution chain for a given fuel was determined via the methodology established by TIAX for its 2003 consultant report entitled "Reducing Petroleum Dependency in California" (TIAX 2003). Where appropriate, spills of

alternative transportation fuels likely to be distributed by means similar to that of incumbent fuels (e.g. gasoline and diesel) were modeled by assuming a similar accident rate and average discharge volumes.

- The water impacts associated with the production, transport, and refining of crude oil were attributed to individual fuels in proportion to the fraction that fuel comprises of the final refinery product. As presented in EIA 2000, California refinery outputs where 45.7, 18.5, and 2.5 percent by volume of gasoline, diesel, and LPG, respectively. The upstream water impacts of these fuels were distributed in proportion to these fractional values.
- Fuels with significant vapor pressures (e.g. LPG, CNG, and hydrogen) were assumed to have negligible water impacts associated with spills or accidents.

Clearly, there are significant limitations to this methodology. The various transportation fuels considered in this analysis differ in terms of physical and chemical characteristics, most critically how quickly they are degraded in the environment. The three figures of merit outlined above are unlikely to provide adequate treatment of the impacts of certain fuels, particularly those with significant toxicity. Furthermore, the impact of the release of a given fuel into the environment may be secondary, as with the case of ethanol, which may aid the transport of other, more toxic, chemicals also found in gasoline. Finally, the impacts of transportation fuels on water quality are likely to be location-specific, with the rate and direction of surface water flow, subsurface conditions, and proximity to urban water supplies all influencing the degree to which discharges directly impact human health and vulnerable ecosystems.

6.3 Sources of Water Impacts

Water impacts associated with fuel production, refining, and distribution come in many forms. Large quantities of water are often used in the production of primary energy resources, either during the secondary production of crude oil or in the agricultural sector when producing biofuel feedstocks. Spills of crude petroleum upstream of refineries are an important source of impacts to water quality. Wastewater discharge from refining and production plants, which separate crude oil into its constituent components or use chemical or biological processes to transform inputs into fuels, are another. Refined petroleum products and other transportation fuels may also be spilled during distribution by tanker truck or pipeline, or leak from underground storage tanks prior to sale to the end-user.

Significant volumes of water are consumed at various stages in the production of transportation fuels. Crude oil production in California's Central Valley typically requires the utilization of secondary production techniques, in particular steam injection, to increase the viscosity of low-gravity crude trapped in the subsurface. The treatment of this water, and its eventual disposal, is a major issue for many oil producers. Biofuel feedstocks such as corn and soybeans likewise require significant volumes of water to produce, either from natural precipitation trapped by plants or via the active irrigation of

cultivated fields. Petroleum refining, ethanol fermentation, and biodiesel production also use significant volumes of cooling water to manage process heat within their facilities.

Fuel production also impacts water due to spills. Spills affect many aspects of the environment, including marine waters, coastline, soil, surface water bodies, and groundwater supplies. Oil pollution in the form of land- and marine-based spills poses a serious threat not only to the environment, but also to public and commercial property and interests. Land-based spills impacting soil have direct environmental ramifications and can also damage public and private properties. Petroleum spills initially impacting soil also have the potential to migrate downward or laterally, and impact groundwater and surface water, or affect air quality by volatilizing beneath an enclosed space. Petroleum released to surface water bodies can impact wildlife such as fish, amphibians, bird, and animal life.

Groundwater supplies can be contaminated by releases to adjacent surface water bodies and soil. Depending on the nature of the petroleum product or additive, it can accumulate and travel in a layer on top of the water table, or in solution after dissolving. Public health can also be impacted in the event that a petroleum release occurs near or is transported to a drinking water supply.

The process of refining crude oil, assembling synthetic fuels from primary components, and fermenting or extracting biofuels from feedstocks likewise impacts water quality through the discharge of waste streams into the environment. Refinery wastewater, which may contain both chemical carcinogens and heavy metals, may be of particular environmental concern. Biofuel production may impact local water supplies due to the high organic content of waste streams, leading to downstream fish kills associated with oxygen depletion. In general, emissions from refineries and biofuel plants are likely to be highly concentrated and therefore heavily impact water quality in a limited geographic area: at the same time, operations are likely to be tightly monitored and regulated by local and regional authorities as significant point source releases.

There are many opportunities for spills to occur along the production and distribution chain for transportation fuels. For refined petroleum fuels, spills can be damaging in each of petroleum's many forms: crude oil, refined gasoline and diesel fuels, and additives such as MTBE. Other fuels, such as ethanol and methanol, may impact water quality through their direct toxicity or by speeding the migration of other contaminants in the subsurface.

To evaluate how transportation fuels impact water quality in California, it is helpful to first examine how fuels are produced, refined, and distributed in California. Imported petroleum arrives via both marine tanker (crude and refined products) and interstate pipeline (refined products only). Petroleum arriving by marine tanker is offloaded at the marine terminal to storage tanks or to feeder pipelines. Petroleum is transported by tanker truck or feeder pipeline to refineries. Crude and refined products are stored in tanks at the refinery. Refined products are transported from the refinery via tanker truck or terminal pipeline. Biofuels, particularly ethanol for use in blending, typically arrive via tanker trains from the Midwest and are blended with refined gasoline at the intermediate

point of distribution. Transportation fuels are then stored in above and underground storage tanks at commercial and private dispensing facilities.

The following sections describe in further detail water quality and quantity impacts associated with fuel production, refining, and distribution in California. Individual treatment is provided to the following five topics: agricultural water use, open ocean and marine terminal spills, spills from pipeline/tanker trains, refinery/production plant discharges, and spills and leaks during distribution and storage. Both qualitative data illustrating the major impacts of these incidents and a further detail regarding the method adopted to estimate the water pollution emission factor for individual fuels is provided in each section.

6.3.1 Agricultural Water Use and Runoff

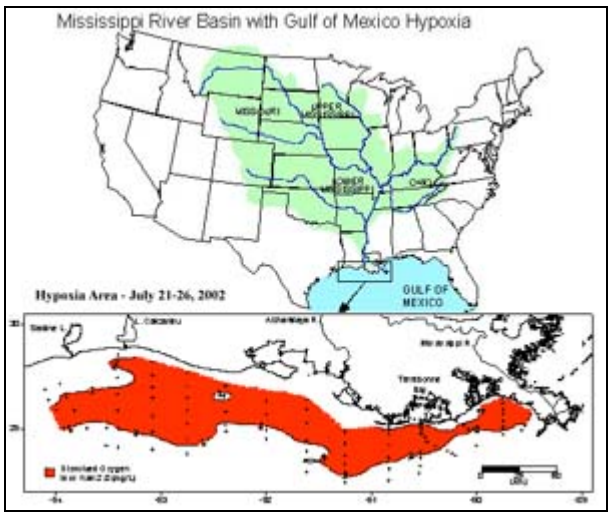
One significant source of multimedia impacts for fuels is agricultural production. The production of feedstocks for biofuels is expected to be associated with substantial water impacts, in terms of both water consumption and "wastewater" produced in the form of agricultural run-off. Agriculture in California is big business, a fact that is reflected in the share of water consumed in the state. A prime motivation for the development of the state's dams, reservoirs, and aqueducts was the promotion of agriculture; correspondingly, agriculture continues to dominate total water use in the state. According to California's Department of Water Resources (CaDWR 2007), California agriculture consumes approximately 30 million acre-feet of water a year, or approximately 80 percent of all water use in California being consumed by the agricultural sector.

While agricultural water use is expected to be a significant proportion of the total multimedia impacts of biofuels, we do not directly incorporate the water burden of producing feedstocks into this analysis. The logic for this approach is two-fold: first, the two most important biofuel feedstocks, corn and soybeans, are not generally grown on irrigated cropland; second, because it is unlikely that those crops will be produced in California in the foreseeable future. As a result, for the purposes of this report we assume that the water requirements for biofuel feedstock production in California are negligible.

Another significant water impact of fuels relates to the production of biofuel feedstocks, predominately corn and soybeans in the Great Plains states of the U.S. Agricultural runoff often contains elevated levels of pesticides and herbicides that degrade water quality, including rural drinking water supplies. High levels of nitrates are particularly common in rural areas, leading to health difficulties such as "blue baby" syndrome when infants are exposed to contaminated well water. In addition, elevated levels of organic matter in agricultural runoff may lead to oxygen depletion in surface water bodies and marine environments, generating large-scale fish kills. The most famous of example of this phenomenon is the so-called "dead zone" in the Gulf of Mexico, created by due to long-range transport of agricultural runoff by the Mississippi River in the summer. The

dead zone, shown in Figure 6-1, measured 7,700 square miles in area in the summer of 1999, or roughly the size of the state of New Jersey.

While significant, these impacts are difficult to quantify due to a variety of factors. In contrast to point source pollution, which is amenable to direct monitoring by regulatory authorities, or mobile source pollution, which can be generally be controlled via emission standards, serious uncertainty exists about area source water pollution. The concentration of contaminants in agricultural runoff is subject to a variety of complex factors, including chemical loadings, surface conditions, and precipitation patterns, generating significant uncertainty about the magnitude and character of water impacts. Agricultural pollution is also subject to a different, and arguably less stringent, set of regulatory rules than other sources of pollution. Finally, at this point most water impacts associated with biofuel production currently occur outside of California, the primary focus of this report. As a result, a treatment of the impacts of agricultural runoff on water quality is considered beyond the scope of this work.



Source: The Science Education Research Center at Carleton College, accessed at http://serc.carleton.edu/microbelife/topics/deadzone/index.html on 18 January 2007 (SERC 2007).

Figure 6-1. Map of the Gulf of Mexico Dead Zone

6.3.2 Open Ocean and Marine Terminal Spills

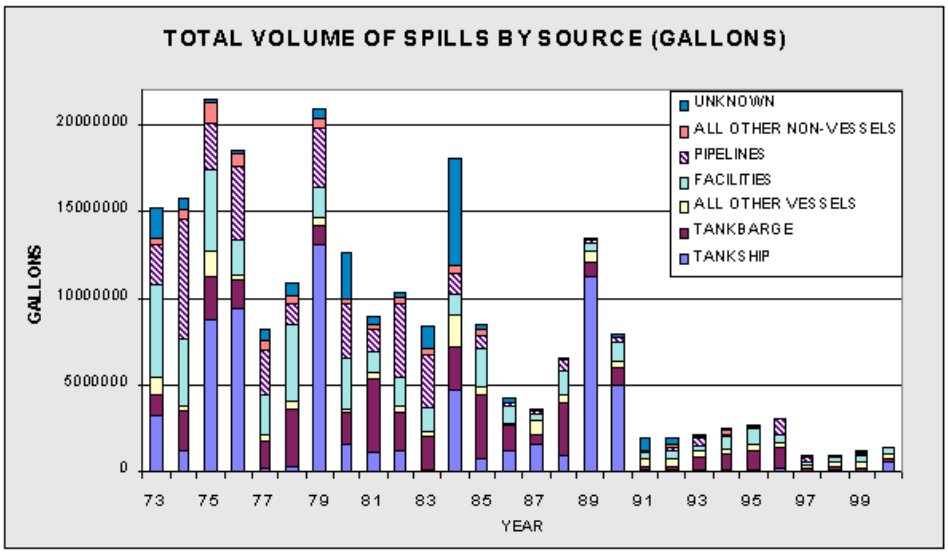
Impacts to marine environments are often high-profile events, such as the Exxon Valdez spill in Alaska and the Prestige spill off the coast of Spain. Spills in the open ocean are often difficult to contain and are spread by prevailing winds and ocean currents. Petroleum spills can impact environmental receptors such as kelp beds and associated fish and animal life – animals such as otters, and birds such as brown pelicans, gulls, cormorants, and murres can be oiled and potentially die. Marine spills that reach and contaminate the coastline can have not only environmental impacts, but also

commercial impacts to tourism and industry, and public health impacts in residential coastal areas.

Marine oil spills can pose a serious threat to the environment as well as to commercial interests (see Figure 6-2). Spills can leave waterways and their surrounding shores uninhabitable for some time. Such spills often result in the loss of plant and animal life. Periodic spill disasters maintain public awareness of these marine events.

Figure 6-2. Beach Cleanup Following Marine Petroleum Spill

Figure 6-3 presents US Coast Guard (USCG) data on marine spill volumes by source from 1973 – 1999 (USCG 2001). Data on the annual number of spills and annual spill volumes for 1995 through 2001 as collected by USCG are also presented in Table 6-2.



Source: U.S. Coast Guard (USCG 2001)

Figure 6-3. Historical Petroleum Marine Spill Volumes by Source — USCG Data

Table 6-2. Marine Petroleum Spill Frequency and Volume

Year	Number of Spills	Annual Volume Spilled (gallons)
1995	5,478	1,624,153
1996	5,586	1,681,020
1997	5,347	380,879
1998	5,172	621,235
1999	5,680	576,475
2000	5,560	1,033,643
2001	5,021	569,856

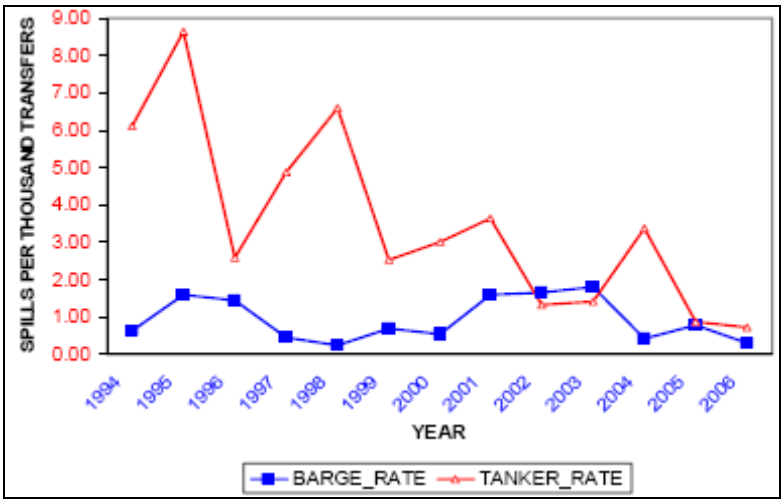
USCG data for tankship, tankbarge, and other vessels.

As the figure and table illustrate, the volume of oil spills in U.S. waters has been on a general downward trend since 1973, with notable events such as the Exxon Valdez disaster interrupting this trend only briefly. According to the USCG, 47 percent of the volume of oil spilled from 1973 to 1999 came from tank vessels (ships/barges); 22 percent from facilities and other non-vessels; 18 percent from pipelines; 6 percent from non-tank vessels; and the remaining 7 percent from unknown sources (USCG 2001).

In addition to incidents in the open ocean, vessels can also discharge crude oil or refined petroleum products during delivery and offloading of ocean tankers at marine terminals. The potential for a spill exists at several points, including:

- Navigation into port
- Cargo offload
- Transfer to tanker truck transport
- Transfer to feeder pipelines

The USCG keeps records specific to the total number and volumes of spills occurring in marine waters. The California State Lands Commission – Marine Terminals Division, keeps a subset of this information, which is specific to spills occurring in marine terminals. The State Lands Commission (SLC) spills database, encompassing 1999 through 2001, contain spill volumes, cleanup costs (if any), and associated federal and/or state fines, and provides data for evaluating marine terminal spills (Chaderjian 2007). Figure 6-4 details trends in the spill rates at marine terminals for tankers and barges at California marine terminals from 1994 to 2006 according to the SLC.



Source: California State Lands Commission, "Oil Spill Summary from California Marine Terminals" (Chaderjian 2007)

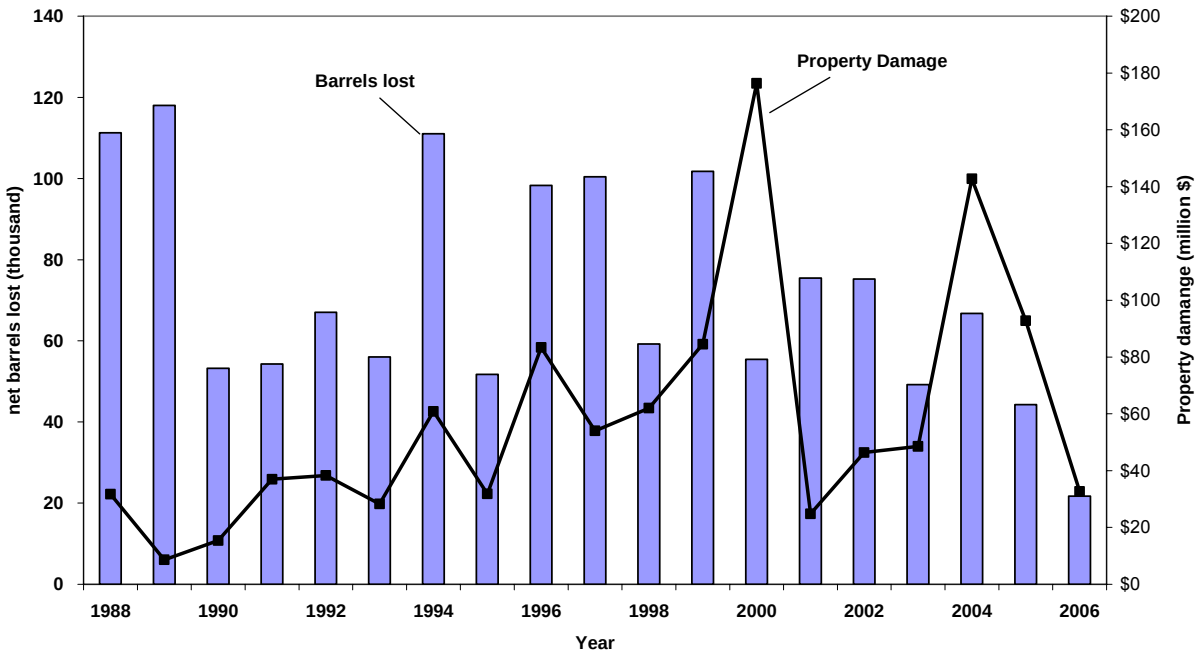
Figure 6-4. Tanker and Barge Transfer Spill Rates, 1994 – 2006

As the Figure 6-4 demonstrates, spill rates vary considerably by mode of transportation, with tankers historically spilling products on the order of five times as often as barges. Overall, the combined spill rates of both vessels declined substantially over time with the advent of tighter regulations, better technology, and increasing attention devoted to the water impact of fuels. That being said, spills still occur in the range of once per one-thousand terminal visits, a not insignificant number given the volume of crude and petroleum products transported in a given visit. For this reason, this analysis indicates that spills at marine terminals are likely to be a substantial fraction of the overall water impacts of fuels in California.

6.3.3 Pipeline and Train Spills

According to the Center for Energy Efficiency and Renewable Technology (CEERT), pipelines transport about 65 percent of the crude oil and refined petroleum products produced in the United States (CEERT 2000). These pipelines carry crude oil to refineries and refined products to distribution points after refining. Pipeline ruptures can release crude or refined petroleum products, with the potential to impact soil, surface water bodies, and groundwater. Commercial and private property can also be damaged; injuries and fatalities, while rare, can result in the event that spilled flammable agents ignite.

The Department of Transportation (DOT) Office of Pipeline Safety (OPS) enforces pipeline safety regulations and compiles a database of spill volumes and associated property damages. Figure 6-5 presents national DOT OPS data for crude oil and petroleum products from 1988-2006 (DOT 2007). We estimated the share of total accidents and damage attributable to petroleum products via reference to 2005, when



Source: U.S. Department of Transportation Office of Pipeline Safety (DOT 2007)

Figure 6-5. Pipeline Spill Volumes and Associated Property Damage from Petroleum Products

those products were responsible for 98 percent of both spill volumes and property damage attributable to the pipeline transport of liquids.

As Figure 6-5 indicates, there is no clear trend in either the number of barrels lost or property damage associated with pipeline spills. At the same time, OPS data indicates that the incidence of pipelines spills has been decreasing over time at the national level. Presumably, spill volumes and property damages have not decreased significantly due to increased pipeline throughput.

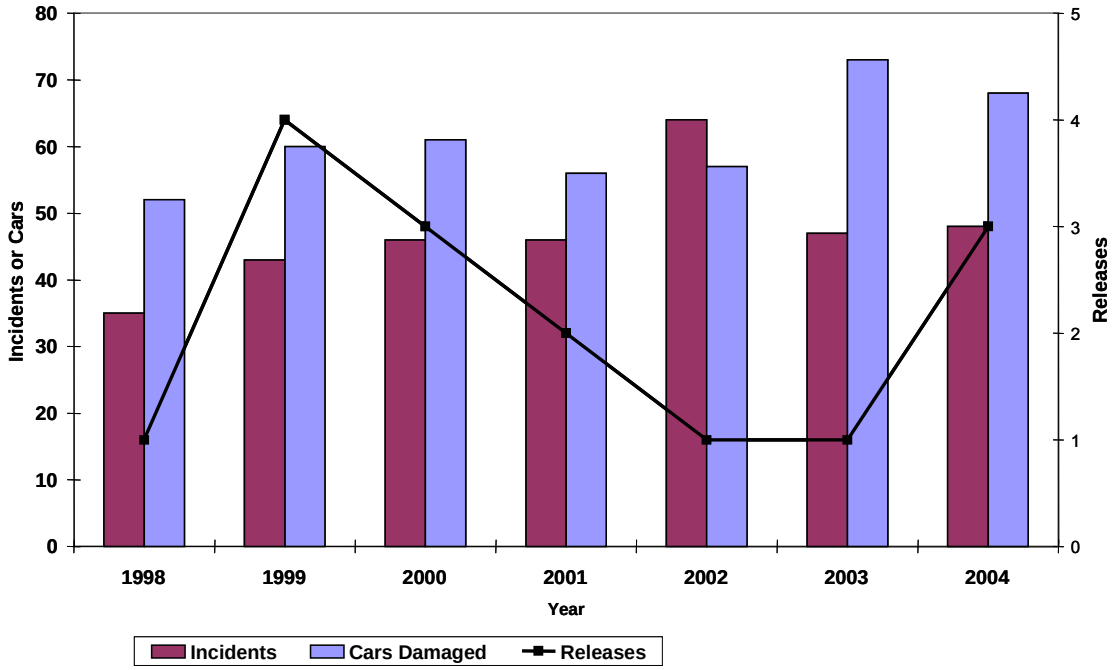
Other fuels have markedly different transportation profiles. Ethanol and biodiesel, which are predominately produced in the Midwest and transported to California by rail, are expected to have different release profiles than fuels transported by pipeline. A number of prominent accidents leading to ethanol spills have occurred in recent years in tandem with increasing demand for ethanol blends:

- January 1, 2005. Two rail tankers derailed and spilled ethanol near Gallup, New Mexico. The resulting 600 gallon spill caused the closure of a nearby highway for approximately three hours.

- October 22, 2006: Twenty-three tankers containing ethanol derailed while crossing a bridge 25 miles northwest of Pittsburg, Pennsylvania, causing a large explosion. Nine tankers burned in the subsequent fire.

- November 22, 2006: 30,000 gallons of ethanol spilled near Courtland, Minnesota when seven tankers carrying ethanol derailed due to poorly maintained tracks.

While spills do occur, accident statistics suggest that the spill rate for rail transport may be relatively low. Figure 6-6 demonstrates raw data for hazardous material transport by rail in California from 1998 to 2004, focusing on the number of incidents, the number of cars damaged in each case, and the number of releases each year. As the figure demonstrates, rail accidents involving hazardous waste material release are notably low in California, suggesting that spill rates associated with rail accidents may be lower for rail tankers than for tanker trucks or pipelines. No obvious trend in the number of accidents, number of cars damaged, and hazardous materials released is apparent.



Federal Railroad Administration Office of Safety Analysis

Figure 6-6. Hazardous Material Accidents, Cars Damages, and Total Releases on California Railways, 1998 – 2004

6.3.4 Refinery and Production Plant Discharges

Crude oil delivered to refineries is converted to gasoline, diesel, and other fuels and petroleum products. Refineries use physical, thermal, and chemical separation

techniques that require high temperatures and pressures to separate crude oil into other products. Approximately 90 percent of all petroleum products that are produced in the United States are fuels. Gasoline and diesel account for 45.7 and 18.5 percent, respectively of the total output from refineries (EIA 2000). Refining causes air and water pollution and produces hazardous wastes, and oil refineries use and release toxic chemicals into the environment (CEERT 2000).

In addition to environmental impacts, refineries are also subject to lethal accidents involving workers. These accidents, often involving explosions and fires, are dangerous to those working on the site and to surrounding residents. Examples of recent refinery accidents include:

- January 15, 2007: A fire broke out at the Chevron Richmond refinery when the pump seal on a crude fuel storage unit failed. The resulting accident, which injured one worker, created a 100 foot tall fire and set off Level 3 warnings in the Contra Costa County emergency warning system. That incident followed a larger explosion in March 1999 which sent hundreds of local residents to the hospital.

- February 1, 1996: A hydrogen unit at a Shell refinery exploded, igniting a fire and causing minor injuries to two workers

- August 22, 1994: Unocal's Rodeo refinery started releasing Catacarb, a toxic catalyst that can cause skin burning, shortness of breath, and headaches. The leak continued for 16 days before the company notified state and federal authorities. Almost 600 residents and 75 employees reported symptoms in the days following the company's disclosure. Unocal later pleaded no contest to 12 criminal counts by the state and agreed to pay a $3M fine.

- April 10, 1989: Three workers were burned in a fire and explosion at the Chevron refinery in Richmond

According to the EIA (EIA 2000), there are currently 23 refineries operating in California (see Figure 6-7).

Spills of crude and refined products can occur during the refining process, as well as during storage. Spills during storage may occur prior to refining, or after refining has occurred, but before transport from the refinery itself.

In addition, wastewater discharges from petroleum refineries contain significant amounts of organic matter, along with heavy metals, that can directly impact water quality. In some cases, significant uncertainty can exist regarding the absolute concentration of contaminants in wastewater discharges, as well as their eventual fate in the environment. This may be true even of chemical species for facilities with substantial operating histories and for species of public concern. Figure 6-8 shows the mass balance for mercury at refiners in the San Francisco Bay Area as understood by the area's Regional Water Quality Control Board in 2005 (CRWQCB 2005). As the figure demonstrates, more than 98 percent of the estimated mercury input into local

refineries was unaccounted for that year. Even larger uncertainties exist for other heavy metal species emitted in refinery wastewater, including chromium, lead, and arsenic.

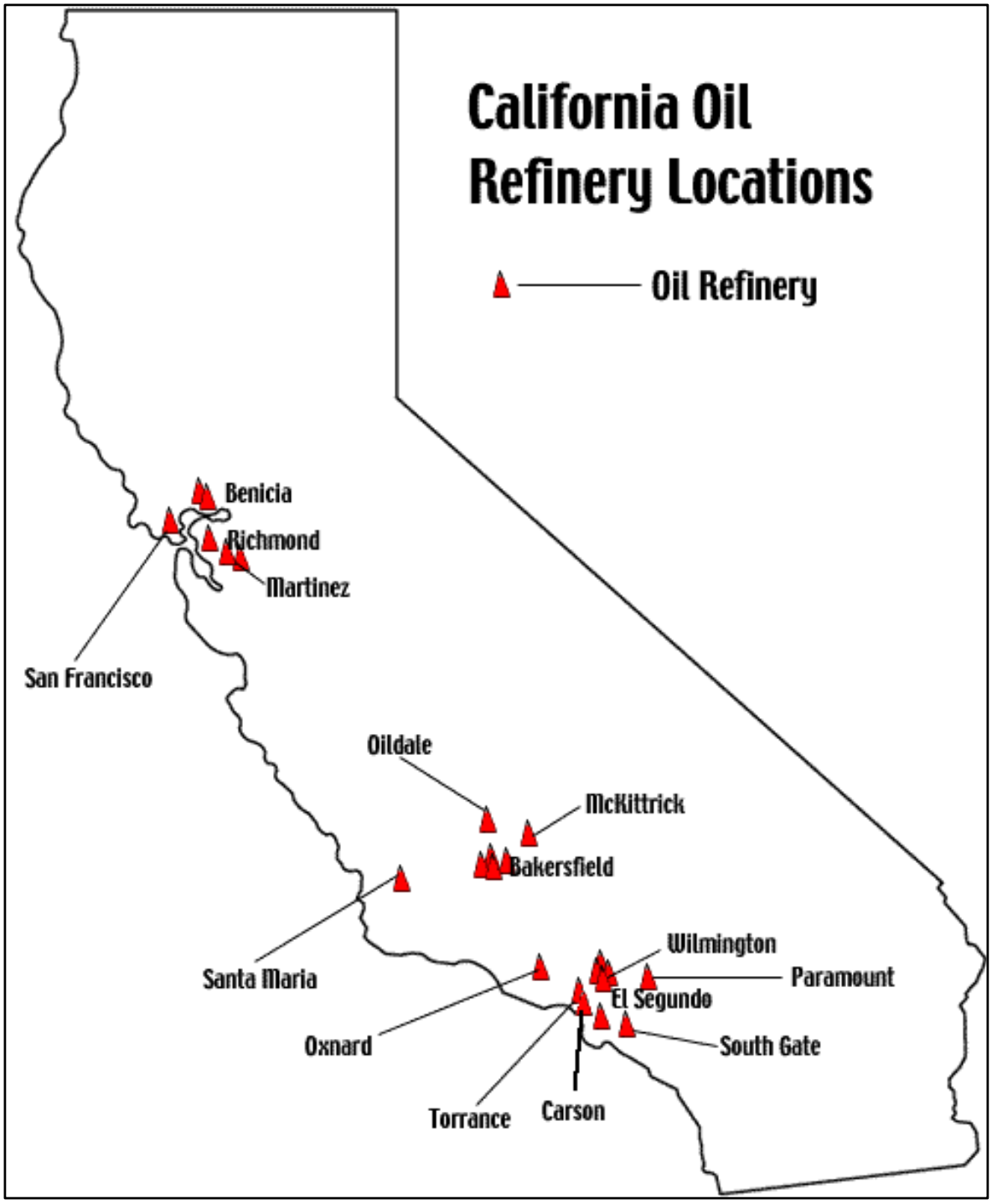
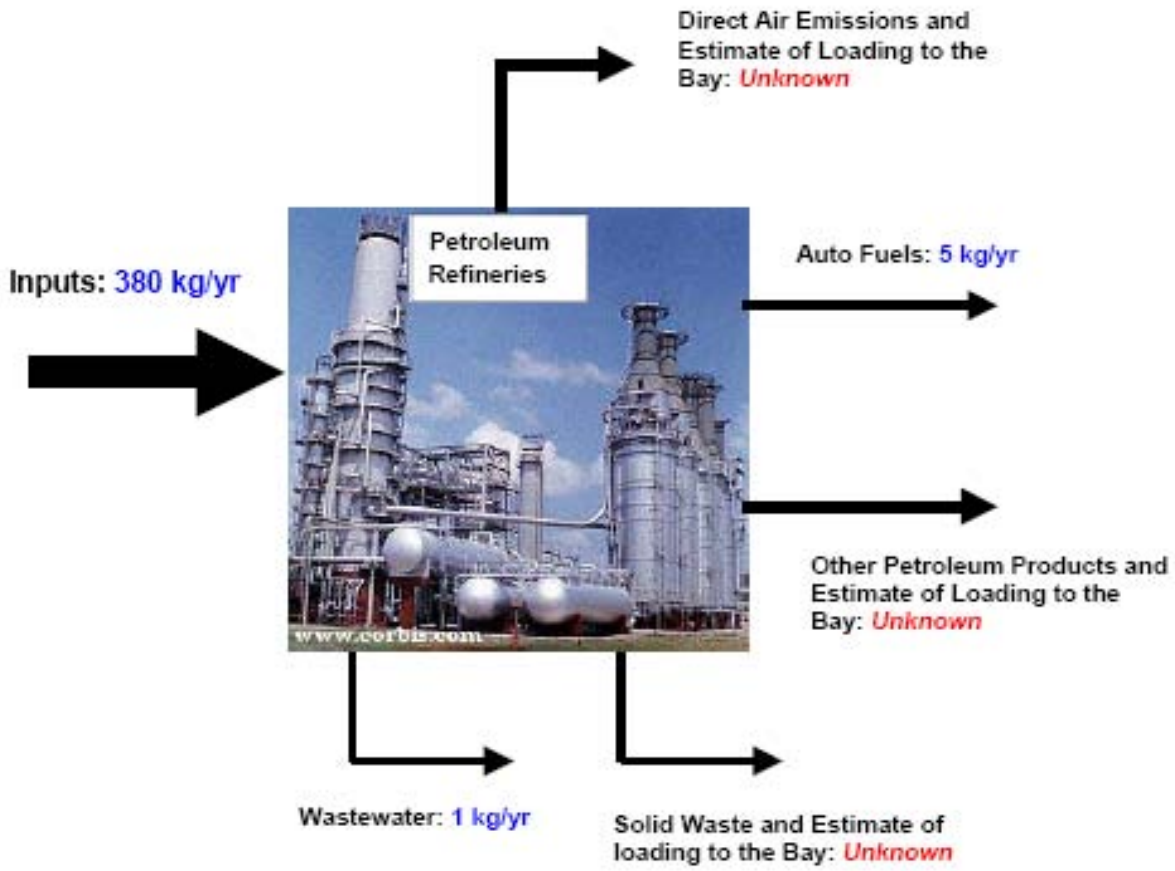


Figure 6-7. California Oil Refinery Location



Source: California Regional Water Quality Control Board, San Francisco Bay Region, "A Letter to Petroleum Refineries Requiring Investigation of the Fate of Mercury in Air Emissions,," (CRWQCB 2005).

Figure 6-8. Mercury Mass Balance for San Francisco Bay Area Refineries

While the precise magnitude of heavy metal and toxic releases associated with energy production is difficult to establish, public databases such as EPA's Toxic Release Inventory (TRI) provide a means to qualitatively assess those releases. Table 6-3 lists toxics released into the air and water for representative production facilities for four transportation fuels according to the TRI: gasoline, diesel fuel, ethanol (consumed either as a blend or as E85), and biodiesel. As the table indicates, the refining of petroleum fuels releases a suite of toxic constituents into the air and water, while relatively fewer releases are associated with the production of biofuels (i.e., ethanol and biodiesel).

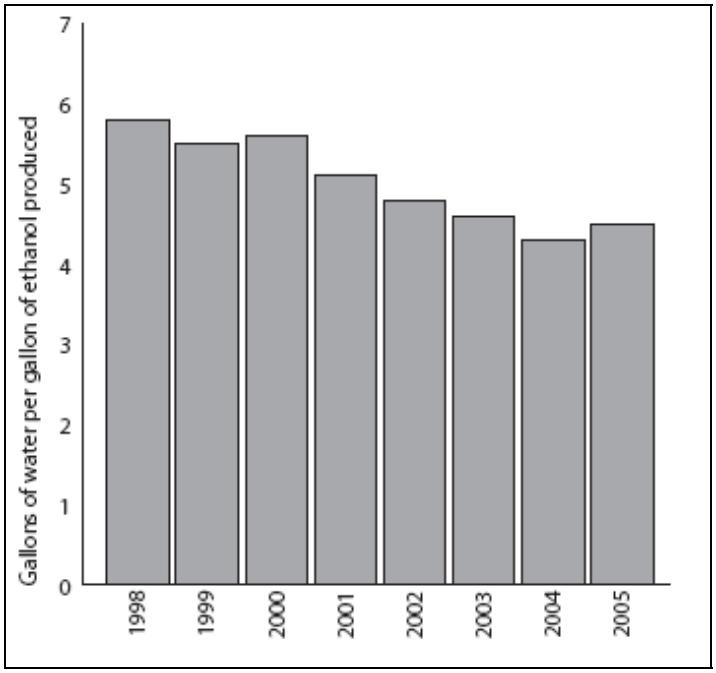
Table 6-3. Toxics Released During Production/Refining by Fuel

Fuel	Toxics released into	
	Air[1]	Water[2]
Gasoline, Diesel Fuel, and LPG	1,2,4-Trimethylbenzene 1,2-Dibromoethane 1,3-Butadiene 2,4-Dimethylphenol Ammonia Benzene Benzo(g,h,i)perylene Chromium compounds Cresol Cyclohexane Diethanolamine Dioxin and Dioxin-like compounds Ethylbenzene Ethylene Hydrochloric acid Lead compounds Mercury compounds Methanol n-Hexane Napthalene Nickel compounds Phenol Polycyclic aromatic compounds Propylene Sulfuric acid Tetrachloroethylene Toluene Vanadium compounds Xylene Zinc compounds	1,2,4-Trimethylbenzene 2,4-Dimethylphenol Ammonia Benzene Benzo(g,h,i)perylene Chromium compounds Cresol Cyclohexane Dioxin and Dioxin-like compounds Ethylbenzene Lead compounds Mercury compounds Methanol n-Hexane Napthalene Nickel compounds Nitrate compounds Phenol Polycyclic aromatic compounds Toluene Xylene Zinc compounds
Ethanol	Acetaldehyde Ammonia Formaldehyde Methanol	N/A
Biodiesel	n-Hexane	N/A

[1] On-site fugitive and point source air emissions
[2] On-site surface water discharges

Source: EPA Toxic Release Inventory for representative facilities.

As Table 6-3 suggests, toxic releases from ethanol and biodiesel facilities pose much less of an issue than for petroleum products. The water impact of those fuels is instead dominated by water consumption and wastewater generation, rather than toxic releases. The production of ethanol, in particular, is believed to be water intensive. Figure 6-9 shows trends in water consumption in ethanol plants in Minnesota. As that graph suggests, a common rule of thumb suggests that ethanol plants require approximately 4 gallons of water for every gallon of ethanol produced. Note than this does not take into account water requirements in agriculture, which are assumed to be minimal since the most common feedstock for ethanol, corn, is not generally grown on irrigated lands.



Source: Institute for Agriculture and Trade Policy, 2006 (IATP 2006).

Figure 6-9. Per Gallon Water Consumption in Minnesota Ethanol Plants, 1998-2006

It should be noted that site-specific factors also influence water consumption and wastewater production, particularly for biofuels. Existing ethanol plants, primarily located in the Midwest, are relatively water intensive relative to planned new facilities. New plants slated for development on the West Coast are required to meet strict environmental regulations regarding water use and wastewater discharge.[51] For example, a plant under construction in Oregon as of February 2006, with an expected

[51] According to the University of Idaho's Jon Van Gerpen, most new, large biodiesel production facilities (> 10 million gallons/year) have no wastewater discharge, either because they use a waterless process or recycle water on-site. Personal communication, 14 October 2006.

ethanol production of 42 million gallons per year, expects to use between 300 and 400 gallons of water per minute (between 3.75 and 5 gallons water/gallon ethanol produced) and produce either no wastewater or discharge one-fourth that volume into the local wastewater treatment facility.[52] It is expected that new plants built to meet incremental fuel demand will have even cleaner environmental profiles than those currently in operation.

6.3.5 Distribution and Storage

Spills of refined transportation fuels with relatively low vapor pressures, including gasoline, petroleum diesel, ethanol, methanol, and biodiesel, during distribution can impact soil, surface water, and groundwater. Spills occur in many modes during transport to private and commercial distribution centers. Tanker trucks distributing fuel spill quantities of fuel during loading, unloading, and while in transit. Volume losses previously estimated by TIAX (TIAX 2003) provided an estimate of total annual spill volumes during transportation for refined petroleum products. Neat fuels such as ethanol and biodiesel, along with blends with gasoline and diesel, are expected to be transported by similar means as gasoline and diesel and therefore subject to spilling at similar rates.

Another multimedia impact of fuel use in California is associated with leaking underground storage tanks (LUSTs). These spills can impact soil, and after percolating down to the water table, groundwater as well. Plumes of contamination can travel on and in groundwater, impacting other regions. Of particular concern is contamination impacting a groundwater aquifer, which is used as a public drinking water supply. The formerly used fuel additive MTBE is a considerable threat to groundwater resources, as it dissolves in water more readily than other gasoline constituents.

Table 6-4 presents statistics regarding LUSTs in California as reported by the U.S. EPA for fiscal year 2006 (USEPA 2007).

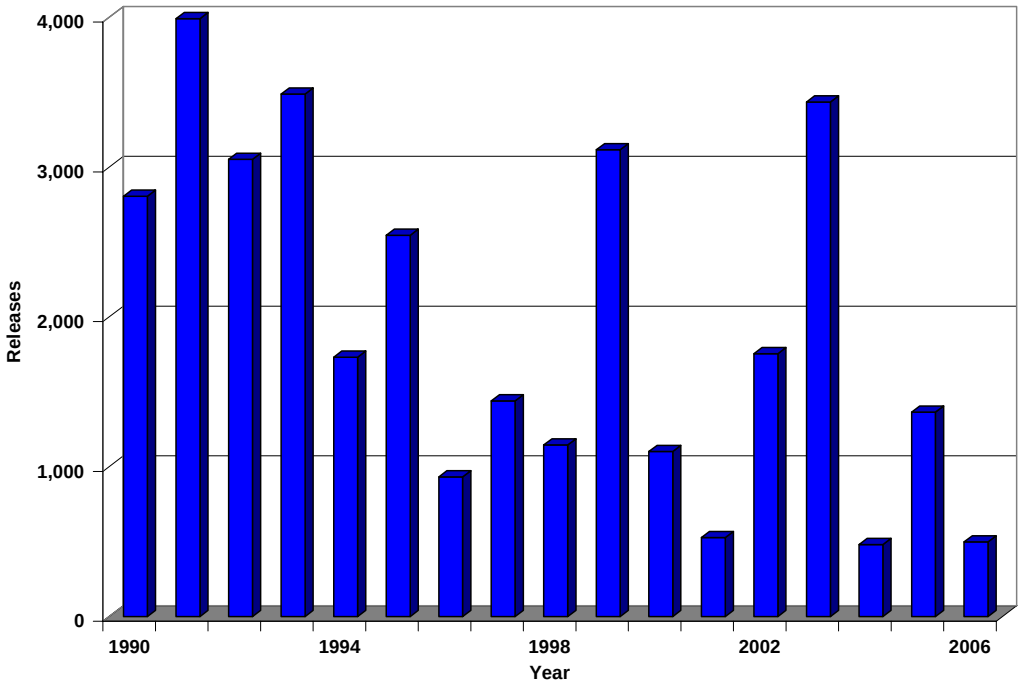
Recent enforcement actions against owners of leaking tanks, along with the introduction of double-walled tanks, provide reason to believe that releases from underground storage tanks are likely to decrease substantially over time. Figure 6-10 shows trends in new confirmed releases from underground storage tanks in California from 1990 to 2006, showing a general reduction over time, punctuated by sporadic years of unusual high discovery. As emissions from known problem tanks is mitigated, and new releases reduced due to the improved performance of new tanks, both total leakage rates and the per gallon emission factor for multimedia impacts are likely to fall as well.

[52] "Notice of Intent to Apply for a Site Certification for the Pacific Ethanol Energy Project" Pacific Ethanol, Inc. February 2006. Accessed at www.lcd.state.or.us/ENERGY/SITING/docs/PEPNOI.pdf on 20 November 2006 (ORDLCD 2006).

Table 6-4. Statistics about Leaking Underground Storage Tanks in California for Fiscal Year 2006

Action	Type	Number
Tanks	Active	37,750
	Closed	123,000
Confirmed Releases	FY 2006	498
	Cumulative	44,967
Clean-ups	Initiated	44,510
	Completed FY 2006	955
	Cumulative Completed	30,865
	Backlog	14,102

Source: U.S. EPA Office of Underground Storage Tanks, "FY 2006 End-of-Year Activity Report (USEPA 2007).



Source: U.S. EPA Office of Underground Storage (USEPA 2007)

Figure 6-10. New Confirmed Releases from Underground Storage Tanks in California, 1990-2006

6.4 Summary of Multimedia Impacts

Section 6.3 outlined various points in the chain of production, refining, and distribution for California fuels with significant multimedia impacts. The following three sub-sections outline the aggregate impact of these steps for five environmental indicators: water consumed, wastewater produced, hydrocarbons discharged into water, biochemical oxidation demand (BOD), and chemical oxidation demand (COD).

6.4.1 Water Use/Wastewater Discharge

Energy production and use impacts water quality via water consumption and wastewater discharge. Table 6-5 summarizes water use and wastewater discharge for the production of gasoline, diesel fuel, biodiesel, and ethanol derived from corn and agricultural waste according to several independent lifecycle analyses.

Table 6-5. Lifecycle Water Use/Wastewater Production by Fuel

	Gasoline	Diesel	Biodiesel	Corn Ethanol	Ag Waste Ethanol
Water Use	0.11	0.13	411	1004	26
Wastewater	0.0019	0.0023	0.0004	1.0	18
% Wastewater	1.8%	1.8%	0.0001%	0.1%	67.8%

Units: gallons water/gallon fuel

Sources: "Life Cycle Inventory of Biodiesel and Petroleum Diesel for Use in an Urban Bus." (NREL 1998).
"Environmental Life Cycle Implications of Fuel Oxygenate Production from California Biomass – Technical Report." (NREL 1999).
"Evaluation of Biomass-to-Ethanol Fuel Potential in California: Ethanol Process Economic Assessments." (CEC 1999).

As Table 6-5 indicates, there are significant differences in the magnitude of water and wastewater used or generated between fuels, and even within a given fuel based upon its method of production. In general, gasoline and diesel fuels are the least water intensive of the transportation fuels, although significant volumes can be consumed in crude oil production during secondary recovery methods such as steam injection. In contrast, biodiesel and ethanol production are relatively water intensive, particularly when produced directly from cash crops rather than through the processing of excess agricultural wastes.

6.4.2 Hydrocarbons Spilled or Discharged

In this analysis, HC releases into surface and groundwater through fuel production, refining, and distribution was estimated via the following methodology:

1. Annual spill volumes of petroleum at marine terminals was estimated according to State Lands Commission data from 1999 through 2001 and by assuming that all spilled petroleum is crude oil. To estimate the spilled volume as a percent of total petroleum production, we assumed that 72 percent of PAD V production volumes apply to California, as presented in EIA 2000.
2. Petroleum spills upstream of refineries were apportioned to refined products in proportion to the percentage ratio of gasoline, diesel, and LPG (45.7:18.5:2.5) produced annually in California (EIA 2000).
3. All liquid fuels were assumed to spill in the same frequency and in equal volumes as gasoline and diesel fuel when transported by the same mode (e.g. tanker truck) or stored in a similar fashion (e.g. underground storage tank).
4. Volatilization of fuels with significant vapor pressures (e.g. propane, hydrogen) was modeled by assuming that spills involving those fuels resulted in negligible hydrocarbons being introduced into surface or groundwater supplies.
5. Where applicable, HC discharges from oil refineries were estimated from a NPDES permit for representative facilities by assuming that the plant discharges at the monthly maximum for hydrocarbons at all times.
6. Biofuels (e.g., ethanol and biodiesel) and synthetic fuels were assumed to be produced out of state and therefore have no HC releases within California. HCs that have been calculated are associated with the transport, distribution and storage of refined products in California.
7. Volumes of fuel leaked from underground storage tanks was based upon annual confirmed releases from the U.S. EPA Office of Underground Storage Tanks for California, in this case 498 cases for fiscal year 2006 (USEPA 2007). It is assumed that a damaged tank leaks an average of 3.25 gallons per day, a value believed by TIAX staff to be representative of small to medium-sized leaks. Tanks identified for corrective action in prior years, and those not yet identified, are assumed to have no leakage releases. As a result, this method of estimation is expected to be conservative in estimating this type of pollution.

Figure 6-11 illustrates the estimated annual spill volumes, combined for crude oil, gasoline, and diesel fuel, at each major point in the chain of producing and distributing refined the petroleum fuels in California.

Figure 6-11 clearly demonstrates that leaks of gasoline and diesel from damaged underground storage tanks are believed to dominate aggregate discharges of crude oil and refined petroleum products into surface and groundwater bodies, being responsible for approximately 80 percent of all releases. This finding holds consequences for gasoline and diesel fuel as well as other liquid fuels, most notably ethanol and biodiesel, likely to be stored in a similar manner.

These discharge numbers, combined with statistics regarding the overall production volumes in California, allows for the estimation of a grams/gallon emission factor for hydrocarbon discharges by fuel. Table 6-6 illustrates the water-borne HC emissions factor for hydrocarbons spills or discharged into ambient waters for representative fuels,

disaggregated by individual step. Unless noted otherwise, all figures are in terms of milligrams per gallon of fuel.

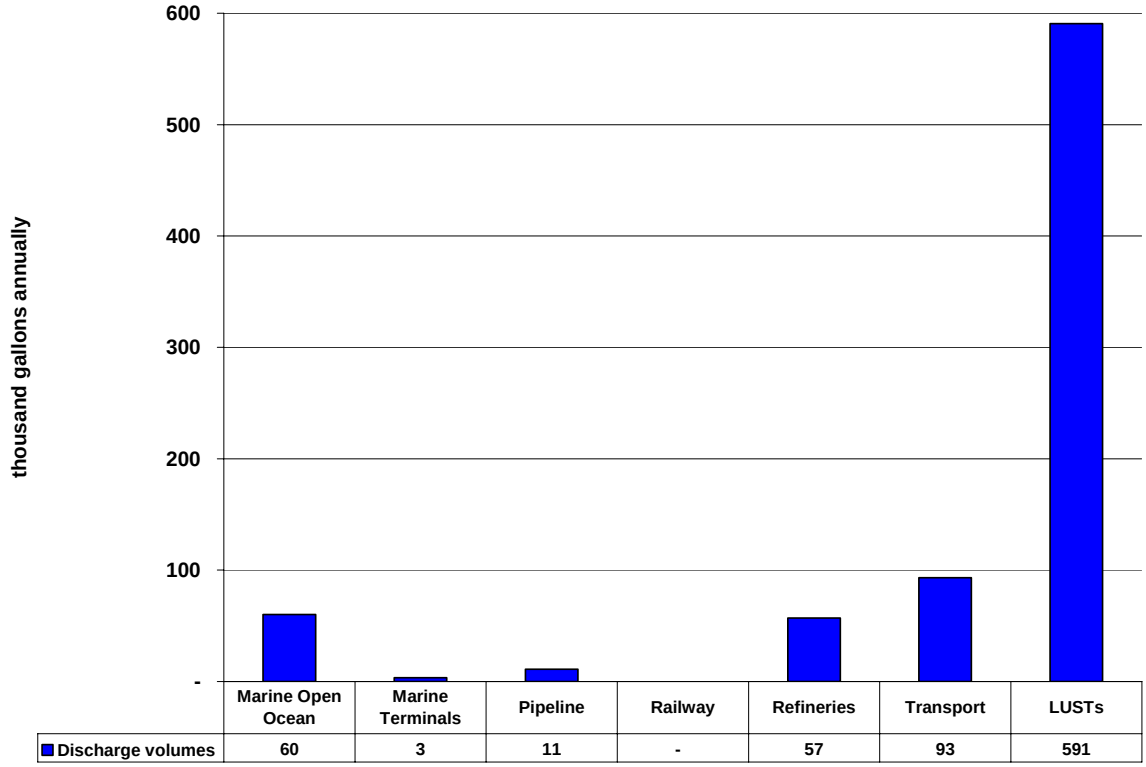


Figure 6-11. Estimated Annual Crude and Refined Petroleum Fuel Discharge Volumes into Water and Soil in California

Table 6-6. Estimated Water HC/Alcohol Emission Factor by Fuel and Process (milligrams/gallon fuel)

Fuel	Marine Open Ocean EF	Marine Terminals EF	Pipeline EF	Railway EF	Refinery EF	Transport EF	LUST EF
Gasoline	9	0	1	—	3	13	79
Diesel	9	0	2	—	1	17	106
LPG	1	0	0	—	0	—	—
Ethanol	3	0	—	2	—	28	87
Biodiesel	4	0	—	3	—	31	97
FT diesel	17	1	—	—	—	14	87
CNG	—	—	—	—	—	—	—
Hydrogen[1]	—	—	—	—	—	—	—

[1] units of mg/kg

Several conclusions may be drawn via reference to Table 6-6. First, the estimated amount of hydrocarbons spilled or discharged into surface waters or groundwater is roughly equal across fuels. This can be explained by the fact that leaking underground storage tanks are believed to dominate each fuel's lifecycle releases, with approximately three-quarters of all hydrocarbon releases traceable to LUSTs. Second, it can be observed that expected HC releases for fuels with significant vapor pressures are either zero or close to zero. Where water releases occur upstream of refineries due to spills of crude oil, such as the case for LPG, those releases are minor due to the relatively small volumes of propane ultimately produced from crude oil.

It should be noted that there are significant limitations to the methodology used to estimate hydrocarbon releases outlined above. The assumption that all bio- and synthetic fuels will be produced outside of California may be overly restrictive; in reality, significant volumes of biofuels in particular may be produced in-state in the future. Second, different refineries are likely to have different release profiles, and may discharge significantly smaller concentrations of hydrocarbons on average than allowed under NPDES permits. Finally, the single most important contributor to water impacts, LUSTs, is highly uncertain due to a lack of good data on both the incidence and leakage rates associated with those tanks. In all likelihood, the problem posed by LUST's is likely to diminish significantly in the future as state and federal regulators continue efforts to identify and mitigate damaged tanks.

SECTION 7. RESULTS AND DISCUSSION

7.1 Petroleum

7.1.1 Pathway Description

Petroleum products are the primary transportation energy source, and include gasoline, diesel, and LPG. These fuels are produced domestically and abroad through a variety of pathways. Crude oil is the common feedstock for most petroleum fuels, but crude can originate in various forms and locations and be transported by a number of methods.

Gasoline and Diesel

Gasoline and diesel are the primary transportation energy carriers. They are generally refined from crude oil from any number of locations, including California, Alaska, the Persian Gulf, and Canadian tar sands. With California refineries operating at maximum capacity and domestic oil production (particularly in Alaska) declining, it is likely that the marginal supply in 2012 will come from the Middle East where it will be refined and shipped to the U.S. as finished product. From bulk terminals at refineries or shipping ports, the product is generally transferred by pipeline to blending terminals where ethanol and other additives are added to meet California regulations for vehicle fuels.

The general steps in producing and distributing gasoline and diesel are shown in Table 7-1.

LPG

In addition to refined crude products, LPG is another fuel that may be used for transport applications and is derived from either crude or natural gas. In the case of natural gas, the feedstock and processing can occur in either overseas (e.g., Borneo) or in California from imported natural gas (from Alberta/U.S. Southwest). If processed in California, LPG can simply be distributed by truck to fueling stations. Alternatively, LPG can be produced from petroleum at refineries where its components are byproducts of liquid fuel production. Generally propane, butane, or LPG will likely originate from the Persian Gulf, where crude is processed to produce the pressurized liquid that is shipped to the U.S. Due to its low vapor pressure, LPG will be transported in specially designed tankers that either keep the fuel at pressure or refrigerated. Trucks will distribute the fuel inside of California.

The general steps in LPG production are shown in Table 7-2. Details for the various cases are also given specified in Table 7-2.

Table 7-1. Production and Delivery Pathway Details for Gasoline and Diesel

Gasoline and Diesel (Overseas Crude)

- Extract crude from Persian Gulf oil fields
- Transport crude to refineries by pipeline
- Refine crude to produce gasoline and diesel
- Transport finished product by tanker ship to California ports
- Store in bulk terminal
- Pipeline to blending terminal
- Combine with ethanol and additives to produce E85, E10, or RFG
- Truck transport to fueling stations

Boundary Assumptions

- Marginal product is imported from overseas
- Change in gasoline has no impact on in-state oil production
- Impact of residual by-product is not included

The analyses are performed for marginal production. The nth gallon of gasoline is imported CARBOB. However, California imports relatively little diesel and refinery based LPG. Nonetheless, the same marginal assumption is applied to crude oil resources and refinery emissions.

Table 7-2. Production and Delivery Pathway Details for LPG

LPG (Crude)

- Extract crude from Persian Gulf oil fields
- Transport crude to refineries by pipeline
- Process crude to produce pressurized LPG
- Transport finished product by refrigerated tanker ship to California ports
- Store in bulk terminal
- Truck transport to fueling stations

Boundary Assumptions

- Marginal product is represented by overseas refinery
- Impact of displacing LPG from other markets or as refinery fuel is not considered

7.1.2 Assumptions

The assumptions for the various petroleum fuel cases are summarized in Table 7-3.

Table 7-3. Petroleum Fuels Pathway Assumptions

Descriptor	RFG, CA Marginal	RFG, Heavy Crude	RFG, 0 Oxygen	RFG, Tar Sands	E10, Corn, MW EtOH	Diesel, CA ULSD	LPG, Petroleum	LPG, Natural Gas
Feedstock	Crude	Heavy Crude	Crude	Tar Sands	Crude/Corn	Crude	Crude	Natural Gas
Feedstock Yield	84.5%	83.2%	85.0%	85.5%	85.8%	85.8%	96.5%	96.5%
Byproducts	4% rejected Pentane	4% rejected Pentane	no rejected pentanes	4% rejected Pentane	8% rejected Pentane	none	From Petroleum	From NG Processing
Product Transport Mode	Marine	Marine	Marine	Marine	Marine	Marine	Rail	Rail
Product Tansport (mi)	9,800	9,800	9,800	2,400	9,800 / 1,400	9,800	50	600
Urban miles	115	115	115	115	115	115	50	178
Net Cargo (Tonne)	150,000	150,000	150,000	150,000	150,000	150,000	2,000	2,000
Local Delivery Mode	Truck	Truck	Truck	Truck	Truck	Truck	Truck	Truck
Local Delivery (mi)	50	50	50	50	50	50	50	50

7.1.3 Results & Interpretations

Gasoline & Diesel

The WTT energy inputs for petroleum fuels are shown in Figure 7-1. These energy inputs reflect the energy required to refine and transport petroleum fuels to fueling stations in California. The energy inputs also include the WTT energy requirements for ethanol, which is a required component in California RFG. Most of the petroleum fuels in California are derived from crude originating in California, Alaska, or the Persian Gulf. Given the continual decline of Alaskan crude production and the stagnant state of California production, it is assumed for this analysis that the marginal supply of petroleum fuels will be imported as finished fuels (CARBOB and ULSD) from the Persian Gulf. This assumption yields a long transport distance, which negatively affects the GHG characteristics of these imported fuels.

The WTT energy requirements also include the additional refining processes that are necessary for California fuels. The California requirement that CARBOB be blended with ethanol necessitates depentanization and additional hydrotreating to remove pentane and sulfur from the fuel. Gasoline and diesel from heavy oils, tar sands, as well as gasoline destined for high ethanol blends will require additional hydrotreating to further remove sulfur and aromatics. The results illustrate the lower refinery efficiency for these cases. In addition to the energy required for additional processing, there are energy requirements for hauling the pentane to disposition areas outside of the state. These pentanes are typically transported by rail contributing to energy needs as well as GHG and criteria pollutant emissions.

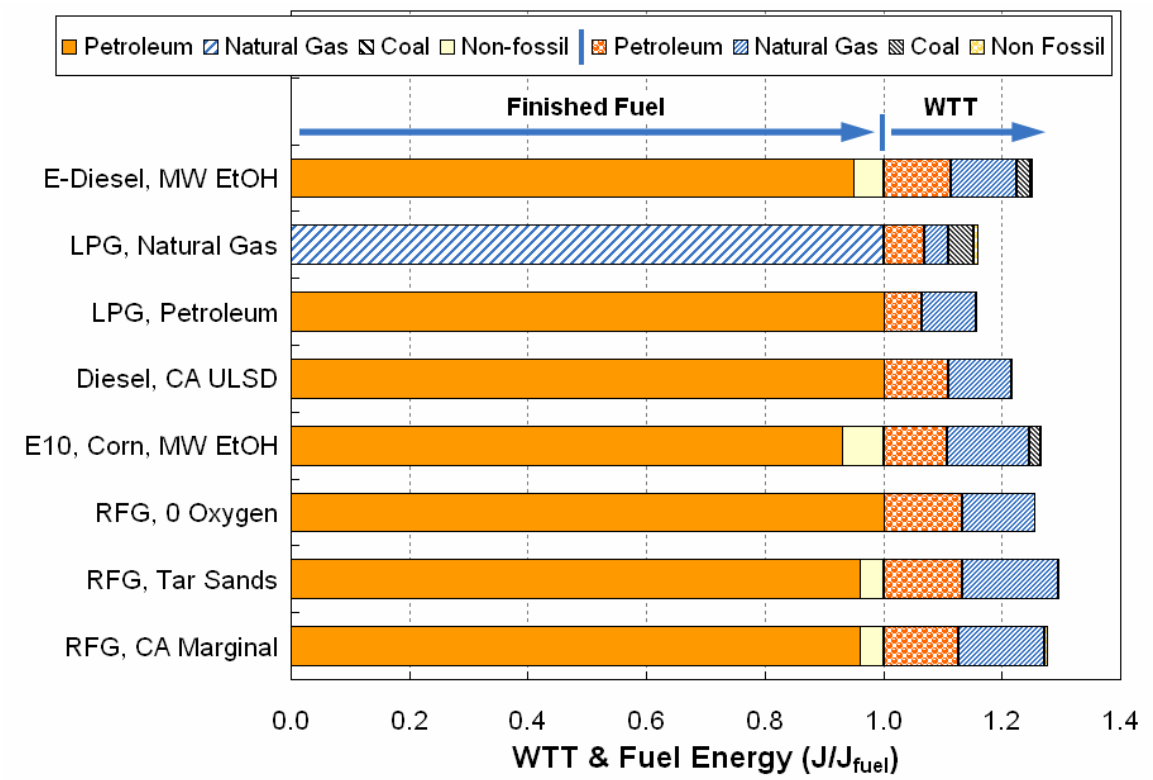


Figure 7-1. Energy Inputs for Petroleum Fuels

Figure 7-2 illustrates the GHG emissions for the petroleum fuel pathways. In general, the GHG emissions reflect the process energy inputs. E10 yields marginal GHG benefits and diesel is negatively affected by the slightly higher carbon factor in the fuel. This, however, is offset by smaller WTT GHG emissions. If the refineries are optimized to produce diesel, as European refineries are, it could cause a lower marginal refining efficiency for gasoline, making diesel appear more appealing on a GHG basis. It is important to remember that these are WTT results and do not include any variation in vehicle efficiencies that might affect fuel performance.

The criteria pollutant emissions associated with petroleum fuel pathways are illustrated in Figure 7-3. Primarily these emissions are associated with the ships and trucks providing fuel transport. Marginal supply assumptions state that refining occurs in the Middle East and, as a result, does not contribute to California criteria pollutant emissions. In the case of California RFG, additional GHG and criteria pollutants are emitted by the rail transport of pentane to disposition locations out of state. These emissions, however, make up a very small component of the overall criteria pollutant emissions.

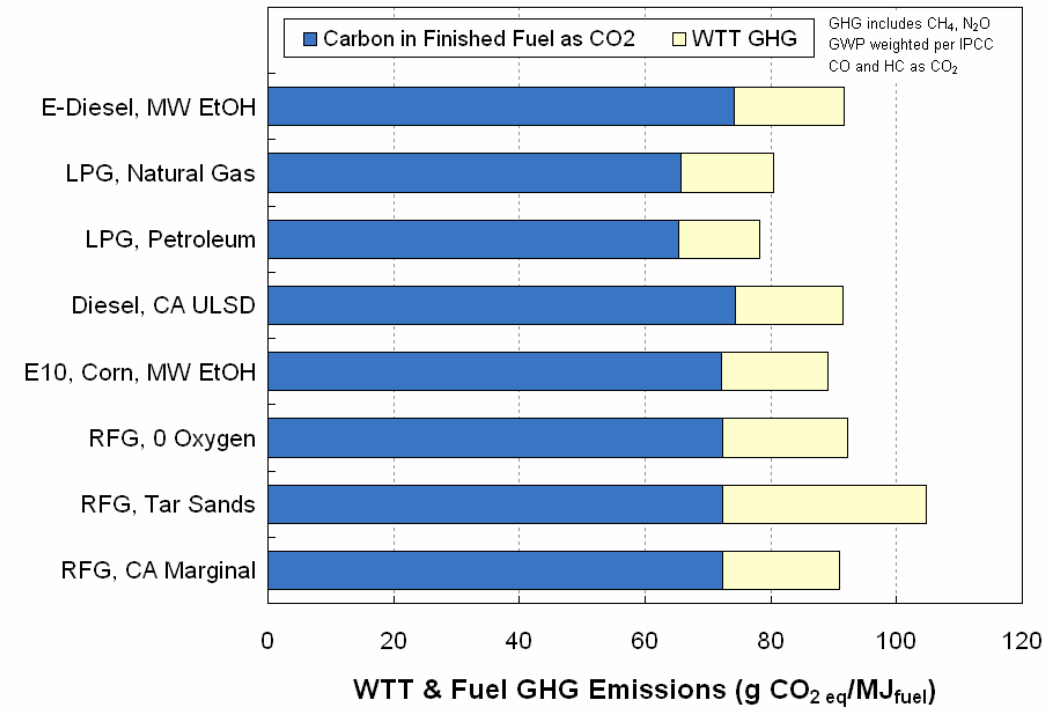


Figure 7-2. GHG Emissions for Petroleum Fuels

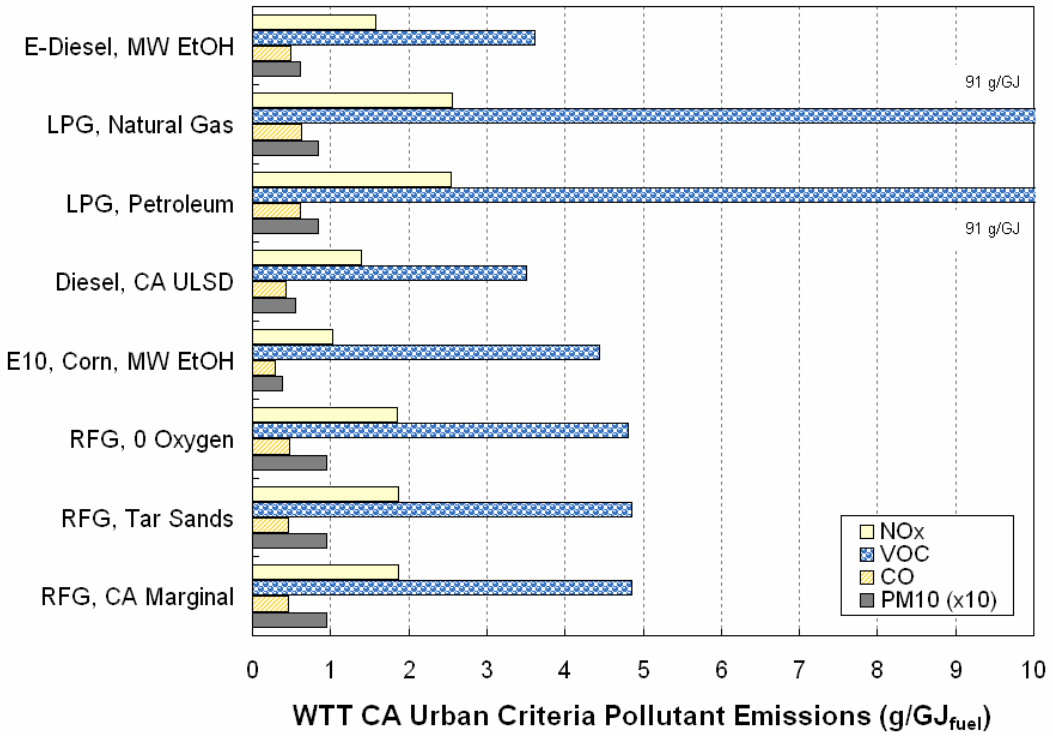


Figure 7-3. Criteria Pollutant Emissions for Petroleum Fuels

The fate of residual fuels was not analyzed in this analysis. Residual fuel is a byproduct of the refining process and is typically used as bunker fuel or power plant fuel. Further analysis should consider the fate of residual oil and petroleum coke when assessing the boundaries for petroleum fuels.

LPG

In addition to those of the major petroleum fuels, LPG's energy inputs are also shown in Figure 7-1. The energy inputs required for a single LPG pathway are similar to that of gasoline, however, at present, LPG can be produced from refinery byproducts. As a result, the refining energy allocated to LPG is low, as is illustrated in Figure 7-1. This is a fair assumption while LPG remains a byproduct of more in-demand fuels. The amount of LPG produced from California refineries would not likely change with a growth in the use of LPG as a vehicle fuel. With significant LPG penetration, other markets for LPG would be affected. Refineries could switch from burning limited amounts of LPG to burning natural gas. LPG price impacts could also affect markets for home heating.

The GHG emissions for LPG; also shown in Figure 7-2, reflect the lower carbon content of LPG relative to gasoline and diesel fuel. In addition, the lower energy input required for production also contributes to the relatively low GHG emission characteristics of LPG compared to gasoline or diesel. Given that LPG is a by product of other petroleum or natural gas production, the GHG impact of LPG is also affected by the displacement effects in the stationary fuel market.

Criteria pollutant emissions for LPG production are also shown in Figure 7-3. Venting losses from LPG production result in significantly higher hydrocarbon emissions than other, non-volatile petroleum sources. The venting losses occur because an outage valve is opened during tank filling. The issue is more regulatory than technical, but has not been successfully addressed to-date. It applies to both vehicle tanks and fueling station tanks.

PM and NO_x emissions are driven by transportation distances, which results in greater emissions for remote natural gas LPG than crude derived LPG. Some refineries separate propene (an ozone precursor) and export it as a chemical feedstock. This allows these refineries to move propene from the vehicle market (where it is regulated by ARB) to non-vehicle markets. The issue of propene emissions is not dealt with in this analysis.

7.2 Natural Gas

7.2.1 Pathway Description

Natural gas for transportation applications will likely originate in either the U.S. Southwest or from natural gas reserves overseas. In particular, Borneo, Indonesia, or Malaysia are likely exporters of natural gas. Natural gas is transported and stored as either a liquid or a compressed gas. Liquefying natural gas is an energy intensive

process and requires storage at high pressures or low temperatures. However, the increase in density makes certain methods of transport viable.

CNG

Compressed natural gas will be supplied from either the U.S. Southwest or Canada. In addition, about 20 percent of future pipeline gas is expected to come from imported LNG. Consequently, the marginal supply of natural gas is likely to originate from outside California via pipeline. Longer transportation distances affect the cost of pipeline gas and limit delivery to California. Additional sources of gas will be derived from LNG from as far away as Malaysia or Algeria. LNG is transported from the liquefaction facility via ship to LNG terminals. Thee LNG will be converted to gas via regasification facilities and distributed through existing and expanding natural gas pipeline infrastructure.

The general steps in producing and distributing CNG are shown in Table 7-4.

Table 7-4. Production and Delivery Pathway Details for CNG

CNG from North American Natural Gas

- Extract natural gas and separate CO_2 and heavy components
- Transport via pipeline using natural gas IC engines and turbines
- Distribute via local pipelines
- Compress to vehicle tank pressures at local fueling station

CNG from Remote Natural Gas via LNG

- Extract natural gas and separate heavy components
- Transport gas to liquefiers by pipeline
- Liquefy natural gas
- Transport LNG by tanker ship to Baja or southern California ports
- Regasify at LNG terminal
- Distribute via NG pipeline
- Compress to vehicle tank pressures at local fueling station

Boundary Assumptions

- Sufficient natural gas is available to supply CNG without significant price or elasticity effects

LNG

LNG will generally be produced in the same manner as CNG, but will be off-loaded from the LNG tanker in the liquid state, and will be stored and transported as a liquid via trucks. This approach preserves the density gains from the liquefaction process. Thus, fueling with LNG allows for more fuel storage on board with vehicle.

Facilities in Southern California are expected to be equipped with regasification facilities with no on-shore LNG storage. Facilities in Baja California or Coos Bay, Oregon, may be equipped with liquid storage tanks from which LNG could be distributed by truck.

The general steps in LNG production are shown in Table 7-5.

Table 7-5. Production and Delivery Pathway Details for LNG from Remote Natural Gas

LNG(Remote Natural Gas)

- Extract and compress natural gas
- Transport natural gas to liquefier by pipeline
- Liquefy natural gas
- Transport LNG by tanker ship to Baja, California or Coos Bay, Oregon
- Store in bulk terminals as LNG
- Distribute via LNG trucks

7.2.2 Assumptions

Table 7-6 summarizes the assumptions underlying the natural gas fuels WTT analyses.

Table 7-6. Natural Gas Fuels Pathway Assumptions

Descriptor	CNG, NA Natural Gas	CNG, LNG, Remote NG	CNG, LFG	LNG, Remote NG	LNG, NA NG, Pipeline Liquefier
Feedstock	Natural Gas	Natural Gas	Landfill Gas	Natural Gas	Natural Gas
Production Process	Compression	Liquefaction / Compression	Compression	Liquefaction	Compression / Liquefaction
Compression/Liquefaction	0.6kWh/therm	2.4 kWh/therm + 0.6 kWh/therm	1.8kWh/therm	2.4 kWh/therm	2.7 kWh/therm
Product Transport Mode	Pipeline	Marine	Local	Marine	Pipeline
Product Tansport (mi)	1,000	7,200	0	7,200	1,000
Urban miles	160	115	0	115	160
Net Cargo (Tonne)	--	68,000	--	68,000	--
Local Delivery Mode	Pipeline	Pipeline	Local	Truck	Truck
Local Delivery (mi)	50	50	0	50	50

2012 assumptions

7.2.3 Results & Interpretations

The WTT energy inputs for North American natural gas-based fuels are shown in Figure 7-4. The major energy consuming processes for natural gas-based fuels are

compression and liquefaction, and in the case of landfill gas (LFG), gas clean-up. All of these processes are accomplished using electrically–powered machinery. Therefore, most of the energy inputs are reflective of electricity derived from natural gas combined cycle plants, with some non-fossil (renewable) generation capacity.

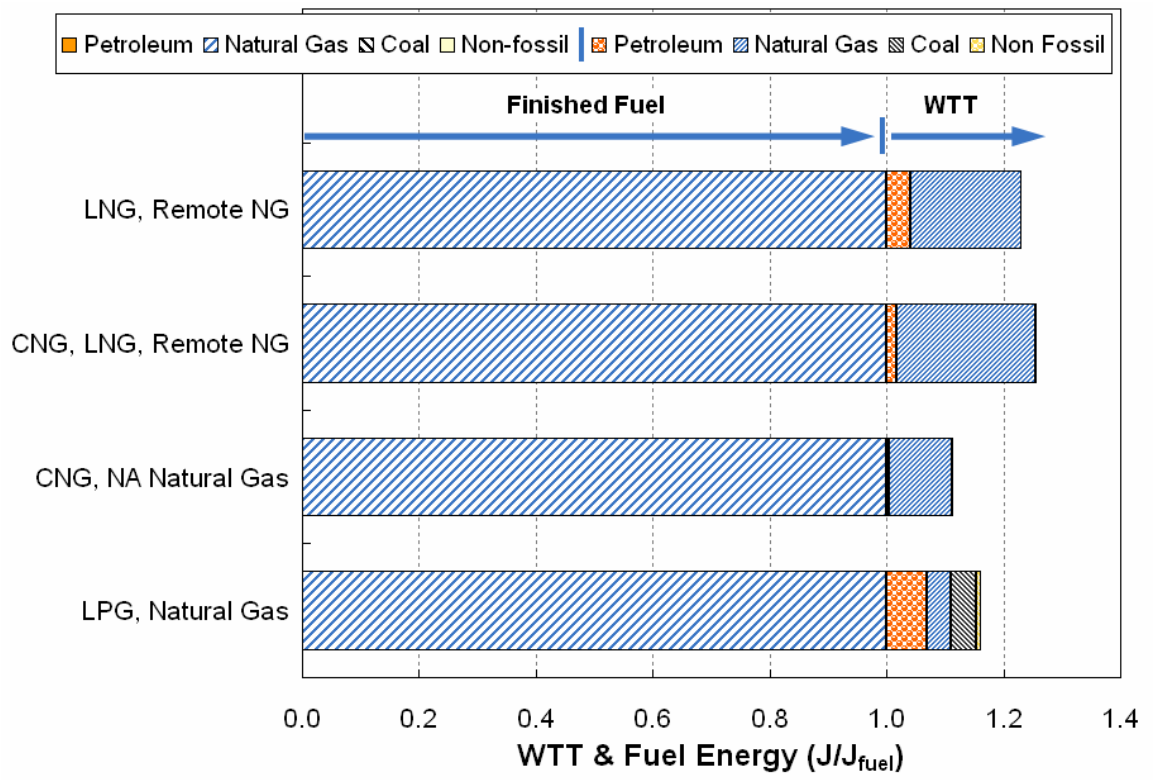


Figure 7-4. Energy Inputs for Natural Gas Fuels

The GHG emissions for natural gas fuel production are shown in Figure 7-5. Clearly the WTT energy inputs have a significant effect on the total GHG emissions. CNG and LNG produce lower overall GHG emissions than other petroleum fuels, in large part because of the low carbon fraction in the fuel. The average carbon factor for natural gas is 57 g/MJ compared to 72 g/MJ for gasoline. For the case in which remote natural gas is supplied to the consumer as CNG derived from LNG, the GHG emissions are quite high as a result of liquefying the gas for ship transit, then subsequently vaporizing and compressing it for distribution in the pipeline network. In addition to the compression and liquefaction steps that must be undertaken, the 7,200 mile transport distance adds significant bunker fuel consumption to the WTT fuel cycle. While this high GHG pathway is of concern, it is unlikely for this and other factors that CNG from imported LNG will supply more than 20 percent of the California demand.

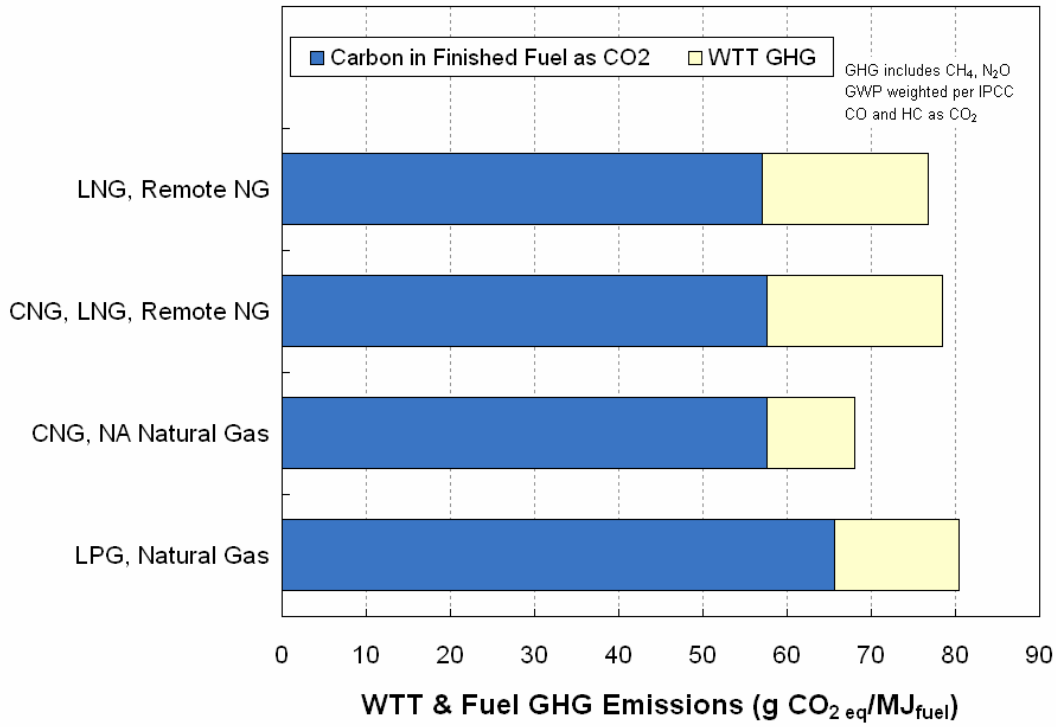


Figure 7-5. GHG Emissions for Natural Gas Fuels

The GHG emissions for the landfill gas option are quite favorable, a result of the assumption that the gas would otherwise be flared at the landfill. Therefore, the use of the LFG for vehicle fuel leads to little or no net increase in GHG emissions. LFG use will also result in an increase criteria pollutant emissions because the relatively high levels of hydrocarbons from LFG flares, the alternate to use as a fuel. This is illustrated in Figure 7-6.

If alternative uses of LFG were available, its use as a vehicle fuel would need to be compared with options such as displacing grid power.

The criteria pollutant emissions correspond primarily to the energy required for compression and liquefaction, and are directly linked to the emission factor for power plants providing electricity to the process machinery. In particular, the power plant emissions add significant PM to the CNG and LNG pathways. In the case of LNG delivered to fueling stations, diesel trucks also contribute to the criteria pollutant and GHG emissions.

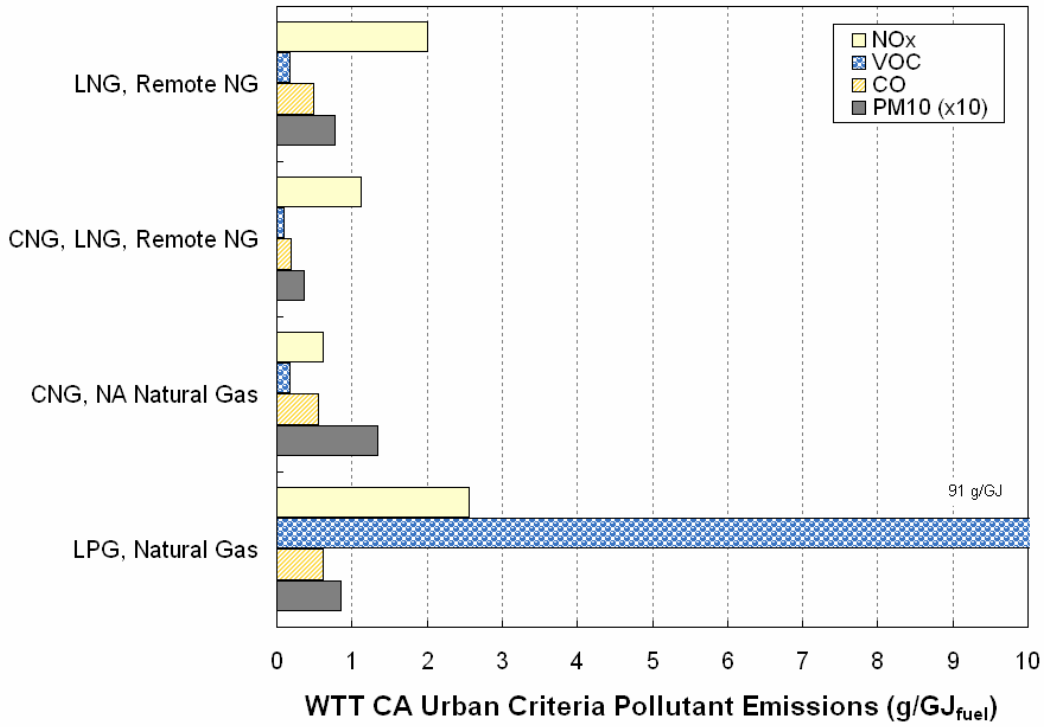


Figure 7-6. Criteria Pollutant Emissions for Natural Gas Fuels

7.3 Synthetic Fuels

7.3.1 Pathway Description

Numerous synthetic fuels exists, but this analysis focuses on three viable options: methanol, dimethyl ether (DME), and Fischer-Tropsch diesel (FTD). All of these fuels can be produced from natural gas and some may be produced from other feedstocks such as methanol from landfill gas or FTD from biomass or coal.

Synthetic Fuels from Natural Gas

Just as the marginal supply of CNG and LNG is likely to come from overseas, so to is the natural gas for synthetic fuel production. Again, Borneo is assumed to be the source for marginal natural gas supply and it is there that the plants for synthetic fuels production will be located. Natural gas will likely be transported by pipeline from the well to the processing facility, where it is processed and loaded onto tanker ships for transport to California's major ports. From the storage vessels at the ports, the fuels will be transported to blending terminals or fueling stations onboard tanker trucks.

The general steps necessary to produce and distribute synthetic fuels from overseas natural gas are shown in Table 7-7.

Table 7-7. Production and Delivery Pathway Details for NG-Based Synthetic Fuels

Synthetic Fuels (Natural Gas)
• Extract natural gas from Borneo wells • Transport via pipeline to processing plants • Convert to synthetic fuel at processing plant • Transport on tanker ships to California port • Distribute to blending terminals or fueling stations by truck

Synthetic Fuels from Coal or Biomass Gasification

In addition to natural gas, coal and biomass can be used as feedstocks for the synthetic fuels evaluated in this report. A significant advantage is that these feedstocks can be harvested domestically and shipped via rail to California processing plants which have easy access to the distribution network. All synthetic fuel production from coal or biomass feedstocks was assumed to occur in state (California) for the two cases analyzed.

The general steps necessary to produce and distribute coal or biomass from overseas natural gas are shown in Table 7-8.

Table 7-8. Production and Delivery Pathway Details for Coal/Biomass-Based Synthetic Fuels

Synthetic Fuels (Coal/Biomass Gasification)
• Mine/grow feedstock • Transport feedstock via rail to California processing facility • Convert to synthetic fuel at processing plant • Distribute to blending terminals or fueling stations by truck

7.3.2 Assumptions

The assumptions underlying the WTT analyses of the synthetic fuels considered are summarized in Table 7-9.

Table 7-9. Synthetic Fuels Pathway Assumptions

Descriptor	Methanol, Remote NG	DME, Remote NG	FTD 30, Remote NG	FTD 30, NG DeSalinization	FTD, CA Poplar	FTD, CA Coal	BD 20, Palm Oil	BD20, MW SoyBean	BD20, CA Mustard
Feedstock	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Poplar	Coal	Palm Oil	Soybean	Mustard
Production Process	Reforming /catalytic synthesis	Reforming /catalytic synthesis	Reforming /catalytic synthesis	Reforming /catalytic synthesis	Gasification /catalytic synthesis	Gasification /catalytic synthesis	Methanol Esterification	Methanol Esterification	Methanol Esterification
Conversion Efficiency	67.5%	70.0%	63.0%	63%, + 5% steam credit	57.7%	40.5%	0.1 kg Methanol/kg oil + 0.03 J/J heat	0.1 kg Methanol/kg oil + 0.03 J/J heat	0.1 kg Methanol/kg oil + 0.03 J/J heat
Primary Transport Mode	Marine	Marine	Marine	Marine	Truck (feedstock)	Rail (feedstock)	Marine (feedstock)	Rail (Soybean Oil)	Truck (feedstock)
Product Tansport (mi)	7,200	7,200	7,200	7,200	40	1,400	7,200	1,400	40
Urban miles	115	115	115	115	40	236	115	236	40
Net Cargo (Tonne)	147,000	147,000	147,000	147,000	25	8,036	147,000	8,036	25
Local Delivery Mode	none	none	Pipeline/ truck	Pipeline/ truck	Pipeline/ truck	Pipeline/ truck	Pipeline/ truck	Pipeline/ truck	Pipeline/ truck
Local Delivery (mi)	60	60	50	50	50	50	50	50	50

7.3.3 Results and Interpretation

Figure 7-7 compares energy inputs for synthetic fuels produced from remote natural gas – methanol, DME, FTD - and the associated delivery pathways. For all of these cases the feedstock assumptions and delivery distances are the same, yielding results that are based primarily on the efficiency of the process used to make synthetic fuels. Differences in gravimetric energy density affect the energy inputs for distribution via marine vessels and local delivery trucks, but these considerations do not affect the outcome to the same degree as the process efficiency.

FTD plants currently consume more energy than methanol plants, but some of this disadvantage is recovered with reduced energy requirements for fuel delivery. As discussed in Section 3, improvements in FTD technology will close the energy gap between FTD and methanol fuels in the future. The large scale DME plants analyzed here have a modest efficiency benefit in comparison to methanol plants. However, no large DME plants are under construction and a DME option is unlikely in the 2012 timeframe. Lastly, LNG is compared to the synthetic fuels as it is another means of using remote natural gas as an alternative transportation fuel.

In addition to natural gas derived FTD, a number of other options were analyzed, including an FTD fuel blend, FTD plants with energy recovery, and from FTD from biomass (poplar) and coal. In the case of FTD30 (a 30 percent FTD/ 70 percent diesel blend), most of the beneficial effects of the FTD are masked by the large fraction of diesel fuel, but the trends are still evident.

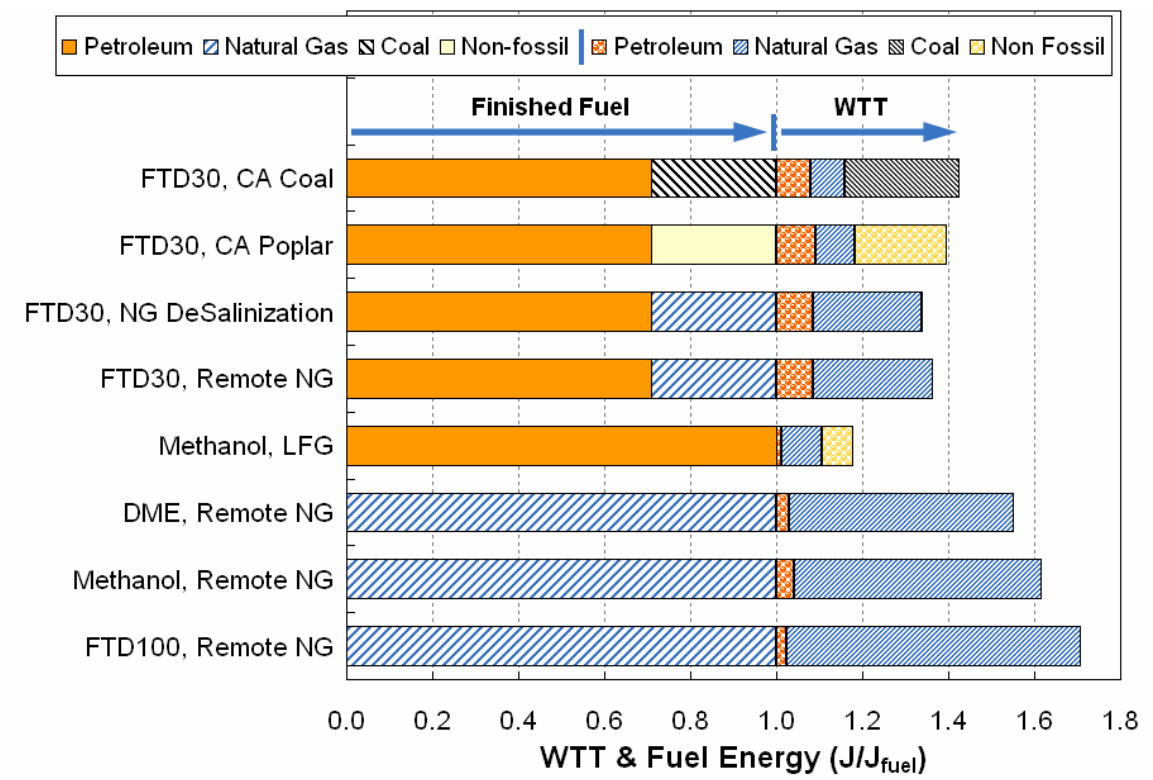


Figure 7-7. Energy Inputs for Synthetic Fuels

The gasification of coal or biomass is a less efficient method for making FTD, with coal being slightly less efficient than poplar feedstock. The GHG results shown in Figure 7-8, however, do not consider the sequestration of the CO_2 in flue gas emissions from the coal plant. This would be necessary for acceptance in California, and this would significantly reduce the GHG emissions from coal-based FTD.

Lastly, the results of a case using landfill gas as a methanol feedstock are also illustrated in Figure 7-7 and 7-8. Figure 7-9 shows the criteria pollutant emissions for this pathway, as well as the other synthetic fuel production pathways evaluated. In principle, landfill gas can be used as a feedstock for any of the synthetic fuels. Methanol was chosen as the evaluation case because there is a significant amount of data with which to make an accurate comparison to direct natural gas production (Wuebben). The use of landfill gas to produce methanol yields very favorable emission levels of GHG and criteria pollutants because it is assumed to be a waste gas that would otherwise be flared. The use of LFG in fuel production does not increase the carbon emissions that would have otherwise been emitted by that feedstock. The use of LFG in methanol production yields especially high reductions in HC and related toxics.

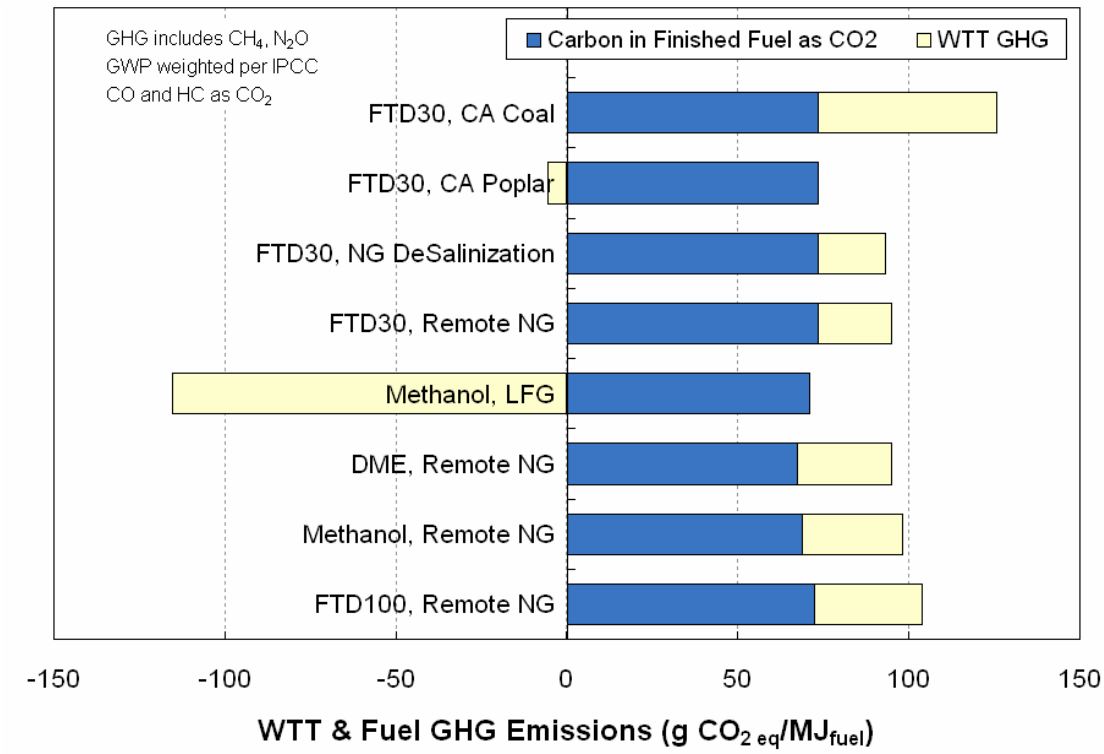


Figure 7-8. GHG Emissions for Synthetic Fuels

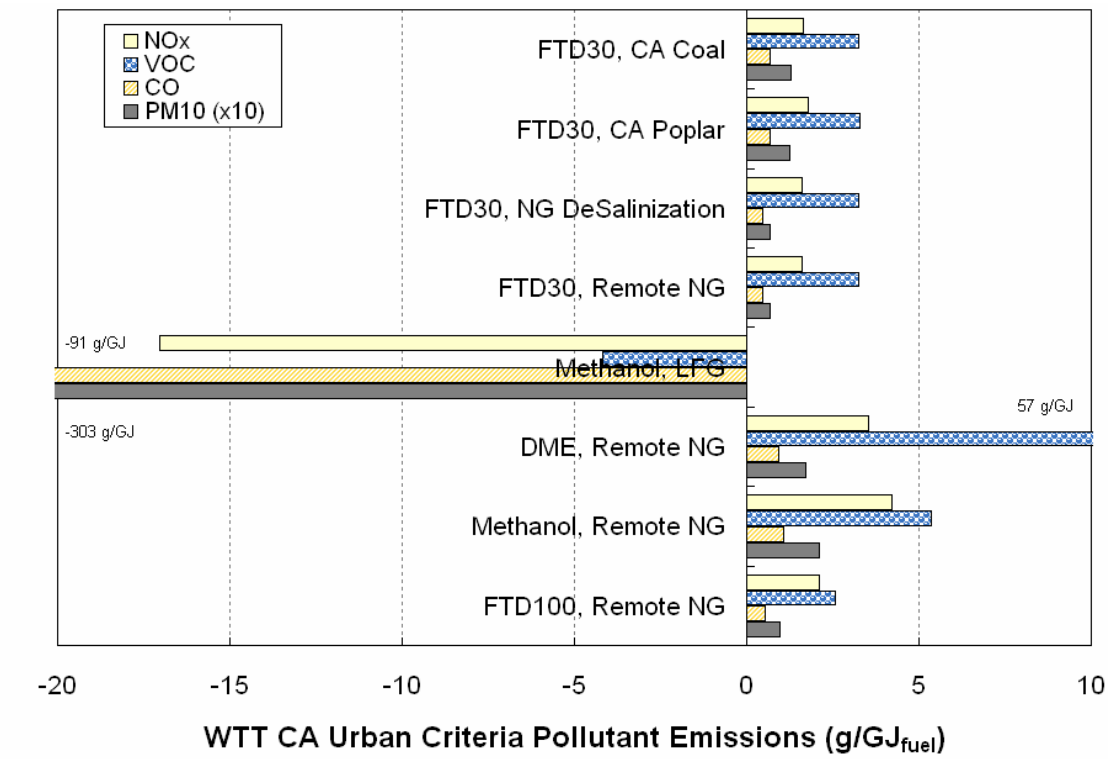


Figure 7-9. Criteria Pollutant Emissions for Synthetic Fuels

The GHG emissions for various synthetic fuels depend on the energy inputs and the carbon intensity of the feedstock. LNG, discussed in Section 7.2, has the lowest GHG emission factor compared with the synthetic fuels derived from natural gas; however, improvements in processing technology are closing the gap. Furthermore, LNG delivery pathways offer the opportunity for high levels of methane releases during upset conditions.

Today's FTD plants produce more GHG emissions than a modern methanol plant, but improvements in GTL technology will likely close this gap further. Given the similarities of the GHG emissions profiles for the synthetic fuels evaluated, the incorporation of the vehicle efficiency in a WTW analysis has a significant impact on which overall fuel cycle will have the more favorable GHG emission characteristic.

Criteria pollutant emissions for synthetic fuel production are shown in Figure 7-9. These are largely the result of tanker ship and truck emissions. Thus, fuel energy density and ship capacity are important factors in the criteria pollutant emissions results. Because of the scaling factors discussed in Section 5, larger ship capacities will have lower emissions levels (on a per ton basis) than smaller ships. In this analysis, methanol, DME, and FTD are all analyzed with shipping capacities of 150,000 DWT, creating a situation in which energy density is the distinguishing factor affecting shipping emissions (on an energy basis). LNG, due to the necessity for insulated, cryogenic containment the cargo, cannot be shipped in comparable quantities and is evaluated at 68,000 DWT. LNG tankers up to 120,000 DWT are under consideration, but may not be compatible with all existing LNG terminals. Moreover, larger loads of LNG will put a strain on the pipeline network's ability to accept such large loads of natural gas. Increased storage capacity at the terminals will be likely be needed.

7.4 Ethanol

7.4.1 Pathway Description

Ethanol can be produced with a variety of feedstocks and processing techniques, of which the most prevalent are evaluated in this analysis. Feedstocks for ethanol production include sugars and starches from agricultural products, petrochemicals, and cellulose from biomass. Present ethanol production employs the fermentation of starches or sugars that are easily broken down. Three categories of feedstock are analyzed in this report: corn, sugar cane, and cellulose. Within each category, agricultural inputs, conversion process assumptions, and transportation logistics affect the fuel cycle.

Corn

Most of corn-based ethanol will be produced in Midwestern dry mills close to the farms on which the corn was grown. This ethanol will be transported by rail to California where it will be mixed with gasoline at bulk terminals to create the vehicle fuels: E85,

E10, and California RFG3. In other cases corn can be shipped via rail to dry mills in California where the process byproducts can be used for cattle feed without any necessary drying or transport.

The general steps in corn based ethanol production are shown in Table 7-10.

Table 7-10. Production and Delivery Pathway Details for Corn Based Ethanol

Ethanol (Corn)

- Seed and fertilize fields
- Harvest and dry corn
- Convert to ethanol in dry mill
  - Distillers dried grain with solubles (IDGS) by product
  - Natural gas, coal, or other process fuel
- Transport to California by unit-train
- Store in rail car or bulk terminal
- Truck/pipeline to blending terminal
- Combine with gasoline components to produce E85, E10, or CA RFG3
- Store in underground tank

Sugar Cane

Sugar cane-based ethanol is a primary export of Brazil, where the climate and regulatory environment have created a large capacity for ethanol production. Ethanol from Brazilian sugar cane is produced at plants in Brazil and transported to California terminals by way of tanker ships. Distribution of fuels containing ethanol is achieved through pipelines and on-board trucks.

The general steps of sugar cane-based ethanol production are shown in Table 7-11.

Cellulose

Cellulosic ethanol can be produced from a number of feedstocks including poplar wood chips, switch grass, forest residue, and waste paper. Most of these feedstocks will be produced in California and easily transported to processing plants by rail. Unlike the fermentation of starches and sugars, cellulosic ethanol relies on an additional process, hydrolysis, to produce the fermentable sugars needed to produce ethanol. Once produced ethanol can be transported by rail or truck to blending terminals.

The general steps of cellulosic ethanol production are shown in Table 7-12.

Table 7-11. Production and Delivery Pathway Details for Sugar Cane Based Ethanol

Ethanol (Sugar Cane)

- Seed and fertilize fields
- Harvest sugarcane
- Convert to ethanol in dry mill
  - Natural gas, coal, or other process fuel
- Transport to California by tanker ship
- Store in bulk terminal
- Truck/pipeline to blending terminal
- Combine with gasoline components to produce E85, E10, or CA RFG
- Store in underground tank

Table 7-12. Production and Delivery Pathway Details for Cellulosic Ethanol

Ethanol (Cellulosic)

- Grow/produce feedstock material
- Harvest/collect feedstock
- Convert to ethanol in plant
  - Lignin by product
  - Natural gas, coal, or other process fuel
- Store in bulk terminal
- Truck/rail to blending terminal
- Combine with gasoline components to produce E85, E10, or RFG
- Store in underground tank

7.4.2 Assumptions

The assumptions underlying the WTT analyses of ethanol fuel are summarized in Table 7-13.

Table 7-13. Ethanol Pathway Assumptions

Descriptor	E85, Corn, MW mix/BR	E85, Corn, MW Coal	E85, Corn, MW NG	E85, Corn, MW NG, Wet Feed	E85, Corn, CA NG, Wet Feed	E85, CA Sugar Cane	E85, Brazil Sugar Cane	E85, CA Poplar, Cellulose	E85, CA Forest Residue	E85, CA Switch Grass
Feedstock	MW Corn/ BR Sugar Cane	MW Corn	MW Corn	MW Corn	MW Corn	Sugar Cane	Sugar Cane	Poplar	Forest Residue	Agricultural Residue
Process	Starch fermentation	Starch fermentation	Starch fermentation	Starch fermentation	Starch fermentation	Starch fermentation	Starch fermentation	Cellulose conversion	Cellulose conversion	Cellulose conversion
Feedstock Yield	2.7 gal/bu	2.7 gal/bu	2.7 gal/bu	2.7 gal/bu	2.7 gal/bu	65 gal/ton	65 gal/ton	85 gal/bdt	77 gal/bdt	80 gal/bdt
Process Energy	36,000 Btu/gal	36,000 Btu/gal	36,000 Btu/gal	25,500 Btu/gal	25,500 Btu/gal	36,000 Btu/gal	36,000 Btu/gal	36,000 Btu/gal	36,000 Btu/gal	36,000 Btu/gal
Energy Input	Natural Gas	Coal	Natural Gas	Natural Gas	Natural Gas	Bagasse	Bagasse	Lignin	Lignin	Lignin
Product Transport Mode	Rail	Rail	Rail	Rail	Rail	Truck	Marine	Truck	Truck	Truck
Product Transport (mi)	1,400	1,400	1,400	1,400	1,400	20	7,300	40	40	40
Urban miles	178	178	178	178	178	20	115	40	40	40
Net Cargo (Tonne)	9,000	9,000	9,000	9,000	9,000	9,000	80,000	25	25	25
Terminal Transport Mode	Truck	Truck	Truck	Truck	Truck	Truck	Truck	Truck	Truck	Truck
Distance (mi)	50	50	50	50	50	50	50	50	50	50
Local Delivery Mode	Truck	Truck	Truck	Truck	Truck	Truck	Truck	Truck	Truck	Truck
Local Delivery (mi)	50	50	50	50	50	50	50	50	50	50

7.4.3 Results and Interpretation

The results of the ethanol analysis are contained below in the figures discussed below. These figures detail the energy consumption, GHG emissions, and criteria pollutant emissions for both corn-based and cellulosic ethanol with a variety of pathways and processing fuels. The finished fuel being considered in this analysis is E85, and the results reflect all of the processes and transport required to bring E85 to the fueling station. This analysis reflects the WTT inputs and emissions of the petroleum fraction in E85. This fuel was selected because it clearly illustrates the trends associated with an ethanol pathway. The data illustrating the effects of E10 is presented with the petroleum pathways.

Figure 7-10 shows the energy inputs for a variety of corn- and sugar cane-based production options and specifically allows for the comparison between wet feed and dry feed, California production and Midwest production, as well as between process energy sources such as coal, natural gas, and digester gas. The energy requirements of the fuel cycle for dry mill plants are greater than those for wet mill plants. By producing wet feed as a byproduct, the energy required to dry the residual material is no longer necessary and can reduce the fuel cycle consumption by 10,000 Btu/gal. The effect of transportation – especially between California and Midwest production – is less pronounced, as it is assumed in the cases of Midwest production that corn for cattle feed is being shipped to California from the Midwest. By shipping corn to California for ethanol production, the byproduct can be used as cattle feed, while simultaneously reducing the importation of other cattle feed. This also negates the requirement of drying the byproduct for transport.

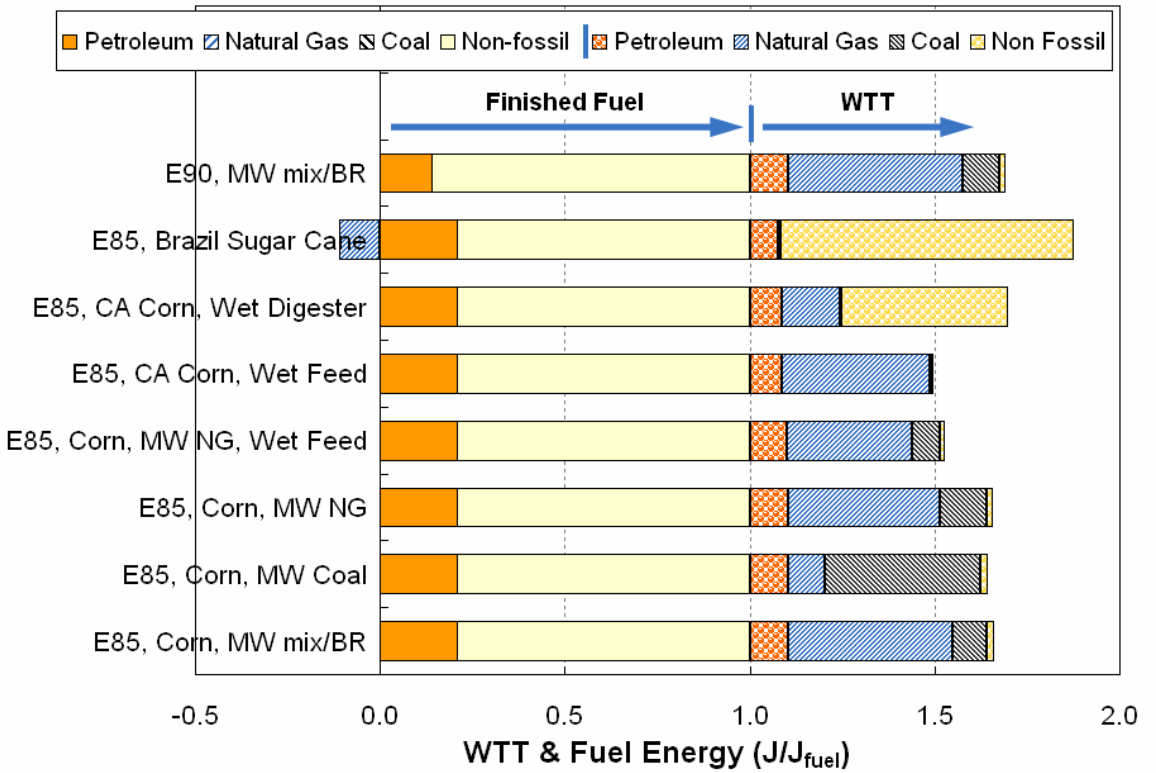


Figure 7-10. Energy Inputs for Starch-Derived Ethanol

Figure 7-11 illustrates the GHG emissions associated with various corn- and sugar cane-based ethanol pathways. The figure shows the carbon in the fuel as well as the GHG emissions occurring in the production and distribution processes, allowing for a better understanding of where the GHG emissions originate. For each pathway, GHG emissions depend significantly on the fuel consumed in the production step. As expected, the coal pathway has the highest GHG emission factor due to its low H/C ratio. At the other end of the spectrum, the use of digester gas yields significantly less emitted GHG emissions, and in fact results in a GHG emissions credit. Still, it is important to remember that there may be other applications that may be more financially or environmentally fitting for the digester gas, thus limiting its availability.

Criteria pollutant emissions from corn-based ethanol are illustrated in Figure 7-12 and are primarily a reflection of transportation distance and processing locations. For all the Midwest production cases, the product is all transported into California in the same fashion, so the California emissions are all equal. Emissions from ethanol in the Midwest plants are not counted towards California criteria pollutant emissions. For those cases in which corn is transported into the state, half of that corn is allocated to ethanol production. The Midwest/Brazlian blend is assumed to be 10 percent Brazilian sugar cane-based ethanol that is imported by tanker ship. The consequence of the small fraction of Brazilian sugar cane included in the assumed mix is that the Midwest emission factors for diesel dominate the total results.

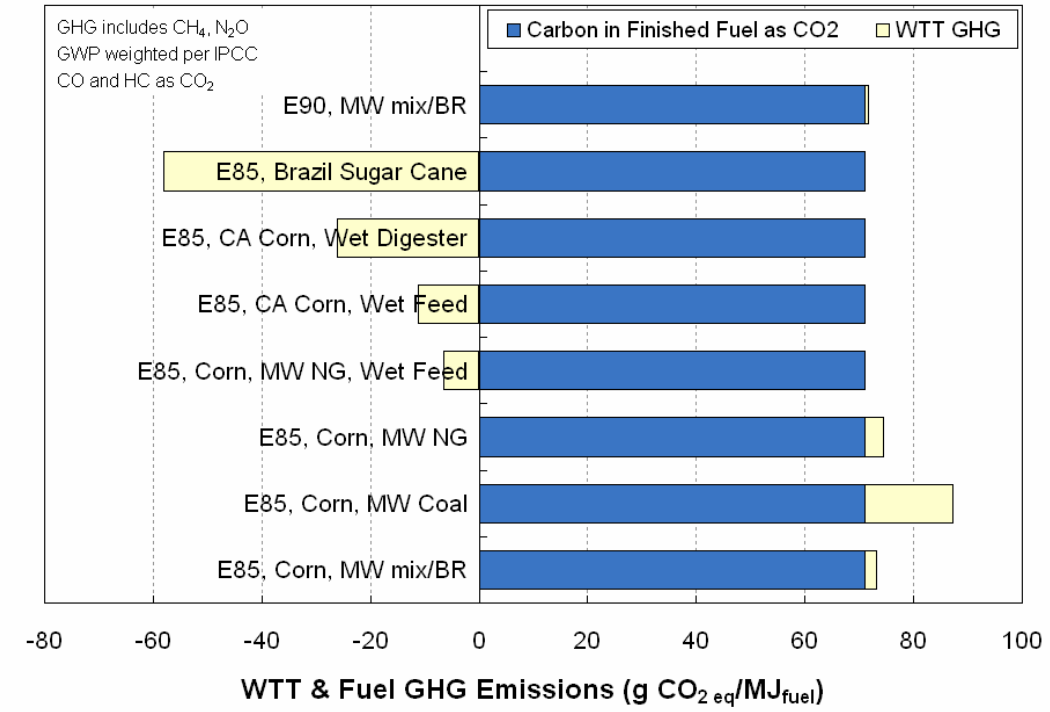


Figure 7-11. GHG Emissions for Starch-Derived Ethanol

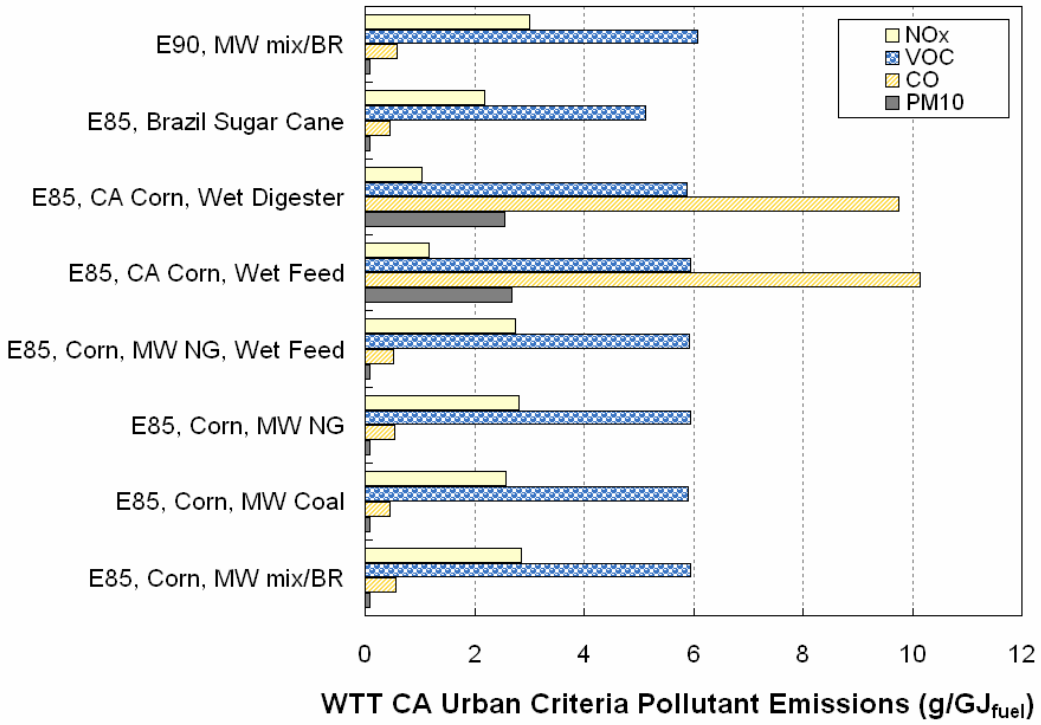


Figure 7-12. Criteria Pollutant Emissions for Starch-Derived Ethanol

The plant emissions attributed to the California cases are based on environmental impact reports and process analyses. From these plants comes an increase in fugitive emissions as well as emissions related to required electric power input.

The results for biomass-based cellulosic ethanol production energy requirements are shown in Figure 7-13. For a more detailed description of the cellulosic processes, please refer to Section 3. The cases shown reflect a high amount of biomass energy because no biomass input is allocated to the byproducts. Projections for future technologies state that excess power can be co-produced during the cellulosic ethanol production process as a result of the energy in the residual lignin (the process byproduct). This byproduct credit would reduce the WTT energy use. In addition, petroleum is a measurable portion of the WTT energy as a result of the energy required for farming and harvesting.

Forest residue requires the smallest energy input because no fertilizer or insecticide is required for the farming process. This has a modest impact on the total energy required for ethanol production from this feedstock.

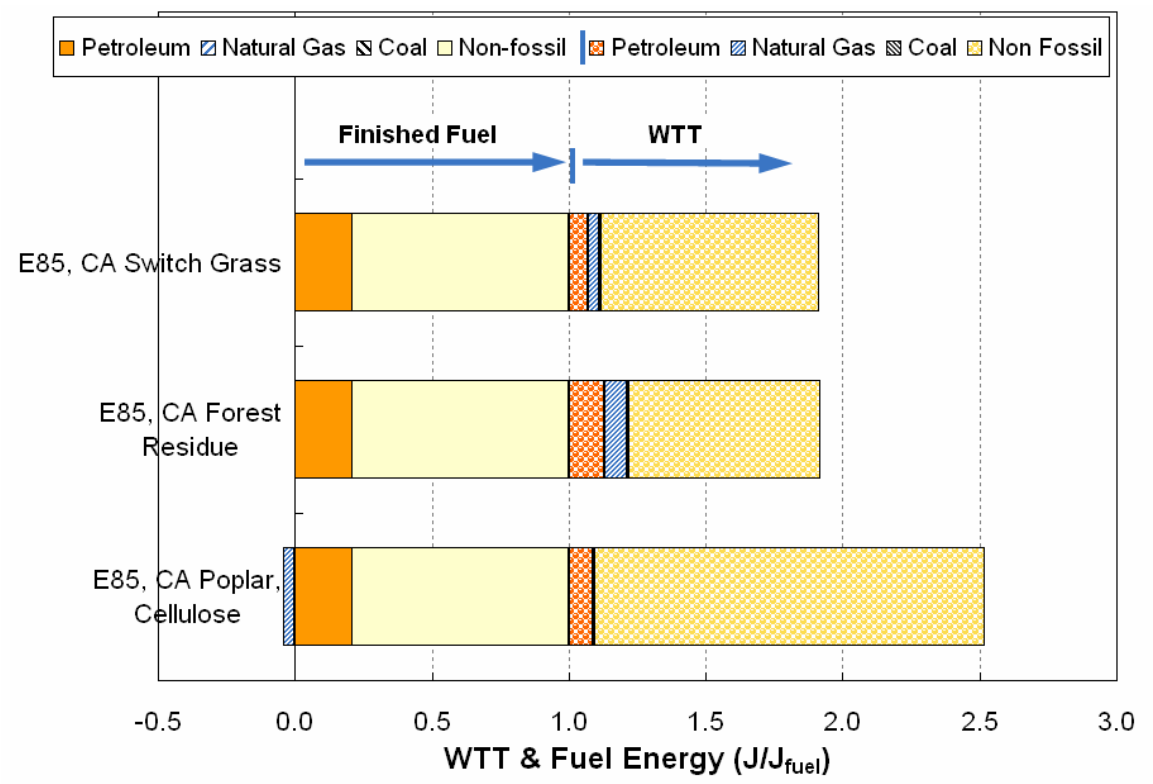


Figure 7-13. Energy Inputs for Biomass-Derived Ethanol

Figure 7-14 shows the WTT GHG emissions for cellulosic ethanol fuels and illustrates that cellulosic ethanol can significantly reduce GHG emissions because all of the viable possibilities show significantly negative WTT GHG emission factors. However, the introduction of these fuels will likely require the procurement of emission credits or implementation of new technologies to reduce the criteria pollutant emissions associated with the firing of lignin as a process fuel.

Criteria pollutant emissions from biomass to ethanol cases, shown in Figure 7-15, are more difficult to assess. The fuel used is often the lignin byproduct of the cellulosic process. Firing lignin in conventional boiler yields high criteria pollutant emissions that would likely require obtaining an offset for NO_x and HC emissions, and perhaps PM too. Alternate methods for dealing with high criteria pollutant emissions include the use of gasification technologies or significant clean-up technologies. The analysis here shows the projected criteria pollutant emissions assuming that NO_x, PM and VOC are offset.

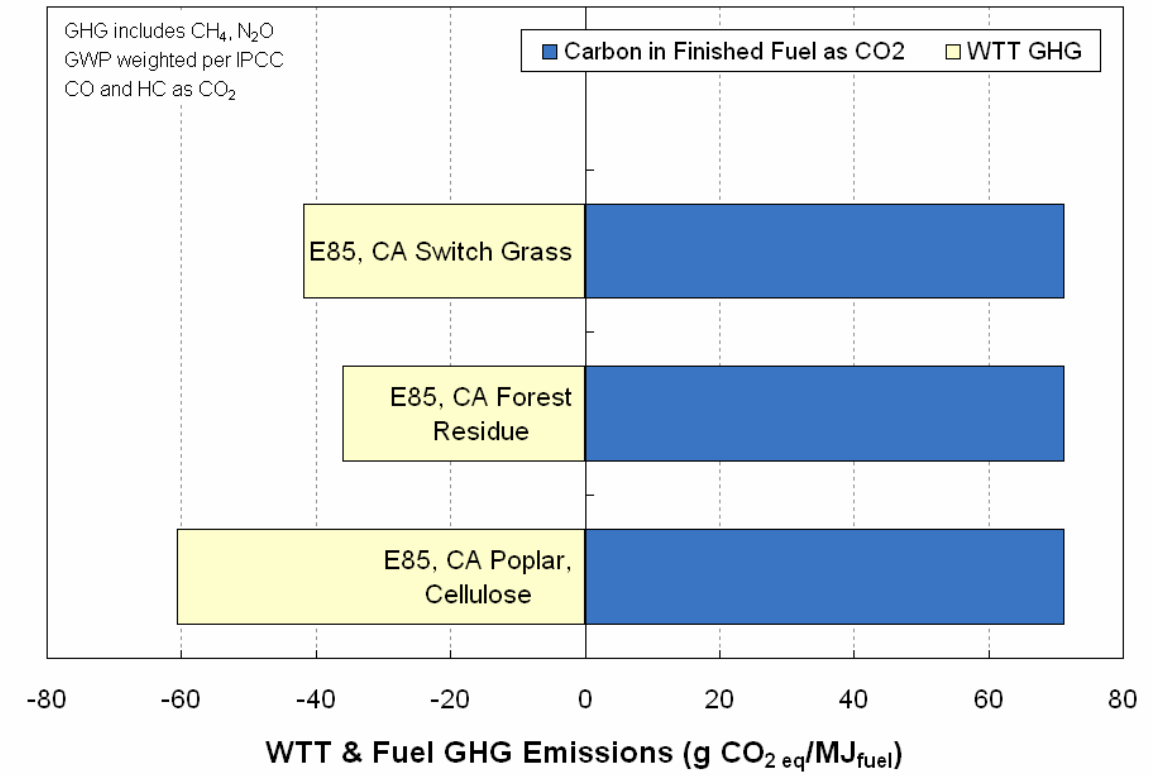


Figure 7-14. GHG Emissions for Biomass-Derived Ethanol

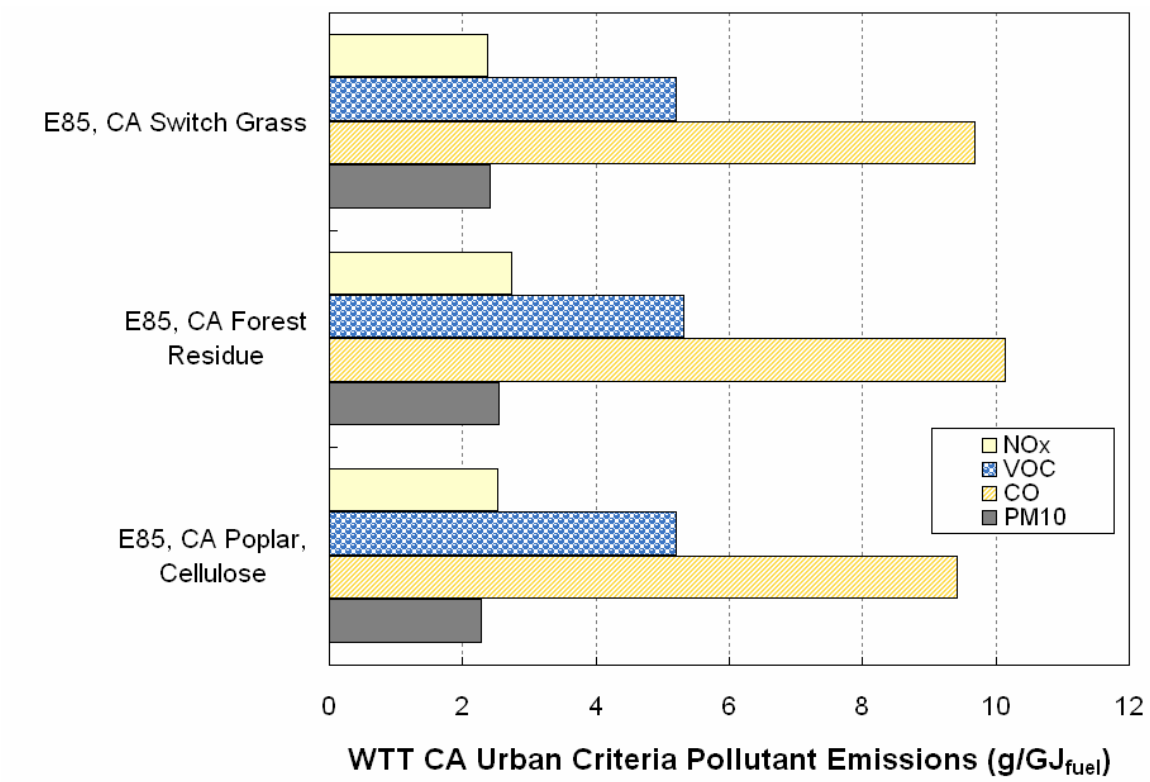


Figure 7-15. Criteria Pollutant Emissions for Biomass-Derived Ethanol

7.5 Biodiesel

Biodiesel can be produced from a variety of oil products including vegetable oils and animal fats. Yellow grease or restaurant waste oil provides a source of biodiesel with very low WTT energy inputs as it is a waste product. The largest source of biodiesel in the U.S. is Midwest soybean oil. Soybeans are an integral part of agriculture because of their protein byproduct, which can produce products as diverse as animal feed to tofu. Rapeseed (Canola) and mustard seed have been considered as sources of biodiesel in California. Rapeseed has a relatively high oil yield per acre; however, the economics of growing rapeseed as strictly an energy crop in California has not been demonstrated. Mustard seed could be a viable option as a cover crop used in rotation with other crops. The agricultural inputs are minimal but yields per acre would also be lower. Palm oil has among the highest oil yields per acre. However, palm oil would be imported from locations such as Borneo, India, or South America.

Vegetable oils are extracted in a process often requiring a hexane solvent that occurs in processing plants relatively close to the farm. These oils are transported to California by railcar or ship to plants where an esterification process is undertaken – a process that requires the addition of an alcohol (generally methanol) to yield biodiesel. Biodiesel will

be distributed to blending terminals via pipeline and delivered to fueling stations onboard trucks.

The general steps necessary to produce and distribute biodiesel from soybeans are summarized in Table 7-14. Table 7-15 and 7-16 provide corresponding summaries of the steps involved for biodiesel from mustard seed and palm oil, respectively.

Table 7-14. Production and Delivery Pathway Details for Soybean-Derived Biodiesel

Biodiesel (Soybean)

- Seed and fertilize fields
- Harvest and dry soybeans
- Recover soybean oil with hexane solvent extraction
- Transport soybean oil to California processing plants by unit-train
- Esterify vegetable oil to produce biodiesel
  - Requires addition of an alcohol (assumed to be methanol)
  - NaOH catalyst
- Transport biodiesel to blending terminal by truck or distribute directly from blending plant
- Deliver to fueling stations onboard trucks

Other Inputs/Products

- Methanol transported to blending plant by truck
- By-product glycerin used as chemical or soap feedstock

Soybean Boundary Assumptions

- Existing agricultural land is used to grow soybeans. Converting forested land to vegetable oil production would have significant negative GHG impacts
- Soybeans displace other crops which impacts U.S. agricultural markets with related life cycle impacts
- Market exists for soybean protein byproducts

Table 7-15. Production and Delivery Pathway Details for Mustard Seed-Derived Biodiesel

Biodiesel (Mustard Seed)

- Seed existing California fields
- Harvest seeds
- Recover oil with hexane solvent extraction
- Transport oil to processing plants by unit-train
- Esterify vegetable oil to produce biodiesel
  - Requires addition of an alcohol (assumed to be methanol)
  - NaOH catalyst
- Transport biodiesel to blending terminal by truck or distribute directly from blending plant
- Deliver to fueling stations onboard trucks

Other Inputs/Products

- Methanol transported to blending plant by truck
- By-product glycerin used as chemical or soap feedstock

Mustand Seed Boundary Assumptions

- Mustard seed is grown on existing agricultural land as a cover crop with minimal agricultural inputs
- Alternative use of land is fallow

Table 7-16. Production and Delivery Pathway Details for Soybean-Derived Biodiesel

Biodiesel (Palm Oil)

- Establish palm plantations
- Harvest seeds
- Recover oil with hexane solvent extraction
- Transport palm oil to California processing plants by tanker ship
- Esterify vegetable oil to produce biodiesel
  - Requires addition of an alcohol (assumed to be methanol)
  - NaOH catalyst
- Transport biodiesel to blending terminal by truck or distribute directly from blending plant
- Deliver to fueling stations onboard trucks

Other Inputs/Products

- Methanol transported to blending plant by truck
- By-product glycerin used as chemical or soap feedstok

Palm Oil Boundary Assumptions

- Palm oil is grown on previously deforested tropical lands
- Use of palm oil could support the continuation of extremely damaging environmental practices unless practices and mitigation measures are incorporated into the production of palm oil

7.5.1 Assumptions

The assumptions underlying the WTT analyses of biodiesel fuels are summarized in Table 7-17.

Table 7-17. Biodiesel Pathway Assumptions

Pathway	BD 20, Palm Oil	BD20, MW SoyBean	BD20, CA Mustard
Feedstock	Palm Oil	Soybean	Mustard Seed
Production Process	Methanol Esterification		
Conversion Efficiency	0.1 kg Methanol/kg oil + 0.03 J/J heat	0.1 kg Methanol/kg oil + 0.03 J/J heat	0.1 kg Methanol/kg oil + 0.03 J/J heat
Primary Transport Mode	Marine (Palm Oil)	Rail (Soybean Oil)	Truck (feedstock)
Product Tansport (mi)	7,200	1,400	40
Urban miles	115	236	40
Net Cargo (Tonne)	150,000	9,000	25
Local Delivery Mode	Delivery Truck		
Local Delivery (mi)	50		

7.5.2 Results

The WTT energy inputs for petroleum fuels are shown in Figure 7-17. Figure 7-18 illustrates the GHG emissions for the biodiesel fuel pathways. Figure 7-19 shows the criteria pollutant emissions for the biodiesel fuel pathways.

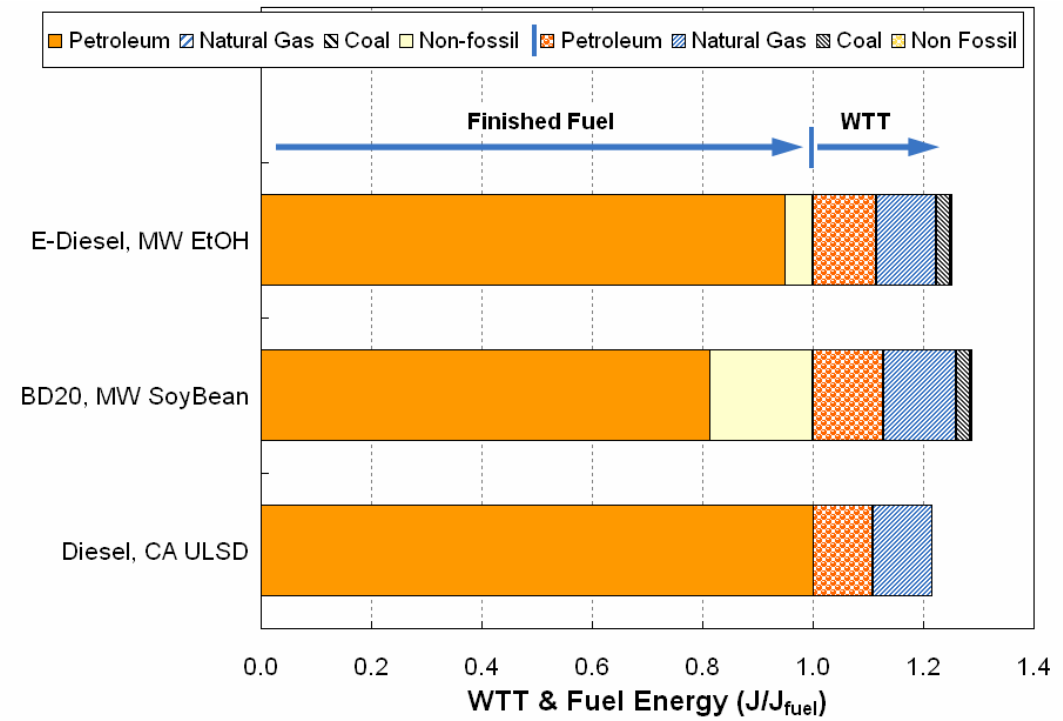


Figure 7-16. Energy Inputs for Biodiesel

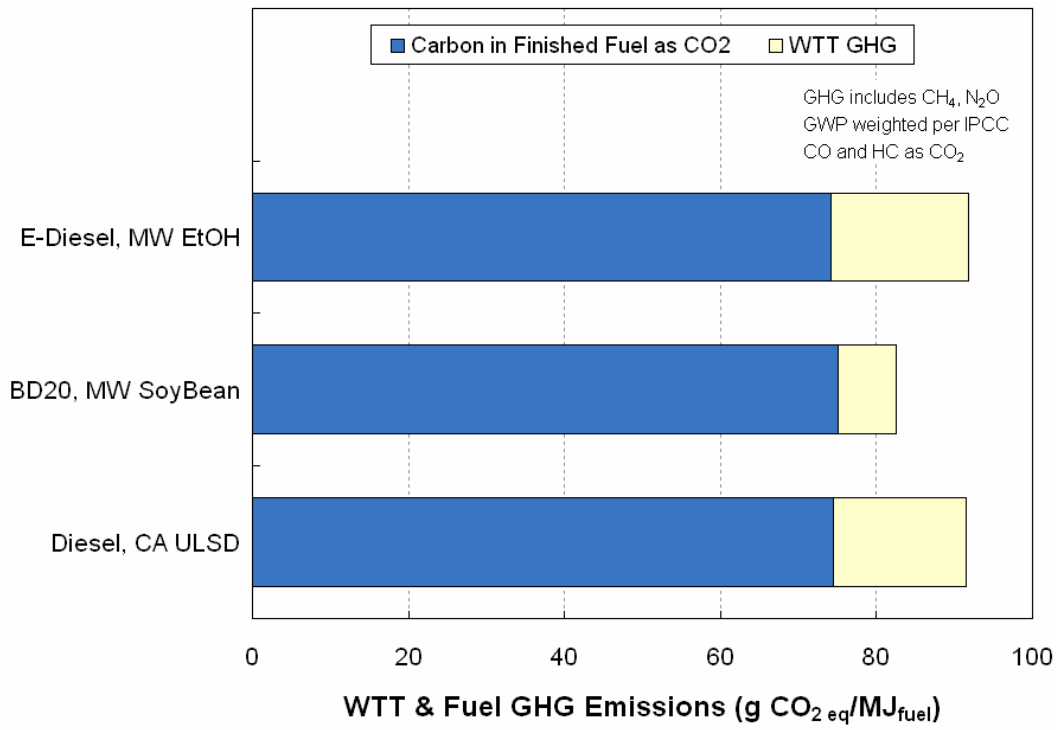


Figure 7-17. GHG Emissions for Biodiesel

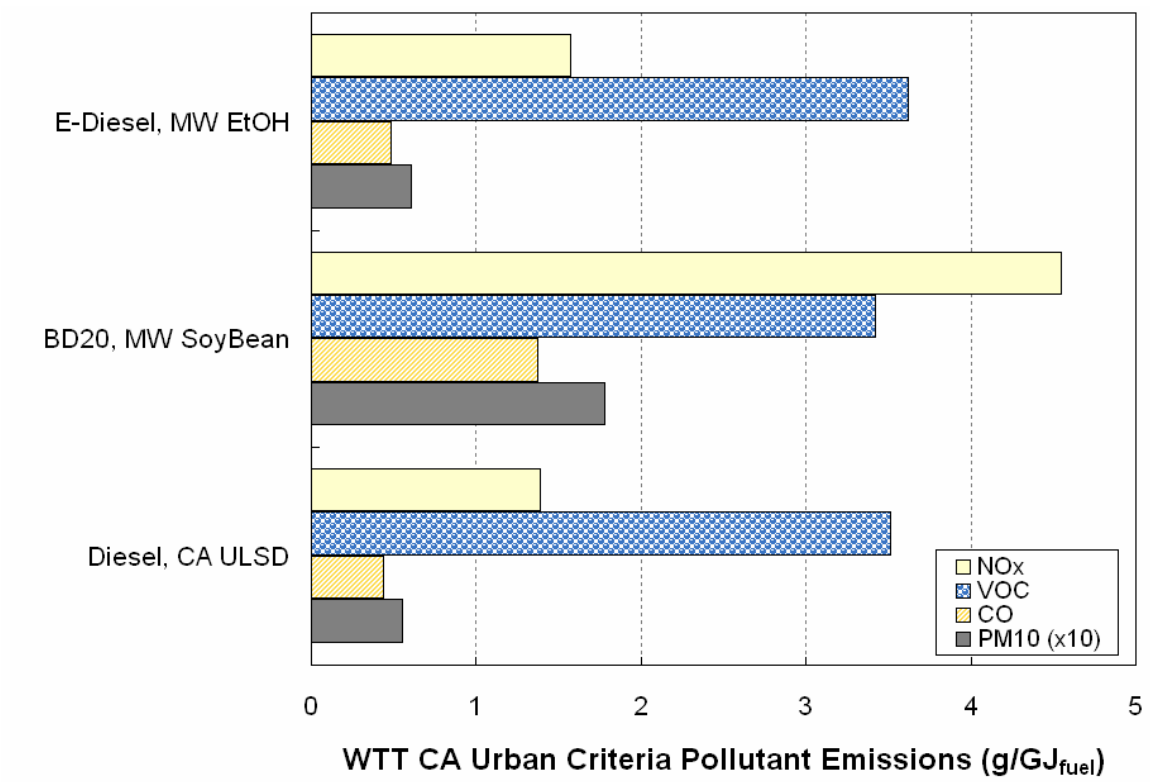


Figure 7-18. Criteria Pollutant Emissions for Biodiesel

7.6 Electricity

7.6.1 Pathway Description

The primary variation between the electricity pathways is the generation method, as all electricity is distributed on the same delivery network, and constant losses are associated with transportation and distribution for all methods of generation. It is assumed that all marginal generation occurs inside of California. The generation methods, or mixes thereof, analyzed include the California average generation mix, the mix specified by RPS regulations, California natural gas combined-cycle plants, wind-power renewable generation and a mix of renewable generation methods.

The general steps in electricity generation and distribution are shown in Table 7-18.

Table 7-18. Production and Delivery Pathway Details for Electricity

Electricity

- Generate electricity
  - Energy sources specified by generation method or assumed mix of generation methods
- Distribute electricity to consumers on existing/expanded transport and distribution network

7.6.2 Assumptions

The assumptions underlying the WTT analyses of electricity production are summarized in Table 7-19.

Table 7-19. Electricity Pathways Assumptions

Pathway	Electricity, NG/RPS	Electricity, NG/RPS, Night	Electricity, CA NG CC	Electricity, Renewable, No Combustion	Electricity, Renewable Mix	Electricity, H2 Pet Coke
Feedstock	Mixed	Mixed	Natural Gas	Wind	Mixed	Pet.Coke
Feedstock Transport (mi)	--	--	1,000	--	--	5900
Urban Miles	--	--	160	--	--	115
Primary Mode	Various	Various	Pipeline	--	Various	Marine
Generation Efficieny, LHV	Various	51.5%	51.5%	--	Various	32.9%
Mode	Power line	Power line	Power line	Power line	Power line	Power line
Delivery Losses	8.1%	8.0%	8.1%	8.1%	8.1%	8.1%

7.6.3 Results and Interpretation

The energy inputs required for electricity generation and distribution are shown in Figure 7-19. These data reflect generation with a variety of feedstocks. The overall energy consumption for WTT processes is driven by the generation and the energy required to transport feedstock – primarily natural gas – to the power plant and to fuel the generator at the power plant. It is important to note that in the case of PHEVs, the WTT results, shown here, will be combined with the vehicle efficiency in the WTW analysis.

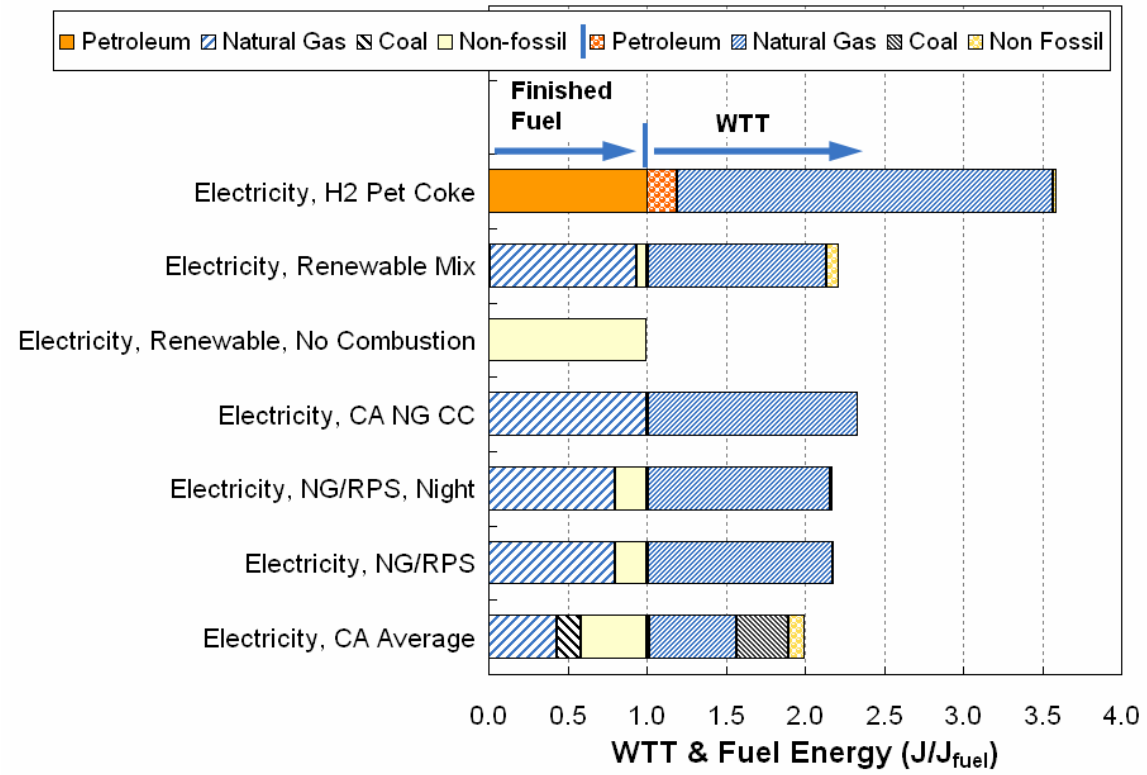


Figure 7-19. Energy Inputs for Electricity

All non-combustion renewable energy sources are defined as having a production efficiency of 100 percent. This means that for every kWh of electricity put on the grid, the fuel cycle reflects only 1 kWh of energy consumed. Once the renewable power is delivered to the grid it is subject to transportation and distribution losses that yield an overall WTT energy input of approximately 1.09. While the actual generation devices (e.g., wind turbines, solar panels) are not 100 percent efficient, the losses in those devices are not considered here due to the renewable characteristics of the resources.

Figure 7-20 shows the GHG emissions for electricity generation and distribution. The emissions are primarily dependent upon the generation efficiency as well as the carbon intensity of the fuel. The effect most clearly illustrated by Figure 7-20 is the effect of adding renewable power sources to the baseline marginal generation method: natural gas combined-cycle plants. Also shown are the GHG emissions for a petroleum coke gasification system. This option involves the sequestration of CO_2 and by products in underground storage media. To the extent that these pollutants remain sequestered, the associated GHG emissions are eliminated. However, Figure 7-20 includes the energy inputs and GHG emissions resulting from the electricity required for the separation and compression of the pollutants.

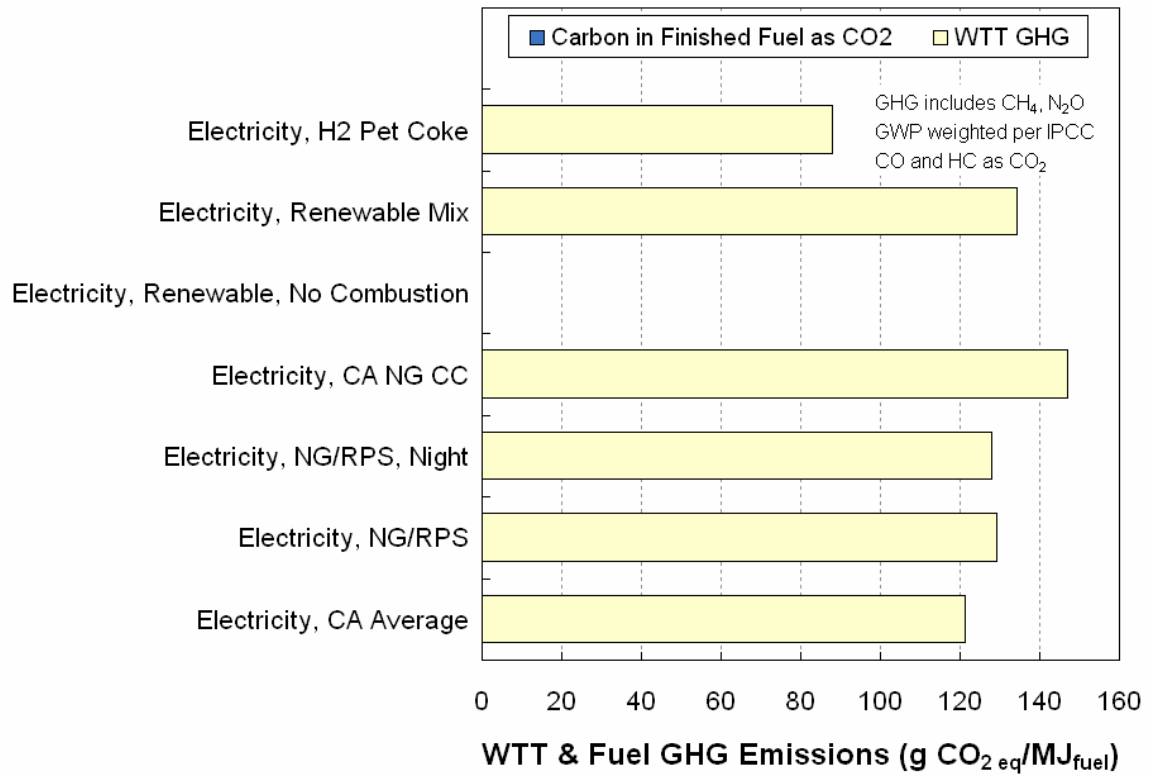


Figure 7-20. GHG Emissions for Electricity

Figure 7-21 shows the California criteria pollutant emissions for the various electricity pathways. In general, emissions from power plants and the emissions associated with distributing natural gas drive these results. Emission constraints on power plants in California non-attainment areas are taken into account so there is no net increase in NO_x or HCs from the power plants.

Criteria pollutant emissions from existing biomass fired power generation equipment were also examined. This is not a realistic scenario for criteria pollutant emissions because the emission levels are significantly higher than those from natural gas based plants, and a substantial growth in wood fired boilers and landfill gas engines would not be permitted without the introduction of new low emission technologies such as biomass gasification. The emissions impacts of these technologies were not examined; however, other analyses have shown that using waste biomass results in a significant reduction in emissions associated with the material (Perez 2001).

Emissions from the petroleum coke option are low for a variety of factors. First, the analysis was based on an oxygen fired combustion system with flue gas recirculation. This yields an ultimate product gas containing minimum quantities of oxygen and nitrogen. As a result, the entire gas stream from the power plant can be compressed for sequestration, thus negating the need for a separation process. In addition, using

petroleum coke as a feedstock eliminates the emissions associated with exporting the material.

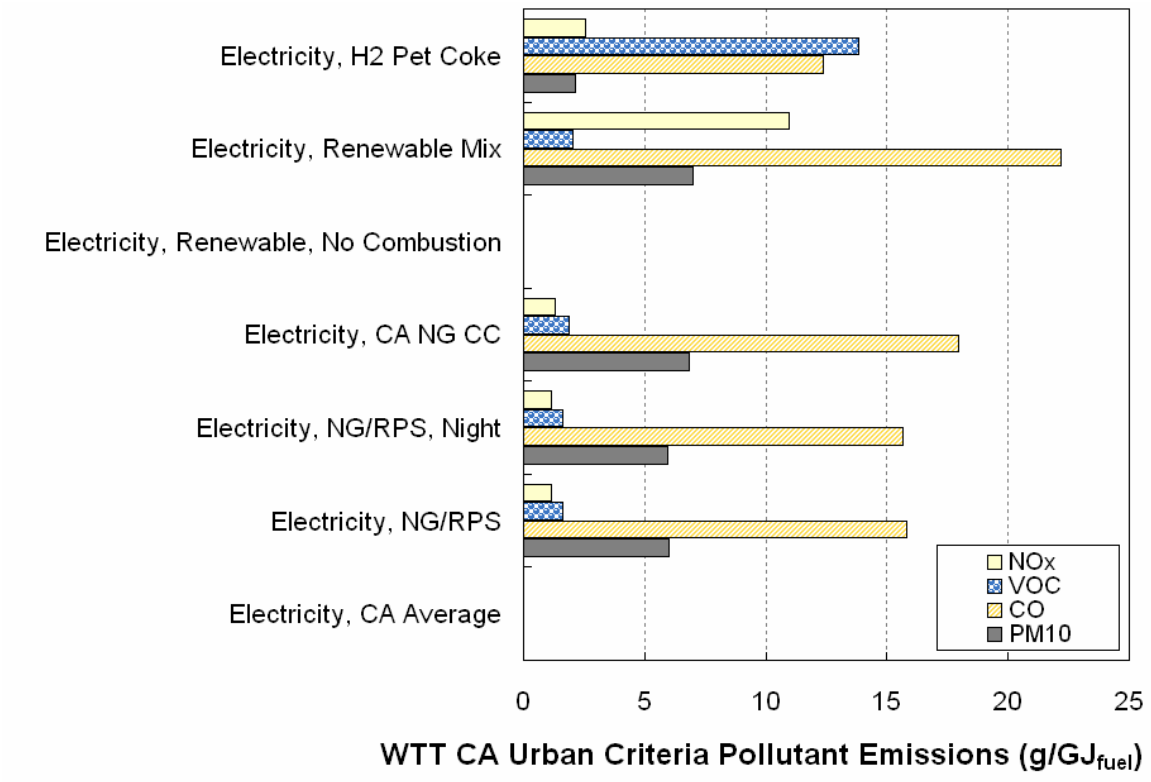


Figure 7-21. Criteria Pollutant Emissions for Electricity

7.7 Hydrogen

7.7.1 Pathway Description

Like so many other fuels, hydrogen can be produced from a number of feedstocks and at a variety of locations yielding quite different transport and distribution strategies. The primary production methods evaluated in this analysis are steam reformation of natural gas, gasification of petroleum coke or biomass, and electrolysis of water. Hydrogen can be produced at central plants or on-site at fueling stations. For those cases requiring transport from a central plant, hydrogen can be shipped via one of two methods: hydrogen is liquefied and transported to the forecourt on-board trucks, or it is compressed and transported in a pipeline network. Transporting hydrogen as a compressed gas in trucks (tube trailers) was not analyzed in this study as it is not a viable method of transport in an environment with reasonable penetration. Tube trailers

may be used as a delivery option in a transitional period, but are not financially or environmentally viable for long-term implementation.

Steam Reforming Natural Gas

Steam reformation is the most common method for producing hydrogen from natural gas. The process involves injecting high pressure natural gas and steam into a reactor where H_2 and CO are the primary products. This analysis evaluates hydrogen produced from North American natural gas, of which the marginal supply is likely to come by pipeline from the American Southwest. Reformation can occur at either a central plant or on-site at the fueling station. If produced at a central plant the hydrogen will be transported either by truck or pipeline. In either case, once at the fueling station, the hydrogen will undergo a compression process to reach a storage pressure of 5,000 psi. In one evaluated case the storage pressure is 10,000 psi, thus requiring greater compression energy. The liquefaction and compression processes rely on electricity, and the pathways can be evaluated with a number of different electricity sources including the average California generation mix, new natural gas combined cycle plants, and renewable production.

If the hydrogen is generated on-site, all of the transportation energy inputs are avoided, and the only electricity demand is from the forecourt compressor.

The general steps of natural gas reformation and hydrogen delivery are shown in Table 7-20.

Table 7-20. Production and Delivery Pathway for Hydrogen from Natural Gas

Hydrogen (Natural Gas)

- Extract natural gas from North American fields
- Transport natural gas to central plants or fueling stations via pipeline
- Convert natural gas to hydrogen in a steam reformer
  - Requires raising high pressure steam
- Liquefy or compress hydrogen for transport to fueling stations by truck or pipeline
- Transport to fueling stations
- Compress to vehicle delivery pressure

Electrolysis

Hydrogen can also be produced by the electrolysis of water. This requires large amounts of electricity which can come from any variety of suppliers. For this analysis, the electrolysis pathway is evaluated with power from new natural gas combined-cycle generating stations as well as a mix made up of 70 percent renewable generation resources. Electrolyzing water with electricity supplied by nuclear power plants is an attractive option due to the low-GHG profile of nuclear power, but with present nuclear capacity committed to providing the base-load and new plant capacity still in development it, is highly unlikely that any nuclear capacity will be available for the production of mass-market hydrogen. Given the simplicity of electrolysis equipment and the distributed supply of water and electricity, hydrogen from electrolysis only makes sense if done on-site, thus negating transport requirements. The hydrogen will still need to be compressed to 5,000 psi for vehicle filling.

The general steps of the water electrolysis process are shown in Table 7-21.

Table 7-21. Production and Delivery Pathway for Hydrogen from Electrolysis

Hydrogen (Electrolysis)

- Generate electrical power from any number of sources
- Transport electricity along electrical transport and distribution network
- Electrolyze water at fueling station
  - Requires constant water supply
- Compress to vehicle delivery pressure

Gasification

The gasification of petroleum coke or biomass is another method for producing hydrogen. However, unlike steam reforming or electrolysis, gasification is not a feasible method for on-site generation. Petroleum coke or biomass – e.g., California poplar - will likely be delivered to the central plant via railcar. After production, hydrogen will be compressed for pipeline transport to the fueling station. At the fueling station the hydrogen will be compressed for vehicle filling like hydrogen from all other means.

The general steps of gasification and hydrogen delivery are shown in Table 7-22.

Table 7-22. Production and Delivery Pathway for Hydrogen from Petroleum Coke or Biomass

Hydrogen (Gasification)

- Collect/harvest petroleum coke or biomass
- Transport feedstocks to central plants on railcars
- Convert feedstock to hydrogen in gasifiers
- Compress hydrogen to pipeline pressure
- Transport hydrogen to fueling stations in pipeline
- Compress to vehicle delivery pressure

7.7.2 Assumptions

The assumptions for the hydrogen pathways evaluated in this analysis are contained in Tables 7-23 and 7-24, with Table 7-23 outlining assumptions for central production and Table 7-24 the assumptions for on-site production.

Table 7-23. Assumptions for Central Hydrogen Production

Descriptor	H2, NG SR LH2	H2, NG SR, LHR, Ren Power	H2, NG SR, Pipeline	H2, Pet Coke Pipeline	H2,Biomass, Pipeline
Feedstock	Natural Gas	Natural Gas	Natural Gas	Pet. Coke	Biomass
Production Process	Steam Reforming	Steam Reforming	Steam Reforming	Gasification	Gasification
Process Energy	78%	78%	78%	61%	51%
Delivery Process	Liquefaction	Liquefaction	Compression	Compression	Compression
Product Transport Mode	Truck	Truck	Pipeline	Pipeline	Pipeline
Urban Product Transport Distance (mi)	50	50	50	50	50
Fueling Station/Delivery Process Energy	12 kWh/kg	12 kWh/kg	3 kWh/kg	7 kWh/kg	3.5 kWh/kg
Compression Energy Source	NG CC/RPS	Renewable Power	NG CC/RPS	NG CC/RPS	NG CC/RPS

Table 7-24. Assumptions for On-site Hydrogen Production

Descriptor	H2, Onsite NG SR	H2, Onsite NG SR, 700 bar	H2, Onsite NG SR, Ren Power	H2, Grid Electrolysis	H2, 70% Renewable, Electrolysis
Feedstock	Natural Gas	Natural Gas	Natural Gas	Grid Electricity	70% Renewable Electricity
Production Process	Steam Reforming	Steam Reforming	Steam Reforming	Electrolysis	Electrolysis
Process Energy	74%	74%	74%	70%	70%
Delivery Process	Compression	Compression	Compression	Compression	Compression
Product Transport Mode	On-site	On-site	On-site	On-site	On-site
Urban Product Transport Distance (mi)	0	0	0	0	0
Fueling Station/Delivery Process Energy	2.8 kWh/kg	3.5 kWh/kg	2.8 kWh/kg	2.8 kWh/kg	2.8 kWh/kg
Compression Energy Source	NG CC/RPS	NG CC/RPS	Renewable Power	NG CC/RPS	70% Renewable Electricity

7.7.3 Results Interpretation

Figure 7-22 illustrates the overall energy requirements to produce and distribute hydrogen. A primary take-away from the analysis of various hydrogen production methods is that the efficiency of the production process drives the overall energy consumption. Steam reformation of natural gas achieves an efficiency equal to or greater than 70 percent. The WTT energy consumption inherent in the use of electricity makes the overall WTT energy consumption for electrolysis less favorable than natural gas steam reformation. The low production efficiency of the gasification pathway leads to a larger overall WTT energy consumption for the gasification pathways than steam reforming.

For the cases in which liquid hydrogen is the preferred delivery mechanism, it is clear that the liquefaction process consumes a significant amount of energy, especially when considering the WTT consumption required for electricity generation.

Figure 7-23 illustrates the GHG emissions for the various hydrogen pathways. For natural gas pathways, the overall GHG pathways are have slightly higher GHG emissions than gasoline. While this is the case, it is important to understand that these are WTT totals and do not account for the varying efficiencies on-board the vehicle.

The liquefaction process is shown to add significant GHG emissions (50 g/MJ) unless the electricity is generated from renewable resources. Both biomass and coal with sequestration have relatively low GHG emissions due to the carbon capture resulting from the use of biomass, a natural carbon sink, or sequestration, a man-made carbon sink.

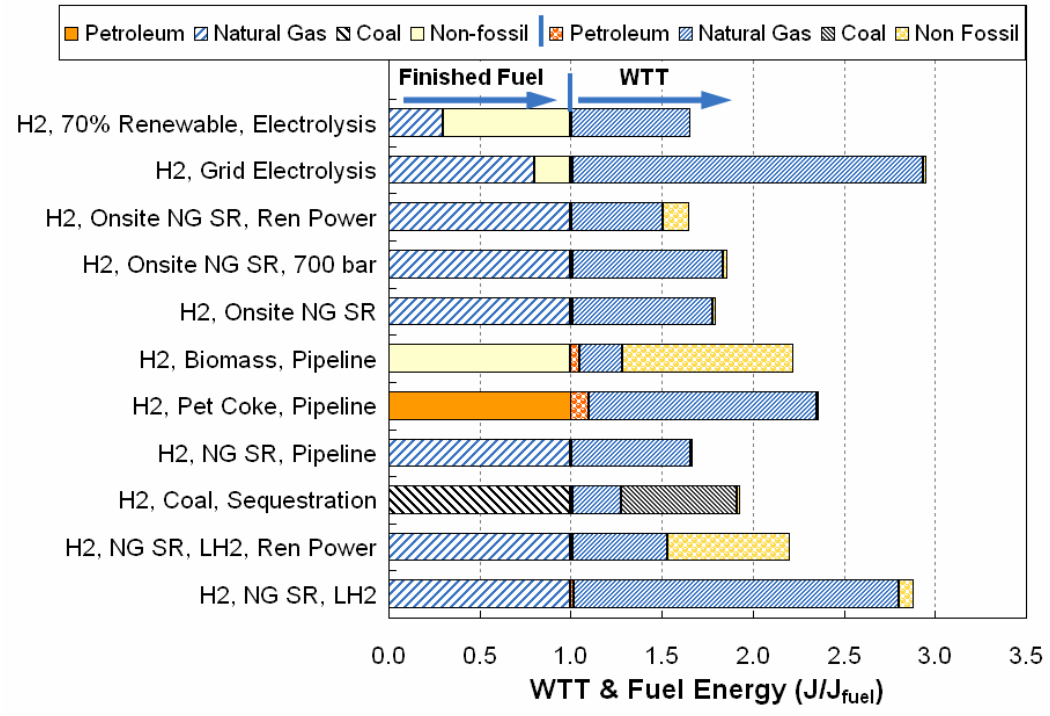


Figure 7-22. Energy Inputs for Hydrogen

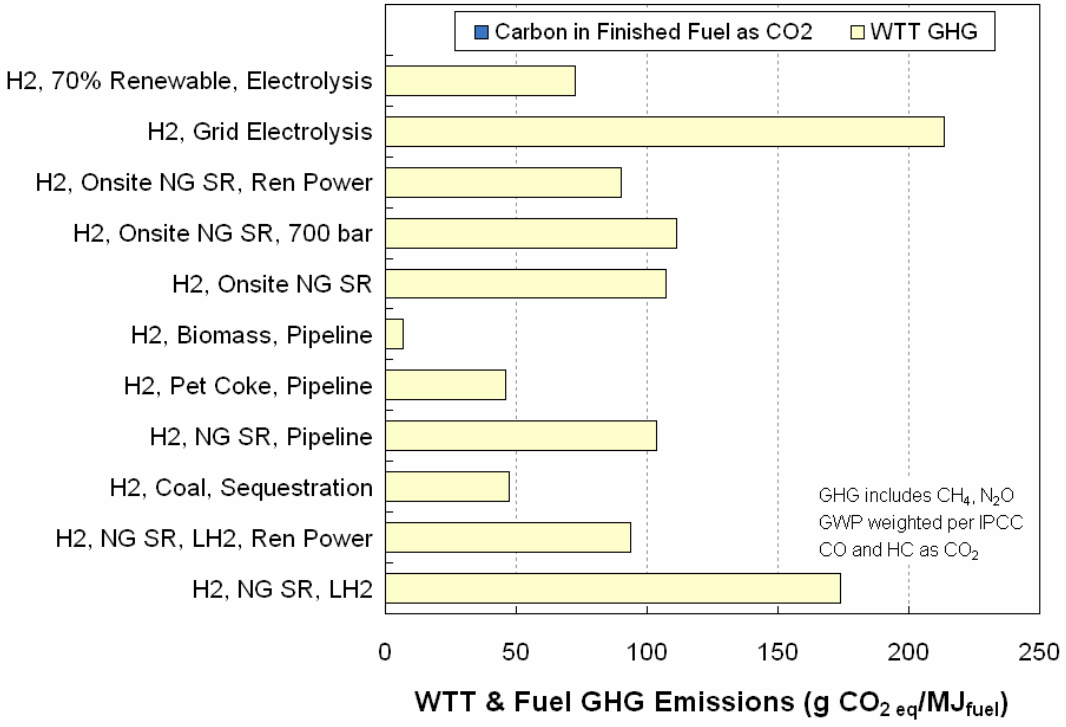


Figure 7-23. GHG Emissions for Hydrogen

The GHG emissions of the electrolysis options are driven by the generation mix assumed. To achieve a WTT GHG emission levels comparable to gasoline, an electrolysis pathway with a renewable / natural gas combined cycle generation mix would require over 50 percent renewable power. Again, it is important to recall that the WTW profile will affected by different vehicle efficiencies that are not evaluated here.

Figure 7-24 illustrates the criteria pollutant emissions in California for hydrogen pathways. In general, emissions from power plants and reformers affect these results. As discussed in Section 5, NO_x and PM emissions (based on source test data) from natural gas steam reformers are very low. The emissions from electric power plants derive from the somewhat high PM emission factor for natural gas combined cycle power plants. It is unclear if this PM is due to ingested air or particulate matter formed from methane, and thus requires further investigation.

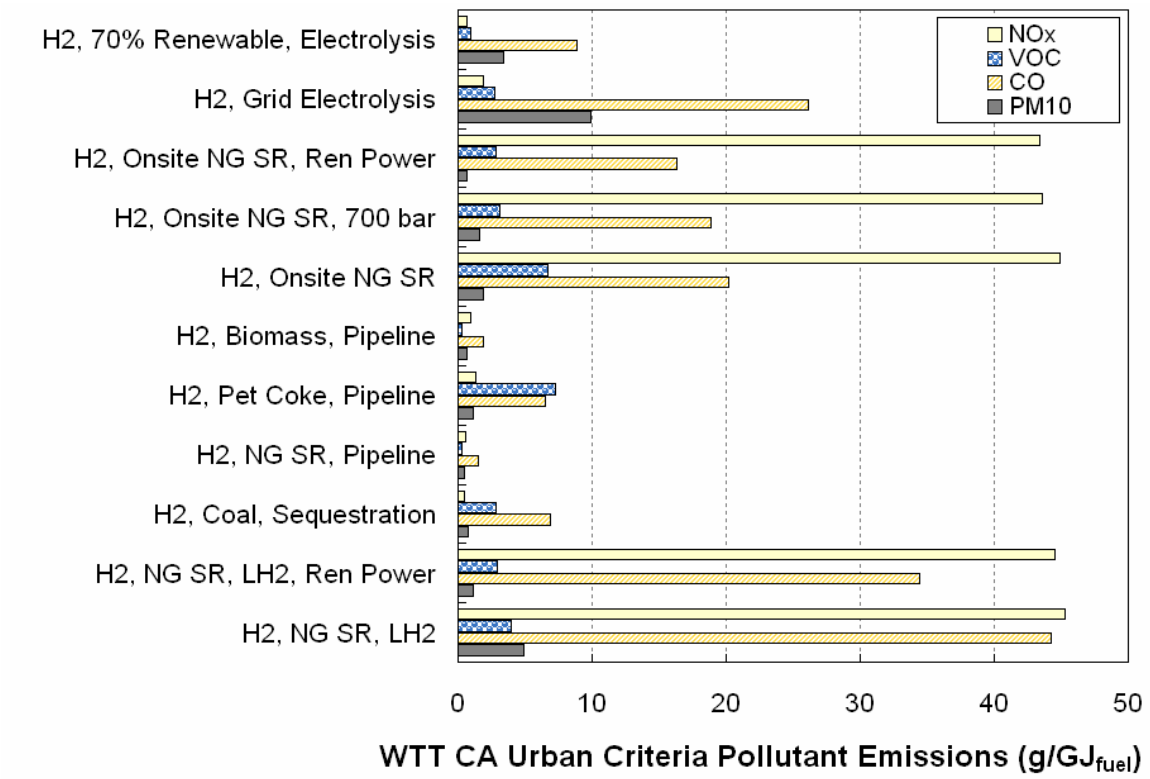


Figure 7-24. Criteria Pollutant Emissions for Hydrogen

The use of diesel trucks to deliver liquid hydrogen results in double the delivery emissions as gasoline delivery by truck. This is a direct result of the low gravimetric energy density of hydrogen.

SECTION 8. CONCLUSIONS AND RECOMMENDATIONS

This report provides an analysis of the impacts of transportation logistics for fuels as well as the production of new fuel conversion facilities in California subject to prevailing emission constraints. Energy and GHG inputs correspond to process assumptions corresponding to timeframes ranging from 2012 through 2030.

WTT emissions were evaluated in the context of marginal emissions associated with marginal alternative fuel consumption or gasoline displacement. A moderate use of alternative fuels would displace gasoline that would be imported to California. Increments of alternative fuel use would displace emissions from fuel hauling, vehicle fueling, and marine vessels used to import refinery blending components. Many alternative fuels would be produced outside of California so the marginal treatment of fuel production is consistent with that applied to gasoline.

Marginal emissions correspond largely to transportation and distribution impacts associated with marine vessel activity, rail transport fuel trucking,or distribution and local vehicle fueling. New fuel production facilities and power plants emissions also contribute to the fuel cycle impacts.

8.1 Energy and GHG Conclusions

The energy inputs and GHG emissions correspond to the conversion efficiency and carbon intensity of fuels. The results of this study are consistent with others in terms of tracking the impacts of energy use. The key conclusions regarding GHG emissions are:

1. HG emissions from fossil fuels depend on both the carbon content of the fuel and process energy inputs. For fossil fuels, GHG factors (carbon in fuel + WTT) ranked from highest to lowest on a MJ basis (without taking vehicle efficiency into account) are:

    - Synthetic fuels from coal without CO_2 sequestration
    - Hydrogen from on-site natural gas reforming
    - RFG with 5.7 percent ethanol
    - E10
    - FT diesel from natural gas without use of process waste heat
    - California ULSD, FTD with waste heat utilization, DME, methanol
    - LNG with modern boil off management practices
    - LPG from petroleum or natural gas
    - CNG
    - Synthetic fuels from coal with CO_2 sequestration

2. A wide range of GHG factors are achieved for various hydrogen and electric generation pathways. An electric generation mix based on natural gas combined cycle power combined with California's RPS constraint is an appropriate mix for electric transportation and the electricity inputs for fuel production. The use of renewable power allows for the mitigation of GHG emissions, which is an option for all fuel providers.

3. GHG emissions from biofuels depend on agricultural inputs, allocation to byproducts, and the level and carbon intensity of process energy inputs. For biofuels, GHG factors (carbon in fuel + WTT) ranked from highest to lowest on a MJ basis (without taking vehicle efficiency into account) are:

   - Ethanol from corn with coal fired boiler
   - Ethanol from corn with natural gas fired boiler
   - Ethanol from corn with reduced energy input by providing wet DDGS byproduct
   - Soybean based biodiesel (depending on N_2O emissions and byproduct credits)
   - Ethanol from cellulose and sugar cane with no fossil fuel input for fuel production
   - Ethanol from waste materials

The GHG emissions for biofuels depend on many other factors. Most important are changes in land use that vary with substantially with scenario assumptions. The analysis here provides the WTT process inputs. Impacts associated with changes in land use can be added to these values. Land use issues for a modest growth in U.S. based crops are likely to replace other crops rather than expand agricultural areas. To the extent that this assumption holds true, the impact of land use from U.S. crops is a small portion of the WTT impact. The issue of deforestation needs to be examined with several biofuel options. In the case of Brazilian ethanol, the sugar cane is not grown in the Amazon, however second order agricultural impacts should be documented.

8.2 Recommendations

Based on the information found in this study, we make the following recommendations to support the requirements of AB1007 and further advance efforts with full fuel cycle analysis. The recommendations include analysis methods, WTT data collection, and system boundary considerations.

Analysis Methods

1. The GREET model served as a suitable tool to assess the transportation logistics for conventional and alternative fuels production and distribution in California. A version of the GREET model provided for this project should be maintained to support continued investigations of criteria pollutant impacts.

2. The authors observed that the WTT energy and GHG emissions for petroleum fuels and electric power do not depend on the WTT analysis for biofuels (unless large scale economic impacts occur). Recursive second order fuel cycle impacts are not an issue with typical biofuel chains (fuel to make the fuel to make the fuel). The analysis of energy and GHG emissions can be accomplished with simple tools that allow for a more detailed examination of agricultural systems and boundaries. Therefore, static WTT parameters from the GREET model or other fuel cycle models for diesel, electricity, uncompressed natural gas, gasoline, and LPG combined with process data for alternative fuel production and agriculture and chemical inputs can be incorporated it a simple database. A simple database approach should be used when only energy and GHG emissions are of interest.

Data Collection

3. Continue to report WTT results with carbon in fuel as CO_2. This reporting method provides an overview of the potential GHG impact from all fuels and prevents confusion when comparing fuels with varying carbon contents.

4. Even though CO_2 is a pollutant, the emissions are often not included in test reports for stationary equipment. The lack of CO_2 data makes further data analysis challenging when the goal is to develop a fuel specific emission factor. (For example some source test data only shows lb/hr). Analysts for this project and many others must then estimate the fuel consumption (bsfc) of equipment and the carbon content of fuel. ARB should require emission testing performed for stationary sources to include reporting of CO_2 emissions.

5. PM emissions associated with natural gas combined cycle power plants persist throughout the fuel cycle. Needs are to measure emissions or summarize source test data from new combined cycle power plants to better quantify the range in particulate source attribution (combustion product or other), hydrocarbons, and hydrocarbon speciation. Also needed is an assessment of the effect that background emissions have on projected and net power plant emissions.

6. The analysis in Section 3 identified improved data for emissions associated with hydrogen and synthetic fuel production facilities. These data should be considered for other fuel cycle models.

Boundary Considerations

7. Displacement effects are a key aspect of a fuel cycle analysis. The assumptions of a marginal analysis, California emission regulations, and offset requirements define the outcome for criteria pollutants. The assumptions on emission boundaries should always be identified.

8. Displacement effects also impact the use of energy avoided by an alternative fuel. In the case of fuels and feedstocks with relatively small volumes (digester gas, LPG,

residential solar power, etc.) the attribution of feedstocks to alternative fuels should be careful examined in order to understand the best use of the feedstock and the displacement effects. Representing the fuel cycle analysis with a well defined system boundary for each feedstock and its significant displacement effects is a favorable approach. The alternative uses of farmland in particular should be identified and evaluated.

9. Changes in agricultural land use has a dominant impact of biofuel pathways. The potential land use impacts should be quantified and shown as a separate component of the WTT analysis. There is a need to provide measurements to support sustainable agricultural practices, and the prevention of tropical deforestation associated with fuel production need to be incorporated into efforts to promote the use of fuels.

SECTION 9. REFERENCES

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9.1 List of Terms and Abbreviations

AP-42	EPA document on emission factors
atm	1 atmosphere = 14.7 psi
EMFAC	ARB model for determining vehicle g/mi emissions
API	American Petroleum Institute
ARB	California Air Resources Board
bbl	barrel of crude oil (42 gal)
Bcf	billion standard cubic feet
BD	biodiesel
bhp-hr	brake horsepower hour (dynamometer measurement)
Btu	British thermal unit = 1.055 kJ
bsfc	brake specific fuel consumption
bu	bushel
CA	California
CARBOB	California Reformulated Gasoline Blendstocks for Oxygenate Blending
CEC	California Energy Commission
cH_2	compressed hydrogen[53]
CNG	compressed natural gas
CH_4	methane
CO	carbon monoxide
CO_2	carbon dioxide
DOE	United States Department of Energy
DME	Dimetnyl Ether
DWT	dead weight ton
E100	ethanol, 100 percent with no blending components
EMA	Engine Manufacturers Association
EMFAC	ARB vehicle emissions factor model
EVs	electric vehicles
FCC	fluid catalytic cracker
FE	Fuel economy
FFV	flexible fuel vehicle
FTD	Fischer Tropsch diesel
GWh	gigaWatt hour = 1,000,000 kWh
GRI	Gas Research Institute
GVW	gross vehicle weight
GWP	global warming potential
HHV	higher heating value of fuel or feedstock
hp-hr	shaft horsepower hour
IC	internal combustion
ICEV	IC engine vehicle
J	Joule
kg	kilogram

[53] The lower case c is used to prevent confusion with hydrocarbon radicals.

kJ	kilo Joule
kWh	kilo-Watt hour = 3.6 MJ = 3,412 Btu
kn	nautical mile, 2000 yards
lb	pound mass = 453.53 g
LHV	lower heating value, HHV less heat of vaporization of water vapor in combustion products
LH2	liquid hydrogen
LPG	liquefied petroleum gas
MJ	Mega Joule = 3.6 kWh
H_2	hydrogen
g	gram
gal	gallon = 3.7854 Liter
g/bhp-hr	grams per brake horsepower-hour
MWh	megaWatt hour
mi	mile
LNG	liquefied natural gas
M100	methanol, 100 percent with no blending components
MMBtu	million Btu
MMscf	million scf
MTBE	methyl tertiary butyl ether
mpg	miles per gallon
MW	molecular weight
NG	natural gas
NGV	natural gas vehicle
NMOG	non-methane organic gases
NO_x	oxides of nitrogen
NREL	National Renewable Energy Laboratory
NSPS	new source performance standards
O_3	ozone
OEM	original equipment manufacturer
psi	pressure, lb/in^2, 14.7 psi = 1 atm
RECLAIM	Regional Clean Air Incentive Market
RFG3	reformulated gasoline, current California requirement
RNG	remote natural gas, produced outside North America
ROW	rest of world
RVP	Reid vapor pressure
SoCAB	South Coast Air Basin
SCAQMD	South Coast Air Quality Management District
SCE	Southern California Edison
scf	standard cubic feet of gas, at 60°F and 1 atm
SCR	selective catalytic reduction
scfm	standard cubic feet per minute
SO_x	oxides of sulfur
SR	steam reformer
SRWC	short rotation woody crops
t/d	tons/day

TEOR	thermally enhanced oil recovery
THC	total hydrocarbons
ton	United States short ton, 2000 lb
tonne	Metric ton, 1000 kg
TOG	total organic gases
TVP	true vapor pressure
UG	underground
U.S. EPA	United States Environmental Protection Agency
ullage	liquid fuel tank vapor space
V_e	equilibrium vapor