A Low Carbon Fuel Standard in Washington: Informing the Decision

Final Report
State of Washington
Department of Ecology
300 Desmond Drive
Lacey, Washington 98504-7600

February 18, 2011

Prepared by
Jennifer Pont and Jeff Rosenfeld
TIAX LLC
20813 Stevens Creek Blvd., Suite. 250
Cupertino, California 95014
408.517.1550

Scott Williamson and Michael Lawrence
Jack Faucett Associates

TIAX No. D0530

Acknowledgements

TIAX wishes to acknowledge the efforts of Brett Rude, Justin Brant and especially Robert Saunders for providing considerable assistance in the development and execution of this analysis as well as interpretation of the results. We also wish to thank Ta-Win Lin from the Washington Office of Financial Management for modeling the impacts of a LCFS on the State economy. His report is provided in the Appendix to this report.

We also wish to thank the following individuals for their input and review:

Mary Beth Lang, Washington State Department of Agriculture

Peter Moulton and Gustavo Collantes, Washington State Department of Commerce

Jeff Doyle, Karin Landsberg, Kathy Leotta, Washington State Department of Transportation

William Pan, Washington State University Department of Crop and Soil Sciences

Dave Sjoding, Washington State University Extension Energy Program, Center for Sustaining Agriculture and Natural Resources.

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Executive Summary

In May 2009, Washington's Governor directed the Department of Ecology (Ecology), in consultation with the Departments of Transportation and Commerce, to assess whether a low carbon fuel standard (LCFS) would best meet Washington's GHG emission reduction goals as part of Executive Order 09-05. Ecology contracted with TIAX to assist in an evaluation of the impacts of a LCFS in Washington. The LCFS objective is to reduce the overall carbon intensity of transportation fuels. Carbon intensity is defined as the well-to-wheel carbon emissions of a fuel pathway per unit energy.[1] Well-to-Wheel (WTW) emissions include the emissions produced during: feedstock recovery, feedstock transport to the fuel production plant, fuel production, fuel transport to refueling stations, and vehicle emissions.

The LCFS considered here assumes that transportation fuel carbon intensity will be reduced 10 percent from 2007 levels by 2023, with reductions beginning in 2014. The compliance curve assumed a gentle start to the 2023 goal with minimal reductions required in the first several years. Our analysis began with an assessment of the types and volumes of biofuels that could be produced from in-state feedstocks. We then quantified the carbon intensity for each fuel type that might be consumed in Washington with a LCFS in place. To bracket the technological and economic range of possible ways compliance with the standard might be achieved, six compliance scenarios were defined; these scenarios are displayed in Table E-1.

Table E-1: Description of the Washington LCFS Scenarios

Scenario A	Compliance mainly through cellulosic ethanol and diesel fuels produced in-state. 10% carbon intensity reduction required for gasoline and diesel pools separately.
Scenario B	Compliance mainly through cellulosic ethanol and diesel fuels produced out-of-state. 10% carbon intensity reduction required for gasoline and diesel pools separately.
Scenario C	Compliance mainly through mixed sources of biofuels: conventional, cellulosic, imported and in-state. 10% carbon intensity reduction required for gasoline and diesel pools separately.
Scenario D	Compliance mainly through high electric vehicle (EVs) sales and in-state cellulosic biofuels. 10% carbon intensity reduction required for gasoline and diesel pools separately.
Scenario E	Compliance mainly through high electric vehicle (EVs) sales and mixed sources of biofuels. 10% carbon intensity reduction required for gasoline and diesel pools separately.
Scenario F	One-Pool: a ""middle-of-the-road" scenario combining a mixture of biofuel and electrical vehicles, and increased use of light duty diesels. 10% carbon intensity reduction required overall, not for gasoline and diesel pools separately.

[1] In this study we utilize units of gCO2e/MJ fuel on a lower heating value basis.

Each scenario was modeled to determine quantities of each fuel type consumed to attain the overall carbon intensity limit each year. For each scenario, consumer fuel and vehicle expenditures were determined along with estimated investment in alternative fuel production and refueling infrastructure. The Washington Office of Financial Management subsequently modeled the impact of each LCFS compliance scenario on employment, household income and gross state product relative to the business as usual (BAU) case. The key results are increased biofuel and electricity consumption in the transportation sector (Figure E-1), decreased petroleum consumption (Figure E-2), decreased greenhouse gas emissions (Figure E-3), and small impacts on the State economy (Table E-2).

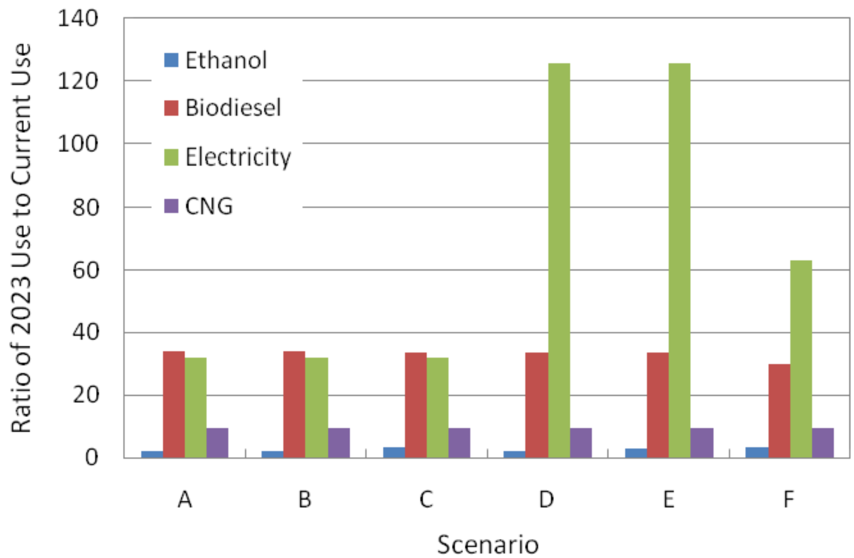

Figure E-1. Predicted Increases in Alternative Fuel Consumption due to LCFS.

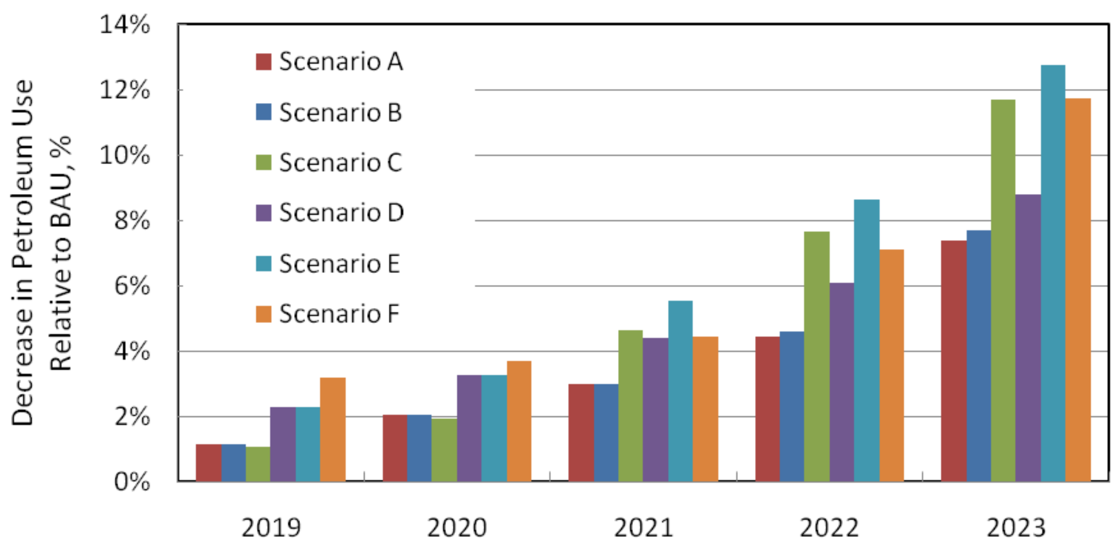

Figure E-2. Predicted Decrease in Petroleum Consumption due to LCFS.

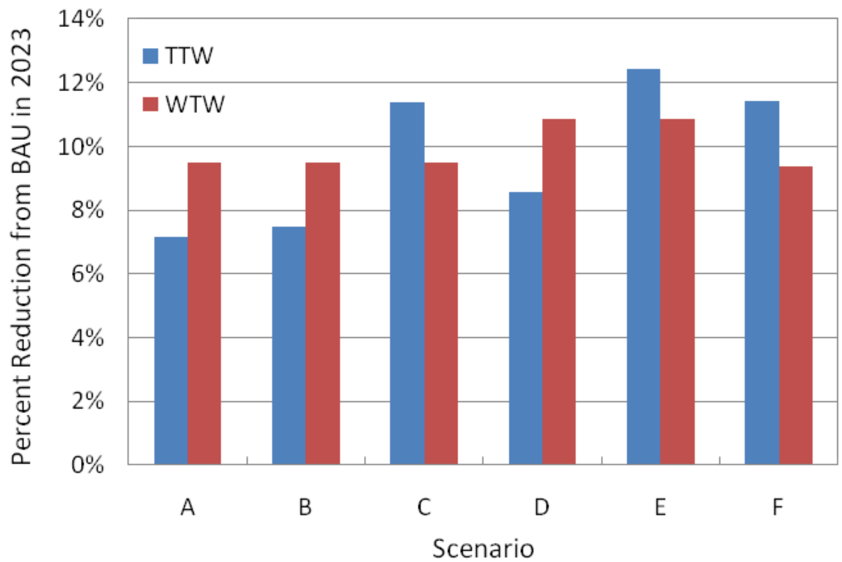

Figure E-3. Predicted Decrease in GHG Emissions due to LCFS.

Table E-3. Predicted Range of LCFS Impact on the State Economy.

	Range of Impact Relative to BAU
Annual Average Change in Employment Relative to BAU	-0.01% to 0.32%
Annual Average Change in Total Personal Income Relative to BAU	-0.01% to 0.20%
Annual Average Change in Gross State Product Relative to BAU	-0.01% to 0.29%

1. Introduction

In 2007, the Washington Legislature adopted statutory GHG reduction limits that require the state to return to1990 emissions levels by 2020, and reduce emissions 25 percent below 1990 by 2035 and 50 percent below 1990 by 2050. Because the transportation sector is responsible for almost half of the State's GHG emissions, reductions from vehicles and fuels are fundamental to achieving its goals. Recognizing the importance of vehicle emissions, the Transportation Implementation Working Group formed by the Washington Climate Action Team recommended a number of strategies to reduce the impact of transportation on climate change. These include expanding public transit, encouraging smart growth, using pricing to reduce vehicle miles traveled, and pursuing a number of non-VMT actions including a low carbon fuel standard.

In May 2009, Washington's Governor directed the Department of Ecology (Ecology), in consultation with the Departments of Transportation and Commerce, to assess whether a low carbon fuel standard (LCFS) would best meet Washington's GHG emission reduction goals as part of Executive Order 09-05. Ecology is also directed to provide a recommendation to the Governor regarding rules or legislation to limit GHG emissions from Washington's transportation sector.

This report summarizes the work done by TIAX to assist Ecology in making its recommendation to the Governor. Specifically, the project was broken down into the following tasks:

- Task 1: Summarize the potential availability of low carbon fuel feedstocks and existing alternative fuel production capacity
- Task 2: Quantify carbon intensity for Washington petroleum and alternative fuel pathways
- Task 3: Analyze six scenarios bracketing the range of possible LCFS compliance mechanisms
- Task 4: Provide REMI model inputs to the Washington Office of Financial Management for a Business as usual case, six compliance scenarios and two sensitivity cases to estimate the impact of a LCFS on Washington's economy.
- Task 5: Assess alternatives to a LCFS

The results of Task 1 (alternative fuel and feedstock potential) are provided in Section 2 of this report. Section 3 provides the carbon intensity estimates for gasoline, diesel and alternative fuel pathways in Washington State. Section 4 provides the assumptions made to perform the Scenario Analysis. Section 5 summarizes the scenarios considered; the analysis results are provided in Section 6. Section 7 provides the infrastructure cost estimates used to create REMI model inputs for the economic analysis performed by Washington's Office of Financial Management (OFM). Section 8 provides the economic modeling results and a summary of the LCFS Alternatives Analysis is provided in Section 9.

2. Washington Alternative Fuels and Feedstocks

Washington State has a multitude of feedstocks for alternative fuel production. The feedstocks and fuels that they can become are illustrated in Figure 2-1. As shown, the feedstocks can be divided into three main groupings: cultivated crops, waste derived materials, and utilities (electricity/natural gas). The utility based feedstocks are assumed to be unlimited here and are not considered further. The following paragraphs step through the potential alternative fuel production capacity from cultivated and waste derived feedstocks.

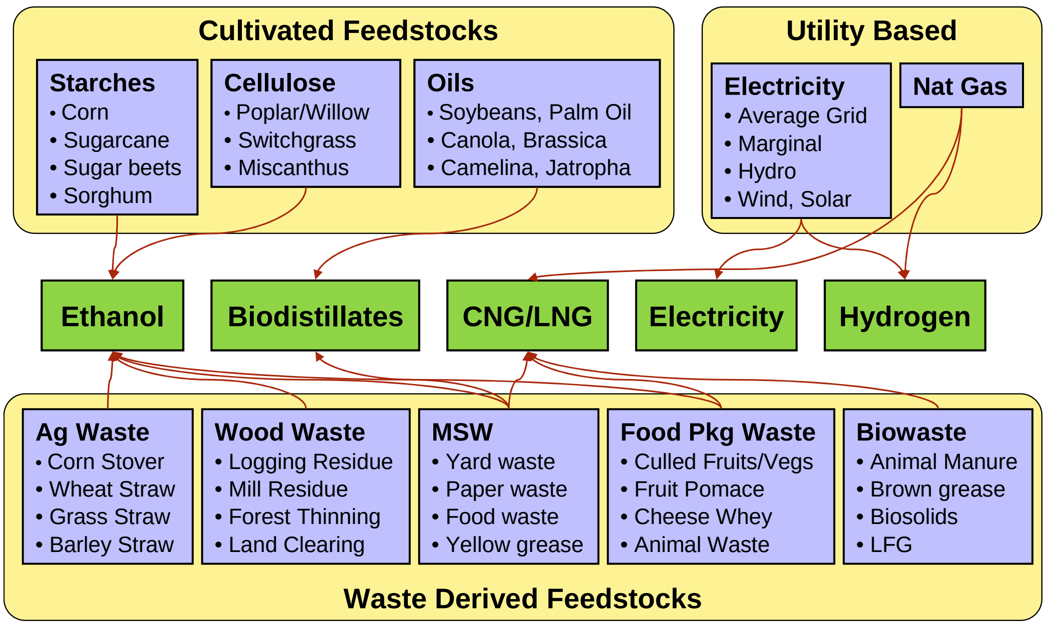

Figure 2-1. Alternative fuels and their feedstocks.

2.1 Cultivated Feedstocks

A small amount of corn and soybeans are currently cultivated in Washington. Table 2-1 provides crop yields and corresponding amounts of biofuels that could be produced assuming these crops could all be diverted into biofuel production. Very small amounts of sunflower seeds and sugar beets are also grown.

Table 2-1. Current Crop Production and Potential Yields

Feedstock	Annual Crop Yield[1]	Biofuel Yield[2]	Biofuel Potential	
			Million gal/yr	Million gge/yr
Corn	24.6 Million Bushels	2.72 gal/bu	67 ethanol	44
Soybeans	0.03 Million Bushels	1.37 gal/bu	0.04 biodiesel	0.04
Canola	7.2 Million lbs oil	0.96 lb Biodiesel/lb oil	1 biodiesel	1

1. 2007 USDA Census
2. GREET 1.8b. Assume canola oil and soyoil produce same amount of Biodiesel

The use of existing corn and soybean crops for biofuel production would cause cultivation of replacement crops elsewhere. When new land is brought into cultivation to replace crops diverted into biofuel production, there may be GHG emissions associated with clearing the land and preparing it for planting. These emissions are an indirect result of increased biofuel production and are referred to as indirect land use change (ILUC) emissions. The use of existing Washington crops for biofuel production would induce ILUC emissions – for the purposes of this analysis, it is assumed that the small amounts of existing corn and soybean crops are not diverted for biofuel production.

At present, a very small amount of canola is also produced in rotation with wheat. Some of this is currently being utilized for biodiesel production. We assume that there is negligible ILUC for this small amount of canola. The ILUC assumptions regarding increased cultivation of canola are discussed several paragraphs below.

Washington has a significant amount of cropland enrolled in the federal Conservation Reserve Program (CRP). Between 2010 and 2020 CRP contracts for over 1.4 million acres are expiring and could be taken out of CRP. Figure 2-2 shows the expiring CRP acres in Washington by region. Crops planted on expired CRP land are assumed to have negligible ILUC GHG emissions because the new crops do not displace existing crops.

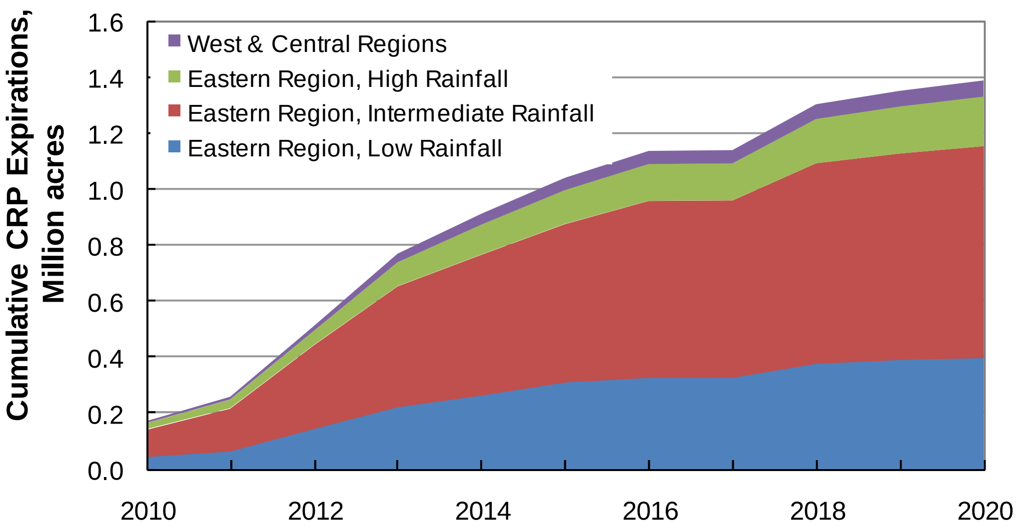

Figure 2-2. Expiring CRP acres in Washington State[2].

To estimate an upper bound on the amount of ethanol that could be produced from cellulosic feedstocks grown on former CRP land, we have assumed that none of the expiring acres would be re-enrolled and would be planted exclusively with one feedstock. Table 2-2 provides the resulting amounts of ethanol that could be produced. Depending on crop type, up to 1 billion gallons/yr of ethanol could be produced.

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[2] USDA CRP Contract Summary and Statistics, February 2010.

Table 2-2. Potential Ethanol Production Volumes from Expiring CRP Acres (2010-2020)

Crop	Years to Harvest	Assumed Harvestable Acres by 2020	Crop Yield	Fuel Yield	2020 Fuel Potential	
			dry ton/acre	gal/dry ton	Million gal/yr	Million gge*/yr
Poplar	7	900,000	7[a]	95	580	380
Switchgrass	3	1,300,000	4[b]	95	480	320
Miscanthus	3	1,300,000	8.4[c]	95	1,000	660

a. "Popular Poplars, Trees for Many Purposes", G. Tuskan, ORNL
b. "Growing Energy", N. Greene, NRDC 2004
c. "Miscanthus Hybrids for Biomass Production", L. Gibson, S. Barnhart, Iowa State University
d. GREET 1.8b assumption for biomass based ethanol.
* gge = gallons of gasoline equivalent

We have estimated the potential quantities of canola/camelina based biodiesel slightly differently as these oilseed crops would be grown as part of the wheat/cereal rotation. For this estimate we have relied on researchers at Washington State University[3]. To be conservative, we have only considered growing oilseeds in the wet and intermediate rainfall sub-regions of Eastern Washington. In these two sub-regions, there are a total of 3.5 million acres of farmland (currently cropped and CRP). On the existing acreage, it would be possible to dedicate 523,000 acres to oilseeds crops each year. This would displace 523,000 acres of cereal/legumes onto CRP land. Approximately 931,000 acres of CRP land in the high/intermediate rainfall sub-regions are due to expire between 2010 and 2020. Assuming that 12.5 percent of this land can be utilized for oilseeds (in rotation with the displaced cereal/legumes), then an additional 116,000 acres could be planted with oilseeds each year for a total of ~ 640,000 acres for oilseed cultivation. Table 2-3 summarizes these values; a total of 56 million gal/yr of oilseed derived biodiesel could be produced with negligible ILUC GHG emissions.

Table 2-3. Potential Ethanol Production Volumes from Expiring CRP Acres (2010-2020)

	Value
Annual existing acres that could support an oilseed rotation[1]	523,000
Displaced cereal/legume acreage moving to expired CRP land	523,000
Acres of oilseeds in rotation with cereal/legumes on expired CRP land	116,000
Total Potential Oilseed acres	640,000
Assumed vegetable oil yield[2]	90 gal oil/acre
Assumed biodiesel yield	0.96 lb BD/lb oil
Oilseed based biodiesel potential	56 Million gal/yr

1. Wet and Intermediate Sub-regions of Eastern Washington. Bill Pan, WSU April 2010
2. Washington State canola yield, USDA 2007 Census of Agriculture: U.S. Summary and State Data

[3] "Potential for Increasing Oilseed Production in Dryland Eastern Washington Cropping Zones", W.L. Pan and D. Roe, April 19, 2010.

2.2 Waste Derived Feedstocks

In addition to cultivated feedstocks there are a number of waste streams that can be utilized to produce alternative fuels. Table 2-4 provides a summary of potential waste streams that could be utilized for ethanol production. In total up to 1.3 billion gallons of ethanol could be produced each year from agricultural, wood and some types of municipal solid waste (MSW). Table 2-5 provides the potential quantity of CNG/LNG that could be produced from food packaging waste, MSW, and bio-waste streams. Over 30 trillion Btus of CNG/LNG could be produced from these streams each year.

In addition to these quantities of ethanol and natural gas fuels, up to 4 million gal/yr of biodiesel could be produced from yellow grease.[4] However, we note that including current upgrades to plants that produce biodiesel from waste oils, the total in-state production capacity will be ~ 23 million gal/yr in the near future. For our scenario analysis we have assumed that maximum in-state waste oil derived biodiesel production is 23 MGY.

Table 2-4. Potential Ethanol Production Quantities from Washington Waste Streams

	Available Quantity (dry tons/yr)[1]	Ethanol Yield (gal/dry ton)[2]	Ethanol Potential (Million gal/yr)	Ethanol Potential (Million gge/yr)[4]
Agricultural Waste				
Corn Stover	73,502	95	7	5
Wheat Straw	1,614,234	95	153	101
Grass Straw	134,640	95	13	8
Barley Straw	318,522	95	30	20
Mint Slug	96,878	95	9	6
Other[3]	164,574	95	16	10
Wood Waste				
Logging Residue	1,901,072	90.4	172	113
Mill Residue	5,278,353	90.4	477	314
Forest Thinning	505,666	90.4	46	30
Land Clearing	418,595	90.4	38	25
Municipal Solid Waste				
Paper waste	1,291,372	90.4	117	77
Yard waste	2,428,084	90.4	219	144

1. WA ECY Publication #05-07-047 “Biomass Inventory and Bioenergy Assessment: An Evaluation of Organic Material Resources for Bioenergy Production in Washington State”, 2005
2. GREET1.8b assumption for ag waste to ethanol and forest residue to ethanol.
3. Other category is control/permit burns and hops residue
4. gge = gallons gasoline equivalent

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[4] Assumes 18,500 dry tons per year of yellow grease (WA ECY Publication #05-07-047) and 0.9 lb biodiesel per lb of yellow grease per California Air Resources Board Used Cooking Oil Pathway Document, http://www.arb.ca.gov/fuels/lcfs/workgroups/workgroups.htm#pathways.

Table 2-5. Potential CNG Production Quantities from Washington Waste Streams

	Available Quantity (dry tons/yr)[1]	CNG Potential (MMBtu/yr)[2]	CNG/LNG Potential (Million gge/yr)
Food Packaging Waste			
Produce Waste	239,266	2,498,000	20
Cheese Whey	44,255	438,000	4
Animal Waste	67,059	866,000	7
Municipal Solid Waste			
Food Waste	288,163	4,282,000	34
Landfill Gas	264,552 CH4	11,374,400	98
Bio-Waste			
Animal Manure	1,904,805	11,044,300	89
Brown Grease	20,528	217,000	2
Bio-solids	94,820	796,000	6

Feedstock quantities, volatile contents and methane production assumptions from "Biomass Inventory and Bioenergy Assessment: An Evaluation of Organic Material Resources for Bioenergy Production in Washington State", 2005.

2.3 *Alternative Fuel Potential Supply Summary*

Figure 2-3 summarizes the types and quantities of alternative fuel that could be produced from Washington feedstocks. As can be seen there is significant potential for cellulosic ethanol production. Figure 2-4 compares the potential alternative fuel production to the 2007 consumption of gasoline and diesel fuel; alternative fuels from Washington feedstocks could potentially displace up to 40 percent of the petroleum consumption in the state.

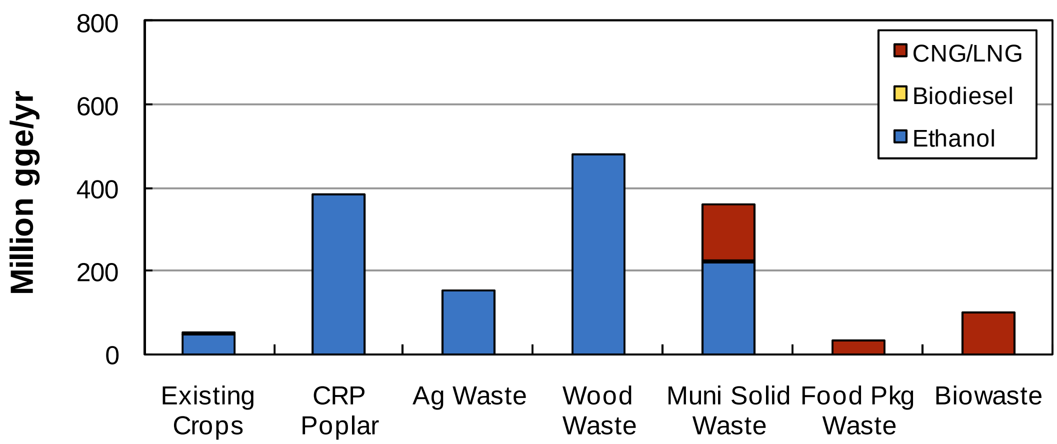


Figure 2-3. Summary of Types and Quantities of Alternative Fuel Production Potential.

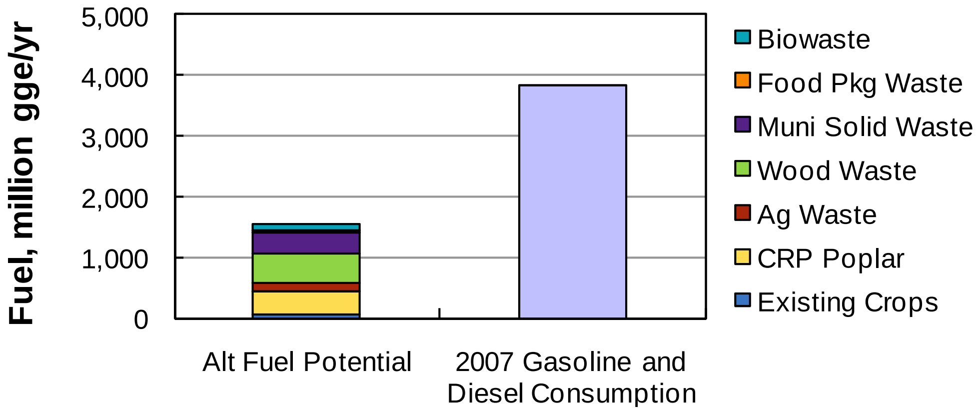


Figure 2-4. Comparison of Alternative Fuel Potential and 2007 Petroleum Consumption.

Despite the significant amounts of cellulosic ethanol feedstock available, there is no ethanol production capacity in Washington at present. Cellulosic ethanol production is on the brink of commercial status, but no known plants are planned for Washington State. There are two demonstration stage cellulosic plants just across the Columbia River in Boardman, OR: Pacific Ethanol and ZeaChem. Ecology staff believes that if these firms are successful in commercializing their production methods it's possible these or other firms could expand into Washington to supply an LCFS driven market.

In contrast to ethanol, there is significant conventional biodiesel production capacity in the state:

- General Biodiesel (5 million gal/yr with plans to increase to 10 million gal/yr)
- Gen-X Energy Group (15 million gal/yr)
- Imperium Group (100 million gal/yr)
- Inland Empire Oilseeds (8 million gal/yr)

These plants produce conventional biodiesel – there is currently no cellulosic diesel production capacity in Washington though this process is also nearing commercial status.

3. Carbon Intensity Estimates

When comparing alternative fuel GHG emissions, the entire fuel cycle needs to be considered, not just vehicle emissions. Fuel cycle emissions are also referred to as well-to-wheel (WTW) emissions and can be broken down into two parts: well-to-tank (WTT) and tank-to-wheel (TTW). The WTT portion of the fuel cycle includes all emissions associated with fuel production while TTW emissions are essentially vehicle tailpipe emissions. The relative significance of the WTT portion of the fuel cycle varies with fuel type. For electricity, all of the WTW GHG emissions are in the WTT portion while for petroleum fuels, most of the GHG emissions come from combustion of the fuel in the vehicle (TTW portion). Fuel cycle GHG emissions are typically expressed in terms of carbon intensity – the WTW grams of equivalent CO_2 emitted per energy unit of finished fuel produced (e.g. gCO_2e/MJ).

To estimate WTW emissions, Argonne National Laboratory's Greenhouse Gases, Regulated Emissions and Energy Use in Transportation (GREET) Model[5] was utilized. GREET is a widely used, publicly available Microsoft Excel based model. EPA and the California Air Resources Board have used GREET to support transportation policy/regulations. Because the model inputs are generally for the U.S. as a whole, TIAX modified a number of inputs to reflect Washington state conditions. A control panel worksheet was created that contains all GREET default values as well as the Washington specific values for each pathway considered. When new versions of the GREET model are published, the control panel can be copied into the new GREET model and tied in to the GREET calculations.

As shown in Table 3-1, carbon intensity estimates were made for sixteen Washington State fuel pathways. The following sections describe the calculations for each fuel group.

Table 3-1. Washington Fuel Pathways Considered

Finished Fuel	Feedstock(s)
Gasoline	Washington crude oil mix
Diesel	Washington crude oil mix
Ethanol	Midwest corn refined in MW, MW corn refined in Oregon, farmed trees, wheat straw, forest residue, mill waste, sugarcane
Biodiesel	MW soybeans, canola, yellow grease, tallow
Renewable Diesel	MW soybeans
CNG	Pipeline natural gas
Electricity	Grid average with renewable portfolio standard

[5] GREET version 1.8c was utilized as it was the most recent version at the time of analysis. In Sept 2010, Argonne released version 1.8d.1 with revised petroleum refinery efficiency estimates, corn and cellulosic ethanol updates, soybean biodiesel updates, new cellulosic diesel pathways, and an LFG to CNG/LNG pathways.

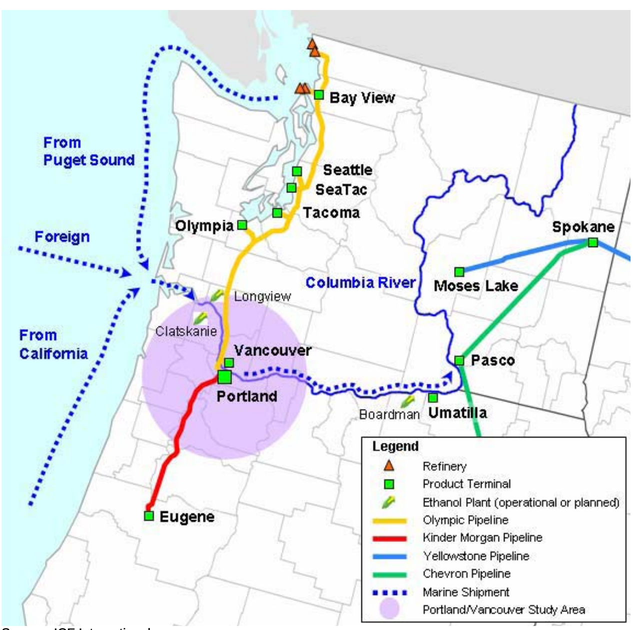
3.1 Gasoline and Diesel Pathways

As shown in Table 3-2, Washington has five petroleum refineries with total capacity of more than 650,000 bbl/day. Because the in-state refining capacity is much greater than consumption, Washington is a net exporter of finished petroleum fuels. However, only 89 percent of the finished fuel consumed in Washington was refined in-state; some gasoline and diesel used in Eastern Washington are imported from Montana (~10%) and Utah (<2%)[6].

Table 3-2. Washington State Petroleum Refining Capacity

Company	Location	bbl/day
BP West Coast Products	Cherry Point	234,000
ConocoPhillips	Ferndale	105,000
Shell Oil Products	Puget Sound	147,500
Tesoro WestCoast	Anacortes	125,000
U.S. Oil and Refining	Tacoma	39,000
	Total	651,000

Figure 3-1 illustrates how gasoline and diesel are transported to and within the State while Figure3-2 provides an estimate[5] of how much of the fuels consumed in Washington are distributed by each route. Fuels refined in Washington travel along the Olympic Pipeline to terminals located nearby and to Portland. From Portland, some of the fuel is barged to a terminal in Pasco. Eastern Washington gets the balance of its gasoline and diesel from Montana and Utah via pipeline.



Source: ICF International

Figure 3-1. Schematic of Washington State Petroleum Transportation (ICF International).

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[6] "2007 Gas Price Study – Phase I Fact-finding", Keith Leffler, University of Washington, July 2007.

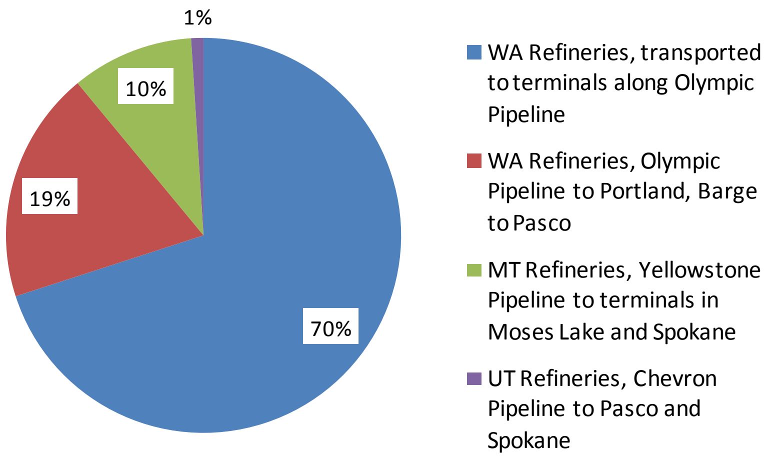

Figure 3-2. Source and transportation of gasoline and diesel consumed in Washington[5].

To estimate the carbon intensity of the gasoline and diesel fuels consumed in Washington, we first needed to determine where the crude originates and whether it is conventional or derived from oil sands. The following sections describe the crude oil sources for gasoline and diesel consumed in Washington and the GREET carbon intensity calculations.

3.1.1 Sources of Crude Oil Utilized in Washington

Figure 3-3 provides the sources of crude oil refined in Washington in 2007 (the most recent year of data at the time of analysis). Over 60 percent of the crude oil is extracted in Alaska. The largest foreign source is Canada via the Trans Mountain Pipeline. Figure 3-4 indicates that the Canadian and African imports are growing as Alaska declines. Most of the African crude oil comes from Angola – very little is imported from Nigeria[7].

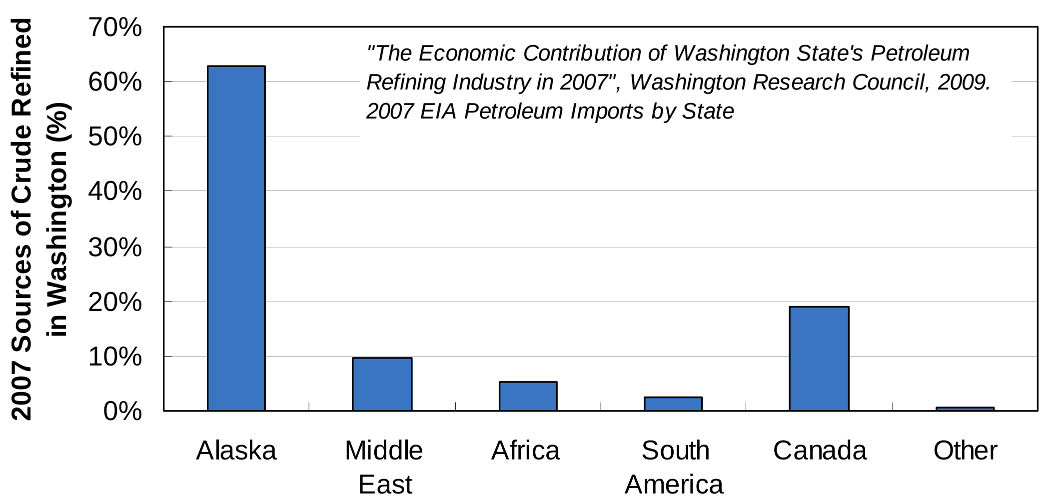

Figure 3-3. Sources of Crude Oil Refined in Washington (2007).

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[7] Nigeria has had very high venting and flaring emissions, leading to significantly higher carbon intensity values.

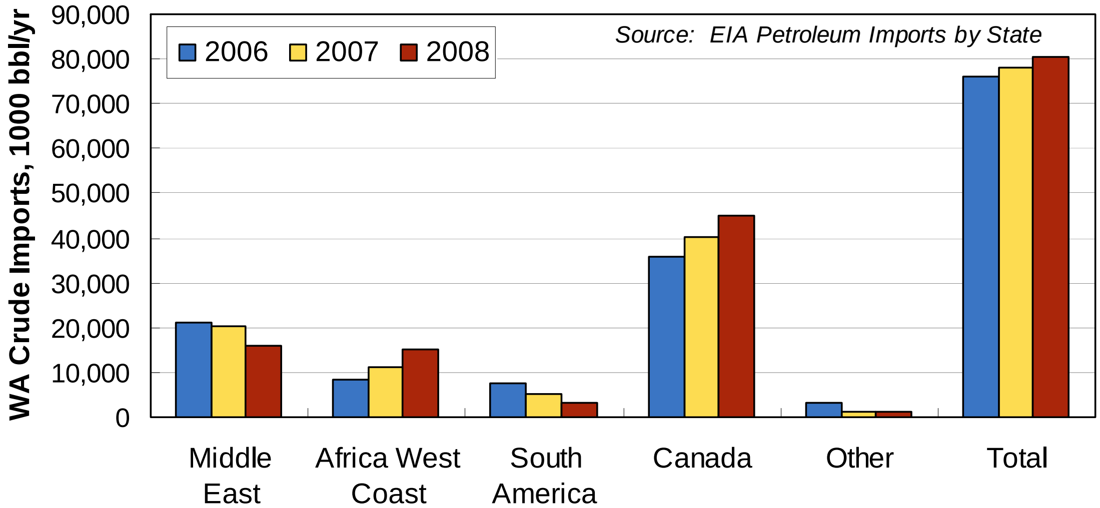

Figure 3-4. Foreign sources of crude oil refined in Washington.

The previous plots show the crude oil sources refined in Washington. Since ~10 percent of the gasoline and diesel consumed in Washington is refined in Montana, we also need to determine where these crudes come from. Figure 3-5 provides the sources of crude oil refined in Montana through 2007. For the past several years, ~ 85 percent of the crude oil refined in Montana has come from Calgary via the Terrasen Express Pipeline.

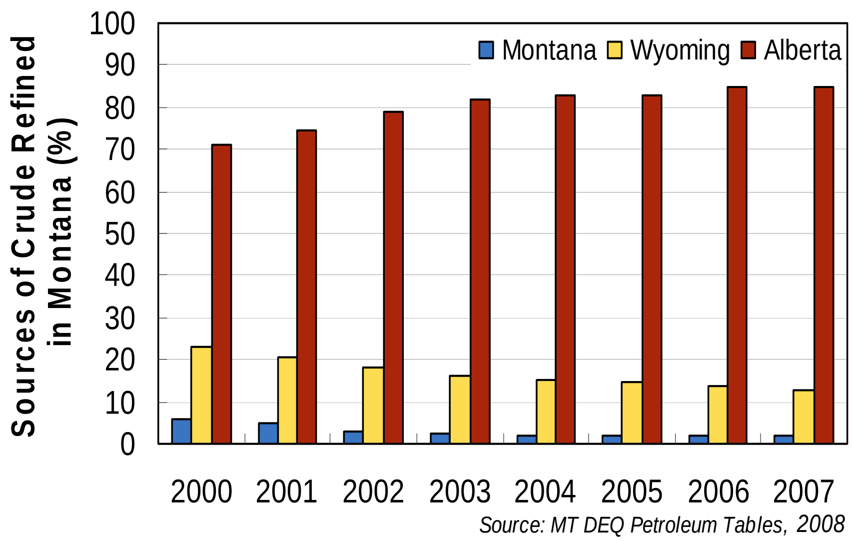

Figure 3-5. Sources of Crude Oil Refined in Montana.

Because the carbon intensity of oil sands derived petroleum products is treated differently in the GREET model than conventional crude products, a key assumption in the analysis is the share of the Canadian crude oil that is derived from oil sands. The first estimate was to simply utilize the 2007 average production data for Alberta and apply this to all Canadian crudes supplied to Washington and Montana. In 2007, 30 percent of the crude produced in Alberta was conventional and 70 percent was derived from oil sands.[8] However, it is not necessarily true that Montana and Washington receive these proportions of crude oil. A new database provided by the Canada National Energy Board[9] indicates that much less oil sands derived crude is imported into Washington and Montana. Table 3-3 summarizes these data for the first half of 2009. The export destinations are by PADD, however the PADD V exports are consistent with the EIA import value from Canada to Washington. We have utilized the PADD IV values for Montana and the PADD V values for Washington. Therefore, for our analysis, 55 percent of the crude sent to Washington and 77 percent of the crude sent to Montana is conventional.

Table 3-3. Canadian Crude Oil Exports by Type and Destination, Jan-June 2009.

	Conventional		Oil Sands	
	bbl/day	%	bbl/day	%
PADD IV (Montana)	340,274	77%	99,193	23%
PADD V (Washington)	133,706	55%	107,393	45%

Once the shares of oil sands crude imported into Washington and Montana was determined, the sources of crude oil used to produce the gasoline and diesel consumed in Washington could be estimated. Figure 3-6 provides the sources of crude oil used to make Washington's fuels. Overall, 10 percent of the crude oil is derived from oil sands, and nearly 60 percent is produced domestically.

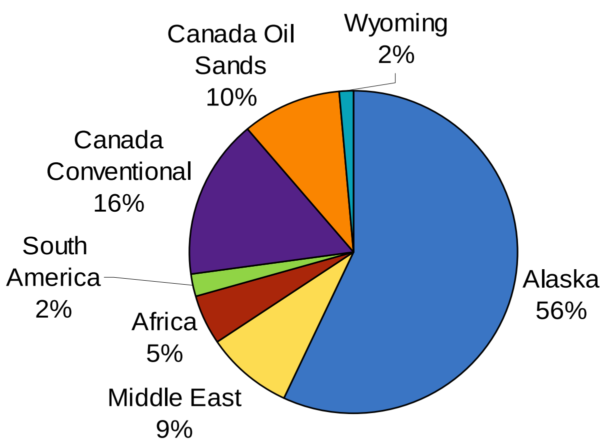

Figure 3-6. Sources of crude oil used to produce Washington gasoline and diesel.

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[8] Canadian Association of Petroleum Producers Statistical Handbook for Canada's Upstream Petroleum Industry, Sept 2009.

[9] Canada National Energy Board Estimated Canadian Crude Oil Exports by Type and Destination, http://www.neb.gc.ca/clf-nsi/rnrgynfmtn/sttstc/crdlndptrlmprdct/stmtdcndncrdlxprttpdstn-eng.html

3.1.2 Carbon Intensity Estimates for Petroleum Consumed in Washington

Once the sources of crude oil were determined, carbon intensity values for gasoline and diesel were estimated with the GREET model. GREET provides two default pathways for gasoline and diesel fuel: conventional crude oil and oil sands derived. In this analysis, eight different petroleum pathways were evaluated:

- Conventional crude oil refined in Washington, gasoline and diesel
- Conventional crude oil refined in Montana, gasoline and diesel
- Oil sands crude refined in Washington, gasoline and diesel
- Oil sands crude refined in Montana, gasoline and diesel

Weighted average carbon intensities for gasoline and diesel were then determined using the crude oil source shares shown above in Figures 3-4 and 3-5 and the split between conventional and oil sands crudes from Alberta in Table 3-3.

The petroleum pathways can be split into four main parts: crude recovery, crude transport, refining, and refined fuel transport. In general we have utilized GREET default values for all assumptions. Specific values that have been adjusted include crude and finished fuel transport modes and distances, crude recovery electricity resource mix, refining electricity resource mix, and finished fuel transport modes and distances.

Crude Oil Transport Modes and Distances

The crude oil transport data was modified to reflect transportation of crude oils to Washington and Montana. Table 3-4 summarizes the crude oil transport assumptions. All ocean tanker miles were determined from Portworld[10]. The oil sands pathway transport is simply the pipeline miles indicated to Washington and Montana.

Table 3-4. Crude Oil Transport Mode and Distances

Crude Origin	Destination	Share (%)	Pipeline Miles	Ocean Tanker Miles
Alaska	Anacortes, WA	69%	800[a]	1,366
Alberta Canada	Anacortes, WA	12%	710[b]	0
Middle East	Anacortes, WA	11%	50	12,714
West Africa	Anacortes, WA	6%	50	11,388
South America	Anacortes, WA	3%	50	9,176
Weighted Average for Crudes Refined in Washington			**646**	**3,207**
Alberta Canada	Billings, MT	81%	560[c]	0
Wyoming	Billings, MT	19%	250	0
Weighted Average for Crudes Refined in Montana			**502**	**0**

a. Prudhoe Bay to Valdez
b. Trans Mountain Pipeline
c. Terrasen Express Pipeline

[10] Portworld Online Route Distance Calculator, http://www.portworld.com/

In addition to the modes and distances shown, we have also adjusted the cargo ship crude oil payload values from the GREET default of 1,000,000 deadweight tons. The Port of Seattle limits payloads to 125,000 deadweight tons, and cargo ships that travel through the Panama Canal are limited to 80,000 deadweight tons.

Electricity Resource Mixes

Electricity is utilized in the crude recovery and refining steps, but the GREET model only allows one electricity mix to be used for a given pathway. This introduces a small error if the electricity mix at the crude recovery location is significantly different from the refining location (e.g. recovery in Alberta vs refining in Washington). We modified GREET to allow different electricity resource mixes to be utilized for the crude recovery and refining steps. The electricity resource mixes for the crude oil source locations are provided in Table 3-5. These were utilized to determine a quantity weighted average electricity mix for crude recovery electricity use for each pathway considered (Table 3-6).

Table 3-5. Electricity Resource Mixes for Crude Source Locations (%)

	Alaska	Saudi Arabia	Angola	Argentina	Alberta	Wyoming
Residual Oil	12%	52%	10%	7%	0%	0%
Natural Gas	57%	48%		50%	12%	1%
Coal	9%			2%	84%	96%
Biomass	0%			1%	0%	0%
Nuclear	0%			7%	0%	0%
Other	22%		90%	33%	3%	3%

Foreign Countries: http://www.iea.org/stats/index.asp
Alaska, Montana, Wyoming, EGRID 2007
2006 Alberta Generation Mix (National Inventory Report: GHG Sources and Sinks in Canada, 1990-2006

Table 3-6. Crude Recovery Electricity Resource Mixes used in Analysis (%)

	Crudes Refined in Washington	Crudes Refined in Montana	Oil Sands
Residual Oil	14%	0%	0%
Natural Gas	47%	10%	12%
Coal	16%	86%	84%
Biomass	0%	0%	0%
Nuclear	0%	0%	0%
Other	22%	3%	3%

The electricity mixes for the two refining locations (Montana and Washington) are provided in Table 3-7. The "other" category includes all non-combustion sources including hydro, solar and wind.

Table 3-7. Electricity Resource Mixes for Refining (%)

	Washington[1]	Montana[2]
Residual Oil	0%	1%
Natural Gas	10%	0%
Coal	17%	64%
Biomass	1%	0%
Nuclear	5%	0%
Other	67%	34%

1. 2007 Fuel Mix Disclosure Report, Washington Dept of Commerce
2. EGRID 2007

Finished Fuel Transport Assumptions

Once the crude oil is refined into gasoline and diesel, it is transported to petroleum terminals and distributed by truck to refueling stations. Table 3-8 provides the finished fuel transport assumptions for the fuel refined in Washington and Montana. A small amount of the fuel consumed in Washington is refined in Salt Lake City – this was not modeled as a separate pathway, we do include the pipeline miles in the finished fuel transport distances. Fuel is transported from Billings Montana to Spokane approximately 540 miles on Yellowstone pipeline. The Chevron pipeline is used to transport fuel from Salt Lake City to Pasco. We have estimated that the distance from petroleum terminals to refueling station is on average 75 miles.

Table 3-8. Finished Fuel Transport Modes and Distances

Refining Location	Destination	Share	Pipeline Miles	Barge Miles	Truck Miles
Seattle	Western Washington	70%	75		75
Seattle	Pasco	19%	150	200	75
Billings	Spokane	10%	540		75
Salt Lake City	Pasco	<1%	600		75
Salt Lake City	Spokane	<1%	740		75
Quantity Weighted Average			143	37	75

GREET Estimates of Gasoline and Diesel Carbon Intensity

The GREET results after making the adjustments mentioned above are provided in Figures 3-7 and 3-8 for gasoline blendstock and ultra low sulfur diesel (ULSD), respectively. The weighted average values for fuel consumed in Washington are 92.3 and 91.5 g/MJ for gasoline blendstock and ULSD, respectively.

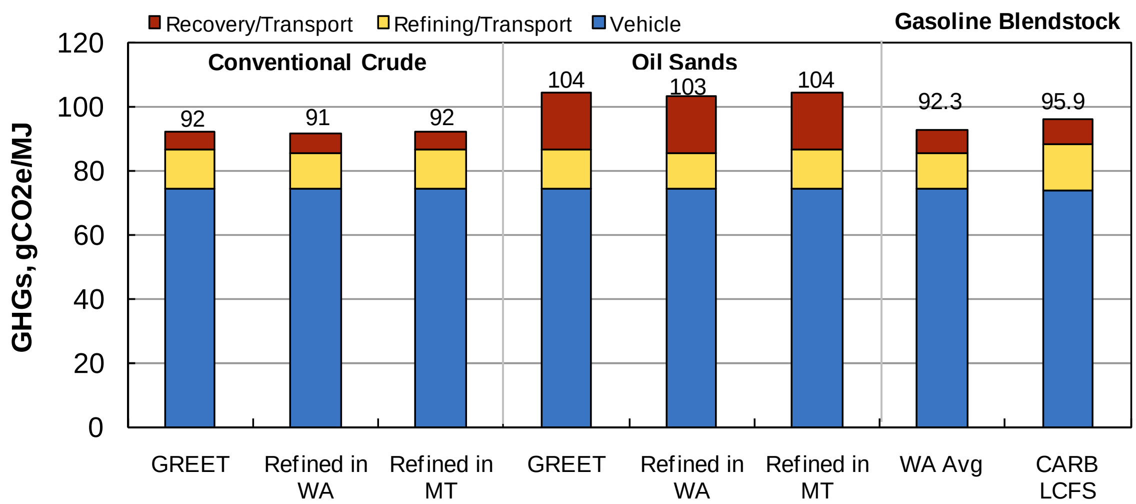

Figure 3-7. Carbon intensity for Gasoline Blendstock[11].

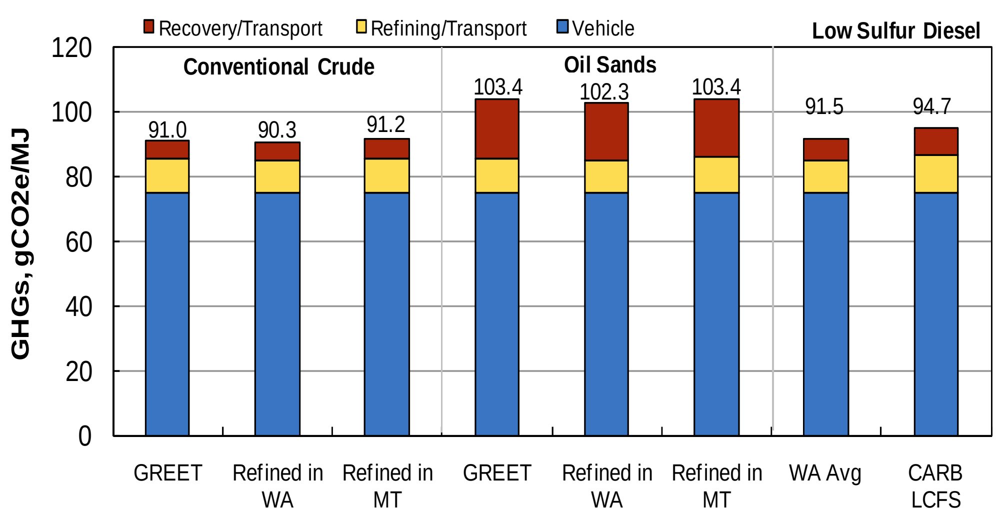

Figure 3-8. Carbon Intensity for Ultra Low Sulfur Diesel[12].

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[11] Vehicle CO_2 emissions based on GREET default fuel composition. Vehicle CH_4 and N_2O emissions from CARB pathway document for CARBOB.
[12] Vehicle CO_2 emissions based on GREET default fuel composition. Vehicle CH_4 and N_2O emissions from CARB pathway document for ULSD.

3.2 *Ethanol Pathways*

Ethanol can be produced from a number of different feedstocks. At present, the vast majority of ethanol consumed in the United States is produced from corn. Sugarcane derived ethanol produced in Brazil and other Caribbean countries could be imported into Washington. In addition to these established feedstocks, commercial plants utilizing cellulosic feedstocks are being constructed in various locations of the country. For the Washington LCFS analysis, to derive transportation and other input factors, we considered the ethanol pathways shown in Table 3-9. Pacific Ethanol currently operates a corn ethanol plant in Boardman Oregon and is currently planning to build a new facility to produce ethanol from poplar and wheat straw. Potential forest residue and mill waste to ethanol plants are assumed to be located in Ellensburg Washington[13] for analysis purposes. The assumptions and carbon intensity results for each pathway are provided in the following paragraphs.

Table 3-9. Ethanol Pathways Considered in Washington LCFS Analysis

Feedstock	Feedstock Source	Plant Location	General Assumptions
Corn	Midwest	Midwest	Midwest Average, GREET Defaults
Corn	Minnesota, South Dakota, North Dakota	Boardman, OR	Dry Mill, Wet DGS, Natural gas process fuel
Poplar	Washington	Boardman, OR	GREET defaults except transport modes/distances and electricity mix
Wheat Straw	Washington	Boardman, OR	Based on GREET corn stover pathway, most assumptions modified
Forest Residue	Washington	Ellensburg, WA	GREET defaults for forest residue gasification pathway
Mill Waste	Washington	Ellensburg, WA	Forest residue pathway with no collection and transport energy use
Sugarcane	Brazail	Brazil	GREET defaults except for transportation distances

3.2.1 Corn Ethanol Pathways

Two corn ethanol pathways were considered: average Midwest corn ethanol and ethanol produced in Oregon from Midwest corn. Figure 3-9 shows schematically the different components of the corn ethanol pathway: farming, corn transport, ethanol production, and ethanol transport.

[13] Ellensburg is the optimum location for a forest residue & mill waste to ethanol plants according to "Biomass Inventory: Technology and Economic Assessment", Khachatryan, Cassavant, Jessup, WSU Sept 2009.

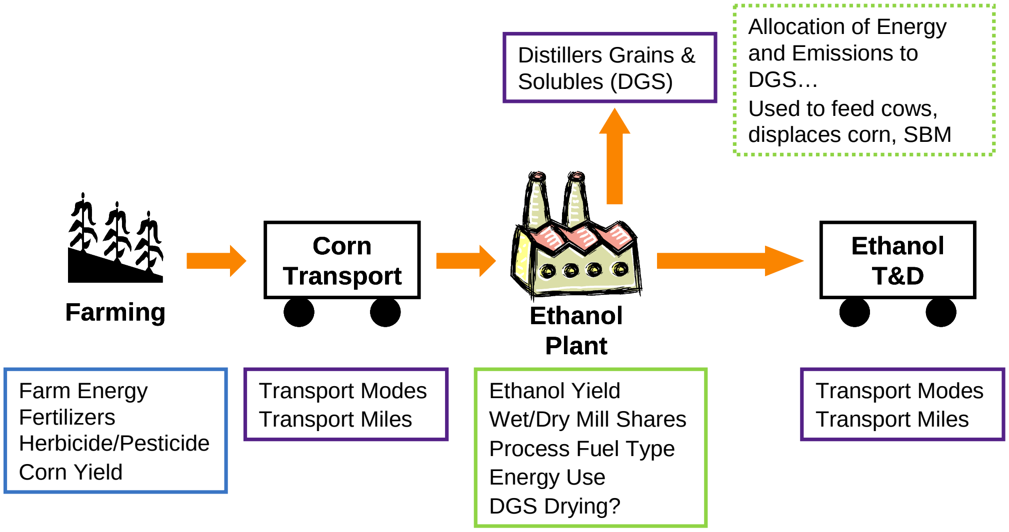

Figure 3-9. Schematic of the Corn Ethanol Pathway.

One of the key considerations in the corn ethanol pathway is treatment of co-products produced at the ethanol plant. With the wet milling process, two co-products are produced: corn gluten feed (CGF) and corn gluten meal (CGM). The dry milling process yields distillers grains and solubles (DGS). These three products are substituted for animal feed. Therefore, some of the energy consumed to make ethanol should really be allocated to the co-products; not all of it should be allocated to the ethanol. There are several ways to allocate the energy consumed between the co-products: by energy content, mass, economic value or with the substitution/displacement method. The different allocation methods can result in significantly different results. The substitution/displacement method is generally the preferred approach as it is the most realistic. The substitution method simply gives a credit equal to the energy required to produce the product that the co-product is replacing. For example, CGF and CGM are used in place of corn, so a credit equal to the amount of energy used to produce the displaced corn would be subtracted from the energy consumed at the ethanol plant.

For corn ethanol production, we utilize the substitution method to allocate ethanol production energy and emissions to the different co-products. Table 3-10 summarizes the co-product credit values assumed in this study. The methane credit is given because cows that eat DGS rather than corn and soybean meal emit less methane. As noted, CARB used lower displacement ratios. EPA utilized the GREET default values in its analysis of RFS2. CARB's substitution ratios increase the pathway carbon intensity by ~ 6 g CO_2e/MJ fuel.

Table 3-11 provides the key inputs used to calculate energy use in corn farming and ethanol production for the two corn ethanol pathways. In the GREET model, energy consumption is calculated first, and then emission factors are applied based on quantities of each fuel type. In addition to farming and ethanol production energy use, the energy associated with transporting the corn and ethanol is also determined. Table 3-12 provides the transportation assumptions.

Table 3-10. Ethanol Production Co-Product Credits

Process	Co-Product	Substitution Ratio	Comments
Wet Milling	Corn Gluten Meal	1 lb corn per lb CGM	GREET Default
	Corn Gluten Feed	1.529 lb corn per lb CGF	GREET Default
Dry Milling	Distillers Grains and Solubles (DGS)	0.992 lb corn/lb DGS	GREET Default. CARB used 1.0 lb corn/lb DGS
		0.306 lb soybean meal /lb DGS	GREET Default. CARB Used 0.
		0.022 lb N-urea / lb DGS	GREET Default. CARB Used 0.
		3,381 gCO2e/MMBtu EtOH	GREET Default Methane Credit. CARB Used 0.

Table 3-11. Corn Ethanol Pathway Key Assumptions

	Average MW Corn Ethanol	Northwest Corn Ethanol	Comments
Farm Yield	158 bu/acre	158 bu/acre	GREET Default
Farming Energy Use	12,635 Btu/bu	12,635 Btu/bu	GREET Default
Dry Mill Ethanol Plants:			
Dry Mill Share	87.5%	100%	87.5% is Default, Boardman facility is Dry Mill
Share of wet DGS	25%	100%	GREET default is 100% dry. Current estimate is 25%[a].
Energy Use	33,097 Btu/gal	24,389 Btu/gal	36,000 for 100% dry DGS, 24,389 for 100% wet DGS[b]
Fuel Shares	80/20 NG/Coal	100% NG	Avg MW case is Default. Boardman uses 100% NG
Ethanol Yield	2.72 gal/bu	2.72 gal/bu	GREET Default
Wet Mill Ethanol Plants:			
Energy Use	45,950 Btu/gal	n/a	GREET Default
Ethanol Yield	2.62 gal/bu	n/a	GREET Default
Fuel Shares	60/40 NG/Coal	n/a	GREET Default
Ethanol Plant Electricity Resource mix	U.S. Average	Oregon	U.S. Mix is 1% Oil, 18% NG, 50% Coal, balance non-combustion Oregon Mix is 14% NG, 38% Coal, balance non-combustion

a. In the RFS2 Regulatory Impact Analysis, EPA assumes 37.5% of DGS is supplied wet. The Renewable Fuel Association indicates 20-25% of DGS is supplied wet, www.ethanolrfa.org/industry/resources/coproducts.
b. “Life-cycle energy and GHG Emission Impacts of Different Corn Ethanol Plant Types”, Argonne National Lab, May 2007

Table 3-12. Corn and Ethanol Transportation Assumptions

	Average MW Corn Ethanol	Northwest Corn Ethanol
Corn Truck Miles	50 Miles from farm to plant	50 Miles from farm to rail terminal
Corn Rail Miles	0	1350 Miles from MN/SD/ND to Portland/Spokane
Ethanol Truck Miles	100 Miles from rail to petroleum terminals, 75 miles to refueling station	25% to Pasco/Spokane (120 miles) 100 Miles from Portland/Spokane to terminals, 75 miles to refueling
Ethanol Barge Miles	0	75% by barge to Portland (160 miles)
Ethanol Rail Miles	2000 Miles Iowa to Portland/Spokane	0

3.2.2 Cellulosic Ethanol Pathways (Fermentation)

Two different cellulosic ethanol production pathways were considered via fermentation: poplar trees and wheat straw. Poplar trees were chosen because the ZeaChem plant in Boardman, Oregon is focusing on that feedstock and Iogen has actively investigated locating in the wheat growing areas of the Northwest. The cellulosic ethanol production pathway is shown schematically in Figure 3-10. A key difference from the corn ethanol pathway is that at the ethanol plant, a portion of the biomass is turned into fuel with the balance used as a process fuel. The excess energy generated at the plant through combustion of biomass is exported as electricity. A credit is given based on the local electricity grid mix. The GREET farmed tree pathway was utilized for the poplar case and the GREET corn stover pathway was used as the basis (with modifications) for the wheat straw pathway.

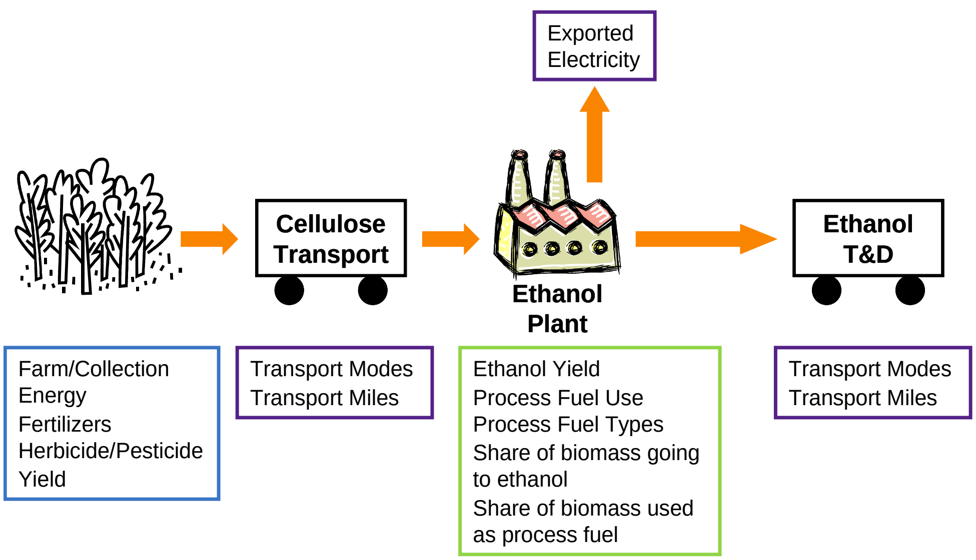

Figure 3-10. Schematic of the Cellulosic Ethanol Pathway (Fermentation).

For poplar farming, the GREET default of 234,770 Btu/dry ton was utilized as were the default fertilizer application rates. We assumed no herbicide/pesticide use[14]. For the wheat straw case, we estimated the amount of wheat straw removed per acre and combined this with the estimated straw removal fuel use per acre. We assume 60 bu/acre wheat and 90 lb wheat straw per bushel wheat, resulting in 5400 lb of straw per acre.[15] A variety of sources recommend leaving behind from 3000 to 5000 lb/acre or ~25 percent for erosion control and nutrient value. We assume that 3000 lbs of straw are left behind which corresponds to 55 percent. The amount of energy consumed in removing the wheat straw from the field is estimated at 205,657 Btu per dry ton[16]. The nutrient value of the straw removed is offset by increased nitrogen fertilizer use based on the wheat straw nitrogen content.[17] A credit is given for reduced N_2O emissions from the wheat straw.

For both cellulosic pathways, we assumed that the ethanol plant would be located near Boardman Oregon. Trees are grown now in eastern Oregon and Washington (~ 50 miles from Boardman) and western Oregon and Washington (~250 miles from Boardman). An average distance of 150 miles by heavy duty truck was assumed. For wheat straw, the distance from Lind Washington (approximate center of the wheat growing region) to Boardman is 120 miles.

Table 3-13 provides the key assumptions for estimating ethanol production plant energy consumption. For both pathways we assume that the ethanol takes the same path that the corn ethanol currently travels from the Boardman plant. Approximately 75 percent travels by barge to Portland for distribution to Western Washington with the balance traveling by truck to Pasco and Spokane for distribution to Eastern Washington. From these cities (Portland, Pasco, Spokane) the ethanol travels ~100 miles to petroleum terminals and ~ 75 miles to refueling stations by heavy duty truck.

Table 3-13. Cellulosic Ethanol Production Assumptions

	Poplar		Wheat Straw	
Plant Yield	90 gal/dry ton	GREET Default	65 gal/dry ton	Estimates range from 45 to 85[18]
Biomass handling diesel use	337 Btu/gal EtOH	GREET Default	180 Btu/gal	GREET Default for Corn Stover
Share of biomass going to fuel	55%	GREET Default	60%	GREET Default for Corn Stover
Share of biomass used as process fuel	45%	GREET Default	40%	GREET Default for Corn Stover
Electricity Export Credit	1.145 kWh/gal	GREET Default	0.572 kWh/gal	GREET Default for Corn Stover

[14] "Crop Profile for Hybrid Poplars in Washington and Oregon", Washington State University
[15] "Wheat Straw for Ethanol Production in Washington: A Resource, Technical and Economic Assessment", Kerstetter, Lyons, WSU 2001.
[16] Based on 1.62 gal/acre per "Machinery Cost Estimates", William Lazarus, University of Minnesota, June 2009
[17] Nitrogen content of 2.11 lb/ton "Nutrient Value of Wheat Straw", Ontario Ministry of Agriculture, Food and Rural Affairs, May 2007
[18] Iogen demonstration plant funded by DOE projected 71 gal/dry ton of wheat straw.

3.2.3 Woody Biomass Ethanol Pathways (Gasification)

Two feedstocks were considered for the woody biomass pathways: forest residue and solid mill waste. These are logical feedstocks given the forestry industry in Washington. The GREET forest residue pathway was utilized as the basis for these pathways. For forest residue, the GREET default collection energy 590,067 Btu/dry ton is utilized. For the solid mill waste pathway, there is no collection energy as the feedstock is a waste product. For both cases, we assume that the feedstock travels 75 miles by heavy duty truck to the ethanol plant.

The GREET default values for ethanol production via gasification were utilized for both pathways – these values are provided in Table 3-14. Recall that in the cellulosic ethanol pathway that all of the energy consumed to produce ethanol was allocated to the ethanol, and then a credit was applied equal to the electricity exported. In the gasification pathway, GREET allocates energy consumed between the electricity and ethanol co-products on an energy basis, not as a credit. Finally, we assumed that the ethanol travels an average of 100 truck miles to a blending terminal and then 75 miles to fueling stations.

Table 3-14. Woody Biomass Ethanol Production (Gasification) Assumptions

Parameter	GREET Default Value
Plant Yield	90.4 gal/dry ton
Biomass handling equipment diesel use	337 Btu/gal ethanol
Process natural gas use	3,236 Btu/gal
Share of biomass that goes to ethanol	45%
Share of biomass used for steam and electricity production	55%

3.2.4 Sugarcane Ethanol

The final ethanol pathway considered is sugarcane ethanol. For farming we utilized the GREET default energy consumption value of 41,559 Btu/tonne of sugarcane. We modified GREET to allow use of the Brazil electricity mix for farming electricity use and the U.S. average electricity mix for fertilizer production. We assumed that all sugarcane "trash" (tops and leaves) was burned in the field prior to manual harvesting. Since the carbon in the straw is renewable, only the N2O and CH4 emissions are considered. We utilized the GREET default fertilizer, pesticide and herbicide application rates.

After harvesting, the sugarcane is transported by truck to the ethanol plant assumed to be 12 miles away (GREET default). The default truck payload is 17 tons with a fuel economy of 5 miles per gallon. The EPA values utilized in the RFS2 Regulatory Impact Analysis are a 42 ton truck payload with a 3.8 mile per gallon fuel economy. The EPA values were utilized.

For ethanol production energy use, the GREET default values were utilized: 0.00642 dry tons of bagasse and 251 Btus of burnt lube oil per gallon of ethanol produced. Bagasse is the part of the sugarcane left over after the juice has been extracted. The ethanol plants export electricity – the GREET default is 23 kWh/tonne of sugarcane processed. In CARB's analysis, no credit is taken for the exported electricity. This analysis applies a credit assuming that the exported electricity displaces natural gas based electricity generation. This is consistent with EPA's treatment in the RFS2 Analysis except that EPA assumed more electricity exports (40-135 kWh/tonne).

For ethanol transport, we utilize the GREET defaults of 500 miles from the plant to the marine terminal. Half of the ethanol travels by rail, half travels by pipeline. The ethanol then travels 9200 miles by cargo ship to Washington, 100 miles by truck to petroleum terminals, and then 75 miles by truck to refueling stations.

3.2.5 Indirect Land Use Change Assumptions

The corn, poplar and sugarcane ethanol pathways need to include a value for indirect land use change (ILUC) emissions. The other pathways use waste streams that have no ILUC emissions. There are two sets of values to choose from: CARB's values generated with Purdue University and the GTAP model and EPA's values generated using a number of models including FASOM and FAPRI. Table 3-15 provides the current CARB and EPA estimates of ILUC for corn, sugarcane and farmed trees. The farmed tree values shown were derived from switchgrass estimates assuming 250 gallons of ethanol per acre for switchgrass, and 900 gallons/acre for farmed trees. Because the analyses are very different and it is extremely difficult to conclude that one is superior to the other, for the purpose of this study Ecology has decided to utilize an average value for this analysis.

Table 3-15. Ethanol ILUC Emission Assumptions, g/MJ

	CARB	EPA RFS2	Average
Corn Ethanol	30	26	28
Sugarcane Ethanol	46	4	26
Farmed Tree Ethanol	5	3	4

3.2.6 Ethanol Pathway Carbon Intensity Summary

Based on the foregoing assumptions, the carbon intensity estimates for the seven different ethanol pathways are provided in Figure 3-11 and Table 3-16.

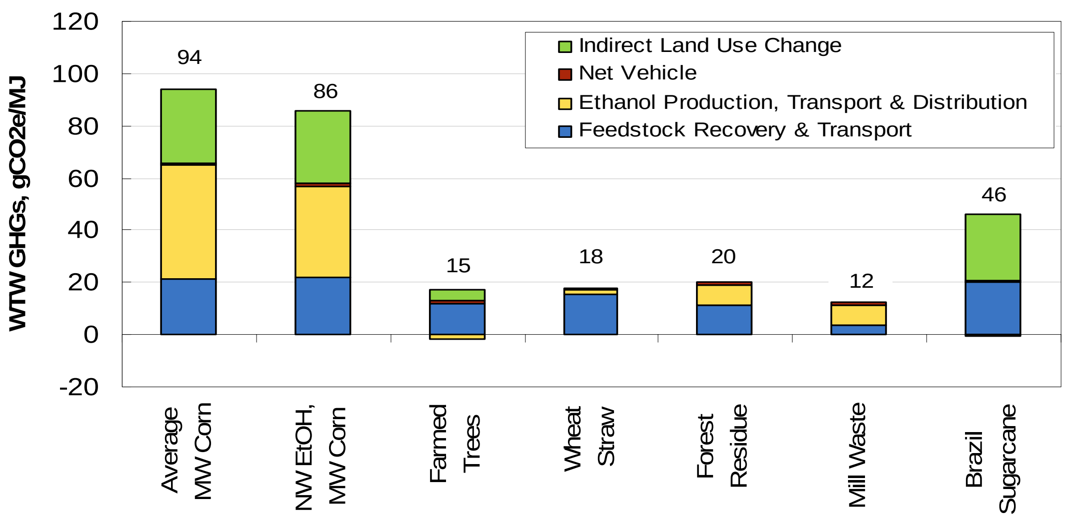

Figure 3-11. Estimated Carbon Intensity Values for the Ethanol Pathways Considered.

Table 3-16. Estimated Carbon Intensity Values for the Ethanol Pathways Considered.

Ethanol Case	Feedstock Recovery and Transport	Ethanol Production, Transport & Distribution	Net Vehicle	Indirect Land Use Change (ILUC)	Total Carbon Intensity (gCO_2e/MJ)
Average Midwest Corn Ethanol	21.4	43.6	0.8	28	94
Northwest Corn Ethanol from Midwest Corn	21.8	35.3	0.8	28	86
Farmed Trees	12.0	-1.6	0.8	5	15
Wheat Straw	15.3	2.0	0.8	0	18
Forest Residue	11.2	7.8	0.8	0	20
Mill Waste	3.7	7.8	0.8	0	12
Brazil Sugarcane	20.0	-0.4	0.8	26	46

Net Vehicle emissions do not include CO_2 since the carbon is derived from the atmosphere

3.3 Biodistillate Pathways

Four biodiesel and one renewable diesel pathways (shown in Table 3-17) were considered in this analysis. A generic biodistillate pathway is shown schematically in Figure 3-12. The four main steps are: feedstock farming/recovery, feedstock transport, biofuel production, and biofuel transportation. Note that two different biodistillate production processes are considered: biodiesel (methyl esters) and renewable diesel. The following sections describe the main assumptions made for the feedstock preparation, biodiesel production, renewable diesel production, feedstock and fuel transportation, indirect land use change emission assumptions. Finally, a summary of the estimated carbon intensity for each pathway is provided.

Table 3-17. Biodistillate Pathways Considered

Feedstock	Fuel	Main Assumptions
Midwest Soybeans	Biodiesel	Produced in MW, shipped by rail to Washington
Washington Canola	Biodiesel	Canola farmed in Washington, Biodiesel produced in Washington
Washington Yellow Grease	Biodiesel	Based on CARB used cooking oil pathway
Washington Tallow	Biodiesel	Based on CARB tallow pathway
Midwest Soybeans	Renewable Diesel	Soybeans grown in Midwest, soyoil shipped to Washington, RD produced in Washington

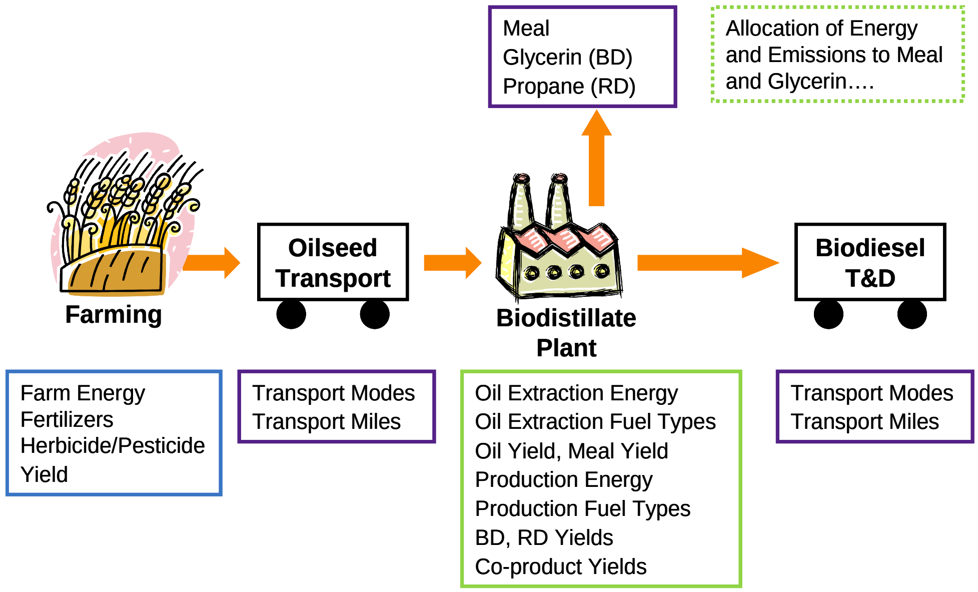

Figure 3-12. Generic Biodistillate Production Pathway.

3.3.1 Feedstock Preparation

The first step in the biodistillate pathways is feedstock preparation. We first describe the soybean farming and soyoil extraction assumptions – these are applicable to the soybean biodiesel and renewable diesel pathways. We next provide the canola farming and oil extraction assumptions. This is followed by the yellow grease and tallow recovery and rendering assumptions.

Soybean Farming and Soyoil Extraction

For the soybean biodiesel and renewable diesel pathways, the GREET default farming energy and fertilizer/herbicide/pesticide application rates were utilized. The farming energy value is 22,087 Btu/bu of soybeans. The next step is soyoil extraction; this produces soyoil and soybean meal. Three different data sources were considered for soyoil extraction process assumptions: CARB LCFS[19], GHGenius[20], and EPA's RFS2[21] analysis. Table 3-18 summarizes the values for each of these analyses and the values selected for our analysis.

For soyoil extraction yield, we selected the CARB value of 0.189 lb oil per lb soybeans. This is CARB's value based on 2007 USDA data. It was felt that this was more representative of U.S. soybean characteristics than the Canadian GHGenius value. We used the GREET default value for soybean meal yield.

[19] CARB LCFS Pathway Document for Biodiesel Produced from Midwest Soybeans
[20] "Biodiesel GHG Emissions Using GHGenius, an Update", (S&T)2 Consultants, January 2005
[21] RFS2 Regulatory Impact Analysis, EPA February 2010

Table 3-18. Soyoil Extraction Assumptions

Parameter	Units	GREET & CARB Values	GHGenius (2005)	EPA RFS2	Values Used in WA Analysis
Soyoil Yield	lb oil / lb soybean	0.189[a]	0.180	0.187	0.189
Soybean Meal Yield	lb SBM / lb oil	4.48	4.37	Not stated	4.48
NG Use	Btu/lb oil	2,800	1,941	1,961	1,951
Electricity Use	Btu/lb oil	551	582	384	483
Hexane Use	Btu/lb oil	182	210	Not stated	182

a. GREET default is 0.19. CARB updated to 0.189 based on 2007 USDA data.

The GREET energy consumption values for soyoil extraction are 12 to 15 years old and biodiesel producers have indicated that they are too high. For our analysis we used an average of the GHGenius and EPA natural gas and electricity consumption values. For hexane, we used the GREET default value.

The valuable soybean meal produced in the oil extraction step is utilized as animal feed. Some of the energy consumed in the oil extraction step needs to be allocated to the meal. If the substitution method is employed (giving a credit to the soyoil for the avoided emissions due to producing an equivalent amount of animal feed), the credit is so large that the pathway becomes negative. Allocating on the basis of energy content doesn't make sense either because soybean meal is not a fuel. The GREET default method is to allocate the extraction energy between the soyoil and the meal on the basis of mass (~ 19% to the soyoil, 81% to the meal). This is the approach adopted by CARB in their LCFS pathway for soybean based biofuels.

Canola Farming and Oil Extraction

GREET does not have a pathway for canola, so this was added to the WA-GREET model. We have utilized the GHGenius canola pathway assumptions for farming (Table 3-19) and oil extraction inputs (Table 3-20). The fertilizer use data are based on farm surveys. It is interesting to note that the nitrogen use is ~ 20 times higher than the soybean nitrogen use since legumes are able to fix nitrogen from the air. It is also interesting to note that much less energy is needed to extract canola oil than soybean oil because canola seeds have higher oil content. Finally, consistent with the soybean pathway, the extraction energy is allocated between the canola oil and canola meal based on mass.

Table 3-19. Canola Farming Assumptions

Parameter	Units	GHGenius Value Utilized in Analysis
Farming Energy Use	Btu/bu	27,149
Nitrogen Use	g/bu	1,043
Phosphorus Use	g/bu	367
Potassium Use	g/bu	86
Nitrogen Content of Residue	g/bu	170

Table 3-20. Canola Oil Extraction Assumptions

Parameter	Units	GHGenius Value Utilized in Analysis
Canola Oil Yield	lb oil / lb seed	0.41
Meal Production	lb meal / lb oil	1.47
Natural Gas Use	Btu/lb oil	874
Electricity Use	Btu/lb oil	134
Hexane Use	Btu/lb oil	44
Total Extraction Energy	Btu/lb oil	1,053

Yellow Grease and Tallow

Waste oils such as restaurant oils (yellow grease) and tallow (animal fats) are low carbon feedstocks for biofuel production since no farming/collection energy is required and there are no indirect land use change emissions to consider. Because GREET does not have waste oil pathways, we have added pathways to the WA-GREET model based on CARB's used cooking oil and tallow pathway documents[22]. The first step in yellow grease pathway is transport to a rendering plant. Because the oils would otherwise be transported to a disposal site, no net increase/decrease in transport emissions is considered. At the rendering plant, the water content of the cooking oil is reduced before it is sent to the biodiesel plant. For yellow grease, two different processes are considered: heating to thermally remove the water and filtration/settling.

Tallow is produced at meat rendering plants. The meat is crushed and cooked to liquefy the fat. The fat is drained, screw pressed and filtered from the solids. CARB found that meat rendering plants could be divided into older plants with higher rendering energy use and newer plants with lower rendering energy use. Table 3-21 provides the CARB rendering energy assumptions utilized in this analysis.

For both the yellow grease and tallow pathways, pretreatment at the biodiesel plant is needed to reduce the free fatty acid levels. We utilize the CARB value of 171 Btu/lb biodiesel for pretreatment energy. This is split between natural gas (91%) and electricity (9%).

Table 3-21. Waste Oil Rendering Energy Use Assumptions

Parameter	Yellow Grease "cooking"	Yellow Grease "no cooking"	Tallow "Old Plants"	Tallow "New Plants"
Total Energy Use, Btu/lb	1,073	140	6,026	1,730
Natural Gas Share	90%	80%	89%	100%
Electricity Share	10%	20%	11%	0%

[22] http://www.arb.ca.gov/fuels/lcfs/workgroups/workgroups.htm#pathways

3.3.2 Biodiesel Production

We have assumed that the biodiesel production process is the same regardless of oil type. Therefore, the same assumptions are utilized to produce biodiesel from each of our oils considered: soy, canola, rendered/pre-treated cooking oil and tallow. In the biodiesel production process, glycerin and biodiesel are co-produced. We allocate the production energy between glycerin and biodiesel based on energy content. This is consistent with CARB's approach.

For the biodiesel production inputs to GREET we have compared the GREET defaults to GHGenius and EPA's RFS2 analysis (Table 3-22). The GREET energy use values are 12 to 15 years old. The GHGenius values were updated in 2005 based on a survey of equipment manufacturers and producers. The EPA RFS2 values were taken from USDA Biodiesel production energy estimates updated in 2009 to reflect a new biodiesel dehydration process. For the Washington analysis we utilized the GHGenius and EPA values for Biodiesel yield and the GHGenius value for glycerin yield. For natural gas and electricity use we have utilized an average of the GHGenius and EPA values.

Table 3-22. Biodiesel Production Energy Use Assumptions

Parameter	Units	GREET Default	GHGenius (2005)	EPA RFS2	Value Used
Biodiesel Yield	lb BD / lb oil	0.96	1.00	1.00	1.00
Glycerin Yield	lb glycerin/lb oil	0.105	0.10	Not stated	0.10
Natural Gas Use	Btu/lb BD	889	645	591	618
Electricity Use	Btu/lb BD	46	30	49	40
Methanol Use	Btu/lb BD	866	850	Not stated	850

3.3.3 Renewable Diesel Production

For the renewable diesel production process we have utilized the GREET defaults for the renewable diesel process utilizing hydrogenation (RDII). The assumptions are provided in Table 3-23. The process fuel is allocated between the two co-products (renewable diesel and propane) based on energy content. This result in ~ 95 percent of the energy use allocated to renewable diesel. Allocation by energy content is consistent with CARB's approach.

Table 3-23. Renewable Diesel Production Energy Use and Yield Assumptions

Parameter	Units	Value Used
Process Fuel Use	Btu/lb RD	1851
Hydrogen	%	90%
Natural Gas	%	5%
Electricity	%	5%
Renewable Diesel Yield	lb RD / lb soyoil	0.85
Propane Yield	lb propane / lb RD	0.059

3.3.4 Biodistillate Transport Assumptions

Table 3-24 provides a summary of the feedstock and fuel transport assumptions.

Table 3-24. Biodistillate Transportation Assumptions

Feedstock	Feedstock Transport Assumptions	Fuel Transport Assumptions
Soybean Biodiesel	12 miles by HD Truck to Plant	40 miles by truck to a rail terminal 2000 rail miles to Seattle 100 heavy duty truck miles to blending terminal 75 heavy duty truck miles to refueling stations
Canola Biodiesel	100 Miles by HD Truck (35 ton payload)[a]	Canola farmed in Washington, Biodiesel produced in Washington
Yellow Grease Biodiesel	50 miles by HD Truck (25 ton payload)	150 miles by HD Truck to blending terminal 75 miles by HD Truck to refueling stations
Tallow Biodiesel	50 miles by HD Truck (25 ton payload)	150 miles by HD Truck to blending terminal 75 miles by HD Truck to refueling stations
Soybean Renewable Diesel	Soybeans: 12 Truck Miles Soy Oil: 2000 rail miles	RD travels 150 miles by HD Truck to blending terminal RD travels 75 miles by HD Truck to refueling stations

a. Inland Empire Oilseeds, Pearson Burke.

3.3.5 Indirect Land Use Change Assumptions

Of the five biodistillate pathways, only the two with soybeans as the feedstock have ILUC emissions. Please refer to the discussion in Chapter 2 regarding the ILUC assumptions for canola. For Washington grown Canola, we assume the canola will be grown in rotation with wheat; the displaced wheat will be grown on retiring CRP acres using low impact farming techniques. Growing fuel feedstocks on retiring CRP acres does not displace any crops, so will not result in ILUC emissions. Further, no-till farming minimizes any release of sequestered soil carbon. The CARB/GTAP soybean BD ILUC value is 62 g/MJ. The EPA RFS2 value is 32 g/MJ. In this analysis we have utilized an average of the two values for soybean biodiesel and renewable diesel (47 g/MJ).

3.3.6 Biodistillate Carbon Intensity Summary

Figure 3-13 and Table 3-25 provide a summary of the carbon intensity values for the biodistillate fuels considered.

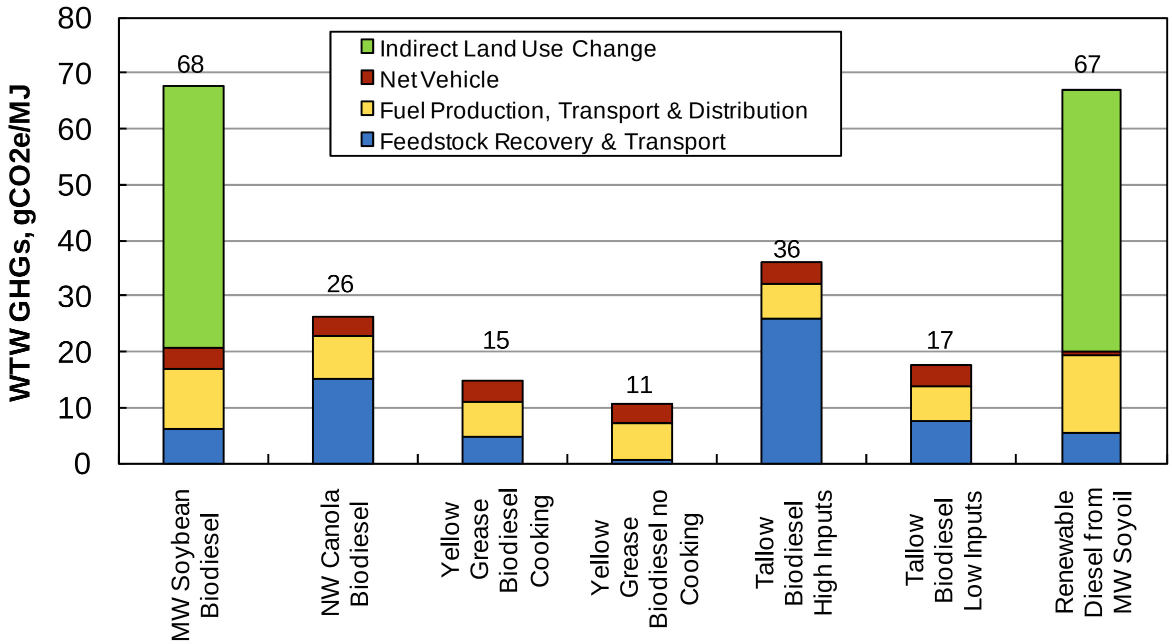

Figure 3-13. Summary of Estimated Biodistillate Carbon Intensity Values.

Table 3-25. Summary of Estimated Biodistillate Carbon Intensity Values.

Biodistillate Cases	Feedstock Recovery and Transport	Biodistillate Production, Transport & Distribution	Net Vehicle Emissions [1,2]	Indirect LUC (g/MJ	WTW (gCO2e/MJ)
Midwest Soybean Biodiesel	6	11	4	47	68
Northwest Canola Biodiesel	15	7	4	x	26
Yellow Grease Biodiesel Cooking	5	6	4	x	15
Yellow Grease Biodiesel no Cooking	1	6	4	x	11
Tallow Biodiesel High Inputs	26	6	4	x	36
Tallow Biodiesel Low Inputs	7	6	4	x	17
Renewable Diesel from Midwest Soyoil	6	14	1	47	67

1. Vehicle emissions include tailpipe N2O and CH4 , but not conversion of renewable carbon in the fuel to CO2.
2. BD vehicle emissions are higher than RD b/c fossil methanol is used to convert triglycerides into methylesters.

3.4 Electricity Pathway

Washington State has one of the lowest carbon intensity grid resource mixes in the country, mainly because of its access to large amount of hydroelectric power. Figure 3-14 provides the resources utilized to generate the electricity consumed in Washington for 2004 through 2007. Figure 3-15 shows relative shares of each resource type for 2007.

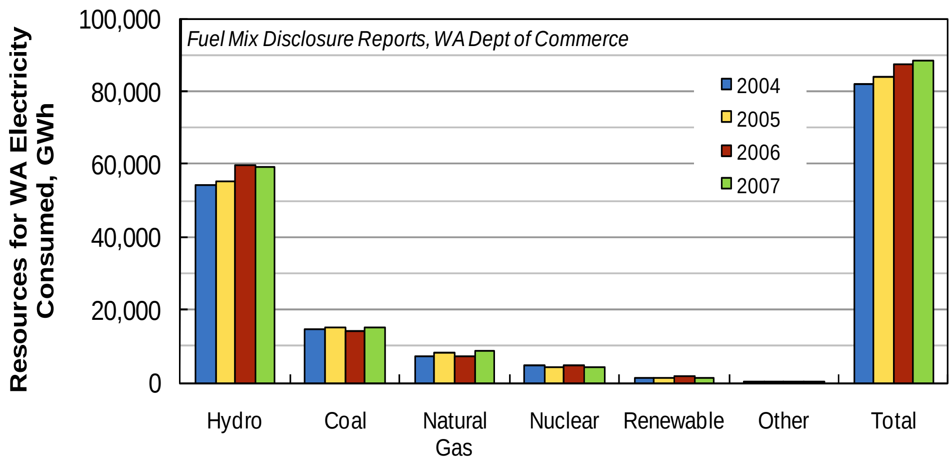

Figure 3-14. Historic Electricity Resource Mix for Electricity Consumed in Washington.

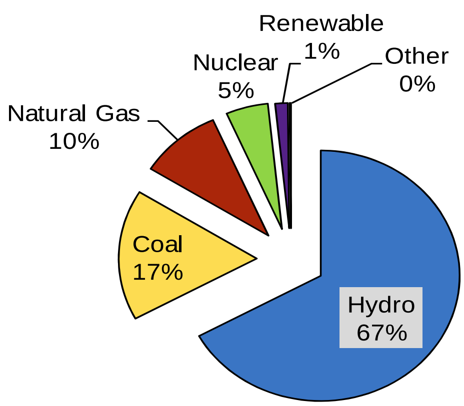

Figure 3-15. Shares of Electricity Resources for 2007.

Despite the large amounts of hydroelectricity, the state has a Renewable Portfolio Standard (RPS) that requires increasing amounts of renewable fuel in the electricity grid mix. Figure 3-16 illustrates the required amount of renewable energy required during the analyzed LCFS timeframe of 2013-2023. During this time period, the average amount of additional renewables is 12 percent of all electricity sold in the state.

For the LCFS electricity pathway, there were two main options: marginal electricity resource mix and average electricity resource mix. For this analysis we have utilized the current average grid mix with 12 percent additional renewable resources. Table 3-26 provides the 2007 grid mix and the LCFS grid mix with an additional 12 percent renewables. We assume that new renewable resources replace all existing resources proportionate to their current use.

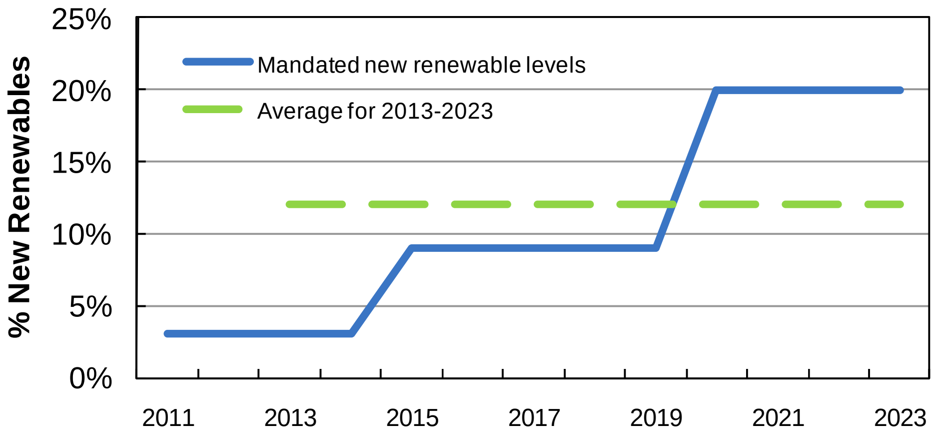

Figure 3-16. Washington State RPS Requirement During a Possible LCFS Timeframe.

Table 3-26. Washington 2007 Electricity Resource Mix and Assumed LCFS Mix

Resource	2007 Mix	LCFS Mix
Petroleum	0.0%	0.0%
Natural gas	9.6%	9.0%
Coal	16.8%	15.9%
Nuclear	4.9%	4.6%
Biomass	0.5%	0.5%
Other Non-Combustion	68.2%	70.0%

The carbon intensity of this resource mix as estimated by WA-GREET is 68 g/MJ. However, since electric vehicles are more fuel efficient than conventional vehicles, an EER factor needs to be applied. The EER for electric vehicles is assumed to be 4.1 at present and is expected to decline to 3.1 in future years (please refer to Section 4 of this report); the resulting carbon intensity for electricity increases from 16.5 in 2010 to and 22 g/MJ in 2023.

3.5 CNG Pathway

The CNG pathway assumes that pipeline natural gas is compressed to CNG at a refueling station. Most of the GREET defaults have been utilized to estimate the carbon intensity for this pathway. For recovery and processing, approximately 53,000 Btu are consumed for each MMBtu of CNG. GREET also assumes a recovery loss rate of 0.35 percent and a processing loss rate of 0.14 percent.

For transmission from the processing plant to the refueling station, we assume a distance of 1200 miles from either Alberta/British Columbia or Wyoming/Utah. The GREET default for transmission energy use is 253 Btu/ton-mile with 94 percent natural gas fired compressors and 6 percent electric compressors.

There is a certain amount of leakage in the transmission and distribution system. The GREET default leakage is 0.0045% over 600 miles, resulting in methane emissions over 80 g/MMBtu of natural gas transmitted. The CARB methodology uses an 0.08% leak rate[23] that is independent of distance. This approach results in methane emissions of 18 grams per MMBtu of natural gas transmitted. In this analysis we adopt the CARB approach.

For compression at refueling stations we assume that only electric drive compressors are utilized with an efficiency of 98 percent[24].

The final carbon intensity of CNG is 69 g/MJ. The recovery, processing and transmission portion is 8 g/MJ, the compression step is 2 g/MJ and the vehicle emits 59 g/MJ.

3.6 Summary of Carbon Intensity Estimates

Figure 3-17 and Table 3-27 provide the carbon intensity values utilized in the rest of the LCFS analysis.

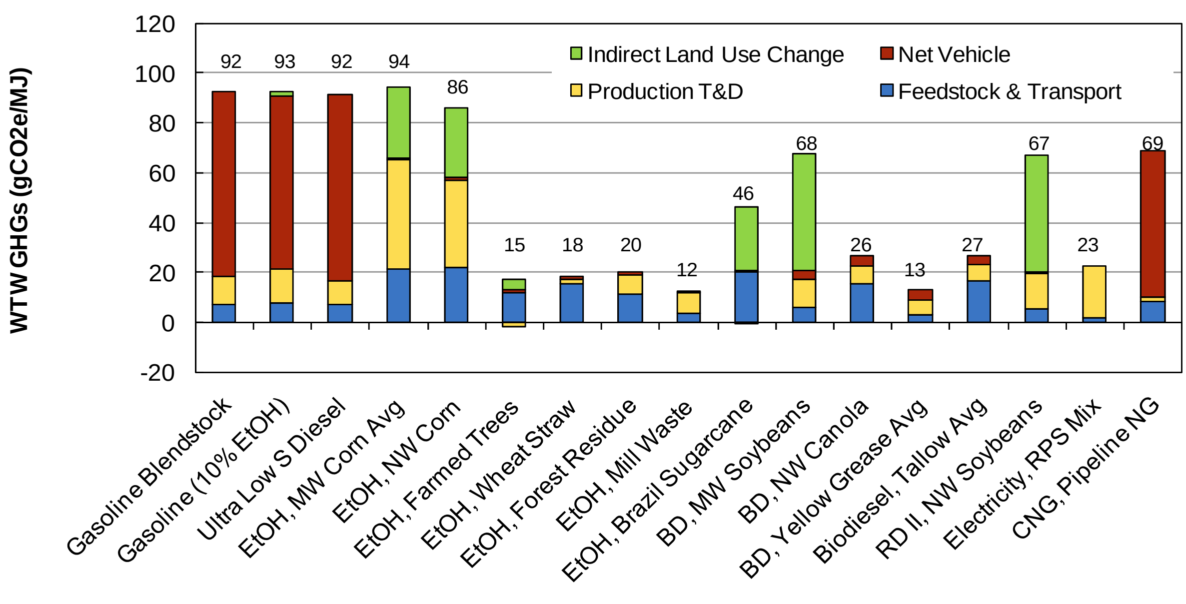

Figure 3-17. Summary of Estimated Carbon Intensity Values for Fuel Pathways Considered.

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[23] The 0.08% leak rate is based on report supplied by SoCal Gas to TIAX documenting its unaccounted for gas losses in support of the California AB1007 Alternative Fuels Plan effort.

[24] During the California AB1007 Alternative Fuel Plan effort, Clean Energy Fuels provided electricity consumption data at California CNG stations indicating that compressor efficiency is 98%, greater than the 97.4% GREET default.

Table 3-27. Summary of Estimated Carbon Intensity Values for Fuel Pathways Considered.

Carbon Intensity (g CO2e/MJ)	WTT			TTW				ILUC	WTW
	Feedstock & Transport	Production & Transport	WTT Total	Vehicle CO2	Vehicle CH4	Vehicle N2O	TTW Total		
Gasoline Blendstock	7	11	18	73	0.1	1.4	74	0	92
Gasoline (10% Corn Ethanol)	8	13	21	68	0	1.4	69	2	92
Ultra Low S Diesel	7	10	16	75	0.02	0.05	75	0	91
Ethanol, MW Corn Average	21	44	65	0	0.25	0.58	0.83	28	94
Ethanol, NW Production, MW Corn	22	35	57	0	0	0.6	1	28	86
Ethanol, Farmed Trees	12	-2	10	0	0	1	1	4	15
Ethanol, Wheat Straw	15	2	17	0	0	1	1	0	18
Ethanol, Forest Residue	11	8	19	0	0	1	1	0	20
Ethanol, Mill Waste	4	8	11	0	0	1	1	0	12
Ethanol, Brazil Sugarcane	20	0	20	0	0	1	1	26	46
Biodiesel, MW Soybeans	6	11	17	3.04	0.01	0.65	4	47	68
Biodiesel, NW Canola	15	7	23	3	0	1	4	0	26
Biodiesel, Yellow Grease Average	3	6	9	3	0	1	4	0	13
Biodiesel, Tallow Average	17	6	23	3	0	1	4	0	27
RD II, NW Production, MW Soy Oil	6	14	19	0	0	1	1	47	67
Electricity, WA Grid Mix + RPS	1	21	23	0	0	0	0	0	23
CNG, pipeline NG	8	2	10	56	0	2	59	0	69

Electricity Assumes EER of 3

4. Scenario Analysis Assumptions

To better understand the range of possible economic effects if a LCFS were adopted in Washington, a Scenario Analysis was conducted. We assume that compliance with a LCFS is possible given estimates of fuel availability and alternative vehicle penetration rates. The Scenarios were designed to be technologically feasible and structured to bound the range of possible compliance strategies. A number of scenarios in addition to a business as usual (BAU) case were considered. The VISION model was utilized to estimate fuel volumes and expenditures as well as vehicle populations and expenditures. These data were subsequently utilized by the Washington State Office of Financial Management (OFM) in the REMI economic model to determine the economic impact of each scenario on the State's economy. This section of the report describes the modeling tool utilized (VISION) along with key assumptions made through the analysis period: fuel prices, vehicle prices, vehicle fuel economy, vehicle miles travelled, and vehicle populations. Section 5 provides descriptions of the Scenarios considered.

4.1 Assumed Structure of a Washington LCFS

To develop compliance scenarios for a possible LCFS in Washington, we first need to define the structure of the standard. We assume here that a LCFS would begin in 2013 and yield the desired reduction by the end of 2023. Table 4-1 indicates the assumed LCFS timing and Figure 4-1 provides the assumed compliance schedule (same curve shape as CARB LCFS).

Table 4-1. Assumed Washington LCFS Structure

Year	Compliance Stage
2007	Data Year
2013	Baseline Year, Reporting Only Baseline carbon intensity projected from 2007 data Carbon intensity reductions measured relative to this Baseline Year
2014	Year 1 – Phased CI reduction required
2015	Year 2 – Phased CI reduction required
2016	Year 3 – Phased CI reduction required
2017	Year 4 – Phased CI reduction required
2018	Year 5 – Phased CI reduction required
2019	Year 6 – Phased CI reduction required
2020	Year 7 – Phased CI reduction required
2021	Year 8 – Phased CI reduction required
2022	Year 9 – Phased CI reduction required
2023	Year 10 – Target reduction from baseline carbon intensity achieved

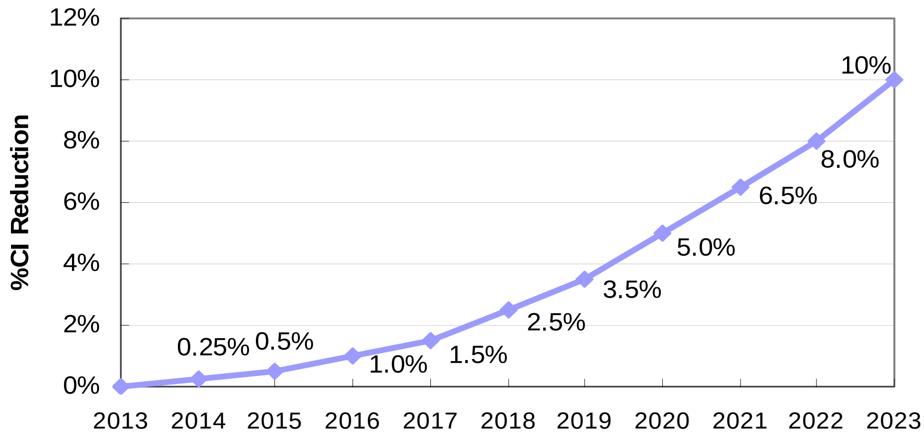

Figure 4-1. Assumed Compliance Schedule.

The "Baseline Year" from which carbon intensity reductions are measured is set at 2013. The "Baseline Carbon Intensity" is the 2013 carbon intensity projected from 2007 fuel data. The gasoline blendstock, neat corn ethanol and ultra low sulfur diesel (ULSD) carbon intensities are provided in Table 4-2. We assume that in 2013, the gasoline consumed in Washington will consist of 10 percent by volume denatured ethanol, and that the carbon intensities of ULSD and gasoline blendstock remain constant at 2007 levels. The carbon intensity of ethanol is assumed to be a weighted average of NW corn ethanol and average MW corn ethanol. The average MW corn carbon intensity is assumed to decrease to 90 g/MJ by 2022 (based on EPA RFS2). The resulting projected 2013 carbon intensities for gasoline and ULSD are indicated in the table.

Most of the scenarios considered in the analysis assume that the gasoline and diesel pools will each achieve a 10 percent reduction in carbon intensity. We have also considered a scenario in which a 10 percent reduction is achieved by the combined gasoline and diesel pools (the "one pool" scenario). The main difference between separate pools and one-pool compliance is that in a one-pool standard, reductions in light duty gasoline consumption due to increases in light duty diesel vehicles would effectively reduce the overall carbon intensity because the diesel carbon intensity coupled with better fuel economy has lower carbon intensity than a light duty gasoline vehicle. In a separate pool standard, changes in volumes of gasoline and diesel fuel would not affect the carbon intensity of either pool.

If a one-pool standard were to be implemented, the average carbon intensity for combined gasoline and ULSD would be determined, weighted by energy units consumed. The 2007 weighted average is shown based on the Washington split between ULSD and motor gasoline in that year. The 2013 split between ULSD and motor gasoline is estimated based on the AEO2010 change in the U.S. split between diesel and motor gasoline from 2007 to 2013. These three 2013 carbon intensity values shown in Table 4-2 are the Baseline Carbon Intensity values utilized in this analysis.

Table 4-2. Baseline Carbon Intensity Values

	Units	Data Year (2007)	Baseline (2013)
Gasoline Blendstock	g CO2e/MJ	92.3	92.3
Neat Ethanol[1]	g CO2e/MJ	93.3	91.8
Fuel Ethanol Blend Level	%	4.4%	10%
Motor Gasoline Baseline[2]	g CO2e/MJ	92.4	**92.3**
Ultra Low Sulfur Diesel	g CO2e/MJ	91.5	**91.5**
ULSD Share[3,4]	% Energy Basis	30%	29%
Motor Gasoline Share[3,4]	% Energy Basis	70%	71%
Average Transportation Fuel Pool	g CO2e/MJ	92.1	**92.2**

1. Assumes half of Boardman capacity plus average MW corn (decreases over time per RFS2)
2. Includes indicated volume of denatured ethanol, denatured ethanol assumed to be 2% by volume gasoline.
3. 2007 Fuel Consumption data from EIA State Energy Data Tables combined with GREET LHVs
4. AEO2010 estimates US diesel use divided by diesel + motor gasoline declines by 0.8% from 2007 to 2013.

4.2 VISION Model Overview

The VISION model (shown schematically in Figure 4-2) is a U.S. fleet turnover model developed and maintained by Argonne National Laboratory. It provides forecasts of energy use, consumer fuel and vehicle expenditures, and vehicle populations by vehicle class and type through the year 2100. It can also provide carbon intensity estimates. VISION uses historic U.S. sales data, combined with annual U.S. fleet turnover data by model year to estimate vehicle survival and age-dependant usage characteristics of the legacy fleet (1970 to present). To project the future fleet characteristics, the legacy fleet data is combined with future sales of conventional and alternative fuel vehicles based on the most recent Energy Information Administration Annual Energy Outlook (AEO) forecast. The current version of the model reflects the AEO 2009 projections through 2030. Some of the assumptions have been modified for this analysis and these modifications are explained in the following section.

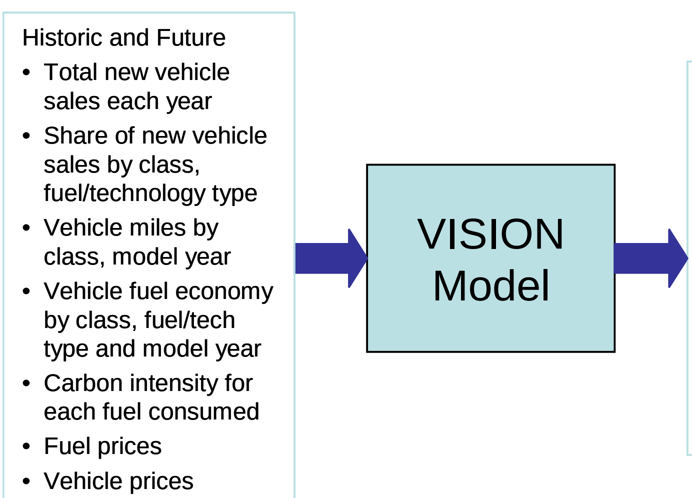

Figure 4-2. VISION Model Inputs and Outputs.

4.3 VISION Assumptions for Washington LCFS Analysis

Before using the VISION model to evaluate Washington State LCFS compliance scenarios, the model inputs shown in Figure 4-2 needed to be evaluated and in some cases adjusted to reflect Washington "business as usual" forecasts. The parameters considered are: fuel prices, vehicle prices, vehicle fuel economy, vehicle miles traveled (VMT), vehicle populations, and Washington's share of the EPA Renewable Fuel Standard 2 biofuel volumes. Each of these topics is discussed below.

4.3.1 Fuel Price Assumptions

In this analysis, we utilized the VISION model fuel expenditure estimates as an input to the REMI economic modeling performed by Washington State OFM. The VISION model utilizes projections of fuel prices to calculate fuel expenditures. With the exception of biodiesel prices, the default fuel prices in the most recent version of VISION were from the U.S. Department of Energy, Energy Information Administration (EIA) 2009 Annual Energy Outlook (AEO2009). For our analysis, we updated the gasoline, diesel, ethanol and CNG retail prices with the AEO2010 Pacific Region fuel prices. The biodiesel and electricity prices were also modified as described in detail below.

Assumed Price Projections for Liquid Fuels

The following summarizes the retail fuel prices for gasoline, diesel, ethanol and biodiesel used in the LCFS Scenario Analysis. Figure 4-3 provides the prices on a $/MMBtu (HHV)[25] basis while Figure 4-4 provides the prices on a $/gal basis. The prices on a $/MMBtu basis are multiplied by the MMBtu of each fuel type consumed to determine fuel expenditures. The Motor Gasoline, Distillate and Ethanol prices are from DOE's EIA AEO2010 for the Pacific Region. The ethanol price provided by AEO2010 is for E85 – we have converted the E85 prices to a 100 percent ethanol basis. The ethanol price projections do not include extension of the ethanol blender's credit, however they do reflect RFS2 ethanol volumes and types, including ethanol produced from cellulosic feedstocks[26]. The distillate price is for diesel – no biodiesel is included in the distillate price.

Biodiesel prices are not projected by EIA; in VISION, the biodiesel price is set by an assumed fuel price in 2005. The biodiesel price in each subsequent year is adjusted based on the increase or decrease in diesel and CNG prices (whichever one changes more each year). The VISION default biodiesel price is approximately $0.65 cents higher than the diesel price in 2009, but by 2023, it is approximately $1.50 higher than diesel due to increases in CNG prices. Figure 4-5 provides the U.S. average biodiesel and diesel retail prices for the past five years. Biodiesel tracks fairly closely with diesel and is on average $0.63 per gallon higher than diesel. For the Scenario Analysis, we have adjusted the VISION biodiesel price to be a fixed $0.63 per gallon higher than the diesel price throughout the analysis period (reflected in Figures 4-3 and 4-4).

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[25] In our analysis, the VISION energy consumption values are in terms of lower heating value (LHV), so the fuel cost data in the model are converted from a higher heating value (HHV) basis to LHV basis. The fuel costs are shown here on an HHV basis as that is more customary.

[26] Conversation with Michael Cole 202-586-7209, EIA on Sept 20, 2010.

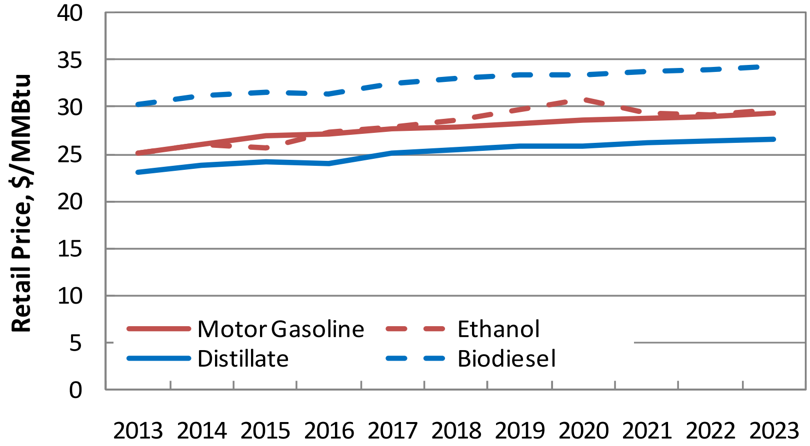

Figure 4-3. Fuel Price Projections Used in Scenario Analysis, Energy Basis

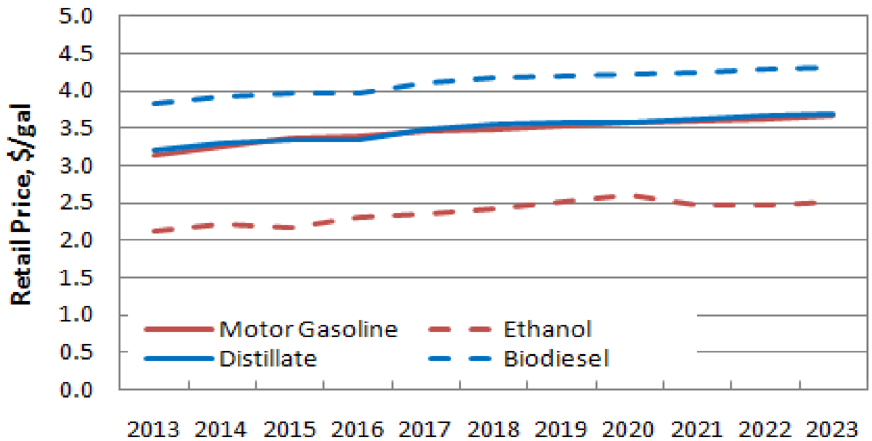

Figure 4-4. Fuel Price Projections used in Scenario Analysis, Volume Basis.

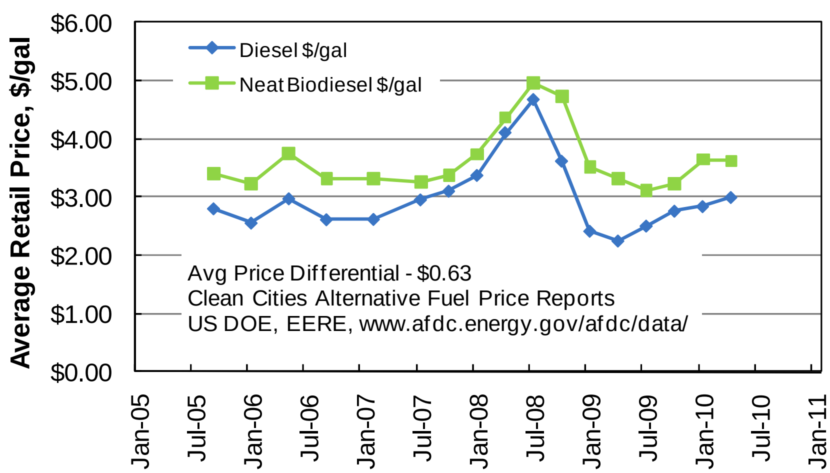

Figure 4-5. Historic diesel and biodiesel retail prices, 2005-2010.

Table 4-3 summarizes the liquid fuel retail prices utilized in the LCFS Scenario analysis. It is important to highlight that the ethanol prices utilized in this analysis do include the effects of RFS2 low carbon intensity ethanol volume requirements. This price was applied equally to all ethanol volumes, corn, sugarcane and cellulosic. However, if a LCFS were enacted, one concern is that to attract lower carbon ethanol into Washington, fuel providers would need to pay more and would pass this cost on to consumers. In the early years of a LCFS, needed volumes of low carbon ethanol are low, so any premium paid for ethanol in Washington would be minimal and spread over all the gallons of ethanol sold. In later years, although significant volumes of low carbon ethanol would be needed, EPA has estimated that production costs of low carbon ethanol in 2022 are actually lower than corn ethanol[27]. Therefore, for the reference cases, we assume that all ethanol has the same price.

Table 4-3. Liquid Fuel Prices Utilized for the LCFS Analysis (Reference Cases).

	Motor Gasoline		Ethanol		Diesel		Biodiesel	
	$/MMBtu	$/gal	$/MMBtu	$/gal	$/MMBtu	$/gal	$/MMBtu	$/gal
2013	25.1	3.14	25.1	2.13	23.0	3.20	30.3	3.83
2014	26.1	3.26	26.1	2.21	23.8	3.30	31.1	3.93
2015	26.9	3.36	25.7	2.18	24.1	3.34	31.5	3.97
2016	27.2	3.39	27.3	2.31	24.1	3.34	31.4	3.97
2017	27.7	3.46	27.8	2.36	25.1	3.48	32.5	4.11
2018	27.9	3.49	28.6	2.42	25.6	3.54	33.1	4.17
2019	28.2	3.52	29.8	2.52	25.8	3.57	33.3	4.20
2020	28.6	3.57	30.8	2.61	25.8	3.58	33.4	4.21
2021	28.7	3.59	29.3	2.48	26.1	3.62	33.7	4.25
2022	29.0	3.63	29.1	2.47	26.4	3.66	34.0	4.29
2023	29.3	3.67	29.7	2.52	26.6	3.69	34.2	4.32

Two sensitivity cases were run: a high petroleum price case and a high cellulosic biofuel price case. For the high petroleum prices, we used the AEO2010 high oil price projection, shown in Figure 4-6. For the high cellulosic ethanol prices, we utilized the incremental production cost estimated by EPA in the RFS2 RIA for cellulosic ethanol production over corn ethanol production in 2010. The incremental production cost is 0.64 $/gal.[28]

For the high cellulosic diesel price, we utilized the EPA RFS2 estimate for current cellulosic diesel production cost ($2.58 $/gal).[29] The current cost to produce soybean biodiesel ($2.10 per gallon) was taken from an EIA analysis[30], yielding an incremental production cost of 0.48 $/gal. This incremental production cost was added to our biodiesel prices and used for the high cellulosic diesel price. Figure 4-7 provides a comparison of the reference case and high biofuel sensitivity case prices.

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[27] EPA RFS2 Regulatory Impact Analysis, Chapter 4, Feb 2010.
[28] EPA RFS2 Regulatory Impact Analysis, Tables 4.1-24 and 4.1-27.
[29] EPA RFS2 Regulatory Impact Analysis, page 782.
[30] "Biofuels in the U.S. Tranportation Sector", 10/15, 2007, http://www.eia.doe.gov/oiaf/analysispaper/biomass.html

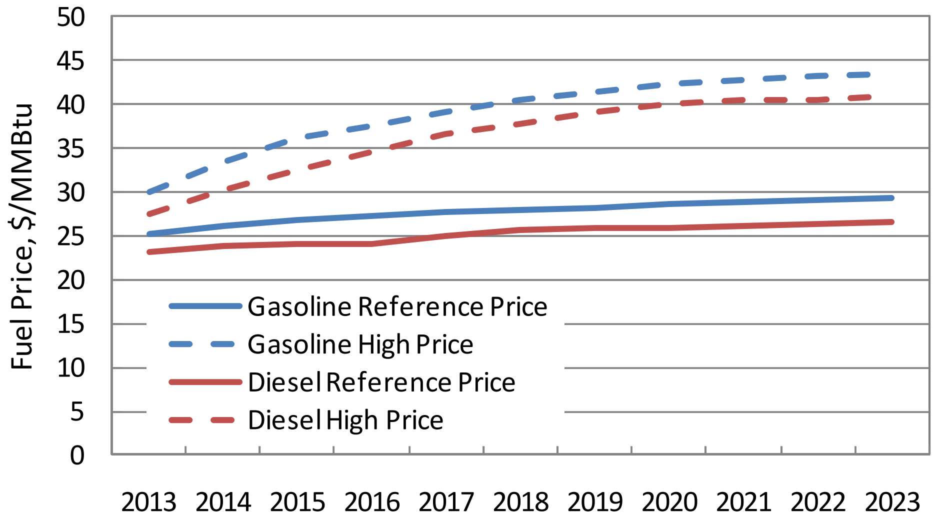

Figure 4-6. Comparison of Reference and High Petroleum Price Sensitivity Cases.

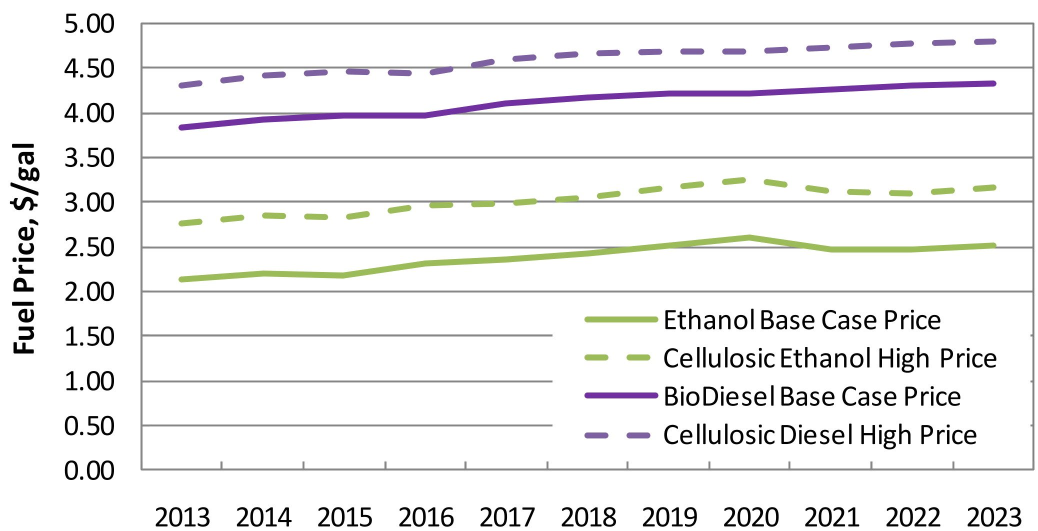

Figure 4-7. Comparison of Reference and High Cellulosic Biofuel Price Sensitivity Cases.

Assumed Electricity Price Projection

Washington State enjoys some of the lowest electricity prices in the country. Figure 4-8 shows the difference between historic electricity retail prices for Washington and the U.S. average. Figure 4-9 provides the ratio of Washington retail prices to U.S. average retail electricity prices. For the VISION modeling, we have applied a factor of 0.72 to the AEO2010 U.S. average electricity projection. A factor of 72 percent is more conservative than the transportation fuel price ratio of 67 percent. Figure 4-10 provides the AEO2010 and factored Washington electricity prices.

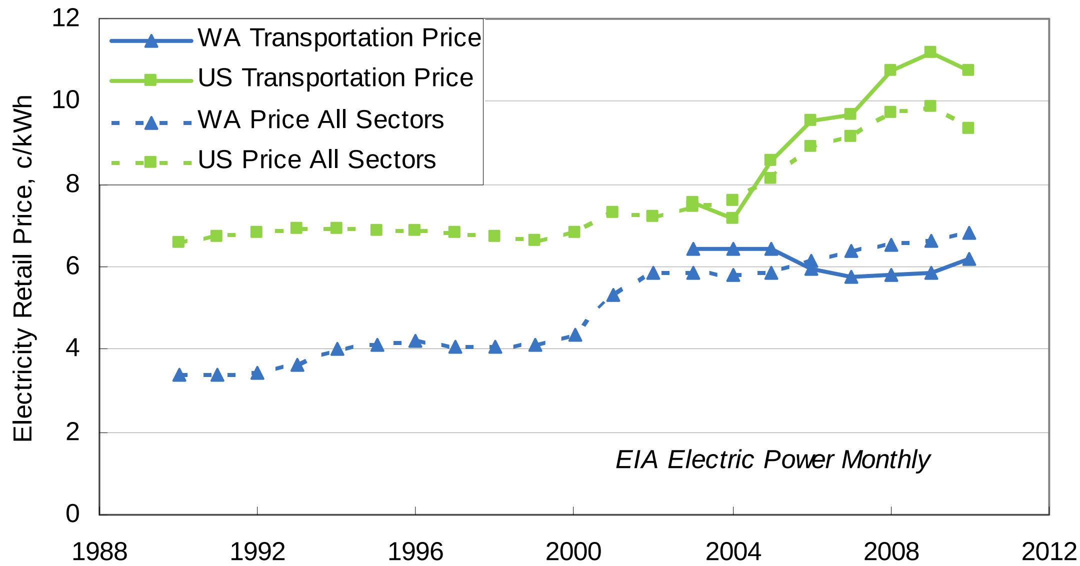

Figure 4-8. Comparison of Historic Washington and U.S. Average Retail Electricity Prices.

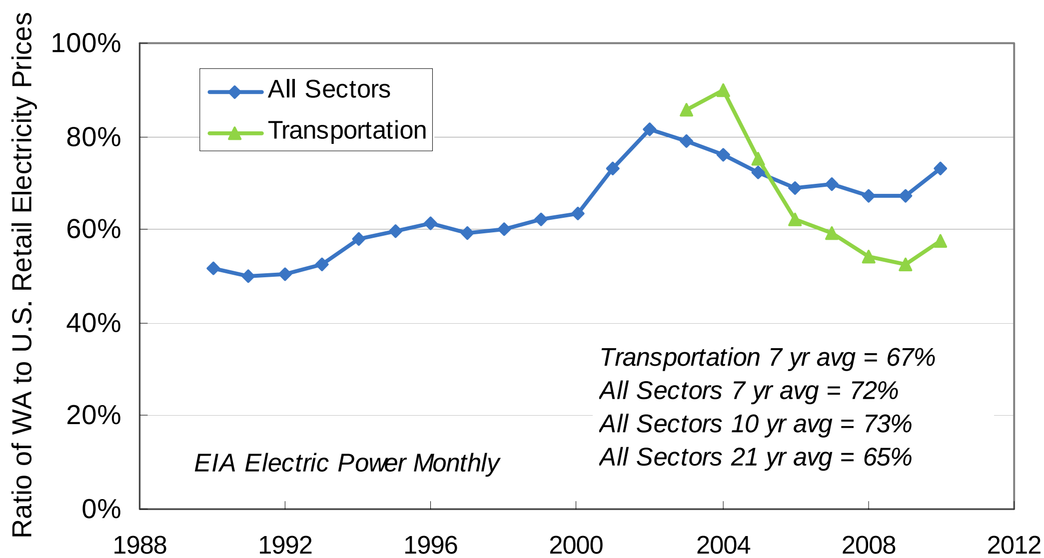

Figure 4-9. Ratio of Historic Washington to U.S. Average Retail Electricity Prices.

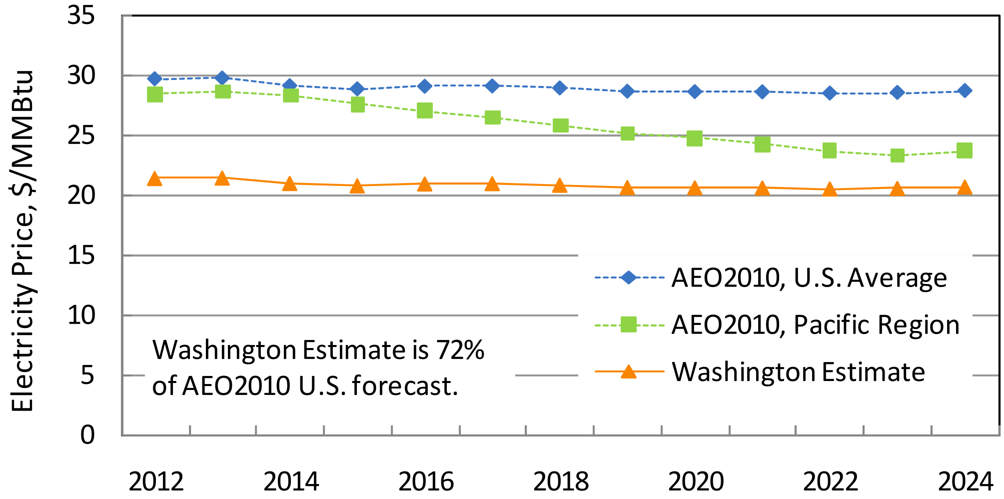

Figure 4-10. Projected Washington (calculated), Pacific, and U.S. Average Retail Electricity Prices.

Assumed CNG Price Projection

Figure 4-11 provides the EIA projections for natural gas prices used in the transportation sector. As can be seen, the Pacific Region prices are lower than the U.S. average prices and are quite stable at approximately 11 $/MMBtu. The Pacific Region prices were used in this analysis.

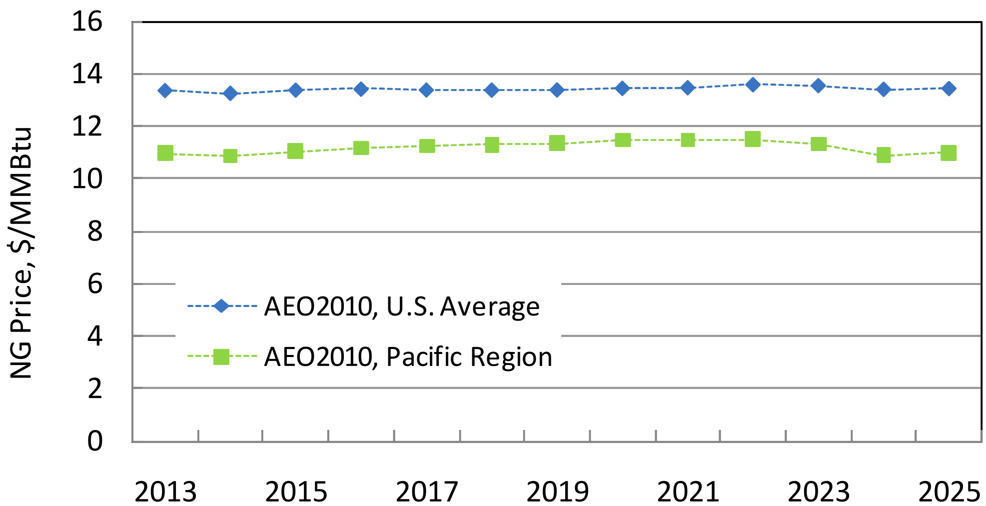

Figure 4-11. AEO2010 Transportation Natural Gas Retail Prices.

4.3.2 Vehicle Price Assumptions

For alternative fuel vehicle prices, VISION uses an incremental cost on top of the base vehicle price. The default values in VISION for incremental consumer cost for light duty autos and light duty trucks are provided in Figures 4-12 and 4-13. Note that the EV incremental cost (~$15,000) is consistent with the Nissan Leaf price relative to a higher end Nissan Versa. The one modification that has been made to the default vehicle prices is to subtract out the sales tax exemption for CNG and pure electric vehicles through July 2015. Also, since VISION did not have heavy duty CNG vehicles, the incremental price assumed for HD CNG vehicles is $75,000 based on the Cummins Westport ILS G CNG engine. For medium duty CNG vehicles, we assumed an incremental price of $42,000.

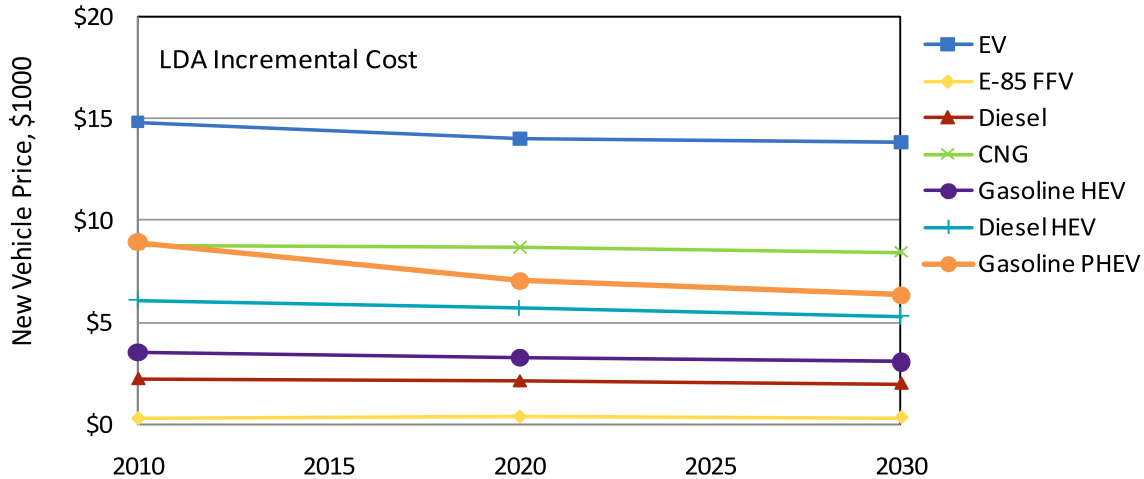

Figure 4-12. Light Duty Auto Incremental Vehicle Prices.

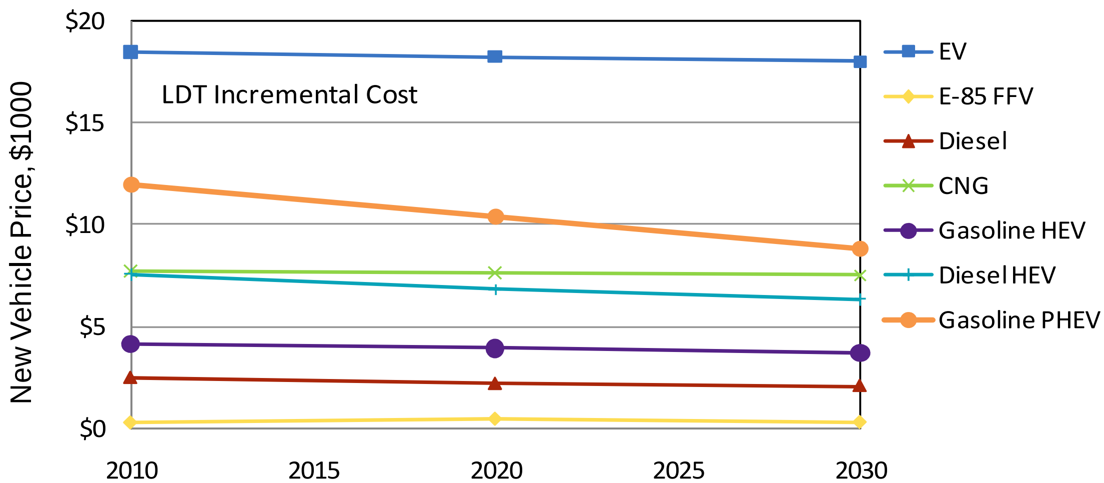

Figure 4-13. Light Duty Truck Incremental Vehicle Prices.

4.3.3 Fuel Economy Assumptions

Another key VISION input is vehicle fuel economy; the fuel economy assumption coupled with the VMT dictates the fuel volumes consumed each year by each vehicle class. Figures 4-14 and 4-15 provide the default fuel economy assumptions in miles per gallon of gasoline equivalent (mi/gge). TIAX adjusted the fuel economy assumptions for light duty electric, CNG and diesel vehicles. These adjustments are explained below.

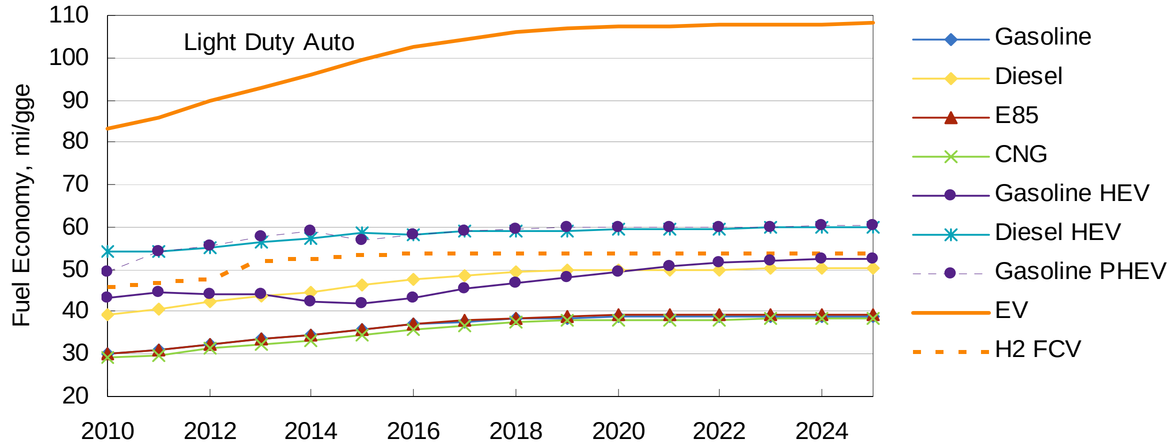

Figure 4-14. VISION Default Fuel Economy Values for New Light New Autos

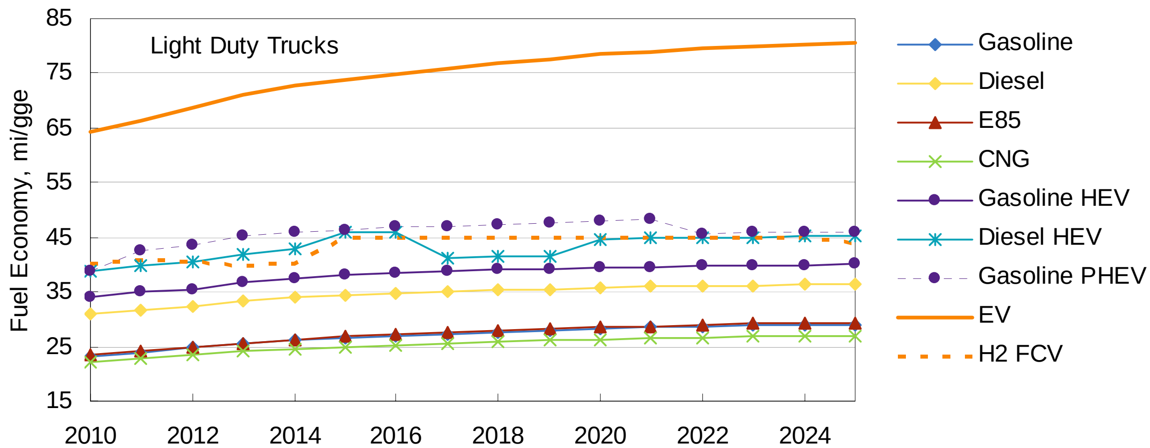

Figure 4-15. VISION Default Fuel Economy Values for New Light Duty Trucks.

In the VISION model, the fuel economy for light duty gasoline vehicles (autos and light trucks) is forecast in miles per gallon of gasoline consumed. The fuel economy for each of the alternative fuel vehicles is equal to the gasoline vehicle fuel economy multiplied by the Energy Economy Ratio (EER). EER is defined as the fuel economy of the alternative fuel vehicle (mi/gge) divided by the fuel economy of the gasoline vehicle.

Not only are the EERs used to calculate alternative fuel vehicle efficiency, they are also used to scale the carbon intensity values. For example, the unadjusted carbon intensity for electricity is 68, but when adjusted with an EER of 4.1, the electricity carbon intensity is 17 g/MJ. CARB does not utilize an EER for light duty diesel vehicles since diesel and gasoline have separate standards. Therefore, for the compliance scenarios that separate diesel from gasoline, the EER will NOT be applied to the diesel consumed by light duty vehicles. For Washington's one pool scenarios, the EER is used to adjust the diesel carbon intensity for the portion of the diesel fuel consumed by light duty vehicles, since light duty diesel substitutes for gasoline.

Table 4-4 compares the VISION and CARB LCFS EER values as well as the EER values utilized in this analysis for light duty electric vehicles. The EER analysis provided in Appendix C of CARB's LCFS Proposal[31] includes estimates of current and future vehicle fuel economies for gasoline and electric vehicles in terms of mi/gge. In their analysis, CARB determined that the present EV fuel economy is 1.0 MJ/mi and the current equivalent gasoline vehicle fuel economy is 29 mpg. The EV fuel economy value is equivalent to 119 mi/gge (if the GREET default for CA RFG lower heating value is used), resulting in an EER of 3.1. CARB has selected an EV EER value of 3.0.

Table 4-4. EV and PHEV Vehicle Fuel Economy Assumptions

		VISION Defaults	California Air Resources Board LCFS	Assumption for Washington Analysis
Light Duty Gasoline Vehicle				
2010	mi/gal	30.0	29	30.0
2020	mi/gal	38.8	38	x
2023	mi/gal	38.9	x	38.9
Light Duty EV Fuel Economy				
2010	MJ/mi		1.0	1.0
2010	mi/gge	83	119[1]	122[2]
2020/2023	mi/gge	108	119[1]	122[2]
Light Duty PHEV/EV EER				
2010		2.8	4.2	4.1
2020/2023		2.8	3.1[3]	3.1

1. Converted to gge basis using GREET default LHV for CARFG 113,927 Btu/gal.
2. Converted to gge basis using GREET default LHV for conventional gasoline of 116,090 Btu/gal.
3. CARB EER is 3.0 – to get this result with 38 mpg base vehicle, the LHV for CA RFG must be 108,000 Btu/gal.

For the Washington analysis, we convert CARB's 1.0 MJ/mi value to a mi/gge basis using the GREET default LHV for conventional (as opposed to reformulated) gasoline, resulting in an EV fuel economy of 122 mi/gge. The resulting EER values for 2010 and 2023 are 4.1 and 3.1; the EER schedule from 2010 to 2023 is assumed to be linear. The same EERs are also applied to light duty trucks; the gasoline LDT reference fuel economies are 23 mi/gal in 2010 and 29 mi/gal in 2023. These EV EERs are applied to the electric portion of PHEV operation as well.

Table 4-5, shows the adjustments made to the light-duty diesel EER value. Light duty gasoline vehicles will undergo significant fuel economy improvement through 2018 due to the recently increased CAFE standards. VISION assumes a constant EER of 1.3 for light duty diesel vehicles; this means that light duty diesel vehicle fuel economy will improve linearly with gasoline vehicle fuel economy through 2018. In contrast to gasoline engines, there are no significant opportunities to improve light duty diesel vehicle efficiency on the horizon. Moreover, there is

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[31] "Proposed Regulation to Implement the Low Carbon Fuel Standard", Volume II Appendices, March 5, 2009.

Table 4-5. Light Duty Diesel and CNG Vehicle Fuel Economy Assumptions

		VISION Defaults	California Air Resources Board LCFS	Assumption for Washington Analysis
Light Duty Gasoline Vehicle				
2010	mi/gal	30.0	29	30.0
2020	mi/gal	38.8	38	x
2023	mi/gal	38.9	x	38.9
Light Duty Diesel Fuel Economy				
2010	mi/gge	39.0	n/a	39.0
2023	mi/gge	50.2		42.8
Light Duty Diesel EER				
2010		1.3	n/a	1.3
2020/2023		1.3	n/a	1.1
Light Duty Auto CNG EER		0.97	1.0	1.0
Light Duty Truck CNG EER		0.94	1.0	1.0
Medium/Heavy CNG EER		n/a	0.90	0.90

1. Converted to gge basis using GREET default LHV for CARFG 113,927 Btu/gal.
2. Converted to gge basis using GREET default LHV for conventional gasoline of 116,090 Btu/gal.
3. CARB EER is 3.0 – to get this result with 38 mpg base vehicle, the LHV for CA RFG must be 108,000 Btu/gal.

no regulatory need to improve light duty diesel fuel economy. Therefore, TIAX assumes a light duty diesel EER of 1.3 in 2010, decreasing linearly to 1.1 in 2018, resulting in a fuel economy of 42.8 mi/gal in 2023 rather than VISION's default of 50.2 mi/gal.

Finally, the default EER for light duty CNG vehicles was increased from 0.97 to 1.0 based on reported Honda Civic CNG fuel economy. VISION does not include MD/HD CNG vehicles. TIAX added these vehicles to VISION and specified an EER of 0.90 based on results from the Cummins Westport ILS G engine. Both of these assumptions are consistent with CARB values.

Figure 4-16 summarizes the light duty vehicle fuel economy values utilized in the analysis. The PHEV fuel economy includes the EV fuel economy for the electric portion and the HEV fuel economy for the gasoline portion. The VISION model increases the electric share of PHEV mileage from 17.4 percent in 2010 to 33.7 percent in 2020, presumably due to improvements in battery technology. This leads to an overall increase in PHEV efficiency over this time period.

The VISION default fuel economy assumptions for new medium and heavy duty vehicles are provided in Figure 4-17. Note that the heavy duty diesel vehicles have ~18 percent fuel economy improvement over the analysis period. This improvement presumably includes SmartWay program type improvements plus electric and hydraulic hybridization of the fleet. TIAX utilized these default values in the analysis.

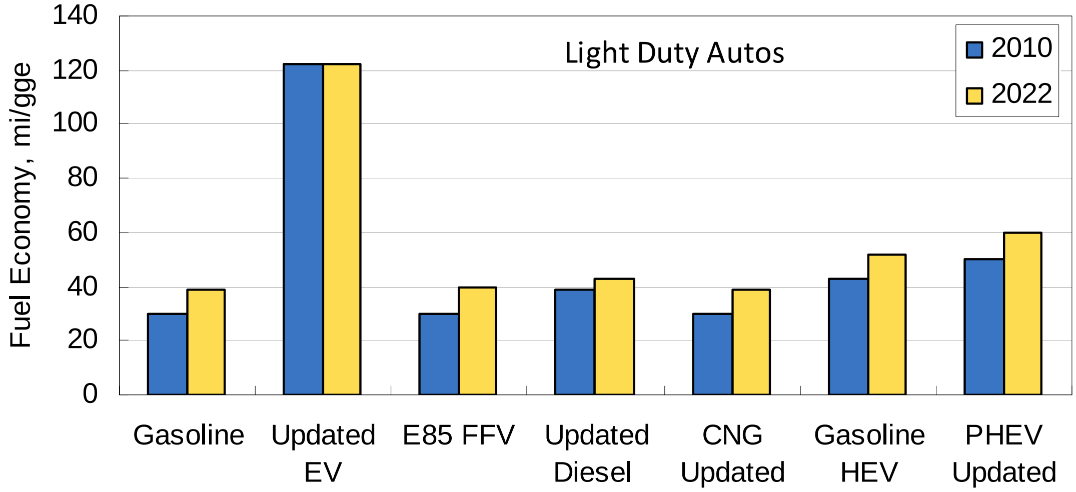

Figure 4-16. Light Duty Auto Fuel Economy Values Used in the Analysis.

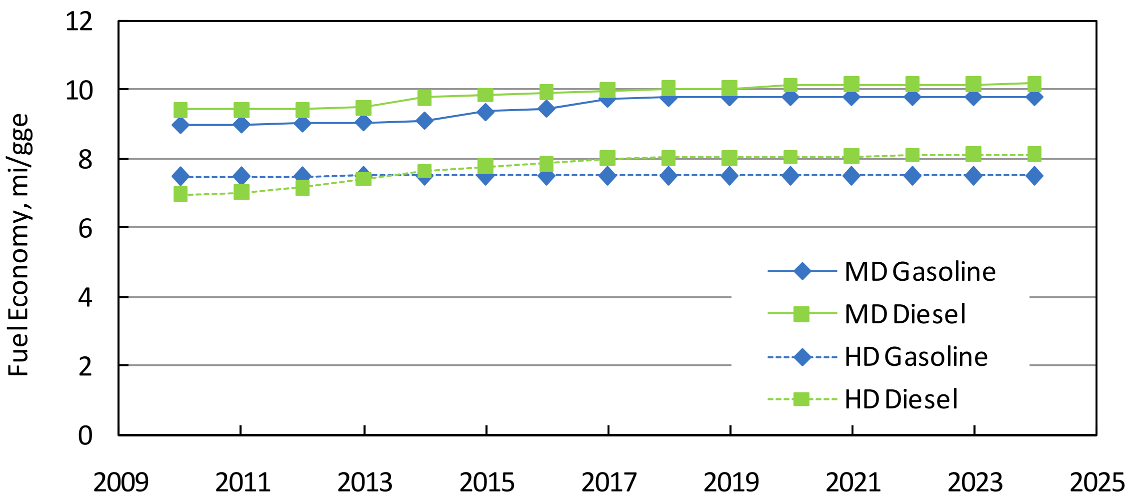

Figure 4-17. VISION Default Fuel Economy Values for New Medium and Heavy Duty Vehicles.

4.3.4 Vehicle Miles Traveled Assumptions

Another key input to the VISION model is annual vehicle miles traveled (VMT). Washington State legislature passed House Bill 2815 in 2008 to establish a statewide VMT reduction goal for light duty vehicles. Washington Department of Transportation has recently updated their VMT modeling tool; the VMT inputs to VISION by class are based on the updated forecast from DOT. In our modeling we assume it takes a number of years for VMT reduction strategies to have any effect. Consequently in order to reach the 2023 VMT value consistent with hitting the 2020 goal, we start the VMT reductions in 2018. The values used in the scenario analysis are provided in Figure 4-18. Also shown for comparison are the VISION defaults scaled to Washington State.

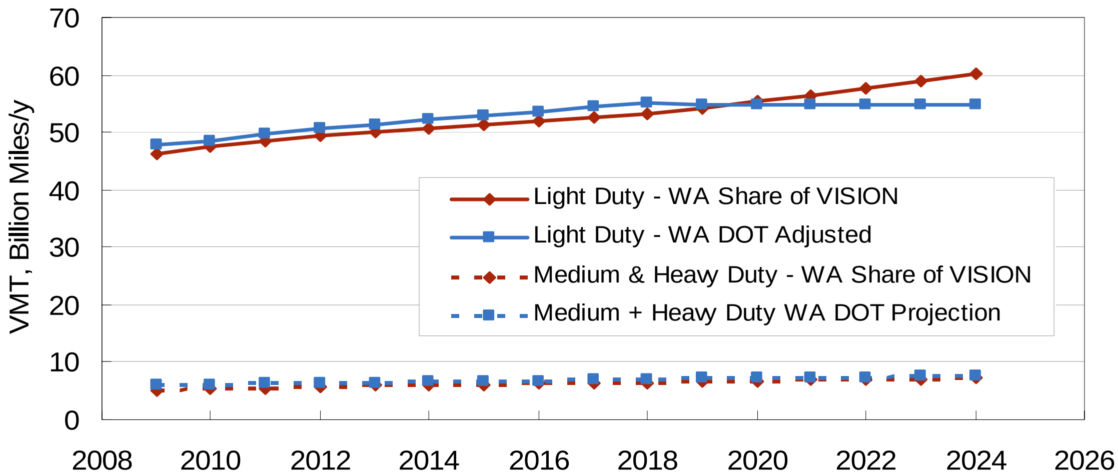

Figure 4-18. Comparison of Washington Scaled VISION and projected Washington State VMT.

4.3.5 Vehicle Population Assumptions

The Washington BAU vehicle population was estimated by: scaling the VISION legacy fleet population (1978-2009), scaling the future sales of vehicles in each class, adjusting the plug-in electric vehicle market share, adjusting the VISION split of plug-in vehicles between EVs and PHEVs, and adding light duty CNG vehicles. Each of these topics is discussed below.

Scaling U.S. Vehicle Populations to Washington State

Because the VISION model was constructed for the United States, the vehicle population estimates (both historic and projected future populations) were scaled down to Washington State. For the legacy fleet, the 1978-2009 Washington vehicle registration data from the Department of Licensing were utilized in conjunction with the VISION turnover and retirement assumptions. To project future vehicle populations, the AEO 2009 U.S. vehicle sales projections were scaled by applying a multi-year (2005-2009) average ratio of Washington new car sales to U.S. new car sales for each vehicle class. These ratios are provided in Table 4-6.

Table 4-6. Washington State Share of U.S. New Vehicle Sales by Vehicle Class.

	Washington Share of U.S. New Vehicle Sales
Light Duty Autos	1.7%
Light Duty Trucks	1.9%
Medium Duty Vehicles	5.5%
Heavy Duty Vehicles	0.9%

Adjusting PHEV/EV Populations

TIAX assumed that the annual increase in plug-in vehicle (both PHEVs and EVs) market share would be twice the U.S. average value in VISION. This is consistent with the hybrid electric vehicle (HEV) market share in Washington compared to U.S. average market share

(Figure 4-19). Independent of these growth rates, we also added a one time sale of 1000 EVs in 2011 as a result of The EV Project[32].

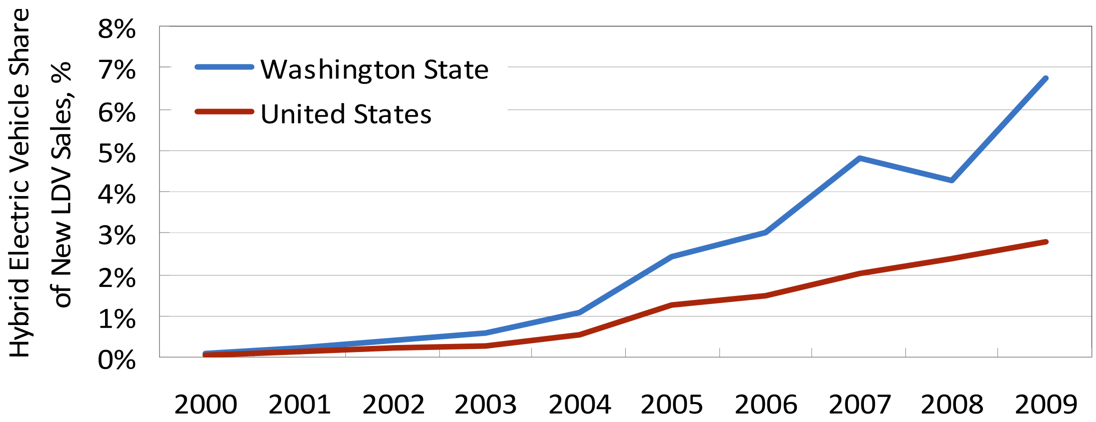

Figure 4-19. Ratio of light duty hybrid electric vehicle sales to total light duty vehicle sales for Washington State and the United States.

One additional adjustment to the PHEV and EV populations was made. The VISION model assumes that very few of the plug-in vehicles sold are BEVs. For example, in 2023, only 1 percent of the light duty plug-in vehicles sold are assumed to be BEVs. Recent projections[33] show a range of BEV share relative to total plug-in vehicle market share in 2020 from 10 percent to 50 percent. We have therefore increased the BEV share of the plug-in vehicle sales to a ratio of 1:6 for EV to PHEV (approximately 14 percent of the total plug-ins sold each year are BEVs) vs. the VISION default of 1 percent. Table 4-7 summarizes the BAU EV and PHEV vehicle market share assumptions and the resulting fleet share and populations in 2023.

Table 4-7. BAU EV and PHEV 2023 Populations and Market Shares.

	Light Duty Autos	Light Duty Trucks	Total Light Duty Vehicles
2023 PHEV Market Share	3.73%	0.99%	2.59%
2023 EV Market Share	0.62%	0.16%	0.45%
2023 PHEV Population	59,421	11,962	71,383
2023 EV Population	10,777	1,995	11,773
2023 Total Vehicle Population	2,606,576	2,256,291	4,862,866
2023 PHEV Fleet Share	2.28%	0.53%	1.47%
2023 EV Fleet Share	0.41%	0.09%	0.26%

[32] The EV Project is an American Recovery and Reinvestment Act (ARRA) project in which 4700 Nissan Leafs will be sold with free home chargers in five U.S. cities including Seattle. Seattle will receive ~ 1/5 of the vehicles.
[33] Results provided by Washington Department of Ecology

Addition of CNG Vehicles

The VISION model does not include CNG medium and heavy duty vehicles. TIAX added Washington's share of the AEO2009 CNG medium and heavy duty vehicles to the model. The CNG vehicle 2023 market share and populations are provided in Table 4-8.

Table 4-8. BAU CNG Vehicle 2023 Populations and Market Shares.

	Light Duty	Medium Duty	Heavy Duty
2023 Market Share	0.06%	6.09%	1.91%
2023 Population	2,546	7,859	1,180

BAU Vehicle Population Summary

The resulting BAU light duty vehicle populations are provided in Figure 4-20; the medium and heavy duty populations are shown in Figure 4-21. The projected 2023 populations are provided in Table 4-9.

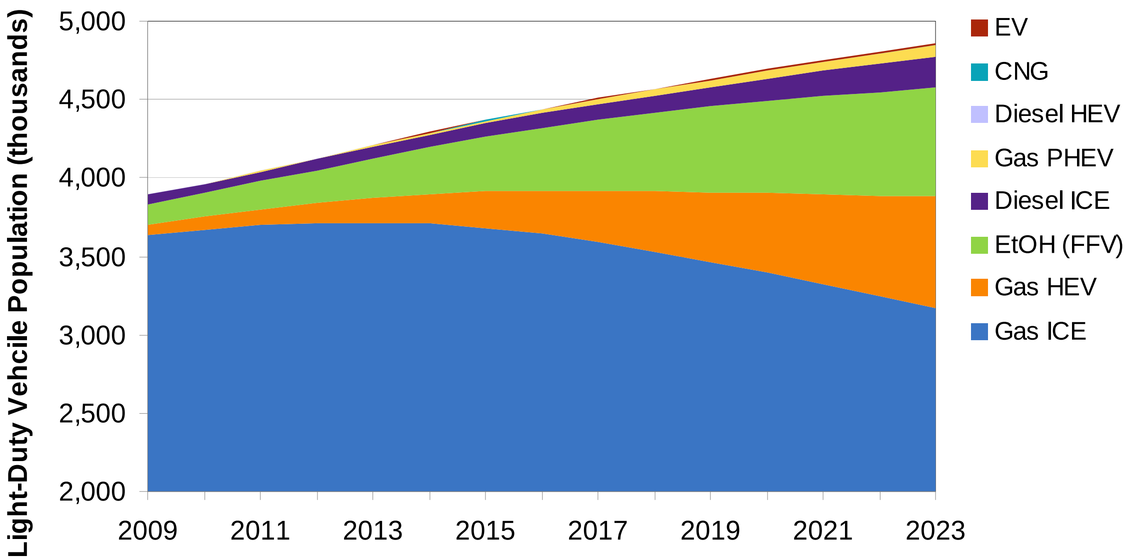

Figure 4-20. Projected BAU light duty vehicle populations.

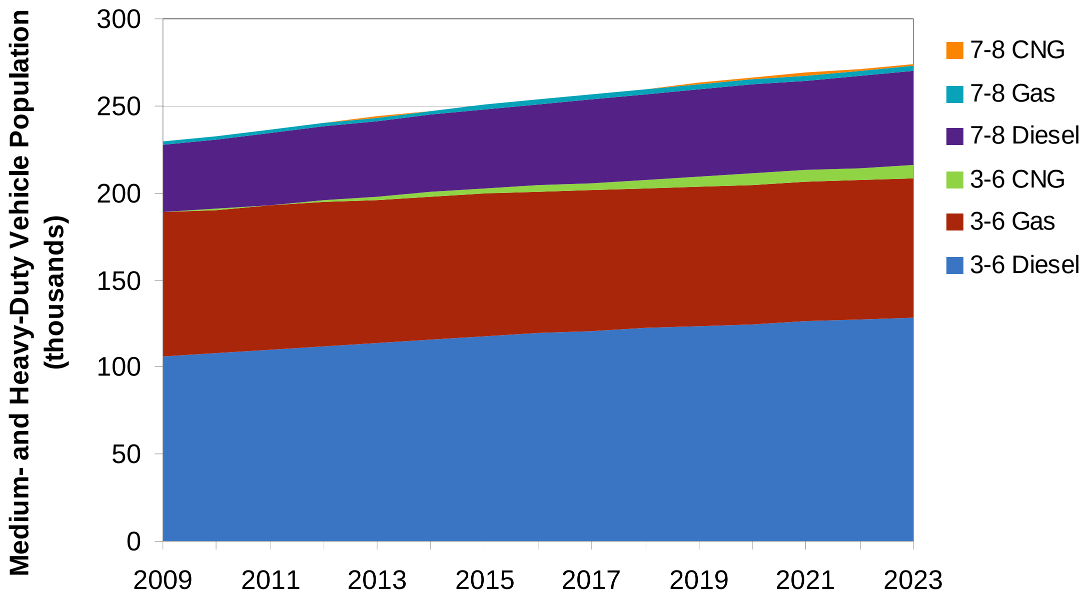

Figure 4-21. Projected BAU medium and heavy duty vehicle populations.

Table 4-9. Projected 2023 Business-As-Usual Vehicle Populations

	Light Duty	Medium Duty (Class 3-6)	Heavy Duty (Class 7-8)
Electric Vehicles (EVs)	11,773		
Compressed Natural Gas (CNG)	2,546	7,859	1,180
Diesel Hybrid Electric Vehicle (HEV)	3,328		
Gasoline Plug-in Hybrid (PHEV)	71,383		
Diesel Internal Combustion Engine (ICE)	199,276	128,436	53,763
E85 Flex Fuel Vehicle (FFV)	688,316		
Gasoline Hybrid Electric Vehicle (HEV)	719,813		
Gasoline Internal Combustion Engine (ICE)	3,165,431	79,818	3,054
Total Vehicles, 2023	4,862,866	360,751	57,997

We note here that VISION projects a total light duty population of 4.9 million vehicles in 2023. This is lower than current vehicle registrations in Washington (5.2 million) and projected registrations in 2023 of 6 million. Despite using Washington historic sales data, the VISION model has a faster vehicle turnover rate than Washington registrations indicate. However, because the total vehicle sales each year are accurate and because the total VMT is accurate, the vehicle expenditures and fuel consumption (and therefore carbon intensity) calculated by the model are accurate.

Finally, to verify that the vehicle sales, turnover rate, and VMT assumptions yield accurate fuel consumption estimates, Figures 4-22 and 4-23 compare the VISION predicted fuel consumption to actual[34] fuel consumption for gasoline and diesel, respectively. The VISION model accurately predicts gasoline fuel consumption over the past four years where data is available. The model underestimates diesel consumption, likely due to pass-through trucks, so the fuel consumption rates have been adjusted to ensure that diesel consumption is accurate.

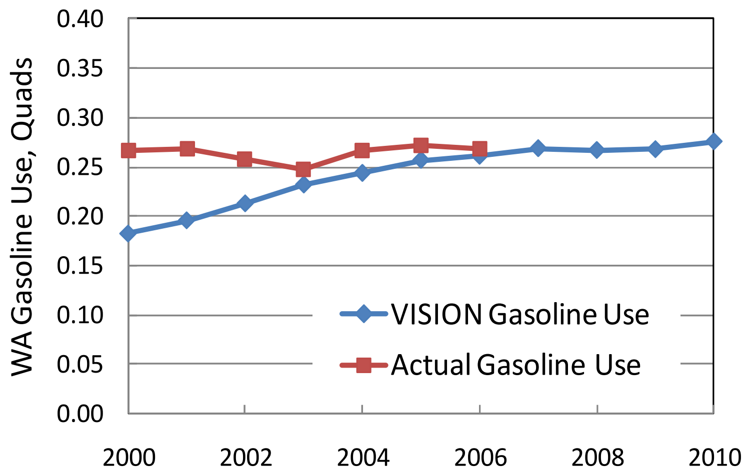

Figure 4-22. Comparison of Historic Gasoline Use (EIA) to VISION Gasoline Use.

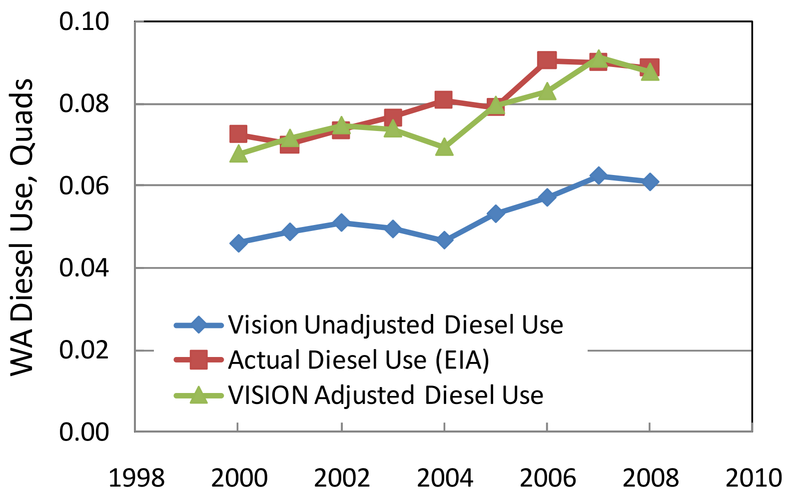

Figure 4-23. Comparison of Historic Diesel Use (EIA) to VISION Diesel Use.

[34] U.S. DOE's Energy Information Administration (EIA) State on-road fuel consumption data.

5. Compliance Scenarios Considered

If Washington State were to implement a LCFS, it would consist of a required percent reduction in average fuel carbon intensity each year over ten years, so that the target percent reduction is achieved in 2023 relative to the baseline year (2013) carbon intensity. The standard might be structured such that gasoline and fuels substituting for gasoline must achieve the required reduction independently from diesel and fuels substituting for diesel. Alternatively, the standard could simply require a reduction in the overall pool of fuels, a “one pool” approach.

To evaluate the economic impact of implementing a LCFS in Washington State, a variety of compliance scenarios are considered. The scenarios are intended to bracket not only the feasible range of potential compliance options, but also the compliance options for the two different implementation approaches: one pool or separate standards for gasoline and diesel. Each compliance scenario assumes a different method of compliance to bracket the range of possible outcomes (e.g. use of cellulosic biofuels, use conventional biofuels, higher penetration rate of electric vehicles etc.). For each scenario, the quantity of each fuel type consumed each year is determined by the required carbon intensity reduction. The VISION model outputs are consumer fuel expenditures, consumer vehicle expenditures and expenditures on infrastructure. These outputs are used in the REMI economic modeling to forecast impacts on employment, personal income, and gross state product. This section of the report provides the VISION outputs for each scenario that were utilized in the REMI modeling.

It is important to note here that because we are uncertain of the exact route to compliance, our modeling methodology considered a number of different scenarios that bracket the range of possible outcomes. This contrasts with an alternative methodology of setting fuel and vehicle prices and modeling consumer behavior in response to these price signals. Predicting consumer behavior is uncertain, so our approach of evaluating a number of different outcomes is a more robust methodology. In addition, we did not model a market failure scenario. Ecology believes that there is ample evidence supporting the assumption that advanced vehicles and fuels are well on their way to commercial status and will be available by the time they are needed for compliance with a LCFS in Washington.

The following compliance scenario elements were combined into six full compliance scenarios for OFM REMI evaluation: five (5) gasoline compliance scenarios, three (3) diesel compliance scenarios and two (2) one pool compliance scenarios. In addition to the compliance scenarios, a business-as-usual (BAU) case was run for comparison. The following paragraphs describe the BAU case and each of the compliance scenario elements.

5.1 Business-As-Usual

One key assumption for the BAU case is how much of the renewable fuel volumes stipulated by the Federal Renewable Fuel Standard 2 (RFS2) will be consumed in Washington. For reference, the RFS2 minimum volumes for the United States as a whole are provided in Table 5-1. Also shown are the volumes of specific fuel categories in EPA’s “Primary Control Case”.

Table 5-1. RFS2 Total Volume Requirements and EPA's Primary Control Case.

RFS2 Volume Requirements	% GHG Reduction	Billion Gallons/yr (2022)			
		Minimum Volume Requirement		EPA Analysis Primary Control Case	
		Ethanol Equivalent	Actual Volumes	Ethanol Equivalent	Actual Volumes
Total Renewable Fuel		36		36	34.5
Total Advanced Biofuel		21		21	15
Cellulosic Biofuel	60%	16		16	11
Cellulosic Ethanol				4.9	4.9
Cellulosic Diesel				11.1	6.5
Biomass-based Diesel	50%		1	1.5	1.0
Biodiesel (fame)				1.28	0.85
Renewable Diesel				0.26	0.15
Other Advanced Biofuel	50%			3.47	3.06
Brazilian Sugarcane Ethanol				2.24	2.24
Other Biodiesel				1.23	0.82
Renewable Fuel	**20%**	15		15	15
Total Ethanol				22.1	22.1
Total Biodiesel				13.9	8.3

As a reference, TIAX estimated Washington's proportionate share of the U.S. RFS2 volume requirements in 2022. Ideally, a ratio of projected 2022 total fuel consumption in Washington to that of the United States would be used to scale the RFS2 volumes. However, EIA's Annual Energy Outlook does not project this for individual states. We do have VISION model projections of 2022 on-road fuel consumption for the U.S. and Washington State, but this omits non-road fuel consumption. Since the non-road fuel consumption is mainly distillate, we compare historic ratios of on-road distillate sales to total distillate sales for the U.S. and Washington State in Figure 5-1.

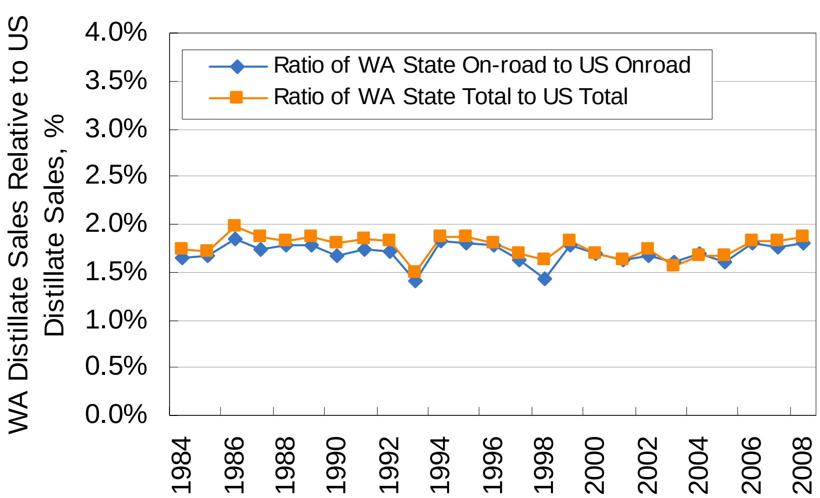

Figure 5-1. Comparison of historic ratios Washington fuel consumption to U.S. fuel consumption.

Since Washington's share of on-road fuel consumption tracks closely with its share of total fuel consumption, we conclude that the ratio of projected 2022 on-road fuel consumption for Washington and the U.S. is a good surrogate for total fuel consumption. Therefore, we have scaled the RFS2 volumes using the projected 2022 shares of on-road fuel consumption from the VISION model. The Washington shares of U.S. gasoline and diesel fuel consumption are 1.8% and 1.5%, respectively. The resulting Washington State shares of the RFS2 required volumes and primary control case volumes are provided in Table 5-2. For the scenario analysis exercise, TIAX has increased the VISION diesel use by 14 percent to account for nonroad consumption[35].

Table 5-2. Estimated Washington Proportionate Shares of RFS2 Volumes.

Washington Proportionate Share of RFS2 Volumes	% GHG Reduction	Million Gallons/yr (2022)			
		Minimum Volume Requirement		EPA Analysis Primary Control Case	
		Ethanol Equivalent	Actual Volumes	Ethanol Equivalent	Actual Volumes
Total Renewable Fuel		578		578	487
Total Advanced Biofuel		344		344	253
Cellulosic Biofuel	60%	260		260	186
Cellulosic Ethanol				80	80
Cellulosic Diesel				180	105
Biomass-based Diesel	50%		18	27	18
Biodiesel (fame)				23	15
Renewable Diesel				4	3
Other Advanced Biofuel	50%			56	49
Brazilian Sugarcane Ethanol				35	35
Other Biodiesel				21	14
Renewable Fuel	**20%**	235		235	235
Total Ethanol				350	350
Total Biodistillates				228	137

These volumes are only provided as a reference – there is no requirement for fuel providers to actually deliver Washington State its proportionate share of RFS2 volumes. RFS2 obligated parties (petroleum refiners and gasoline/diesel importers) may comply with the volume requirements on a company wide basis, e.g. a refiner with operations in 30 states could choose to provide all the required volume in only 10 of those states. In the absence of an LCFS, it is unlikely that Washington fuel providers would invest in the infrastructure required to sell E85. Moreover, the majority of low carbon biofuels will be consumed in the states that have an LCFS, leaving the higher carbon biofuels for the other states. With 11 Northeast and 10 Midwest states considering LCFS in addition to Oregon and California, the low carbon fuels will have a market.

For the BAU case (no LCFS in Washington), the following assumptions regarding biofuel consumption have been made:

[35] http://tonto.eia.doe.gov/dnav/pet/pet_cons_821dsta_dcu_swa_a.htm EIA "Washington Adjusted Sales of Distillate Fuel Oil by End Use". Includes 75% of EIA's off-highway category, 25% of railroad, and 50% of vessel bunkering.

- EPA increases the amount of ethanol that can be blended into gasoline to 15 percent after 2014.
- Each year, Washington consumes its proportionate share of ethanol up to the E15 blendwall
    - No E85 is consumed
    - Washington will continue to consume half of the corn ethanol from the Boardman plant (40 MGY)
    - Washington will consume 20 percent of the ethanol from the Clatskanie OR plant (108 MGY) beginning in 2012 (based on relative population between Portland and Vancouver).
    - The balance of ethanol will be Midwest average corn ethanol (with the carbon intensity decreasing over time)
  - Washington maintains its 0.6 percent biodiesel consumption rate, assumed to be derived from waste oils.

Figure 5-2 compares the impact of these BAU biofuel consumption assumptions to the RFS2 proportionate shares. One of the metrics used in the figure is flex fuel vehicle vehicle miles traveled using E85 (E85 FFV VMT). The amount of ethanol needed in each scenario is determined by ethanol types and quantities. Scenarios in which the ethanol carbon intensity is low result in lower quantities of ethanol consumption to meet the standard. In contrast, scenarios with higher carbon intensity ethanol will require consumption of larger volumes of ethanol to comply with the standard. Ethanol can be consumed as a low level blend in motor gasoline (up to 15 percent by volume here). If the amount of ethanol needed for compliance is greater than what can be consumed as a low level blend, then the ethanol must be consumed as E85. E85 can only be utilized in FFVs, so the metric used here to indicate the amount of ethanol consumed as E85 is the share of the FFV VMT that utilizes E85 rather than motor gasoline. In all scenarios, we kept the FFV population at the VISION default levels.

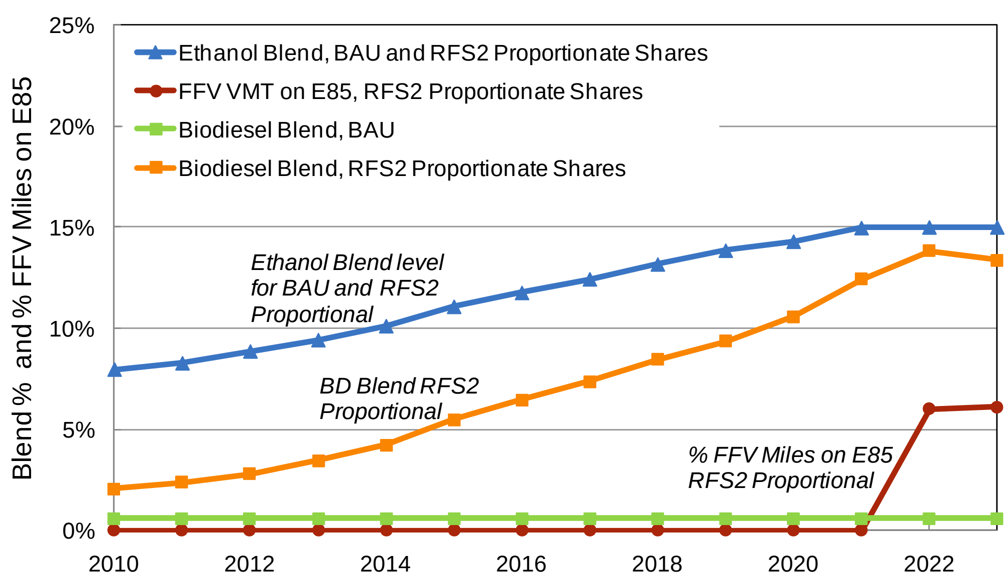

Figure 5-2. Projection of biofuel blends and percent of miles driven on E85 by the FFV fleet for BAU and Washington's proportionate share of the RFS2 Primary Control Case.

Figure 5-2 shows that ethanol consumption increases steadily through 2020 for both the BAU and the RFS2 proportionate share cases, but only as a blend component in gasoline. In 2020, Washington hits the E15 blendwall, so in the BAU case, the ethanol consumption (as a percent of gasoline) does not increase after 2020. If the RFS2 proportionate share of ethanol were to be consumed in 2020 and beyond, then the amount of E85 consumed has to increase; the figure indicates that FFV E85 VMT increases beginning in 2020 for the proportionate share case to approximately 6 percent of the FFV miles by 2023. The FFV VMT in the BAU is constant at zero since we assume that no E85 will be sold during the analysis period without an LCFS.

Washington's proportionate share of RFS2 biodistillate volumes is 105 million gal/yr of cellulosic biodiesel and 32 million gallons of conventional biodiesel. Washington State currently has biodiesel production capacity of 141 million gal/yr, including 23 million gal/yr from waste oils. Less than 3 million gal/yr is currently consumed. In the absence of a LCFS, we assume that this level of biodiesel consumption (0.6 percent blend) will continue. In contrast, if Washington were to consume its proportionate share of biodiesel fuels projected in EPA's RFS2 Primary Control Case, then the blend level would increase to 15 percent by 2022.

Figure 5-3 compares the 2022 biofuel volumes consumed in the BAU case and Washington's proportionate share of the RFS2 Primary Control Case. Approximately one third less renewable fuel is consumed in the BAU case, and the renewable fuel consumed is primarily corn ethanol. Figure 5-4 provides the projected carbon intensity of the gasoline, diesel and combined gasoline and diesel pools. The reduction in gasoline pool carbon intensity can be attributed to increasing levels of ethanol and slightly decreasing corn ethanol carbon intensity. The diesel pool reduction is attributed to increases in the CNG population.

Finally, Figure 5-5 illustrates the reduction in carbon intensity if Washington consumed its proportionate share of the RFS2 Primary Control Case biofuel volumes. Overall, a 5 percent reduction in carbon intensity would be achieved.

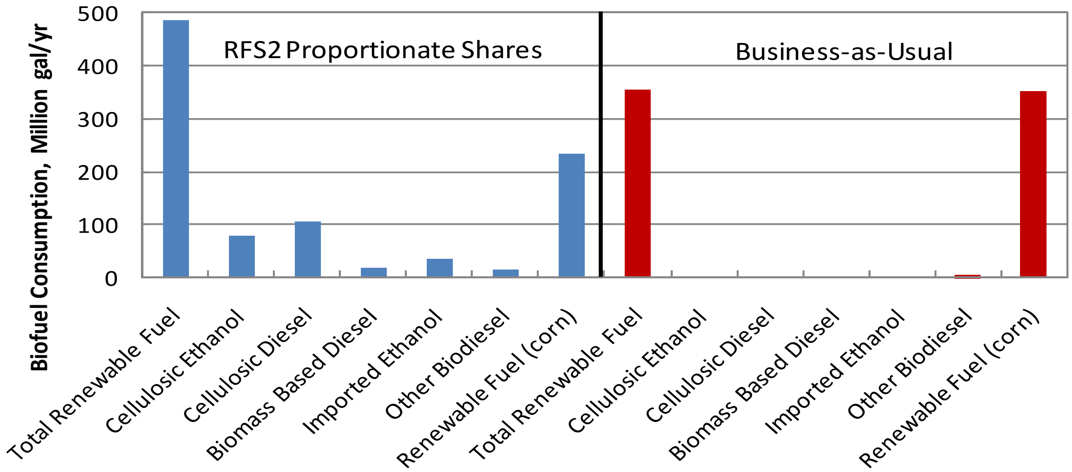

Figure 5-3. Comparison of the Business-as-Usual to Washington State's Proportionate Share of the RFS2 Primary Control Case Biofuel Volumes.

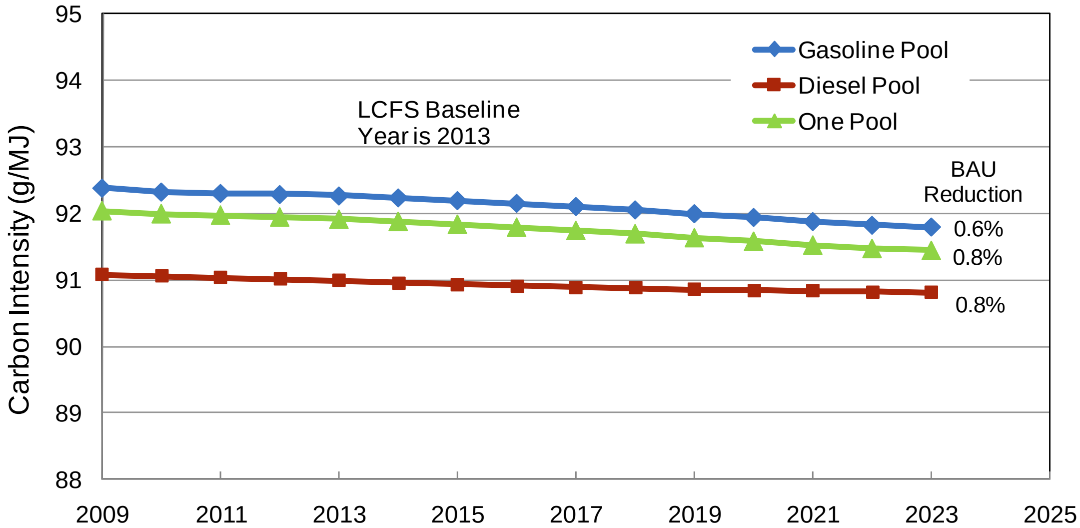

Figure 5-4. BAU Carbon Intensity Projection.

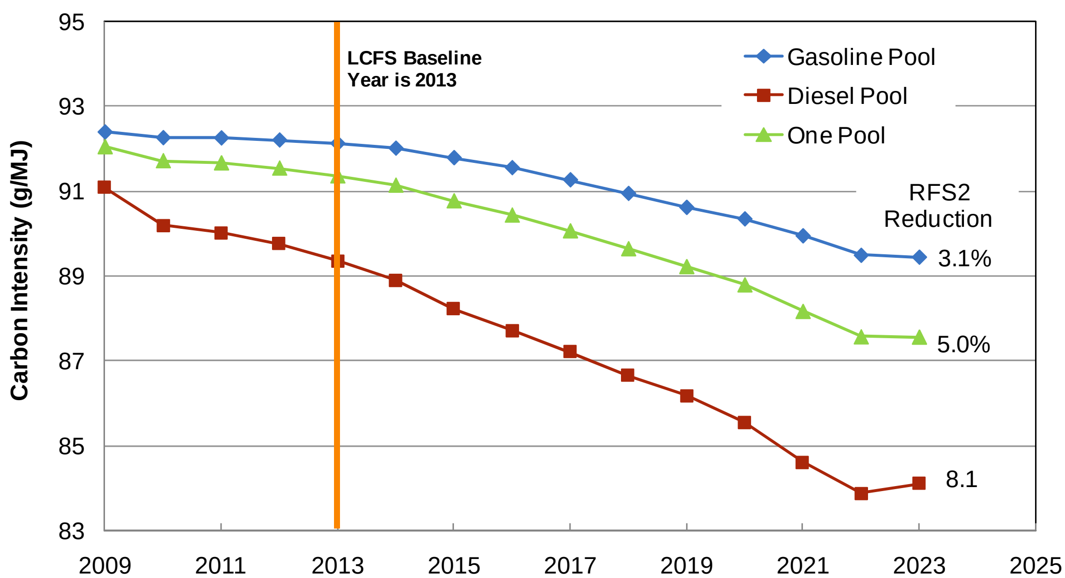

Figure 5-5. Carbon Intensity Reduction Assuming Washington Consumes its Proportionate Shares of the RFS2 Primary Control Case Volumes (RFS2 Proportional Shares).

5.2 Gasoline Pool Compliance VISION Runs

Table 5-3 provides the carbon intensity values for the fuel pathways considered as replacements for gasoline. The two main LCFS compliance fuels for gasoline are ethanol and electricity. The current and projected populations of light duty CNG vehicles are low. As a LCFS compliance option, CNG provides a modest reduction in carbon intensity relative to gasoline while the infrastructure hurdles for refueling and vehicles are similar to plug-in vehicles. Additional CNG light duty vehicles above the BAU levels are not considered here as compliance options.

Table 5-3. Summary of Carbon Intensity Values for Gasoline and its Replacements

Fuel	Carbon Intensity (g/MJ)	Reduction Relative to Baseline
Baseline Gasoline (10% Corn Ethanol)	92	
Diesel	91*	10% to 24%
Ethanol, Midwest Corn Average	94	-2%
Ethanol, Produced in OR from Midwest Corn	86	7%
Ethanol, Low Carbon Intensity Midwest Corn	74	20%
Ethanol, Washington Farmed Trees	15	84%
Ethanol, Washington Wheat Straw	18	80%
Ethanol, Brazil Sugarcane	46	50%
Electricity, Washington RPS Mix	68*	76% to 82%
CNG (North American, pipeline)	69	25%

* CI Value not corrected for EER. Reduction reflects range of assumed EERs over time

Furthermore, we have made a simplifying assumption that all CNG derived from landfill gas will be allocated to heavy duty vehicles and therefore will only help with diesel and one-pool compliance options.

As indicated in Table 5-3, there is a wide range of carbon intensity for ethanol fuels, and the economic impact associated with increased use of ethanol will depend upon whether it is produced in-state or is imported. In addition, if the volumes of ethanol required to achieve the LCFS are higher than what can be blended into gasoline and used in conventional vehicles, then the ethanol will need to be consumed as high level blends (E85). Use of E85 will result in fueling infrastructure costs. In the BAU and all compliance scenarios, the FFV populations are anticipated to grow to approximately 15 percent of the light duty population by 2023 (please refer to Table 4-8). In all scenarios, we have maintained the FFV populations at the BAU levels.

The proposed gasoline pool scenarios are shown in Table 5-4. There are three ethanol scenarios and two electricity scenarios. In all scenarios we assume that Washington continues to consume half of the production from the Boardman corn ethanol plant and 20 percent of the ethanol production from the 100 million gallon Cascade Grain plant[36] at Clatskanie, Oregon. Two of the ethanol scenarios use predominantly cellulosic ethanol to comply with the standard. The first cellulosic scenario assumes that the ethanol is produced in-state while the second scenario assumes that the ethanol is imported. Because the cellulosic ethanol carbon intensity is low, these two scenarios should have minimal amounts of E85 VMT and bracket the range of economic impact for a high cellulosic case.

[36] Cascade Grain Company completed construction of this plant in 2008 but entered bankruptcy in 2009. The plant was purchased by the builder (J.R. Kelly of Vancouver Washington) and is currently being sold to another company. It is expected to operate at capacity.

Table 5-4. Gasoline Compliance Scenarios

	In-State Cellulosic Ethanol (Run 1)	Out-of-State Cellulosic (Run 2)	Mixed Ethanol (Run 3)	Max EVs, In-State Cellulosic (Run 4)	Max EVs, Mixed Ethanol (Run 5)
2023 Reduction	10%	10%	10%	10%	10%
Ethanol Volume	At least BAU	At least BAU	At least BAU	At least BAU	At least BAU
Ethanol Sources:					
Avg MW Corn	100% - Cellulosic - NW Corn	100% - Cellulosic - NW Corn - Brazil	Balance as needed	100% - Cellulosic - NW Corn	Balance as needed
Low Carbon MW Corn	0%	0%	0.7∗(100% - Cellulosic-NW Corn)	0%	0.7∗(100% - Cellulosic-NW Corn)
Northwest Corn	BAU	BAU	BAU	BAU	BAU
Brazil Sugarcane	0%	Proportionate Share of RFS2 Primary Control Case	0.3*(100% - Cellulosic-NW Corn)	0%	0.3*(100% - Cellulosic-NW Corn)
Cellulosic Ethanol	Min to achieve reduction - NW Corn	Min to achieve reduction - NW Corn - Sugarcane	2∗RFS2 Primary Case Share = 44%	100%-NW Corn	2∗RFS2 Primary Case Share = 44%
In-State	100%	0%	50%	100%	50%
Out-of-State	0%	100%	50%	0%	50%
Vehicle Populations					
EVs	BAU	BAU	BAU	4 ∗ BAU	4 ∗ BAU
PHEVs	BAU	BAU	BAU	4 ∗ BAU	4 ∗ BAU
Light Duty CNG	BAU	BAU	BAU	BAU	BAU
Medium Duty CNG	1.2 ∗ BAU	1.2 ∗ BAU	1.2 ∗ BAU	1.2 ∗ BAU	1.2 ∗ BAU
FFV E85 VMT	Float as needed to use EtOH over 15% Blendwall	Float as needed to use EtOH over 15% Blendwall	Float as needed to use EtOH over 15% Blendwall	Float as needed to use EtOH over 15% Blendwall	Float as needed to use EtOH over 15% Blendwall

The third gasoline pool VISION run is a middle ground ethanol case in which 44 percent of the ethanol is cellulosic (this is twice the RFS2 Primary Control Case share). The cellulosic ethanol is then split between in-state and out-of-state supplies. The remainder of the ethanol required for compliance is split 70/30 between low carbon Midwest corn ethanol and sugarcane ethanol from Brazil. It is anticipated that the total volume of ethanol needed for this case will increase because the average carbon intensity of the ethanol mix is higher than the pure cellulosic ethanol scenarios. As a result, this scenario results in high E85 consumption.

In all VISION runs using in-state cellulosic ethanol, we assume that wheat straw ethanol is consumed first followed by ethanol produced from farmed trees on retired CRP acres. We estimate[37] that 153 million gallons of wheat straw ethanol could be produced annually. If all CRP land were planted with poplar trees, up to 620 million gallons of ethanol could be produced. In our diesel pool scenarios we assume that some of the CRP land will be utilized for canola production – in all cases, we do not use more CRP land than is available. We need to point out here that because we have assumed that all of the farmed tree ethanol is produced on CRP land, the ILUC value should be 0 rather than the 4 g/MJ assumed. In the analysis, the farmed tree carbon intensity should have been 11 g/MJ rather than 15 g/MJ; the result is that slightly less ethanol will be required than was estimated.

The remaining gasoline pool VISION runs are high EV scenarios; we have assumed that the EV and PHEV sales rates will be 4 times the BAU penetration rates, 11.4 percent overall . This

[37] "Biomass Inventory and Bioenergy Assessment", WA Department of Ecology Publication #05-07-047, Dec 2005.

results in 2023 PHEV and EV shares of the light duty population of 5.8 percent and 1 percent, respectively. Table 5-5 compares the PHEV/EV market share and populations of the CARB, NESCAUM and Washington State high EV scenarios. The Washington State values are similar to the CARB values, but much lower than the NESCAUM assumption. Because it takes time for new vehicles to achieve significant shares of the population, the high EV cases will need additional ethanol to comply with the LCFS. We therefore consider two max EV cases with the supplemental ethanol: in-state cellulosic ethanol (similar to Run 1) and mixed ethanol (similar to Run 3). It is felt that these five scenarios bracket the technological and economic range of LCFS compliance possibilities for gasoline.

Table 5-5. Comparison of CARB, NESCAUM and Washington State High EV Scenarios.

	Business as Usual Washington		High EV Scenario Washington		High EV Scenario CARB LCFS		High EV Scenario NESCAUM 11 States	
LCFS End Year	2023		2023		2020		2022	
Total Vehicle Population								
Light Duty Auto	2,606,576		2,606,576		13,000,000			
Light Duty Truck	2,256,291		2,256,291		8,200,000			
Total Light Duty	4,862,866		4,862,866		21,200,000		37,000,000	
LCFS End Year Data	PHEV	EV	PHEV	EV	PHEV	EV	PHEV	EV
Market Share								
Light Duty Auto	3.7%	0.6%	14.9%	2.5%				
Light Duty Truck	1.0%	0.2%	4.0%	0.7%				
Total Light Duty	2.5%	0.4%	9.8%	1.6%			35%	19%
Share of Population								
Light Duty Auto	2.3%	0.4%	9.1%	1.5%				
Light Duty Truck	0.5%	0.1%	2.0%	0.3%				
Total Light Duty	1.5%	0.3%	5.8%	1.0%	6%	2%	23%	13%
Population								
Light Duty Auto	59,421	10,777	236,789	40,339				
Light Duty Truck	11,962	1,995	46,123	7,689				
Total Light Duty	71,383	12,773	282,912	48,028	1,340,000	440,000	8,500,000	4,700,000

NESCAUM Values taken from April 2010 Stakeholder Presentation
NESCAUM LDV Population value extrapolated to 2022 assuming 36 million in 2020 and 28 million in 2005, July 2009 NESCCAF Report
CARB Values from LCFS ISOR Appendix C

5.2 Diesel Pool Compliance VISION Runs

For diesel, there are only two compliance fuels available in the LCFS timeframe: bio-distillates and CNG. Table 5-6 summarizes the carbon intensities for these fuels. For the BAU, we assumed that Washington will continue to consume its biodiesel at its historic rate of 0.6 percent. Table 5-7 illustrates the diesel pool compliance runs. In all cases, we have increased the CNG vehicle population by 20 percent. A portion of this CNG will be produced from biogas. Two projects have been announced in Washington: King County landfill project and a Cedar Grove composting project. These two biogas projects have the potential to yield a total of 2 trillion Btu/yr of CNG. We assume in our scenarios that half of this potential will be available for transportation. We also assume that all of the waste oil biodiesel will be consumed in-state.

Table 5-6. Summary of Carbon Intensity Values for Diesel and its Replacements

Fuel	Carbon Intensity (g/MJ)	Reduction Relative to Baseline
Baseline ULSD	92	
Biodiesel, MW Soybeans	68	26%
Biodiesel, NW Canola	26	72%
Biodiesel, Waste Grease	20[1]	86%
Renewable Diesel, MW Soybeans	67	27%
Cellulosic Diesel (from forest residue)	37	60%
CNG (from Natural Gas)	69[2]	25%
CNG (Landfill Gas, CARB Lookup Table)	11[2]	88%

1. Average of Tallow and Yellow Grease Carbon Intensities.
2. Not divided by EER of 0.90

Table 5-7. Diesel Compliance Scenarios

	In-State Cellulosic Diesel (Run 6)	Out-of-State Cellulosic Diesel (Run 7)	Maximum In-State Conventional (Run 8)
Percent Reduction	10%	10%	10%
Biodistillate Volumes	Minimum needed to achieve 10%	Minimum needed to achieve 10%	Minimum needed to achieve 10%
Biodistillate Shares			
Waste Oil	Max In-State	Max In-State	Max In-State
Cellulosic	0.8∗(100% - Waste)	0.8∗(100% - Waste)	100%-Canola-Waste
In State	100%	0%	50%
Out-of-State	0%	100%	50%
Conventional	0.2∗(100% - Waste)	0.2∗(100% - Waste)	Max In-State
In-State Canola	Up to max available	Up to max available	Max Available
MW Soybeans	If Needed	Balance	0%
CNG			
Vehicle Population	1.2 ∗ BAU	1.2 ∗ BAU	1.2 ∗ BAU
Biogas Derived	Maximum Available	Maximum Available	Maximum Available
Pipeline Natural Gas	Balance	Balance	Balance

The first two runs assume that compliance will mainly be met (after the waste oil and biogas derived CNG) through the use of cellulosic biodistillate. For these two cases, it is assumed that 80% of the biodistillates will be cellulosic based on the RFS2 Primary Control Case split between cellulosic and conventional feedstocks. The balance of the biodistillates (20%) is assumed to be conventional biodiesel produced in-state from Washington canola oil. The first run assumes that all of the cellulosic biodiesel is produced in-state while the second assumes that all of the cellulosic biodiesel is produced out-of-state.

The maximum in-state canola supply is assumed to be 56 million gal/yr. For Washington grown Canola we use WSU information that concluded all the displaced wheat production from adding canola to the wheat rotation can be offset with new wheat production on retired CRP land. The total amount of retiring CRP acres is shared between farmed trees for cellulosic ethanol (665 gal/acre) and canola for biodiesel.

The third diesel compliance run is a maximum in-state conventional biodiesel case. This case assumes that the current waste oil and landfill gas CNG are all utilized. On top of this, the maximum possible canola biodiesel production (using the balance of the CRP acres after maximum in-state cellulosic ethanol production) is the primary compliance strategy. All additional biodiesel required beyond this, is assumed to be cellulosic diesel, half of which is produced in-state and half produced out-of-state.

5.3 One-Pool Compliance Scenario

The overall theme of the one-pool compliance scenario is mid-level assumptions for all alternative fuels. The assumptions in Table 5-8 were guiding principles for the iterative process of achieving an overall 10 percent reduction target. The main feature of this scenario is to assume more light duty diesel vehicles than in the separate gasoline or diesel scenarios; these are a compliance option in the one-pool scenario because light-duty diesel vehicles are more fuel efficient than comparable gasoline vehicles.

Table 5-8. Proposed One-Pool Scenario (Run 9)

	One Pool 10% Reduction
Ethanol Volume	BAU at minimum
Ethanol Shares:	
Cellulosic Ethanol	2X RFS2 Primary Control Case = 44%
In-State	50%
Out-of-State	50%
Brazil Sugarcane	WA Share of RFS2 Primary Control Case
NW Corn	BAU
Average MW Corn	0%
Low Carbon MW Corn	Balance
EV Population	2 * BAU
PHEV Population	2 * BAU
CNG Light-Duty Population	1.2 * BAU
FFV VMT	Float as needed to use EtOH beyond BW
Light Duty Diesel Population	1.5 * BAU
Biodistillate Volumes	WA Share of RFS2 Primary Control Case
Biodistillate Shares	
Cellulosic Biodistillate	100% - Waste - Canola
In-State	50%
Out-of-State	50%
Conventional (WA Canola)	Max In-State
Waste Oil Derived	Max In-State
CNG	
CNG Vehicle Population	1.2 * BAU
Biogas Derived	Maximum
Pipeline NG	Balance

6. Scenario Analysis Results

The individual VISION runs described in Section 5 were combined into LCFS scenarios as shown in Table 6-1. The following sections provide the VISION model projections from 2013 through 2023 for vehicle populations and expenditures, fuel consumption, fuel expenditures, emission reductions and petroleum displacement. We also present the fuel expenditure results from the two sensitivity cases: high petroleum prices and high cellulosic biofuel prices.

Table 6-1. Summary of Compliance Scenarios Considered

	Scenarios					
	A	**B**	**C**	**D**	**E**	**F**
LCFS Structure	Two Separate Pools, 10% Reduction Each					One Pool, 10% Reduction
Gasoline Compliance Method	In-State Cellulosic Ethanol (Run 1)	Out-of-State Cellulosic Ethanol (Run 2)	Mixed Ethanol (E85) (Run 3)	Max EVs, In-state Cellulosic Ethanol (Run 4)	Max EVs, Mixed Ethanol (Run 5)	Mid EVs, Mixed Ethanol (Run 9)
Diesel Compliance Method	In-State Cellulosic Diesel (Run 6)	Out-of-State Cellulosic Diesel (Run 7)	In-State Canola Biodiesel (Run 8)	In-State Canola Biodiesel (Run 8)	In-State Canola Biodiesel (Run 8)	Light duty diesel, Mixed Biodiesel (Run 9)

6.1 Vehicle Populations and Expenditures

The BAU vehicle population projections were provided in Figures 4-20, 4-21 and Table 4-8. For light duty vehicles, all LCFS scenarios utilized the BAU market penetrations and populations except for the high EV Scenarios (D and E) and the One Pool Scenario (Scenario F). These scenarios had higher EV and PHEV market penetrations than the BAU. Additionally, in Scenario F, we have assumed a 20 percent increase in light duty diesel and CNG vehicles. The change in vehicle populations relative to the BAU for the high EV scenarios and the One Pool Scenario are provided in Figures 6-1 and 6-2, respectively. In the High EV Scenarios, there are approximately 230,000 more electric vehicles (PHEVs plus EVs) than the BAU by 2023. For the One Pool Scenario, there are approximately 100,000 more light duty diesel vehicles and 100,000 more plug-in vehicles (EV and PHEV) than the BAU by 2023.

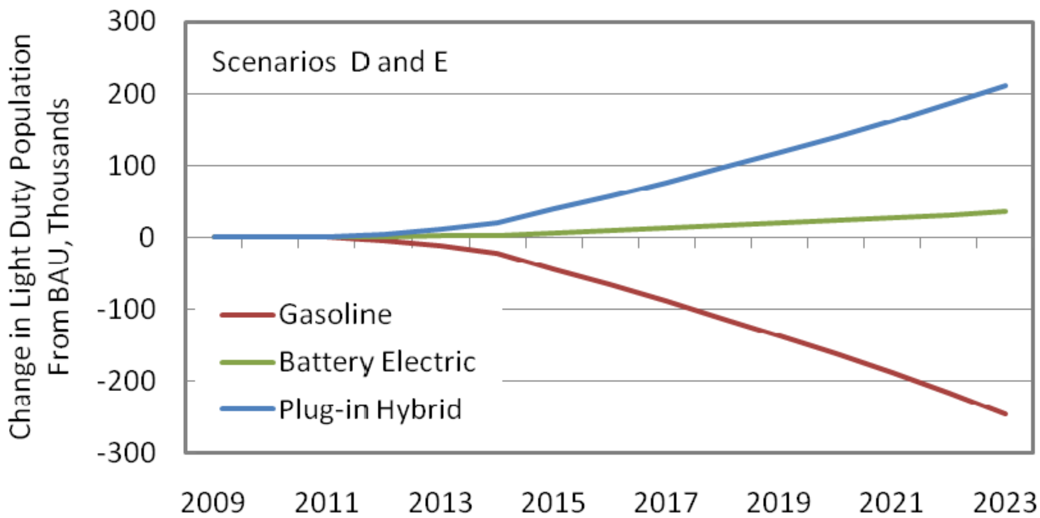

Figure 6-1. Change in Light Duty Vehicle Populations for Scenarios D and E.

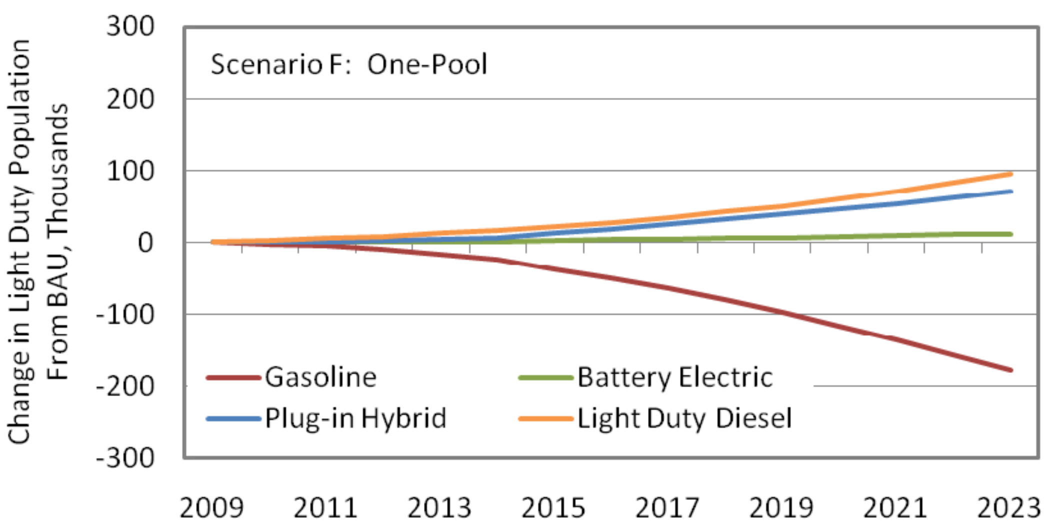

Figure 6-2. Change in Light Duty Vehicle Populations for Scenario F.

For all scenarios, we have assumed a 20 percent increase in medium and heavy duty CNG vehicle sales relative to the BAU. Figure 6-3 provides the medium and heavy duty vehicle populations relative to the BAU. It was assumed that the medium duty CNG vehicles displaced medium duty gasoline and that heavy duty CNG vehicles displaced heavy duty diesel vehicles. Although the heavy duty CNG vehicle populations increase more than the heavy duty diesel populations decrease (~ 100 vehicles different), the total heavy duty vehicles sold each year in the scenarios is the same as in the BAU.

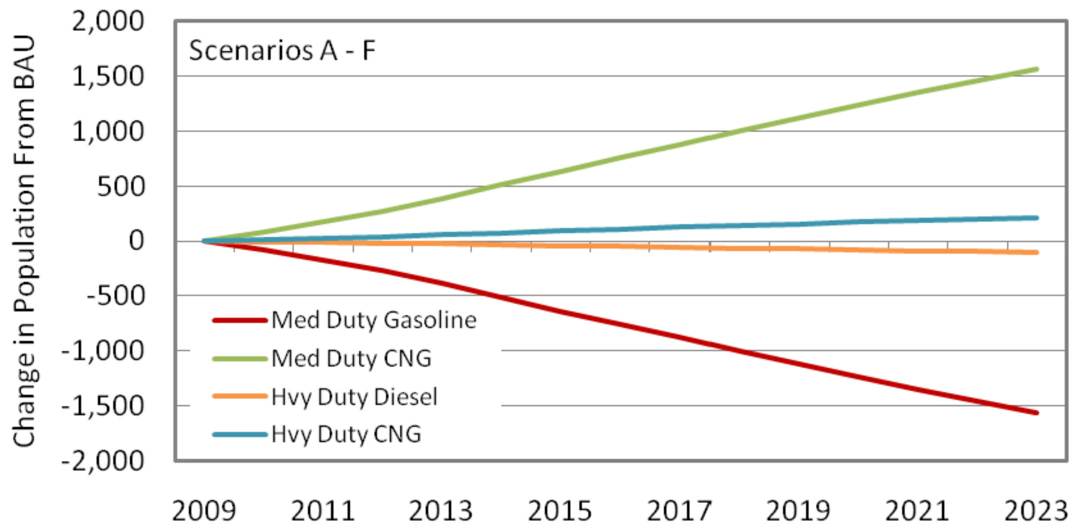

Figure 6-3. Change in Medium and Heavy Duty Vehicle Populations for all Scenarios.

The changes in vehicles sales each year result in changes in vehicle expenditures relative to the BAU. Section 4 provided the incremental vehicle price assumptions – these are applied to the sales data each year to arrive at incremental vehicle expenditures. Figures 6-4 and 6-5 provide the light duty incremental vehicle expenditures for the High EV scenarios and the One Pool scenario, respectively. Scenarios D and E result in nearly $250 Million in incremental vehicle expenditures by 2023; Scenario F results in just over $100 Million in incremental vehicle expenditures. Finally, Figure 6-6 provides the incremental expenditures for medium and heavy duty CNG vehicles relative to the BAU for all compliance scenarios. On the heavy duty side, the total incremental expense is ~ $6 million.

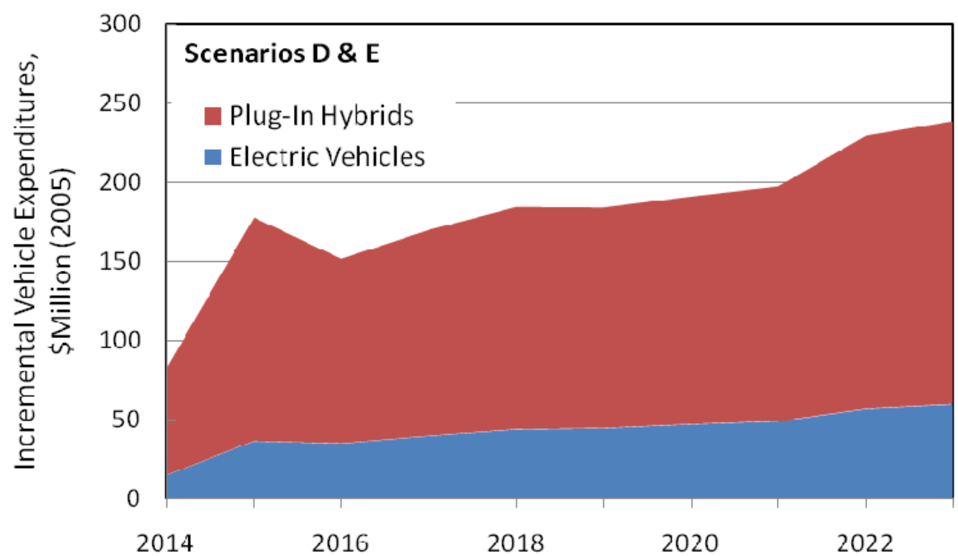

Figure 6-4. Increase in Light Duty Vehicle Expenditures for Scenarios D & E

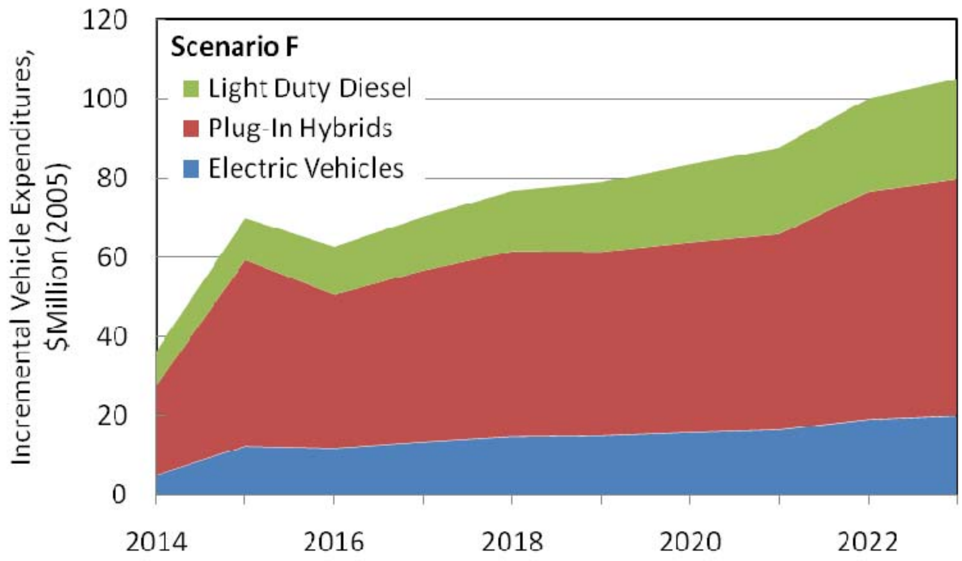

Figure 6-5. Increase in Light Duty Vehicle Expenditures for Scenario F.

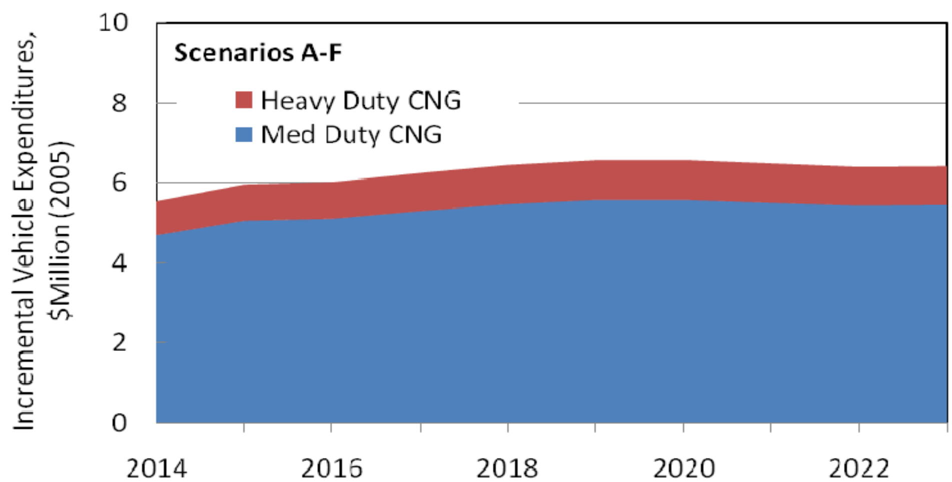

Figure 6-6. Increase in Medium and Heavy Duty Vehicle Expenditures for all Scenarios.

6.2 Fuel Consumption

Each scenario and the RFS2 proportional case have different fuel consumption characteristics. The following subsections provide the changes in fuel consumption relative to the BAU, the types and quantities of biofuels consumed, and the amount of ethanol that is consumed as E85.

6.2.1 Fuel Consumption Relative to BAU

Figures 6-7 through 6-13 indicate the changes in fuel consumption by type relative to the BAU case by fuel type for the RFS2 Proportional Shares case and each compliance scenario. For the RFS2 proportional case, there is a significant difference relative to the BAU in biodiesel consumption – recall that for the BAU we have assumed that biodiesel continues to be blended at current levels through the analysis period (0.6 percent). The RFS2 proportional case has slightly more total ethanol volume than the BAU.

Scenarios A and B are quite similar with biodiesel and ethanol volumes higher than the RFS2 Proportionate shares case. The increase in ethanol relative to the BAU begins in 2021; in the BAU, we project meeting the E15 blendwall in 2021. Scenario C biodiesel use is similar to Scenarios A and B. This is because much of the biodiesel volumes in Scenario C are derived from canola which has a carbon intensity similar to cellulosic diesel. In contrast, the ethanol volumes are much higher in Scenario C because “mixed” ethanol has a higher carbon intensity than cellulosic ethanol, requiring larger volumes to achieve the 10 percent reduction in carbon intensity.

Scenarios D and E are the high electricity cases. Since electric vehicles are 3 to 4 times more efficient than gasoline vehicles, the gasoline decreases by more than the electricity and ethanol energy use increases. Scenario D assumes cellulosic ethanol is consumed, so much less of it is needed than in Scenario E to achieve the 10 percent reduction in carbon intensity.

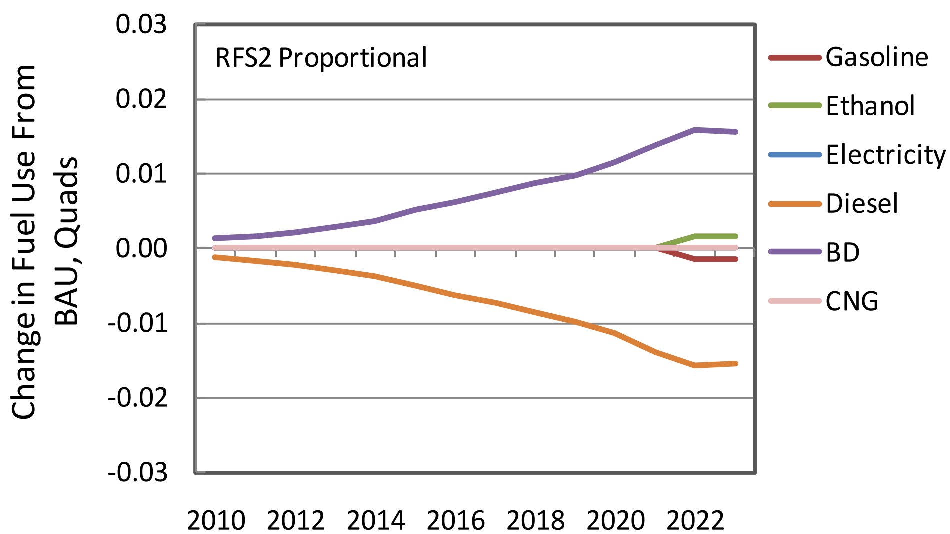

Figure 6-7. Change in Fuel Use Relative to the BAU for the RFS2 Proportionate Shares Case.

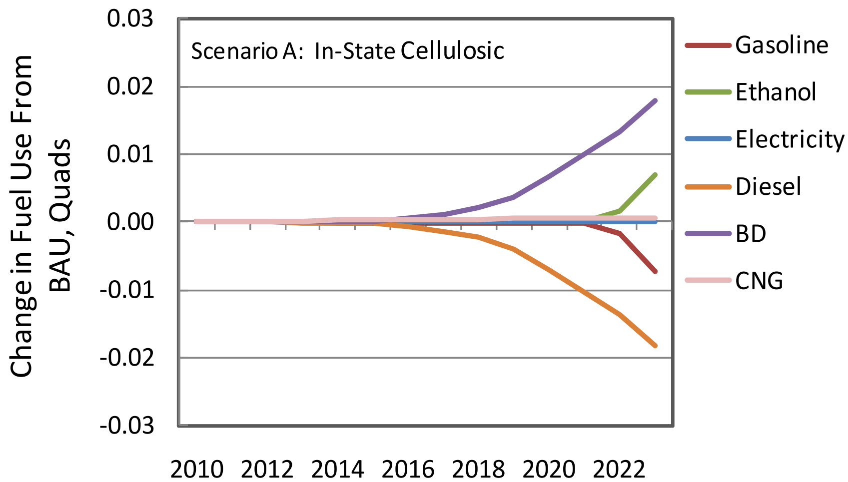

Figure 6-8. Change in Fuel Use Relative to the BAU for Scenario A.

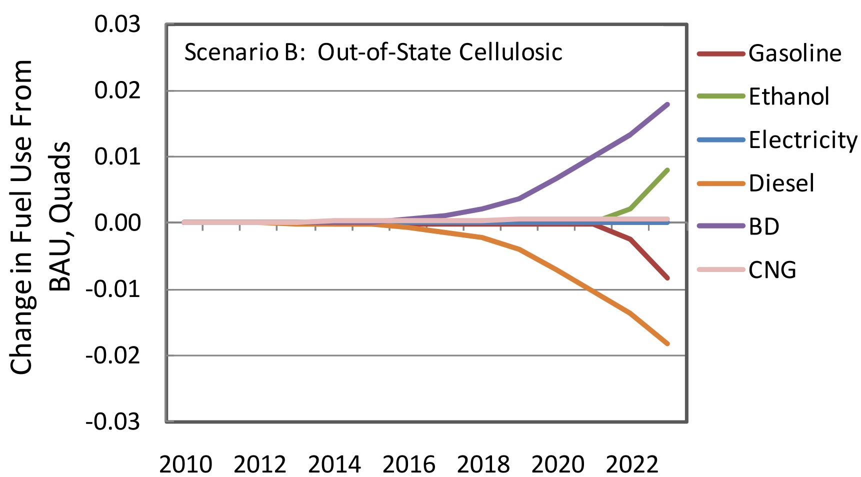

Figure 6-9. Change in Fuel Use Relative to the BAU for Scenario B.

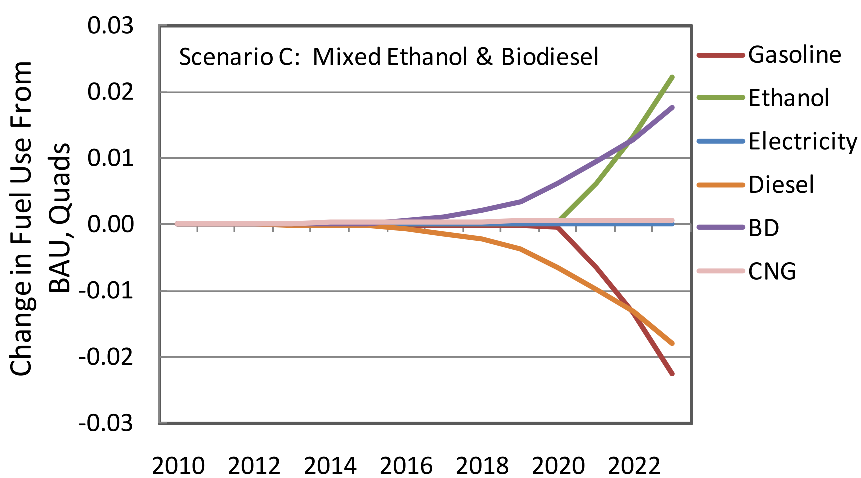

Figure 6-10. Change in Fuel Use Relative to the BAU for Scenario C.

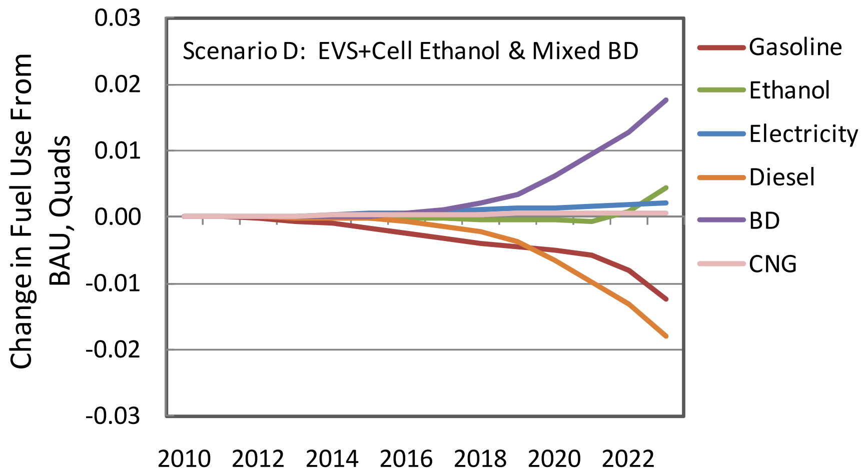

Figure 6-11. Change in Fuel Use Relative to the BAU for Scenario D.

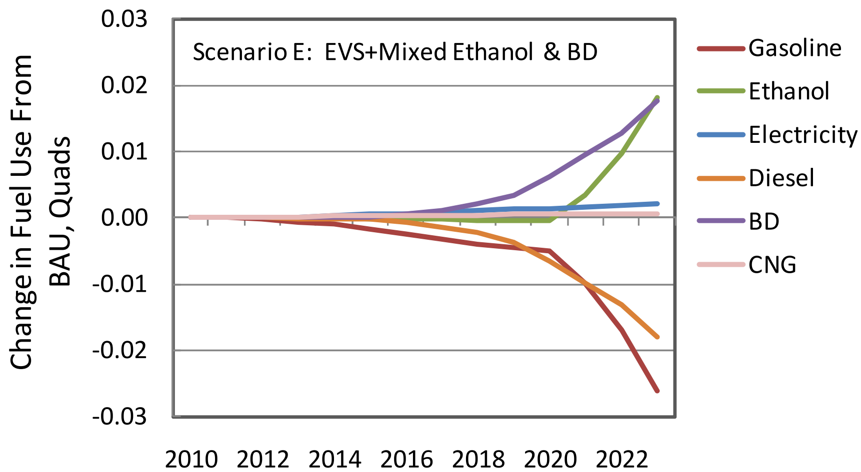

Figure 6-12. Change in Fuel Use Relative to the BAU for Scenario E.

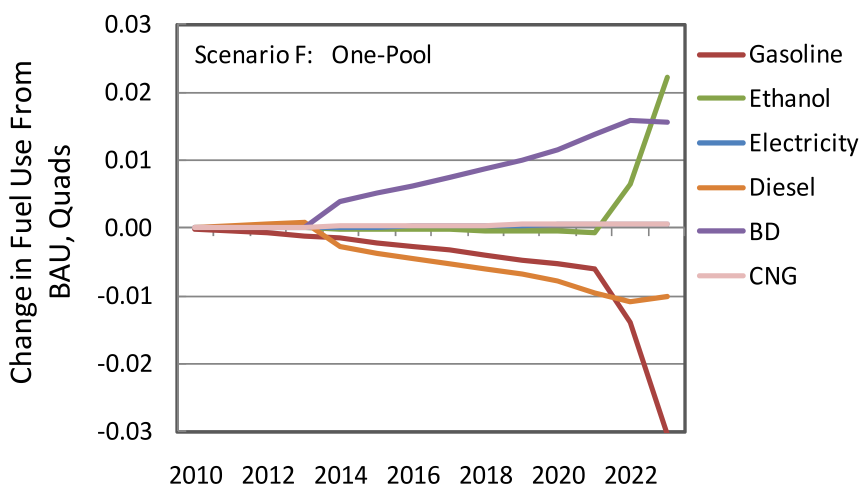

Figure 6-13. Change in Fuel Use Relative to the BAU for Scenario F.

Finally, Scenario F in Figure 6-13 shows the steepest decrease in gasoline use for two reasons: the ethanol utilized has moderate carbon intensity, and because light duty diesels displace some of the gasoline.   The biodiesel consumption is the same as the RFS2 proportionate share case (by design).

6.2.2 Biofuel Consumption

Figures 6-14 and 6-15 illustrate the types and quantities of biofuels consumed in the BAU and RFS2 proportional shares cases. As mentioned earlier, the total amount of ethanol consumed in the BAU is slightly less than the RFS2 proportional share case, but the ethanol types are different. In the BAU, we assume that all of the ethanol is derived from corn, with a small amount coming from existing production facilities in the Northwest. The RFS2 proportional share case also has sugarcane and cellulosic ethanol.

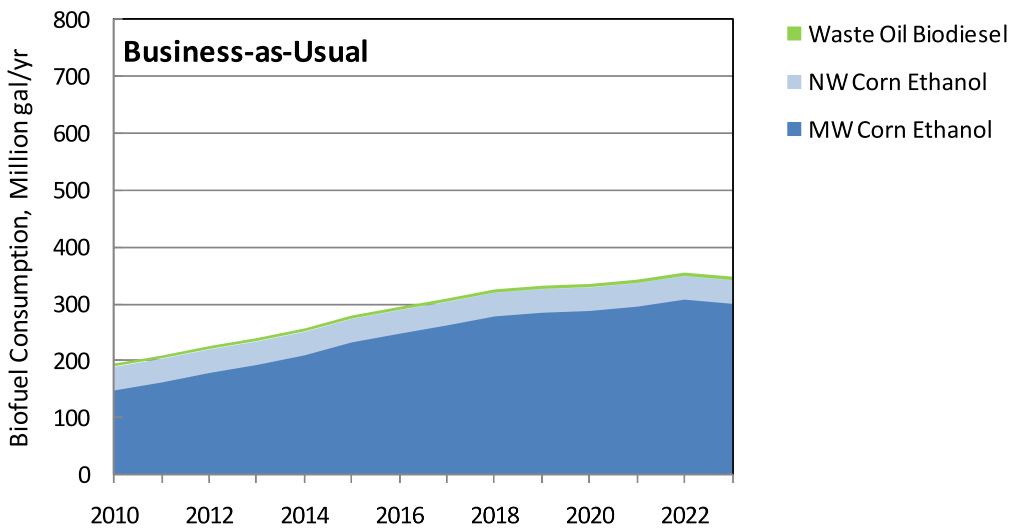

Figure 6-14. Biofuel Consumption by Type for the BAU Case.

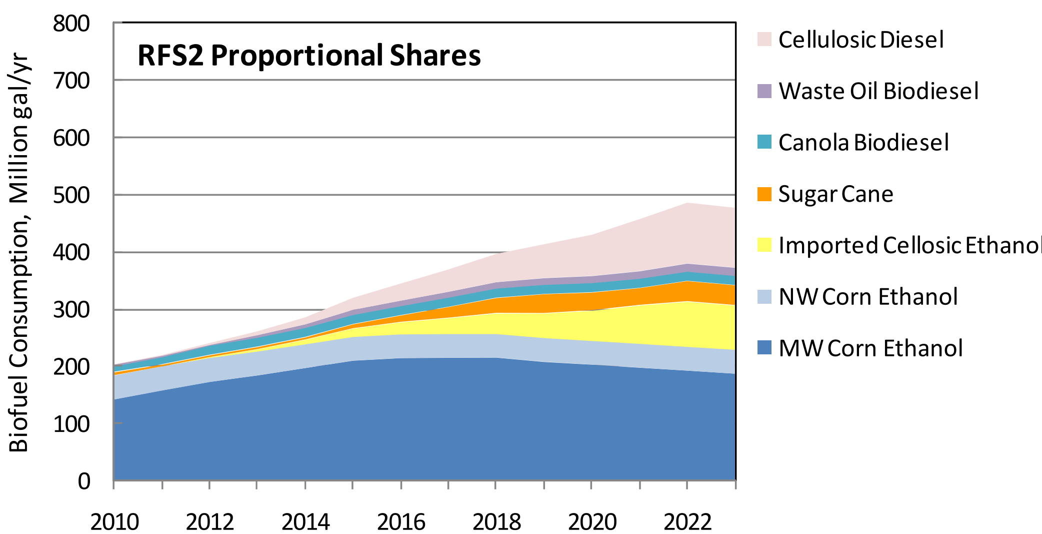

Figure 6-15. Biofuel Consumption by Type for the RFS2 Proportional Shares Case.

Figures 6-16 through 6-21 illustrate the quantities and types of biofuels consumed in the LCFS scenarios to achieve the 10 percent reduction in carbon intensity. Scenarios A and B have similar quantities since the only difference is the location of cellulosic fuel production. We see again that Scenario C has moderate amounts of each type of ethanol, resulting in larger quantities required to achieve a 10 percent reduction (relative to the cellulosic pathways).

Scenarios D and E need less ethanol to achieve a 10 percent reduction in the gasoline pool carbon intensity because of the increased use of electricity. Scenario D can be compared to Scenario A to see the impact of electricity on ethanol use while Scenario E can be compared to Scenario C. Scenarios C, D and E all have the same amounts of biodiesel.

Scenario F utilizes large volumes of biofuels because it is a moderate approach to compliance, resulting in moderate carbon intensities of the biofuels consumed.

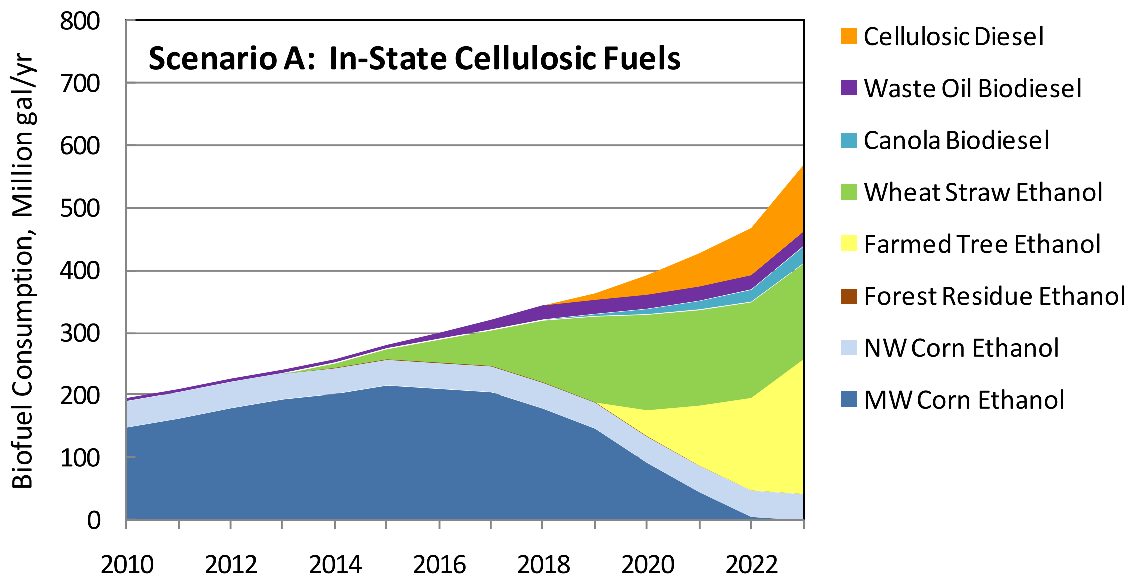

Figure 6-16. Biofuel Consumption by Type for Scenario A.

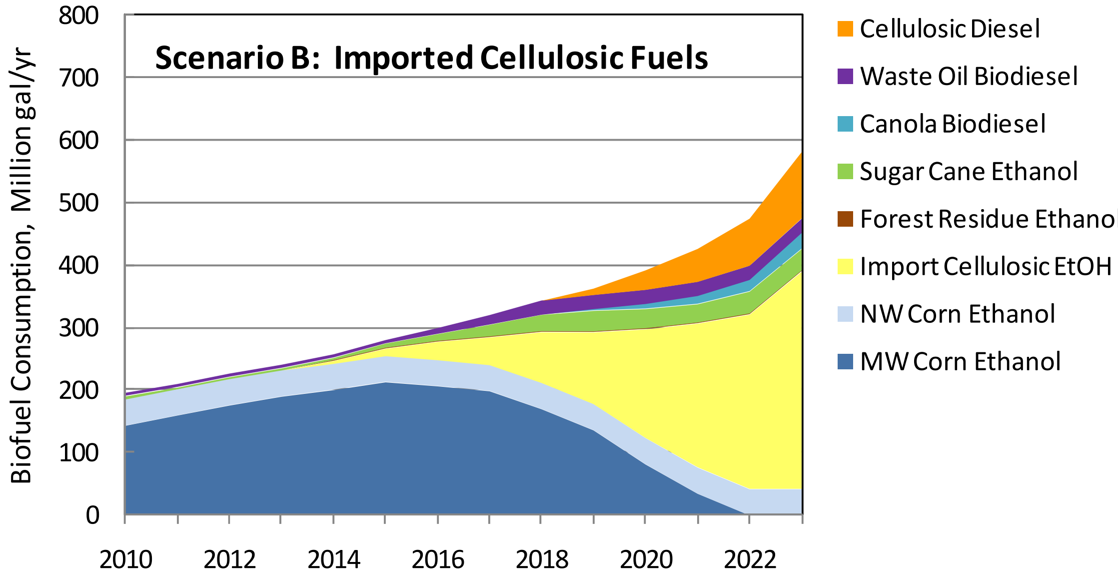

Figure 6-17. Biofuel Consumption by Type for Scenario B.

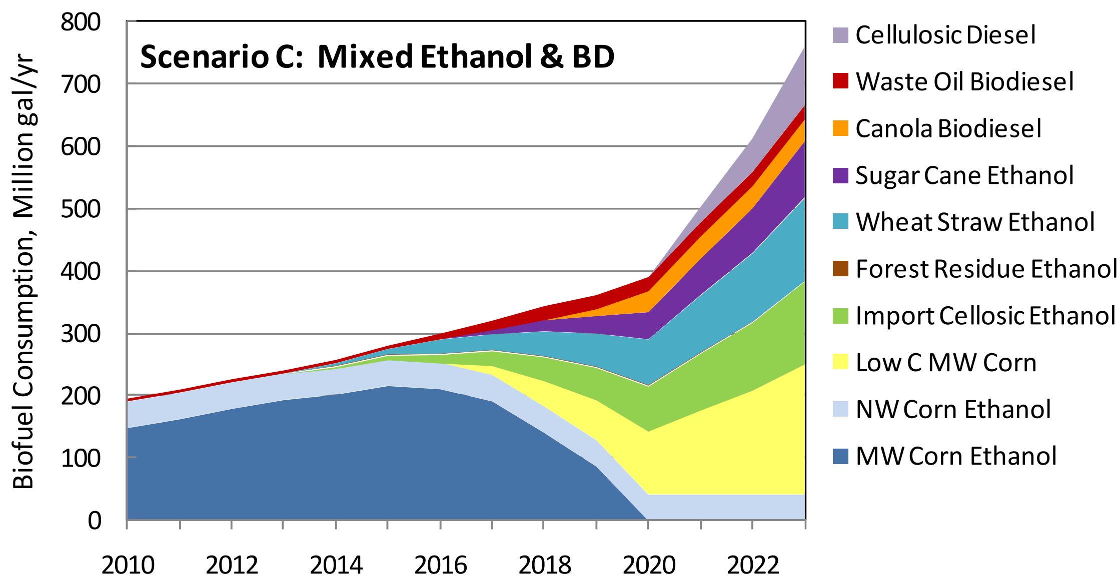

Figure 6-18. Biofuel Consumption by Type for Scenario C.

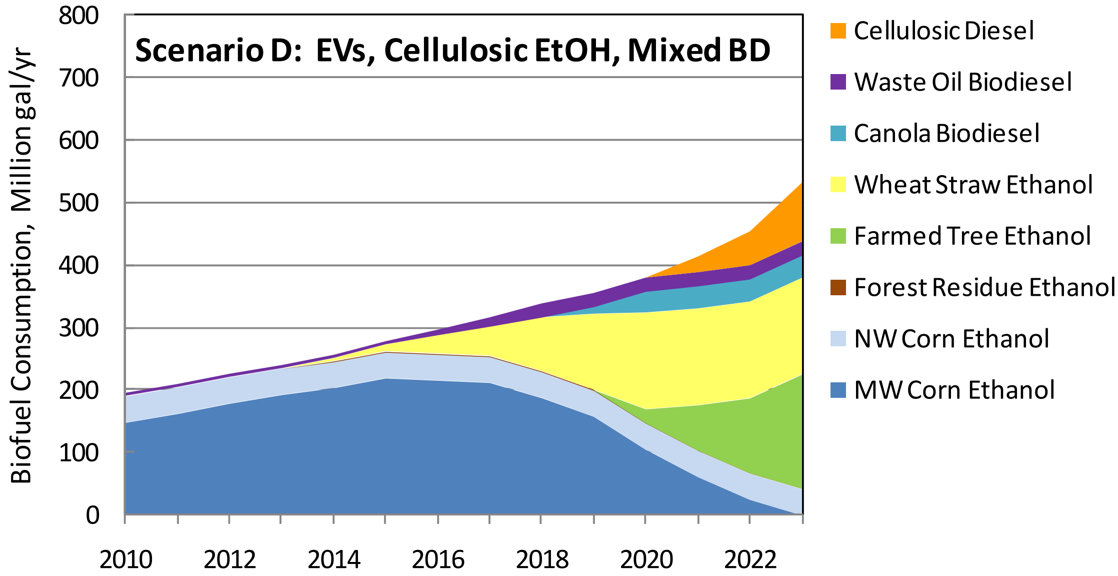

Figure 6-19. Biofuel Consumption by Type for Scenario D.

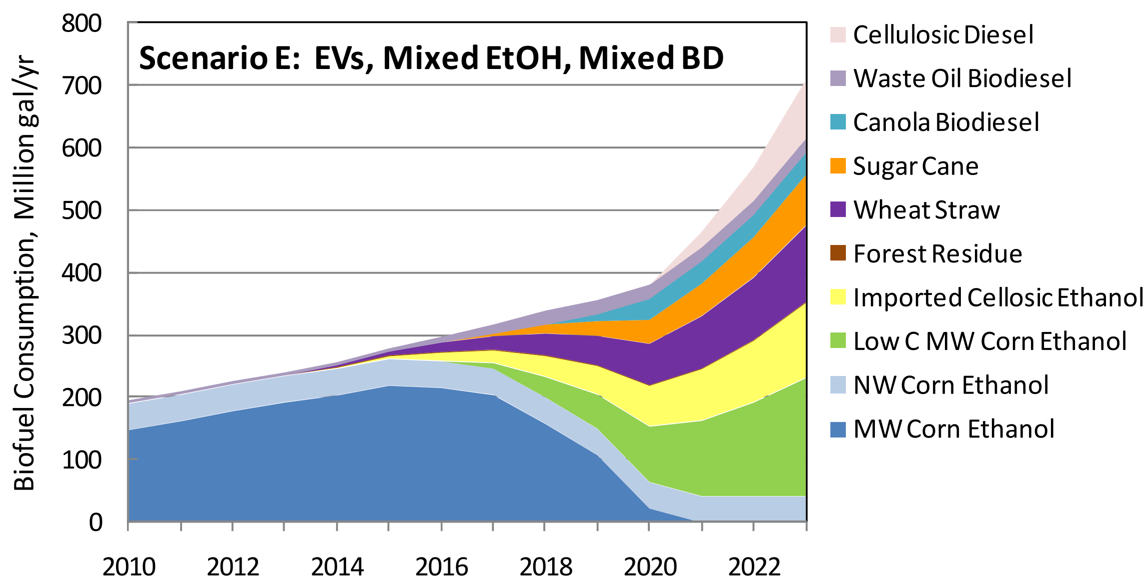

Figure 6-20. Biofuel Consumption by Type for Scenario E.

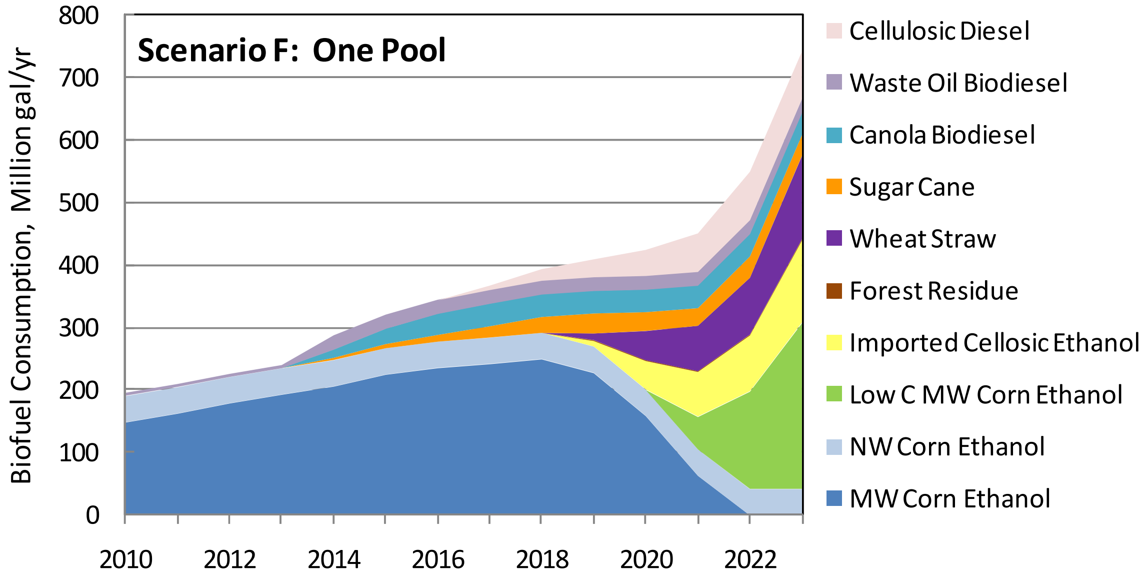

Figure 6-21. Biofuel Consumption by Type for the One Pool Scenario.

6.2.3 E85 Consumption

Ethanol can be consumed in gasoline vehicles as a low level blend and in flex fuel vehicles (FFVs) as E85 (85% by volume ethanol). For the BAU, we assumed that EPA would approve an E15 blend for all vehicles by 2015. We further assumed that once the E15 blendwall was met, no further increases in ethanol would occur since it is unreasonable to expect investment in E85 infrastructure in the absence of a LCFS. The RFS2 Proportional case requires a small amount of E85 in the last year to allow Washington to consume its share of the ethanol.

Each compliance scenario considered required more ethanol in the last three years of the program than could be consumed as E15. Figure 6-22 illustrates the volume of ethanol that must be consumed as E85 in each scenario. The Scenarios with lower carbon intensity ethanol (A, B, D) result in less ethanol consumed as E85. The mixed ethanol cases (C, E, F) result in the largest amounts of E85 consumption.

Figure 6-23 takes the E85 volume result and shows the share of the miles that FFVs must use E85 to consume the required volumes of ethanol. By 2023, the mixed ethanol scenarios required that FFVs utilize E85 80 to 90 percent of the time.

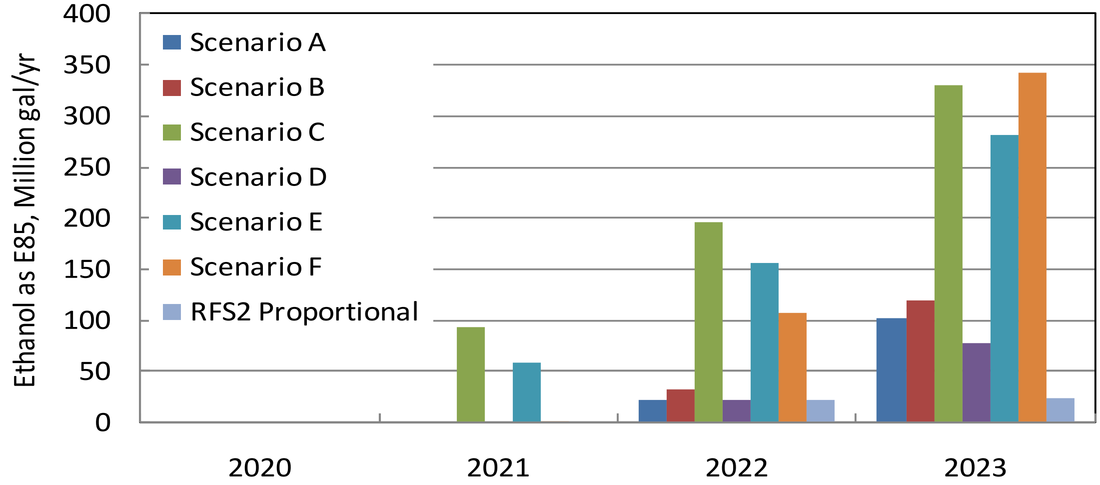

Figure 6-22. Quantity of Ethanol Consumed as E85.

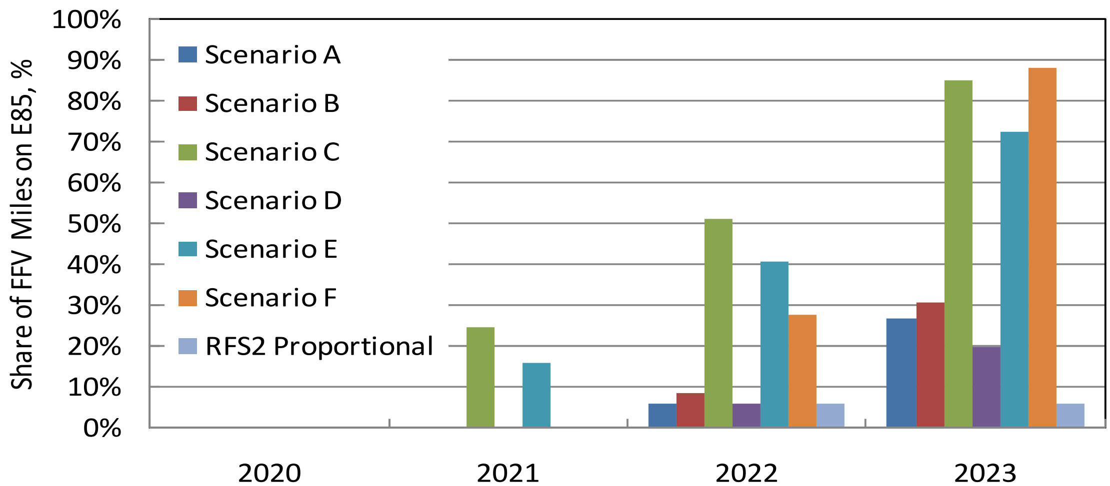

Figure 6-23. Share of Flex Fuel Vehicle Miles Utilizing E85.

6.3 Fuel Expenditures

The projected fuel volumes are combined with the assumed fuel prices to estimate fuel expenditures. Figure 6-24 provides the fuel expenditures for the BAU case. As expected, the bulk of the expenditures are gasoline followed by diesel and ethanol. The ethanol expenditures are 7 to 10 percent of the gasoline expenditures because the assumed prices are similar on an energy basis and ethanol makes up approximately 7 to 10 percent of the low level blend on an energy basis (10 to 15% on a volume basis).

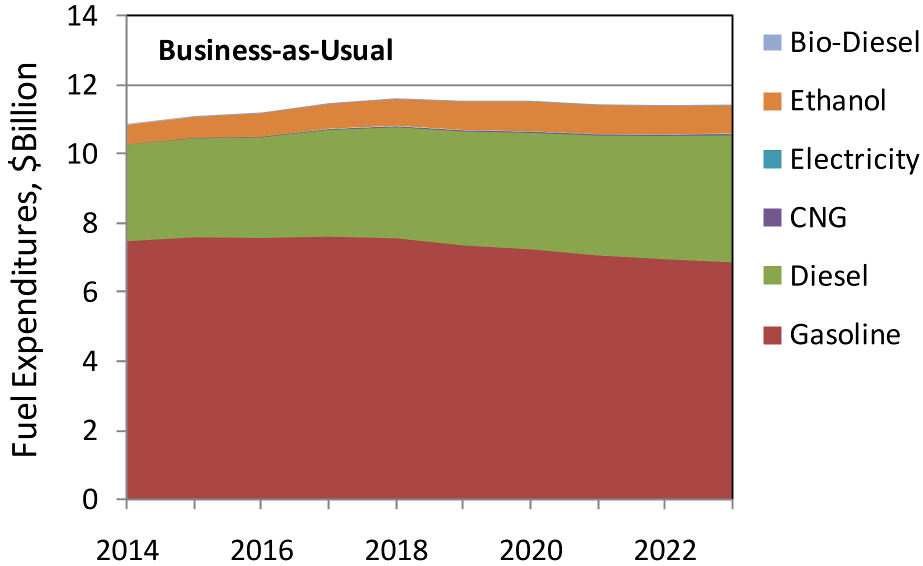

Figure 6-24. Projected Fuel Expenditures for the Business-as-Usual Case.

Figures 6-25 through 6-28 provide the changes in gasoline, diesel, ethanol and biodiesel expenditures for each scenario and the RFS2 proportional case through 2023 relative to BAU. The changes in electricity and CNG expenditures are very small, so are not shown. Scenarios C, E and F result in the largest decreases in gasoline expenditures (tracks with decrease in consumption shown in Section 6.1). All the scenarios had similar reduction in diesel consumption though Scenario F had the least change due to the increase in light duty diesel vehicles.

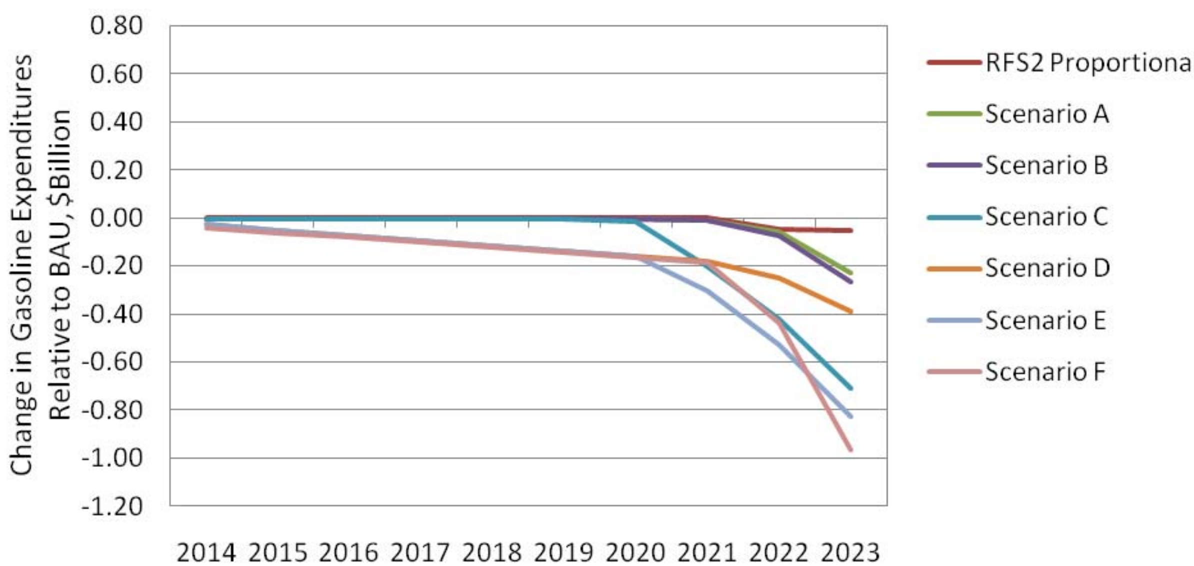

Figure 6-25. Change in Gasoline Expenditures Relative to the BAU.

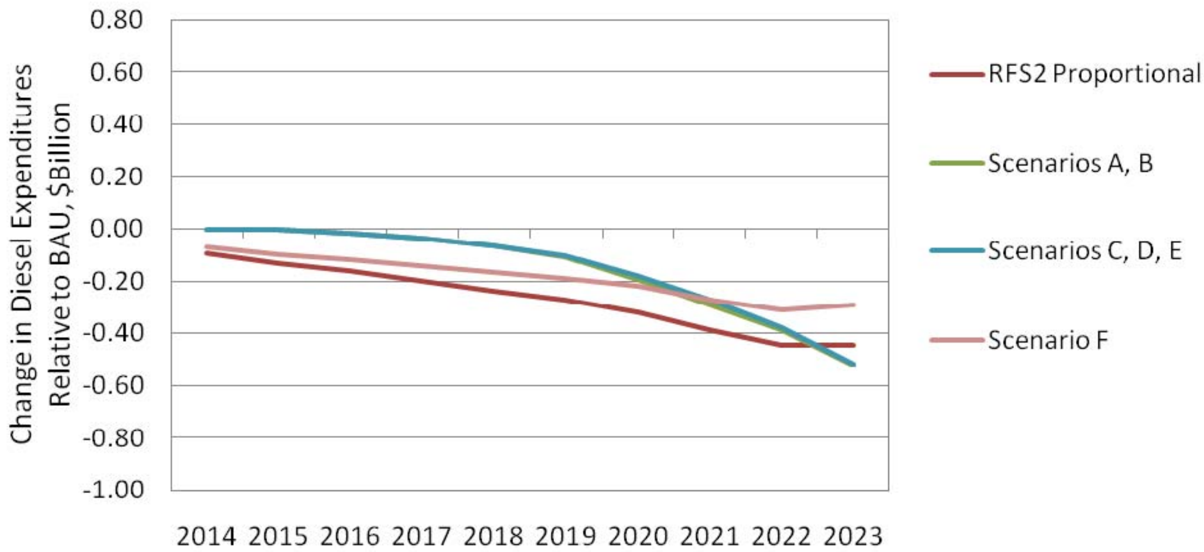

Figure 6-26. Change in Diesel Expenditures Relative to the BAU.

Figure 6-27 shows that the mixed ethanol scenarios (C, E, and F) had the largest increases in ethanol expenditures (tracks with increase in consumption). The biodiesel expenditures shown in Figure 6-28 mirror the changes in biodiesel consumption.

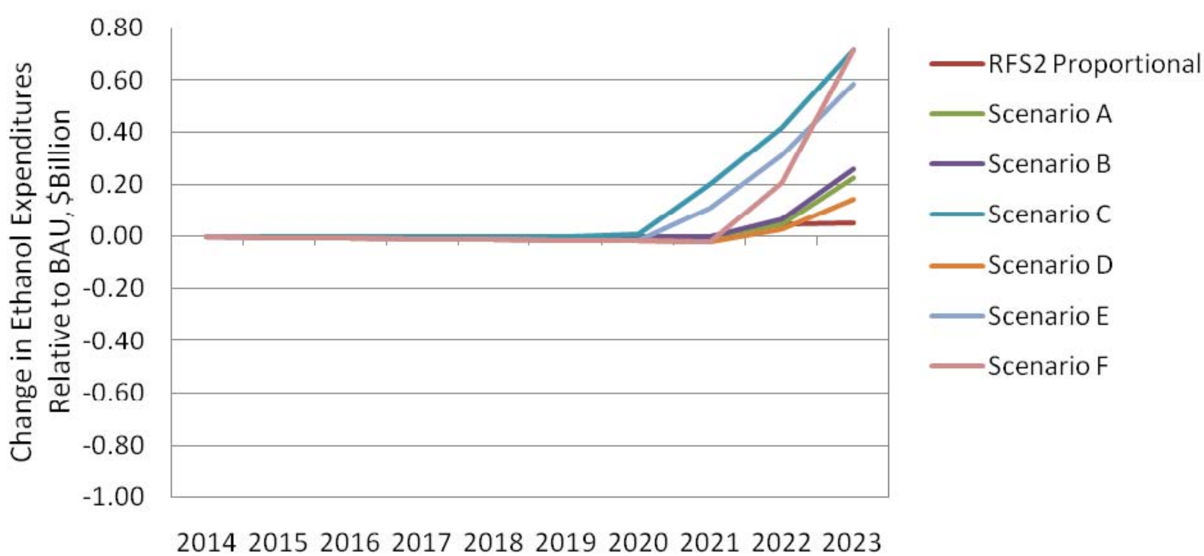

Figure 6-27. Change in Ethanol Expenditures Relative to the BAU.

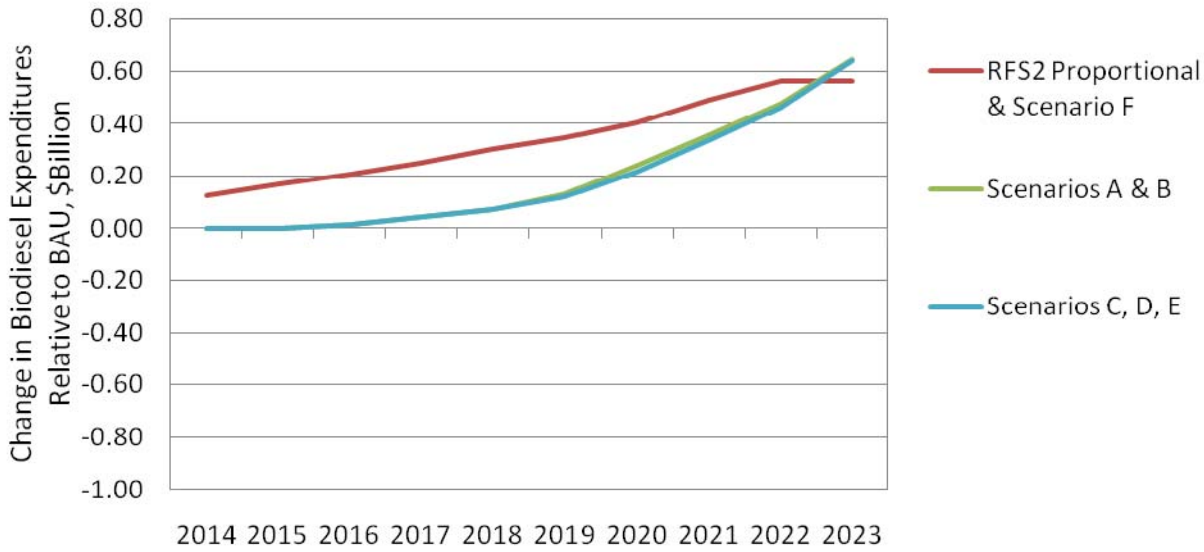

Figure 6-28. Change in Biodiesel Expenditures Relative to the BAU.

Finally, Figure 6-29 provides the net change in fuel expenditures. The two EV scenarios have a net decrease in fuel expenditures because electricity is much less expensive than gasoline and because EVs use less energy than gasoline vehicles. The other scenarios show small increases in total fuel expenditures.

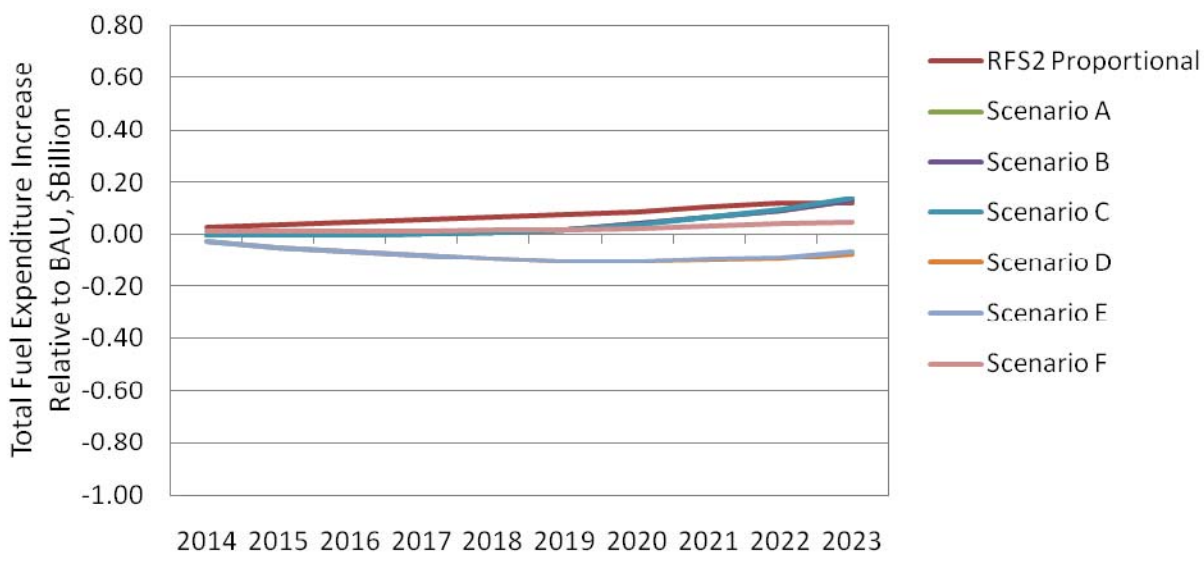

Figure 6-29. Overall Change in Fuel Expenditures Relative to the BAU.

6.4 Emission Reductions

The LCFS reduces the well-to-wheels (WTW) carbon intensity of the fuels consumed by a known amount. The WTW emissions are composed of the well-to-tank (WTT) portion and the tank-to-wheel (TTW) portion. The WTT portion is composed of feedstock recovery and transport as well as fuel production and transport. The WTT emission reductions may or may not occur within Washington State while the TTW or vehicle portion does occur within the State. The following sections quantify the projected emission reductions achieved for the RFS2 proportional case and each LCFS Compliance Scenario. In contrast to the LCFS method of measuring reductions relative to the 2010 baseline, we have calculated reductions relative to the BAU each year. We estimate changes in both GHG and criteria pollutant emissions below.

6.4.1 GHG Emission Reductions

The GHG emission reductions were quantified on both a TTW and WTW basis. To calculate reductions on a TTW basis, the TTW emission factors for each fuel type shown in Table 6-2 were multiplied by the amount of the corresponding fuel type to arrive at a total quantity of emissions. The differences between the TTW GHG emissions in the BAU and the scenarios are illustrated in Figure 6-30. The RFS2 proportional case results in 1.5 million tonnes of reductions relative to the BAU. Scenario E (with the most ethanol and max EVs) resulted in nearly 3.5 million tonnes of GHG reductions relative to the BAU.

Table 6-2. TTW Emission Factors

	TTW Emissions (g CO2e/MJ)
Gasoline Blendstock	74.3
Ethanol	0.8
Diesel	75.0
Biodiesel	3.7
CNG (pipeline)	58.5
CNG (biogas)	2.3
Electricity	0

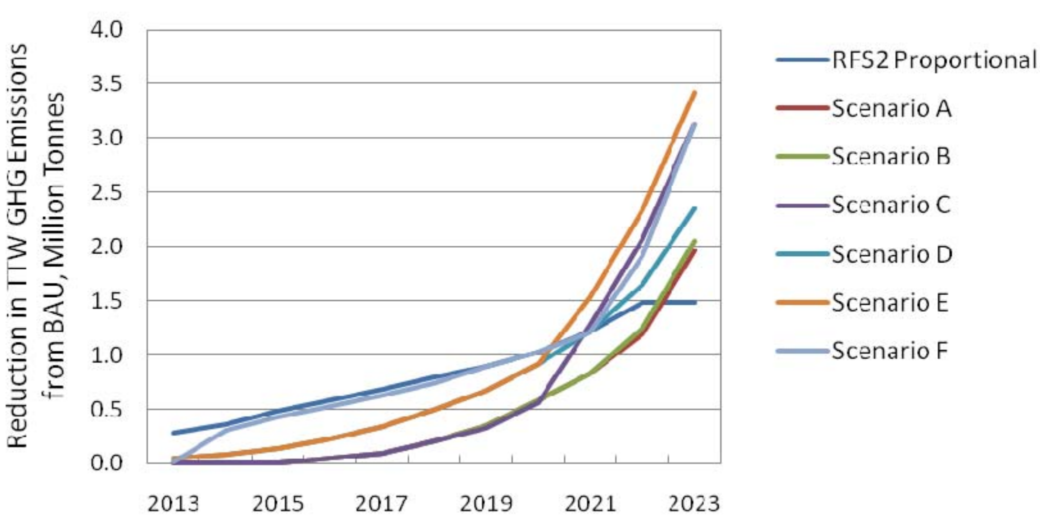

Figure 6-30. TTW GHG Emission Reduction Relative to BAU.

To estimate reductions in WTW GHG emissions we take the gasoline pool carbon intensity profile (see Figure 4-1) and multiply by the gasoline pool fuel use (gasoline, ethanol, electricity, light duty CNG and a portion of the MD CNG) to get gasoline pool tonnes of emissions. The process is repeated for the diesel pool fuels and the resulting tonnes are added to the gasoline pool tonnes to arrive at total tonnes of WTW GHG emissions each year.

Figure 6-31 illustrates the reductions in WTW GHG emissions relative to the BAU. The RFS2 proportional case results in 1.5 million tonne reduction by 2023. The two EV scenarios achieve the largest reduction (~ 4 million tonnes in 2023) pools while the other scenarios result in slightly less than this. Table 6-3 provides the TTW and WTW GHG reductions for 2020 and 2023.

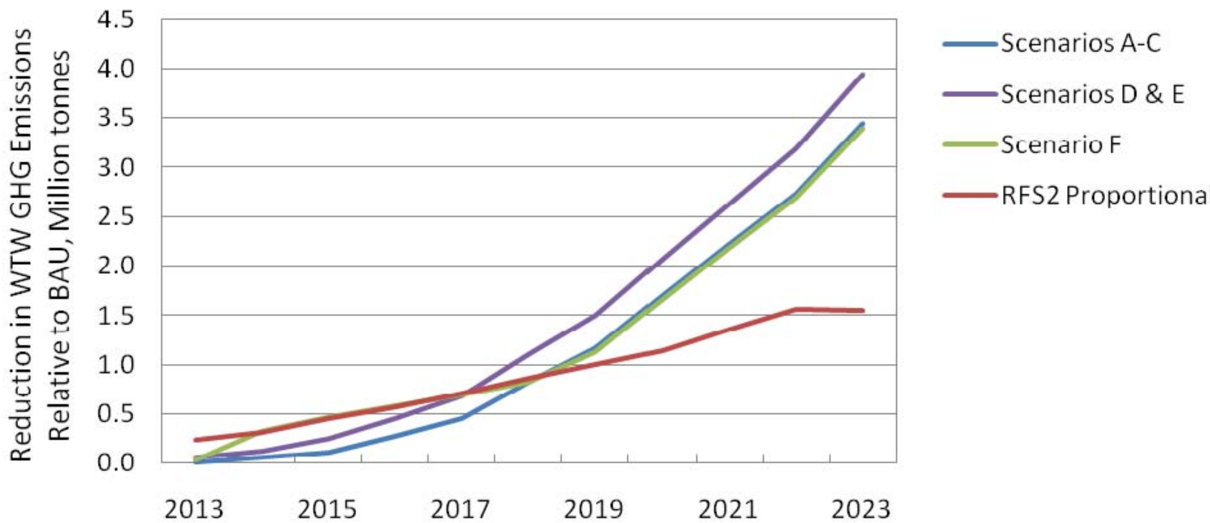

Figure 6-31. WTW GHG Emission Reductions Relative to BAU.

Table 6-3. TTW and WTW GHG Emission Reductions Relative to the BAU

	TTW GHG Reduction from BAU (Million tonnes)		TTW GHG Reduction from BAU (%)		WTW GHG Reduction from BAU (Million tonnes)		WTW GHG Reduction from BAU (%)	
	2020	2023	2020	2023	2020	2023	2020	2023
Scenario A	0.6	2.0	2%	7%	1.7	3.4	5%	9%
Scenario B	0.6	2.1	2%	7%	1.7	3.4	5%	9%
Scenario C	0.6	3.1	2%	11%	1.7	3.4	5%	10%
Scenario D	0.9	2.4	3%	9%	2.1	3.9	6%	11%
Scenario E	0.9	3.4	3%	12%	2.1	3.9	6%	11%
Scenario F	1.0	3.1	4%	11%	1.7	3.4	4%	9%
RFS2 Proportional	1.0	1.5	4%	5%	1.1	1.5	3%	4%

6.4.2 Criteria Pollutant Emission Reductions

In addition to GHG emission impacts of a LCFS, the criteria pollutant impacts of a LCFS have been estimated for each Compliance Scenario. Similar to the GHG emissions, the criteria pollutant emissions are quantified on a well-to-wheel (WTW) basis, but only the emissions from activities within Washington State are included. The following paragraphs step through the WTT and TTW assumptions and provide the WTW criteria pollutant results.

Well-to-Tank Criteria Pollutant Emissions

Table 6-4 provides a summary of the fuel pathways considered and the portions of the WTT fuel cycle that occur within Washington State. Figures 6-32 through 6-36 provide the estimated WTT criteria pollutant emissions that occur within Washington for each fuel pathway. The striking result from these figures is that the criteria pollutant emission estimates for the in-state ethanol production pathways are ~ an order of magnitude higher than the gasoline emissions. This result is consistent with the CARB criteria pollutant analysis,[38] EPA's RFS2 Analysis[39], and a recent EPA publication[40] tabulating the criteria pollutant permit limits for seven U.S. cellulosic ethanol production plants. Key assumptions for each fuel pathway are provided below.

Table 6-4. Overview of Portions of WTT Emissions Occurring in Washington

	Feedstock		Fuel	
	Recovery	**Transport**	**Production**	**Transport**
Gasoline	-	Portion	Portion	Portion
Diesel	-	Portion	Portion	Portion
MW Corn Ethanol	-	-	-	Portion
NW Corn Ethanol	-	-	-	Portion
Forest Residue Ethanol	All	All	All	All
Farmed Tree Ethanol	All	All	All	All
Wheat Straw Ethanol	All	All	All	All
Sugarcane Ethanol	-	-	-	Portion
Imported Cellulosic Ethanol	-	-	-	Portion
Canola Biodiesel	All	All	All	All
Waste Oil Biodiesel	All	All	All	All
Cellulosic Diesel	All	All	All	All
Imported Cellulosic Diesel	-	-	-	Portion
CNG (pipeline NG)	-	Portion	All	N/A
Electricity	Biomass	Portion	All	All

[38] "Proposed Regulation to Implement the Low Carbon Fuel Standard, Volume II", CARB, March 2009.
[39] EPA's Renewable Fuel Standard Regulatory Impact Analysis, Chapter 3. EPA, Feb 3, 2010.
[40] "Potential Air Emission Impacts of Cellulosic Ethanol Production at Seven Demonstration Refineries in the United States", Jones, Donna Lee, U.S. EPA, J.of Air & Waste Management Association 60:1118-1143, Sept 2010.

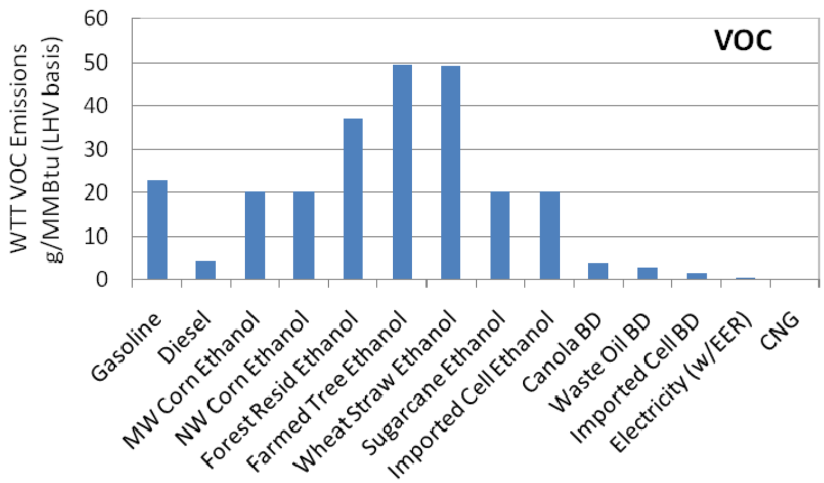

Figure 6-32. Estimated WTT VOC Emissions Occurring in Washington for each Fuel Pathway.

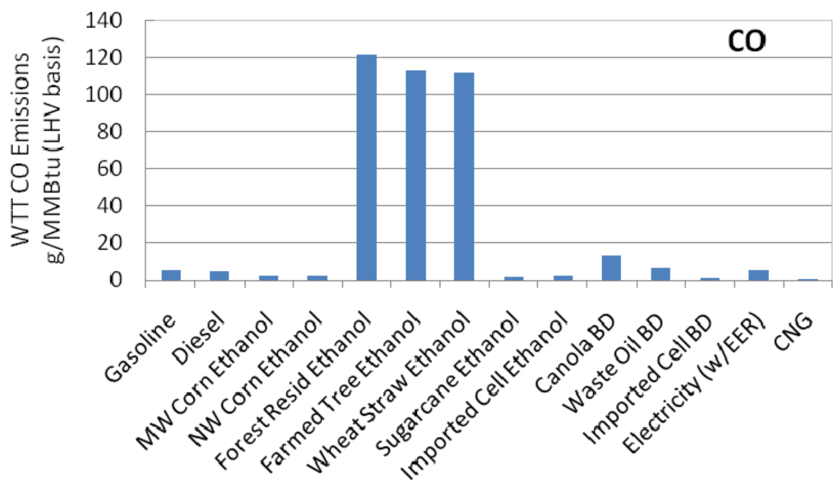

Figure 6-33. Estimated WTT CO Emissions Occurring in Washington for each Fuel Pathway.

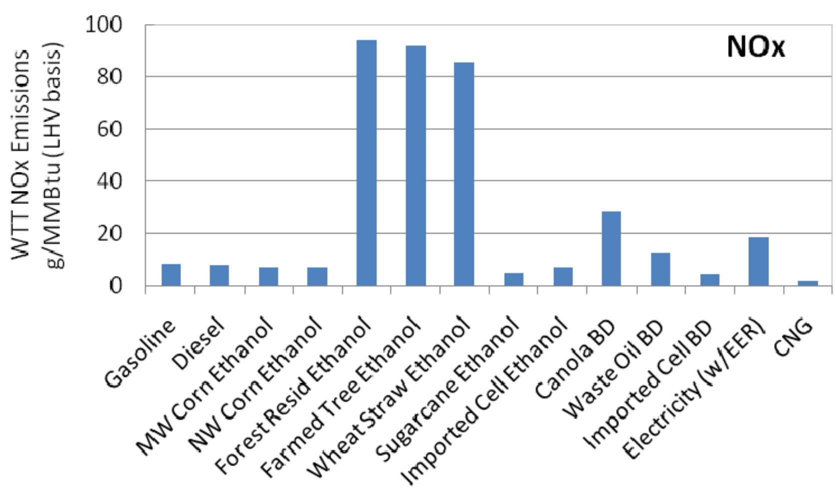

Figure 6-34. Estimated WTT NO_x Emissions Occurring in Washington for each Fuel Pathway.

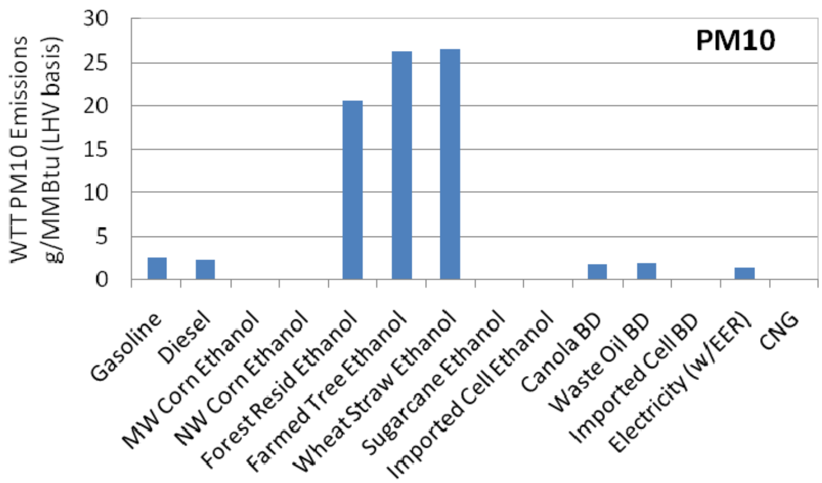

Figure 6-35. Estimated WTT PM_{10} Emissions Occurring in Washington for each Fuel Pathway.

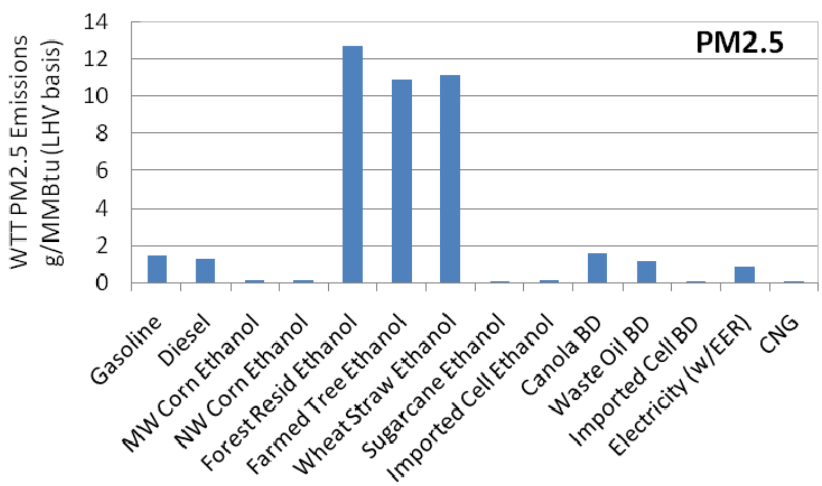

Figure 6-36. Estimated WTT $PM_{2.5}$ Emissions Occurring in Washington for each Fuel Pathway.

Gasoline and Diesel

No crude oil recovery occurs in Washington, so these emissions are not included. Most of the gasoline and diesel consumed in Washington is refined in Washington; approximately ~10 percent of the gasoline and diesel consumed is imported from Montana and Utah. For the Washington refined crude oil, only the portions of the crude oil transport emissions that occur within Washington are included. This includes all of the Washington crude pipeline emissions and 100 miles of the cargo ship emissions. The Washington refining emissions are included as are all of the gasoline and diesel transport emissions for that portion of the fuel that is refined in the State. For the gasoline and diesel produced in Montana, only the portions of the transport emissions that occur within Washington are included. The Washington GREET model was utilized to estimate fuel cycle criteria pollutant emissions. Table 6-5 provides the composite emissions for the gasoline and diesel fuels consumed in Washington.

Table 6-5. Average Washington Criteria Pollutant Emissions for Petroleum Fuels

g/MMBtu (LHV Basis)	VOC	CO	NO_x	PM_{10}	$PM_{2.5}$
Crude Transport					
Gasoline	0.73	0.11	0.44	0.02	0.01
Diesel	0.73	0.11	0.44	0.02	0.01
Refining					
Gasoline	2.3	4.5	5.3	2.4	1.4
Diesel	2.2	4.0	4.7	2.1	1.2
Fuel Transport					
Gasoline	19.9	0.8	2.8	0.1	0.0
Diesel	1.3	0.8	2.8	0.1	0.0
Total WTT					
Gasoline	23.0	5.4	8.6	2.5	1.5
Diesel	4.2	4.9	8.0	2.2	1.3

Ethanol Pathways

Emission estimates for feedstock recovery, feedstock transport and ethanol transport are from the Washington GREET model. To determine emissions from cellulosic ethanol production plants, three sources were considered: the GREET model, the CARB LCFS criteria pollutant analysis, and the recent EPA publication previously mentioned that tabulates the criteria pollutant permit limits for seven cellulosic ethanol production plants in the United States. For out-of-state ethanol production pathways (e.g. corn, sugarcane and out-of-state cellulose), only the ethanol transport emissions that occur in Washington are included.

As shown in the preceding figures, the in-state cellulosic ethanol pathways have significantly higher criteria pollutant emissions than the other fuel pathways. This is due to high feedstock recovery emissions, high feedstock transport emissions, and higher fuel production emissions than the other pathways, including gasoline. Figure 6-37 shows the contribution of each stage of the fuel cycle to total WTT NO_x emissions for the farmed tree to ethanol pathway. The PM_{10} emissions are distributed similarly.

For the cellulosic ethanol pathways, feedstock recovery represents ~ one quarter of the WTT NO_x emissions. Feedstock recovery emissions are calculated from default GREET fuel use and emission factors.[41] The feedstock transport emissions are based on transport to the ethanol plant with heavy duty trucks over a distance of 150 miles. The wheat straw and forest residue pathways assume 120 miles and 75 miles, respectively. Because only approximately 1000 gallons of ethanol are produced from each truckload, locating plants very close to feedstock sources is key to minimizing emissions. Alternatively, ethanol producers could elect to utilize only new or repowered trucks for transport; these could reduced PM and NO_x truck emissions by up to 85 and 90 percent, respectively.

[41] GREET farming tractor default emission factors are 690 g/MMBtu NOx and 62 g/MMBtu PM10

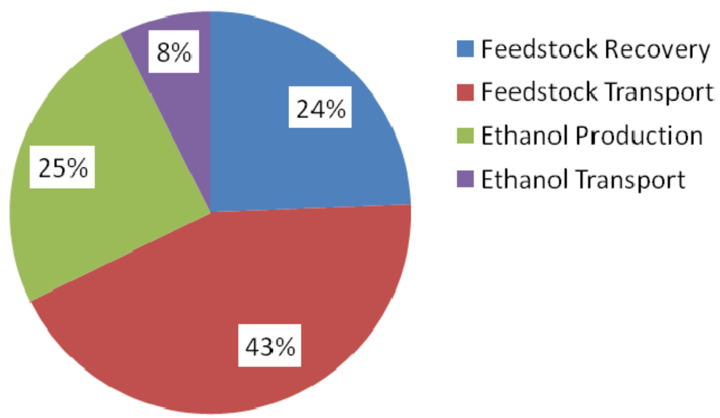

Figure 6-37. Farmed Tree Ethanol WTT NO_x Emissions.

Two different cellulosic ethanol production processes are available: thermo-chemical (gasification) and bio-chemical. In the Washington analysis, the forest residue pathway utilizes gasification while the farmed trees and wheat straw pathways utilize biochemical production processes. The largest permitted cellulosic ethanol production plant is the 100 Million gal/yr Range Fuels plant; ethanol is produced via gasification. Table 6-6 compares the GREET default emissions to the Range Fuels permit limits, and indicates the values utilized for the forest residue pathway in the Washington analysis. The Range Fuel values are used when available. For PM_{10}, the GREET ratio of PM_{10} to $PM_{2.5}$ was used to estimate the Range Fuels PM_{10} emission factor. CARB did not analyze a thermo-chemical ethanol plant.

Table 6-6. Thermo-Chemical (Gasification) Ethanol Production Emission Factors

Pollutant	GREET Default	Range Fuels Permit Limit	Value Used In WA Analysis
	g/MMBtu of Ethanol Produced, LHV Basis		
VOC	6	10	10
CO	82	x	82
NO_x	118	11	11
PM_{10}	14	x	15
$PM_{2.5}$	7	8	8

For the farmed trees and wheat straw pathways, bio-chemical production is assumed. According to the EPA analysis, there are 6 permitted ethanol plants using bio-chemical processes. The largest of these is the 25 million gal/yr POET plant. The five remaining plants each produce less than 3 million gal/yr, so their emission factors are not representative of a commercial scale plant. In their LCFS rulemaking, CARB estimated criteria pollutant emission factors from cellulosic ethanol plants based on actual permit applications, assuming that commercial plants would install Best Available Control Technology (BACT). CARB utilized the Western Biomass pilot plant permit data, scaled the plant up to 50 million gal/yr, and reduced emission factors to reflect installation of BACT on each emission source. Table 6-7 compares the GREET, POET, and CARB criteria pollutant emission factors for bio-chemical cellulosic ethanol production. The Table also provides the values used in the Washington analysis. Table 6-8 summarizes the WTT criteria pollutant emission factors for each ethanol pathway.

Table 6-7. Bio-Chemical Ethanol Production Plant Emission Factors

Pollutant	GREET Farmed Trees	GREET Wheat Straw	CARB Values	POET Permit Limit	Value Used In WA Analysis
	g/MMBtu of Ethanol Produced, LHV Basis				
VOC	21	21	60	24	24
CO	83	87	x	x	85
NO_x	116	122	23	79	23
PM_{10}	25	25	23	87	23
$PM_{2.5}$	9	9	x	x	8

Table 6-8. Summary of WTT Ethanol Criteria Pollutant Emissions.

Pollutant	VOC	CO	NO_x	PM_{10}	$PM_{2.5}$
	g/MMBtu of Ethanol Produced, LHV Basis				
Feedstock Recovery					
MW Corn	0	0	0	0	0
NW Corn	0	0	0	0	0
Brazil Sugarcane	0	0	0	0	0
Forest Residue	5.9	30.7	58.0	5.3	4.7
Farmed Trees	2.3	11.8	22.4	2.0	1.8
Wheat Straw	2.9	15.1	28.5	2.6	2.3
Imported Cellulosic	0	0	0	0	0
Feedstock Transport					
MW Corn	0	0	0	0	0
NW Corn	0	0	0	0	0
Brazil Sugarcane	0	0	0	0	0
Forest Residue	1.3	6.3	18.6	0.3	0.3
Farmed Trees	2.7	13.5	39.9	0.7	0.7
Wheat Straw	1.9	9.4	27.6	0.5	0.5
Imported Cellulosic	0	0	0	0	0
Ethanol Production					
MW Corn	0	0	0	0	0
NW Corn	0	0	0	0	0
Brazil Sugarcane	0	0	0	0	0
Forest Residue	9.5	82.4	11.4	14.9	7.6
Farmed Trees	24.2	85.0	22.8	23.3	8.3
Wheat Straw	24.2	85.0	22.8	23.3	8.3
Imported Cellulosic	0	0	0	0	0

Pollutant	VOC	CO	NO_x	PM_{10}	$PM_{2.5}$
	g/MMBtu of Ethanol Produced, LHV Basis				
Ethanol Transport					
MW Corn	20.2	2.3	7.0	0.1	0.1
NW Corn	20.2	2.3	6.8	0.1	0.1
Brazil Sugarcane	20.1	1.7	5.0	0.1	0.1
Forest Residue	20.2	2.2	6.4	0.1	0.1
Farmed Trees	20.2	2.3	6.8	0.1	0.1
Wheat Straw	20.2	2.3	6.8	0.1	0.1
Imported Cellulosic	20.2	2.3	6.8	0.1	0.1
WTT Total					
MW Corn	20.2	2.3	7.0	0.1	0.1
NW Corn	20.2	2.3	6.8	0.1	0.1
Brazil Sugarcane	20.1	1.7	5.0	0.1	0.1
Forest Residue	36.9	121.5	94.4	20.6	12.7
Farmed Trees	49.4	112.7	91.9	26.2	10.9
Wheat Straw	49.2	111.8	85.7	26.5	11.2
Imported Cellulosic	20.2	2.3	6.8	0.1	0.1

Biodiesel Pathways

Consistent with the ethanol pathway methodology, the Washington GREET model was used to estimate emissions for feedstock recovery, feedstock transport, and biodiesel transport. Actual emissions from a biodiesel production plant were utilized for biodiesel production emission estimates. GREET does not have a cellulosic diesel pathway – for this fuel we have assumed the same emissions as the forest residue ethanol case, adjusting for the considerable difference in heating value. Table 6-9 summarizes the biodiesel WTT criteria pollutant emission factors.

Table 6-9. Summary of WTT Biodiesel Criteria Pollutant Emissions.

Pollutant	VOC	CO	NO_x	PM_{10}	$PM_{2.5}$
	g/MMBtu of Ethanol Produced, LHV Basis				
Feedstock Recovery					
NW Canola	2.1	10.7	18.7	1.4	1.2
Waste Oil	1.1	4.3	5.0	1.6	0.8
In-State Cellulosic	3.8	19.6	37.0	3.4	3.0
Imported Cellulosic	0.0	0.0	0.0	0.0	0.0
Feedstock Transport					
NW Canola	0.2	0.8	2.4	0.0	0.0
Waste Oil	0.0	0.2	0.3	0.0	0.0
In-State Cellulosic	0.8	4.0	11.9	0.2	0.2
Imported Cellulosic	0.0	0.0	0.0	0.0	0.0

Pollutant	VOC	CO	NO_x	PM_{10}	$PM_{2.5}$
	g/MMBtu of Ethanol Produced, LHV Basis				
Biodiesel Production					
NW Canola	0.1	0.1	0.8	0.2	0.2
Waste Oil	0.1	0.1	0.8	0.2	0.2
In-State Cellulosic	6.1	52.6	7.3	9.5	4.9
Imported Cellulosic	0.0	0.0	0.0	0.0	0.0
Biodiesel Transport					
NW Canola	1.5	2.2	6.5	0.1	0.1
Waste Oil	1.5	2.2	6.5	0.1	0.1
In-State Cellulosic	1.5	2.2	6.5	0.1	0.1
Imported Cellulosic	1.5	1.5	4.4	0.1	0.1
WTT Total					
NW Canola	3.9	13.8	28.4	1.7	1.6
Waste Oil	2.7	6.7	12.7	2.0	1.1
In-State Cellulosic	12.2	78.4	62.7	13.2	8.2
Imported Cellulosic	1.5	1.5	4.4	0.1	0.1

CNG Pathway

Two CNG pathways were considered in the GHG analysis: CNG from pipeline natural gas and CNG derived from biogas. Because relatively small amounts of biogas derived CNG are forecast, we have made the assumption for the criteria pollutant estimate that all CNG is from pipeline natural gas. For this pathway, only a portion of the natural gas transmission occurs in Washington along with the compression emissions. All emission estimates are from Washington GREET. Table 6-10 provides the CNG emission factors (note that the WTT total is slightly different from sum of components due to rounding).

Table 6-10. Summary of WTT CNG Criteria Pollutant Emissions.

Pollutant	VOC	CO	NO_x	PM_{10}	$PM_{2.5}$
	g/MMBtu of Ethanol Produced, LHV Basis				
Feedstock Recovery	0.0	0.0	0.0	0.0	0.0
Feedstock Transport	0.1	0.1	0.3	0.0	0.0
CNG Compression	0.0	0.3	1.1	0.1	0.0
WTT Total	0.1	0.5	1.5	0.1	0.1

Electricity Pathway

For the electricity pathway, approximately 75 percent of the generation has no combustion generated emissions. For the balance of the generation, coal, natural gas and a small amount of biomass are consumed. Of these, the only feedstock that is recovered in Washington is biomass. Biomass transport to the powerplant as well as a portion of the NG and coal transport emissions are included. All of the electricity production emissions are assumed to occur in Washington. The Washington GREET model was used to estimate the criteria pollutant emissions. For the coal fired generation, the actual emission factors from Washington's only coal plant (Centralia) were used in GREET.[42] The GREET default emission factors for natural gas combustion were very close to the Washington plant actual emissions. Table 6-11 provides the criteria pollutant emission factors for the electricity pathway. Recall that these must be divided by the EER before comparing to the other pathways.

Table 6-11. Summary of WTT Electricity Criteria Pollutant Emissions (no EER applied).

Pollutant	VOC	CO	NO_x	PM_{10}	$PM_{2.5}$
	g/MMBtu of Ethanol Produced, LHV Basis				
Feedstock Recovery & Transport	0.0	0.1	0.2	0.0	0.0
Electricity Generation	1.5	18.1	60.0	4.6	2.5
WTT Total	1.5	18.2	60.2	4.6	2.6

Vehicle (TTW) Emission Factors

The vehicle emission factors are MOVES[43] outputs provided by Ecology. The MOVES outputs for gasoline and diesel vehicles for calendar years 2013 through 2023 were consolidated into the four VISION vehicle classes: light duty auto, light duty truck, medium duty vehicles (classes 3-6), heavy duty vehicles (classes 7 & 8) for gasoline and diesel. Table 6-12 provides the vehicle emission factors for 2013 and 2023. The assumption was made that vehicles utilizing E85 would have the same TTW emissions as the corresponding gasoline vehicle. Similarly, CNG and biodiesel fueled vehicles were assumed to have the same TTW emissions as the corresponding diesel vehicle.

[42] From EPA's Clean Air Markets website.
[43] EPA's Motor Vehicle Emissions Simulator (MOVES) model.

Table 6-12. Vehicle Emission Factors for 2013 and 2023 from MOVES, g/MMBtu (LHV Basis)

Cal Year	Class	Fuel	Vehicle Emissions, g/MMBtu (LHV)				
			VOC	CO	NOx	PM10	PM2.5
2013	LDA	Gasoline	87	1,458	123	7.2	3.8
2013	LDA	Diesel	17	149	178	9.7	6.8
2013	LDT	Gasoline	144	2,375	230	8.4	4.8
2013	LDT	Diesel	55	257	389	24.2	21.2
2013	MDV	Gasoline	136	3,046	282	7.9	4.0
2013	MDV	Diesel	51	238	388	24.8	21.4
2013	HDV	Gasoline	136	3,046	282	7.9	4.0
2013	HDV	Diesel	26	124	427	22.2	19.1
2023	LDA	Gasoline	46	1,253	43	7.5	3.6
2023	LDA	Diesel	17	605	77	6.2	2.7
2023	LDT	Gasoline	90	1,959	131	9.1	4.9
2023	LDT	Diesel	21	175	197	9.4	6.8
2023	MDV	Gasoline	82	2,765	220	7.7	3.5
2023	MDV	Diesel	18	152	181	9.4	6.4
2023	HDV	Gasoline	82	2,765	220	7.7	3.5
2023	HDV	Diesel	10	57	162	7.7	5.0

WTW Emissions

Once the WTT and TTW emission factors had been determined, a WTW emission factor for each fuel pathway, vehicle class and calendar year was determined (15 fuel pathways, 4 vehicle classes, 11 calendar years). The fuel/vehicle class/calendar year specific WTW emission factors were combined with the amount of each fuel type used each calendar year to estimate the total WTW criteria pollutant emission factors for each Compliance Scenario. Decreases in emissions due to decreased petroleum fuel consumption are offset by increases in emissions due to increased alternative fuel consumption. Figures 6-38 through 6-42 show the percent increase in emissions relative to the BAU for VOC, CO, NO_x, PM_{10} and $PM_{2.5}$, respectively.

In general, the impact on WTW criteria pollutant emissions is small (< 5 percent) except for PM_{10} and $PM_{2.5}$. Emissions of PM_{10} and $PM_{2.5}$ increase as much as 20 percent for the in-state cellulosic fuel scenarios (A and D). These increases are a result of the high assumed feedstock recovery, transport and production emissions. As mentioned earlier, if biofuel producers elected to utilize late model trucks for transporting feedstock as well as new or repowered off-road equipment to recover the feedstock, the NO_x and PM emissions would be significantly lower for these pathways.

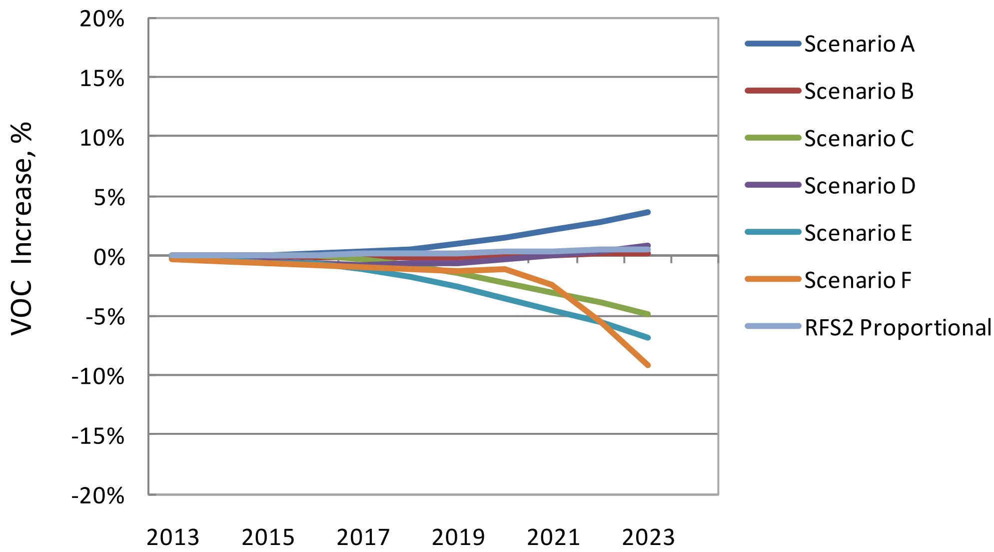

Figure 6-38. Increase in VOC Emissions Relative to BAU.

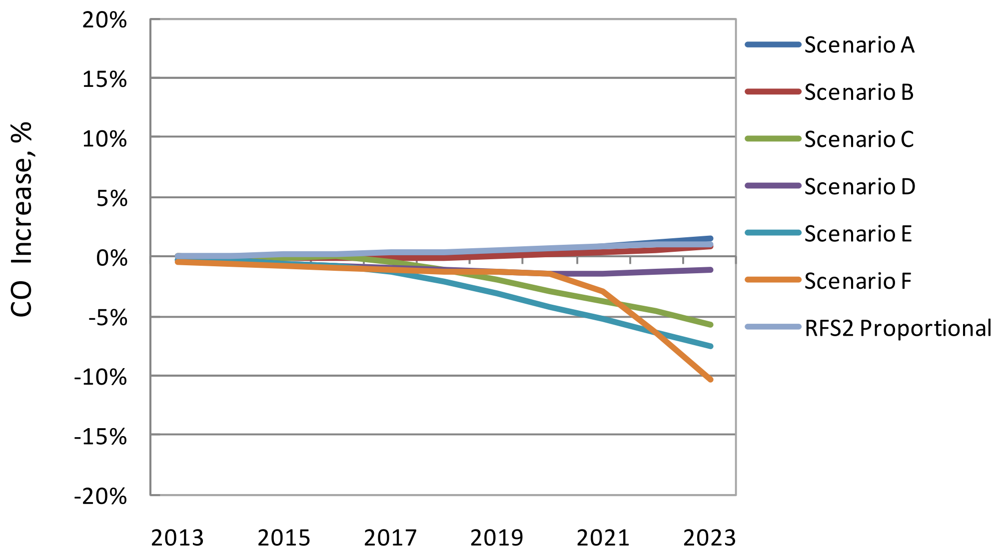

Figure 6-39. Increase in CO Emissions Relative to BAU.

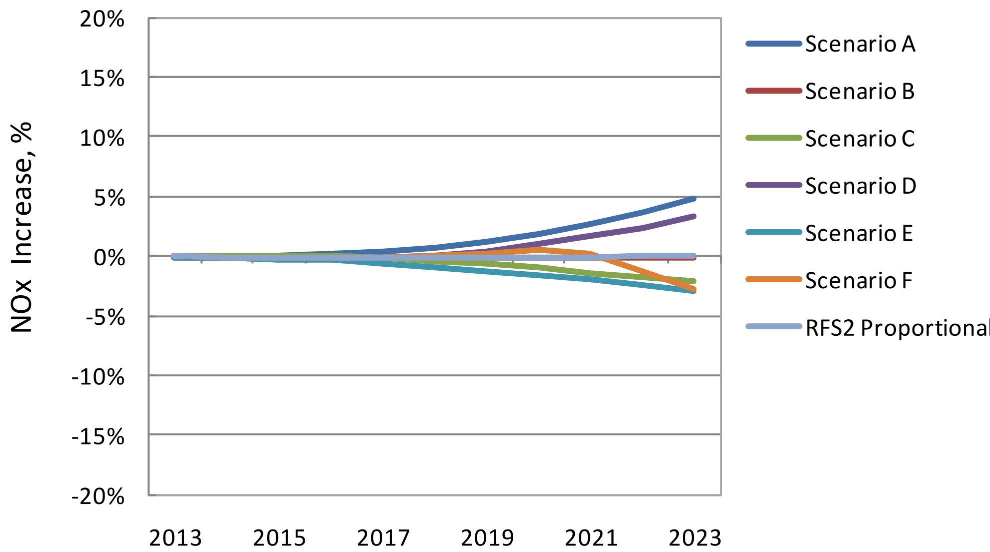

Figure 6-40. Increase in NO_x Emissions Relative to BAU.

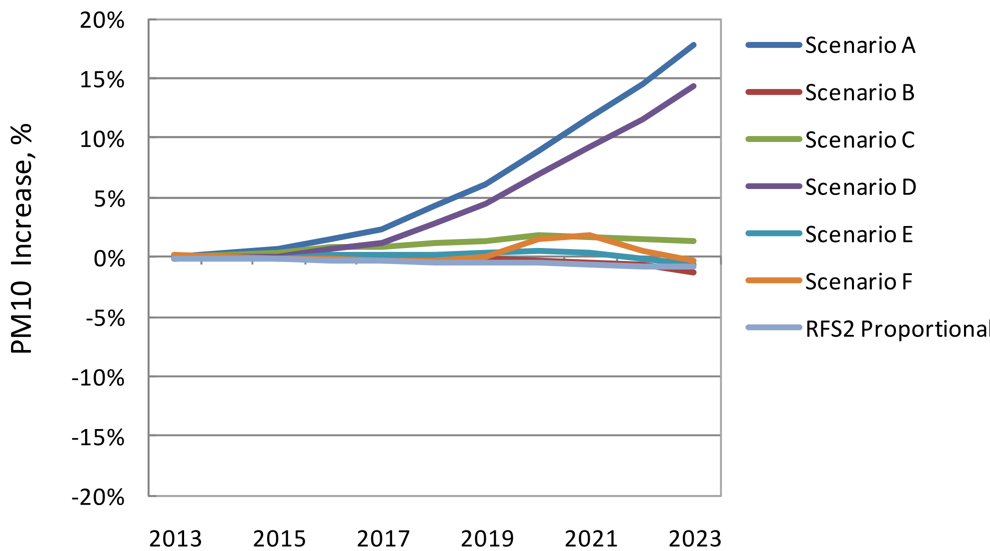

Figure 6-41. Increase in PM_{10} Emissions Relative to BAU.

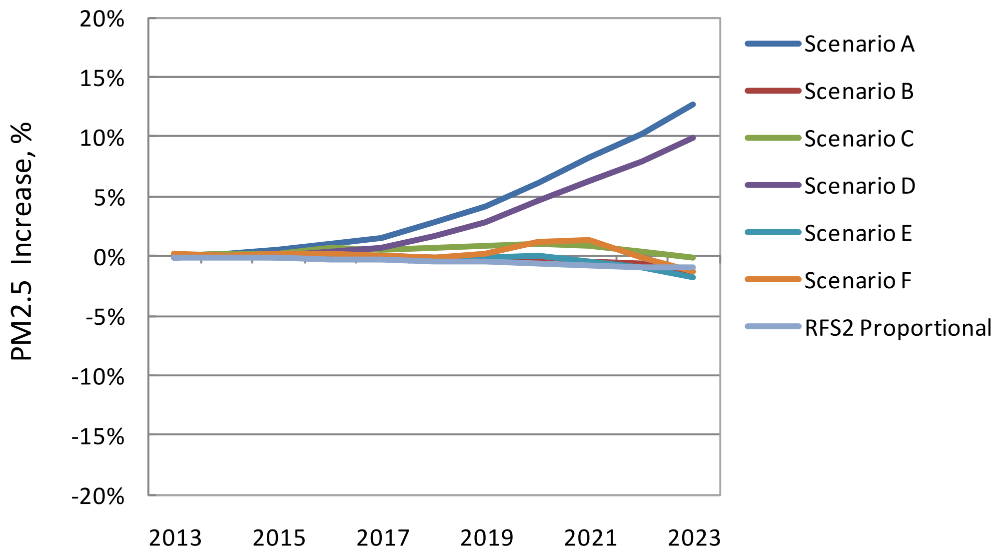

Figure 6-42. Increase in $PM_{2.5}$ Emissions Relative to BAU.

6.5 Petroleum Displacement

A further effect of a LCFS is petroleum displacement. Figures 6-32 and 6-33 illustrate the decreases in gasoline and diesel consumption relative to the BAU for the RFS2 proportional case and for each Compliance Scenario. The RFS2 proportional share case results in minimal gasoline reductions since the BAU has similar levels of ethanol. The Scenarios provide from 3 to 14 percent reduction in gasoline consumption by 2023 and 8 to 14 percent reduction in diesel consumption. Figure 6-34 provides the reduction in combined diesel and gasoline consumption relative to the BAU on an energy basis. The scenarios utilizing higher levels of cellulosic fuels provide relatively less petroleum displacement. This is because cellulosic biofuels have low carbon intensity values, so less is needed for compliance.

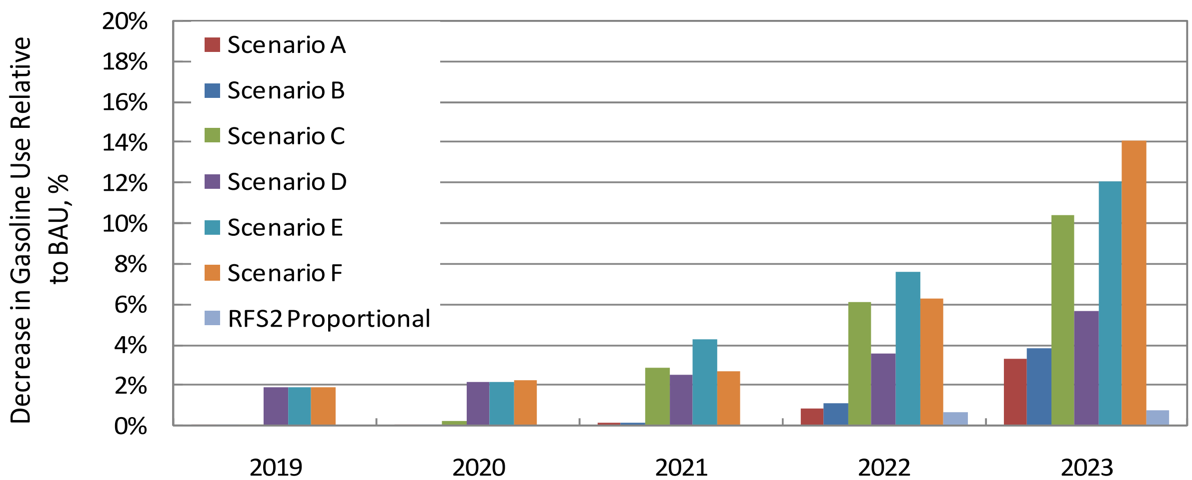

Figure 6-32. Decrease in Gasoline Use Relative to BAU.

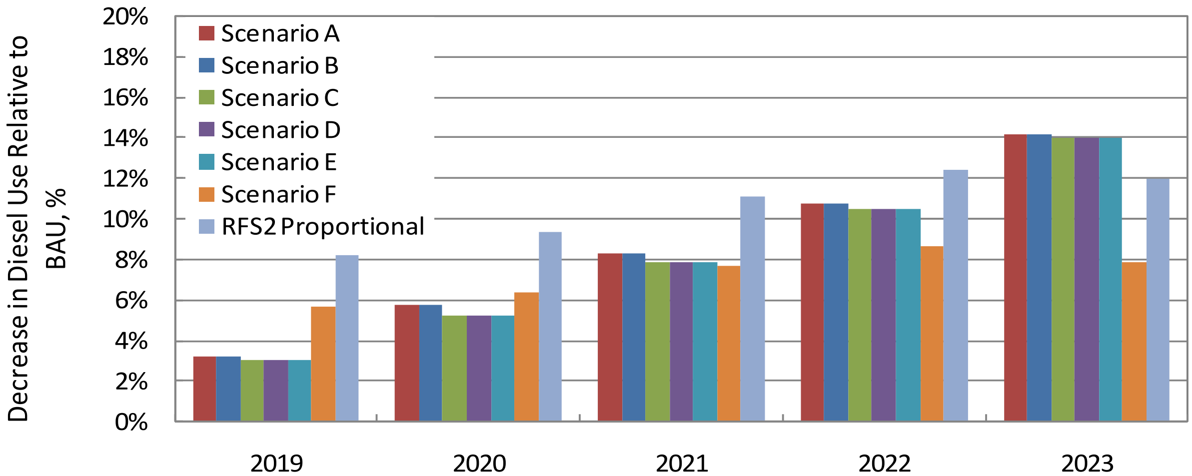

Figure 6-33. Decrease in Diesel Use Relative to BAU.

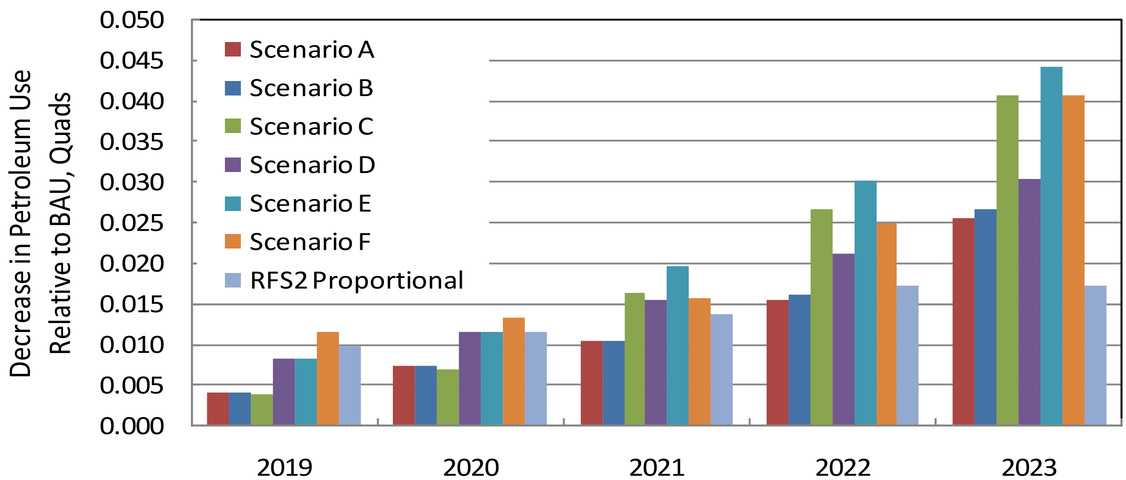

Figure 6-34. Decrease in Overall Petroleum Use Relative to BAU.

6.6 Relative Contributions to Compliance

For each scenario, compliance with the carbon intensity reduction is achieved through a combination of increased biofuel, electricity and CNG consumption. Figure 6-35 demonstrates how much each fuel type contributes to overall compliance in 2023. Note that even in the high EV scenarios (D and E), electricity contributes less than 10 percent to the overall reduction in transportation fuel carbon intensity (less than 20 percent of the gasoline pool reduction). This is because it takes decades to introduce significant levels of new vehicle technology; the benefits that are available in the timeframe of the LCFS are mainly derived from biofuels.

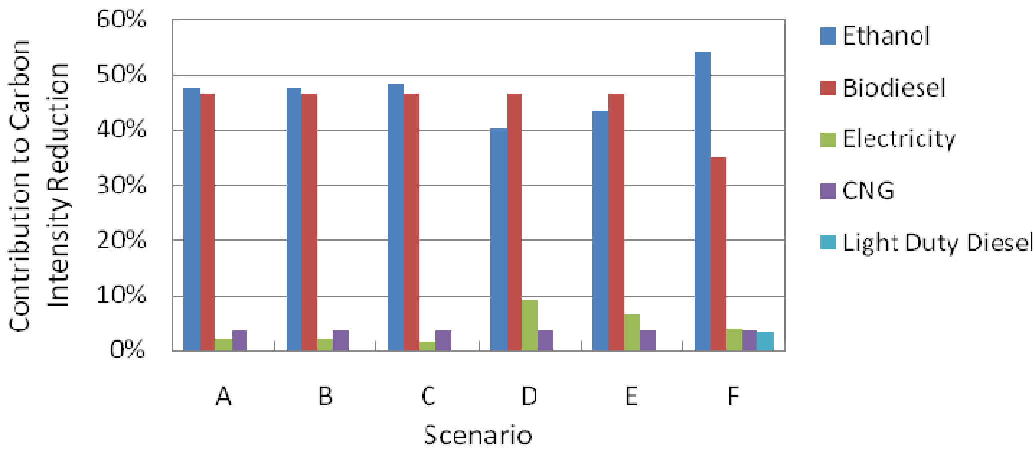

Figure 6-35. Contribution to Overall Carbon Intensity Reduction by Fuel Type.

6.7 High Petroleum Price Sensitivity Case

As mentioned earlier, one of the sensitivity cases considered was a high petroleum price scenario. The AEO 2010 high petroleum prices were utilized (Figure 4-6) for this sensitivity case. In the real world, if the petroleum prices increase, one would expect petroleum consumption and VMT to decrease. The VISION model does not decrease petroleum consumption when price increases, so the impact when prices go up is that expenditures increase. With the LCFS scenarios, reductions in petroleum consumption therefore have a larger positive impact on fuel expenditures. Figures 6-36 and 6-37 show the impact of the high petroleum prices on gasoline and diesel expenditures relative to the BAU. As expected higher prices result in larger decreases in spending on petroleum fuels. These increased fuel expenditures were used in REMI modeling of the high petroleum price sensitivity case.

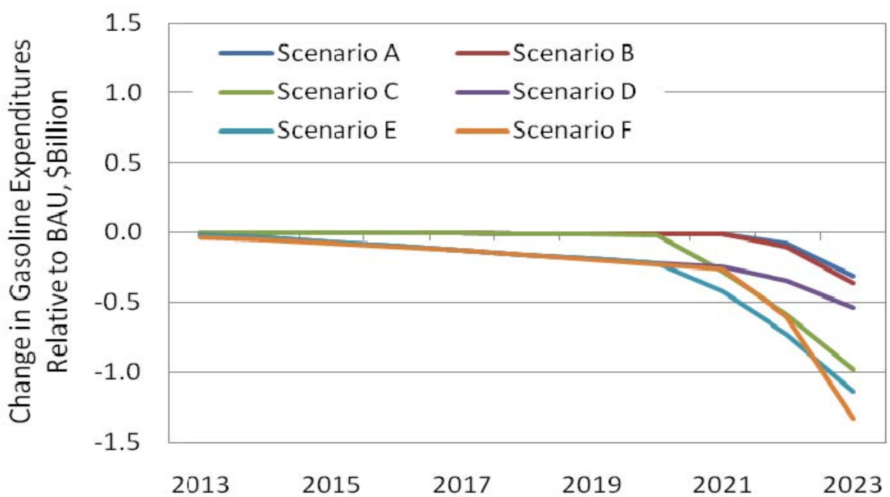

Figure 6-36. Change in Gasoline Expenditures Relative to BAU for High Petroleum Price Sensitivity.

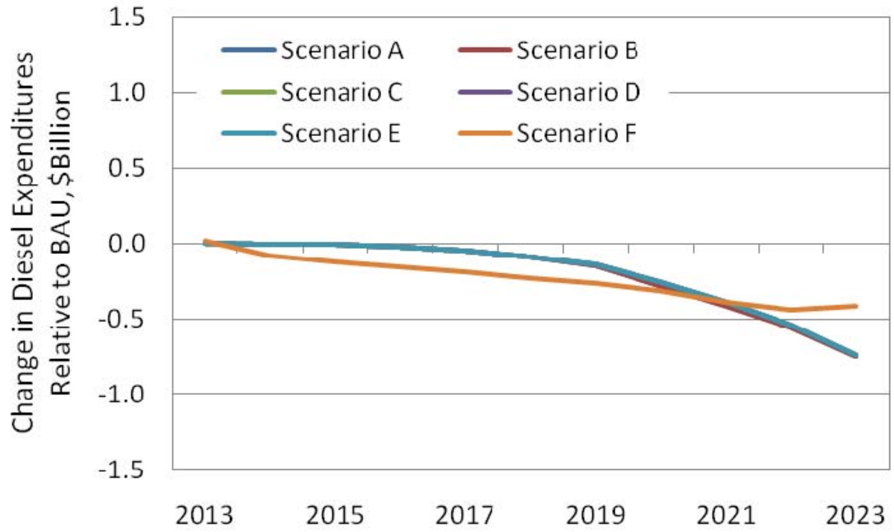

Figure 6-37. Change in Diesel Expenditures Relative to BAU for High Petroleum Price Sensitivity.

6.8 High Cellulosic Biofuel Prices Sensitivity Case

Similarly to the high petroleum price sensitivity cases, the high cellulosic biofuel sensitivity cases applied the prices shown in Figure 4-7 to the cellulosic biofuel volumes in each scenario. Figures 6-38 and 6-39 provide the resulting increased expenditures on ethanol and biodiesel. These increased fuel expenditures were used in REMI modeling of the high cellulosic biofuel price sensitivity case.

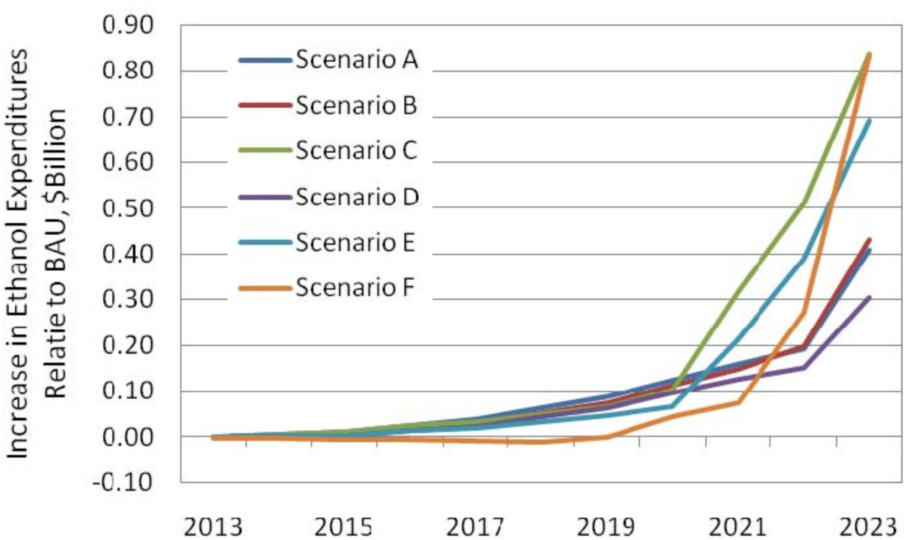

Figure 6-38. Increase in Ethanol Expenditures Relative to BAU for High Cellulosic Biofuels Sensitivity Case.

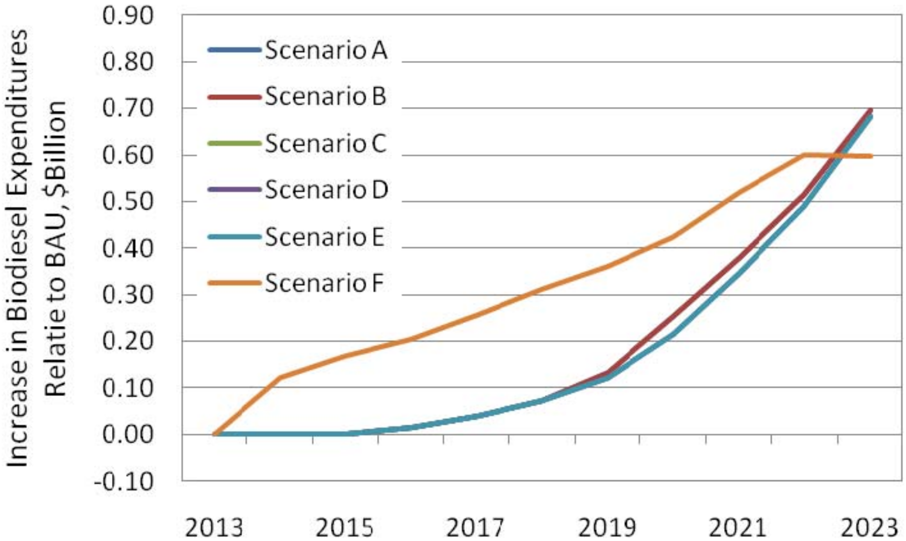

Figure 6-39. Increase in Ethanol Expenditures Relative to BAU for High Cellulosic Biofuels Sensitivity Case.

7. Cost Analysis Assumptions

To support Ecology's LCFS analysis, fuel use and vehicle population assumptions were made for business as usual (BAU) and a range of LCFS compliance scenarios using the VISION model. The Office of Financial Management ran the REMI model for the BAU and compliance scenarios to estimate the economic impact of a LCFS on the State of Washington. TIAX and subcontractor JFA provided REMI model inputs for OFM based on the VISION model outputs. These model documents assumed alternative fuel infrastructure cost assumptions used to create REMI inputs. We provided cost assumptions for plug-in vehicle charging infrastructure, CNG vehicle refueling infrastructure, ethanol handling infrastructure and E85 fueling infrastructure.

7.1 Electric Vehicle Infrastructure Assumptions

Plug-in electric vehicles require chargers. In the early 1990s, the Electric Power Research Institute defined three different charging levels:

- Level 1: 120 volt AC, 15/20 amp circuit (vehicle charging only to prevent overload)
- Level 2: 240 volt AC, single phase 40 amps
- Level 3: 480 volt AC, three-phase circuit fast charger

For battery electric vehicles (BEVs), a Level 2 home charging system is required. For PHEVs, the charging system depends upon battery size; larger vehicles and electric ranges have larger batteries. The amount of time required to charge a range of PHEV vehicles was estimated in a recent report by Battelle Energy Alliance[44] – the results are provided in Table 7-1.

Table 7-1. Estimated Charging Times for Level 1 and Level 2 Systems (Batelle, 2008).

Hours		PHEV-10	PHEV-20	PHEV-40
Level 1	Economy Vehicle	2.7	5.5	10.9
	Mid-size Vehicle	3.6	7.3	14.5
	Light Duty Truck/SUV	4.5	9.1	18.2
Level 2	Economy Vehicle	0.5	1	2
	Mid-size Vehicle	0.7	1.3	2.7
	Light Duty Truck/SUV	0.8	1.7	3.3

For the economic analysis, we assume that one Level 2 charging system is purchased for each EV sold. Based on the estimated charging times above, we further assume that a mix of Level 1 and Level 2 charging systems is purchased for each PHEV as indicated in Table 7-2. Table 7-3 provides the total number of Level 1 and Level 2 home chargers purchased through 2023.

[44] Morrow, Karner, Francfort, "Plug-in Hybrid Electric Vehicle Charging Infrastructure Review", Battelle Energy Alliance, U.S. Department of Energy Idaho National Laboratory. Nov 2008.

Table 7-2. Assumed Shares of Home Charger Type Purchased for Analysis Vehicles.

	Light Duty Auto		Light Duty Truck	
	PHEV	EV	PHEV	EV
Level 1 Charger Share	50%	0%	10%	0%
Level 2 Charger Share	50%	100%	90%	100%

Table 7-3. Cumulative Home Charger Installations by 2023

	BAU and Scenarios A, B, C	Scenarios D & E	Scenario F
PHEV Auto Population	59,421	236,789	118,544
PHEV Light Truck Population	11,962	46,123	23,349
EV Population	12,773	48,028	24,524
Number of Level 1 Chargers	30,907	123,007	61,607
Number of Level 2 Chargers	53,249	207,933	104,810

Estimated costs to install Level 1 and Level 2 home charging systems are provided in Table 7-4. The Level 2 costs are provided by eTec and are for the Greater Seattle area. The Level 1 total cost is from Battelle (2008); it has been divided between labor materials and permit fees according to the Level 2 breakdown. The federal home charging station tax credit expires in 2010, which is earlier than our analysis period, however, there is a Washington state sales tax exemption on labor, materials and services for all EV charging infrastructure installed through January 1 2020. We have assumed a sales tax of 8.8 percent. We also assume that the chargers are produced outside of Washington. Table 7-5 provides total home charger costs through 2023.

Table 7-4. Plug-in Vehicle Home Charger Installed Costs.

	2013-2019 (sales tax exemption)		2020-2023	
	Level 1	Level 2	Level 1	Level 2
Labor	$347	$962	$381	$1,050
Materials	$375	$1,041	$412	$1,137
Permit	$85	$85	$85	$85
Total	$807	$2088	$878	$2,272

Table 7-5. Plug-in Vehicle Home Charger Total Costs, $Million

	BAU and Scenarios A, B, C	Scenarios D & E	Scenario F
2013-2019 (no sales tax)	61.4	251.3	124.7
2020-2023 (with sales tax)	69.7	283.1	140.8
Total	131.1	534.4	265.5

In addition to home charging, we need to consider public charging infrastructure. This consists of a number of commercial and public Level 2 charging locations (e.g. work places, shopping malls parking lots) and commercial Level 3 fast charging stations located in the major urban areas and on connecting highways.

We first estimate the number of Level 2 publicly accessible charging stations. There is a wide range of estimated need for Level 2 charging away from home. The emerging consensus seems to be fewer Level 2 charging stations than some of the earlier thinking. This is due to a number of factors including strong indications that EV ranges will increase over the next several years, decreased costs for Level 3 charging stations, and relatively short driving distances in the Greater Seattle Area[45]. Figure 7-1 provides data from a PSRC household survey about driving habits. For non-work trips, 96 percent of trips are less than 20 miles in length; 90 percent of trips to work are less than 20 miles long.

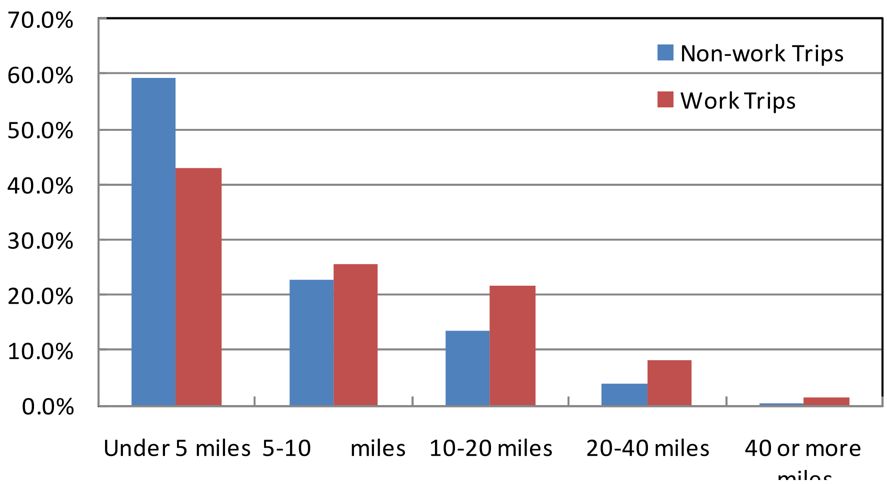

Figure 7-1. Puget Sound Regional Council 2006 Driving Survey Results.

Under the EV Project, eTec will be installing 1500 Level 2 charging stations with Clean Cities installing approximately 300 more. We assume that there will be another similar large public investment in L2 charging infrastructure in Washington State over the next 3-5 years[46]. EV numbers remain small for a number of years. We further assume that there will be a small amount of commercial investment in L2 charging and some ongoing local government investments funded from various grant sources. For our Scenario Analysis, we make the assumptions indicated in Table 7-6.

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[45] Puget Sound Regional Council data indicate that non-work trips are relatively short: 60% less than 5 miles, 82% less than 10 miles.

[46] Assumption is consistent with recent announcement of the Electric Highway program by Washington's Departments of Commerce and Transportation.

Table 7-6. Level 2 Charging Station Installation Assumptions

	BAU and Scenarios A, B, C	Scenarios D & E	Scenario F
The EV Project	1500	1500	1500
Clean Cities	300	300	300
Additional Publicly funded L2 Charging stations by 2012	2000	2000	2000
Total Publicly Funded by 2014	3800	3800	3800
Additional Locally Funded and Commercial L2 Chargers	2%/yr	5%/yr	2%/yr
Additional by 2023	925	1161	925
Total by 2023	4,725	4,961	4,725

Table 7-7 provides estimated costs for installation of L2 publicly accessible charging stations based on the eTec Infrastructure Deployment report[47]. Note that each station has two charging points. Finally Table 7-8 provides total cumulative L2 public charging costs.

Table 7-7. Level 2 Publicly Accessible Charging Station Cost Estimate

	Two Charger L2 Station	
	2010-2019 (no tax)	2020+
Labor	$4,292	$4,670
Materials	$6,287	$6,840
Trenching and Repairs	$4,136	$4,500
Permit	$85	$85
Total	$14,800	$16,095

Table 7-8. Level 2 Charging Station Cumulative Costs through 2023, $Million

	BAU and Scenarios A, B, C	Scenarios D & E	Scenario F
2013-2019 (no sales tax)	8.4	11.6	8.4
2020-2023 (with sales tax)	5.8	6.1	5.8
Total	14.2	17.7	14.2

The Level 3 fast charging station network has two components: distributed along major highways for plug in vehicles traveling long distances, and concentrated in city centers. Table 7-9 shows the estimated number of chargers distributed along major highways for the BAU and LCFS Compliance scenarios. We assume for the BAU the fast charge stations will be located every 40 miles and for the high EV scenarios every 30 miles.

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[47] "Electric Vehicle Charging Infrastructure Deployment Guidelines for the Greater Seattle Area", eTec, Jan 2010.

Table 7-9. Number of Distributed Fast Charge Stations

Highway	Point to Point		Miles
I-5	Vancouver to Blaine		246
I-90	Spokane Valley to Seattle		297
I-82	Ellensburg to Umatilla		137
195	Spokane to Lewiston		118
395	Spokane to Christina Lake		116
20	Kettle Falls to Anacortes		430
16	Tacoma to Kitsap		44
		Total	1,388
		Miles Between	Number of L3 Chargers
BAU & Scenarios A, B, C		40	35
LCFS Scenarios D & E		30	46
LCFS Scenario F		35	40

Next, the number of fast charge stations located within city centers is estimated as shown in Table 7-10. For the BAU and Scenarios A-C we assume that one charger will be located every 6 square miles. For the high EV scenarios (D and E) one charger is assumed every 5 square miles, and for Scenario F we assume one charger every 5.5 square miles.

Table 7-10. Number of Fast Charge Stations Located in City Centers

	Square Miles	Number of Level 3 Chargers		
		BAU and Scenarios A, B, C	Scenarios D & E	Scenario F
Square Miles Per Charger		6	5	5.5
Seattle	142	24	28	26
Bellevue	34	6	7	6
Tacoma	63	11	13	11
Everett	48	8	10	9
Port Orchard	5	1	1	1
Bellingham	32	5	6	6
Spokane	58	10	12	11
Vancouver	46	8	9	8
Olympia	18.5	3	4	3
Tri-cities	92.5	15	19	17
Yakima	20	3	4	4
Total City Fast Chargers		94	113	102

Table 7-11 provides the estimated installed cost for Level 3 Quick Charge Stations[48]. We assume some will be funded through another large federal EV infrastructure initiative and a smaller number will be funded through other sources after 2020. We assume 64 percent are installed through 2019 and 36 percent are installed between 2020 and 2023. Table 7-12 provides estimated cumulative Level 3 charging station costs through 2023. Table 7-13 summarizes the EV charging infrastructure investment.

Table 7-11. Level 3 Charging Station Cost Estimate

	Two Charger Station	
	2010-2019 (no tax)	**2020+**
Labor	$6,452	$7,020
Materials	$52,264	$56,863
Trenching and Repairs	$1,379	$1,500
Concrete Work	$1,379	$1,500
Permit	$85	$85
Total	$61,558	$66,968

Table 7-12. Level 3 Charging Station Cumulative Costs through 2023, $MM

	BAU and Scenarios A, B, C	Scenarios D & E	Scenario F
2013-2019 (no sales tax)	5.1	6.3	5.6
2020-2023 (with sales tax)	3.1	3.8	3.4
Total	8.2	10.1	9.0

Table 7-13. Summary of Cumulative EV Infrastructure Installments through 2023

	BAU and Scenarios A, B, C	Scenarios D & E	Scenario F
Total Home Chargers	84,156	330,940	166,417
Total L2 City Chargers	4,725	4,961	4,725
Total L3 Fast Charge Stations	129	159	142
Home Charger Cost	131.1	534.4	265.5
L2 City Charger Cost	14.2	17.7	14.2
L3 Fast Charge Station Cost	8.2	10.1	9.0
Total Cost, $Million	153.5	562.2	288.7

[48] "Electric Vehicle Charging Infrastructure Deployment Guidelines for the Greater Seattle Area", eTec, Jan 2010.

7.2 CNG Infrastructure Assumptions

Table 7-14 provides our projected CNG vehicle populations for each compliance scenario. Table 7-15 provides the estimated CNG consumption in 2013 and 2023. The amount of CNG consumed in 2023 is approximately three times the 2013 level.

Table 7-14. CNG Vehicle Population Forecasts for BAU and Compliance Scenarios

Scenario	Light Duty		Medium Duty		Heavy Duty	
	2013	2023	2013	2023	2013	2023
BAU	871	2,546	1,946	7,859	494	1,180
Scenarios A-E Gasoline Pool	871	2,546	2,332	9,429	n/a	n/a
Scenarios A-E Diesel Pool	n/a	n/a	2,332	9,429	548	1,394
Scenario F	1,011	3,047	2,332	9,429	548	1,394

Table 7-15. Scenario CNG Consumption Forecasts, MMBtu/yr

Scenario	Light Duty		Medium & Heavy Duty	
	2013	**2023**	**2013**	**2023**
BAU	68,900	146,600	992,300	2,913,700
Scenarios A-E, Gasoline Pool[a]	68,900	146,600	158,300	419,200
Scenarios A-E, Diesel Pool[b]	n/a	n/a	992,100	3,016,900
Scenario F	80,143	175,400	1,150,300	3,490,900

a. Only includes gasoline share of MD/HD CNG use
b. Only includes diesel share of MD/HD CNG use

For light duty vehicles, we assume that 20 percent are purchased by individuals and 25 percent of these will be fueled at home. Therefore, 5 percent of light duty vehicles will have home charging equipment. The rest of the vehicles will refuel at public/private CNG stations. The installed cost of home CNG fueling equipment is estimated at $5500. This includes $4000 for equipment and $1500 for installation[49]. Table 7-16 provides our estimated cumulative home charger costs between 2013 and 2023.

Table 7-16. Estimate of Total Home CNG Refueling Systems Installed by 2023

	Number of Home Refuelers	Total Cost	Labor Cost
BAU	84	$460,600	$125,600
Scenarios A-E	84	$460,600	$125,600
Scenario F	102	$560,000	$152,700

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[49] BRC FuelMaker, pre Gas Equipment Systems, 909-466-6920.

Washington currently has fifteen CNG stations with six open to the public. The average throughput for each station is less than 60,000 MMBtu/yr. The following cost data were provided by Clean Energy Fuels[50]. New CNG refueling station sizes range from 6,000 to12,000 gge/day with corresponding installed costs ranging from $1.5 to $2.8 million. According to Clean Energy Fuels, for a station to be reasonably profitable, throughput must be a minimum of 15 percent of capacity.

We assume for our analysis that the average new station capacity is 8,000 gge/day, with a capacity factor of 30 percent. This results in annual throughput of 120,000 MMBtu/yr per station. The assumed installed cost per station is $2.15 million. Table 7-17 provides our estimate of cumulative CNG station installed costs for BAU and LCFS compliance scenarios. We estimate that half of installed cost is labor.

Table 7-17. Estimated New CNG Refueling Station Cumulative Costs through 2023

	Units	BAU	Scenarios A-E Gasoline Pool	Scenarios A – E Diesel Pool	Scenario F
CNG Use, 2013	MMBtu/yr	1,061,200	227,200[a]	992,100[b]	1,230,443
CNG Use, 2023	MMBtu/yr	3,060,300	565,800	3,016,900	3,666,300
CNG Use Increase	MMBtu/yr	1,999,100	338,600	2,024,800	2,435,857
CNG to be Supplied by Stations[c]	MMBtu/yr	1,995,215	334,715	2,024,800	2,431,094
Estimated Number of Stations		17	3	17	20
Estimated Capital Cost	$	36,550,000	6,450,000	36,550,000	43,000,000
Estimated Labor Cost	$	18,275,000	3,225,000	18,275,000	21,500,000

a. Gasoline pool CNG only
b. Diesel pool CNG only
c. Total less home refueling volumes

For the LCFS diesel and one-pool compliance scenarios, we have assumed that 1 MMBtu/yr of the CNG consumed will be produced from landfill gas. Two LFG to natural gas projects were identified in Washington – we assume that half of the production (1 trillion Btu/yr) would go towards vehicle fueling. The installed cost for a landfill gas cleanup system has been estimated for 1 million MMBtu/yr capacity and is shown in Table 7-18[51].

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[50] Clean Energy Fuels presentation at 2009 Integrated Energy Policy Report workshop.
[51] Cost estimated developed by TIAX under contract to Pacific Gas and Electric Company, 2009.

Table 7-18. Estimated LFG Capture and Cleanup System Costs

	All LCFS Scenarios
Materials	13,212,996
Labor	3,826,715
Site Prep	851,986
Engineering	3,068,592
Permitting	512,635
Contingency	1,703,971
Total Installed	23,176,895

7.3 Ethanol Infrastructure Assumptions

Under the BAU and LCFS compliance scenarios significant increases in ethanol consumption are anticipated. This is achieved through increasing the blend level in gasoline to 15 percent and increased volumes of E85 consumption. The infrastructure costs can be divided into two main categories: ethanol production, handling and storage infrastructure and E85 blending, distribution and refueling infrastructure. Table 7-19 provides the total ethanol volumes for the BAU and compliance scenarios. Because the BAU assumes no increase in E85 consumption, all E85 infrastructure costs will be attributed to the LCFS.

Table 7-19. Projected Ethanol Consumption Volumes (million gal/yr)

	Total Ethanol Consumption 2023	Total E85 Consumption 2023
BAU	343	0
Scenario A (In-state cellulosic)	411	103
Scenario B (out-of state cellulosic)	425	119
Scenario C (mixed Ethanol)	607	330
Scenario D (EVs, in-state cellulosic)	379	77
Scenario E (EVs, out-of state cellulosic)	555	281
Scenario F (One Pool)	607	342

7.3.1 Ethanol Production Facility Costs

For all of the scenarios except Scenario B some level of in-state cellulosic ethanol production is assumed. Table 7-20 provides the projected volumes of in-state cellulosic ethanol for each of the scenarios. Also shown is EPA's estimate of average cellulosic production plant size in 2015 and corresponding plant installed cost. The number of in-state cellulosic ethanol plants is expected to range from 2 to 5, at a cost of $400 million to over $1 billion. It is assumed that the BAU will not result in any additional ethanol plants in Washington.

Table 7-20. Estimated Ethanol Production Plant Costs

	Units	Scenarios					
		A	B	C	D	E	F
In-State Production, 2023	MM Gal/yr	368	0	134	336	122	134
Plant Size[a]	MMGal/yr	69	69	69	69	69	69
New Plants by 2023		5	0	2	5	2	2
Capital Cost per Plant[a]	$MM	220	220	220	220	220	220
Total Capital Cost by 2023	$MM	1,100	0	440	1,100	440	440

a. EPA RFS2 RIA Chapter 4.1, page 754.

7.3.2 Ethanol Transportation and Storage Costs

We assume here that no upgrades are needed at marine terminals to handle increased levels of sugarcane ethanol since these volumes are expected to enter through Seattle for U.S. compliance with RFS2. Imported ethanol is also received by rail in Spokane and Portland. In Spokane, there is already an ethanol unit train receipt facility in place. Therefore, it is assumed that no upgrades to the Washington rail terminals are needed to handle increased volumes of imported ethanol.

To transport the increased volumes of ethanol to the petroleum terminals (from rail, marine or production plants), new tanker trucks will be needed. Using the EPA RFS2 assumptions of 8000 gallon capacity and 6 trips per day per tanker truck, we estimate the numbers of new trucks needed by 2023 to transport increased volumes of ethanol to the petroleum terminals shown in Table 7-21.

Table 7-21. Estimated Number of Tanker Trucks to Transport Ethanol to Petroleum Terminals

	Units	Scenarios						
		BAU	A	B	C	D	E	F
Ethanol Volumes, 2023	MMgal/yr	343	411	425	607	379	555	607
Volume Increase from 2013	MMgal/yr	108	176	190	372	144	320	372
Truck Capacity[a]	Gallons	8,000	8,000	8,000	8,000	8,000	8,000	8,000
Truck Trips per day[a]		6	6	6	6	6	6	6
Total New Trucks by 2023		6	10	11	21	8	18	21
Truck Price	$1000	180	180	180	180	180	180	180
Total Cost of New Trucks	$MM	1.08	1.80	1.98	3.78	1.44	3.24	3.78

a. EPA RFS2 RIA Chapter 4.2

To handle the increased volume of ethanol at the petroleum terminals, new storage tanks will need to be constructed (some petroleum tanks can be retrofit). Additional truck unloading, blending and ancillary equipment will be needed. EPA estimated these costs for the RFS2 primary control case at 0.113 $/annual gallon of ethanol. This includes a 15 percent working inventory and assumes that much of the storage capacity could be accommodated by storage tanks that had previously stored gasoline displaced by the increased volumes of ethanol. However, ethanol has a lower energy density than gasoline, so only 67 percent of the new ethanol storage capacity can be satisfied by modified existing gasoline storage tanks. The EPA value is utilized directly to estimate the petroleum terminal costs for each scenario (Table 7-22).

Table 7-22. Petroleum Terminal Upgrade Costs, cumulative through 2023

	Units	Scenarios						
		BAU	**A**	**B**	**C**	**D**	**E**	**F**
Ethanol Volumes, 2023	MMgal/yr	343	411	425	607	379	555	607
Increased Volume from 2013	MMgal/yr	108	176	190	372	144	320	372
Terminal Upgrade Costs[a]	$/gal/yr	0.113	0.113	0.113	0.113	0.113	0.113	0.113
Total Terminal Costs, 2023	$Million	12.2	19.9	21.5	42.1	16.3	36.2	42.1

a. EPA RFS2 RIA Chapter 4.2

7.3.3 E85 Infrastructure Costs

To handle increased E85 consumption, we consider costs associated with transporting E85 from terminals to fueling stations, and the fueling station costs. Because the increase in volumes of E85 is less for all scenarios than the decrease in gasoline volumes by 2023, no increase in the number of tanker trucks to distribute E85 to the refueling stations is needed. Therefore, only modifications to refueling stations are considered. In the RFS2 RIA, EPA assumes that 25 percent of gasoline refueling stations will have E85 dispensing equipment. Depending upon the ethanol volumes, EPA assumed varying numbers of E85 dispensers per station. There are currently 3086 gasoline stations in Washington; 16 of these can dispense E85[52]. Table 7-23 provides the estimated cost for E85 station retrofit costs by 2023.

Table 7-23. Estimated E85 Refueling Infrastructure Costs, Cumulative through 2023

	Units	Scenarios					
		A	**B**	**C**	**D**	**E**	**F**
Projected E85 Use in 2023	MMGal/yr	103	119	330	77	281	342
Existing Gasoline Stations		3,086	3,086	3,086	3,086	3,086	3,086
New Stations with E85 by 2023		756	756	756	756	756	756
Average E85 Station Throughput	MMGal/yr	0.133	0.154	0.427	0.100	0.364	0.443
Share of Stations w/ 1 Dispenser	%	50%	50%	0%	100%	0%	0%
Share of Stations w/ 2 Dispensers	%	50%	50%	100%	0%	100%	100%
One Dispenser Station Cost[a]	$	131,000	131,000	131,000	131,000	131,000	131,000
Two Dispenser Station Cost[a]	$	154,000	154,000	154,000	154,000	154,000	154,000
Total Cost by 2023	$Million	108	108	116	99	116	116

a. EPA RFS2 Chapter 4.2. Installed cost including 15,000 underground storage tank.

[52] EIA: http://www.eia.doe.gov/state/state_energy_profiles.cfm?sid=WA

7.4 Biodistillate Infrastructure Assumptions

Conventional biodiesel production facilities are already in place, however, new plants to produce cellulosic biodiesel will be needed in Washington for each scenario except Scenario B. The capital costs for installing cellulosic biodiesel plant capacity are shown in Table 7-24. The plant size and capital cost are from EPA RFS2 RIA Chapter 4.1.

Additional trucks are needed to transport biodiesel volumes from either the production plant or the rail terminal to the petroleum terminals. Table 7-25 provides the number of new trucks and associated cost needed by 2023 to transport BD from rail/plant to petroleum terminal using EPA's assumptions from RFS2 RIA.

Upgrades at the petroleum terminals are needed to unload the tanker trucks, store the biodiesel and blend it into conventional diesel. The cost estimate for these upgrades is provided in Table 7-26, based on EPA's RFS2 RIA Chapter 4.2.

Table 7-24. Estimated Cellulosic Diesel Production Plant Costs in Washington by 2023

	Units	Scenario				
		BAU	A	B	C, D, E	F
In-State Cellulosic Production, 2023	MMGal/yr	0	106	0	47	38.1
Cellulosic BD Plant Capital Cost	$MM	346	346	346	346	346
Plant Size	MMGal/yr	33	33	33	33	33
Number of Plants in Washington		0	3	0	1	1
Installed Cost of Plants	$MM		1,038	0	346	346

Table 7-25. Estimated Cost of New Trucks to Transport BD to the Petroleum Terminals

	Units	Scenario				
		BAU	A	B	C, D, E	F
Increase in BD Use by 2023	MMGal/yr	1	152	152	150	133
Truck Capacity	Gal	8,000	8,000	8,000	8,000	8,000
Truck Trips per Day		6	6	6	6	6
Number of New Trucks by 2023		0	9	9	9	8
Cost per truck	$1000	198	198	198	198	198
Total Cost of New Trucks by 2023	$Million	0	1.8	1.8	1.8	1.8

Table 7-26. Estimated Cost to Upgrade Petroleum Terminals to Unload, Store and Blend BD

	Units	Scenario				
		BAU	A	B	C, D, E	F
Increase in BD Use by 2023	MMGal/yr	1	152	152	150	133
Terminal Upgrade Cost	$/gal/yr	0.051	0.051	0.051	0.051	0.051
Cumulative Upgrade Cost by 2023	$Million	0.05	7.7	7.7	7.6	6.7

As mentioned in the ethanol section, total volumes of liquid transportation fuel decrease from 2013 to 2023. Therefore, no increase in trucks to distribute fuels from the petroleum terminal to the refueling station is needed. No upgrades at the refueling station are needed to dispense BD.

7.5 Summary of Alternative Fuel Infrastructure Investments

The total estimated alternative fuel infrastructure investment for the BAU and each compliance scenario are shown in Figure 7-2. Investment is estimated to range from $300 Million for the imported cellulosic biofuel scenario (Scenario B) to $2.5 Billion for the in-state cellulosic biofuel scenario. Building new cellulosic biofuel facilities is the largest contributor to cost. Electric vehicle and E-85 station costs are the next largest component each costing ~$150 Million. For the high EV penetration cases (Scenarios D and E), the EV charging infrastructure was much larger at ~$550 Million.

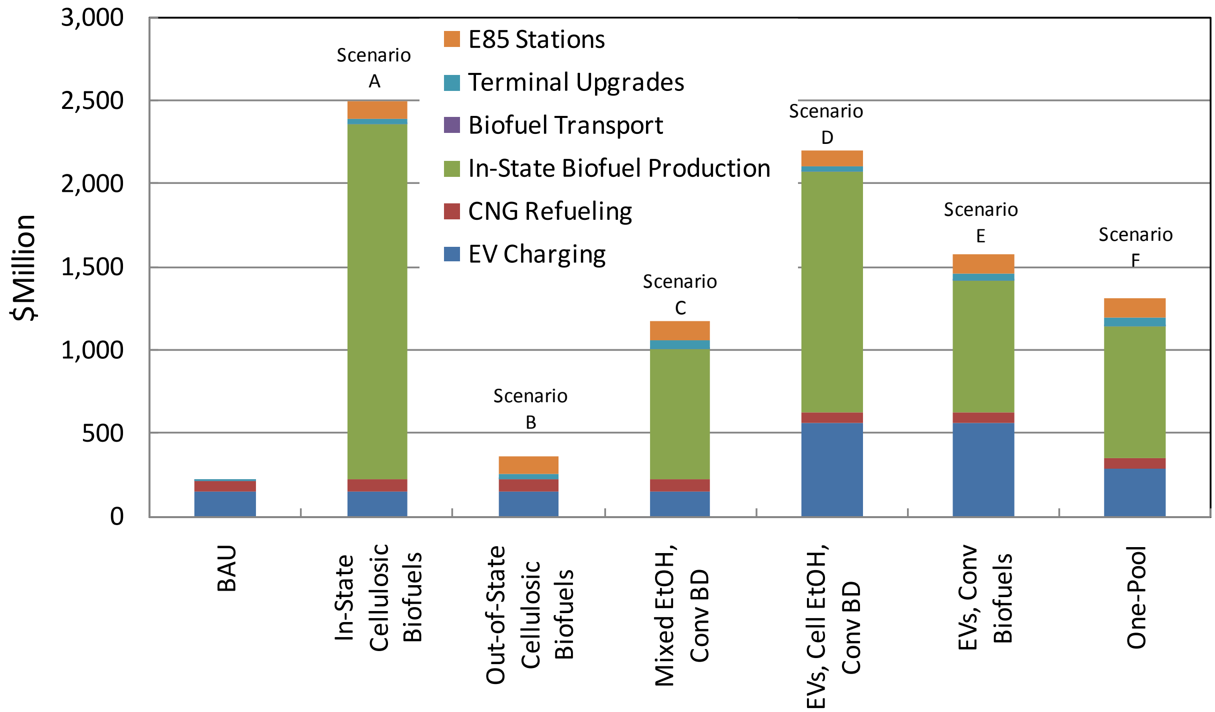


Figure 7-2. Summary of Estimated Infrastructure Investment.

8. Economic Analysis

The VISION estimates of fuel and vehicle expenditures for each compliance scenario were coupled with the infrastructure cost estimates provided in Section 7 and used in the REMI model to estimate impacts on employment, personal income and state gross product. These are the classic metrics of an economic impact analysis. An alternative analysis that is sometimes conducted to evaluate policy impacts is a cost-benefit analysis. A cost-benefit analysis measures consumer welfare or utility; these analyses are subject to a wide margin of uncertainty. Moreover, it is very difficult to measure total consumer utility, making it hard to use cost-benefit analysis to determine the significance of the impact. An economic impact analysis was conducted here because it provides more effective and useful information for policy makers than a cost-benefit analysis. The following sections describe how the microeconomic VISION outputs were translated into macro-economic REMI inputs and provide the REMI model results.

8.1 REMI Model Inputs

The VISION model is a valuable tool for measuring the impacts of changes to vehicle fleets and fuels, but it does not produce macroeconomic impacts that show how such changes might reverberate through the broader economy. Significant increases in the consumption of biofuels, particularly of biofuels produced in-state, can be expected to impact farming and agricultural sectors of the economy. Significant shifts away from petroleum-based fuels (gasoline and diesel) can be expected to have impacts on businesses involved in oil production, refining and transportation. Significant new utilization of natural gas or electricity produced in-state would also affect related industries. Macroeconomic models seek to estimate these broader impacts. For this project, the study team utilized the “REMI PI+” model, produced by Regional Economic Models, Incorporated.

As mentioned above, VISION provides only some of the values necessary to fully inform the REMI PI+ model of the direct economic expenditures expected under the different scenarios (fuel and vehicle expenditures). These were coupled with estimates described in Section 7 for a number of direct expenditures expected as part of each scenario. The expenditures included:

- New refining capacity for ethanol and for biodiesel
- Labor, utilities and feedstock costs for new refinery operations
- Distribution and fueling infrastructure (including additional tanker fleet costs) for additional biofuels and natural gas
- Fueling infrastructure and additional vehicle costs for electric/plug-in hybrid-electric fleet
- Additional vehicle costs for natural-gas powered heavy-duty vehicles

All expenditures (fuel, vehicles, infrastructure) were translated to 2008 dollar basis. The infrastructure costs were also fit to an expenditure schedules. For example, the cost of building a cellulosic ethanol production plant was distributed over two years. The number of plants built each year was synchronized with the cellulosic ethanol consumption rate for each scenario.

8.2 REMI Model Results

The Washington State Office of Financial Management and Department of Ecology jointly conducted an economic impact assessment of a possible LCFS in Washington. The economic impact analysis built on the modeling described in the preceding sections using a localized version of VISION 2009. The economic impacts of the Washington LCFS compliance scenarios were estimated using the 2009 Regional Economic Modeling Incorporated's Policy Insight (REMI PI+) model for the state. This section provides a summary of the REMI modeling results – the full report is provided in the Appendix.

In the impact analysis, six future compliance scenarios were defined to take into account the uncertainties in technology development and pace of innovation breakthroughs, they identify upside benefits, downside risks and middle-road future developments. Table 8-1 lists these scenarios, with a brief summary of assumptions imbedded in each.

Table 8-1: Description of the Washington LCFS Scenarios

Scenario A	Compliance through cellulosic ethanol and diesel fuels produced in-state
Scenario B	Compliance through cellulosic ethanol and diesel fuels produced out-of-state
Scenario C	Compliance through mixed sources of biofuels: conventional, cellulosic, imported and in-state.
Scenario D	Compliance through high electric vehicle (EVs) sales and in-state cellulosic biofuels.
Scenario E	Compliance through high electric vehicle (EVs) sales and mixed sources of biofuels.
Scenario F	One-Pool: a ""middle-of-the-road" scenario combining a mixture of biofuel and electrical vehicles, and increased use of light duty diesels.

The VISION model was used to estimate future energy uses under the different scenarios. Since VISION was calibrated using data from the U.S. Energy Information Administration's 2010 Annual Energy Outlook (AEO), the model's estimates are consistent with the U.S. Energy Department's energy uses, prices, and technology projections for the future. The VISION model's original projection, without local LCFS interventions, is treated as a "Business-As-Usual" (BAU) or do-nothing scenario. The BAU thus incorporates all the national energy policies currently in action. Please refer to Section 4 of this report for the VISION assumptions.

With future energy uses/demand as inputs, REMI PI+ was then run to forecast future economic paths under different scenarios. The difference in the economic outcomes between each scenario and the BAU represents that scenario's net economic impact on the state economy. Magnitudes of the impact are generally measured by the scenario-induced changes, relative to BAU, in state employment, personal income, and Gross Domestic Product (GDP).

Changes in fuel demand, new investment in biofuel production plants, additional investment in equipment (including LDV's and trucks) required for LCFS compliance will impact the

Washington economy. Expenditures in these areas affect the economy directly, and these direct effects then generate changes in spending on intermediate and investment goods and services from related sectors of the economy. In addition, the corresponding employment and income changes will alter the buying power of the state residents, again induce more changes in spending on goods and services. The REMI PI+ model, given direct impact (from VISION), estimates the complete indirect (or so-called "rippling") economic impact. Direct and indirect impacts add up to total impact. The state-level LCFS impact analyses have been performed for the period 2014-2023, and the results are shown in Table 8-2. As can be seen, impacts are small – less than half a percent in all cases.

Table 8-2. Annual Average Economic Impact for Each Scenario Relative to BAU (2014-2023)

Reference Case	Change in Employment		Change in Total Personal Income		Gross Domestic Product	
	1,000 jobs	% Relative to 2009	$2008, Millions	% Relative to 2009	$2000, Millions	% Relative to 2009
Scenario A	12.0	0.3%	526.4	0.2%	741.3	0.3%
Scenario B	-0.2	0.0%	-13.8	0.0%	-36.5	0.0%
Scenario C	3.9	0.1%	177.7	0.1%	225.3	0.1%
Scenario D	8.2	0.2%	341.7	0.1%	454.2	0.2%
Scenario E	3.6	0.1%	147.6	0.1%	164.4	0.1%
Scenario F	6.0	0.2%	281.6	0.1%	389.3	0.1%
BAU, 2009 Level	*3,727.4*		*26,3524.4*		*259,603.0*	

The Reference Case analysis summarized above incorporates the projected future fuel prices in the 2010 U.S. Energy Department's 2010 Annual Energy Outlook (AEO) Baseline forecast. To examine the effect of future uncertainties in the price forecasts, additional impact analyses have A **"High petroleum prices"** case that assumes future petroleum prices would be about 33 percent above the levels assumed in the Reference Case;

- A **"High cellulosic ethanol and diesel prices"** case that assumes future cellulosic biofuel prices to be about double the levels of that in Reference Case.

For detailed descriptions of the fuel price assumptions, please refer to Section 4.3 of this report. Table 8-3 summarizes the results for these two alternative cases relative to the BAU and compares them to the reference case results.

Table 8-3. Annual Average Economic Impact for Alternative Cases Relative to BAU (2014-2023)

	Reference	High Petroleum Fuel Prices	High Ethanol and Diesel Prices
Change in Employment (1,000 jobs)			
Scenario A	12.0	12.3	11.0
Scenario B	-0.2	0.5	-1.6
Scenario C	3.9	4.8	2.7
Scenario D	8.2	9.1	7.4
Scenario E	3.6	4.9	2.5
Scenario F	6.0	7.2	5.5
BAU, 2009 Total Emp.	*3727.4*		
Change in Total Personal Income ($2008, Millions)			
Scenario A	526.4	561.1	479.9
Scenario B	-13.8	21.5	-83.1
Scenario C	177.7	226.9	118.7
Scenario D	341.7	395.3	308.1
Scenario E	147.6	213.7	92.6
Scenario F	281.6	353.4	257.7
BAU, 2009 Personal Income	*263,524.4*		
Change in Gross Domestic Product ($2000, Millions)			
Scenario A	741.3	801.9	650.3
Scenario B	-36.5	25.5	-163.0
Scenario C	225.3	313.0	118.3
Scenario D	454.2	545.0	381.7
Scenario E	164.4	278.5	64.4
Scenario F	389.3	509.1	343.2
BAU, 2009 GDP	*259,603.0*		

"High petroleum prices" Case - In all of the LCFS scenarios, the quantities of petroleum fuels consumed are lower than in the BAU scenario. As a result, higher future prices of petroleum fuels enlarge the negative fuel spending gap between each LCFS scenario and BAU. A larger negative spending gap means the consumers get to retain a larger portion of their income for non-fuel consumption. This results in higher positive economic impact for each scenario. Measured by employment change, scenario impact in this Case ranges from 2.4 percent (Scenario A) to 35.1 percent (Scenario E) higher than the corresponding impact in the Reference Case.

"High cellulosic ethanol and diesel prices" Case – In every LCFS scenario the quantity of biofuel consumption is higher than that in the BAU scenario. This positive gap enlarges when the prices of biofuels increase. Consumers will then have to spend more of their income on (bio)fuels and less on nonfuel consumptions. Therefore, higher biofuel prices translate into more negative economic impact (relative to the Reference Case). The result is that each scenario's employment impact in this Case ranges from 8.4 percent (Scenario A) to 31.0 percent (Scenario E) lower than the corresponding impact in the Reference Case. Again, impacts are small.

Interpretations and Limitations of the Economic Impact Analysis

- Unlike many climate or energy studies, this study does not involve any complementary policies such as building energy conservation programs or industrial energy efficiency programs.

- The LCFS's impact through climate-related channels is not included. Although the economic benefits of preventing or slowing down climate change have been extensively studied and documented, the LCFS's effect on climate improvements can hardly be determined. So the LCFS's climate-related impact cannot be reliably estimated.

- The Cases and Scenarios are not mutually exclusive. For example, high petroleum fuel prices may encourage biofuel consumption and thus the investment in biofuel production plants. So the same scenario should not carry the same weight (i.e. likelihood of occurrence) in different cases. This should be noted when using the results of this impact analysis for policy discussions.

- The impact analysis estimates and presents net impact, which is not the same as the gross changes. It is possible that a small net impact can result from two large gross changes of similar sizes but in opposite directions (one positive and one negative). But in reality the magnitudes of economic gross flows are usually positively related to the corresponding net change; so if the estimated net impact is small, it's reasonable to expect the corresponding gross changes would be small as well.

9. Alternatives to a LCFS

Washington is obligated to reduce GHG emissions from its transportation sector, so if the LCFS is not selected as the emission reduction mechanism, there are a variety of alternatives that might be pursued including mandates, incentives, and pricing mechanisms. This section of the report provides an overview of these alternatives and compares them to the LCFS. First, we summarize here what a LCFS provides:

- Meaningful and guaranteed GHG emission reductions: ~ 10 percent on a WTW basis, and 7 to 12 percent on a TTW basis by 2023, depending on which fuels are utilized for compliance.

- Regulators do not pick a technology/fuel winner. Success of the program is not dependent on a single technology or fuel; rather the market decides how the reductions are accomplished over time, resulting in lowest overall cost to consumers.

- As structured in the foregoing analysis, the standard phases in gradually, allowing time for low carbon intensity fuels and vehicles to enter the market and gain acceptance.

- Economic modeling shows very small effects on the State economy. If the alternative fuels are imported, the effect is slightly negative, if the fuels are produced in Washington, the effect is slightly positive.

The main negative aspect of a LCFS is that it is difficult to implement and enforce for both regulators and regulated parties (fuel suppliers). With a LCFS, a carbon intensity value must be developed and assigned to each different fuel type sold, and the quantity of each fuel type sold must be tracked and reported. Both alternative and petroleum fuel pathways need to be considered. On the petroleum side, future increases in oil sands derived crude oil will need to be considered as Alaska crude oil continues to decline. For biofuels, estimates of GHG emissions resulting from ILUC are highly uncertain and evolving rapidly. One mitigating factor is that California, Oregon and British Columbia are currently implementing similar standards. If Washington decides to implement a LCFS, it would be able to take advantage of the lessons learned by these other groups.

The following sections provide summaries of the three main LCFS alternatives available for reducing transportation GHG emissions: mandates, incentives, and carbon pricing.

9.1 Regulatory Mandate Approach

Because compliance with the LCFS requires some combination of biofuels (substituting for both gasoline and diesel) and use of electric vehicles, an alternative to the LCFS could consist of a Zero Emission Vehicle (ZEV) standard, an ethanol blend mandate, and/or a strengthened biodiesel blend mandate. Each of these are briefly described below along with their estimated GHG emission reductions.

9.1.1 ZEV Mandate

The following is an estimate of the GHG emission reductions achieved by a CA style ZEV mandate in Washington compared to the emission reductions achieved by increased sales of PHEVs and EVs in the LCFS High EV Scenario (Scenarios D and E). A ZEV program would achieve ~ 1.3 times the GHG emission reductions from electric vehicles in the LCFS high EV scenario. However, this exercise compares only the LCFS emission reductions achieved by the increased use of electricity relative to gasoline, not the additional reductions achieved due to increased use of other alternative fuels. In Scenarios D and E of the LCFS, electricity provided less than 20 percent of the reductions from the gasoline pool GHG emissions. It did not provide any reductions in the diesel pool. Therefore, a ZEV program on its own would not provide nearly the same level of emission reductions as the LCFS.

For our analysis here, we assume that the ZEV rule would have no travel provisions and that actual market shares for 2025 are 7 percent ZEVs, 7 percent PHEVs.[53] Table 9-1 provides the BEV and PHEV sales in 2020 and 2023 for LCFS Scenarios D/E and the ZEV 2025 goal (we use a linear interpolation between 2017 and 2025 to estimate 2020 and 2023 ZEV market shares). In 2023, the ZEV goal results in ~ half of the LCFS Scenario PHEV market share, and ~ 3 times the LCFS Scenario BEV market share.

Table 9-1. PHEV and BEV Populations

	LCFS Scenarios D/E		ZEV Goal[2]				ZEV/LCFS	ZEV/LCFS
	2020	2023	2017	2020	2023	2025	2020	2023
Total LDV Sales[1]	301,631	308,997						
PHEV Sales	25,822	32,609						
BEV Sales	4,304	5,435						
PHEV Market Share	8.6%	10.6%	1.0%	3.3%	6%	7%	0.4	0.5
BEV Market Share	1.4%	1.8%	1.0%	3.3%	6%	7%	2.3	3.1
1. For 2020, use 2015-2017 avg, for 2023 use 2018-2020 avg								
2. Goal for 2025 and 2017 values from Anna Wong (CARB) Nov 10, 2010.								

To estimate the GHG emission reductions due to EVs and PHEVs, we compare the total electricity consumption in 2020 and 2023 to the estimated electricity consumption under a ZEV mandate. Table 9-2 provides the total transportation electricity consumed in 2020 and 2023 by PHEVs and EVs in the BAU and the High EV scenario. This electricity is consumed by all existing electric vehicles on the road in 2020 and 2023, not just the vehicles sold in 2020 and 2023. To estimate the amount of electricity consumed under the ZEV case, we apply the ratios in Table 9-1 (0.4 and 0.5 for PHEVs in 2020 and 2023, respectively and 2.3 and 3.1 for BEVs in 2020 and 2023, respectively). This assumes that the penetration rates for BEVs and PHEVs from 2013-2023 is the same under both the LCFS and ZEV mandate, just scaled by the total numbers.

[53] Conversation with Anna Wong (CARB) on Nov 10, 2010. Estimate for 2017 is 2% total PHEV+EV.

Table 9-2. Estimated TTW GHG Emission Reductions due to PHEVs and BEVs.

	Units	Business-as-Usual		LCFS High EV Scenario		ZEV Mandate[2]	
		2020	2023	2020	2023	2020	2023
PHEV Electricity Use	MMBtu	344,773	488,483	1,359,360	1,940,559	516,066	1,011,368
BEV Electricity Use	MMBtu	148,450	194,890	527,726	741,072	1,202,074	2,317,362
Total Electricity Use[1]	MMBtu	493,223	683,373	1,887,086	2,681,631	1,718,140	3,328,731
Total Electricity Use	MJ	520,350,632	720,958,684	1,990,876,172	2,829,120,711	1,812,637,492	3,511,810,723
Decrease in TTW Carbon Intensity[3]	g/MJ	74.3	74.3	74.3	74.3	74.3	74.3
Decrease in TTW GHGs Rel to Gasoline	tonnes	38,671	53,579	147,955	210,251	134,709	260,986
Decrease in TTW GHGs Rel to BAU	tonnes			109,285	156,672	96,039	207,407
ZEV TTW Benefit relative to LCFS Benefit						0.9	1.3
Decrease in WTW Carbon Intensity[4]	g/MJ	70.9	70.9	70.9	70.9	70.9	70.9
Decrease in WTW GHGs Rel to Gasoline	tonnes	36,898	51,123	141,172	200,611	128,533	249,020
Decrease in WTW GHGs Rel to BAU	tonnes			104,274	149,488	91,635	197,897
ZEV WTW Benefit relative to LCFS Benefit						0.9	1.3

1. Total Electricity use is for all Evs and PHEVs on the road in specified year - not just sold in 2020 or 2023
2. For PHEV electricity, ZEV mandate is 0.38 times 2020 LCFS PHEV use and 0.52 times 2023 LCFS PHEV Use
For BEV electricity, ZEV mandate is 2.28 times 2020 LCFS EV use and 3.13 times 2023 LCFS EV use.
3. Decrease in TTW Carbon Intensity is Gasoline TTW CI (74.3 g/MJ) less electricity TTW CI (0 g/MJ)
4. Decrease in WTW Carbon Intensity is Gasoline WTW CI (92.5 g/MJ) less electricity WTW CI (21.5 g/MJ, EER = 3.14)

The table compares the TTW and WTW GHG emission reductions for the LCFS Scenario (electric vehicle portion of reductions only) and the ZEV mandate. The LCFS results in ~0.15 million tonnes of GHG reductions relative to BAU in 2023 due to EVs. The ZEV mandate would result in ~0.20 million tonnes reduced relative to BAU. Therefore, a ZEV program would provide ~33 percent more GHG reductions than the electric vehicles provide in the high EV penetration LCFS Scenarios considered in 2023. Remember that the electric vehicles provided less than 20 percent of the gasoline pool reduction in these scenarios and none of the diesel pool reductions.

Table 9-3 compares the LCFS overall emission reductions (including contribution from biofuels) to the ZEV mandate. A ZEV mandate on its own is not a viable alternative to the LCFS in terms of emission reductions over the next ten years. However, with a ZEV mandate, EV sales and fleet penetration would continue to increase rapidly after 2023 and eventually would provide large benefits. To achieve similar emission reductions to a LCFS in the near term, a biofuel mandate would need to be implemented in addition to the ZEV mandate.

Table 9-3. Comparison of LCFS and ZEV Mandate GHG Emission Reductions (MMT)

	Annual WTW GHG Reduction (MMT)		**Annual TTW GHG Reduction (MMT)**	
	2020	2023	2020	2023
LCFS GHG Reduction	1.7 to 2.1	3.4 to 3.9	0.6 to 1.0	2.0 to 3.4
ZEV reduction	0.09	0.20	0.10	0.21

One key disadvantage of a ZEV rule is that it is a mandate – LCFS has more market flexibility. Moreover, Washington's low GHG grid and green mentality make it a good EV market without a ZEV mandate. ZEV requirements before 2017 have travel provisions; EV sales do not need to occur in Washington for the manufacturers to comply. Therefore, a ZEV mandate does not guarantee emission reductions in Washington. Finally, a ZEV mandate is fairly complicated to enforce and comply with.

9.1.2 Biodiesel Mandate

For this option, we consider strengthening Washington's existing biodiesel standard. For example, we assume here that the mandate requires blending up to the RFS2 proportional shares into diesel without considering type of biodiesel consumed. This assumption results in a B20 blend by 2018 and constant thereafter. We further assume that waste oil derived biodiesel use will continue at approximately 2 MGY and the canola derived biodiesel consumption increases to half of its potential in-state production before ILUC is introduced (18 MGY). The balance is assumed to be imported soybean based biodiesel. This mandate would only provide emission reductions from the diesel pool; a separate ethanol standard needs to be considered to achieve reductions from the gasoline pool.

Table 9-4 compares CI reduction of diesel pool in LCFS Run 8 to the BD mandate. With these assumptions, the mandate provides 60 percent of the carbon reduction provided by the LCFS for the diesel pool only (note the gasoline pool would not be affected by this standard). Unless some requirement to use low CI biodiesel (e.g. no soybean biodiesel) was included, the emission reductions for the diesel pool may not be as large as those achieved with the LCFS. However, this requirement would negate the key benefit of a biodiesel mandate – simplicity.

Table 9-4. Comparison of LCFS and B20 Mandate Carbon Intensity Reductions in 2023.

	Biodiesel Consumed in 2023 (Million gal/yr)				2023 Carbon Intensity (g/MJ)	Reduction in Diesel Pool CI from Baseline (%)
	Waste Oil	Canola	Cellulosic	Soybean		
LCFS*	23 (max)	36.5 (max)	94	X	82.4	10%
B20	2	18	X	184	86.3	6%

* LCFS Scenarios C & E (Conventional BD) is shown. Blend level is B15, reduction includes contribution from increased CNG use with pipeline and biogas derived natural gas.

One disadvantage of a biodiesel standard in lieu of a LCFS is that it would not provide a role for CNG. CNG is an important alternative for medium and heavy duty vehicles. CNG may develop on its own depending on vehicle availability and costs relative to diesel prices. Unlikely that biogas would be developed for transportation use in the absence of a LCFS.

Finally, the economic impact of a strong biodiesel standard would need to be carefully considered. Recall that in our LCFS economic modeling, the fuel expenditures under the LCFS increase due to higher biodiesel prices. In the scenarios with new in-state fuel production, this increase in fuel costs was more than offset by the positive effects of construction and operation of new cellulosic diesel production plants. If a biodiesel mandate were utilized in place of a LCFS, the State would need to consider incentivizing in-state production rather than importing biodiesel from the Midwest.

9.1.3 Ethanol Mandate

An ethanol mandate provides an opportunity to achieve carbon reductions from the gasoline pool. We consider two options here:

> Option 1: require RFS2 proportional volumes without regard to ethanol type
>
> Option 2: RFS2 proportional total volumes, volumes split according to EPA's primary control case (cellulosic, sugarcane, corn)

Both of these options assume the same volumes of ethanol consumed and result in a blend level of 17 percent by 2023. This is higher than the current maximum blend levels, so some of the ethanol would need to be consumed as E85, resulting in infrastructure costs equivalent to those assumed in the LCFS analysis.

Table 9-5 compares these two options to LCFS Scenario D (high EVs and cellulosic ethanol). Clearly, the mandate does not provide similar WTW GHG emission reductions, even with the primary control case volumes. Unless some requirement to use low CI biodiesel (e.g. no soybean biodiesel) was included, the emission reductions for the diesel pool may not be as large as those achieved with the LCFS. However, this requirement would negate the key benefit of a biodiesel mandate – simplicity. To achieve any emission reductions in the gasoline pool, a requirement to use low CI ethanol would be needed, rendering the standard as complex as a LCFS.

Table 9-5. Comparison of Ethanol Mandate Examples to LCFS Scenario D.

	Ethanol Consumption in 2023 (Million gal/yr)				Ethanol Blend Level* (% vol)	Carbon Intensity in 2023 (g/MJ)	Reduction in Gasoline Pool CI from Baseline (%)
	NW Corn	Sugar-cane	Cellulosic	MW Corn			
LCFS Scenario D	42	0	337	0	18%	83	10%
Option 1	42	0	1	332	17%	92	0%
Option 2	42	38	83	212	17%	90	3%

In summary, none of the mandate examples considered can achieve emission reductions equivalent to a LCFS. The biodiesel and ethanol mandates can not achieve reductions similar to the LCFS without adding a carbon intensity requirement to the mandate. Adding a carbon tracking component to these volume mandates negates their attractiveness as simpler alternatives to the LCFS.

Moreover, these mandates do not provide a role for CNG/LNG. CNG and LNG are available now and are important compliance options for the medium and heavy duty fleets. When derived from biogas, the GHG emissions are extremely low. Displacing diesel fuel may be the most beneficial use for biogas from a GHG standpoint.

9.2 Incentive Programs

Incentive programs are intended to pull new vehicles/fuels into the market place. Users are more likely to risk purchasing new technology if it is cost competitive. The incentives help manufacturers increase volumes which in turn drive down prices. Incentives are most effective if used in the early stages of deployment. In general, incentives require relatively large expenditures for modest emission reductions that are not guaranteed to make a permanent change in consumer behavior.

Washington could implement an incentive program to encourage alt fuel vehicles (EVs, E85 FFVs), infrastructure (charging equipment, E85 dispensing, CNG refueling) or cellulosic fuel production. The incentives would need to be funded through either tax revenue or a small fee on widely used products/services (oil changes, tires, registration, electricity, etc). To achieve the GHG emission reductions of a LCFS, Washington would need to incentivize a variety of vehicles and fuels and hope that the vehicles and fuels selected for incentives are winners from cost/technological status/consumer acceptance standpoints.

As an example of an incentive program, we consider here incentivizing electric vehicles. At present, there is a $7,500 federal tax credit for the first 200,000 plug-in vehicles sold. Once 200,000 vehicles have been sold, the credit is $3,750 for the next six months, and $2,500 for following six months and nothing thereafter. For our example, we assume that 200,000 plug-in vehicles are sold in the U.S. by the end of 2013. We further assume that Washington pays the difference between the reduced credit and $7,500 for the following year and then provides a $7,500 tax credit for each year through 2018.

Table 9-6 shows numbers of EVs and PHEVs sold and the cost in incentive fees to Washington. For plug-in vehicle sales, we consider two cases: the BAU and the LCFS high EV Scenarios. For BAU levels of plug-in vehicles, a total of $200 million in incentives are needed. For the higher penetration rate, nearly $800 million is required. These large expenditures provide only modest GHG and criteria pollutant reductions.[54]

[54] EVs provide 4 to 20 percent of the gasoline pool carbon intensity reduction in the compliance scenarios considered.

Table 9-6. Incentive Funding and Emission Reductions for Extending the Federal EV Tax Credit.

Year	BAU & Scenarios A-C Plug-In Vehicle Sales			LCFS Scenarios D/E Plug-In Vehicle Sales		
	EV Sales	PHEV Sales	Incentives $Million	EV Sales	PHEV Sales	Incentives $Million
2014	395	2,368	12	1,579	9,474	48
2015	911	5,464	48	3,643	21,857	191
2016	775	4,649	41	3,099	18,595	163
2017	884	5,303	46	3,535	21,213	186
2018	979	5,872	51	3,915	23,489	206
TOTAL	3,943	23,657	198	15,771	94,628	793

One type of incentive that could potentially provide significant reductions at no net cost is a feebate. In a feebate program, a fee is charged to the consumer for purchasing higher emitting vehicles while rebates are provided to consumers purchasing lower emitting vehicles. The program is intended to have a net zero cost because it is designed such that the sum of the fees collected is equal to the sum of the rebates provided plus the administration fees. Clearly the values of the fees and rebates would need to be carefully determined and modified as needed to achieve the desired result.

Feebates can provide significant GHG benefits, however a single state program would have a much smaller effect on manufacturer response than a U.S. program. It has been projected that a state program can produce a 3 to 5 percent GHG reduction while a federal program could produce a 10 percent reduction.[55] The LCFS can provide a 7 to 12 percent GHG reduction on a TTW basis. Therefore, a feebate on its own would not be enough to provide GHG reductions equivalent to a LCFS. In addition, a feebate program would be very difficult to design such that the consumer receives the appropriate price signals to achieve the desired result.

One benefit to a feebate program is that it is not regressive – the majority of new cars are purchased by higher income households. Over the long term, feebates may provide increased household income due to lower fuel expenditures. Feebates considered to date have been focused on the light duty market; little work has been done to date on heavy-duty feebate programs.

[55] "Potential Design, Implementation, and Benefits of a Feebate Program for New Passenger Vehicles in California: Interim Statement of Research Findings", David Bunche, David Greene, University of California, April 2010, prepared for CARB.

9.3 Carbon Pricing Approach

The last LCFS alternative approach places a price on carbon. Two different approaches are considered: "cap and trade" and a carbon tax. In a cap and trade program, an emission cap is placed on a group of sources; the collective emissions from the group of sources may not exceed the cap. To achieve reductions, the cap decreases over time. Cap and trade promotes innovation and yields the most cost effective route to emission reductions; it has been successfully implemented in the U.S. to control stationary source emissions.[56] Cap and trade provides known emission reductions at an unknown cost to emitters.

Cap and trade would be impractical to implement across stationary and transportation sectors since technology costs and source sizes are so different. Economists argue that cap and trade works best when the marginal cost curve is flat (meaning that each incremental emission reduction costs about the same as the previous reduction). Moreover cap and trade does not work unless there are a number of different options available and many market participants. In the transportation sector, this is not the case at present.

In the near-term, a transportation cap & trade would result in reduced VMT since there are limited alternatives to petroleum. In the mid-term, there would be higher market shares of fuel efficient vehicles, and in the long-term, there might be improved land use planning. Cap and trade does not promote development of lower carbon alternative fuels.

The alternative carbon pricing mechanism is a carbon tax. Taxes encourage the use of lower carbon emitting technologies across all sectors of the economy. In this approach, in direct contrast to the cap and trade approach, the emission reductions achievable are not known, but the cost is known. Tax mechanisms work best when the marginal benefit curve is flat (each additional increment of cost yields about the same benefit. This is not the case for transportation GHG emissions.

An economy-wide carbon tax would be difficult to implement since the cost of control varies substantially. A tax on the transportation sector might be draconian for the stationary sector. Table 9-7 provides an example of the impact of a \$50/mt CO2 tax on different fuels. As can be seen, the transportation sector would not be nearly as affected as the power generation industry.

Table 9-7. Effects of a \$50/mtCO2 Tax on Different Fuels

\$50/mt CO2 Tax	Coal (\$/ton)	Natural Gas (\$/mcf)	Gasoline (\$/gal)
Cost of Tax	94.5	2.75	0.45
Price Increase	135%	70%	15%

A tax on the transportation sector would have similar effects as the cap & trade approach. In the near term, the only response possible is reduced VMT. In the mid-term higher market shares of

56 Acid Rain Program (SO2), NOx Budget Program, NOx SIP Call, RECLAIM and impending implementation of CATR.

fuel efficient vehicles would be seen and possibly the long-term result would be improved land use planning. In contrast to the cap and trade approach, the price of carbon is known; the impact on emissions is not.

Estimates of short and long-term price elasticities are relatively small, requiring large price increases to achieve reductions achieved by a LCFS. Table 9-8 provides estimates of price increases needed to achieve short and long-term reduction of 10 percent gasoline use.

Table 9-8. Effects of a $50/mtCO2 Tax on Different Fuels

Gasoline-Price Elasticity	Short-Term (-0.2 elasticity)	Long-Term (-0.7 elasticity)
Gasoline Price Increase for 10% Reduction in Use	50%	14%

9.4 *Summary of LCFS Alternatives*

In summary, we find that the LCFS is the preferred approach for reducing transportation sector GHG emissions. A regulatory approach could achieve similar levels of reductions but there are drawbacks. A ZEV mandate on its own can achieve significant emission reductions, but these reductions won't be realized until well beyond the timeframe of a LCFS. Biofuel mandates will not yield similar emission reductions to the LCFS without a low carbon intensity requirement, negating their primary benefit – ease of implementation and compliance. Finally, some potential emission reduction opportunities such as biogas derived CNG will be lost.

Traditional incentive programs are costly and in general yield only modest emission reductions that are not necessarily sustainable without continued funding. A feebate program might provide reductions for the light duty fleet if it were done on a national level. For a Washington State feebate program to yield emission reductions equivalent to a LCFS, the fees and rebates would need to be very large. Further, the reductions would mainly take place in the light duty sector.

Transportation pricing mechanisms would result in very high costs in the short-term as there are limited alternative options available. Moreover, carbon taxes are regressive and therefore politically difficult to implement. However, pricing mechanisms are very efficient and may be the favored approach once alternatives to petroleum are truly available. A LCFS over the next ten years could pull real alternatives into the marketplace so that in 2023, a pricing mechanism might be a viable alternative.

Appendix — Economic Impact Analysis

ECONOMIC IMPACT ANALYSIS

THE WASHINGTON LOW CARBON FUEL STANDARD

The Washington State Office of Financial Management and Department of Ecology jointly conducted an economic impact assessment of the Washington Low Carbon Fuel Standard (LCFS). The economic impact analysis built on the energy modeling performed by the contracted consultant TIAX using a localized version of VISION 2009 model, developed and maintained by the U.S. Department of Energy. The economic impacts of the Washington LCFS energy scenarios were estimated using the 2009 Regional Economic Modeling Incorporated's Policy Insight (REMI PI+) model for the state.

In the impact analysis six future energy scenarios were assembled to take into account the uncertainties in technology development and pace of innovation breakthroughs, they identifies upside benefits, downside risks and middle-road future developments. Table 1 lists these scenarios, with a brief summary of assumptions imbedded in each scenario.

Table 1: Description of the Washington LCFS Scenarios

Scenario A	High in-state production of cellulosic ethanol and diesel fuels
Scenario B	No in-state production of cellulosic ethanol and diesel fuels
Scenario C	Mixed uses of locally produced and imported ethanol and biodiesel fuels
Scenario D	High electrical vehicle (EVs) sales - High investment in ethanol production
Scenario E	High electrical vehicle (EVs) sales - Low investment in ethanol production
Scenario F	One-Pool: a ""middle-of-the-road" scenario combining a mixture of biofuel and electrical vehicles, with low petroleum fuel consumption in the future.

The VISION model was used to estimate future energy uses under the different scenarios. Since VISION model had been calibrated using data from the U.S. Energy Information Administration's 2010 Annual Energy Outlook (AEO), the model's estimates are consistent with the U.S. Energy Department's energy uses, prices, and technology projections for the future. The VISION model's original projection, without local LCFS interventions, is treated as a "Business-As-Usual" (BAU) or do-nothing scenario. The BAU thus incorporates all the national energy policies currently in action, including the federal Renewable Fuel Standard (RFS2).

The overriding assumption in the analysis is that the (future) energy prices will not be materially affected by the state-level LCFS policy actions; this assumption is reasonable since Washington is basically an energy price taker and thus in all scenarios changes in energy consumption relative to the BAU/baseline will have a very minor influence on energy prices. Table 2 shows the VISION projections of future energy spending for the different Washington LCFS scenarios and BAU's. Still, two additional impact analyses have been prepared on two alternative "Cases" to address the risks of future high petroleum fuel prices and high biofuel prices.

Table 2: 2014-23 Total Fuel Consumptions ($2008, millions)

Reference Case	Gasoline & Diesel	Ethanol & Bio-Diesel	Electricity	CNG
BAU	105,597	7,621	83	286
Scenario A	103,645	9,177	83	336
Scenario B	103,591	9,232	83	628
Scenario C	102,649	10,187	83	336
Scenario D	102,549	8,927	311	336
Scenario E	101,710	9,783	311	336
Scenario F	101,436	11,642	159	340

With future energy uses/demand as inputs, REMI PI+ was then run to forecast future economic paths under different scenarios. The difference in the economic outcomes between each scenario and the BAU represents that scenario's net economic impact on the state economy. Magnitudes of the impact are generally measured by the scenario-induced changes, relative to BAU, in state employment, personal income, or Gross Domestic Product (GDP). Table 3 lists the major direct channels through which future energy demand affects the state economy. Through each impact channel, an energy scenario could directly exert either positive or negative effect, or sometimes both, on the Washington economy.

The Washington LCFS Economic Impact

Changes in fuel demand, new investment in biofuel production plants, additional investment in equipment (including LDV's and trucks) required for biofuel consumption as predicted by VISION will impact the Washington economy. Expenditures in these areas affect the economy directly, and these direct effects then generate changes in spending on intermediate and investment goods and services from related sectors of the economy; in addition, the corresponding employment and income changes will alter the buying power of the state residents, again induce more changes in spending on goods and services. The REMI PI+ model, given direct impact (from VISION), estimate the complete indirect (or so-called "rippling") economic impact. Direct and indirect impacts add up to total impact. The state-level LCFS impact analyses have been performed for the period 2014-2023, and the results are shown in Table 4.

Table 3
The LCFS Direct Impact Channels *

	Positive	Negative
Fuel Consumptions	*	*
Vehicle Purchases[1]	*	*
Infrastructure - Home[2]	*	*
Infrastructure - Businesses[3]	*	
Infrastructure - Public[3]	*	
New Plant Investment & Operations[4]	*	

[1] Gasoline automobiles and light trucks; electric vehicles and plug-in hybrid vehicles; compressed natural gas automobiles and light trucks; ethanol-fueled medium- and heavy-duty ethanol and biodiesel trucks.

[2] Electric- Home Levels 1&2 electric chargers, government Level-2 charger; CNG- home CNG; and upgrades biodiesel and ethanol terminal costs

[3] Business investment in Level-2 EV charging stations; E85 fueling station upgrades; compressed gas fuel station; biodiesel and ethanol terminal costs.

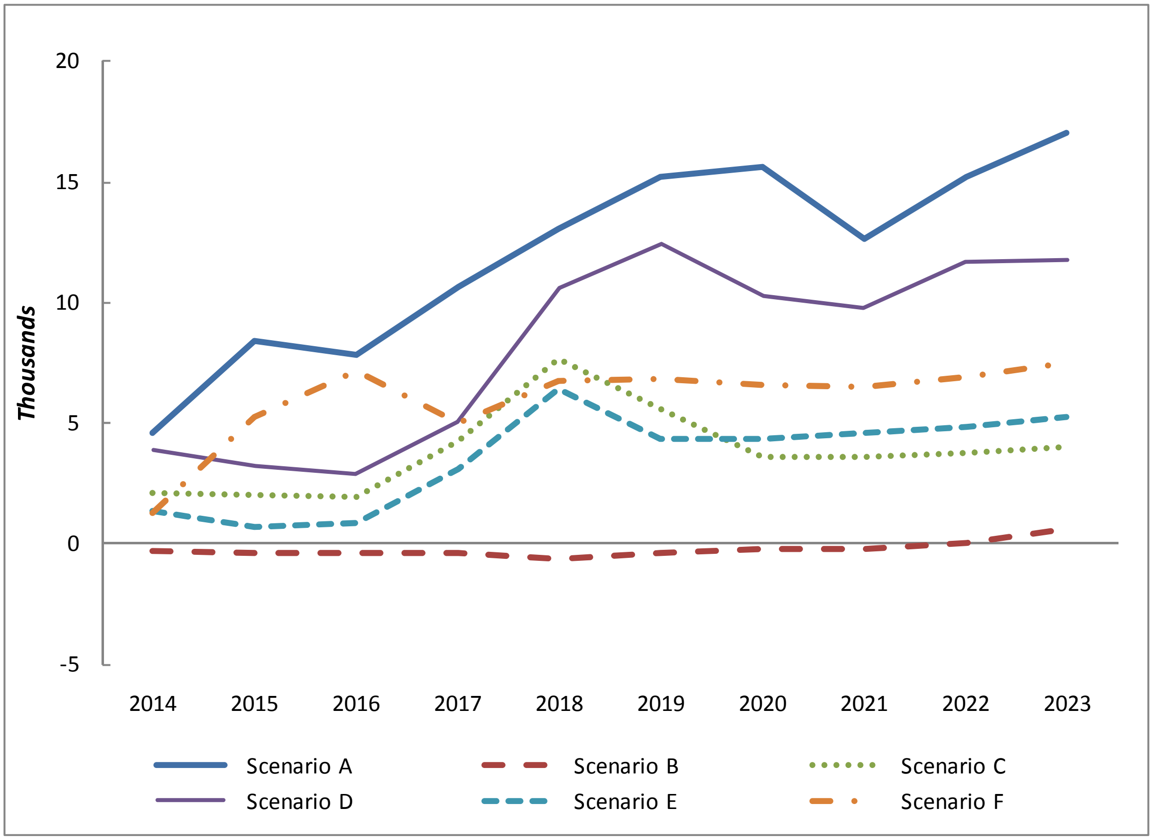
[4] Landfill gas Plant; cellulosic ethanol production plant; biodiesel production plant.

**Variations in future vehicle operating costs is not included in the analysis.*

Table 4
Economic Impact - The Washington LCFS Scenarios 2014-2023 Annual Average Impact

Reference Case	Employment (1,000s)	Total Personal Income ($2008, Millions)	Gross Domestic Product ($2000, Millions)
Scenario A	12.0	526.4	741.3
Scenario B	-0.2	-13.8	-36.5
Scenario C	3.9	177.7	225.3
Scenario D	8.2	341.7	454.2
Scenario E	3.6	147.6	164.4
Scenario F	6.0	281.6	389.3
BAU, 2009 Level	*3727.4*	*263524.4*	*259603.0*

Chart 1
The Washington LCFS Employment Impact
(2014-2023)



Scenario A (High in-state production of cellulosic ethanol and diesel fuels)

High level of investment leads to an average annual addition of 12,000 jobs for the 2014-23 period, which is equivalent to 0.3 percent of 2009 Washington total employment level. Impact on state personal income and economic output (GDP) averages about $526.4 million ($2008) and $741.3 million ($2000) a year, respectively. Magnitude of the impact rises and fluctuates over time, with peaks corresponding to the assumed timing of new fuel plant construction. By 2023, the annual job impact reaches 17,000, about 0.5 percent of total employment in the state in 2009.

The most-impacted industrial sectors are listed in Table 6. These sectors are investment-related construction and administration and support services, and equipment repair and maintenance. Also heavily impacted are forestry and logging and retail trade industries, the former provides feedstock for biofuel production, and the later benefits from the increased earnings and consumption.

Conservatively, the analysis does not assume that the new production facilities in the state would result in Washington biofuel exports to other states.

Scenario B (No in-state production of cellulosic ethanol and diesel fuels)

This scenario assumes that no new biofuel production facility would be located in Washington. Since plant construction plays a dominant role in driving positive economic impact, this scenario establishes the lower bound of a spectrum of impacts that the LCFS scenarios are expected to generate.

An average annual employment reduction of 200 is projected for the 2014-23 period, which represents only a negligible percentage of total employment in the state. Impacts on state personal income and economic output (GDP) are projected to average about -$13.8 million ($2008) and -$36.5 million ($2000) a year, respectively. The (negative) economic impact remains fairly steady during the period.

Basically, none of the industrial sectors would be significantly impacted in this scenario. Merely detectable, some consumption-related retail and services sectors will see negative effects due to income changes.

Scenario C (Mixed uses of locally produced and imported ethanol and biodiesel fuels)

In this “mixed uses” scenario, demand for biofuels in the state is high, but about 40 percent of the consumption would be supplied by out-of-state producers. This translates into fewer (relative to Scenario A) new biofuel production plants in the state.

During the 2014-23 period, an average annual increase of 3,900 jobs is projected, which represents about 0.1 percent of Washington total employment in 2009. Impacts on state personal income and economic output (GDP) are forecast to average about $177.7 million ($2008) and $225.3 million ($2000) a year, respectively. The scenario’s economic impact is fairly stable over time, with a single peak taking place around 2018.

The most-affected industrial sectors in this scenario are the same as those in Scenario A – construction, retail, forestry and logging, equipment repairmen and maintenance, administration and support services. But the magnitudes of the industrial impact in this scenario are only about one-third of those in Scenario A.

Scenario D (High EV-high investment in biofuel production)
Scenario E (High EV-low investment in biofuel production)

These two scenarios postulate high penetration/adoption rates of electrical vehicles in Washington. Also, different levels of investment in ethanol production plants are assumed. The resulting level of electricity consumption is, according to VISION's estimation, nearly four times the levels in Scenarios A-C.

For Scenario D, an average annual increase of 8,200 jobs is projected, which is equivalent to about 0.2 percent of 2009 total employment level in the state. Impacts on state personal income and economic output (GDP) average about $341.7 million ($2008) and $454.2 million ($2000) a year, respectively. This scenario has the second-largest economic impact among the six LCFS scenarios, only smaller than that of Scenario A. The impact rises and fluctuates over time, with peaks taking place around 2018-19.

Scenario E assumes the same high level of EV adoption as in Scenario D, but the in-state investment in new ethanol production facilities is much lower. This means a major portion of the demand for ethanol would be satisfied by imports. With lower level of production investment (relative to Scenario D), this scenario has a smaller economic impact of 3,600 jobs a year. The estimated impacts on state personal income and economic output (GDP) average $147.6 million ($2008) and $164.4 million ($2000) a year, respectively. The impact is fairly stable over time, with a peak taking place around 2018.

High adoption rates of electrical vehicles actually does not have significant impact on the state economy, this is because that the analysis assumes little EV production capacity would exist in the state. So the impact is dominated by the assumed investment in biofuel production facilities. The mix of most impacted industries of Scenarios D&E are thus the same as that of Scenario A - construction, retail, forestry and logging, equipment repairmen and maintenance, administration and support services. The magnitudes of the industrial impact are different depending on the assumed investment levels.

Scenario F: One-Pool program

This is a "mid-range" scenario: a mix of locally-produced and imported biofuels as in Scenario C, combined with the EV adoption rates about half of that assumed in Scenarios D&E.

The scenario results in an average annual addition of 6,000 jobs, roughly 0.2 percent of 2009 state total employment. Impacts on state personal income and economic output (GDP) are expected to average about $281.6 million ($2008) and $389.3 million ($2000) a year, respectively. The impact is fairly stable over time, with a single peak occurring around 2016.

The most affected industries are: investment-related construction and administration and support services, and equipment repair and maintenance; forestry and logging sector that produces feedstock for biofuel production, and consumption-related retail sector due to income changes

Alternative Cases

The Reference Case analysis summarized above incorporates the projected future fuel prices in the 2010 U.S. Energy Department's 2010 Annual Energy Outlook (AEO) Baseline forecast. To examine the effect of future uncertainties in the price forecasts, additional impact analyses have been performed on two alternative price trajectories:

- A **"High petroleum prices"** case that assumes future petroleum prices would be about 33 percent above the levels assumed in the Reference Case;
- A **"High cellulosic ethanol and diesel prices"** case that assumes future cellulosic biofuel prices to be about double the levels of that in Reference Case.

"High petroleum prices" C**ase** - Because in all the LCFS scenarios the quantities of petroleum fuels consumed are lower than that in the business-as-usual (BAU) scenario, so higher future prices of petroleum fuels enlarge the negative fuel spending gap between each LCFS scenario and BAU. Since a larger negative spending gap means the consumers get to retain a larger portion of their income for non-fuel consumptions, which accordingly results in higher positive economic impact for each scenario. Measured by employment change, scenario impact in this Case ranges from 2.4 percent (Scenario A) to 35.1 percent (Scenario E) higher than the corresponding impact in the Reference Case.

"High cellulosic ethanol and diesel prices" Case – In every LCFS scenario the quantity of biofuel consumption is higher than that in the BAU scenario. This positive gap enlarges when the prices of biofuels increase in this alternative Case; consumers will then have to spend more of their income on (bio)fuels and less on nonfuel consumptions. So assumption of higher biofuel prices translates into more negative economic impact (relative to the Reference Case). The result is that each scenario's employment impact in this Case ranges from 8.4 percent (Scenario A) to 31.0 percent (Scenario E) lower than the corresponding impact in the Reference Case.

Table 5 shows the economic impact of all three Cases.

Table 5
Economic Impact – Alternative Cases
Annual Average (2014-2023)

	Reference	High Petroleum Fuel Prices	High Ethanol and Diesel Prices
Employment Impact(1,000s)			
Scenario A	12.0	12.3	11.0
Scenario B	-0.2	0.5	-1.6
Scenario C	3.9	4.8	2.7
Scenario D	8.2	9.1	7.4
Scenario E	3.6	4.9	2.5
Scenario F	6.0	7.2	5.5
BAU, 2009 Total Emp.	*3727.4*		
Total Personal Income ($2008, Millions)			
Scenario A	526.4	561.1	479.9
Scenario B	-13.8	21.5	-83.1
Scenario C	177.7	226.9	118.7
Scenario D	341.7	395.3	308.1
Scenario E	147.6	213.7	92.6
Scenario F	281.6	353.4	257.7
BAU, 2009 Personal Income	*263,524.4*		
Gross Domestic Product ($2000, Millions)			
Scenario A	741.3	801.9	650.3
Scenario B	-36.5	25.5	-163.0
Scenario C	225.3	313.0	118.3
Scenario D	454.2	545.0	381.7
Scenario E	164.4	278.5	64.4
Scenario F	389.3	509.1	343.2
BAU, 2009 GDP	*259,603.0*		

Interpretations and Limitations of the Economic Impact Analysis

- Unlike many climate or energy study, this study does not involve any complementary policies such as building energy conservation programs or industrial energy efficiency programs.

- The LCFS's impact through climate-related channels is not included. Although the economic benefits of preventing or slowing down climate changes have been extensively studied and documented, the LCFS's effect on climate improvements can hardly be determined. So the LCFS's climate-related impact cannot be reliably estimated.

- The Cases and Scenarios are not mutually exclusive. For example, high petroleum fuel prices may encourage biofuel consumption and thus the investment in biofuel production plants. So the same scenario should not carry the same weight (i.e. likelihood of occurrence) in different cases. This should be noted when using the results of this impact analysis for policy discussions.

- The impact analysis estimates and presents net impact, which is not the same as the gross changes. It is possible that a small net impact can result from two large gross changes of similar sizes but in opposite directions (one positive and one negative). But in reality the magnitudes of economic gross flows are usually positively related to the corresponding net change; so if the estimated net impact is small, it's reasonable to expect the corresponding gross changes would be small as well.

Table 6
Washington LCFS Most-Impacted Industries
Total 2014-2023 Job Impact (1,000)
(Reference Case)

Scenario A		Scenario B		Scenario C	
Most Positive Sectors		**Most Positive Sectors**		**Most Positive Sectors**	
Retail trade	7.7	Electrical equip. & appliance manuf.	0.3	Forestry & logging/Fishing/Hunting	2.8
Forestry & logging/Fishing/Hunting	9.3	Utilities	0.4	Retail trade	2.9
Equip. repair & maintenance	9.9	Construction	0.5	Equip. repair & maintenance	3.2
Construction	20.3			Administrative & support services	7.8
Administrative & support services	24.5			Construction	7.9
Most Negative Sectors		**Most Negative Sectors**		**Most Negative Sectors**	
Petroleum & coal product manuf.	-0.1	Social assistance	-0.2	Other transportation equip. manuf.	-0.1
Other transportation equip. manuf.	-0.2	Administrative and support services	-0.2	Petroleum & coal product manuf.	-0.2
		Retail trade	-0.3		
		Food services and drinking places	-0.4		
		Real estate	-0.5		
		Petroleum & coal product manuf.	-0.2		

Scenario D		Scenario E		Scenario F	
Most Positive Sectors		**Most Positive Sectors**		**Most Positive Sectors**	
Agriculture & forestry supports	4.3	Agriculture & forestry supports	2.2	Forestry & logging/Fishing/Hunting	3.4
Forestry & logging/Fishing/Hunting	6.9	Forestry & logging/Fishing/Hunting/t	3.5	Equip. repair & maintenance	3.7
Equip. repair & maintenance	8.1	Equip. repair & maintenance	3.9	Retail trade	5.8
Construction	17.2	Administrative & support services	9.4	Construction	9.1
Administrative & support services	20.0	Construction	10.9	Administrative & support services	9.3
Most Negative Sectors		**Most Negative Sectors**		**Most Negative Sectors**	
Other transportation equip. manuf.	-0.1	Other transportation equip. manuf.	-0.1	Other transportation equip. manuf.	-0.1
Petroleum & coal product manuf.	-0.2	Private households	-0.2	Petroleum & coal product manuf.	-0.3
		Personal and laundry services	-0.2		
		Ambulatory health care services	-0.4		
		Petroleum & coal product manuf.	-0.3		