Life Cycle Associates

Assessing Greenhouse Gas Emission and Petroleum Reduction Scenarios for the U.S. Transportation Sector

Final Report

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DISCLAIMER

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Life Cycle Associates, LLC performed this study under contract to Fuel Freedom Foundation. Michael Jackson of MDJ Consulting was the project manager.

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Terms and Abbreviations

AEO	Annual Energy Outlook
ARB	California Air Resources Board
BAU	business-as-usual
BD	biodiesel
BEV	batter electric vehicle
BGY	billion gallons per year
Btu	British thermal unit
CA	California
CAFE	Corporate Average Fuel Economy
CH_4	methane
CI	carbon intensity
CNG	compressed natural gas
CNGV	compressed natural gas vehicle
CO_2	carbon dioxide
EER	Energy Economy Ratio
EtOH	ethanol
eVMT	electric mode vehicle miles travelled
EVSE	electric vehicle supply equipment
FCV	fuel cell vehicle
FFV	flex fuel vehicle
g	gram
GHG	greenhouse gas
HEV	hybrid electric vehicle
ICE	internal combustion engine
LCFS	Low Carbon Fuel Standard
LCA	Life Cycle Associates, LLC
LDA	light duty auto
LDT	light duty truck
MPG	miles per gallon
MJ	megajoule
MT	million tonnes
N_2O	nitrous oxide
PHEV	plug-in hybrid electric vehicle
RD	renewable diesel
RIN	renewable identification number
RFS2	Renewable Fuel Standard 2
RNG	renewable natural gas
TTW	tank-to-wheel
VMT	vehicle miles travelled
WTT	well-to-tank
WTW	well-to-wheel

Executive Summary

The Paris Agreement[1] committed the U.S. to a 26-28% reduction in greenhouse gas (GHG) emissions from 2005 levels by 2025. This intermediate-term goal was to be a stepping stone on the way to the Obama Administration's 2050 target of 80% reduction (consistent with the failed 2009 Waxman-Markey legislation). In California, an Executive Order[2] requires an 80% GHG reduction from 1990 levels by 2050. Recognizing that the light duty automobile fleet represents a significant share of U.S. and California GHG emissions, reducing its emissions will be key to achieving the 2050 goals.

The purpose of this analysis was to project U.S. and California business-as-usual (BAU) light duty GHG emissions through 2050 and determine whether the 80% reduction goals can be achieved through a combination of advanced vehicle technology and introduction of lower carbon transportation fuels. Advanced vehicle technologies considered include battery electric vehicles (BEVs), plug-in hybrid electric vehicles (PHEVs), high octane fuel (HOF) vehicles, hydrogen fuel cell vehicles, and hybrid electric vehicles (HEVs). Changes in consumer spending on vehicles and fuels were also quantified, as was petroleum consumption. The U.S. and California BAU GHG emissions, costs and petroleum consumption were established using published projections of vehicle sales (by class and technology type), fuel economy, vehicle miles travelled, fuel cost, and incremental vehicle cost (relative to a 2015 gasoline internal combustion engine vehicle). Four GHG reduction scenarios were designed, each emphasizing aggressive roll in rates of a different vehicle technology as follows:

Table 1. Maximum Technology Market Share Assumptions

Scenario	Emphasis Technology	Fuel	U.S. Maximum Market Share		CA Maximum Market Share	
			LDA	LDT	LDA	LDT
1	BEV	Electricity	70%	45%	70%	43%
2	PHEV	Electricity & Gasoline	80%	45%	75%	45%
3	E85 PHEV	Electricity & E85	80%	45%	65%	43%
4	E85 HEV	E85	80%	90%	65%	83%

In all cases, market share of the emphasis technology was increased at the expense of gasoline ICEs, with market share of gasoline ICEs decreasing to less than 5%. To achieve this low level of gasoline ICE market share while limiting maximum EV market share to reasonable values, the market share of E85 HEVs was also increased for Scenarios 1-3. Because of the ZEV mandate, the maximum market share of PHEVs and the E85 HEVs in the California analysis were limited by the market share values of other ZEVs. Total vehicle sales and vehicle miles travelled (VMT) were the same for the BAU and the GHG reduction scenarios. Technology market shares in the GHG reduction scenarios were assumed to be the same as the BAU until 2025 at which point the emphasis technology market shares began to increase above BAU levels.

[1] http://www4.unfccc.int/submissions/indc/Submission%20Pages/submissions.aspx
[2] Governor Jerry Brown Executive Order B-30-15, April 2015.

The scenarios were considered with projected BAU carbon intensity (CI) emission factors and with an optimistic low CI set of factors. The optimistic electricity emission factor assumed a 70% non-fossil grid while the optimistic ethanol emission factor assumed that half of the ethanol would be derived from cellulosic material. The GHG emission factors are on a well-to-wheel basis and therefore include emissions from feedstock recovery and transport, fuel production and transport, and vehicle emissions.

Figure 1 provides the projected U.S. emissions for the BAU and GHG reduction scenarios. Even with aggressive market share assumptions of the cleanest technologies, none of the scenarios achieves the light duty 2050 goal. More time is needed for older vehicles to retire and be replaced with more efficient less carbon intensive options, or the cleaner options have to be introduced faster. The figure indicates that all of the base scenarios yield similar GHG emission levels in 2050. The low CI versions of the scenarios are shown with dashed lines. The BEV and E85 PHEV options provide more reduction than the PHEV and E85 HEV options. The BEV and E85 PHEV scenarios with low CI fuels might achieve the goal by 2060.

Figure 2 provides the California's projected emissions. California's BAU emissions decrease substantially compared to the U.S. BAU emissions due to the ZEV Mandate, the Low Carbon Fuel Standard (LCFS), and low carbon electricity grid. The scenarios provide very similar results with the low CI BEV and E85 PHEV options providing slightly better performance than the others. While it looks difficult for California to achieve its 80% reduction goal by 2050, it should be possible by 2055 or 2060.

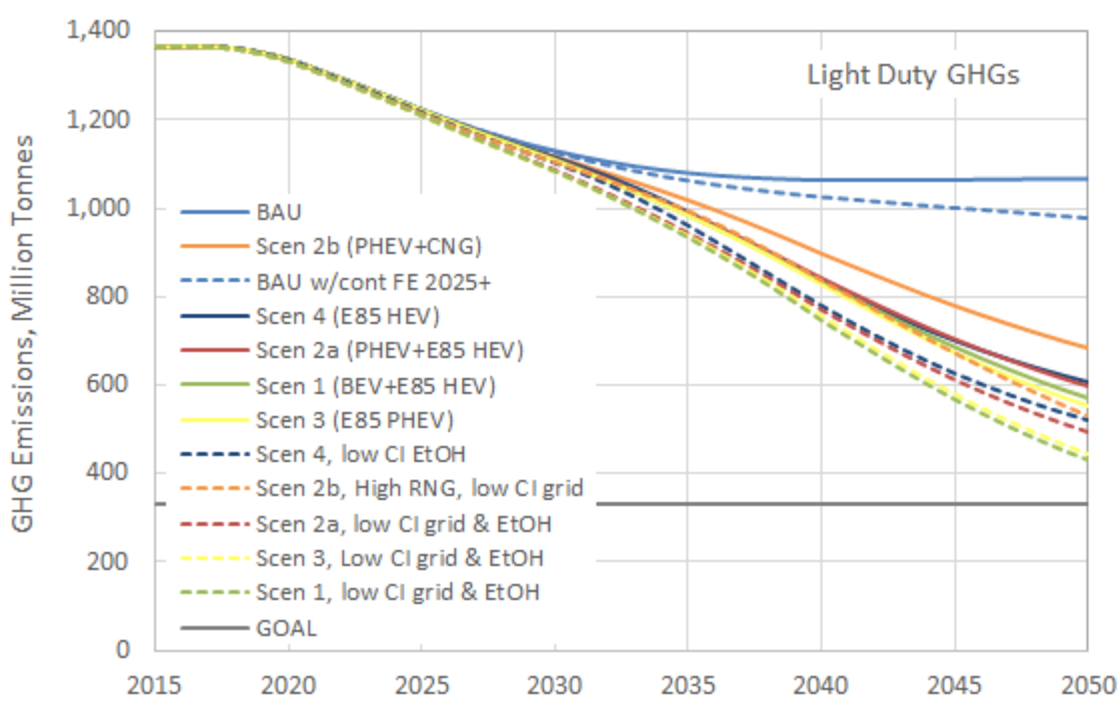

Figure 1. Projected U.S. Light Duty GHG Emissions.

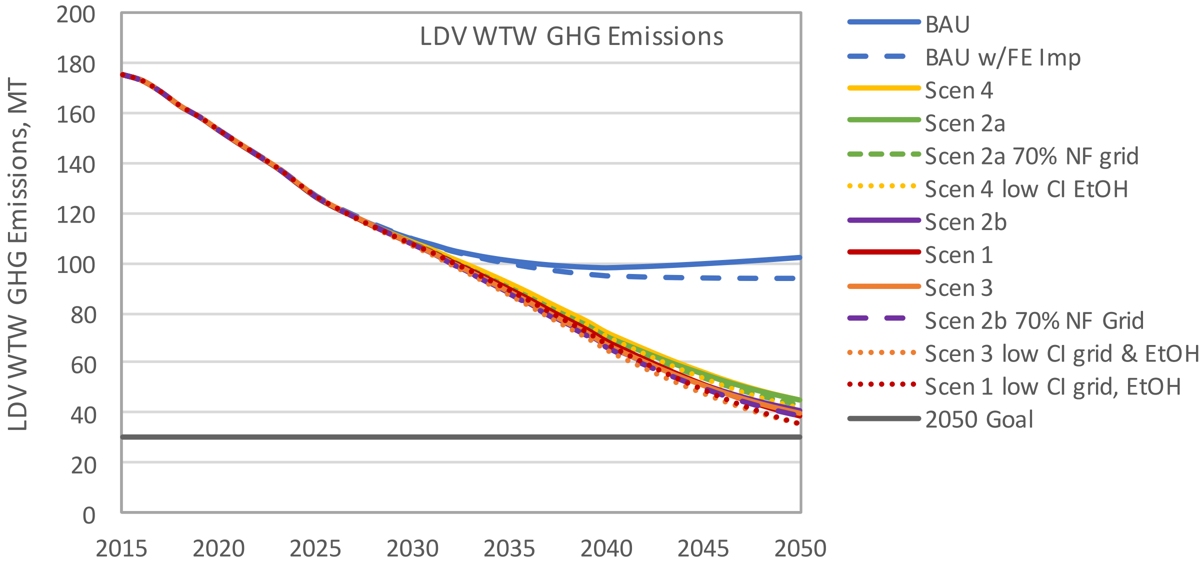

Figure 2. Projected California Light Duty GHG Emissions.

It is important to note that the low CI options for Scenario 3 (E85 PHEV) and Scenario 4 (E85 HEV) require significant volumes of advanced (cellulosic) ethanol. For the U.S. analysis, 15 BGY of cellulosic ethanol would be required by 2050 for Scenario 3 while 27 BGY would be required for Scenario 4. For California, 1.6 BGY of cellulosic ethanol would be required by 2050 for Scenario 3 and 3.1 BGY would be required for Scenario 4. Petroleum consumption decreases dramatically for all scenarios, with a 75% decrease in 2050 from 2015 levels for the U.S. and an 85% decrease from 2015 levels for California.

Because GHG emissions accumulate in the atmosphere, projected cumulative GHG reductions from the scenarios are a better indicator of climate impact than GHG emission levels in 2050.[3] Table 2 summarizes the cumulative GHG reduction, as well as cumulative fuel savings, incremental vehicle costs and electric vehicle supply equipment (EVSE, charging equipment) costs. Cost effectiveness is also calculated, defined as cumulative costs divided by cumulative reductions. As can be seen, all scenarios provide large fuel savings that offset increased vehicle and EVSE costs.

Figure 3 provides the U.S. analysis results in graphical form. As can be seen, the low CI versions of each scenario provide more cumulative GHG reduction at higher cost. The base case versions of each scenario offer similar GHG reductions except for Scenario 2b (PHEV supplemented with CNG rather than E85 HEV) which provides less reduction and high vehicle costs. If cellulosic ethanol and/or a low carbon grid are unlikely, Scenario 4 (E85 HEV) is an extremely cost-effective way to achieve moderate reductions. This scenario, however, requires over 50 BGY of ethanol. For reference, the Renewable Fuel Standard mandates 36 BGY by 2022. Using 50%

[3] The IPCC relates cumulative GHG emissions to atmospheric concentrations of CO2 (refer to the IPCC Fifth Assessment Report, Summary for Policy Makers) and “Warming Caused by Cumulative Carbon Emissions Towards the Trillionth Tonne”, Nature 458, 1163-1166 (30 April 2009) by Myles Allen et al.

cellulosic ethanol increases the GHG reduction such that the goal could eventually be achieved at a net cost savings, however up to 27 BGY of cellulosic ethanol are required. The next most cost effective low CI option is Scenario 2a (PHEV supplemented with E85 HEV) at $20 per tonne. The BEV and E85 PHEV options provide an additional 10% GHG reduction, but the cost per tonne more than doubles.

Table 2. Summary of Cumulative GHG Reduction and Cumulative Costs for U.S. Analysis

	Cumulative GHG Abated	Fuel Costs	Vehicle Costs	EVSE Costs	Net Costs	Cost Effectiveness
	Billion tonne	Billion $2015				$/tonne
Scen 1 (BEV)	5.0	-1,531	1,541	156	166	34
Scen 1, Low CI	6.9	-1,338	1,541	156	360	52
Scen 2a (PHEV-E85)	4.7	-1,483	1,364	60	-58	-12
Scen 2a, Low CI	6.3	-1,306	1,364	60	118	19
Scen 2b (PHEV-CNG)	3.6	-1,648	1,713	60	125	34
Scen 2b, Low CI	5.2	-1,323	1,713	60	450	87
Scen 3 (E85 PHEV)	5.1	-1,445	1,442	62	58	11
Scen 3, Low CI	6.7	-1,227	1,442	62	277	41
Scen 4 (E85 HEV)	4.7	-771	345	0	-426	-90
Scen 4, Low CI	5.9	-425	345	0	-81	-14

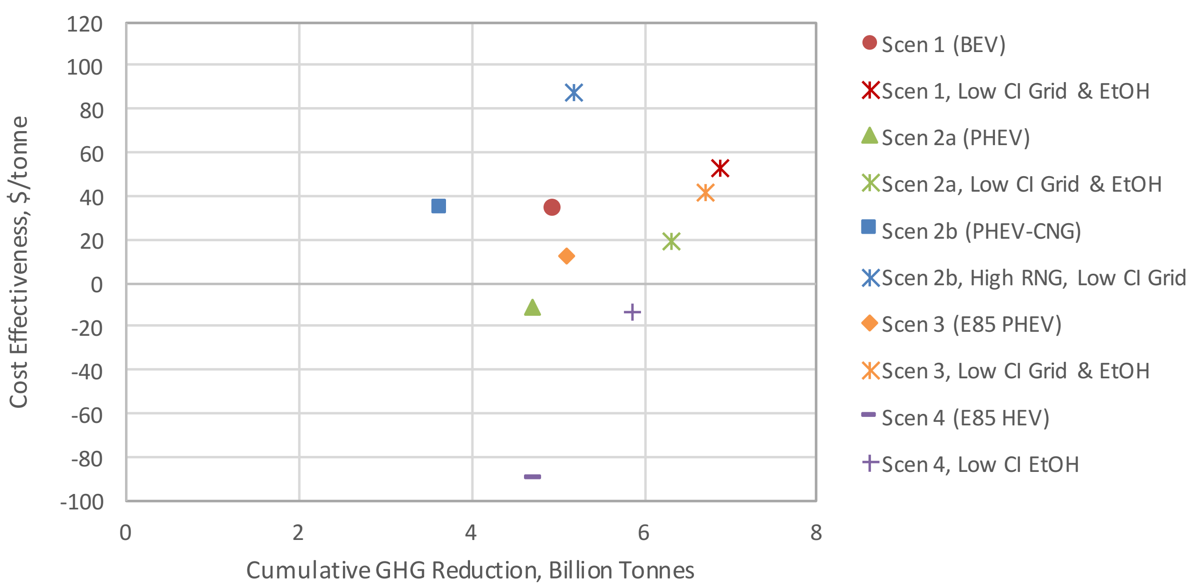

Figure 3. Cost effectiveness vs cumulative GHG reduction, U.S. analysis.

Table 3 and Figure 4 provide the corresponding information for California. As noted above, the low CI options do not provide significantly more GHG reduction than the base CI cases because the BAU emission factors are already fairly low. Scenario 3 (E85 PHEV) offers the most GHG reduction at a modest cost per tonne. Scenario 1 (BEV) and Scenario 2b (PHEV-CNG) provide similar reductions at much higher cost. Scenario 2a (PHEV-E85 HEV) provides slightly less reduction, but at a net cost savings while Scenario 4 provides less reduction at a significant cost savings. Scenario 4 requires an increase in ethanol consumption from the current 1.5 BGY to nearly 4.5 BGY in 2050. The base case assumes that half of this ethanol will be cellulosic while the low CI case assumes 3 BGY of cellulosic ethanol by 2050.

Table 3. Summary of Cumulative GHG Reduction and Cumulative Costs, California Analysis

	Cumulative GHG Abated	Fuel Costs	Vehicle Costs	EVSE Costs	Net Costs	Cost Effectiveness
	Million tonne	Billion $2015				$/tonne
Scen 1 (BEV)	646	-192.8	228	21	56.1	87
Scen 1, low CI	680	-189.9	228	21	59.1	87
Scen 2a (PHEV-E85 HEV)	595	-176.7	164	8	-5.2	-9
Scen 2a, low CI	625	-173.5	164	8	-2.0	-3
Scen 2b (PHEV-CNG)	660	-180.3	214	8	41.1	62
Scen 2b, low CI	678	-180.3	214	8	41.1	61
Scen 3 (E85 PHEV)	667	-164.2	171	8	14.5	22
Scen 3, low CI	703	-159.0	171	8	19.7	28
Scen 4 (E85 HEV)	572	-78.7	34	0	-44.7	-78
Scen 4, low CI	602	-69.5	34	0	-35.4	-59

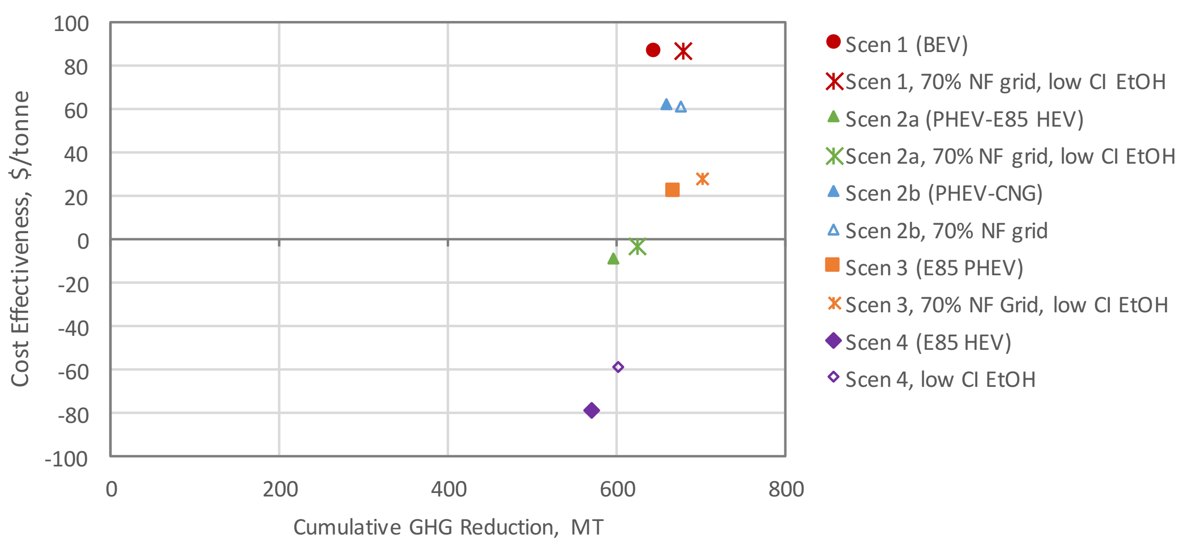

Figure 4. Cost effectiveness vs cumulative GHG reduction, U.S. analysis.

Based on the foregoing results, we conclude that if the U.S. decides to honor the GHG reduction goals set by the Obama Administration, progress must continue on fuel economy standards, cellulosic biofuels must be made available, the electricity grid needs to continue to decarbonize, and strategies must be put in place to ensure aggressive deployment of advanced technology vehicles. A combination of electric (either BEV or PHEV) and use of high level ethanol blends in lieu of gasoline provides the most flexibility. Specific suggestions include:

- Keep the 2022-2025 CAFE standards in place, set more stringent standards for 2026-2050, and provide incentives to shift consumers from light trucks to light autos
- Continue and extend the Renewable Fuel Standard; send clear and consistent signals on cellulosic volumes to spur financing of fuel production plants
- Consider adopting a national Low Carbon Fuel Standard
- Implement the Clean Power Plan and identify strategies to further decarbonize the grid
- Consider adopting a nationwide ZEV Mandate to aggressively deploy advanced vehicles

California is on its way to achieving its goals; the BAU achieves approximately half of the reduction needed between now and 2050. However, aggressive deployment of advanced technology vehicles will be needed. The existing ZEV Mandate could be used as the tool to achieve this transformation of the fleet.

1. Introduction

The transportation sector generates approximately 30% of U.S. greenhouse gas (GHG) emissions; therefore, reducing emissions from vehicles and the production of fuels is an essential component of a GHG reduction strategy. California and the U.S. have committed to challenging GHG reduction goals. Last year, the U.S. signed on to the Paris Agreement, committing to a 26 to 28% reduction in GHG emissions from 2005 levels by 2025[4]. As stated in the Paris commitment, the Obama Administration's long-term goal was an 80% reduction from 2005 levels by 2050, the same goal that was in the 2009 American Clean Energy and Security Act (Waxman-Markey)[5] that passed the U.S. House of Representatives but failed in the Senate. The California GHG reduction goal, codified in the Global Warming Solutions Act[6] is to reduce emissions to 1990 levels by 2020 and to 80% below 1990 levels by 2050. Governor Brown has recently issued an Executive Order[7] to achieve an interim reduction of 40% below 1990 levels by 2030. Note that the California 2050 goal is more difficult than the U.S. goal because the baseline year is 15 years earlier.

Figure 1-1 illustrates the distribution of energy used in the U.S. transportation sector in 2013. The majority of the fuel used (76%) was consumed on-road. Of this, over 70% is consumed by light duty cars and trucks. The overall objective of this study is to perform a wedge analysis of the U.S and California light duty fleets to determine how the 2050 goals might be achieved and to quantify the corresponding changes in consumer spending on fuel and vehicles. Changes in petroleum consumption are also quantified.

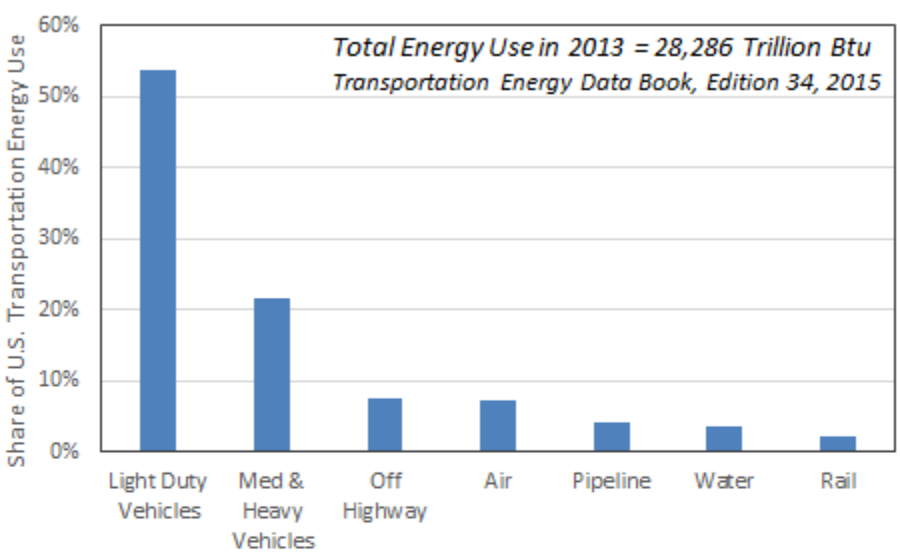

Figure 1-1. Transportation Energy Use by Mode, 2013.

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4 http://www4.unfccc.int/submissions/indc/Submission%20Pages/submissions.aspx
5 https://www.congress.gov/bill/111th-congress/house-bill/2454
6 Assembly Bill 32, 2006. Codified in CA H&S Codes 38500, 38501, 28510, 38530
7 EO B-30-15, April 29, 2015

1.1 Light Duty GHG Emission Reduction Measures

There are three ways to reduce light duty GHG emissions: improve vehicle fuel economy, reduce fuel carbon content, and reduce vehicle miles travelled (VMT). Although VMT reduction measures such as increased public transit, ridesharing, and pay-as-you-go insurance are an important piece of the solution, this study considers reductions that can be achieved from the other two strategies (improved fuel economy and use of lower carbon fuels).

The federal government currently limits light duty GHG emissions through the 2011 joint ruling[8] by the National Highway Traffic Safety Administration (NHTSA) and the Environmental Protection Agency (EPA). The joint 2011 rule sets the Corporate Average Fuel Economy (CAFE) standard for new light duty autos and trucks to 34.1 mpg by 2016 and 54.5 mpg by 2025. The 2011 ruling stipulates an interim review of the standards for model years 2017-2025. In July 2016, EPA, NHTSA and ARB issued a draft Technical Assessment Report. In early 2017, EPA issued its final determination[9] that "automakers are well positioned to meet the standards at lower costs than previously estimated" and retained the existing standards "despite a technical record that suggests the standards could be made more stringent."

The final standards are provided in

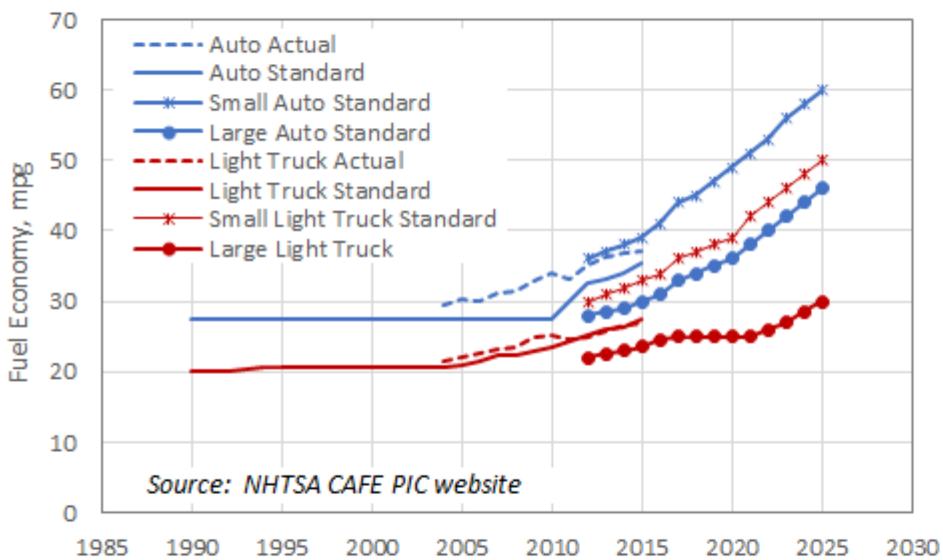

Figure **1-2**. For 2012-2025 there are actually four separate standards that depend on the vehicle's footprint. The actual fuel economy standard is therefore a sales weighted average by footprint bin. Note that the actual auto fuel economy is better than the standard while the actual light truck fuel economy just meets the standard. In 2011, EPA and NHTSA estimated that the fleet average fuel economy for 2025 would be 54.5 mpg. The estimate for fleet average fuel economy from the more recent rulemaking is 50 mpg due to a shift away from light autos towards light trucks.

[8]NHTSA: 49 CFR Parts 531, 533, 536, 537 and 538; EPA: 40 CFR Parts 85, 86, and 600

[9] January 2017, EPA-420-R-17-001. The Trump Administration has since re-opened this review.

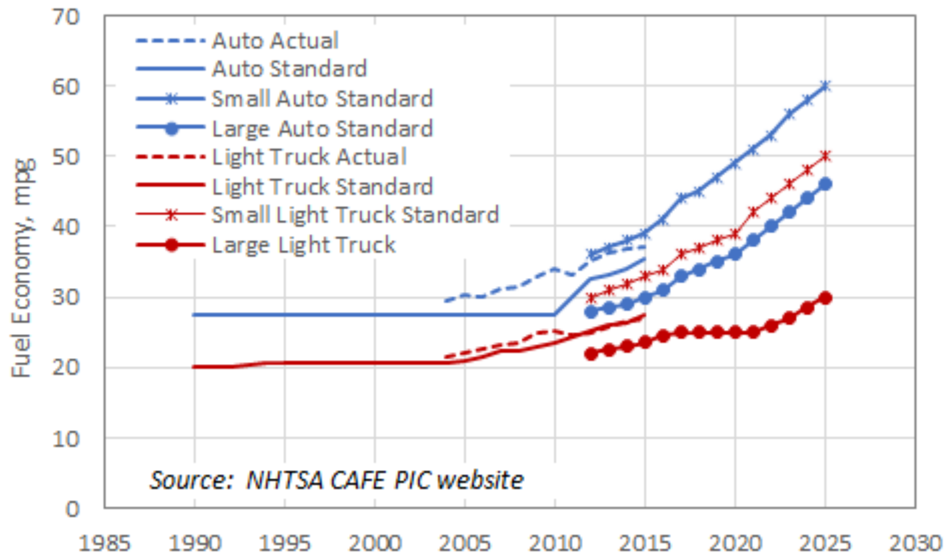

Figure 1-2. Corporate Average Fuel Economy standards and actual fuel economy.

Another federal regulation that limits GHG emissions from the light fleet is the Renewable Fuel Standard (RFS). The RFS was created under the Energy Policy Act of 2005 and subsequently expanded by the Energy Independence and Security Act of 2007. The RFS requires obligated parties (refiners and fuel importers) to provide set volumes of four different types of fuel each year as indicated in Figure 1-3. By 2022, 36 billion gal/yr of renewable fuel are mandated.

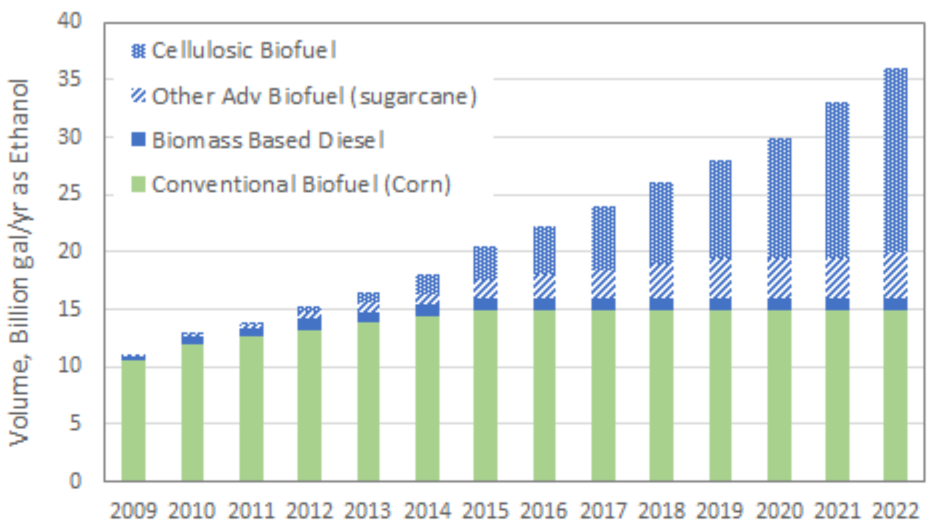

Figure 1-3. Original RFS renewable fuel volume requirements

The four different renewable fuel categories are summarized in Table 1-1. Each ethanol equivalent gallon of renewable fuel produced generates a renewable identification number (RIN) with a "D-Code". The D-Code assigned depends on the feedstock type, fuel type and lifecycle GHG reduction achieved relative to baseline petroleum. Obligated parties must submit a certain number of each type of RIN each year to demonstrate compliance. RINS can be acquired by purchasing renewable fuel with RIN attached or may purchase RINS on the market.

In recent years, EPA has reduced the volume requirement for advanced and cellulosic biofuels because of commercialization delays. For example, the 2017 volumes for cellulosic ethanol is 311 MGY compared to the original volume of 5.5 BGY. EPA classifies CNG produced from renewable natural gas as cellulosic biofuel, so this has generated the bulk of the D3 RINS in the past several years. Obligated parties may also purchase cellulosic waiver credits rather than purchasing D3 RINS. The RFS volumes were originally set through 2022, but the rule technically does not expire and EPA can continue to require renewable fuel sales beyond 2022.

Table 1-1. RFS Fuel Categories.

	GHG Reduction	RIN D Code
Cellulosic Fuel	60%	3
Biomass Based Diesel	50%	4
Advanced Biofuel	50%	5
Conventional Biofuel	20%	6

The RFS encourages lower carbon fuels through a volume mandate. Another approach to reducing fuel carbon intensity is a low carbon fuel standard (LCFS). In contrast to a volume mandate, an LCFS requires the average carbon intensity (CI) of transportation fuel to decrease over time. In the absence of a federal standard, California adopted an LCFS[10] which requires obligated parties (fuel suppliers and blenders) to reduce transportation fuel well-to-wheel (WTW) carbon intensity 10% from 2009 levels by 2020. Figure 1-4 provides the original compliance curve as stated in the 2009 standard and the modified curve resulting from litigation and subsequent re-adoption in 2015. The figure also indicates the actual transportation fuel carbon intensity through 2015. Obligated parties have been well below the required CI levels through 2015, likely due to credit banking provisions in the rule. By over-complying in early years, obligated parties can generate surplus credits which may either be sold to other obligated parties or saved for compliance in future years.

[10] The LCFS was an early action item under AB32, the Global Warming Protection Act. ARB adopted the LCFS in 2009, amended it in 2011 and readopted it in 2015. The final regulation order may be found here: https://www.arb.ca.gov/regact/2015/lcfs2015/lcfsfinalregorder.pdf

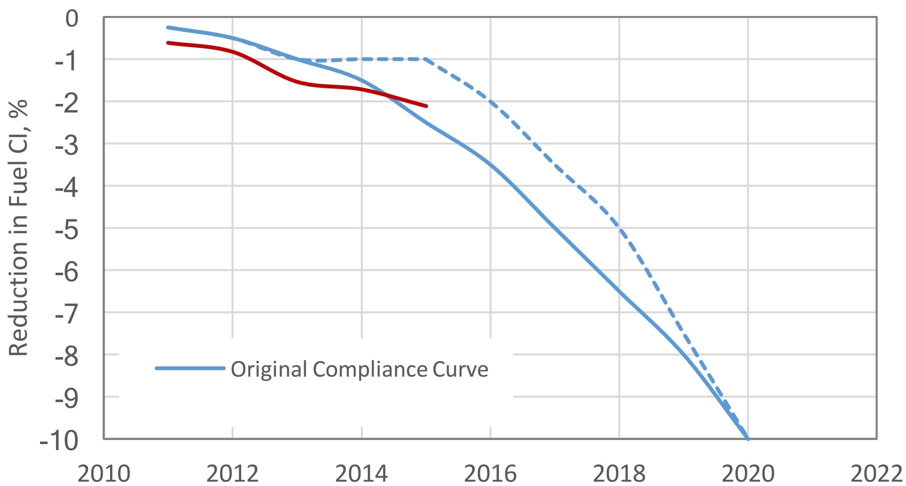

Figure 1-4. California LCFS GHG reduction targets.

Another policy currently being utilized in California and nine other states[11] to reduce vehicle GHG emissions is the Zero Emission Vehicle (ZEV) Mandate. Automobile manufacturers are required to generate ZEV credits through the sale of electric drive vehicles; a set number of credits must be created per total vehicles sold. For every 100,000 vehicles sold, 4500 credits must be generated in 2018 increasing to 22,000 credits by 2025. The number of credits generated for each vehicle depends on electric range. Plug-in hybrid electric vehicles (PHEVs) receive 0.4-1.3 credits while battery electric vehicles (BEVs) receive up to 4 credits depending on electric range. Since there is not a 1:1 ratio between credits and vehicles, it is hard to forecast the number of ZEVs sold. ARB's most recent forecast[12] indicates that in 2025, nearly 8% of ZEV state light vehicles will be ZEVs and PHEVs.

1.2 Scope of Present Analysis

It has been ten years since EPA published a wedge analysis[13] of the U.S. transportation sector GHG emissions. The analysis projected business-as-usual (BAU) GHG emissions through 2050 and determined measures needed to stabilize emissions at 2006 levels and identified additional measures that could reduce emissions below 2006 levels. In this project, GHG emissions from the U.S. and California light duty fleet are forecast through 2050, taking into account current CAFE standards, the RFS, the LCFS and ZEV Mandate. Incremental spending on vehicles (relative to conventional 2015 gasoline vehicles) and fuel spending are also quantified. These updated light duty BAU cases are then compared to the federal and California GHG emission reduction goals to determine additional reductions that will be needed. Scenarios were constructed utilizing advanced vehicles and low carbon fuels to determine if the GHG goals might be achieved and to estimate the corresponding vehicle and fuel costs relative to the BAU.

There are a variety of ways to reduce emissions from the light duty fleet. These include:

[11] Connecticut, Maine, Maryland, Massachusetts, New Jersey, New York, Oregon, Rhode Island, Vermont
[12] 2017 ZEV Calculator Tool https://www.arb.ca.gov/msprog/zevprog/zevcalculator/zevcalculator.htm
[13] A Wedge Analysis of the U.S. Transportation Sector, EPA420-R-07-007, Mui, Alson, Ellies, Ganss, June 2007

- Improve gasoline internal combustion engine (ICE) vehicle efficiency
- Use high octane ethanol fuels in dedicated and conventional ICE vehicles
- Increase use of hybrid electric vehicles
- Increase use of battery electric and fuel cell vehicles
- Reducing the CI of fuels

In complying with current CAFE standards, automakers are bringing a considerable amount of innovation to gasoline ICE vehicles. Improvements are being made in engine technology, transmissions, accessory loads, drag and vehicle weight. Key gasoline engine technologies include cylinder deactivation, variable valve lift, direct injection (allows higher compression ratio and enables downsizing and boost). Adding gears to the automatic transmissions (6-8 gears) and continuously variable transmission provides significant fuel economy benefit. Powering accessories with battery electricity when needed rather than adding a parasitic engine load is another area that is being optimized. Reducing aerodynamic drag and utilizing low rolling resistance tires also offer improvement.

Gasoline is currently a 10% volume blend of ethanol with gasoline blendstock. Because ethanol acts to increase octane rating, the blendstock octane rating has decreased as ethanol volume has increased, maintaining pump octane at 87 for regular gasoline. One idea being considered is designing vehicles to operate on mid (30% ethanol or E30) and high (85% ethanol or E85) level blends of ethanol in gasoline. Dedicated vehicles that operate exclusively on E30 or E85 could be optimized for the higher octane fuel by increasing compression ratio without having to retard the spark timing. The increased power output would allow engines to be downsized, improving fuel economy. Moreover, ethanol promotes rapid combustion which results in cooler exhaust, increasing the amount of exhaust gas recirculation that can be tolerated.

Hybrid electric vehicles (HEVs) have two different power sources: a downsized engine and a battery. The battery can assist the smaller engine when needed. The gasoline engine is shut off when motive power is not needed (coasting, idling, stopped). Most hybrids have regenerative braking to capture heat lost in braking and store it as electricity in the battery. HEVs are mostly seen in the light auto sector since batteries are quickly depleted when towing and light trucks are marketed with towing capability. Most current HEVs are so-called power split HEVs with a main motor-generator driving the transmission and the gasoline engine either providing additional power to the main motor generator or charging the battery.

Plug-in electric vehicles (PHEVs) are similar to HEVs except they have a larger battery that allows all-electric vehicle operation for 10-60 miles. Full battery electric vehicles (BEVs) operate only on battery power; the batteries are plugged to an external power source to recharge. Hydrogen fuel cell vehicles (FCVs) are similar to BEVs except they carry hydrogen tanks and fuel cells to convert hydrogen to electricity for motive power.

Improvement in ICE fuel economy can be coupled with reduced CI fuel. For example, ethanol can be made from cellulosic feedstocks rather than corn, compressed natural gas (CNG) vehicles can use renewable natural gas (RNG) rather than fossil natural gas, and diesel vehicles can use more biodiesel. Vehicles with internal combustion engines (ICEs, HEVs, and PHEVs) can increase the amount of ethanol from 10% by volume in gasoline to a mid-level blend (30%) or a high-level blend (85%). Finally, vehicles using electricity can benefit from a lower carbon grid.

The present analysis forecasts BAU GHG emissions for the U.S. and California light fleets incorporating the latest research on fuel economy for different vehicle technologies, conventional and alternative fuel WTW carbon intensity estimates, and technology costs. Scenarios were constructed considering market acceptance and penetration rates to determine whether the 2050 GHG goals are possible and to quantify the corresponding increase/decrease in fuel and vehicle spending. The scenarios assess the tradeoffs between electrification of the fleet and improvement of existing ICE technologies. This report presents the results of this updated wedge analysis and is organized as follows:

- Section 2 describes the analysis methodology and presents key analysis assumptions
- Section 3 provides BAU projections for the California and U.S. analyses
- Section 4 provides 2050 emissions and costs on a per mile basis for a wide range of vehicle technology and fuel combinations
- Section 5 provides results for the U.S. scenario analysis
- Section 6 provides the California scenario analysis results
- Section 7 summarizes the conclusions drawn from the results
- 1.a.i.1.a.Appendix A provides support for fuel economy and incremental cost projections utilized
- 1.a.i.1.a.Appendix B provides details on the WTW CI values used in the U.S. analysis
- 1.a.i.1.a.Appendix C describes the WTW CI values used in the California analysis
- 1.a.i.1.a.Appendix D and 1.a.i.1.a.Appendix E describe the new vehicle market share projections for each of the compliance scenarios in the U.S. and California Analyses, respectively.

2. Methodology and Analysis Assumptions

As discussed above, this study strives to project annual GHG emissions from the U.S. and California light duty fleets. A business-as-usual (BAU) case was defined that estimates annual GHG emissions through 2050 assuming no new standards or regulations are adopted. This case is subsequently compared to a range of scenarios that attempt to achieve the 2050 GHG goals. This section describes the modeling methodology employed and the efforts made to use realistic assumptions for key model inputs. The following sections describe the modeling methodology and the key assumptions utilized to generate the BAU results.

2.1 Methodology

To generate projections of fuel consumption, fuel spending and vehicle spending, a vehicle stock model is used as illustrated schematically in Figure 2-1. As indicated, the main feature of the model is keeping track of the number of vehicles by model year (MY) and technology type on the road each year. This is accomplished by specifying the total light auto and light truck sales each year, splitting the sales between different technology types (e.g. gasoline, HEV, BEV, etc), and then applying an assumed survival rate profile so that as each calendar year goes by, fewer vehicles of a certain MY remain. Note that vehicle sales and survival rates must be modeled at least 25 years prior to the first analysis year (2016) so that 2016 has the realistic spread of model years in the vehicle population.

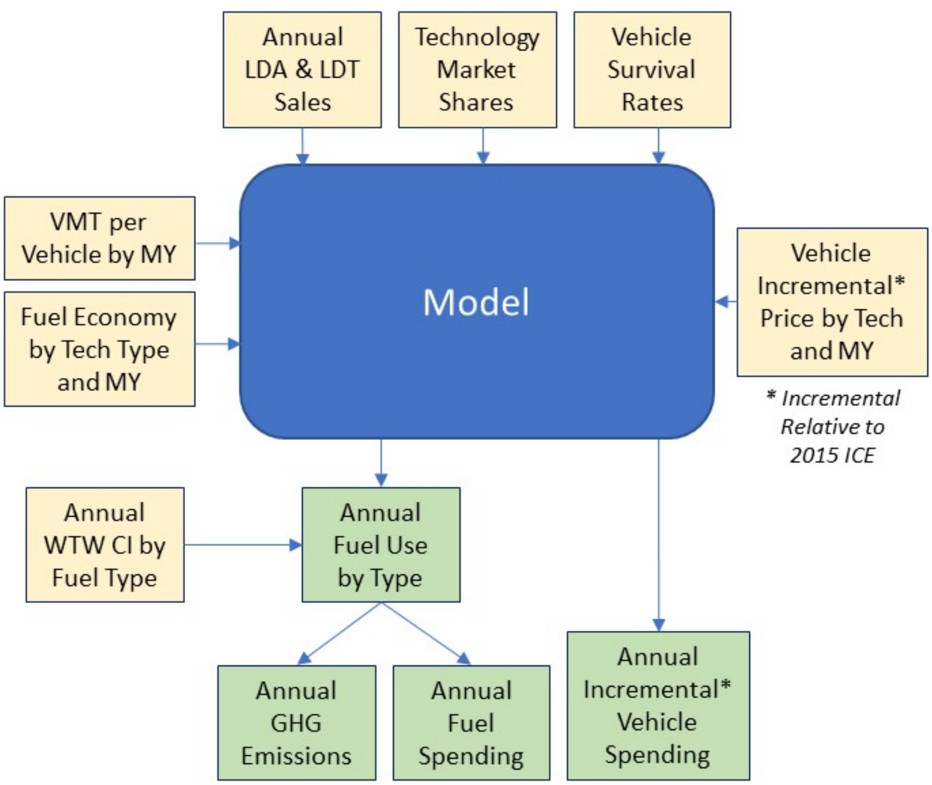

Figure 2-1. Schematic illustrating the modeling methodology.

The second key assumption in the model is the average fuel economy for each technology type over the analysis period. Since fuel economy standards change over time, each model year and technology type has an average fuel economy value assigned to it. Each calendar year, a population weighted average fuel economy is calculated for each technology type. For example, to calculate the average light auto ICE fuel economy in 2020, the number of MY2020 ICE vehicles is multiplied by the MY2020 fuel economy and added to the number of MY2019 vehicles multiplied by the MY2019 fuel economy and so on. The sum of these products is then divided by the total number of vehicles in calendar year 2020 to arrive at the weighted average fuel economy for light auto ICEs in 2020. This calculation is performed for each calendar year from 2016-2050 and each vehicle technology type.

The third key input is the average vehicle miles traveled (VMT) per vehicle. Like fuel economy, this factor varies by vehicle age with new vehicles traveling more miles than older vehicles. At this point, the number of vehicles can be combined with the average fuel economy and average per vehicle VMT yielding total annual fuel consumption (by fuel type) for the analysis period.

For this portion of the modeling effort (quantifying annual fuel consumption), Argonne National Laboratory's VISION2015 model was utilized as the starting point for the U.S. light fleet analysis. Each year, Argonne updates the VISION model with the Department of Energy's Annual Energy Outlook (AEO) projections for vehicle sales, technology market shares, VMT, and fuel economy. The VISION2015 model is populated with AEO2015 data. LCA updated VISION2015 with data from AEO2016 and other sources as described later in this section and in the Appendices. For the California analysis, the California Air Resources Board (ARB) VISION model[14] provided the starting point for the California light fleet analysis. The U.S. and California VISION models divide the light duty sector into light duty autos (LDAs) and light duty trucks (LDTs). The light truck category includes vehicles up to 8500 lbs[15] (Class 2b trucks are not included).

For this analysis, LCA added three features to the basic VISION modeling framework. First, CI factors for each fuel/feedstock combination were developed and added to the models so that annual GHG emissions from the LDA and LDT fleets could be quantified. U.S. average factors were used in the U.S. model and California specific factors were used in the California model. Second, profiles of incremental vehicle cost relative to a 2015 ICE vehicle were developed for each technology type. The incremental cost profiles were applied to the annual vehicle sales to determine annual incremental vehicle costs relative to a 2015 ICE. Finally, LCA added fuel cost profiles to quantify fuel spending over the analysis period.

The following sections provide the underlying assumptions for developing the U.S. and California BAU forecasts.

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[14] VISION 2.1 Passenger Fleet Module https://www.arb.ca.gov/planning/vision/downloads.htm#2016vision21lr
The ARB model is a Microsoft Access database file. The data for light duty vehicles was extracted and LCA constructed a Microsoft Excel version of the model consistent with the structure of the U.S. VISION model.
[15] Class 1 and Class 2a for the federal analysis and LDT1, LDT2, MDV for the California analysis.

2.2 Vehicle Sales Forecast

Projections of annual vehicle sales are critical to accurate projections of fuel consumption and GHG emissions. For the U.S. analysis, the VISION2015 model (the starting point for this analysis) utilizes historic sales for 2014 and prior and EIA's AEO2015[16] projections for 2015-2040. Figure 2-2 provides the default VISION (AEO2015) vehicle sales and the AEO2016 sales (dashed lines). The AEO2015 sales were replaced with the AEO2016 sales in the model because the AEO2016 projections are more recent. Note that a short-term increase in light truck sales is anticipated followed by a gradual increase in light auto sales relative to light truck sales for 2020-2050. Total light duty sales are not projected to re-attain the peak achieved in 2000 (17,350 vehicles) until 2048. Vehicle sales responded to many important economic events including the recession after the 9/11 attacks, the 2008 economic crisis, and the drop in oil prices which started in 2014. AEO2016 projections extend through 2040; for the analysis, the 2041-2050 LDA and LDT sales are assumed to continue linearly along their respective VISION2015 slopes.

For the California analysis, vehicle sales projections are taken directly from ARB's VISION model. Figure 2-3 provides the light auto and light truck historic and projected sales. It is interesting to note that in contrast to the national experience, light autos have recovered more strongly than light trucks in California, and light auto sales are predicted to be approximately twice light truck sales for 2020-2050. In addition, California is expected to return to pre-recession sales volumes by 2016.

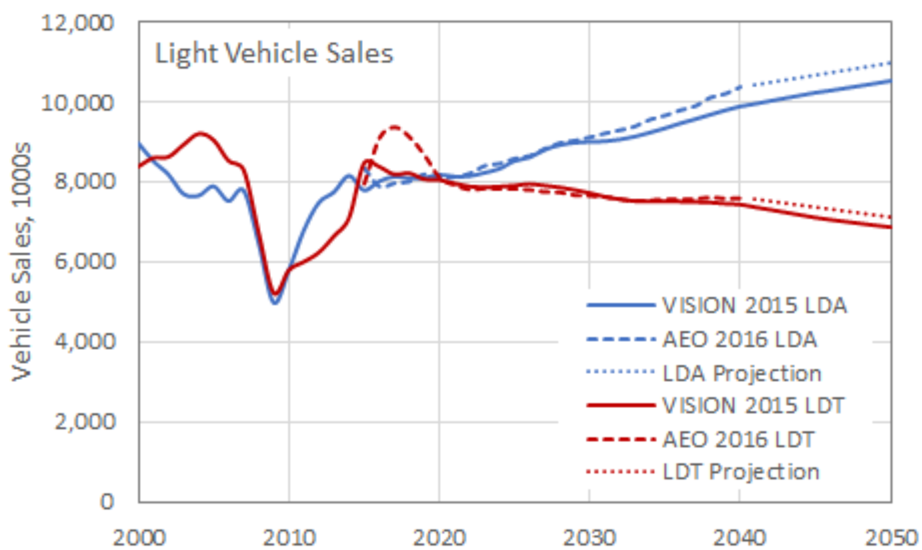

Figure 2-2. Historic and projected U.S. light duty vehicle sales.

[16] The DOE Energy Information Administration Annual Energy Outlook reference case with Clean Power Plan.

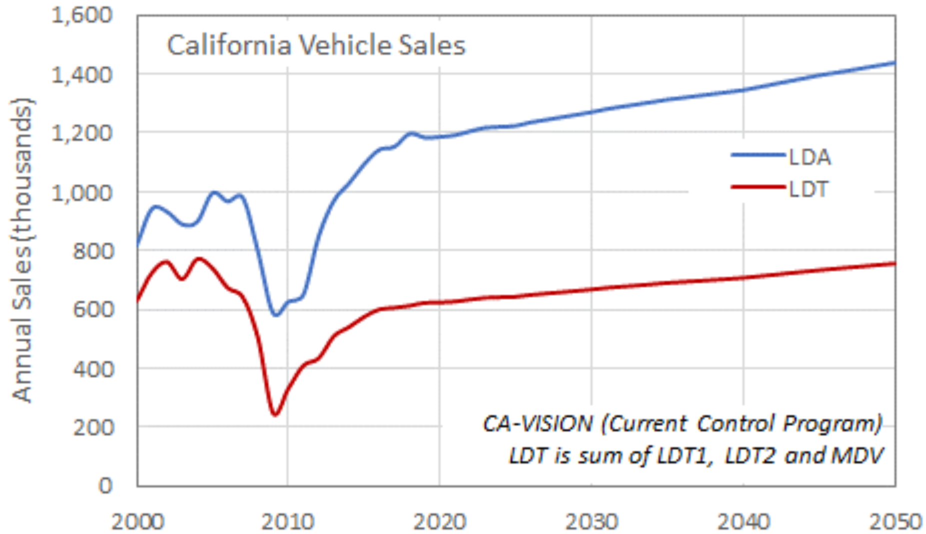

Figure 2-3. Historic and projected California light duty vehicle sales.

2.3 New Vehicle Technology Market Shares

The other key assumption for vehicle populations is technology market share. Specifically, annual projections for the share of new LDAs and LDTs sold each year that are gasoline ICE, diesel, FFV, HEV, PHEV, BEV, or FCV. Figure 2-4 provides historic and projected new LDA vehicle technology market shares for the U.S. market. The market share values for 2016 and later are taken from AEO2016 with three exceptions. First, AEO2016 projects that LDA diesel shares steadily increase to 6% by 2023. In contrast, the recent EPA Midterm Evaluation[17] assumes diesel vehicles will have 0.9% market share in 2025. In light of issues with Volkswagen's emission controls, and because Volkswagen represented the majority of LDA diesel vehicles sold, this analysis assumes 0.9% for LDA diesel new vehicle market share.

Second, the AEO2016 projection for full hybrids increases from 4.6% in 2016 to 6.6% in 2025 and then continues to grow linearly to over 8% by 2040. In contrast, the EPA Midterm Evaluation (MTE) projects a market share of 4.5% by 2025. For this analysis, a midpoint value between the MTE and AEO2016 of 5.5% in 2025 is used. Although the MTE suggests that ICE technologies will be able to meet the 2025 standards without use of hybridization (no growth in HEV shares), it may be that HEVs pick up some of the lost diesel sales. Although the AEO2016 projection shows a linear increase, this analysis maintains a steady market share from 2025-2050, consistent with the MTE forecast. Because the current CAFE standard ends in 2025 and there are no other measures beyond 2025, there is no reason for shares to increase after 2025.

[17] EPA, NHTSA, CARB Technical Assessment Report, Midterm Evaluation of Light-Duty Vehicle GHG Emissions Standards for Model Years 2022-2025, July 2016.

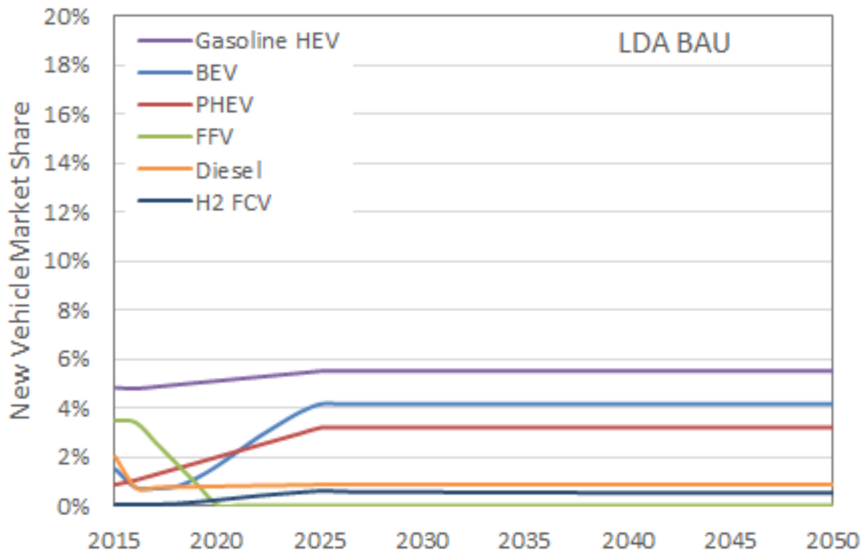

Figure 2-4. Projected U.S. LDA Technology Market Shares.

Finally, the AEO2016 projection for FFVs decreases slightly from 3.4% in 2016 to 2.6% in 2025 and constant thereafter. For many years, auto manufacturers have received a significant CAFE credit for each FFV sold. Beginning in 2017, CAFE credits will be granted depending upon how much E85 those vehicles consume. At present, it isn't feasible to track E85 use, so there is no incentive for manufacturers to continue providing FFVs, even though the additional cost is low. For this reason, the FFV market share profile has been reshaped with a linear decrease from 2016 levels to 0% by 2020.

The EPA MTE values for BEVs and PHEVs agree well with the AEO2016 projections. The MTE does not include a value for hydrogen FCVs, so the AEO2016 forecast is utilized. AEO2016 also divides the BEV category into BEVs with 100 mile range and BEVs with 200 mile range or more. For 2015, AEO2016 states that the BEV100/BEV200 split was 63/37 and projects that the BEV100/BEV200 split by 2025 will be 40/60. Strangely, the AEO BEV100/BEV200 split for 2040 is 57/43. LCA disagrees with the 2040 forecast and believes that the 2015-2025 trend of more BEV200 models will continue through the end of the analysis period due to continuous improvement in battery technology. This analysis retains the AEO2016 splits for 2015-2025, but sets the 2050 BEV100/BEV200 split for light autos at 15/85.

Figure 2-5 provides the resulting vehicle stock by technology type for the assumed market shares for the analysis period. It is interesting to note the decrease in vehicle stock after the 2008 economic crisis and subsequent slow rise back to pre-crisis levels. By 2050, the gasoline ICE vehicle is still dominant. The population of FFVs is expected to dwindle by 2035 without the CAFE credit.

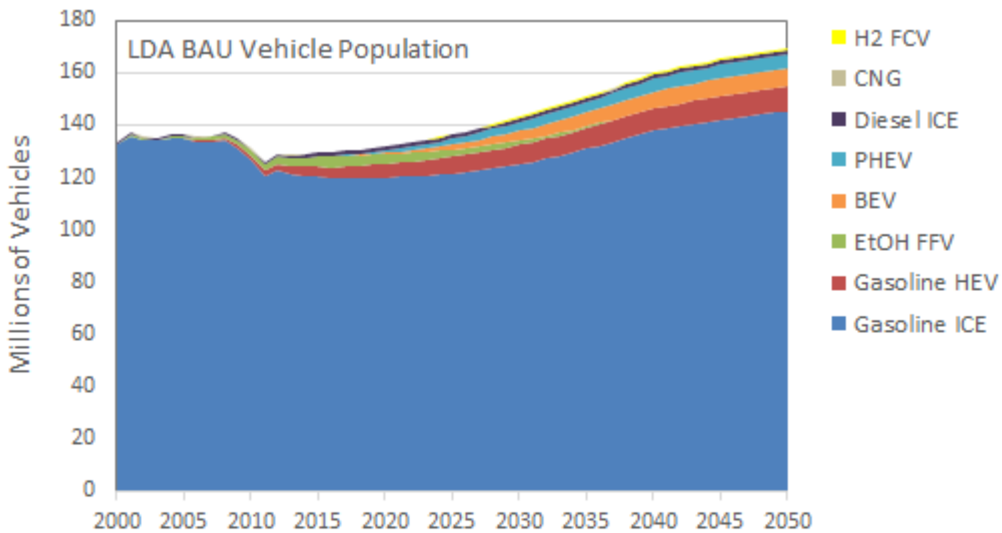

Figure 2-5. Projected U.S. LDA population by technology type for BAU

The LDT market share values used for the BAU case are illustrated in Figure 2-6. For diesels, AEO2016 assumes an increase from 1.4% in 2015 to 2% in 2025 and remaining constant thereafter. VISION2015 assumes 0.6% in 2015 increasing to 1.9% in 2025 and decreasing back down to 1.6% in 2040. The 2025 EPA MTE estimate is 1%. An intermediate value of 1.5% is used in 2025 with shares remaining constant for the remainder of the analysis period.

For HEVs, VISION2015 forecasts an increase from 0.3% in 2015 to 0.6% in 2025 and increasing gradually to 0.8% by 2050. The AEO2016 forecast begins at 0.6% in 2015 and increases to 1.1% in 2025 and gradually increasing to 1.4% by 2050. The EPA MTE 2025 estimate is 0.5% market share. An intermediate value of 0.75% is assumed for 2025 with no increase beyond 2025 without further increases in CAFE requirements.

For light truck BEVs, AEO2016 projects an increase in market share from 0.1% in 2015 to 1.5% in 2025 and holding constant at 1.5% through the end of the analysis period. The EPA MTE forecasts 0.4% by 2025. This analysis assumes a linear increase to 1% by 2025 and constant thereafter. The AEO2016 BEV100/BEV200 split for 2015 is 60/40 and gradually decreasing to 50/50 by 2025. The AEO assumption was utilized here. Similarly, for light truck PHEVs, AEO2016 projects an increase in market share from 0.2% in 2015 to 0.9% in 2025 the MTE forecasts 0.5% by 2025. For this analysis, we assume a linear increase to the intermediate value of 0.7% in 2025 and constant through the end of the analysis period.

EPA does not provide a forecast for FFVs, but the AEO2016 projection assumes a 17% market share for the entire analysis period. Because of the change in the FFV CAFE credit for MY 2017 and later, this analysis assumes that FFV market share decreases linearly to 0% by 2020. The near-term decrease is confirmed in that the number of FFV models has decreased from 167 in 2015/2016 to 133 in 2016/2017[18].

[18] www.fueleconomy.gov

In the absence of EPA MTE projections for CNG vehicles and hydrogen FCVs, the AEO2016 projections are utilized. Figure 2-7 provides light truck populations calculated in the VISION model based on the assumed market share values provided above.

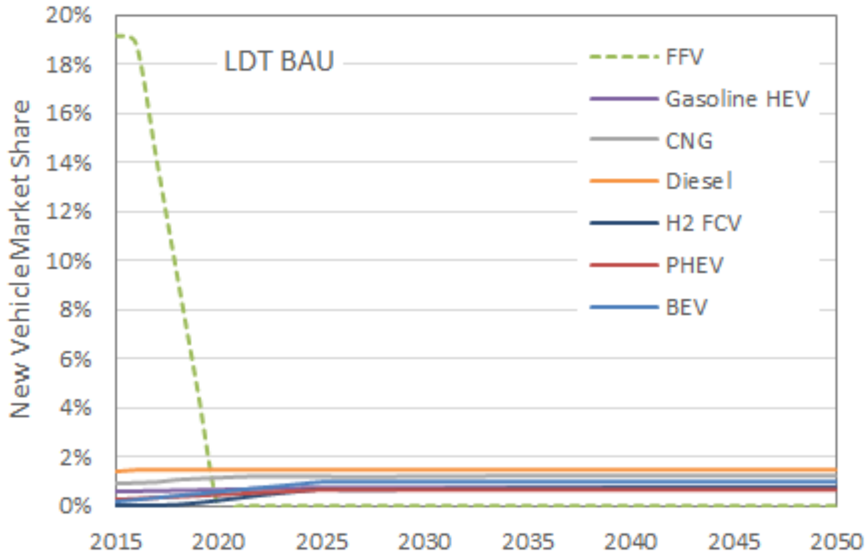

Figure 2-6. Projected U.S. LDT Technology Market Shares.

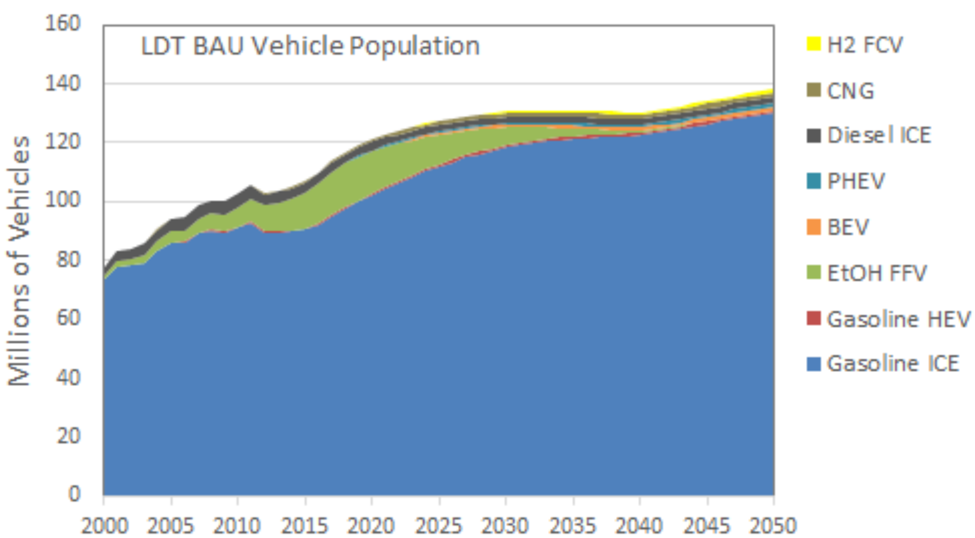

Figure 2-7. Projected U.S. LDT population by technology type for BAU.

For the California fleet, the default ARB market share values were utilized. ARB groups CNG vehicles, FFVs and HEVs in the gasoline ICE category. An HEV category was created by using the average ratio of 2007-2009 California HEV sales to U.S. Sales[19]. This ratio was applied to the U.S. HEV market share forecasts for LDA and LDT through 2050 to approximate the California market shares. Because California consumes negligible amount of E85, a separate FFV category was not created. Additionally, the BEV category does not distinguish between BEV100 and BEV200. We have utilized the BEV100/BEV200 split from the U.S. analysis for California. Figure 2-8 summarizes LDA market shares and Figure 2-9 provides the LDA stock by technology type for the BAU case.

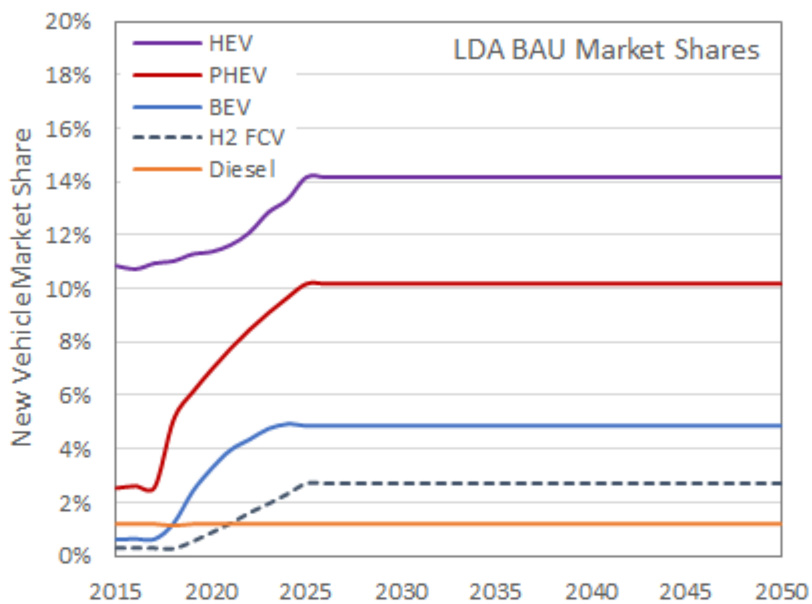

Figure 2-8. Projected California LDA Technology Market Shares.

[19] The ratio is 2.4. California specific HEV sales data were not available for more recent years.

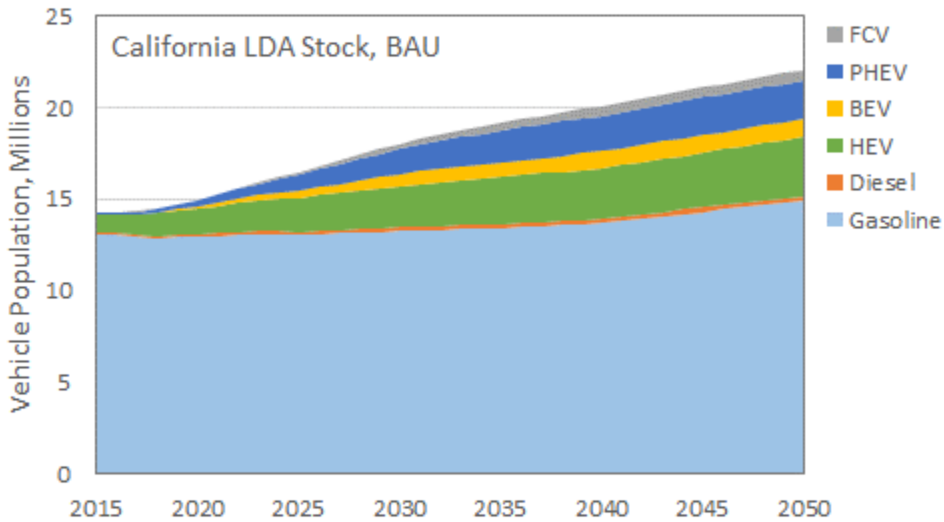

Figure 2-9. Projected California LDA stock by technology type for BAU.

For California LDTs, a CNG category was created by assuming the same market share as the U.S. analysis; these vehicles were taken from the gasoline ICE category. As with LDAs, ARB does not divide BEVs into BEV100 and BEV200 categories. LCA utilized the BEV100/BEV200 market share split from the U.S. analysis. Figure 2-10 illustrates the assumed LDT BAU market shares for California while Figure 2-11 provides the resulting vehicle population by technology type. Note that the California market share forecasts for BEVs, PHEVs, and FCVs are higher than the U.S. values because of the ZEV Mandate.

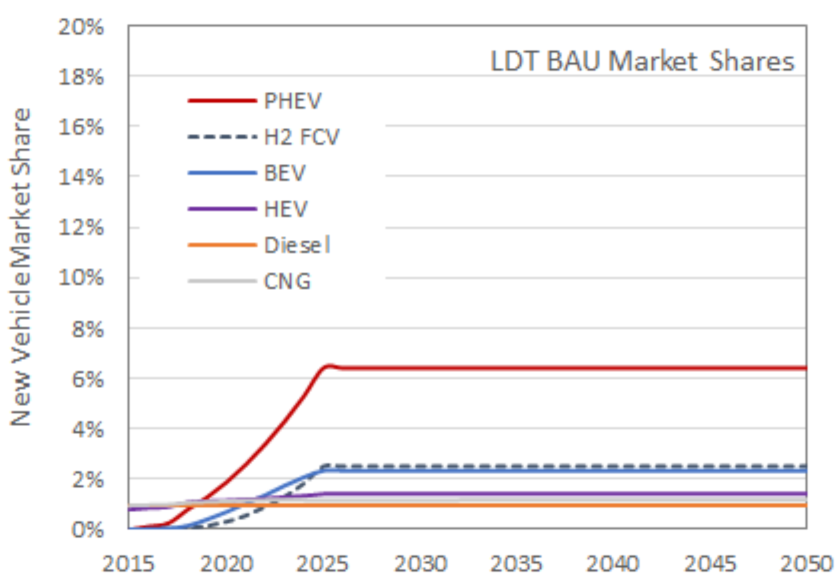

Figure 2-10. Projected California LDT Technology Market Shares.

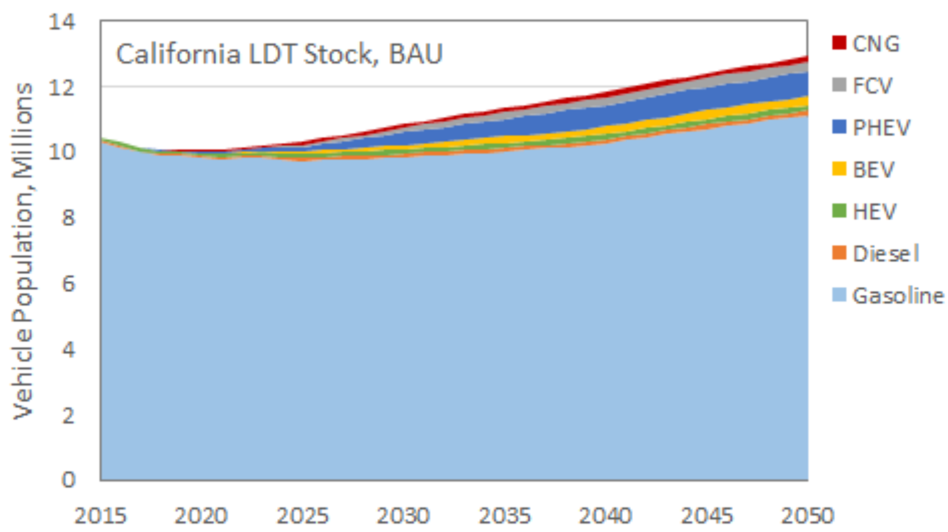

Figure 2-11. Projected California light truck stock by technology type for BAU.

2.4 Vehicle Miles Traveled

Another key input in quantification of fuel use is vehicle miles travelled (VMT). Figure 2-12 illustrates the average LDA and LDT VMT per vehicle forecasts in VISION2015. Note that AEO2015 projects through 2040; Argonne extrapolated the forecasts through 2050. The figure also shows the AEO2016 VMT projection. Unfortunately, AEO2016 does not provide separate forecasts for LDA and LDT, but it is evident that the profiles are different. AEO2015 assumes a fairly steady increase in VMT while AEO2016 assumes a near-term increase (likely based on low petroleum prices) followed by slower growth. This analysis uses the AEO2016 profile but separates it into LDA and LDT components by using the VISION2015 (AEO2015) VMT per vehicle forecasts for LDA and LDT and the ratio of LDA and LDT population. These values are indicated.

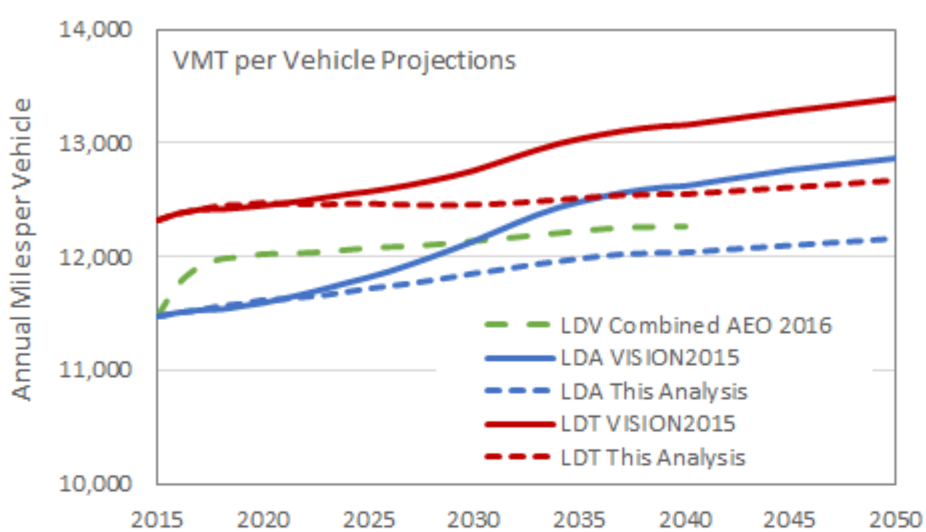

Figure 2-12. Projected U.S. Average VMT per vehicle for light duty autos and trucks.

For the California analysis, VMT data were extracted from CA-VISION. Different vehicle technologies and model years have different annual VMT. The weighted average VMT values are provided in Figure 2-13. It is interesting to note that the U.S. analysis assumes that LDTs have higher annual VMT than LDAs while in California the opposite is true. Moreover, while the U.S. is projected to have slightly increasing VMT through 2050, the VMT in California is projected to decrease significantly, presumably due to provisions of SB 375[20].

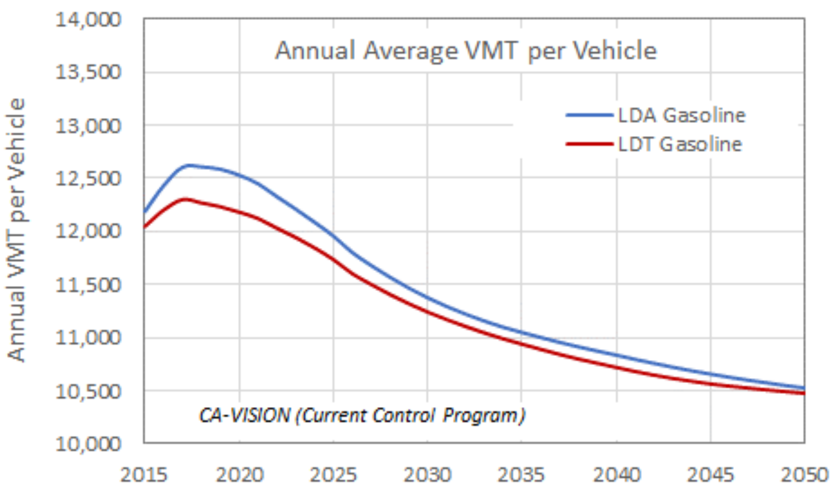

Figure 2-13. Projected California Average LDA and LDT VMT.

2.5 Fuel Economy Forecasts

Projected vehicle fuel economy for the range of technologies considered is a key input to this analysis. Several studies were utilized to inform the development of fuel economy and incremental cost values for the present analysis. These include:

- Energy Information Administration Annual Energy Outlook 2016 (AEO2016)
- VISION2015 Default Values (same as AEO2015)
- NAS Transitions Report[21]
- Argonne C2G Analysis[22]
- Draft MTE (EPA and NHTSA did separate analyses)[23]
- EPA Fuel Economy Guide[24]
- ARB[25]

[20] The Sustainable Communities and Climate Protection Act of 2008

[21] Transitions to Alternative Vehicles and Fuels, National Research Council of the National Academies, 2013.

[22] Cradle-to-Grave Lifecycle Analysis of U.S. Light Duty Vehicle Fuel Pathways: A GHG Emissions and Economic Assessment of Current (2015) and Future (2025-2030) Technologies, Argonne National Laboratory, June 2016

[23] Draft Technical Assessment Report: Midterm Evaluation of Light Duty GHG Emission Standards and Corporate Average Fuel Economy Standards for Model Years 2022-2025, U.S. Environmental Protection Agency, California Air Resources Board, National Highway Traffic Safety Administration, EPA-420-D-16-900, July 2016.

[24] www.fueleconomy.gov

[25] California Air Resources Board projection based on EMFAC and VISION2.1 fuel consumption and VMT projections

As mentioned above, the VISION model divides the light duty sector into two categories: autos and light trucks. A composite fuel economy for new vehicles in these two categories is utilized. The composite value is a sales-weighted average (based on AEO sales projections) of corporate average fuel economy (CAFE) certification values by sub-class. In the VISION model, the certification fuel economy is degraded to reflect on-road performance. The degradation factor is 0.817 for gasoline, diesel, FFV, CNG and PHEV ICE operation, 0.85 for HEV and hydrogen FCVs, and 0.70 for EVs. EIA provided these degradation factors to Argonne for the VISION model[26]. Figure 2-14 and Figure 2-15 provide the LDA and LDT fuel economy values utilized in this analysis. The analysis values were selected after consulting the studies listed above; please refer to 1.a.i.1.a.Appendix A for a technology by technology comparison of estimates from these studies. All fuel economy values shown are non-degraded CAFE certification values.

These fuel economy values were utilized for both the U.S. and California analyses with one exception. The California analysis uses the on-road fuel economy values for gasoline and diesel vehicles back-calculated from CA-VISION2.1 fuel consumption and VMT values. These values are close to the U.S. analysis values and may also be found in Appendix A . In addition, the fuel economy value for California's consolidated BEV category is a market share weighted average of the BEV100 and BEV200 fuel economy values.

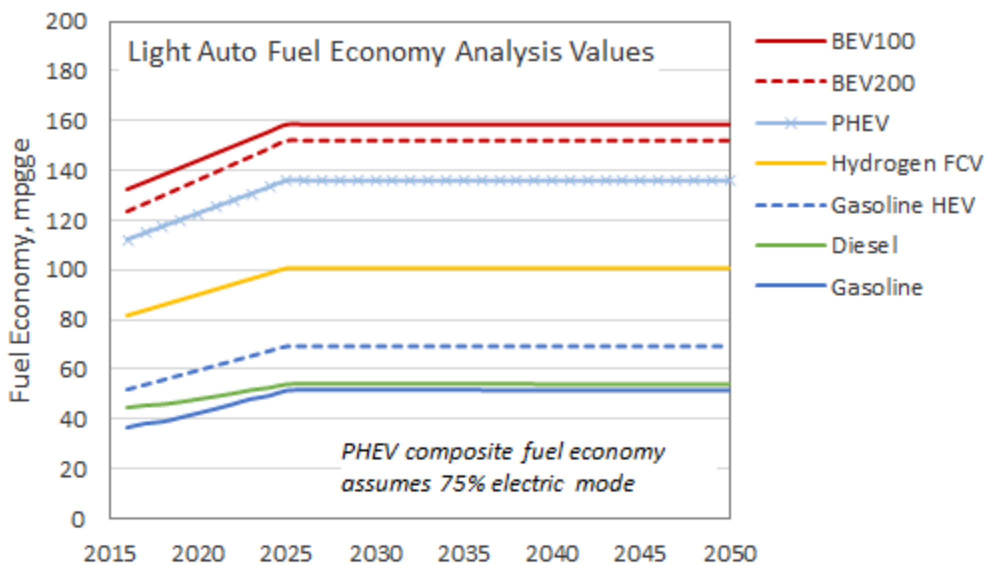

Figure 2-14. Summary of light auto certification fuel economy values

[26] Conversation with Yan Zhou, Argonne National Laboratory

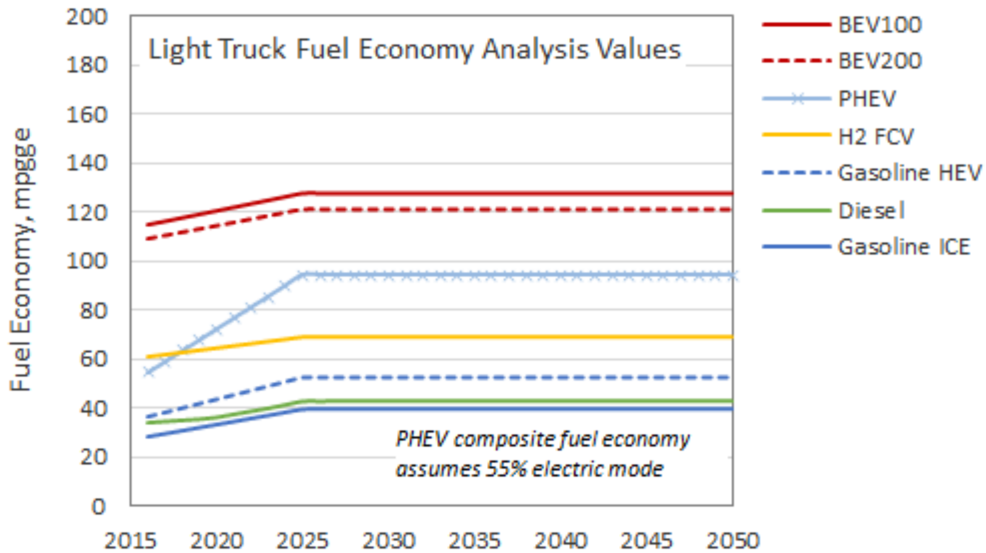

Figure 2-15. Summary of light truck certification fuel economy values

As indicated in the figures, the BAU case assumes that no further improvement in fuel economy occurs after 2025 because current CAFE standards end in 2025. However, for the GHG reduction scenarios the presumption is that an effort will be made to reduce GHG emissions and as a result, fuel economy for each vehicle technology will continue to improve from 2025-2050. To estimate the amount of improvement each technology might experience, the change in fuel economy and MSRP for the Toyota Prius was considered (Figure 2-16). As can be seen, the fuel economy improved 1.7% per year from 2001 to 2017 while the MSRP decline by 0.6% per year. Based on these data, we have assumed for the GHG reduction scenarios that there is continued fuel economy improvement for 2025-2050. Gasoline ICEs are assumed to continue improving by 0.5% per year, HEVs improve at 1% per year and electric drive vehicles continue improving at 1.5% per year. It is further assumed that there is no increase in incremental cost associated with these improvements.

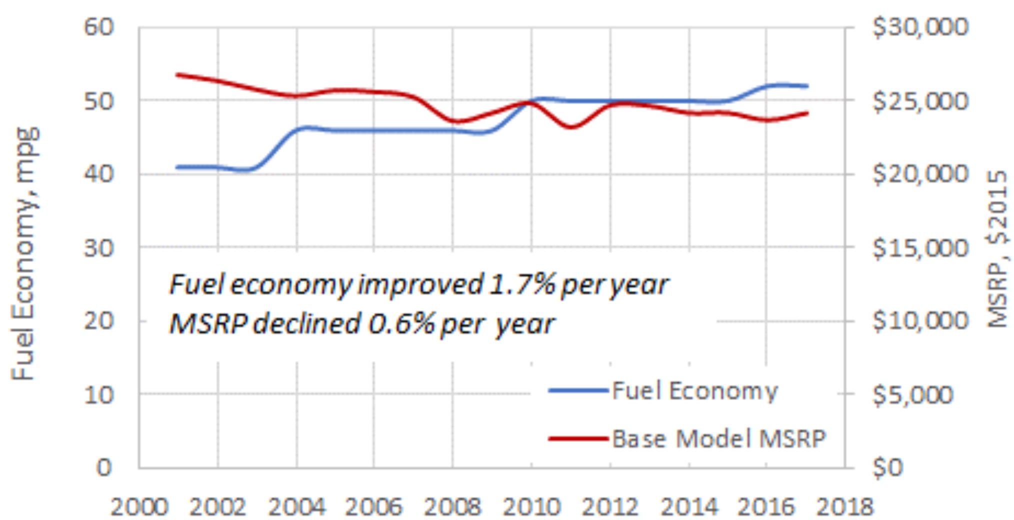

Figure 2-16. Change in Toyota Prius fuel economy and MSRP.

Although not considered in the BAU case, an additional category of vehicles was included in some of the GHG reduction scenarios considered. These are vehicles whose engines are designed to operate on high octane fuels (HOF) such as E30 with a research octane number (RON) of 100 and E70/E85 with a RON of 103. Note that in addition to ICEs, HEVs and PHEVs can also be dedicated HOF vehicles. Please refer to the Dedicated High Octane Fuel (HOF) Vehicles section of Appendix A for a detailed discussion of the fuel economy benefit assigned to HOF vehicles in this analysis.

Table 2-1 summarizes the analysis certification fuel economy values and corresponding energy economy ratios (EERs) in tabular form. For the BAU, there is no improvement in fuel economy beyond 2025 because the current CAFE standard does not include reductions beyond 2025, so for the BAU the values used in 2050 are the same as the 2025 values. In the GHG reduction scenarios, continued improvement in fuel economy is assumed. The 2050 values shown in the table were used in the GHG reduction scenarios.

For the LDA category, most of the fuel economy estimates from the studies reviewed were in good agreement. However, there is a fair amount of spread on BEV100 fuel economy. The analysis values selected for LDA BEV100 may be slightly low; a sensitivity analysis is run using current values for 2016 and increasing to the Argonne C2G/AEO2016 2025 value of 172 instead of 162 mpgge. Because the BEV200 fuel economy forecast is based on the BEV100 forecast, the BEV200 fuel economy is also increased in the sensitivity test case.

For LDTs, there is uncertainty around future fuel economy estimates of BEVs and PHEVs operating in electric mode. The analysis values selected are realistic, but it would be valuable if Argonne expanded their recent C2G study to also include LDTs.

Table 2-1. Summary of certification fuel economy and EER analysis values

Certification Fuel Economy in mpgge	Light Duty Auto						Light Duty Truck					
	Fuel Economy			EER			Fuel Economy			EER		
	2016	2025	2050	2016	2025	2050	2016	2025	2050	2016	2025	2050
Gasoline ICE	37	51	58	1.00	1.00	1.00	28	40	45	1.00	1.00	1.00
Diesel	44	54	62	1.21	1.06	1.06	34	42	48	1.21	1.07	1.07
FFV-Gasoline Mode	37	51	58	1.00	1.00	1.00	28	40	45	1.00	1.00	1.00
FFV-EtOH Mode	38	53	60	1.03	1.03	1.03	29	41	46	1.03	1.03	1.03
Gasoline HEV	52	69	83	1.42	1.35	1.43	36	53	64	1.28	1.33	1.41
PHEV-Gasoline Mode	52	69	83	1.42	1.35	1.43	36	53	64	1.28	1.33	1.41
PHEV-Electric Mode	136	162	221	3.71	3.16	3.80	70	128	175	2.48	3.22	3.88
BEV-100	136	162	221	3.71	3.16	3.80	115	128	175	4.08	3.22	3.88
BEV-200	129	158	216	3.53	3.09	3.72	109	121	166	3.87	3.06	3.68
Hydrogen FCV	81	101	138	2.22	1.97	2.37	61	69	94	2.16	1.74	2.10
E30 ICE (RON 100)	39	54	61	1.06	1.06	1.06	29.8	41.9	47.5	1.06	1.06	1.06
E30 HEV (RON 100)	55	73	88	1.49	1.42	1.51	38.0	55.7	67.1	1.35	1.40	1.49
E70 ICE (RON 103)	40	56	63	1.08	1.08	1.08	30.6	43.1	48.8	1.08	1.08	1.08
E70 HEV (RON 103)	56	75	90	1.53	1.46	1.55	39.0	57.2	69.0	1.38	1.44	1.53

2050 values shown assume continuing technology improvement to meet tighter CAFE standards for 2026-2050.

2.6 Fuel Blend Assumptions

Projected light duty fuel consumption is computed from vehicle population, fuel economy and VMT projections. Several fuels are blends of different feedstocks and several vehicles are able to use more than one fuel. For example, gasoline is currently a blend of denatured ethanol and gasoline blendstock. Diesel contains a certain amount of biodiesel and renewable diesel. CNG is a blend of renewable natural gas (RNG) and fossil natural gas. The following assumptions are made about fuels for the BAU and GHG reduction scenarios.

- Current motor gasoline contains 9.8% by volume denatured ethanol[27]. This blend level is utilized for 2016 and then increased to 10% for the remainder of the analysis period.
- Denatured ethanol is assumed to contain 2% by volume gasoline blendstock
- FFVs can consume gasoline (E10) or a high-level ethanol blend. The AEO2016 reference case[28] sets current FFV E85 fuel use at 4.5%, growing to 17% by 2040. However, as discussed above, AEO2016 also projects increasing sales of FFVs despite expiration of the FFV CAFE credit. This analysis quickly phases out FFV sales (see above) and sets 2016 FFV E85 fuel use at 4.5%, maintaining it there through 2050.
- High level ethanol blends are assumed to be 70% ethanol for the BAU and 85% ethanol for the GHG reduction scenarios.
- PHEVs consume both electricity and gasoline; one key assumption is the share of operation in electric mode vs gasoline mode. This depends on battery size. This analysis assumes that future PHEVs will have a 40 mile range or more and that PHEVs with 10 mile range are being phased out[29]. Based on EV Project[30] data for the Chevy Volt (40 mile range), 74.5% of LDA miles driven are electric miles. The Dodge Ram PHEV portion of the report indicates that LDT eVMT is between 22% and 46%. However, the authors state that Ram drivers were not enthusiastic about maximizing eVMT and these fleet vehicles were not placed into operation that allowed charging. Less than 5% of light trucks are sold into fleets and it is expected that most SUVs would be operated like LDAs. For this analysis, we use an intermediate value of 55% for LDT eVMT.
- U.S. cellulosic ethanol volumes are assumed to consist entirely of volumes consumed in the two LCFS states (California and Oregon). ARB's most recent compliance forecast[31] is utilized for BAU cellulosic, sugarcane and corn/sorghum/wheat volumes. ARB forecasts 400 MGY of cellulosic ethanol by 2025. The volumes are increased by 3% since Oregon's on-road gasoline consumption is approximately 3% of California's.

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[27] EIA 2015 fuel ethanol and motor gasoline consumption

[28] Based on AEO2016 projections of ethanol use in high level blends and VISION FFV projected fuel consumption

[29] Conversation with Eileen Tutt, CalETC

[30] *Plug-in Electric Vehicle and Infrastructure Analysis (Chapter 11)*, Idaho National Laboratory, September 2015.

[31] ARB LCFS Illustrative Compliance Scenario, 4-1-2015

- Figure 2-17 provides the AEO2016 projected biodiesel (BD) and renewable diesel (RD) blend levels. Although the majority of diesel fuel is consumed by the heavy-duty fleet, it is assumed that the light duty and heavy duty fleet all use the same biodiesel and renewable diesel blend levels.
- Four different feedstocks are considered for biodiesel and renewable diesel: soybean, canola, corn oil, and UCO/tallow. A recent UCS-ICCT sponsored study[32] found that in 2014, the shares of biodiesel produced from these feedstocks were 53% soybean, 25% tallow/UCO, 12% canola, and 11% corn. These feedstock shares were used in this analysis through 2050 for biodiesel and renewable diesel.
- The RNG share of CNG is based on ARB's projected California RNG use through 2025 divided by total on-road U.S. CNG consumption projected by VISION (Figure 2-18). For the BAU case, the ARB forecast is extended linearly to 2050. In the max RNG scenario, it is assumed that production follows CNG, reaching 80% of total by 2050. The projected volume, 4 BGY (diesel equivalent) is well within commercial potential of ~ 18 BGY[33] according to the American Gas Foundation, but much higher than the 0.6 BGY thought to be commercially viable at today's RIN and LCFS credit prices by UC Davis researchers[34].

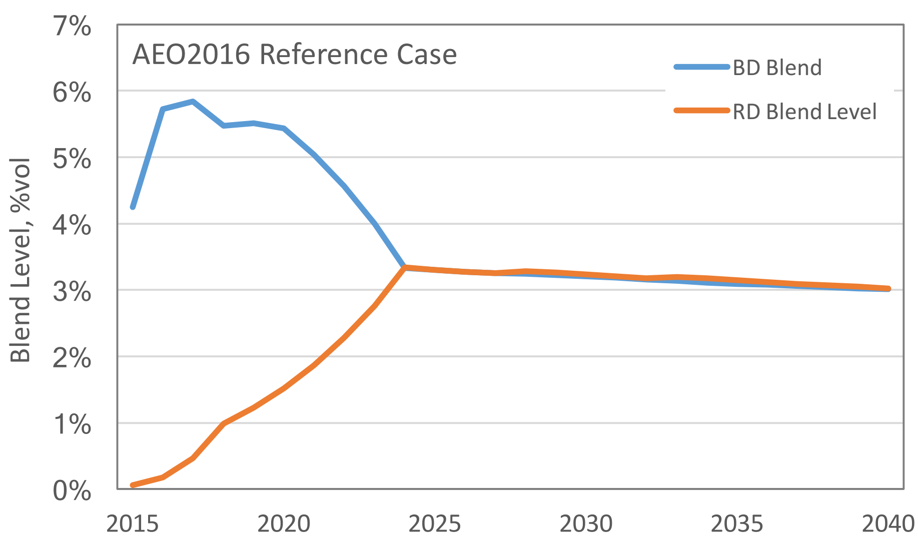

Figure 2-17. AEO2016 projected RD and BD blend levels.

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32 "Projections of U.S. Production of Biodiesel Feedstock", Wade Brorson for Union of Concerned Scientists and International Council on Clean Transportation, July 2015.

33 The Potential for Renewable Gas: Biogas Derived from Biomass Feedstocks and Upgraded to Pipeline Quality, American Gas Foundation, Sept 2011.

34 ARB Contract No. 13-307, The Feasibility of Renewable Natural Gas as a Large-Scale, Low-Carbon Substitute, Draft Final Report, June 2016, Amy Myers Jaffe, UC Davis ITS.

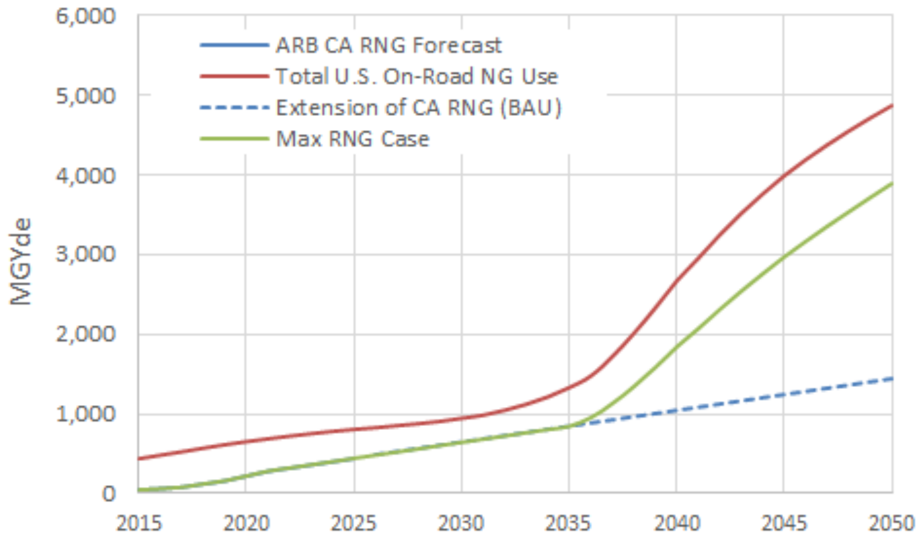

Figure 2-18. AEO2016 projected renewable and fossil natural gas volumes.
Note: ARB RNG forecast for 2015-2035 is same as Max RNG case.

2.7 Fuel Carbon Intensity

To quantify GHG emissions in this analysis, carbon intensity (CI) values for each fuel type were used. CI is defined as the mass of GHG emissions per unit energy of fuel; the quantity of fuel used is multiplied by its CI to determine GHG emissions for that fuel. The GHG pollutants included are CO_2, CH_4, and N_2O[35] and emissions are quantified on a "well-to-wheel" basis which includes emissions from both fuel production activities and vehicle emissions. Two sets of CI values were developed – one for California and one for the entire U.S. Because the wedge analysis extends to 2050, changes in CI over time are quantified. Key considerations for the time dependent estimates are crude oil origin and type, natural gas sources and leakage rates, and electricity generation resource mix.

The CI values reflect not just vehicle emissions but also the emissions from producing and transporting the fuel; the so-called lifecycle or well-to-wheel (WTW) emissions. In brief, for each step in a fuel's life cycle, the direct and upstream GHG emissions are estimated. Direct emissions for each step are calculated based on an assumed process efficiency that dictates the total amount of fuel consumed per unit of product produced. The total fuel consumption is split among different fuel types (e.g. crude oil, residual oil, gasoline, natural gas, electricity, etc.). For each fuel type, the portion consumed in each different type of combustion equipment is also assumed. Non-combustion emissions such as venting are also included. With these assumptions (process efficiency, fuel shares, combustion device shares, other process emissions), the total direct emissions can be calculated.

[35] GHGs = $CO_2 + GWP_{CH4}*CH_4 + GWP_{N2O}*N_2O$ where the GWP values are Global Warming Potential factors. The AR5 values were used in this analysis: 1 for CO_2, 30 for CH_4, and 265 for N_2O. For the California analysis, the values used by ARB for the LCFS were used: 1 for CO_2, 25 for CH_4, and 298 for N_2O.

Upstream emissions are the emissions generated in production and transport of process fuels directly consumed. For example, a process might specify that an amount of natural gas is combusted in a boiler. The direct emissions of natural gas combustion in a boiler are quantified, and the upstream emissions associated with natural gas recovery, processing, transmission and distribution are added. Inclusion of the upstream emissions renders the calculations iterative, and changes to one fuel pathway affect all pathways that utilize that fuel. For example, changes in assumptions about natural gas recovery affect not only the CI of compressed natural gas (CNG), but also the CI values for all fuels that utilize natural gas as a process fuel in their production. The sections below provide CI values used in the U.S. and California analyses.

2.7.1 U.S. Average Carbon Intensity Values

Carbon intensity values utilized in the U.S. wedge analysis were calculated with Argonne National Laboratory's GREET model.[36] Values for 2015, 2020 and 2040 were calculated. CI values are assumed to change linearly for the periods 2015 to 2020 and 2020 to 2040; 2050 values are assumed to be equal to 2040 values. The GREET1_2015 model was modified to develop CI values for this analysis; recently Argonne released GREET1_2016 with modified assumptions on natural gas recovery leakage rates, crude slates, and refining efficiency. These updated assumptions were used in the modified GREET1_2015 model used here. Please refer to Appendix B for a detailed discussion of the GREET modeling effort.

One key input for the CI calculation of most fuels is the resource mix that is utilized to generate electricity. The AEO2016 reference case assumes implementation of EPA's Clean Power Plan (CPP). The CPP was finalized but stayed by the U.S. Supreme Court in February of 2016 to allow the U.S. Court of Appeals for the District of Columbia to review whether EPA overstepped its bounds. The lower court will make its ruling in early 2017. With a Clinton presidency, it seemed likely that the CPP would go forward though with a late start[37]. Since the new President has vowed to eliminate the CPP, it is not clear what the future holds. The base case for this analysis utilizes the AEO2016 reference case. An additional set of CI values was also generated using AEO2016's side case without the CPP. Finally, an optimistic set of CI values was calculated assuming coal generation ceases by 2040 (70% non-fossil case). Figure 2-19 provides the 2040 CI values for neat fuels; Figure 2-20 shows the 2040 values for finished fuels with EERs applied to correct for differences in vehicle fuel economy. Electrification with a very clean grid (70% Non-Fossil) is significantly lower than all of the other options. Eliminating the CPP increases BEV emissions by 22% in 2040.

Table 2-2 summarizes the CI values for the two AEO2016 cases while the grid mix profile for the 70% non-fossil case is shown in Table 2-3. Note that the grid mix affects CI values for all of the fuels because production of all fuels requires electricity.

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[36] Greenhouse Gases, Regulated Emissions and Energy Use in Transportation Model.

[37] "EPA's Clean Power Plan Does Well in Court: Both sides in the fierce legal battle acknowledge that EPA has the early edge", Emily Holden, September 2016, Scientific American. https://www.scientificamerican.com/article/epa-s-clean-power-plan-does-well-in-court/

Figure 2-19 provides the 2040 CI values for neat fuels; Figure 2-20 shows the 2040 values for finished fuels with EERs applied to correct for differences in vehicle fuel economy. Electrification with a very clean grid (70% Non-Fossil) is significantly lower than all of the other options. Eliminating the CPP increases BEV emissions by 22% in 2040.

Table 2-2. Projections of U.S. average electricity generation resource mix.

	AEO2016 Reference					AEO2016 Reference w/o CPP				
	Oil	NG	Coal	Nuclear	Renew -able	Oil	NG	Coal	Nuclear	Renew -able
2015	1%	26%	37%	22%	14%	1%	26%	37%	22%	14%
2020	0%	22%	37%	21%	20%	0%	22%	38%	21%	19%
2025	0%	24%	31%	21%	23%	0%	23%	37%	20%	20%
2030	0%	29%	25%	21%	25%	0%	24%	35%	20%	20%
2035	0%	28%	24%	20%	27%	0%	25%	34%	19%	22%
2040	0%	29%	22%	20%	28%	0%	26%	32%	19%	23%

Table 2-3. Grid mix for 70% non-fossil CI case.

	AEO2016 Reference				
	Oil	NG	Coal	Nuclear	Renew -able
2015	0.7%	26%	37%	22%	14%
2020	0.4%	22%	30%	21%	27%
2025	0.3%	24%	23%	21%	32%
2030	0.3%	29%	15%	21%	35%
2035	0.2%	28%	8%	20%	43%
2040	0.1%	30%	0%	20%	50%

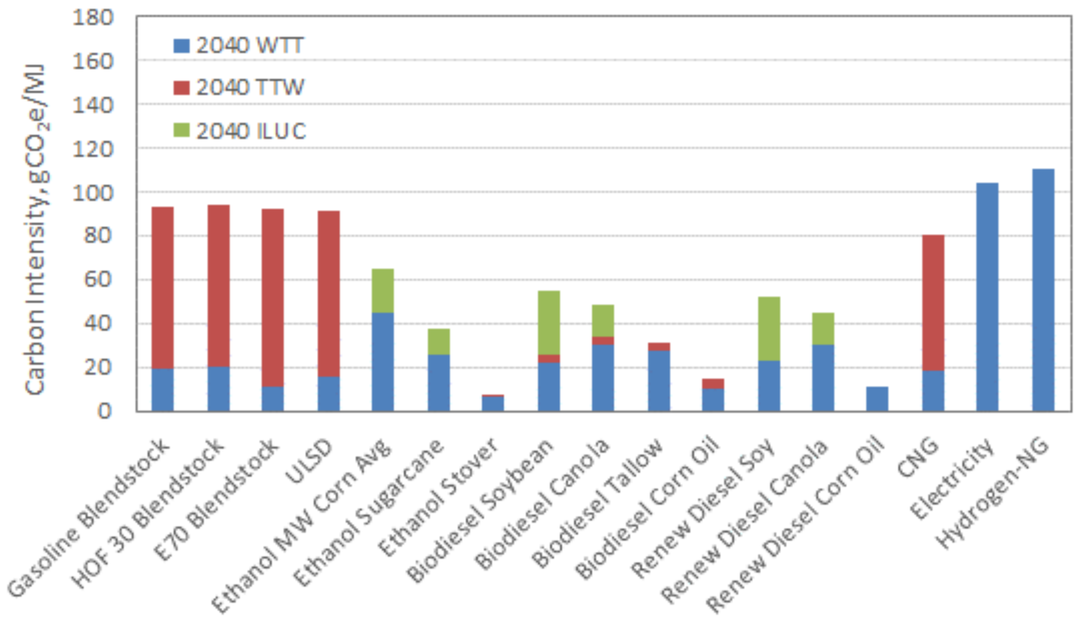

Figure 2-19. Estimated 2040 CI Values (Base case).

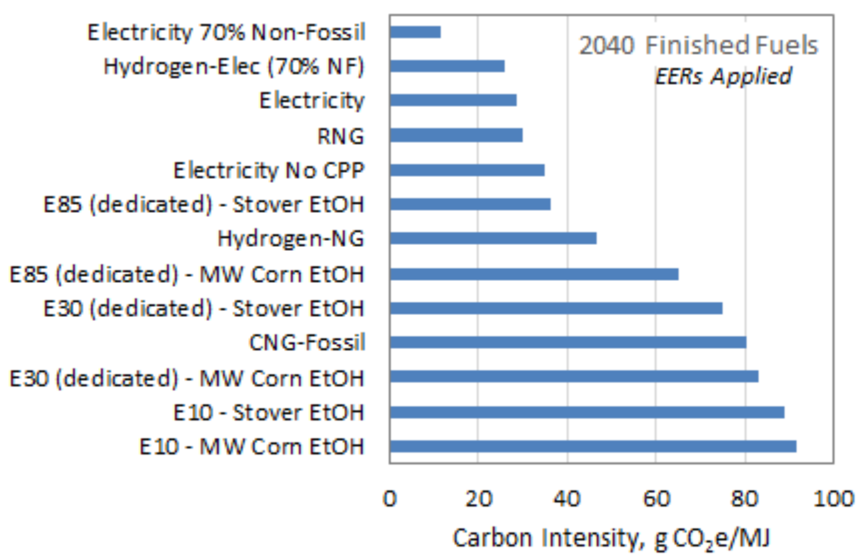

Figure 2-20. Carbon intensity values for U.S. finished fuels (BEV and FCV EER Applied).

2.7.2 California Carbon Intensity Values

For the California analysis, CI values for all fuels except electricity and hydrogen were taken directly from ARB's most recent LCFS compliance scenario.[38] The ARB scenario extends to 2025.

[38] ARB LCFS Illustrative Compliance Scenario, 4-1-15.

For the base case, it is assumed that the composite ethanol and composite biodiesel CI values are constant from 2025 to 2050. For electricity, LCA ran ARB's CA-GREET2 model to capture the 2025 Diablo Canyon retirement and the 2030 50% renewables requirement. In addition, a low CI case for 2050 with 70% non-fossil generation was run. CARBOB, ULSD, and CNG CI values for 2025-2050 were recalculated with the changing electricity grid mix.

California law requires that 33% of hydrogen sold be generated from renewable resources. To comply, two different hydrogen pathways were run through CA-GREET (with the updated electricity grid mixes): Electrolysis with 100% renewable electricity and on-site natural gas steam reforming. The composite hydrogen value is 33% of the electrolysis pathway and 67% of the natural gas pathway.

The analysis CI values for neat fuels are provided in Figure 2-21. The values for finished fuels with EER applied are shown in Figure 2-22. The hydrogen FCV using hydrogen produced from 100% renewable electrolysis has the lowest emissions, while the natural gas reforming hydrogen pathway emissions provide a 50% reduction from gasoline. Aside from the 100% renewable hydrogen pathway, the electricity pathway offers extremely low emissions. Please refer to Appendix C for more detail regarding the California CI calculations.

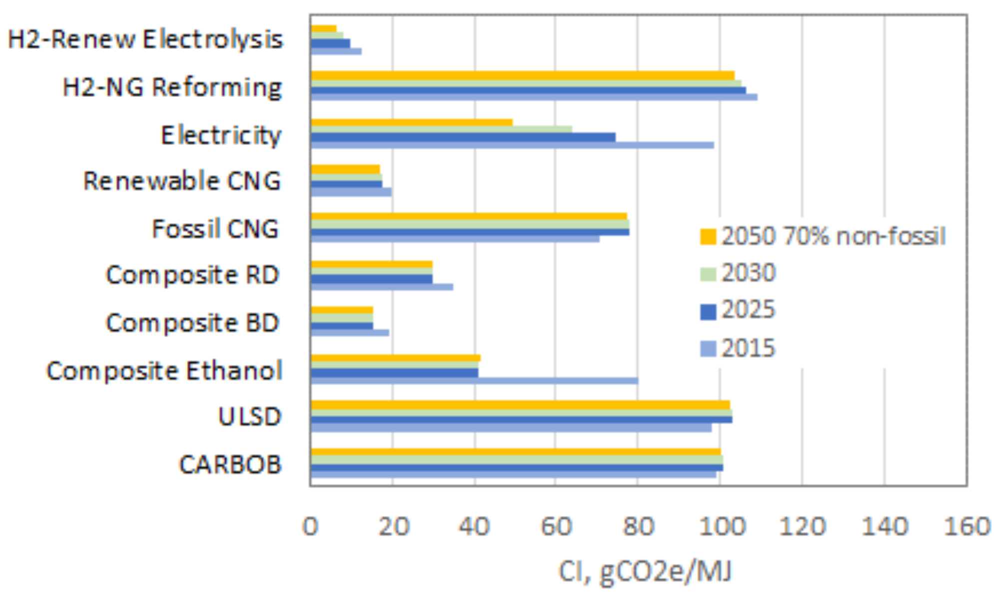

Figure 2-21. Carbon intensity values for neat fuels.

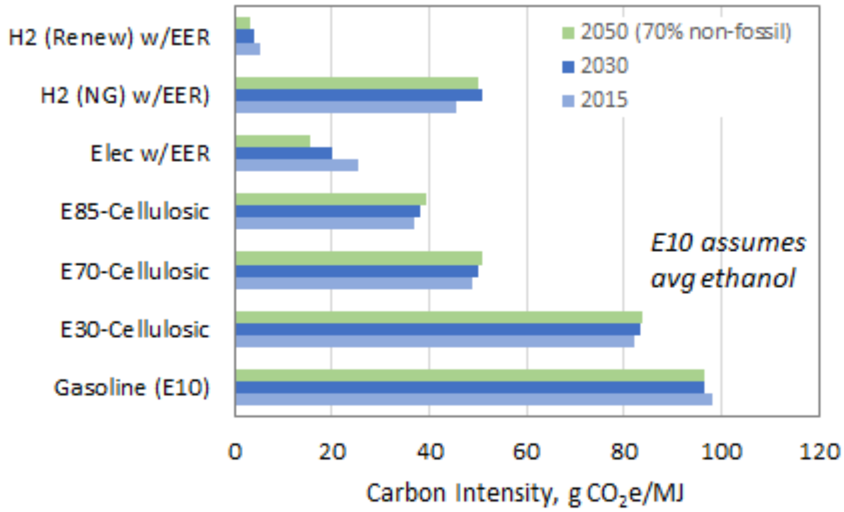

Figure 2-22. California CI values for finished fuels (BEV/FCV EER Applied).

As can be seen, there are differences between the California and U.S. average CI values. This is to be expected for a wide range of reasons including source of feedstock and feedstock transport distances, electricity grid mix for fuel production, and transportation of final fuel. California gasoline and diesel CI values are about 8% higher than the U.S. average because of crude sources and more energy intensive refining requirements. Perhaps the most striking difference between California and U.S. average CI values is for electricity. In 2025, the California CI is projected to be slightly more than half of the U.S. value (74 vs 136-138 g/MJ). By 2050, California will be down to 64 g/MJ as compared to 104 (with Clean Power Plan) or 127 (without Clean Power Plan).

2.8 Incremental Vehicle Price Estimates

Because fuel economy and incremental cost are connected, the same studies[39] utilized to define fuel economy forecasts in Section 0 were used to project incremental vehicle prices for the different technologies over time. Each of the studies consulted provides incremental vehicle cost on a retail price equivalent basis. In this analysis, the phrase incremental vehicle cost means the incremental price paid by consumers relative to a 2015 ICE vehicle. It was also possible for some technologies to determine a current incremental price based on 2016 manufacturer suggested retail price (MSRP) if there was a comparable gasoline ICE version of a given vehicle technology. For some technologies, there was significant disagreement between the studies on incremental price. For a detailed presentation of incremental price forecasts for each technology by the studies consulted and the rationale for selecting the incremental prices for this analysis, please refer to Appendix A Appendix A .

The same incremental costs were used for the U.S. and California analyses. This is appropriate because the fuel economy values for the two analyses are the same except for slight differences for gasoline ICE and diesel vehicles. Figure 2-23 and Figure 2-24 provide the LDA and

[39] NAS Transitions, EPA MTE, NHTSA MTE, Argonne C2G, AEO2016

LDT incremental vehicle prices, respectively. Table 2-4 provides this information in tabular form. Note that for the consolidated BEV category in the California analysis, a market share weighted average of the BEV100 and BEV200 incremental prices is used.

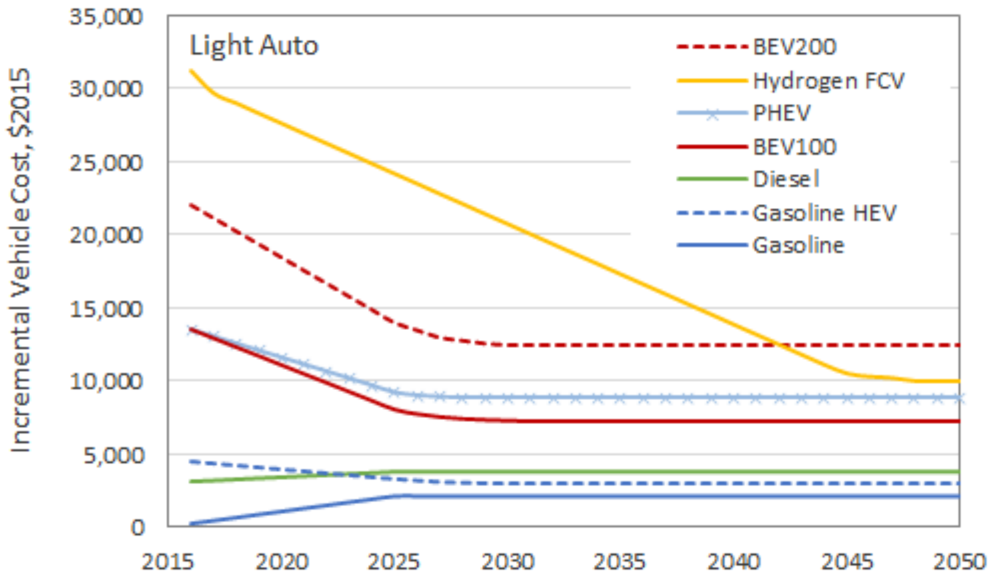

Figure 2-23. LDA incremental vehicle price.

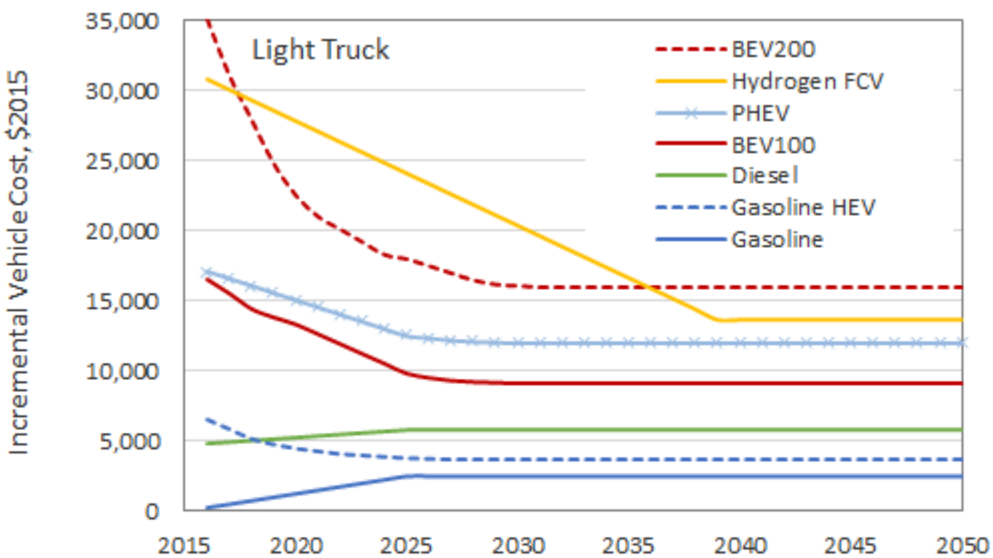

Figure 2-24. Projected California Average VMT per Vehicle.

Table 2-4. Summary of incremental vehicle prices relative to 2015 ICE, $2015

	LDA			LDT		
	2015	2025	2050	2015	2025	2050
Gasoline ICE	0	2,149	2,149	0	2,438	2,438
Diesel	3,100	3,800	3,800	4,600	5,770	5,770
CNG	x	x	x	9,500	11,938	11,938
Gasoline HEV	4,484	3,300	3,000	6,500	3,700	3,600
PHEV	13,500	9,200	8,850	17,000	12,500	12,000
BEV-100	13,500	8,000	7,200	16,500	9,800	9,100
BEV-200	22,000	14,000	12,500	35,000	18,000	16,000
Hydrogen FCV	31,190	24,159	10,000	30,744	24,050	13,638
E30 ICE (RON 100)	226	2,375	2,375	320	2,759	2,759
E30 HEV (RON 100)	4,710	3,526	3,226	6,820	4,020	3,920
E70 ICE (RON 103)	320	2,470	2,470	415	2,853	2,853
E70 HEV (RON 103)	4,804	3,620	3,320	6,915	4,115	4,015

One interesting finding in this exercise is that electric vehicle costs are assumed to reach economy of scale and be fully learned by 2025. This is generally assumed to occur once five manufacturers have each produced 500,000 vehicles. The ZEV Mandate requires 3.3 million ZEV sales by 2025[40] in California and 9 additional states. This corresponds to approximately 6 manufacturers reaching 500,000 vehicles by 2025. Figure 2-25 shows the cumulative ZEV sales predicted by the VISION model used in this analysis for the BAU case (with new vehicle sales and technology share assumptions presented in the previous sections). This contrasts with FCVs which are not anticipated to reach fully learned costs until 2040 due to lower sales.

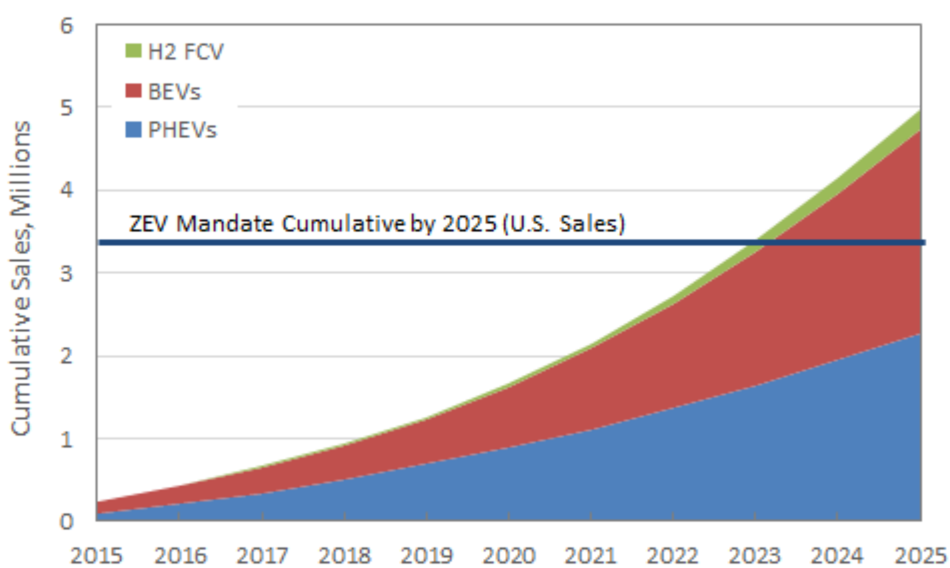

Figure 2-25. Comparison of BAU ZEV sales to ZEV Mandate.

[40] Alliance of Automobile Manufacturers ZEV Facts website

2.9 Fuel Price Projections

Transportation fuel price projections for gasoline, diesel, CNG, E85 and electricity were taken directly from AEO2016 reference case for the U.S. analysis and from AEO2016 Pacific Region reference case for the California analysis. Figure 2-26 provides the U.S. projection while Figure 2-27 illustrates the California projection. It is worth noting that the Pacific region prices for each fuel are higher than for the U.S. average.

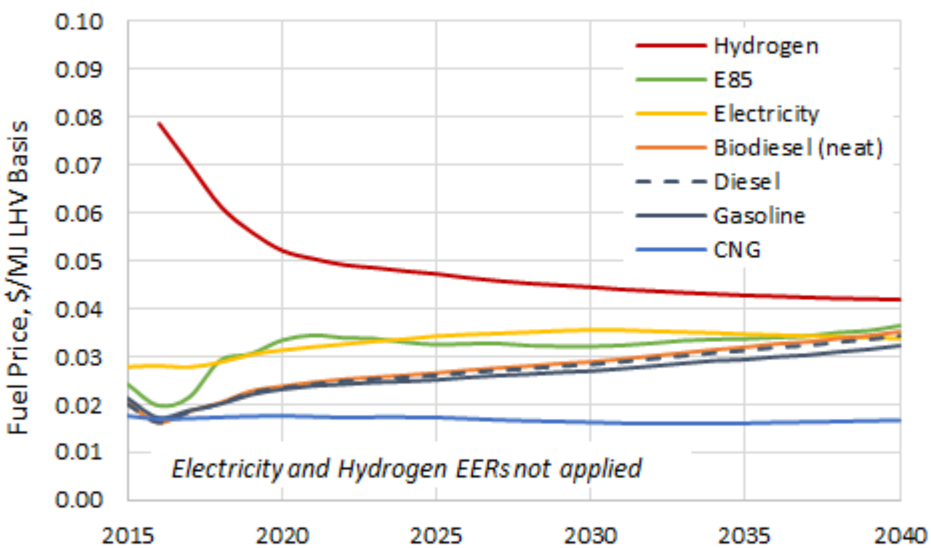

Figure 2-26. Fuel price forecast for the U.S. analysis (with Clean Power Plan).

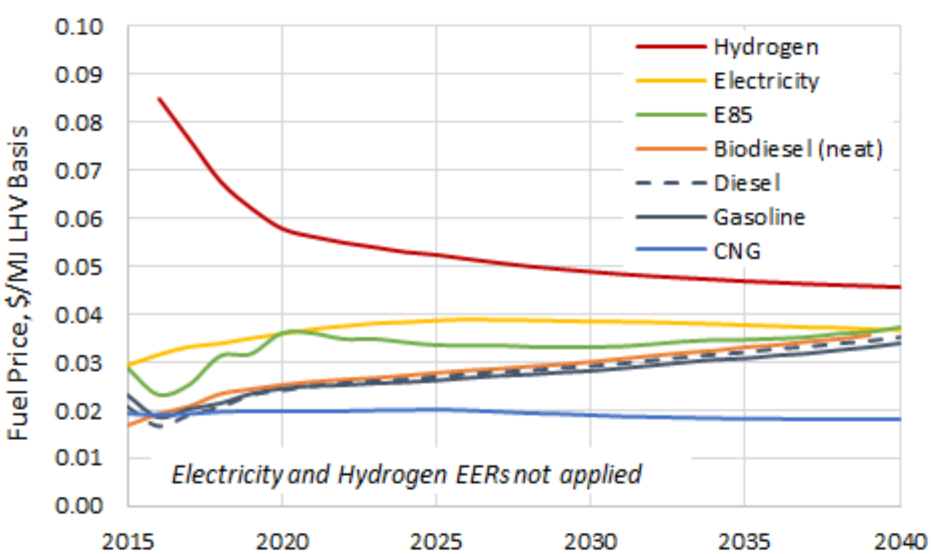

Figure 2-27. Fuel price forecast for the California analysis.

The AEO2016 fuel prices utilized in this analysis are from the reference case; the reference case includes implementation of the Clean Power Plan (CPP). AEO2016 has a side case without the CPP. The fuel prices without CPP have been compared to the reference case prices; only electricity prices are different. Figure 2-28 illustrates the difference in projected U.S. transportation electricity prices for the reference case and the side case without the CPP. In 2030, the reference case electricity prices are ~ 5% higher than the side case. For this analysis, the reference case prices are used.

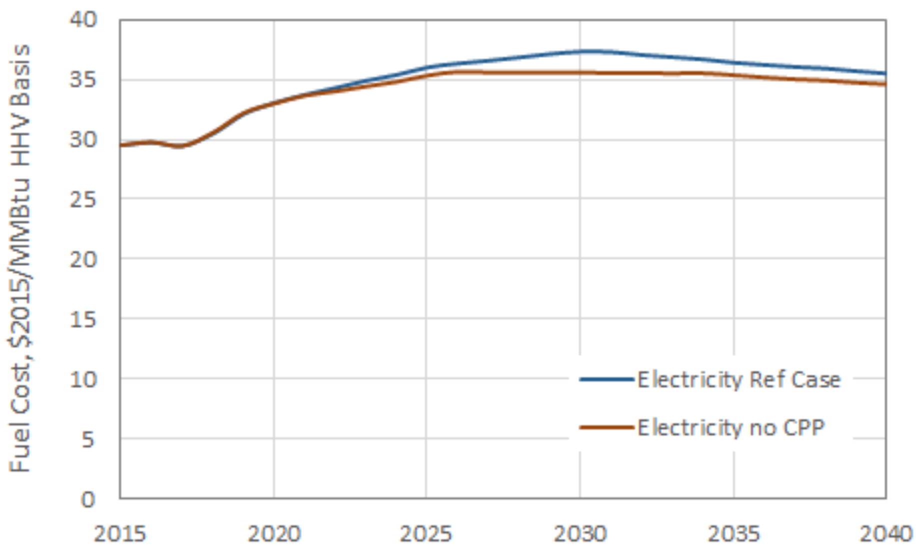

Figure 2-28. AEO2016 reference case and no CPP case transportation electricity prices.

AEO2016 does not provide a price for biodiesel. However, based on conversations with producers and representatives of the National Biodiesel Board, biodiesel sells at a discount to diesel on a per gallon basis. In 2014 (100$ crude) the wholesale discount was 25 cent/gal or about 6.5% (3.82 $/gal in 2014). In the present analysis, we assume that biodiesel sells at a 6.5% discount to diesel over the analysis period. At today's price ($2.70), this is an 18 cent per gallon discount. Moreover, for renewable diesel (not shown), Propel Fuels prices renewable diesel at a 3% to 5% discount to diesel. For this analysis, the renewable diesel price is set at a 4% discount to diesel.

Hydrogen prices are also omitted from AEO2016 forecasts. LCA has developed hydrogen fuel prices based on current hydrogen fuel prices at California refueling stations (13 $/kg)[41], AEO2016 projections of industrial natural gas and electricity prices, and volume scaling factors. Two different price projections were developed for the U.S. and California analyses: a price for on-site natural gas steam reforming (NGSR) and a price for electrolysis. For the U.S. analysis, it is assumed that all of the hydrogen is produced from natural gas. For the California analysis, it is

[41] http://www.altfuelprices.com/stations/HY/California/Chula-Vista/

assumed that one third is produced from electrolysis with the balance produced from natural gas steam reforming. This satisfies the California requirement that one third of hydrogen produced must be renewable.

Figure 2-29 provides the hydrogen production and delivery cost scaling factors utilized. The U.S. hydrogen demand curve is based on projections from the model with assumed FCV market shares and vehicle fuel economy. The chart also provides the volume dependent cost scaling factors for fuel production and delivery. These scaling factors project fuel production costs and allow for cost reductions due to economy of scale and learning.

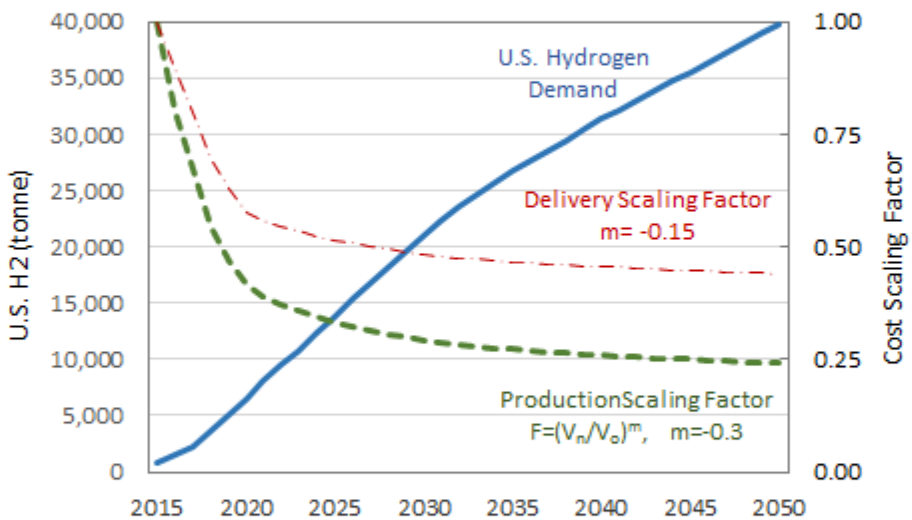

Figure 2-29. Hydrogen production scaling factors.

The scaling factors were applied to the hydrogen cost buildups for electrolysis and NGSR pathways to generate fuel prices as a function of time (volume) for the U.S. and California. Figure 2-30 compares the prices developed by LCA to the future prices estimated by the Department of Energy's H2A program[42]. The California and U.S. industrial natural gas prices are nearly identical, resulting in identical prices for hydrogen produced from natural gas. In contrast, industrial electricity prices are forecast to be significantly lower in California than in the U.S. as a whole (possibly due to higher renewable content), resulting in a lower electrolysis hydrogen price in California than in the U.S. This contrasts with the transportation electricity prices; California transportation electricity prices are markedly higher than the U.S. average price. It is not clear why transportation electricity is priced at such a premium.

[42] https://www.hydrogen.energy.gov/h2a_analysis.html

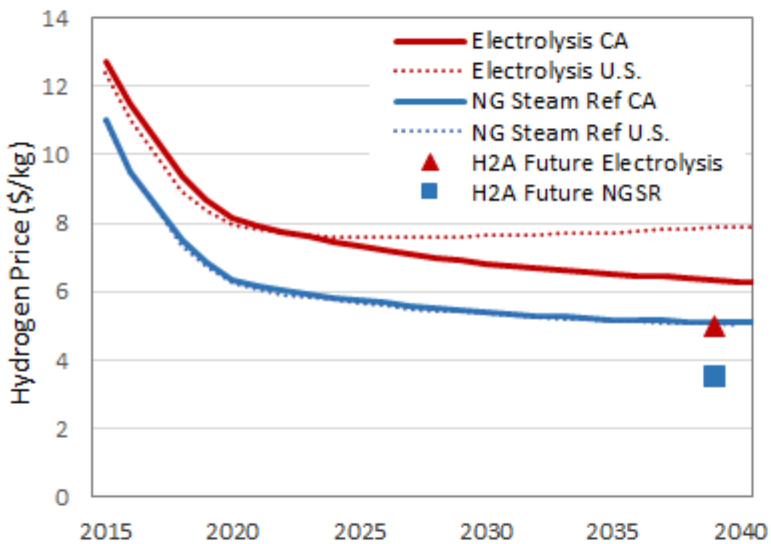

Figure 2-30. LCA estimated hydrogen fuel prices.

An additional cost associated with biofuels arises from the Renewable Fuels Standard (RFS). The standard requires volumes of different types of renewable fuel to be sold each year. The volumes are tracked with renewable identification numbers (RINS), denominated in gallons of ethanol; RINs are generated by producers of renewable fuel. RINS can be detached from actual gallons and sold as credits to regulated parties and subsequently surrendered for compliance. Table 2-5 provides the assumed costs for the various RIN D codes. In addition to RIN costs, cellulosic ethanol producers receive a $1.01 per gallon tax credit. Biodiesel and renewable diesel producers also receive a $1 per gallon credit. These credits were extended by congress through 2016; for the purposes of this analysis it is assumed that the credits continue to be renewed through 2025 and are discontinued at that time.

Table 2-5. RIN Definitions and Assumed Values

RIN Label	Fuel Types	Current Value ($/RIN)	RINS per gal
D3	Cellulosic Ethanol, Renewable NG	1.76	1
D4	Biodiesel, Renewable Diesel	0.82	1.5
D5	Advanced Ethanol (e.g. sugarcane)	0.89	1
D6	Renewable Fuel (e.g. corn ethanol)	0.76	1

One final consideration with regard to fuel prices is that cellulosic ethanol is estimated by LCA to be $0.80 to $1.30 per gallon more expensive than conventional ethanol to produce. Between the D3 RIN ($1.76) and the tax credit ($1), this extra cost is more than compensated. This analysis assumes that the tax credit is renewed each year through 2025 at which point it ends. It is not clear who pays for the cellulosic RIN premium. The producer could be forced to absorb the cost, the obligated party might absorb the cost, or the obligated party might pass the cost on to consumers in the form of increased gasoline prices. In this analysis, cellulosic ethanol is assigned the market price of ethanol and the RIN costs are tracked and added to the fuel costs as a surrogate for higher production costs. This results in an effective premium for cellulosic ethanol of $2 per gallon for 2016-2025 and $1 per gallon for 2026-2050. For the high volume cellulosic ethanol GHG reduction scenario, it is possible that the incremental price for cellulosic ethanol relative to conventional ethanol decreases to less than $1 per gallon due to learning and economies of scale. In lieu of a sensitivity test case on the cellulosic price premium, we can compare the high volume conventional ethanol scenario to the high volume cellulosic ethanol case.

The situation for CNG produced from renewable natural gas (RNG) is similar. RNG is recovered from landfills and produced by digesters at dairies and waste water treatment (WWT) plants. Digesters can also produce RNG from municipal solid waste (MSW). In all cases, the raw gas is cleaned to pipeline quality and injected into the natural gas pipeline system. A recent UC Davis analysis[43] developed RNG cost estimates for each feedstock that includes collection, cleanup and pipeline injection. Costs are presented as a function of volume, with cost increasing as volume increases, reflecting less economically feasible projects coming on-line as demand increases. Table 2-6 summarizes the RNG costs for each feedstock at half of the California potential volume and at approximately 90% of California potential volume.

Assuming 90% of the RNG currently used is recovered LFG, 9.5% is from WWT digesters and that the balance is split between MSW and dairy digesters and assuming half-potential volume costs (the half-potential volume costs are similar to minimum volume costs), the resulting 2016 cost to get RNG into the natural gas distribution system is $8.25 per MMBtu.

Table 2-6. Cost of RNG for Different Feedstocks

Feedstock	Half of Potential CA Volume		~90% Potential CA Volume	
	$/MMBtu	Volume (bcf/yr)	$/MMBtu	Volume (bcf/yr)
Landfill Gas	7.5	25	15	45
MSW Digester	17.0	7.5	20	12.5
Dairy Digester	55	7	90	12.5
WWT Digester	14	3	35	6

Source: UC Davis ITS

The cost of compression and refueling is assumed to be the difference between the AEO2016 industrial natural gas price and the transportation price. This difference is $14 per MMBtu for 2016 decreasing to just over $11 per MMBtu by 2050. The Pacific and U.S. average increments are nearly identical. This increment brings the 2016 RNG-CNG price $23.5 per MMBtu (LHV basis). The fossil CNG price for 2016 is just under $18 per MMBtu (LHV), making RNG-CNG $5.5 per MMBtu more expensive than fossil CNG.

[43] "The Feasibility of Renewable Natural Gas as a Large-Scale, Low Carbon Substitute", UC Davis Institute for Transportation Studies (Myers-Jaffe, Parker, Dominguez-Faus, Scheitrum, Wilcock, Miller), Dec 2016.

To encourage the use of RNG-CNG, RNG used as a transportation fuel is considered to be a cellulosic biofuel under the RFS program and therefore D3 RINs, currently valued at $1.76 per gal ethanol ($23 per MMBtu) is generated. This RIN value more than offsets the current cost of producing RNG-CNG. As in the case of cellulosic ethanol, it is not clear which party pays for the RIN value (producer, obligated party, consumer). Consistent with the treatment of cellulosic ethanol pricing, this analysis assigns CNG produced from RNG the market price of fossil CNG and the RIN costs are tracked and added to the fuel costs as a surrogate for higher production costs.

2.10 Infrastructure Costs

Utilizing lower CI fuels in the transportation sector results in increased infrastructure spending to accommodate them. For example, new plants must be built to produce cellulosic ethanol and hydrogen and fueling stations must be retrofitted to store and dispense E85 and hydrogen. In all cases, this analysis assumes that infrastructure costs are recovered in the price consumers pay for the fuels. One exception to this rule is the electric vehicle supply equipment (EVSE) used to charge electric vehicles. It is assumed here that 90% of BEV and 30% of PHEV purchases[44] trigger purchase and installation of a Level 2 EVSE at $1200 per unit. This is a conservative estimate in that some of the future EV purchases will be for replacement EVs with a residential charger already in place.

[44] Center for Sustainable Energy PEV Owner Survey, Feb 2014

3. BAU Projections and Goals

Last year the U.S. signed the Paris Agreement, committing to a 26-28% reduction in GHG emissions from 2005 levels by 2025. The Obama Administration's long-term goal was an 80% reduction from 2005 levels by 2050, the same goal that was in the 2009 American Clean Energy and Security Act (Waxman-Markey) which passed in the U.S. House of Representatives but failed in the Senate. With a new President and EPA Director that have professed skepticism about man-made climate change, it is not clear what the new goals will be for the United States. Nonetheless, this analysis assumes that the U.S. goal is 80% below 2005 levels by 2050.

Based on forecasts of vehicle sales, VMT, fuel economy, and fuel CI provided above the WTW GHG emissions can be calculated and compared to GHG reduction goals. Figure 3-1 illustrates the resulting BAU forecast of light duty GHG emissions. To establish 2005 GHG emissions and calculate the emission rates that correspond to the 2025 and 2050 goals, LCA pulled the default fuel consumption for 2005 from the VISION model and multiplied it by the GREET default 2005 gasoline and diesel carbon intensity values. The fleet is on track to meet the 2025 Paris goal, but beginning in 2025, a 5% per year reduction is required to achieve the 80% reduction goal in 2050.

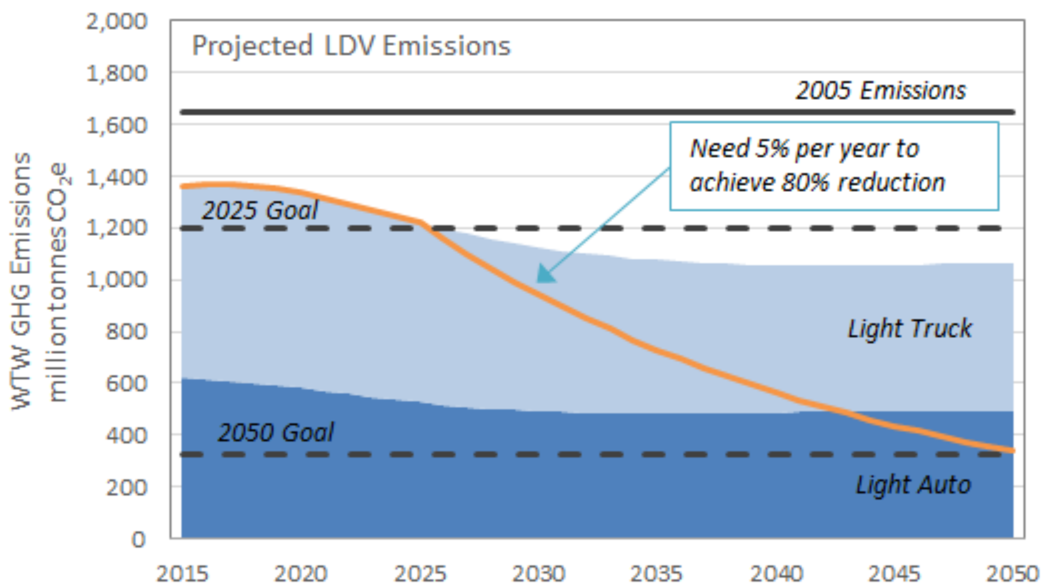

Figure 3-1. Projected U.S. light duty GHG emissions and goals.

The California GHG reduction goals are to reduce emissions to 1990 levels by 2020[45], to reduce by 40% below 1990 levels by 2030[46], and to reduce by 80% by 2050[47]. Note that the California goal is more difficult than the U.S. goal as the baseline year is 15 years earlier when there were similar per vehicle emissions but many fewer vehicles. Figure 3-2 illustrates the BAU projection of light duty emissions compared to the AB32 goals. On the estimated trajectory, it appears that California will be slightly higher than 1990 levels in 2020. To attain the 2030 and 2050 goals, 6.5% reduction per year is needed for 2025-2030 period and 5.5% per year for 2030-2050. These reductions are larger than those needed to achieve the U.S. goal.

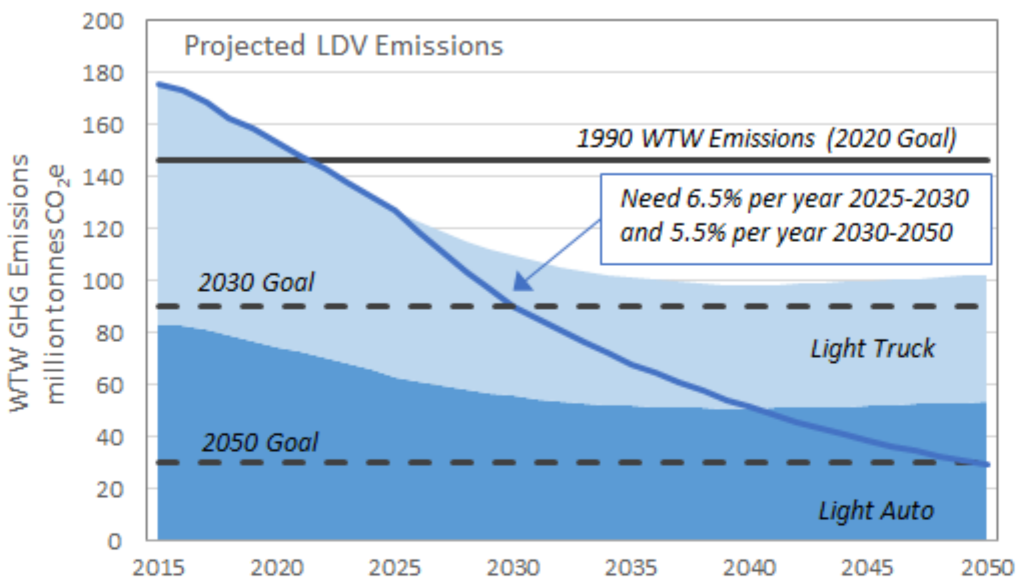

Figure 3-2. Projected California light duty GHG emissions and goals.

45 Global Warming Solutions Act, AB32 2006
46 Governor Brown Executive Order B-30-15, April 2015
47 Governor Schwarzenegger Executive Order S-3-05, June 2005

4. Individual Vehicle GHG Emissions

To inform scenario definition, the 2050 emission reduction potential for each vehicle/fuel combination was quantified. Costs are also shown, but were not used to define scenarios. Rather costs were quantified for each scenario considered and used to evaluate the relative merits of each GHG reduction scenario. This section provides the 2050 GHG emissions and incremental costs on a g/mi basis for the U.S. and California analyses.

4.1 2050 Emissions and Costs per Mile, U.S. Average

To achieve the 2050 GHG goal at the predicted VMT levels, the average light duty emission rate must achieve 86 gCO_2e/mi.

Figure **4-1** illustrates the LDA emission rates for a wide range of vehicle technology and fuel combinations assuming continued fuel economy improvements beyond 2025 (please refer to Section 0). The combinations that do not achieve the goal are blue. This includes all E10 and E30 ICEVs, diesels and diesel HEVs regardless of fuel blend. Combinations that achieve the goal without the use of advanced ethanol or a 70% non-fossil grid are colored orange. These include the PHEV, dedicated E85 PHEV and BEV200 (even without CPP). Combinations that achieve the goal but require advanced ethanol, a 70% non-fossil grid or both are colored green. The lowest emission rate is for the BEV200 with 70% non-fossil grid.

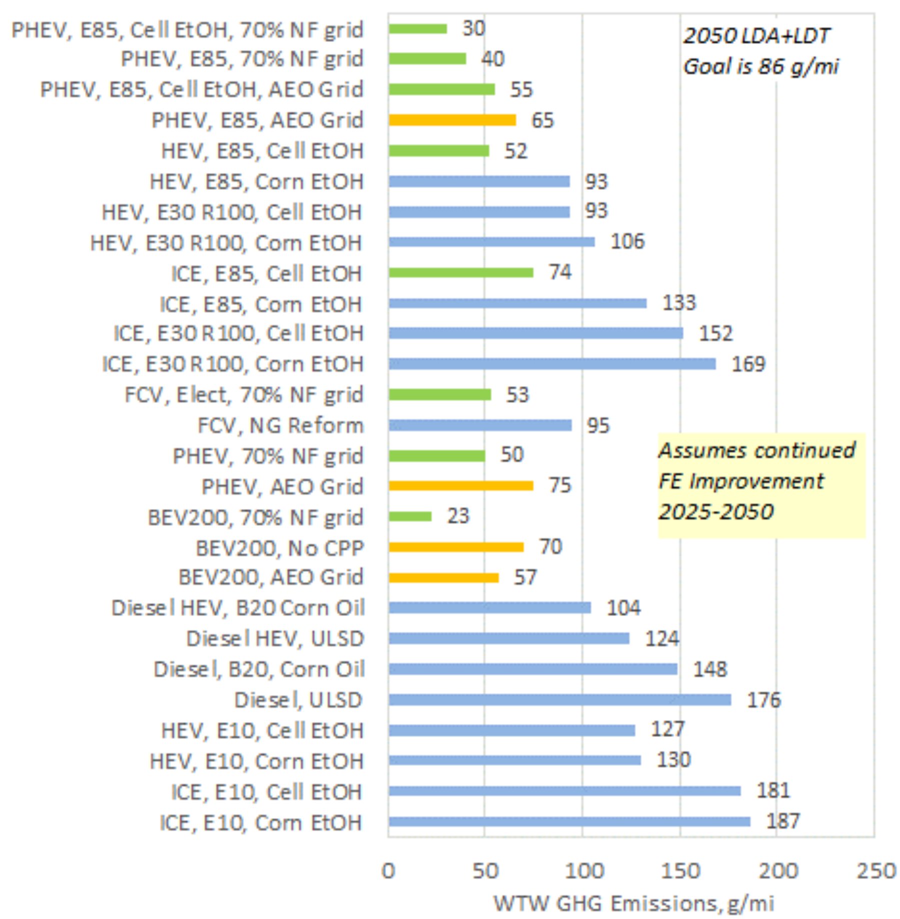

Figure 4-1. U.S. LDA emissions in 2050 with fuel economy improvement 2025-2050

Figure 4-2 provides the same information but it is assumed that the fuel economy does not improve beyond 2025. Without further fuel economy improvement, only the BEV200 and the dedicated E85 PHEV can meet the goal without advanced ethanol and/or 70% non-fossil grid. Without the CPP, the BEV200 does not meet the goal. Without the CPP, continued fuel economy improvements allow the BEV200 and E85 PHEV to meet the goal. Without the CPP and without continued fuel economy improvement, the only options that meet the 2050 goal are E85 vehicles (dedicated ICE, HEV and PHEV) using 100% advanced ethanol.

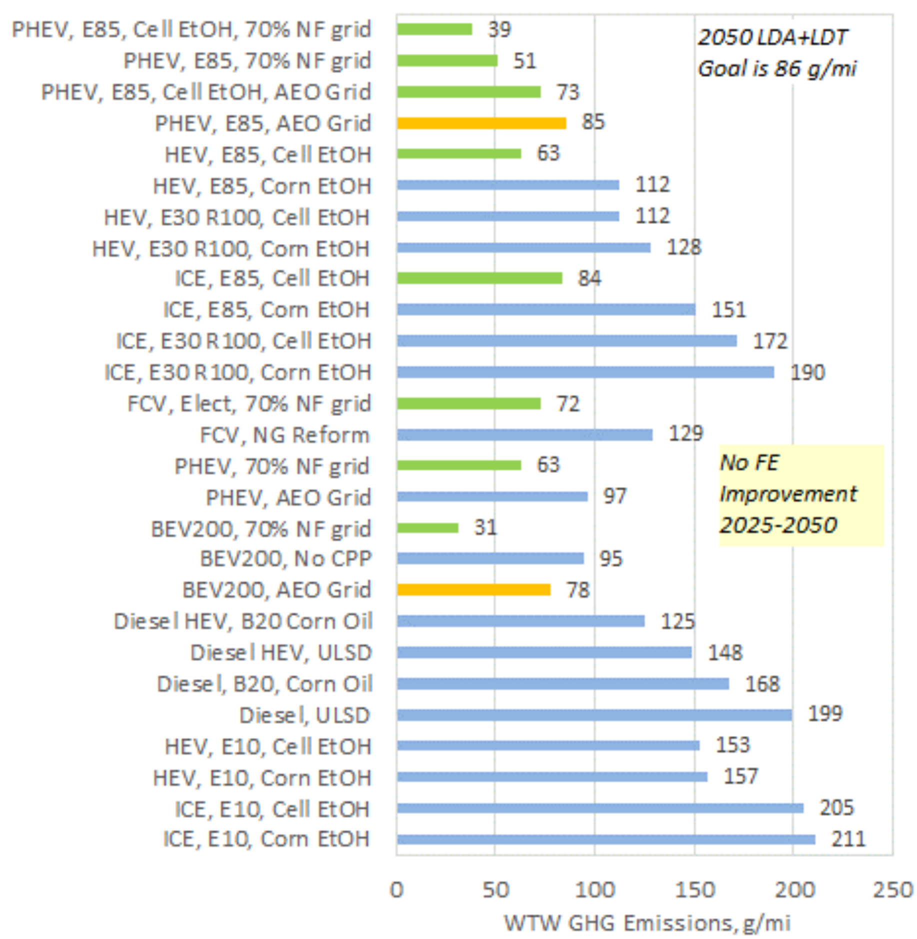

Figure 4-2. U.S. LDA emissions in 2050 with constant fuel economy for 2025-2050

Figure 4-3 provides the incremental vehicle, fuel and charger costs per mile for each vehicle-fuel combination relative to the 2015 gasoline ICE. Vehicle costs assume 150,000 lifetime miles. Electrification options have the highest vehicle costs while E85 options have the highest fuel costs. Other costs of vehicle ownership, such as operation and maintenance are not included. These costs were examined in more detail (a net present value analysis of costs was estimated) in the Draft MTE. In this analysis, the only costs considered were incremental vehicle and fuel costs (and charging equipment for plug-in vehicles).

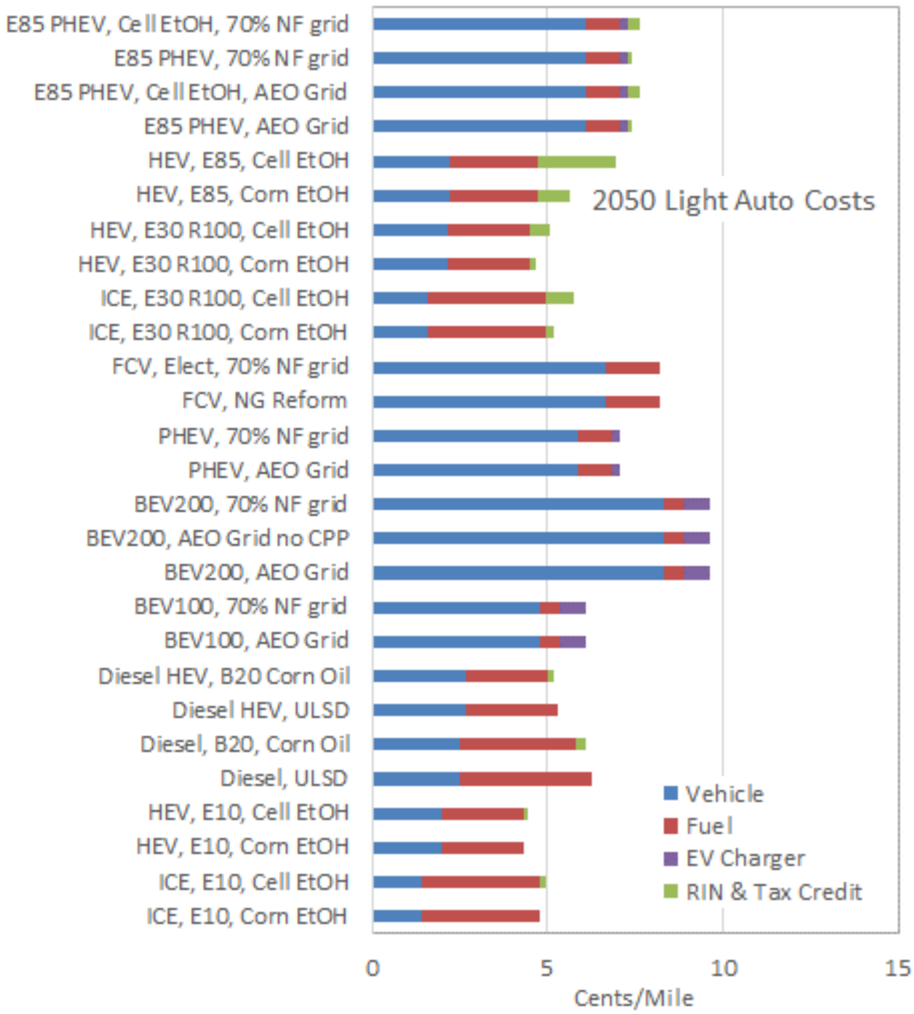

Figure 4-3. U.S. LDA costs in 2050 (with continued FE improvement 2025-2050).

Incremental cost and GHG reduction relative to 2015 gasoline vehicle are combined in

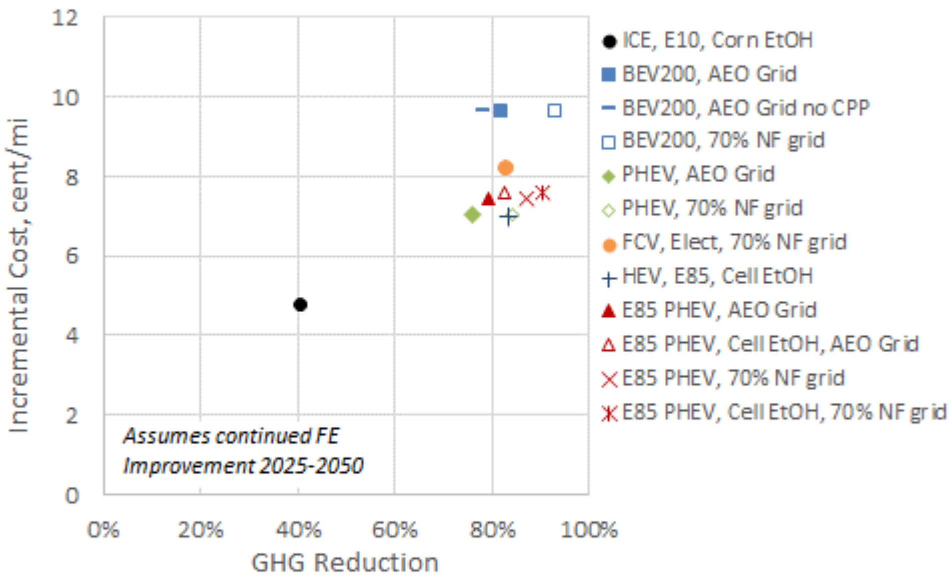

Figure **4-4** for the options that achieve the 2050 goal (assuming continued fuel economy improvement). For reference, the gasoline ICE vehicle costs and GHG emission reductions are also shown. The vehicle/fuel combinations provide similar reductions; the BEV200 has the highest cost while the dedicated E85 HEV using advanced ethanol has the lowest cost. The values shown assume that electricity prices are the same for the low carbon grid and AEO grid mixes. A sensitivity case is run in the scenario analysis exercise to quantify the impact of electricity price.

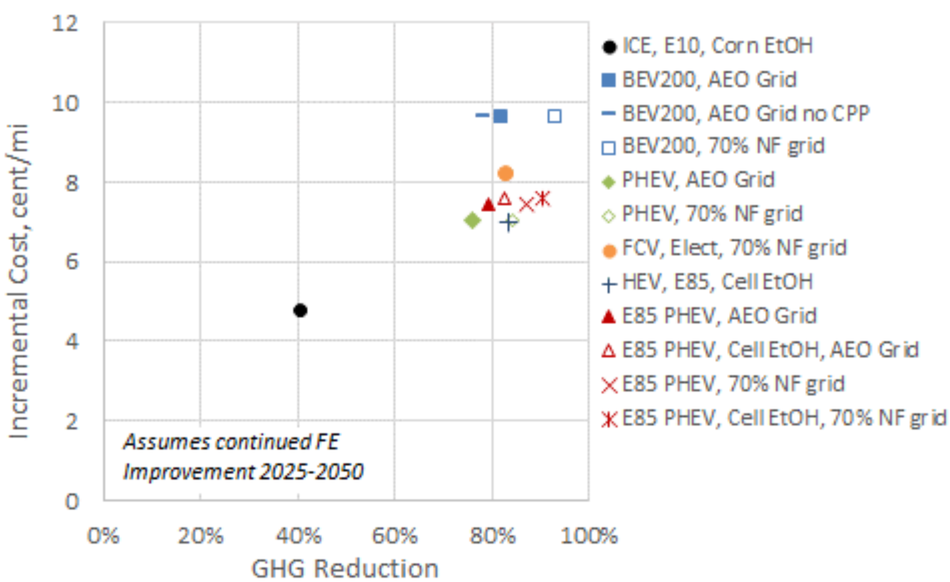

Figure 4-4. U.S. LDA incremental costs and GHG reduction in 2050.

Figure 4-5 provides 2050 emission rate information for light trucks with continuing fuel economy improvement. The combinations that do not achieve the goal are blue. Combinations that achieve the goal without the use of advanced ethanol or a 70% non-fossil grid are colored orange; only the BEV200 meets the goal without a low carbon grid but does not achieve the goal without the CPP. Combinations that achieve the goal but require advanced ethanol, a 70% non-fossil grid or both are colored green (E85 PHEV, E85 HEV, FCV, CNG). If continued fuel economy improvement does not occur (Figure 4-6), none of the technologies meet the goal without a low carbon grid or advanced ethanol. In a "dirty grid" situation without fuel economy improvement, only the E85 HEV using advanced ethanol achieves the goal. If the dirty grid is combined with fuel economy improvement, then the CNG truck using RNG also achieves the goal. However, since 86 g/mi is the LDV fleet average goal, LDTs can be slightly above the average if LDAs achieve an emission rate below the average. Even so, losing the CPP negatively impacts options for achieving the 2050 GHG goal and illustrates the importance of decreasing electricity CI for BEVs.

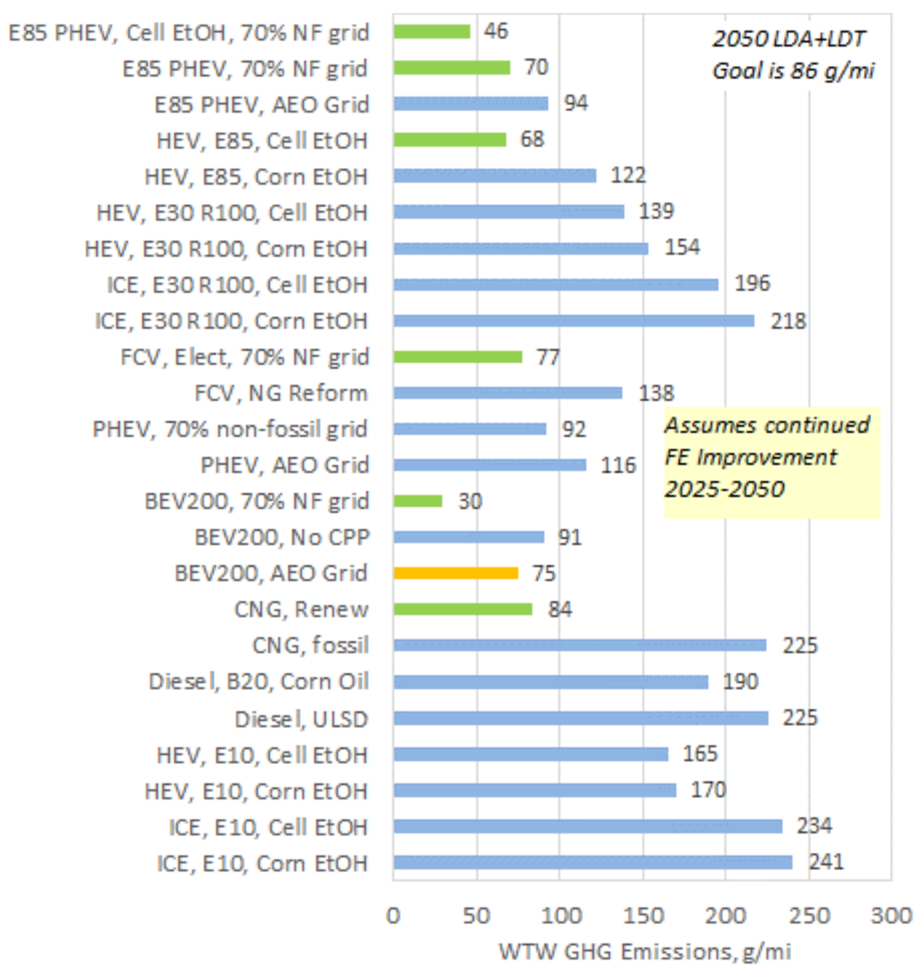

Figure 4-5. U.S. LDT emissions in 2050 with fuel economy improvement 2025-2050

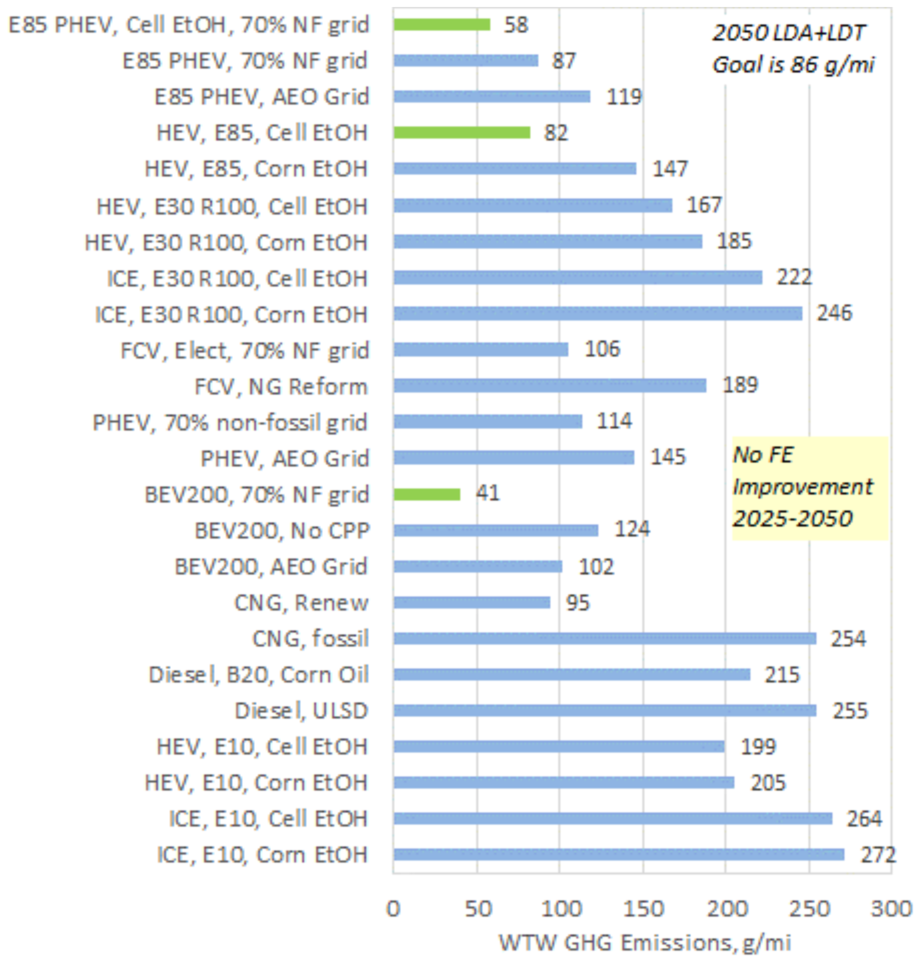

Figure 4-6. U.S. LDT emissions in 2050 with constant fuel economy for 2025-2050.

Figure 4-7 provides the incremental vehicle, fuel and charger costs per mile for each vehicle/fuel combination relative to the 2015 gasoline ICE. The per mile vehicle and EVSE costs assume 150,000 lifetime miles. Electrification and CNG options have the highest vehicle costs while E85 options have the highest fuel costs. Fuel costs for CNG are lower than gasoline costs, but RNG has higher costs (due to production costs which are represented in this analysis by RIN costs). Finally, costs and GHG reductions with continuing fuel economy improvement are combined in Figure 4-8. The trends are similar to the LDA trends. Most options provide similar reductions; E85 HEV using advanced ethanol is the lowest cost option while the CNG vehicle using RNG is the highest cost option.

Based on the GHG reduction potential, the compliance scenarios focused on options that maximize penetration of BEVs, PHEVs, E85 PHEV, and E85 HEV and LDT CNG vehicles. Mid-level ethanol blend (E30) dedicated vehicles, diesel and hydrogen FCVs do not offer the dramatic reductions needed to meet the goal.

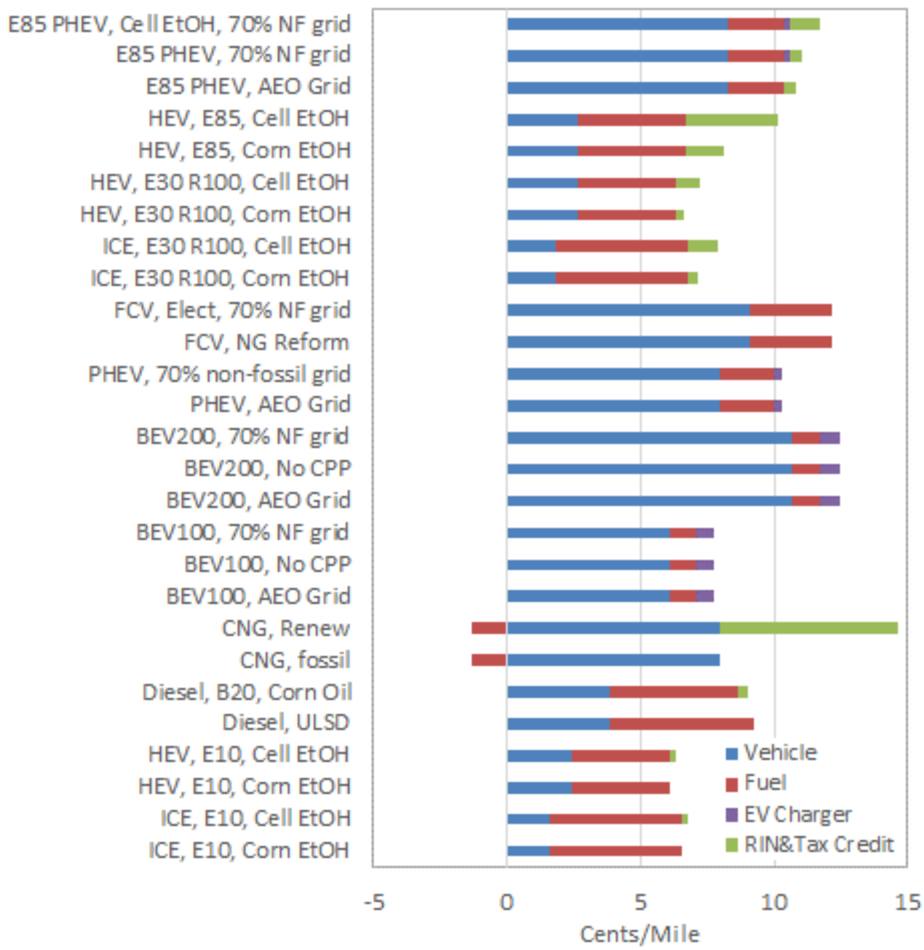

Figure 4-7. U.S. LDT costs in 2050 (with continued FE improvement 2025-2050).

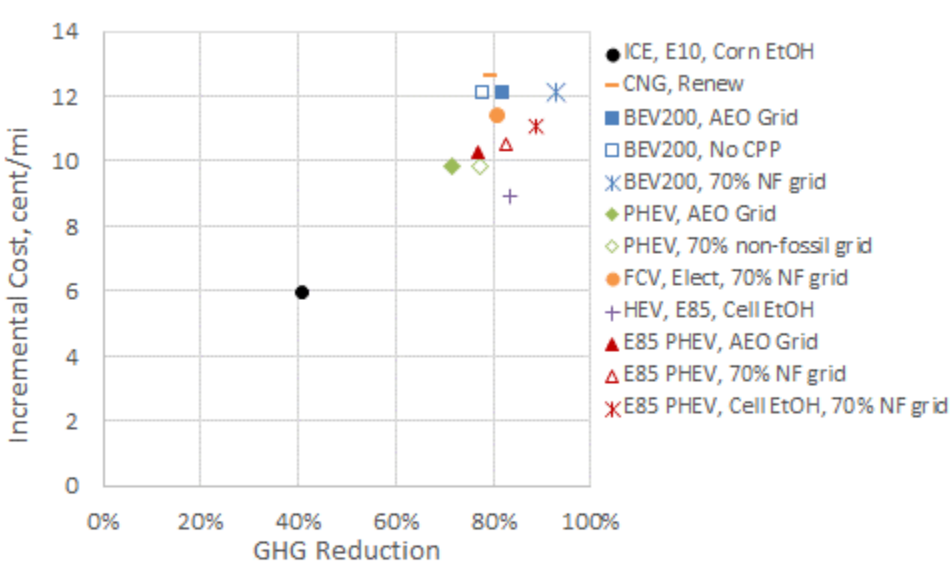

Figure 4-8. U.S. LDT incremental costs and GHG reduction (continued FE improvement) in 2050.

4.2 2050 Emissions and Costs per Mile, California Analysis

For the California analysis, LDA emission rates in 2050 are shown in Figure 4-9. The 2050 average LDV goal is 81 g/mi compared to the U.S. goal of 86 g/mi. Without reducing electricity and ethanol carbon content beyond BAU levels, four options meet the goal (marked in orange): E85 PHEV, FCV, PHEV, and BEV[48]. Reducing grid CI reduces emission rates of the electrified options, but does not enable any additional options to meet the goal. With advanced ethanol, the E85 HEV becomes a compliance strategy and the E85 PHEV emission rate drops even lower (though not quite as low as the BEV with a 70% non-fossil grid).

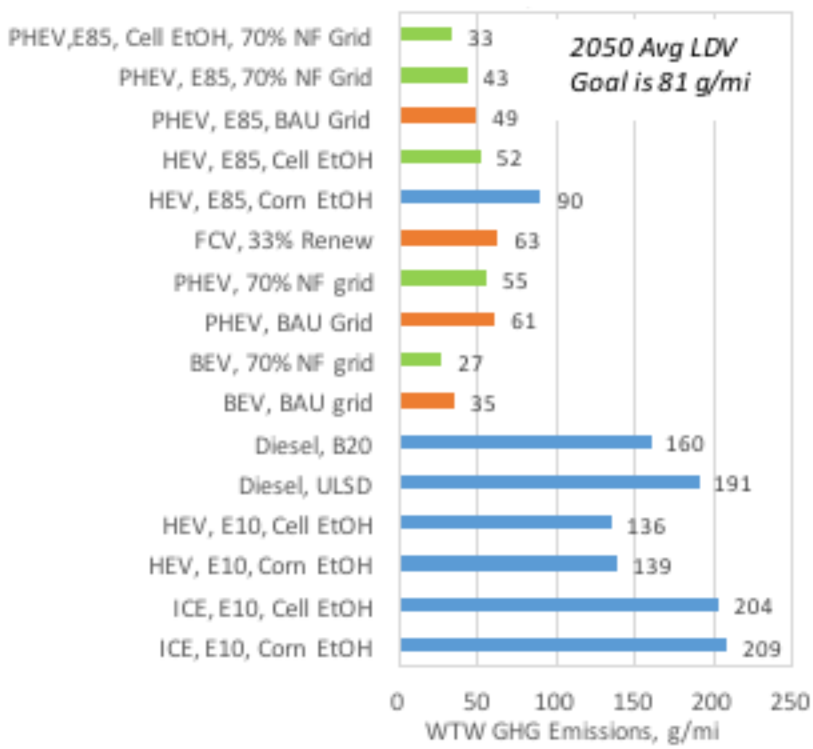

Figure 4-9. California LDA emissions in 2050 with improved fuel economy 2025-2050.

Incremental cost per mile is provided in Figure 4-10 with relative contributions from vehicle, fuel, EVSE, and RIN indicated. The most expensive option is the BEV, with double the incremental cost of a 2050 ICE vehicle. The next most expensive option is the FCV with 33% renewable hydrogen followed by the dedicated E85 PHEV. The E85 PHEV shows very little difference between cellulosic ethanol and corn ethanol because most of the LDA PHEV miles are powered by electricity. The dedicated E85 HEV is a lower cost option; if cellulosic ethanol is used, the RIN costs (assumed to be today's value of $1 per gallon more than corn) increase the total cost significantly. However, a 2050 cellulosic E85 option requires a robust supply of cellulosic ethanol which would likely result in a decrease in the premium paid for cellulosic

[48] ARB does not distinguish between BEV100 and BEV200. Because a 50/50 split is assumed in the U.S. analysis, the fuel economy and incremental cost values for the CA BEV are the averages of the BEV100 and BEV200 values.

RINS. A sensitivity case was run to evaluate the effect of lower D3 RIN prices on the E85 HEV cellulosic case in the Scenario Analysis exercise.

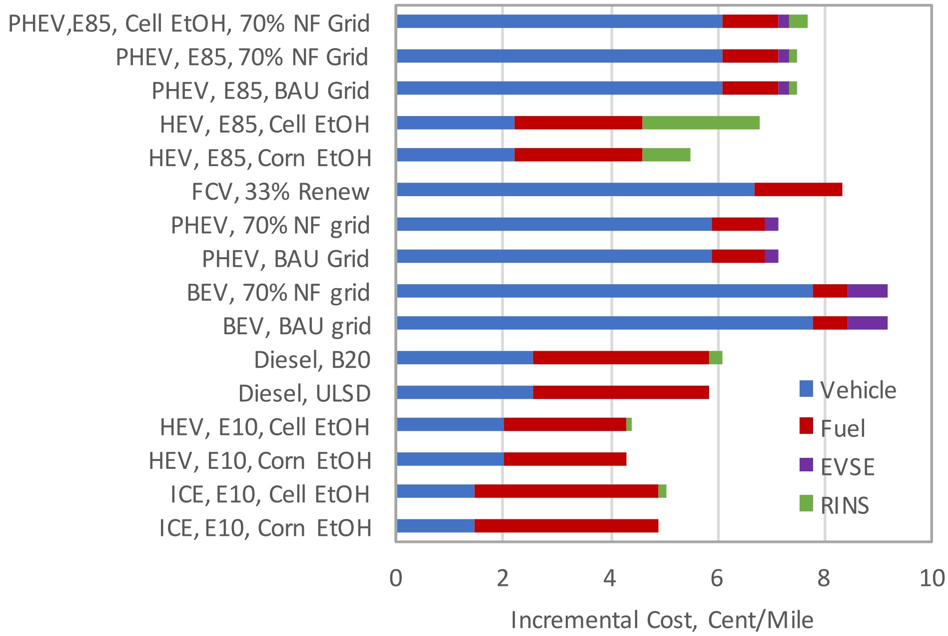

Figure 4-10. California LDA incremental costs in 2050.

California LDA incremental cost is plotted as a function of GHG reduction in Figure 4-11. Most scenarios provide GHG reduction in the 80-90% range. BEVs provide the most reduction at the highest cost. It is interesting to note that for California BEVs, the amount of reduction achieved with a 70% non-fossil grid mix is not significantly larger than that achieved by the BAU grid mix; this is because the BAU grid mix in California is already very low carbon. E85 HEVs using advanced ethanol have the lowest cost per mile, even with the current cellulosic RIN premium.

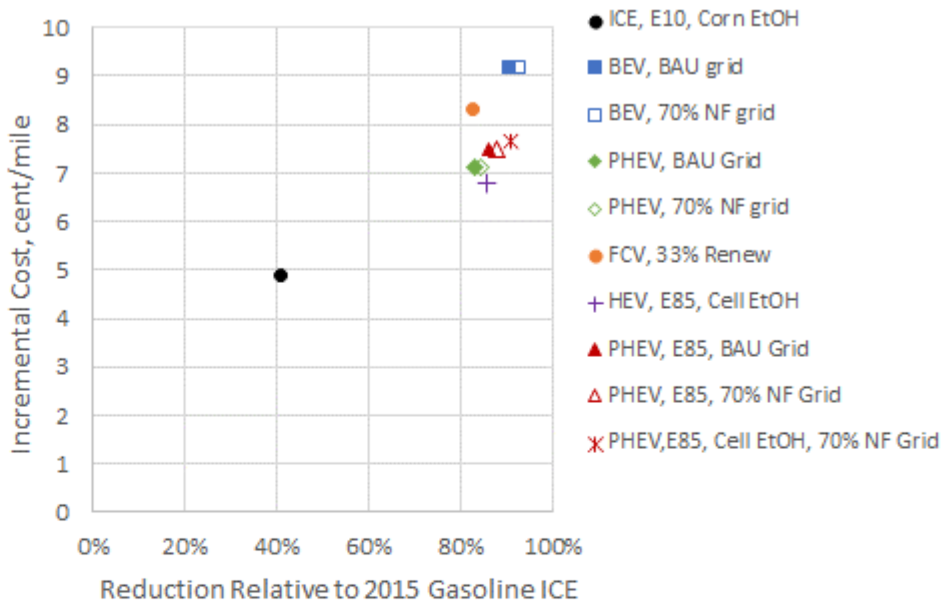

Figure 4-11. California LDA incremental costs and GHG reduction in 2050.

Figure 4-12 through Figure 4-14 provide the corresponding results for California LDTs. Only BEVs are able to achieve the goal without further reduction in fuel carbon intensity. None of the E10 PHEVs meet the goal, the dedicated E85 PHEV meets the goal if either advanced ethanol or a 70% non-fossil grid are available. Non-electrified options that meet the goal include CNGV using RNG and E85 HEV using advanced ethanol. CNG-RNG case has the highest cost. Note that California's average BEV category has lower cost than the U.S. BEV200 costs (Figure 4-8) because in 2050, 25% of the LDT BEVs are BEV100 with lower costs.

Consistent with the U.S. analysis, the California scenarios consider maximum penetration of BEVs, PHEVs, E85 PHEVs, E85 HEVs, and CNG vehicles using high levels of RNG.

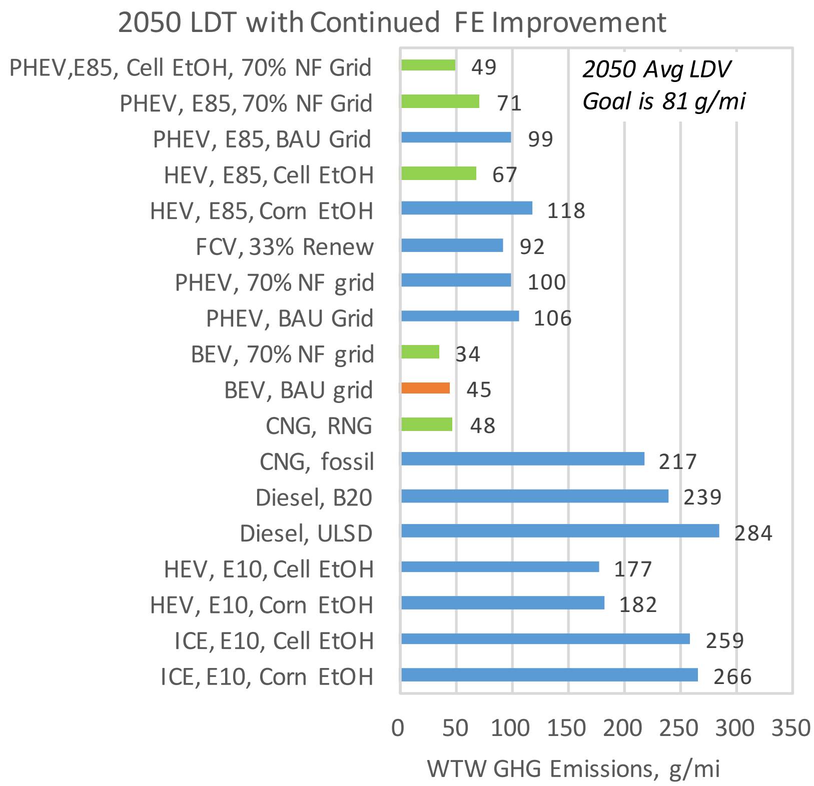

Figure 4-12. California LDT emissions in 2050 with improved fuel economy 2025-2050.

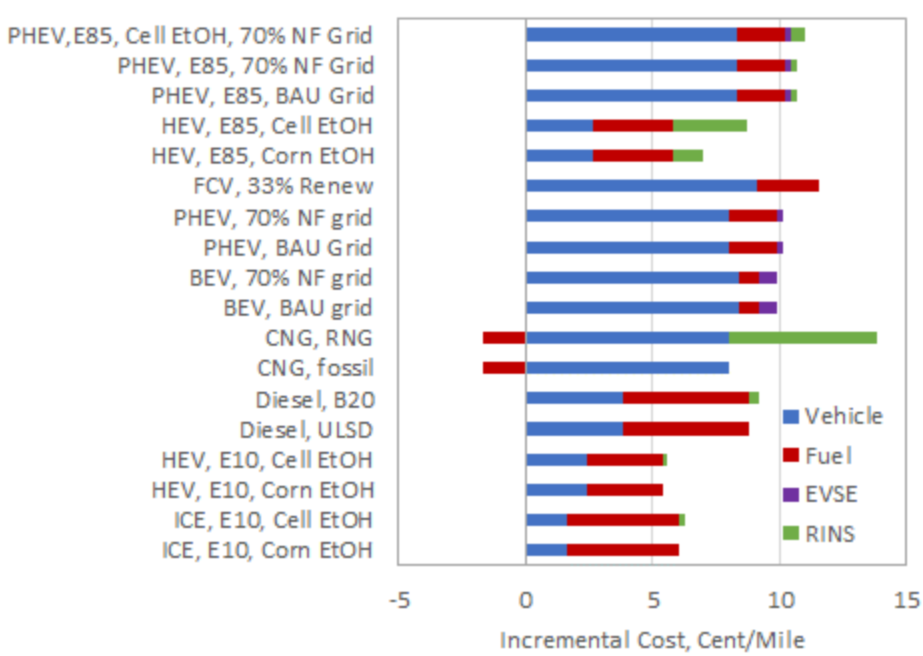

Figure 4-13. California LDT incremental costs in 2050.

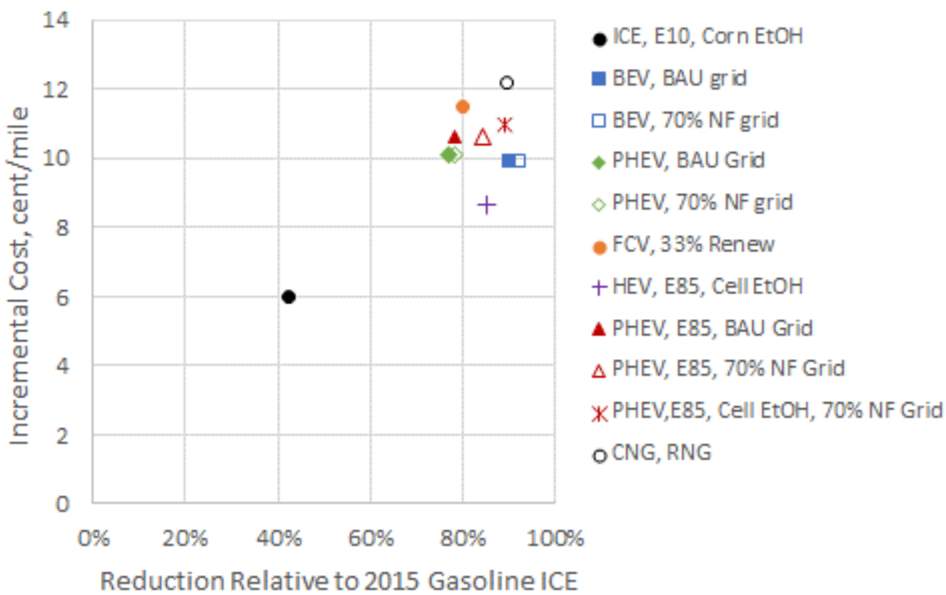

Figure 4-14. California LDT incremental costs and GHG reduction in 2050.

5. Scenario Analysis – U.S. Fleet

The objective of this U.S. scenario analysis is to determine if an 80% GHG emission reduction from 2005 levels is possible, and if so, what is needed in terms of vehicle technology penetration and fuel carbon intensity. To answer these questions, scenarios were constructed that maximize the market penetration of each promising technology/low CI fuel combination identified in Section 4.1 that reaches or exceeds the 2050 goal. The midterm report by EPA, ARB and NHSTA indicated that the 2025 standards could largely be achieved with advanced gasoline ICE vehicles. As a result, the GHG reduction scenarios assume that the new car sales through 2025 are the same as the BAU case (mainly gasoline ICE vehicles). To meet the 80% GHG reduction goal, GHG reduction scenarios were developed with increased levels of electrification and/or low CI fuels. The following sections provide a description of the scenarios evaluated for the U.S. analysis, analysis results, and the results of sensitivity tests.

5.1 Scenario Definition

There are four main scenarios, one for each key vehicle technology (BEV, PHEV, E85 PHEV, E85 HEV)[49]. While total vehicle sales in the scenarios remain the same as in the BAU case, each scenario increases the market share of one of the four key technologies at the expense of gasoline ICE vehicles. Maintaining total fleet population and VMT assumptions, the altered technology market shares result in changes in fuel consumption quantity and type, resulting in lower overall GHG emissions. Table 5-1 provides the new vehicle market share values in 2050 for each scenario. The following guidelines were used to adjust new vehicle market shares:

- To ensure a fair comparison between scenarios, alternative technologies replaced gasoline ICE vehicle market shares. In each scenario gasoline ICE market share decreased to 4.3% for LDA and 4.6% for LDT by 2050.
- All other technology shares were maintained at BAU levels unless noted
- Because BEV market share is potentially limited by homes with EVSE access[50], it is assumed that maximum possible BEV market share is 70% for LDA, and maximum PHEV market share is 80% for LDA.
- Because electrification is not currently compatible with towing capability, it was assumed that maximum LDT market share for BEVs and PHEVs is 45%. To maximize LDT alternative vehicles, PHEVs and BEVs were supplemented with E85 HEVs or NGVs.
- It is assumed that E85 HEVs have a faster ramp up to goal market penetration than plug-in options because incremental price is lower, range is not an issue, and charging capability is not required.

[49] Hydrogen FCVs are also a possible low emission vehicle strategy but were not included in this study.
[50] The addition of public charging infrastructure will potentially increase use of BEVs but it is still not expected to achieve more than 70% due to BEV attributes that will continue to lag other vehicle technologies.

Table 5-1. New vehicle market share assumptions for U.S. analysis scenarios.

Scenario	2050 LDA Market Share	2050 LDT Market Share
BAU	85% Gasoline ICE 1% Diesel 6% HEV 3% PHEV 4% BEV 1% H2 FCV	94% Gasoline ICE 2% Diesel 1% HEV 1% PHEV 1% BEV 1% FCV
1. Max BEV	70% BEV 15% E85 HEV 4.3% Gasoline ICE All others BAU	45% BEV 45% E85 HEV 4.6% Gasoline ICE All others BAU
2a. Max PHEV/E85 HEV	80% E10 PHEV 4.4% E85 HEV 4.3% Gasoline ICE All others BAU	45% E10 PHEV 45% E85 HEV 4.6% Gasoline ICE All others BAU
2b. Max PHEV/CNG	Same as 2a	45% PHEV 46% CNG 4.6% Gasoline ICE All others BAU
3. Max E85 PHEV	81% E85 PHEV 4.3% Gasoline ICE All others BAU	45% E85 PHEV 45% E85 HEV 4.6% Gasoline ICE All others BAU
4. Max E85 HEV	81% E85 HEV 4.3% Gasoline ICE All others BAU	90% E85 HEV 4.6% Gasoline ICE All others BAU

Figure 5-1 and Figure 5-2 illustrate the assumed LDA and LDT new vehicle market shares for Scenario 1 (Max BEV). Note that in this scenario the main alternative technology is supplemented with dedicated E85 HEV sales since the maximum penetration of BEVs is limited. In addition, note the slower market share ramp rate for BEVs relative to HEVs; the effect is more evident for LDTs since both have the same maximum market share values. Note also the near-term increase in gasoline ICE vehicles as FFVs are phased out. Please refer to 1.a.i.1.a.Appendix D for similar new vehicle market share figures for Scenarios 2-4.

The scenarios were also evaluated with the following fuel mix assumptions:

- Scenarios 1-3 (plug-in technologies) were evaluated with two sets of CI values: AEO2016 reference case grid mix and 70% non-fossil grid mix.
- All scenarios were evaluated with the base case ethanol mix and a low CI mix (Please see Section 2.6).

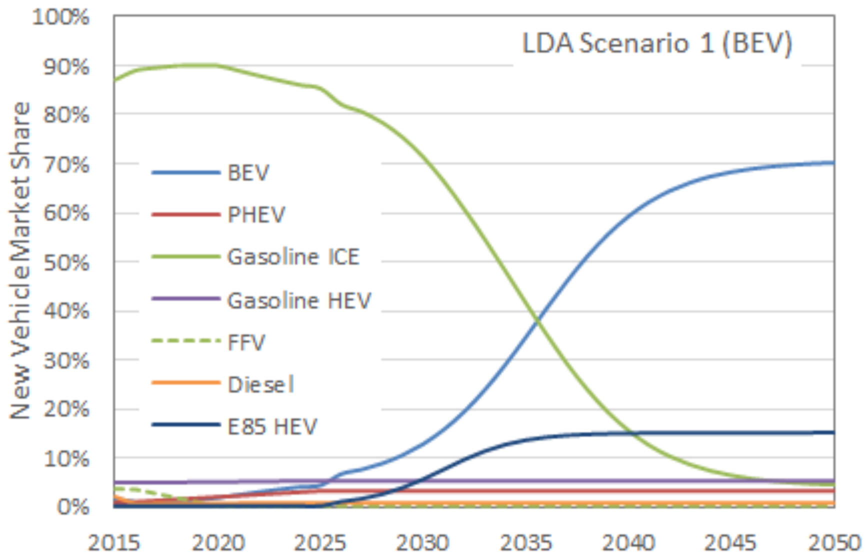

Figure 5-1. LDA assumed new vehicle market shares for Scenario 1.

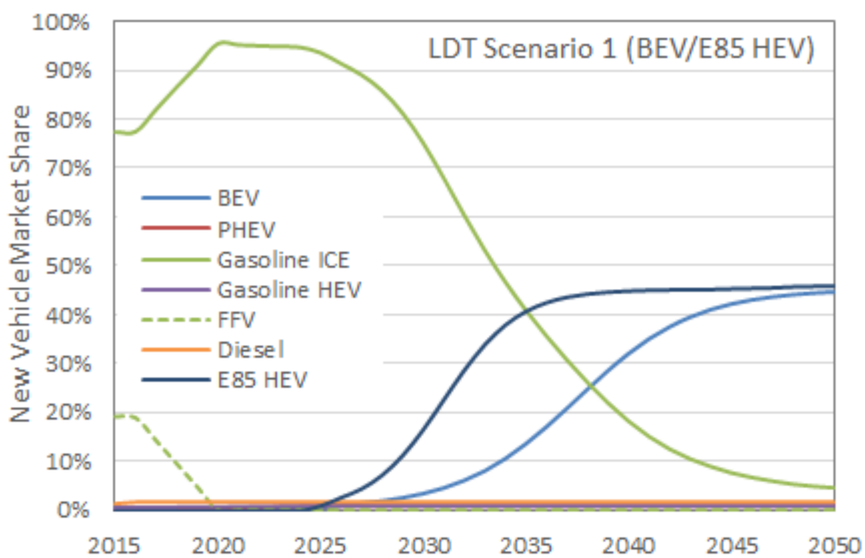

Figure 5-2. LDT assumed new vehicle market shares for Scenario 1.

It is doubtful that the GHG reduction scenarios will take place without some kind of regulatory driver such as continued CAFE pressure and/or a federal ZEV Mandate. It is therefore assumed for the GHG reduction scenarios that auto manufacturers will continue improving fuel economy of existing technologies for 2025-2050. Please refer back to Section 0 for the assumed improvement in vehicle fuel economy for the GHG reduction scenarios. The BAU case assumes no improvement in fuel economy for 2025-2050.

Finally, because of uncertainty in several future model inputs, sensitivity cases were evaluated:

- Because of wide range of projections for future BEV fuel economy (1.a.i.1.a.Appendix A), a sensitivity case was run for Scenario 1 and the BAU with 2050 BEV fuel economy increased by approximately 7.5% over the values assumed in the main analysis, with linear approach from assumed 2025 values.
- Because the Clean Power Plan might be repealed, a sensitivity case was run for Scenario 1 and the BAU using CI values reflecting the AEO2016 grid mix side case without the Clean Power Plan.
- Scenario 2b was evaluated with base case RNG shares and a high RNG mix (Please see Section 2.6).
- A sensitivity case was run to evaluate the impact of higher electricity prices for the 70% non-fossil electricity prices.

5.2 Fuel Volumes

One key metric of this analysis is fleet energy consumption. Projected light duty fuel use is provided in Figure 5-3. Due to improving fuel economy, U.S. BAU fuel use declines steadily through 2030 as more efficient vehicles replace older models. Because of increasing vehicle population and VMT per vehicle, BAU fuel consumption should increase, but a switch from LDT to LDA keeps fuel consumption fairly constant. For the BAU case with continuing fuel economy improvement (but no change in technology market share), fuel consumption continues decreasing through 2050 at about half the rate from 2015-2030.

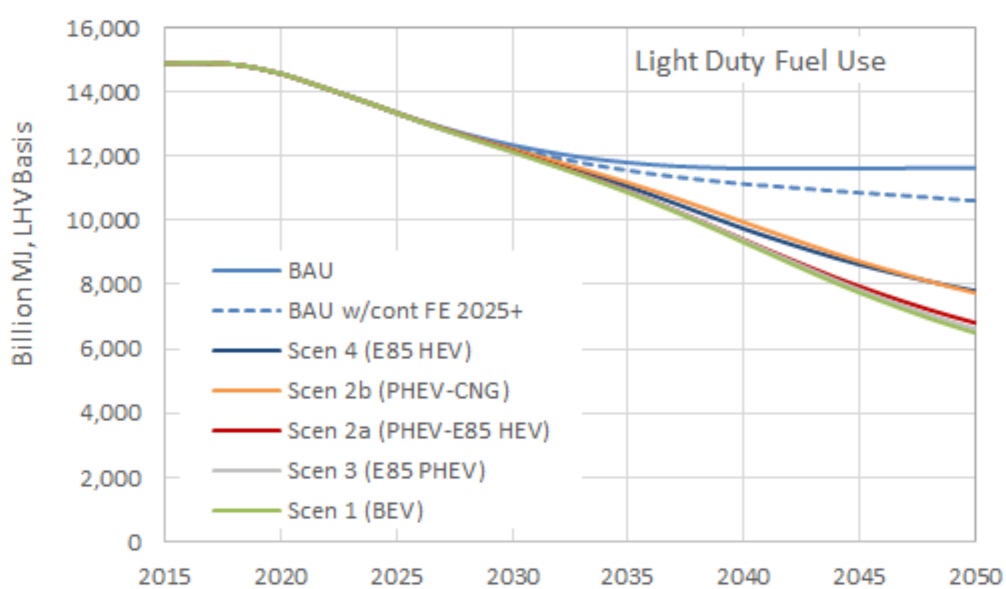

Figure 5-3. Projected U.S. total light duty fuel use.

The maximum electrification scenarios (1, 2a, 3) all result in a ~55% reduction in fuel use between 2015 and 2050. Electric vehicles are approximately 3 times more fuel efficient than conventional vehicles. Scenario 4, the non-electrification scenario yields a 47% reduction in fuel use, similar to scenario 2b which consists of PHEVs and CNG vehicles. Evidently, scenario 2b's average fuel economy (PHEV/CNG) is similar to scenario 4's HEV fuel economy. All scenarios provide similar levels of petroleum reduction (Figure 5-4); the BAU experiences a 24-30% reduction while the GHG reduction scenarios achieve a 71-78% reduction.

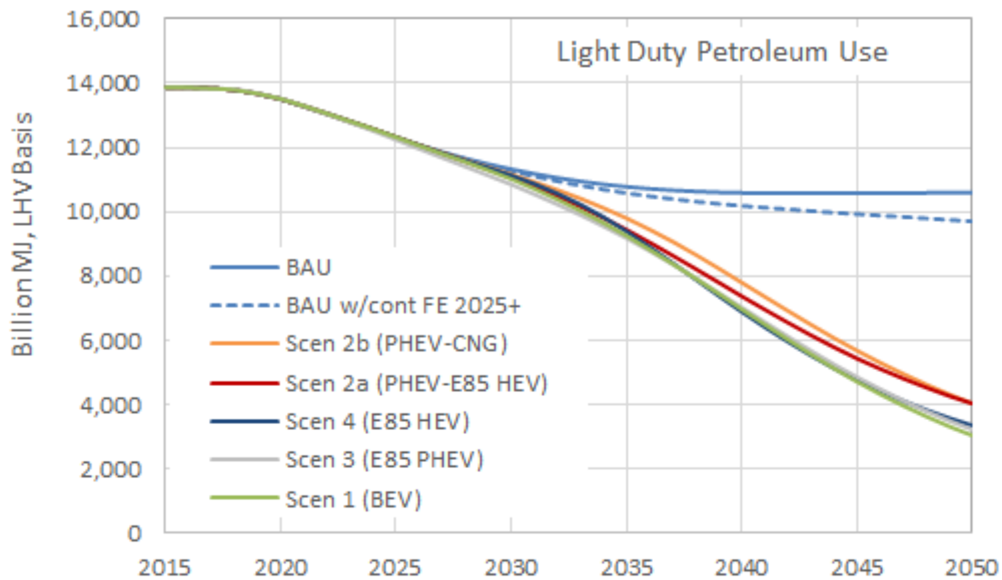

Figure 5-4. Projected U.S. light duty petroleum consumption.

Figure 5-5 illustrates the projected total light duty ethanol consumption for each of the scenarios. For reference, the figure also provides the total renewable fuel volume mandated for 2022 by the RFS (36 BGY). Although this is the mandated volume for all renewable fuels, historically, the lion share has been ethanol. For example, the total renewable fuel volume for 2015 was set at just under 17 BGY[51]; of this, nearly 15 BGY was ethanol (mainly corn). Note that the figure shows less than 15 BGY of ethanol for 2015 because some ethanol is consumed by the medium and heavy duty fleets. The RFS mandates volumes of renewable fuel without regard for improvements in fuel economy or changes in VMT. It appears from the projections that there will need to be a significant increase in BD/RD use in the heavy-duty sector over the next five years for the 36 BGY mandate to be achieved.

For the BAU, ethanol use is expected to decrease 23% from 2015 levels by 2050. The BAU with continued fuel economy improvements from 2025-2050 (dashed line in figure), total ethanol use is projected to decrease by 29% to under 9 BGY in 2050. This is due to the phase out of FFVs and improved fuel economy.

[51] https://www.epa.gov/renewable-fuel-standard-program/final-renewable-fuel-standards-2014-2015-and-2016-and-biomass-based

Scenario 2b yields a 60% decrease in ethanol consumption from 2015 levels due to the high market share of light truck CNG vehicles. Scenarios 1 and 2a experience 81% and 62% increases in ethanol use due moderate sales of E85 HEVs. Scenario 1 has more light auto E85 HEVs than Scenario 2a since the maximum penetration of BEVs was set at 70% as opposed to the maximum PHEV penetration of 80%. Scenario 3 (E85 PHEVs) more than doubles light duty ethanol use (up to 29 BGY) compared to current levels. The non-electrification scenario (Scenario 4 E85 HEV) results in nearly 53 BGY of ethanol use by 2050.

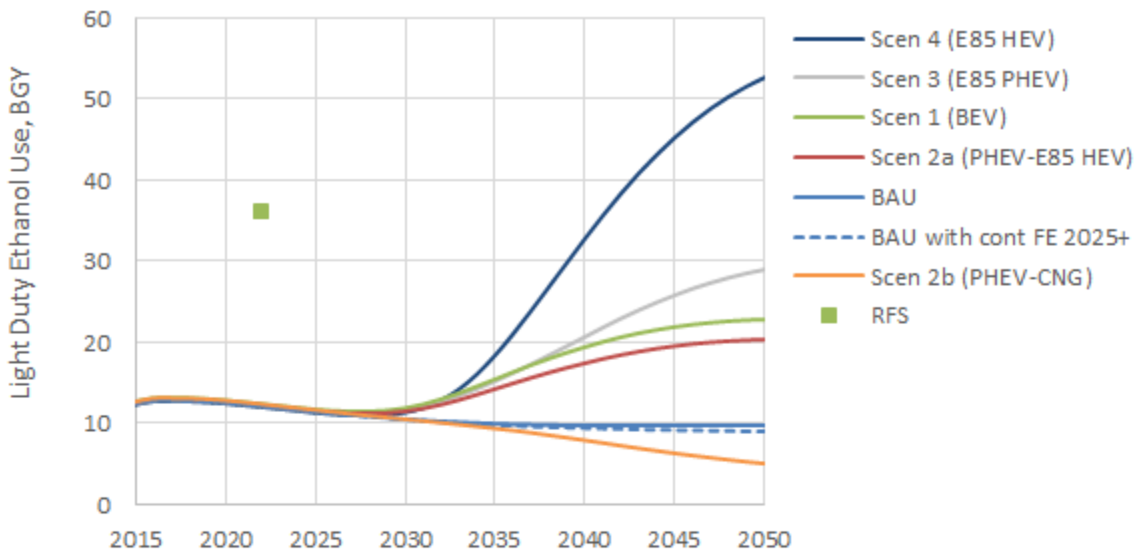

Figure 5-5. Projected U.S. light duty total ethanol use for BAU and scenarios.

Ethanol consumption on the order of 50 BGY would be a significant shift in light duty energy use. Recall (Figure 1-3) that the original RFS assumed up to 15 BGY of conventional corn ethanol use for 2015-2022; the corn ethanol industry has experienced exponential growth over the past decade to achieve this capacity. Whether an additional 40 BGY of ethanol could economically be produced from corn is unknown. Recent DOE estimates from the Billion Ton Update[52] indicate that this level of ethanol consumption is well within domestic feedstock supply potential for cellulosic ethanol production. In fact, the study states that 1.2 billion dry tons of biomass (forest, agricultural residue and waste) are recoverable at a moderate price of $60 per ton. With a yield of 85 gal/dry ton[53], this corresponds to potential cellulosic ethanol production of 100 BGY. It is also possible to produce ethanol from natural gas; from a carbon standpoint this is not a preferable option, but it may represent an economic alternative to renewable ethanol.

[52] U.S. Department of Energy. 2016. 2016 Billion-Ton Report: Advancing Domestic Resources for a Thriving Bioeconomy, Volume 1: Economic Availability of Feedstocks. M. H. Langholtz, B. J. Stokes, and L. M. Eaton (Leads), ORNL/TM-2016/160. Oak Ridge National Laboratory, Oak Ridge, TN.

[53] Slightly more conservative than the GREET yield assumption of 90 gal per dry ton.

Projected cellulosic ethanol consumption (a subset of total ethanol) is shown in Figure 5-6. The BAU and all base scenarios require the same amount of cellulosic ethanol – up to 0.5 BGY. In contrast, the low CI versions of the scenarios assume that ~ 50% of ethanol is cellulosic. Scenario 4 with low CI ethanol requires the most cellulosic ethanol at 26.4 BGY. As discussed above, this consumption level is well within domestic production potential according to the Billion Ton Update.

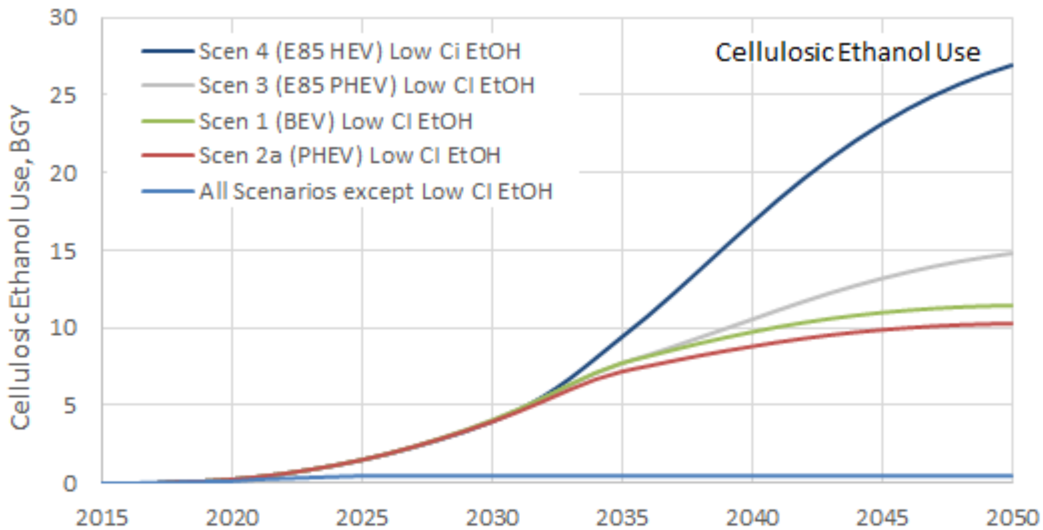

Figure 5-6. Projected light duty cellulosic ethanol volumes.

Scenario 2b assumes a large penetration CNG light trucks. This scenario requires 12.8 BGY of RNG for the light fleet. Combining this with estimated MD and HD RNG use results in a total of 16 BGY. This is just under what is thought to be the commercial potential[33].

5.3 GHG Emission Reductions

GHG emissions as a function of time for the BAU and each GHG reduction scenario are illustrated in Figure 5-7 (Light Auto) and Figure 5-8 (Light Truck). For all cases, emissions decrease steadily through 2030 as CAFE standards become more stringent and older vehicles retire and are replaced with newer more efficient vehicles. For light autos, BAU emissions start increasing again after 2035 while light truck emissions decrease; this is expected as light auto sales increase at the expense of light trucks (Please see Figure 2-2). For LDA and LDT, the GHG reduction scenarios without increased use of low CI fuels yield similar GHG emissions by 2050 with the exception of light truck Scenario 2b (PHEV+CNG, the orange line). CNG vehicles with fossil natural gas have higher emissions than E85 HEVs, so Scenario 2b has higher emissions than its counterpart, Scenario 2a with E85 HEVs. For autos and trucks, Scenario 1 (BEV+E85 HEV) and Scenario 3 (E85 PHEV+E85 HEV) with low CI fuels have lower emissions than Scenario 2a (PHEV+E85 HEV) and Scenario 4 (E85 HEV). For light autos, the lower CI fuel version of Scenario 2 has lower emissions than the low CI version of Scenario 4 while for light trucks, the low CI fuel versions of Scenario 2a and 4 yield similar emissions. This is because light trucks have a lower market share of PHEVs than light autos.

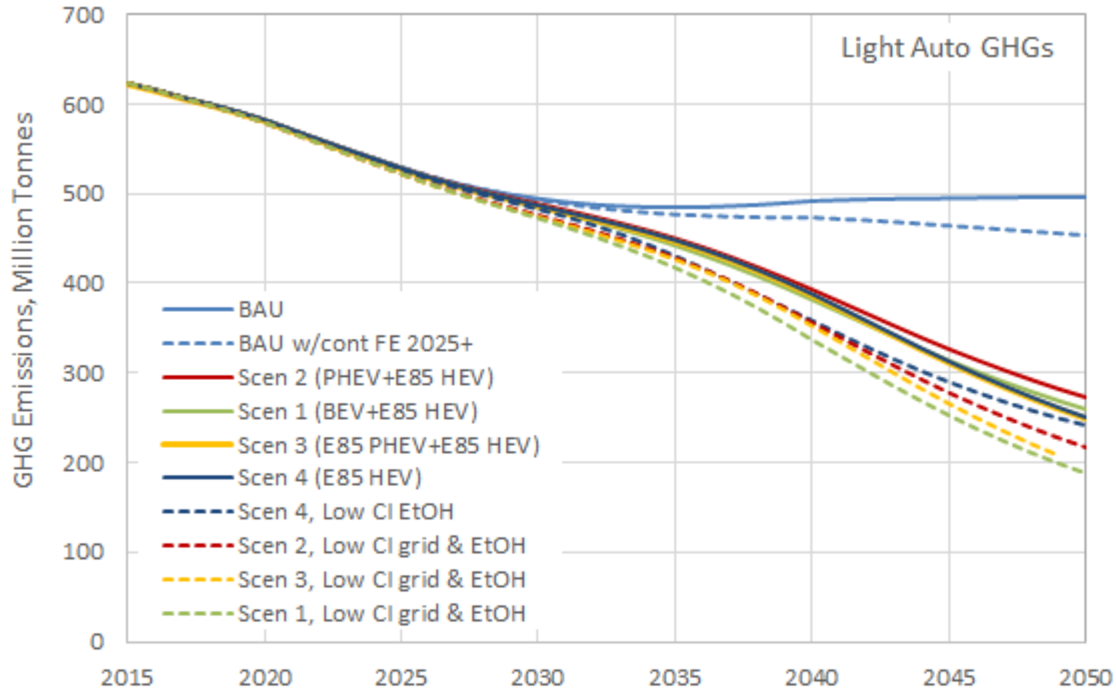

Figure 5-7. Projected U.S. LDA GHG emissions.

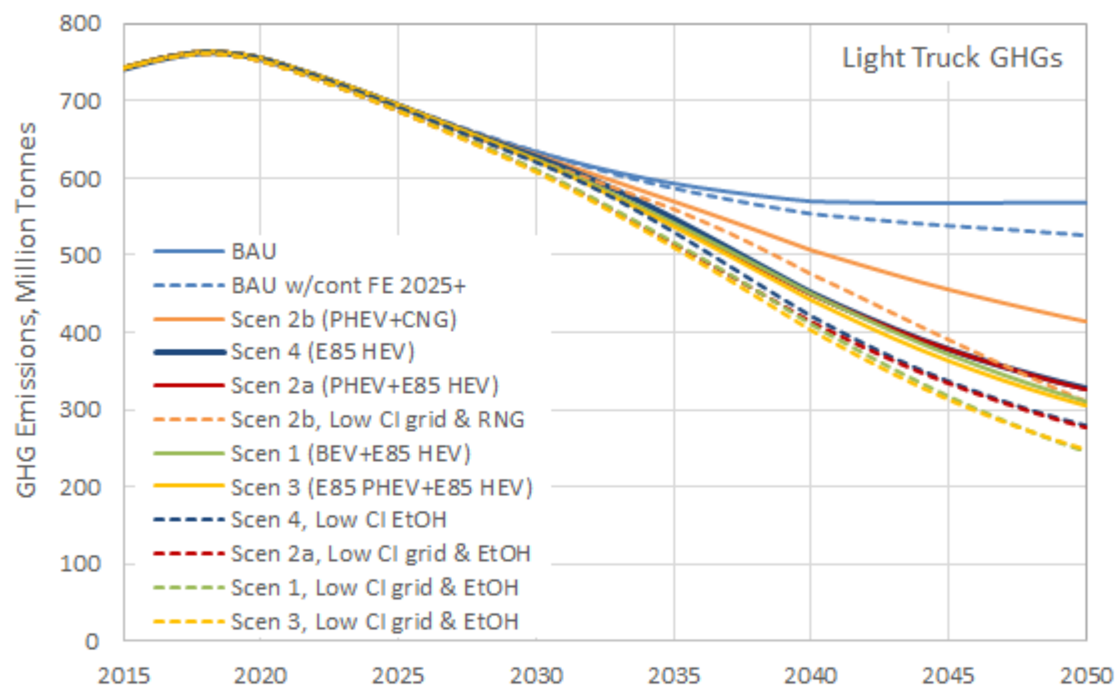

Figure 5-8. Projected U.S. LDT GHG emissions.

As discussed in Section 4.1, several individual vehicle and fuel technology combinations considered in the scenario analysis achieve the 2050 goal of 80% GHG reduction. However, as shown in Figure 5-9, even with aggressive market share assumptions of the cleanest technologies, none of the scenarios achieves the combined light duty 2050 goal. More time is needed for older vehicles to retire and be replaced with more efficient less carbon intensive options, or the cleaner options have to be introduced faster. The figure indicates that all of the base scenarios yield similar GHG emission levels in 2050. The low CI versions of the scenarios are shown with dashed lines. The BEV and E85 PHEV options provide more reduction than the PHEV and E85 HEV options.

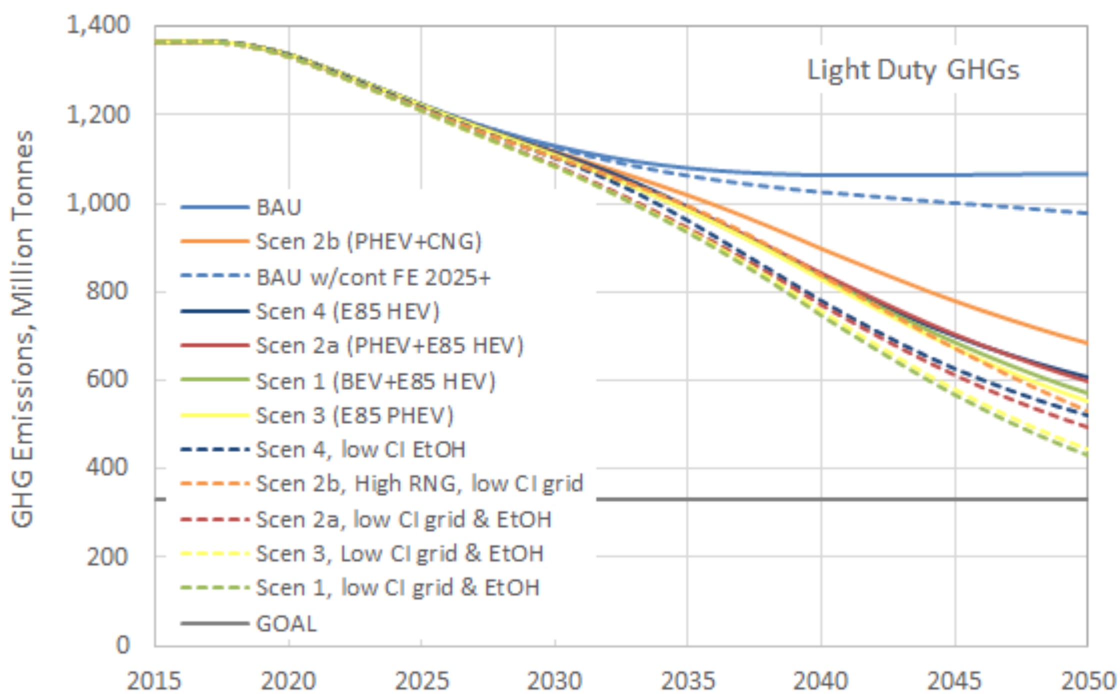

Figure 5-9. Projected U.S. LDA+LDT GHG emissions.

Because GHG emissions accumulate in the atmosphere, projected cumulative GHG reductions from the scenarios are a better indicator of climate impact than GHG emission levels in 2050.[54] For each scenario (including the BAU with improved fuel economy for 2025-2050), the annual GHG reduction relative to the BAU level is determined and a running sum is calculated to represent cumulative reductions relative to the BAU over time. Figure 5-10 provides the cumulative GHG reduction over time for each GHG scenario relative to the BAU. With just moderately increased fuel economy and no change in vehicle technology market shares, 1 billion tonnes of GHG can be abated by 2050. The scenarios with conventional fuel provide 5 billion tonnes abated while the low CI versions abate up to 7 billion tonnes of GHGs.

[54] The IPCC relates cumulative GHG emissions to atmospheric concentrations of CO2 (refer to the IPCC Fifth Assessment Report, Summary for Policy Makers) and “Warming Caused by Cumulative Carbon Emissions Towards the Trillionth Tonne”, Nature 458, 1163-1166 (30 April 2009) by Myles Allen et al.

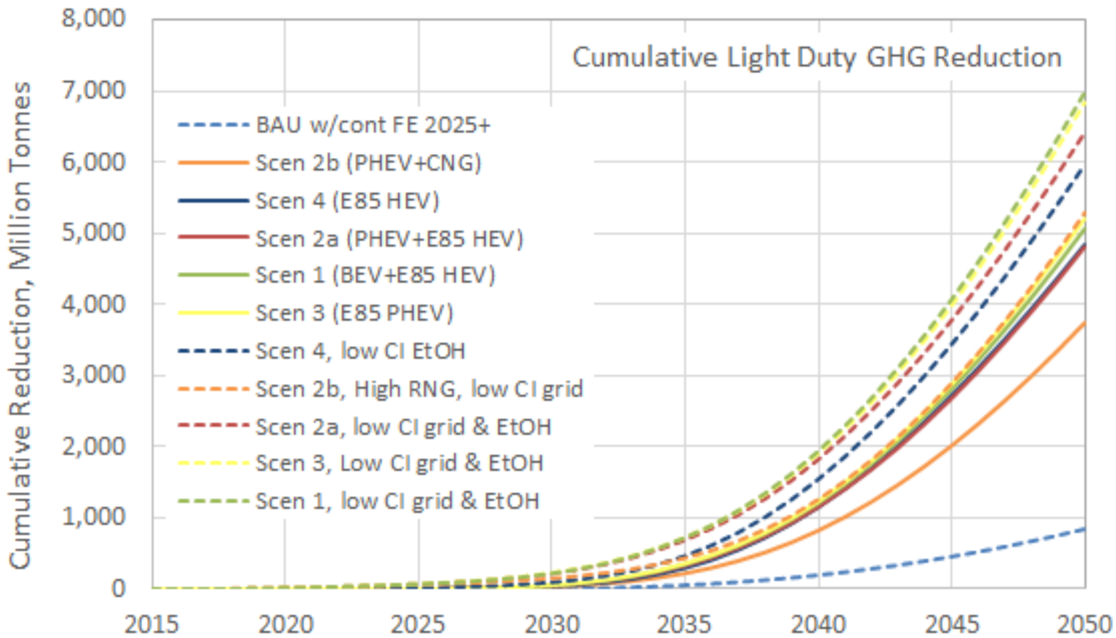

Figure 5-10. Projected U.S. LDA+LDT cumulative GHG reduction relative to BAU.

Figure 5-11 illustrates relative contribution of LDA and LDT to the 2015-2050 cumulative reduction. For Scenario 1 (BEV), the CPP provides an additional 460 million tonnes of reduction over the analysis period. Also for Scenario 1, the low CI grid assumption provides an additional 1340 million tonnes of reduction while low CI ethanol provides an additional 590 million tonnes. For the non-electrification scenario (Scen 4, E85 HEV), low CI ethanol results in an additional 1200 million tonnes of reduction over the analysis period.

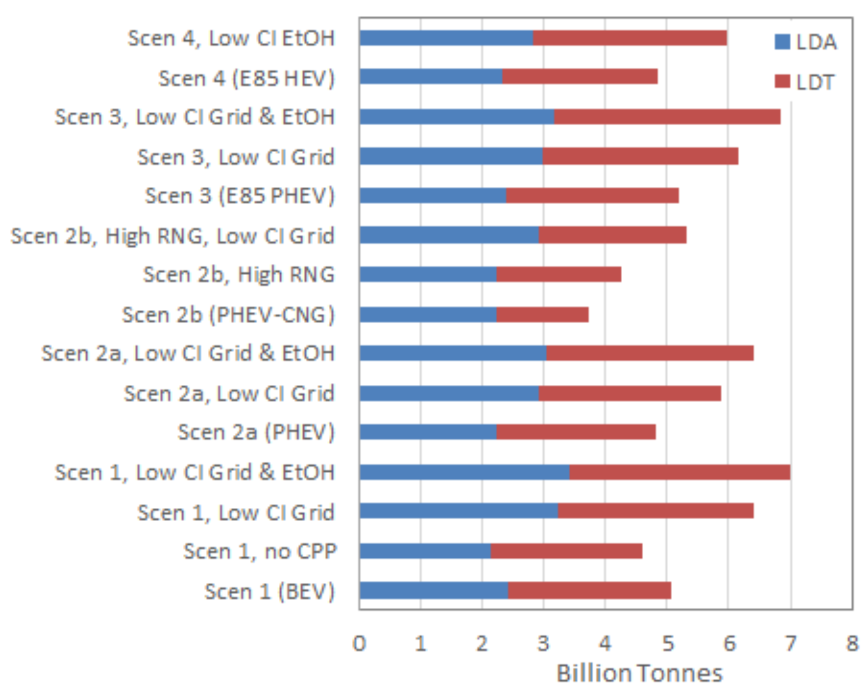

Figure 5-11. Cumulative GHG reductions relative to BAU (2015-2050)

5.4 Change in Fuel Costs

Change in spending on fuel is provided in Figure 5-12. All scenarios experience net reductions in fuel spending. Table 5-2 provides these results in tabular form. Although electricity is more expensive than gasoline and E85, electrification options provide more fuel savings than the E85 HEV scenario because electric vehicles are ~ 3 times more efficient than an ICE. Scenarios with more ethanol use (particularly cellulosic ethanol) and RNG have higher production costs. These higher production costs are assumed to be captured by increased RIN costs and tax credits. The tax credits for cellulosic ethanol, biodiesel and renewable diesel are assumed to expire in 2025 and therefore have minimal impact on results. However, the RIN cost for cellulosic ethanol is assumed to stay at today's value of $1 per gallon higher than conventional ethanol throughout the analysis period. For the low CI version of Scenario 4 (E85 HEV) with significant cellulosic ethanol use, it might be expected for the production costs to decrease through learning and economies of scale. A separate sensitivity case was not run with lower RIN costs, but the conventional ethanol version of Scenario 4 can be used as a least cost estimate (assuming that cellulosic ethanol production is never less expensive than corn ethanol production).

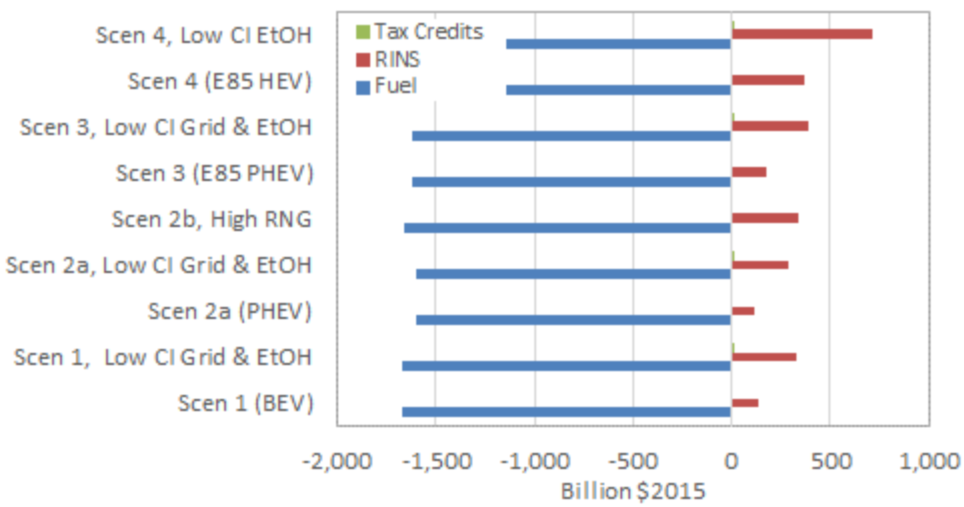

Figure 5-12. Change in cumulative fuel spending relative to BAU (2015-2050).

Table 5-2. Summary of cumulative (2015-2050) fuel costs relative to BAU, Billion $2015

	Change in Fuel Spending	Change in RIN Costs	Change in Tax Credits	Net Change in Fuel Costs
Scen 1 (BEV)	-1,671	140	0	-1,531
Scen 1, Low CI Grid & EtOH	-1,671	330	3	-1,338
Scen 2a (PHEV)	-1597	114	0	-1,483
Scen 2a, Low CI Grid & EtOH	-1597	288	3	-1,306
Scen 2b, High RNG	-1,664	340	0	-1,323
Scen 3 (E85 PHEV)	-1,624	178	0	-1,445
Scen 3, Low CI Grid & EtOH	-1,624	394	3	-1,227
Scen 4 (E85 HEV)	-1,142	371	0	-771
Scen 4, Low CI EtOH	-1,142	714	3	-425

5.5 Change in Vehicle and EVSE Spending

The cumulative increase in vehicle spending relative to the BAU is provided in Figure 5-13. The non-electrification option, Scenario 4, has the lowest incremental vehicle costs. The rest of the scenarios have similar costs, with Scenario 2b having the highest since CNG trucks have a higher incremental cost than E85 HEVs. The income tax credit for plug-in vehicles expires when 200,000 PEVs per manufacturer are sold. Assuming 15 manufacturers, the tax credits will expire once 3 million vehicles have sold. This threshold is crossed in 2018. Since all of the scenarios have the same PEV sales up to 2025, the tax credit does not impact scenario vehicle costs. Individual state rebates for 2025-2050 were not considered here.

The change in cumulative spending on residential EV charging equipment relative to the BAU case is provided in Figure 5-14. Scenario 1 incurs nearly three times the EVSE costs of Scenarios 2 and 3 while Scenario 4 has the same EVSE costs as the BAU.

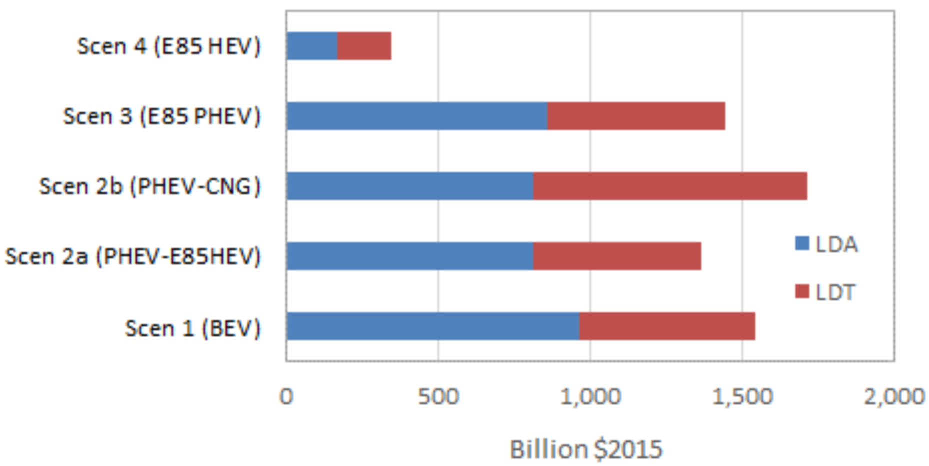

Figure 5-13. Change in cumulative vehicle spending relative to BAU (2015-2050).

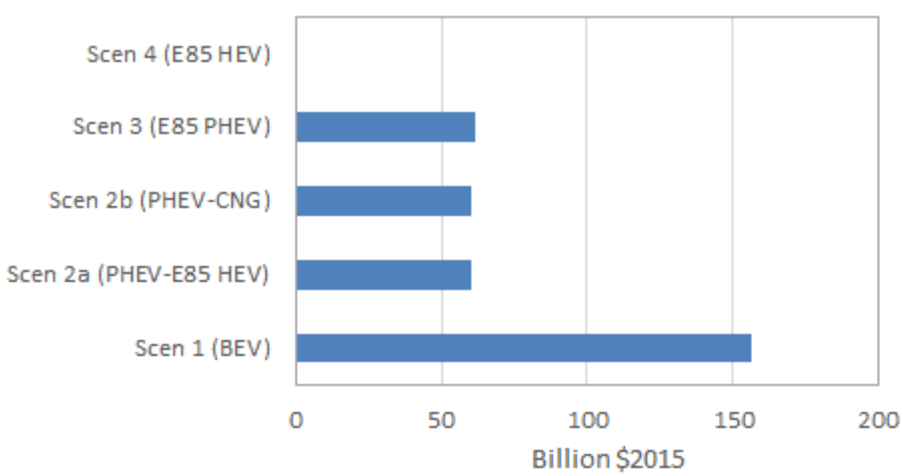

Figure 5-14. Change in cumulative EVSE spending relative to BAU (2015-2050).

5.6 Cost Effectiveness

To compare the scenarios, overall cumulative cost (not discounted) is summarized in Figure 5-15 and Table 5-3. All scenarios provide substantial fuel cost savings relative to the BAU case with similar increases in vehicle spending. EVSE costs are an order of magnitude lower than fuel and vehicle savings and costs. Scenario 4 (E85 HEV) cumulative vehicle costs and fuel savings are both ~ 3 to 5 times lower than the other scenarios. Scenario 2a (PHEV + E85 HEV) and Scenario 4 (E85 HEV) both provide net cumulative savings, however the low CI ethanol version of Scenario 4 dramatically reduces the savings due to increased RIN (higher production) costs.

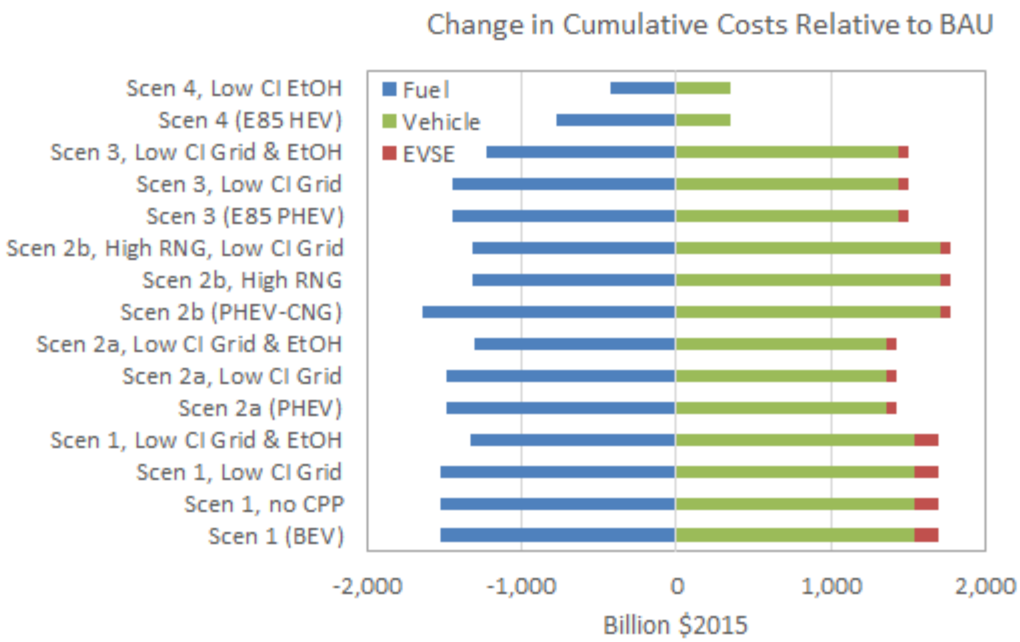

Figure 5-15. Change in U.S. light duty cumulative costs relative to BAU (2015-2050).

Table 5-3. Summary of cumulative (2015-2050) U.S. light duty costs relative to BAU

Billion $2015	Fuel Spending	Vehicle Spending	EVSE (Chargers)	Cumulative Cost
Scen 1 (BEV)	-1,531	1,541	156	166
Scen 1, Low CI Grid & EtOH	-1,338	1,541	156	360
Scen 2a (PHEV-E85 HEV)	-1,483	1,364	60	-58
Scen 2a, Low CI Grid & EtOH	-1,306	1,364	60	118
Scen 2b (PHEV-CNG)	-1,648	1,713	60	125
Scen 2b, High RNG	-1,323	1,713	60	450
Scen 2b, High RNG, Low CI Grid	-1,323	1,713	60	450
Scen 3 (E85 PHEV)	-1,445	1,442	62	58
Scen 3, Low CI Grid & EtOH	-1,227	1,442	62	277
Scen 4 (E85 HEV)	-771	345	0	-426
Scen 4, Low CI EtOH	-425	345	0	-81

The low CI ethanol version of Scenario 2a results in net cumulative costs, also due to increased fuel production (RIN) costs. Despite having the highest vehicle costs, Scenario 2b provides the most fuel cost savings (due to low CNG prices relative to gasoline and ethanol), resulting in a fairly low net cost. The high RNG version of Scenario 2b substantially increases fuel production (RIN) costs, yielding the highest net cost of all the scenarios.

Cost effectiveness, defined as cumulative costs relative to the BAU divided by cumulative GHG reductions relative to the BAU is presented in Figure 5-16. Cost effectiveness ranges from a savings of $87 per tonne for Scenario 4 to a cost of $104 per tonne for Scenario 2b with high RNG shares.

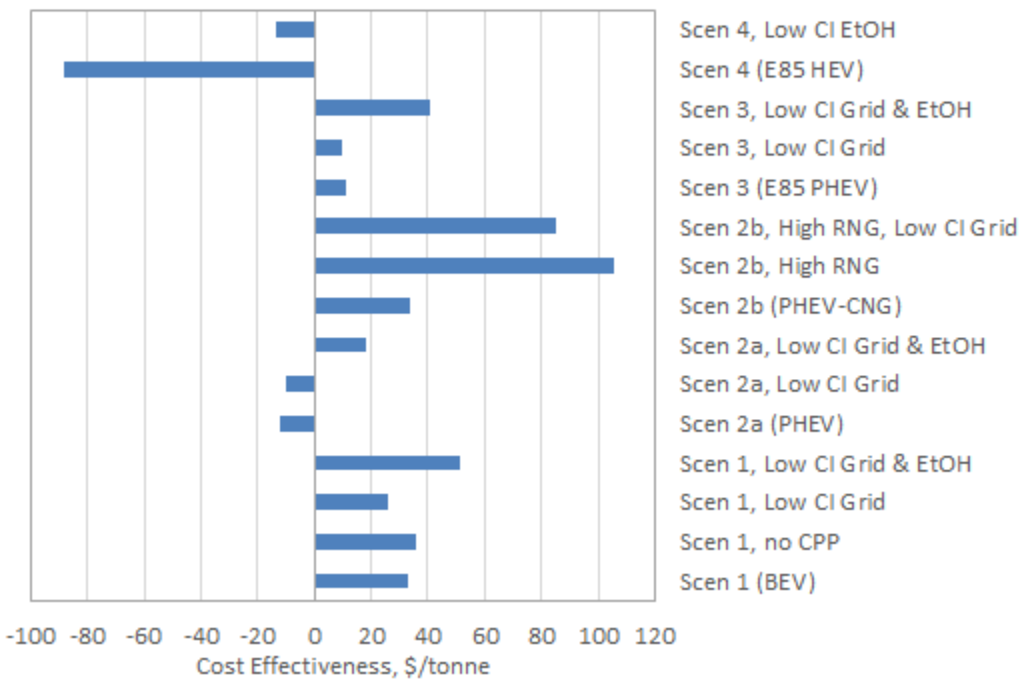

Figure 5-16. U.S. Light duty cost effectiveness (cumulative cost/cumulative reduction).

Cost effectiveness is plotted as a function of GHG reduction in Figure 5-17. Scenario 4 (E85 HEV) with conventional ethanol (- symbol in the figure) is an interesting case since it provides modest GHG reduction at a significant cost savings relative to the BAU scenario. Consumer spending on vehicles is much lower than other scenarios since it does not rely on electrification. It does, however, require ethanol volumes (please refer to Figure 5-5) of more than 50 BGY, more than three times current consumption levels. While this scenario has minimal vehicle technology risk, it carries risk in terms of ethanol supply.

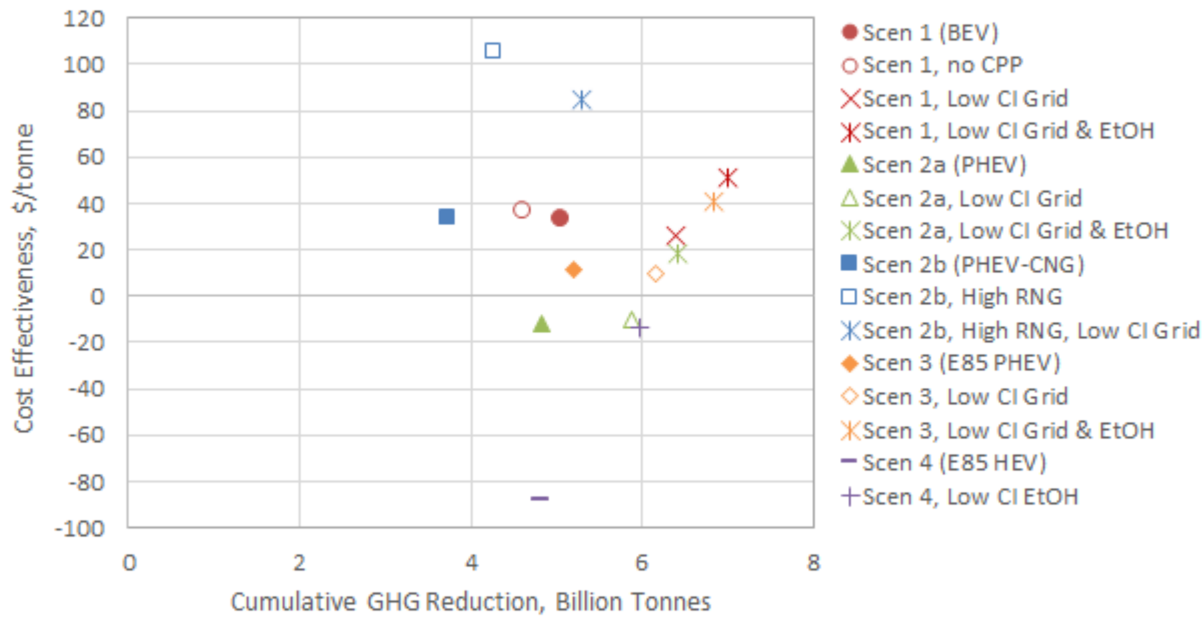

Figure 5-17. Cost effectiveness vs cumulative reduction for U.S. light duty fleet.

Scenario 4 with cellulosic ethanol (+ symbol) provides 20% more GHG reduction than its conventional ethanol counterpart, with significantly higher (though still negative) net cost effectiveness. However, this scenario requires large amounts of cellulosic ethanol, which is even more of a risk than Scenario 4 with conventional ethanol. It is important to remember that the production cost premium for cellulosic ethanol, is approximated here by the difference in current cellulosic RIN price and conventional ethanol RIN price and this premium is assumed to stay at current levels through 2050. However, a scenario that utilizes significant quantities of cellulosic ethanol would likely experience a decrease in production costs due to learning and economies of scale. In the limit, the price could decrease to the price of corn ethanol, essentially having the same cost as Scenario 4 with conventional ethanol (a cost effectiveness of -$88 per tonne). A production price decrease by even half would greatly increase the attractiveness of this scenario, but the technical risk still remains.

The other two scenarios with cumulative cost savings are Scenario 2a and 2a with a low CI grid (green symbols). It is assumed here that a low CI grid has the same retail electricity price as the AEO forecast grid mix. The low CI grid provides substantially more GHG reduction, than the AEO grid. The addition of low CI ethanol increases costs and GHG reduction. Cellulosic ethanol volumes are markedly lower than Scenario 4 (10 vs 26 BGY), though still significant.

The orange symbols in Figure 5-17 are for Scenario 3 (E85 PHEV). This scenario provides more GHG reduction compared to reductions to Scenario 2a (PHEV), but at a higher cost (though costs are still reasonable). The difference in cost is due to higher prices for E85 relative to gasoline on an energy basis (Figure 2-26). Scenario 3 carries the risk of supplying significant amounts of ethanol (30 BGY total ethanol for Scen 3 vs 20 BGY for Scen 2a).

Scenario 1 (BEV) is shown with red symbols in Figure 5-17. The BEV centric scenario is more expensive than Scenarios 2a and 3 because BEVs are more expensive than PHEVs, especially since in the later years this analysis assumes more BEV200 than BEV100. The low CI grid option provides a large benefit for Scenario 1 while the absence of the CPP results in ~ 11% less cumulative GHG reduction. Scenario 1 is more affected by grid mix than the other scenarios; Scenarios 2 and 3 would likely experience a ~5% reduction in cumulative GHG emissions without the CPP.

Finally, Scenario 2b, which is the same as Scenario 2a except that light truck E85 HEVs are replaced by CNG trucks, provides the lowest cumulative GHG reduction of all the scenarios. The case with large volumes of RNG provides slightly better GHG reductions, but at a much higher cost due to higher fuel production costs (RINS). The addition of low CI grid brings GHG reductions to moderate level.

Table 5-4 ranks the results by assigning a score in each of four categories: GHG reduction, cost effectiveness, vehicle technology risk, and fuel supply risk. Each of these categories is given equal weight to come up with a single score for each scenario. The simplistic scoring assumes that a red score neutralizes a green score and that blue scores are neutral.

One option received the "best" overall score of 5. Scenario 3 (E85 PHEV) with a low CI grid provides high GHG reduction at low cost per tonne with medium vehicle technology and fuel supply risk. Six scenarios received a score of four: Scenario 1 (with and without low CI grid) and Scenario 2a with and without a low CI grid, Scenario 4 with conventional ethanol and Scenario 4 with low CI ethanol. Nearly half of the options considered resulted in a high score; this indicates that there is no preferred solution – electrification and dedicated biofuel vehicles both yield beneficial results.

Table 5-4. Scenario ranking based on four criteria

	GHG Reduction	Cost ($/tonne)	Vehicle Technology Risk	Fuel Supply Risk	Overall Score
Scen 1 (BEV)	Medium	Medium	Medium	Low	4
Scen 1, no CPP	Low	Medium	Medium	Low	3
Scen 1, Low CI Grid	High	Medium	Medium	Medium	4
Scen 1, Low CI Grid & EtOH	High	High	Medium	High	2
Scen 2a (PHEV)	Low	Low	Medium	Low	4
Scen 2a, Low CI Grid	Medium	Low	Medium	Medium	4
Scen 2a, Low CI Grid & EtOH	High	Medium	Medium	High	3
Scen 2b (PHEV-CNG)	Low	Medium	Medium	Medium	2
Scen 2b, High RNG	Low	High	Medium	High	0
Scen 2b, High RNG, Low CI Grid	Medium	High	Medium	High	1
Scen 3 (E85 PHEV)	Medium	Medium	Medium	Medium	3
Scen 3, Low CI Grid	High	Low	Medium	Medium	5
Scen 3, Low CI Grid & EtOH	High	Medium	Medium	High	3
Scen 4 (E85 HEV)	Low	Low	Low	Medium	4
Scen 4, Low CI EtOH	Medium	Low	Low	High	4

The scenarios with the lowest scores were Scenario 2b (PHEV+LT CNG) with and without low CI fuels and Scenario 1 (BEV) with a low CI grid and low CI ethanol. Scenario 2b received a 2 because of low GHG reductions. Scenario 2b with low CI fuels had improved GHG reductions but higher cost fuel and higher fuel supply risk. Scenario 1 with low CI grid and ethanol had high GHG reductions, but high cost and high fuel supply risk. The additional risk of two low CI fuels negates the improvement in GHG reduction and increases cost.

5.7 Sensitivity Tests

The results presented above included some sensitivity tests (effect of grid CI, effect of carbon CI, effect of CNG CI, and effect of CPP implementation). This section provides the results of four additional sensitivity tests performed – the effects of electricity price, fuel production costs (as increased RIN costs), assumed share of PHEV eVMT, and light auto BEV fuel economy on GHG reduction and costs.

The electricity price projection used in the main analysis assumes that the price of electricity for a 70% non-fossil grid is the same as the price for the AEO grid mix. Because it is unknown what the impact of a 70% non-fossil grid might be on retail prices, the model was run assuming a 20% increase and a 20% decrease in electricity prices beginning in 2025. Since BEVs are the most impacted by electricity price, the electricity price impact was tested on Scenario 1. Sensitivity of cost effectiveness to electricity prices for Scenario 1 with a low CI grid is shown by the vertical error bars on the × symbol in Figure 5-18. Changing the electricity price by +/- 20% changes the cost effectiveness by 68%. In this scenario, the cost effectiveness increases to 43 $/tonne (still reasonable) for a 20% increase in electricity price and decreases to a very attractive 8 $/tonne for a 20% decrease in electricity price.

The other cost assumption evaluated is the premium paid for cellulosic ethanol. The base analysis assumes that current fuel production costs (RIN values) persist through the analysis period. Currently, the premium paid for cellulosic ethanol over conventional ethanol is $1.00. For the sensitivity test, it was assumed that fuel production costs (D3 RIN price) decreases to a $0.50 premium relative to conventional ethanol by 2025 and remains there through 2050. Scenario 4 (E85 HEV) using low CI ethanol is the scenario most impacted by higher cellulosic ethanol production costs (D3 RIN prices), so we have performed the sensitivity test on this case.

The impact of higher cellulosic production costs (RIN premiums) on the low CI E85 HEV scenario is shown by the vertical error bar on the + symbol in Figure 5-18. Reducing the fuel production cost premium relative to conventional ethanol to $0.50 per gallon reduces cumulative fuel spending by $180 billion over the analysis period. This improves cost effectiveness by 225%, from a savings of 13 $/tonne to a savings of nearly 44 $tonne. A reduction in cellulosic RIN premium would only occur if cellulosic production is able to increase in an orderly fashion without supply constraints.

The sensitivity of results to the assumed share of miles that PHEVs operate on electricity as opposed to gasoline or E85 is tested. For the base case, it is assumed that eVMT share for light autos is 74.5% and the light truck eVMT share is 55%. For the sensitivity test, we assume the eVMT share drops to 60% and 40% for light autos and light trucks, respectively. This test is performed on Scenario 2a, with the maximum penetration of PHEVs and is compared to a BAU with the same eVMT assumptions. The sensitivity of the PHEV scenario to assumptions regarding eVMT shares is shown by the error bars attached to the ▲ symbol. Decreasing the eVMT share reduces cumulative GHG reduction by 9 percent, and more than doubles cost ($/tonne) due to increased use of gasoline and fixed vehicle spending.

The sensitivity of analysis results on projected LDA BEV fuel economy is also tested. There was a wide range of projections for LDA fuel economy, and the analysis values selected might be considered conservative (low). Alternative BAU and Scenario 1 cases are run with slightly higher fuel economy values based on the Argonne C2G analysis. The 2025 BEV100 certification value increases from the analysis value of 162 mpgge to the Argonne C2G value of 172 mpgge, a 7% increase. The BEV200 value is increased proportionally. As can be seen in Figure 5-15, a 7% improvement in BEV fuel economy has a very small impact on both cumulative GHG reductions and cost effectiveness.

Although these sensitivities were tested on scenarios where they would have maximum impact, it can be concluded that cost effectiveness results are quite sensitive to assumptions regarding fuel price and technology performance while cumulative GHG reductions are less sensitive.

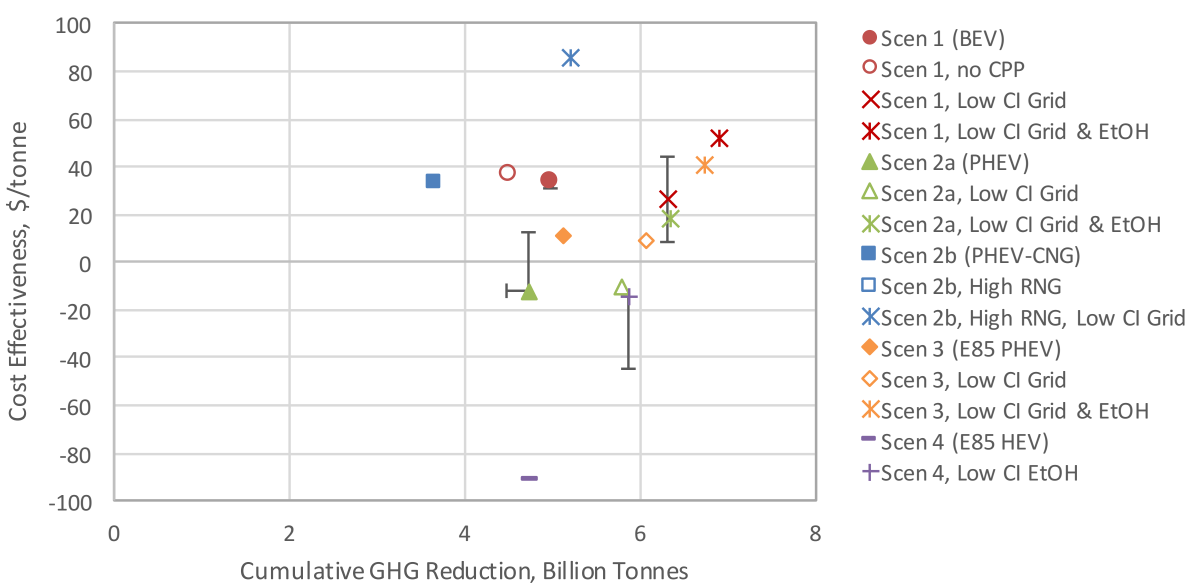

Figure 5-18. Cost effectiveness vs reduction with sensitivity case error bars.

6. Scenario Analysis – CA Fleet

For the California light duty fleet, the objective of this study is to determine if an 80% GHG emission reduction from 1990 levels is possible, and if so, what is needed in terms of vehicle technology penetration and fuel carbon intensity. To answer these questions, scenarios were constructed to maximize the market penetration of each promising low GHG emission technology and fuel type identified in Section **Error! Reference source not found.**. Because the current CAFE standards end in 2025, the scenarios are designed to increase low GHG vehicle and fuel technologies above BAU levels beginning in 2026. The midterm report by EPA, ARB and NHSTA indicated that the 2025 standards could largely be achieved with advanced gasoline ICE vehicles. Consequently, by 2025 the majority of new car sales are still projected to be gasoline ICE vehicles. To continue GHG reductions, vehicle platform electrification or low CI fuels or their combination will be required. Therefore, scenarios were developed with various levels of electrification and low CI fuels to meet the goals of 80% reduction in 2050. The following sections provide a description of the scenarios evaluated and the analysis results.

6.1 Scenario Definition

In parallel to the U.S. analysis, four main scenarios were considered, one for each key vehicle technology (BEV, PHEV, E85 PHEV, E85 HEV). While total vehicle sales in the scenarios remain the same as in the BAU case, each scenario increases the market share of one of the four key technologies at the expense of gasoline ICE vehicles. Maintaining total fleet population and VMT assumptions, the altered technology market shares cause changes in fuel consumption quantity and type, resulting in lower overall GHG emissions. Table 6-1 provides the new vehicle market share values in 2050 for each scenario. Note that the California BAU has significantly higher market share of alternative fuel vehicles than the U.S. average analysis. Only 67% of 2050 LDAs is forecast to be gasoline ICE compared to 85% for the U.S. average. This is due to California's ZEV Mandate, which requires sales of BEVs, PHEVs, and FCVs.

For purposes of scenario definition, the following guidelines were used to adjust new vehicle market shares:

- To ensure a fair comparison between scenarios, gasoline ICE market shares in each scenario were decreased to 2% for LDA and LDT.
- All other technology shares were maintained at BAU levels unless otherwise noted.
- Because BEV market share is limited by homes with EVSE access, it is assumed that maximum BEV market share is 70%, and maximum PHEV market share is 80% for LDA.
- Because electrification is not currently compatible with towing capability, it was assumed that maximum LDT market share for BEVs and PHEVs is 43%. To maximize LDT alternative vehicles, PHEVs and BEVs were supplemented with E85 HEVs or NGVs.
- It is assumed that E85 HEVs have a faster ramp up to goal market penetration than plug-in options because incremental price is lower, range is not an issue, and charging capability is not required.

Figure 6-1 and Figure 6-2 illustrate the assumed California LDA and LDT new vehicle market shares for Scenario 1. Please refer to Appendix E for corresponding figures for California Scenarios 2-4.

Table 6-1. New vehicle market share assumptions for California analysis scenarios.

Scenario	2050 LDA Market Share	2050 LDT Market Share
BAU	67% Gasoline ICE 1% Diesel 14% Gasoline HEV 5% BEV 10% PHEV 3% FCV	85% Gasoline ICE 1% Diesel 1% Gasoline HEV 2% BEV 6% PHEV 3% FCV 1% CNG
1. Max BEV	70% BEV 2% Gasoline ICE All others BAU	43% BEV 43% E85 HEV 2% Gasoline ICE All others BAU
2a. Max PHEV/E85 HEV	75% PHEV 2% Gasoline ICE All others BAU	45% PHEV 45% E85 HEV 2% Gasoline ICE All others BAU
2b. Max PHEV/CNG	Same as 2a	45% PHEV 46% CNG 2% Gasoline ICE All others BAU
3. Max E85 PHEV	65% E85 PHEV 2% Gasoline ICE All others BAU	43% E85 PHEV 43% E85 HEV 2% Gasoline ICE All others BAU
4. Max E85 HEV	65% E85 HEV 2% Gasoline ICE All others BAU	83% E85 HEV 2% Gasoline ICE All others BAU

It is doubtful that the GHG reduction scenarios will take place without some kind of regulatory driver such as continued CAFE pressure and/or a federal ZEV Mandate. It is therefore assumed for the GHG reduction scenarios that auto manufacturers will continue improving fuel economy of existing technologies for 2025-2050. Please refer back to Section 0 for the assumed improvement in vehicle fuel economy for the GHG reduction scenarios. The BAU case assumes no improvement in fuel economy for 2025-2050.

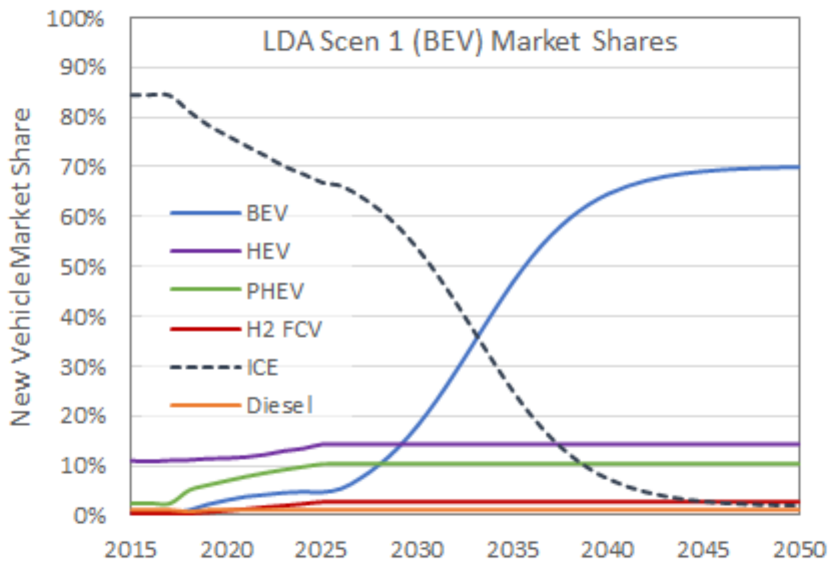

Figure 6-1. California LDA assumed new vehicle market shares for Scenario 1.

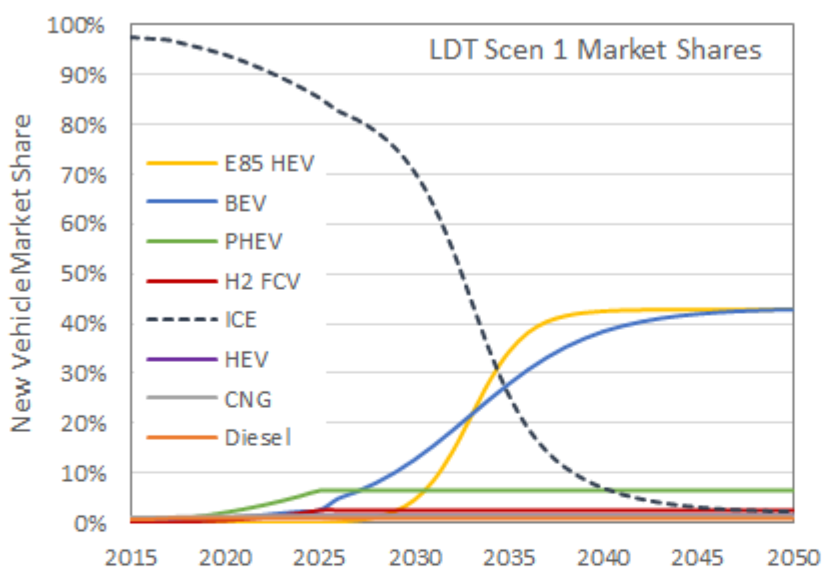

Figure 6-2. California LDT assumed new vehicle market shares for Scenario 1.

The scenarios were also evaluated with the following fuel mix assumptions:

- Scenarios 1-3 (plug-in technologies) were evaluated with two sets of CI values: California BAU grid mix and 70% non-fossil grid mix.
- All scenarios were evaluated with the base case ethanol mix and a low CI mix (Please see Section 2.6).
- Scenario 2b was evaluated with base case RNG shares (Section 2.6). Because the base case has a high fraction of RNG, a high RNG case was not evaluated.

6.2 Fuel Volumes

One key metric of this analysis is fleet energy consumption. Projected light duty fuel use is provided in Figure 6-3. Due to improving fuel economy, BAU fuel use declines steadily through 2030 as more efficient vehicles replace older models. Fuel consumption holds steady from 2030 to 2040 and then begins to increase through 2050 due to increasing vehicle populations. For the BAU case with continuing fuel economy improvement (but no change in technology market shares), fuel consumption remains constant from 2040 through 2050. The maximum electrification cases (1, 2a, 3) all result in a ~68 to 71% reduction in fuel use between 2015 and 2050. Scenario 2b is slightly lower at 67%. Electric vehicles are ~ 3 times more fuel efficient than conventional vehicles. Scenario 4, the non-electrification scenario yields a 62% reduction in fuel use. Figure 6-4 illustrates predicted decreases in petroleum consumption. The BAU experiences a 43-48% reduction while the scenario reductions range from 82-87%.

Figure 6-5 illustrates the projected total ethanol consumption for each of the scenarios. For the BAU, ethanol use is expected to decrease 43% from 2015 levels. With continued fuel economy improvements from 2025-2050, total ethanol use is projected to decrease by 48% to under 800 MGY in 2050. Scenario 2b results in a 84% decrease in ethanol consumption (230 MGY in 2050) due to the high market share of light truck CNG vehicles. Scenarios 1 and 2a experience 18% and 10% decreases in ethanol use; Scenario 1 has more light auto E85 HEVs than scenario 2a since the maximum penetration of BEVs was set at 70% as opposed to the maximum PHEV penetration of 80%.

Scenario 3, focusing on E85 PHEVs is predicted to have a more than 50% increase compared to current ethanol consumption. Finally, the non-electrification scenario (Scenario 4) requires a tripling of ethanol consumption to nearly 4.5 BGY.

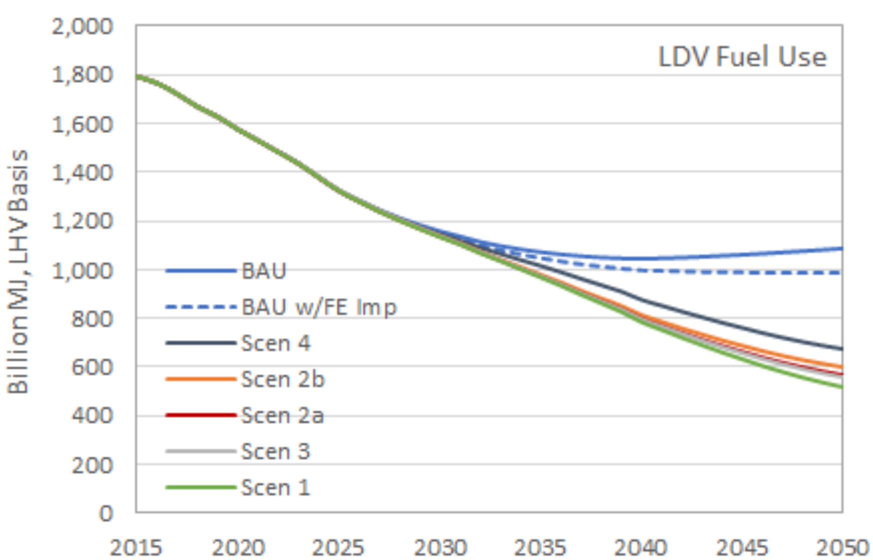

Figure 6-3. Projected California total light duty fuel use.

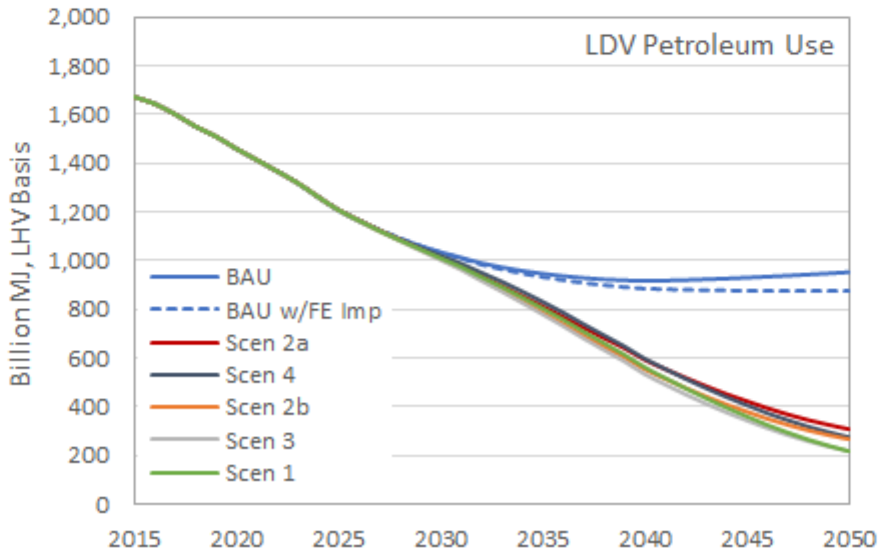

Figure 6-4. Projected California light duty petroleum consumption.

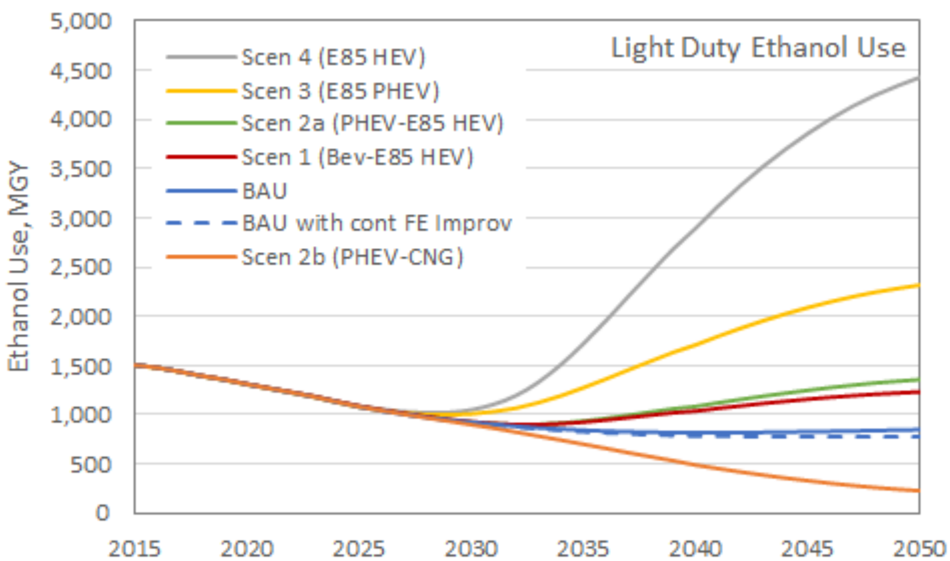

Figure 6-5. Projected California light duty ethanol volumes for BAU and scenarios.

Finally, the projected cellulosic ethanol consumption is shown in Figure 6-6. The BAU assumes that 400 MGY will be consumed, consistent with ARB's most recent LCFS compliance projection[55]. Scenario 4 with low CI ethanol requires the most cellulosic ethanol, up to 3 BGY by 2050. According to the Billion Ton Update mentioned above, this consumption level is well within domestic production potential.

[55] LCFS Update to Illustrative Compliance Scenarios, April 2015

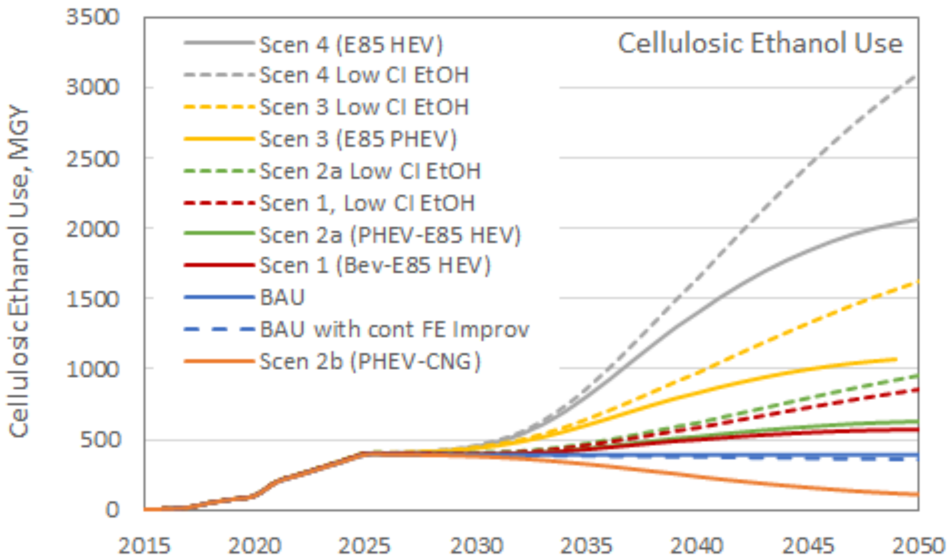

Figure 6-6. Projected California light duty cellulosic ethanol volumes.

Figure 6-7 illustrates the anticipated RNG volumes for the BAU and scenarios. Scenario 2b assumes a large penetration CNG light trucks and requires over 1 BGYde of RNG for the light fleet by 2050. ARB has projected 450 MGYde of RNG for the entire on-road fleet by 2025; Scenario 2b would result in total on-road demand (light, medium and heavy duty) of over 1.5 BGYde by 2050. This is well under what is thought to be the U.S. commercial potential (please refer to footnote 33) by the American Gas Association, but more than the potential recently estimated by UC Davis researchers (Footnote above).

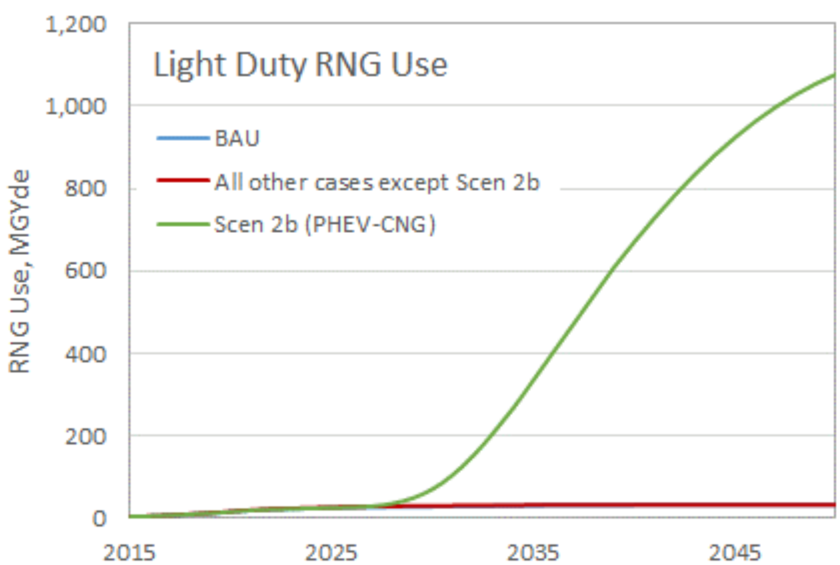

Figure 6-7. Projected California light duty RNG volumes.

6.3 GHG Emission Reduction

Figure 6-8 and Figure 6-9 provide LDA and LDT GHG emissions over time for the BAU and each of the scenarios. As discussed in Section 4.2, several individual vehicle and fuel technologies considered achieve the 2050 goal of 80% GHG reduction. However, as shown in Figure 6-10, even with aggressive market share assumptions for the cleanest technologies, the light fleet does not achieve the 2050 goal in any of the scenarios. More time is needed for older vehicles to retire and be replaced with more efficient less carbon intensive options or the cleaner options have to be introduced sooner. The figure indicates that all of the base scenarios yield similar GHG emission levels in 2050. The low CI options are shown with dashed lines. The BEV and E85 PHEV options provide slightly more reduction than the PHEV and E85 HEV options.

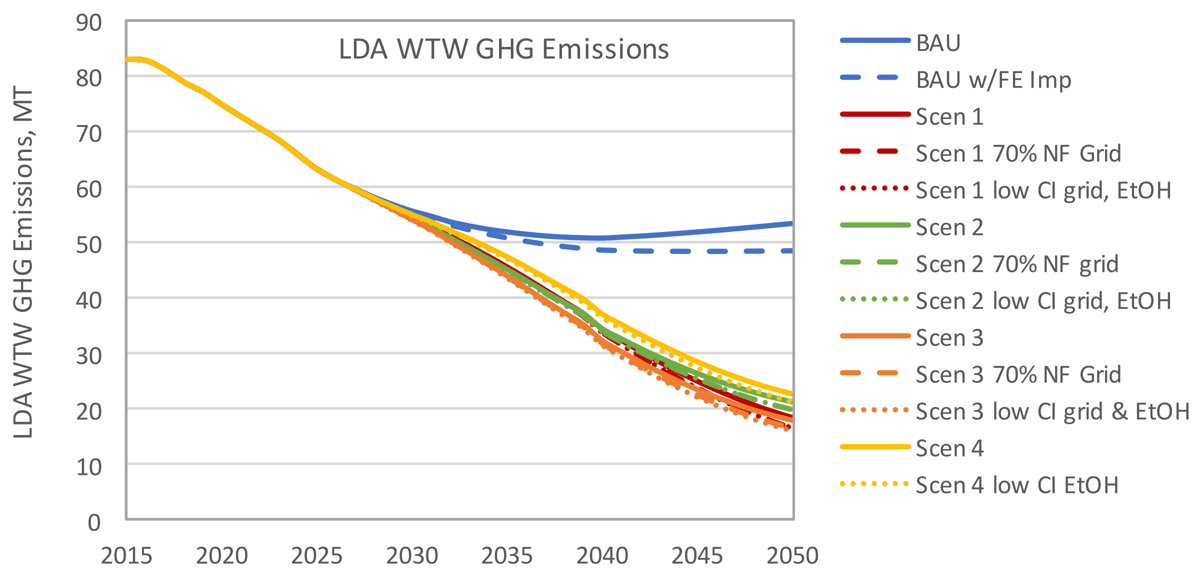

Figure 6-8. Projected California LDA GHG emissions.

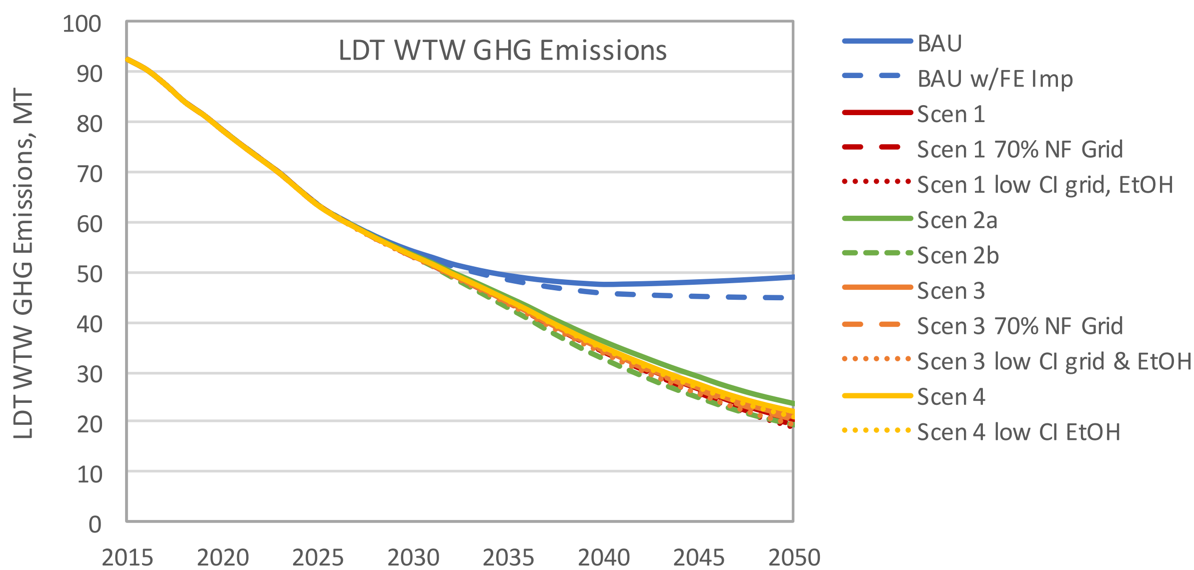

Figure 6-9. Projected California LDT GHG emissions.

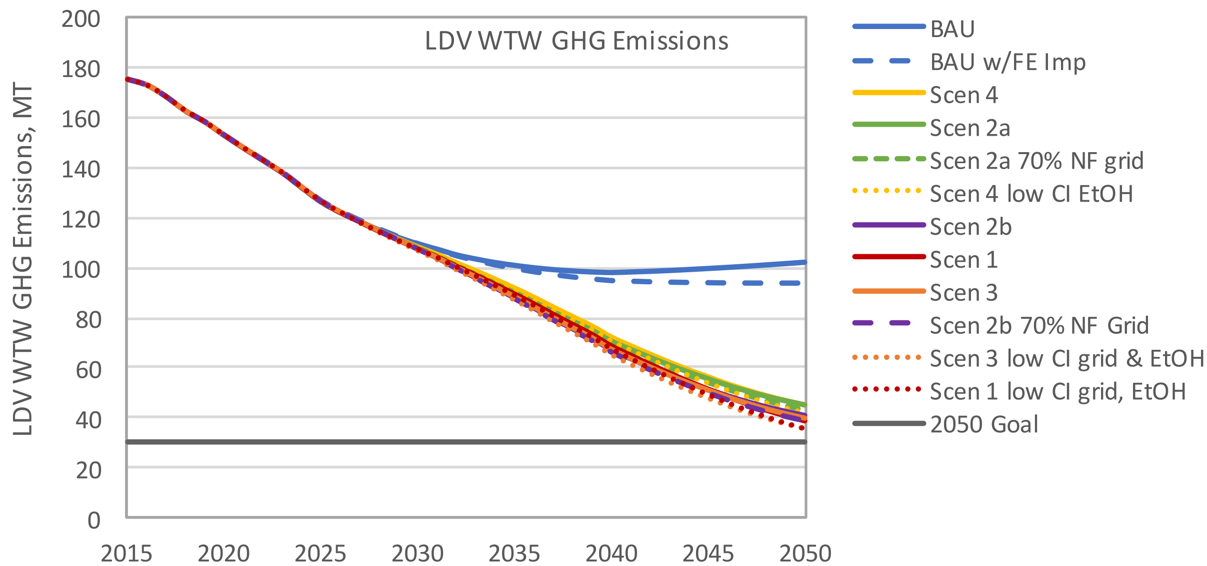

Figure 6-10. Projected California total light duty GHG emissions.

Because GHG emissions accumulate in the atmosphere, it is appropriate to compare the scenarios on a cumulative reduction basis. Figure 6-11 illustrates the cumulative GHG reductions (2015-2050) for each scenario. Scenarios 1, 2b and 3 offer similar cumulative reductions. Scenario 2a with E85 HEVs does not provide as much reduction as Scenario 2b with CNG operating on high levels of RNG. Scenario 4 provides similar reductions to Scenario 2a.

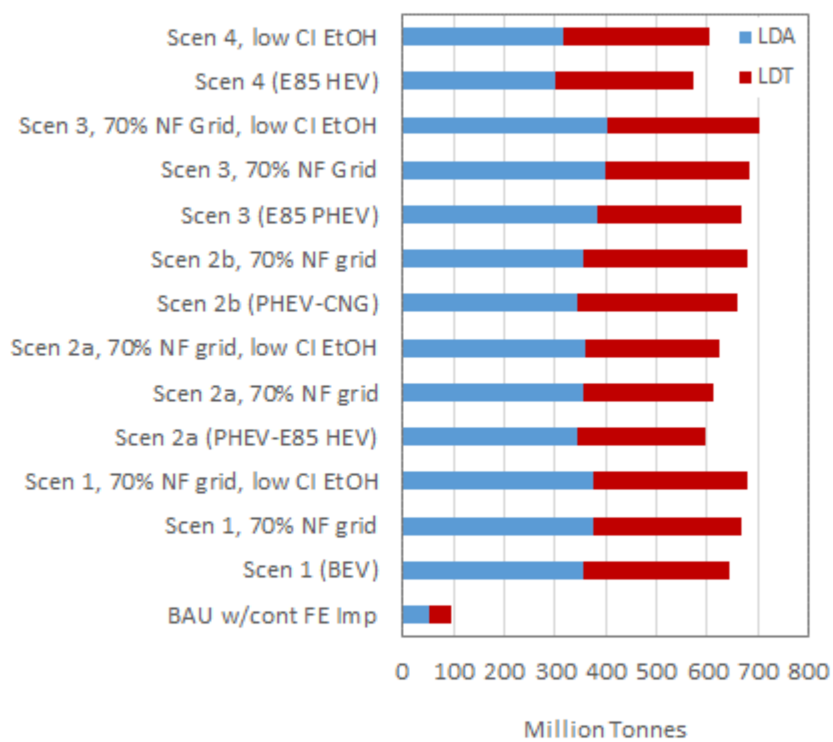

Figure 6-11. Cumulative California GHG reductions relative to BAU (2015-2050)

6.4 Change in Fuel Costs

Change in spending on fuel is provided in Figure 6-12. Electrification options provide more fuel savings than the E85 HEV option. The BEV scenario with factors of 0.8 and 1.2 applied to electricity costs are also shown. A 20% change in electricity price has a 10% impact on cumulative fuel costs. Scenarios with more ethanol use (particularly cellulosic ethanol) and RNG have higher RIN costs. The tax credits for cellulosic ethanol, biodiesel and renewable diesel are assumed to expire in 2025 and therefore have no impact on results. All scenarios experience net reductions in fuel spending. Table 6-2 provides these results in tabular form.

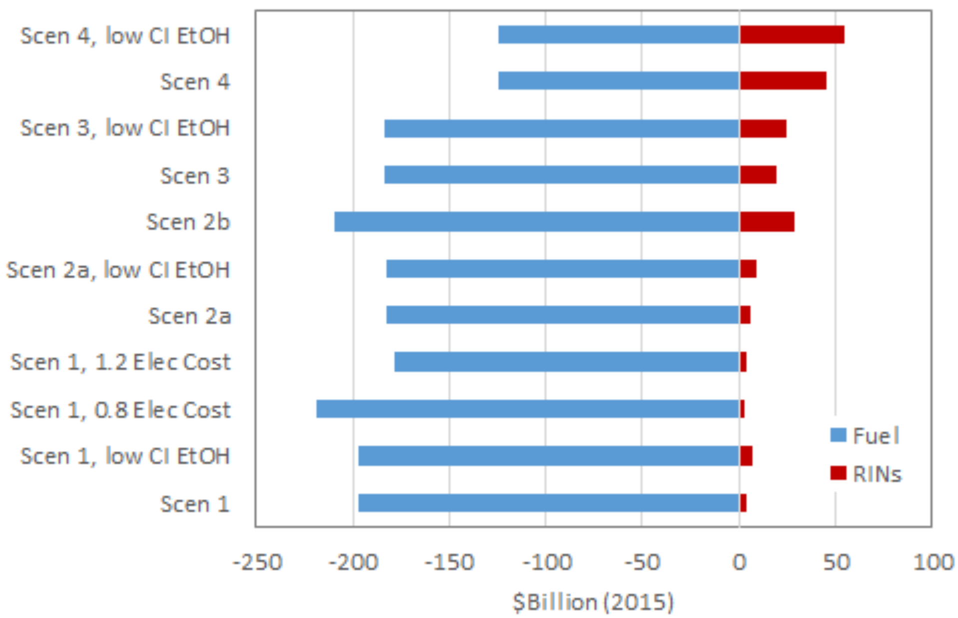

Figure 6-12. Change in California cumulative fuel spending relative to BAU (2015-2050).

Table 6-2. Summary of California cumulative (2015-2050) fuel costs relative to BAU

Billion $2015	Change in Fuel Spending	Change in RIN Costs	Net Change in Fuel Costs
Scen 1 (BEV)	-197	4	-193
Scen 1, low CI EtOH	-197	7	-190
Scen 1, 0.8 Electricity Cost	-218	3	-215
Scen 1, 1.2 Electricity Cost	-178	4	-174
Scen 2a (PHEV-E85 HEV)	-182	6	-177
Scen 2a, low CI EtOH	-182	9	-174
Scen 2b (PHEV-CNG)	-210	29	-180
Scen 3 (E85 PHEV)	-184	20	-164
Scen 3, low CI EtOH	-184	25	-159
Scen 4 (E85 HEV)	-125	46	-79
Scen 4, low CI EtOH	-125	55	-70

6.5 Change in Vehicle and EVSE Spending

The cumulative increase in vehicle spending relative to the BAU is provided in Figure 6-13. The non-electrification option, Scenario 4, has the lowest incremental vehicle costs. The rest of the scenarios have similar costs, with Scenario 2b having costs nearly as high as the BEV scenario (due to higher natural gas light duty truck costs). The income tax credit for plug-in vehicles expires when 200,000 PEVs per manufacturer are sold. Assuming 15 manufacturers, the tax credits will expire once 3 million vehicles have sold. This threshold will likely be crossed in 2018. Since all of the scenarios have the same PEV sales up to 2025, this tax credit does not have an impact on scenario vehicle costs.

The change in cumulative spending on residential EV charging equipment relative to the BAU case is provided in Figure 6-14. Scenario 1 incurs nearly three times the EVSE costs of Scenarios 2 and 3 while Scenario 4 has the same EVSE costs as the BAU. Note that EVSE costs are low relative to other costs.

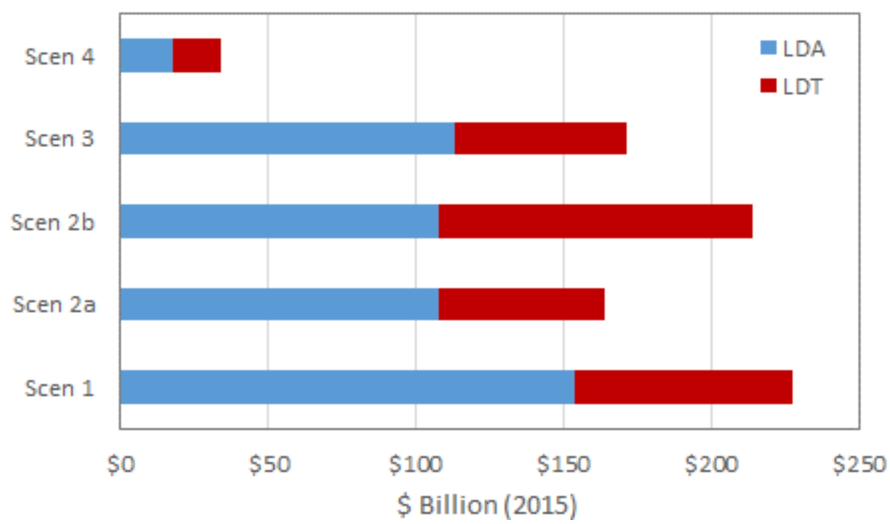

Figure 6-13. Change in California cumulative vehicle spending relative to BAU (2015-2050).

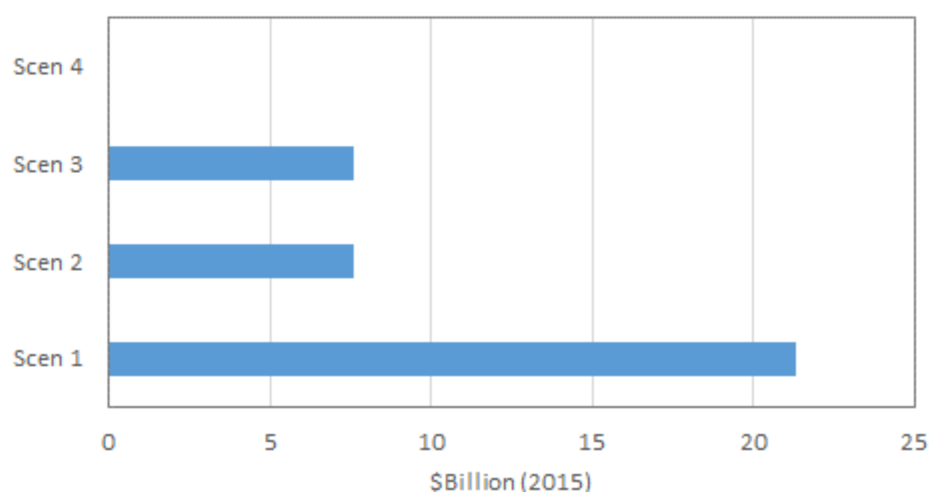

Figure 6-14. Change in California EVSE spending relative to BAU (2015-2050).

6.6 Cost Effectiveness

To compare the scenarios, overall cumulative cost (non-discounted) is summarized in

Figure **6-15** and Table 6-3. All scenarios provide substantial (non-discounted) fuel cost savings relative to the BAU case with similar increases in vehicle spending. EVSE costs are more than an order of magnitude lower than fuel and vehicle savings and costs. Scenario 4 (E85 HEV) cumulative vehicle costs are approximately 5 times lower than the other scenarios because HEVs are less expensive than the BEVs and PHEVs that are the focus of the other scenarios. However, fuel savings are less than half that of the other scenarios because the HEVs do not have the higher efficiency and lower electricity costs of the BEV and PHEV scenarios. Scenario 2a and Scenario 4 both provide net cumulative savings.

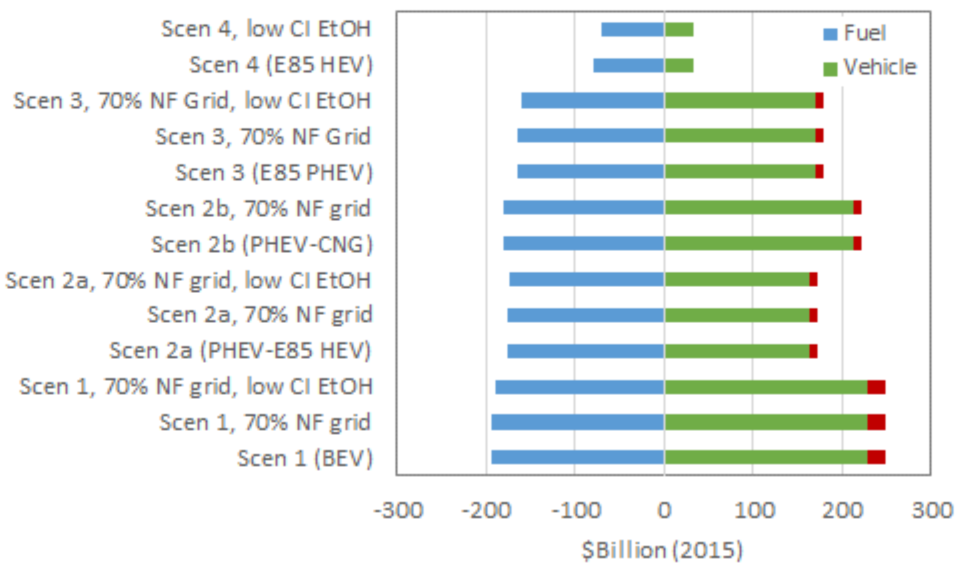

Figure 6-15. Change in California cumulative costs relative to BAU (2015-2050).

Table 6-3. Summary of California cumulative (2015-2050) total costs relative to BAU

Billion $2015	Fuel Spending	Vehicle Spending	EVSE (Charger)	Cumulative Cost
Scen 1 (BEV)	-192.8	228	21	56.1
Scen 1, 70% NF grid, low CI EtOH	-189.9	228	21	59.1
Scen 2a (PHEV-E85 HEV)	-176.7	164	8	-5.2
Scen 2a, 70% NF grid, low CI EtOH	-173.5	164	8	-2.0
Scen 2b (PHEV-CNG)	-180.3	214	8	41.1
Scen 3 (E85 PHEV)	-164.2	171	8	14.5
Scen 3, 70% NF Grid, low CI EtOH	-159.0	171	8	19.7
Scen 4 (E85 HEV)	-78.7	34	0	-44.7
Scen 4, low CI EtOH	-69.5	34	0	-35.4

Cost effectiveness, defined as cumulative costs relative to the BAU divided by cumulative GHG reductions relative to the BAU, is presented in Figure 6-16. Cost effectiveness ranges from a savings of $80 per tonne for Scenario 4 to a cost of $87 per tonne for Scenario 1.

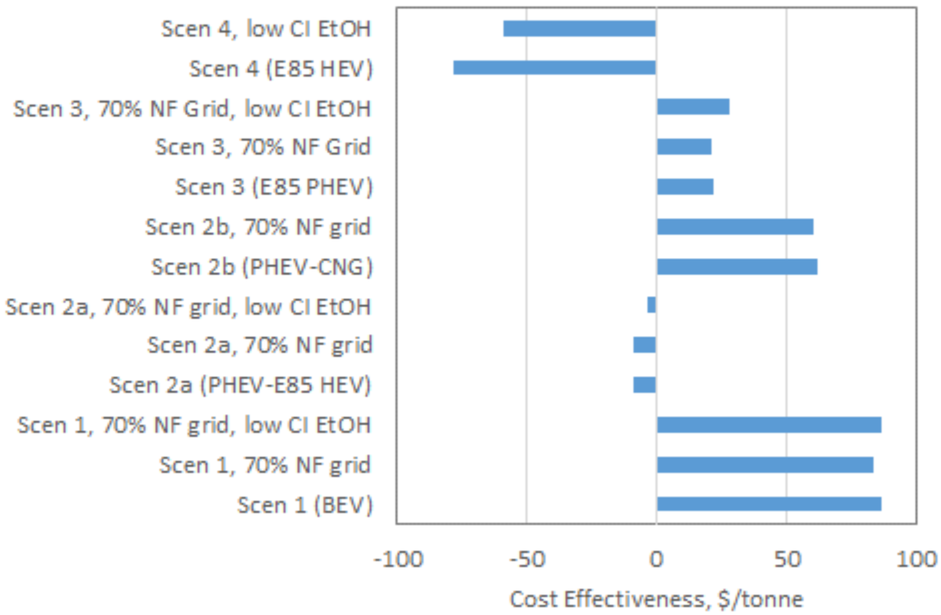

Figure 6-16. California cost effectiveness (cumulative cost / cumulative reduction).

Cost effectiveness is plotted as a function of GHG reduction in Figure 6-17. Scenario 4 with conventional ethanol is an interesting case since it provides modest GHG reduction at a significant cost savings relative to the BAU scenario. Consumer spending on vehicles is much lower than other scenarios since it does not rely on electrification. It does, however, require substantial ethanol volumes (please refer to Figure 6-5). This scenario requires 4.5 BGY of ethanol, approximately 3 times current consumption levels. Moreover, it requires over 2 BGY of cellulosic ethanol. While this scenario has minimal vehicle technology risk, it carries risk in terms of ethanol supply. Scenario 4 with more cellulosic ethanol provides more GHG reduction, but requires even more cellulosic ethanol.

Scenario 2a and its variations also provide cumulative cost savings (red symbols). It is interesting to note that in contrast to the U.S. analysis, the addition of low CI grid and more low CI ethanol does not dramatically increase cumulative GHG reductions. The base case grid is 60% non-fossil in 2050 and the base case ethanol is assumed to have 40% advanced ethanol. Scenario 2a provides similar GHG reduction to Scenario 4 with low CI ethanol, with markedly lower cellulosic ethanol volumes (600 MGY vs 3.1 BGY).

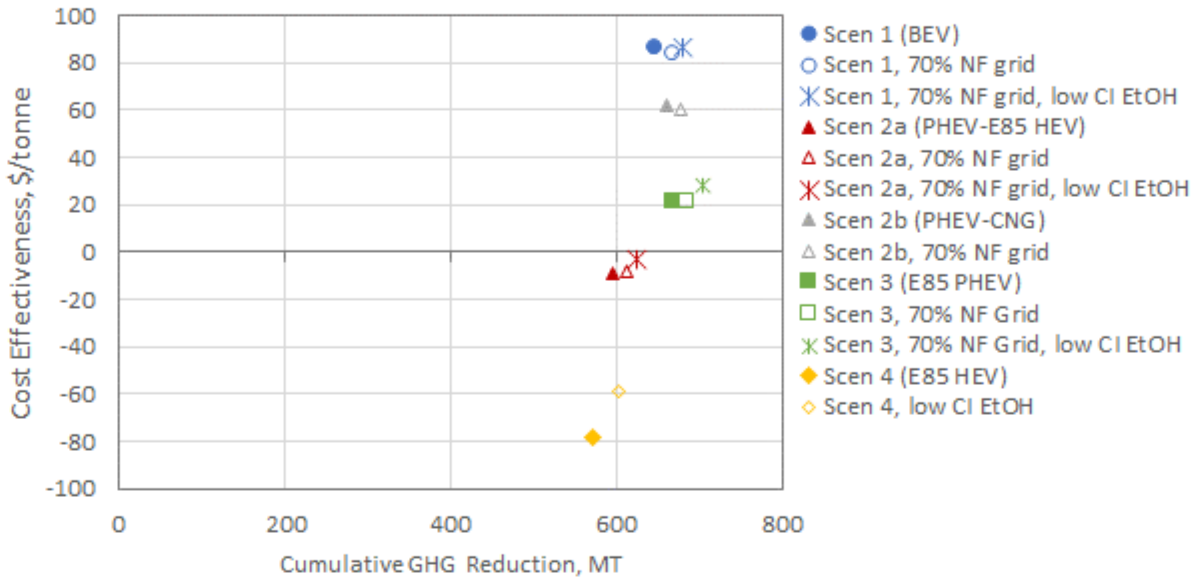

Figure 6-17. California cost effectiveness vs cumulative reduction.

The green symbols in Figure 6-17 are for Scenario 3 (E85 PHEV). This scenario provides more reduction than Scenario 2a at a higher cost (though costs are still low). The difference in cost is due to higher prices for E85 relative to gasoline on an energy basis (Figure 2-26) and slightly higher vehicle spending. Scenario 3 carries the risk of needing significant amounts of ethanol (2.3 BGY total ethanol, 1 BGY advanced).

Scenario 1 (BEV) and Scenario 2b (PHEV-CNG) provide similar reduction to Scenario 2a (PHEV-E85 HEV), but at a higher cost. Scenario 2b, with elevated CNG vehicle market shares has higher vehicle costs that are somewhat offset by lower fuel prices (CNG less expensive that gasoline). Again, the low CI grid and ethanol options do not have a large impact on either GHG reduction or price because the BAU CI values for these fuels are similar to the low CI versions.

Table 6-4 ranks the results by assigning a score in each of four categories: GHG reduction, cost, vehicle technology risk, and fuel risk. Each of these categories is given equal weight to come up with a single score for each scenario. The simplistic scoring assumes that a red score neutralizes a green score and that blue scores are neutral. Two options receive the top score of 5: Scenario 2a (PHEV-E85 HEV) and Scenario 3 (E85 PHEV). Scenario 3 has more GHG reduction, but higher cost while Scenario 2a has lower GHG reduction but lower cost. Both options are PHEV centric with Scenario 3 (E85 PHEV) having the added capability of utilizing lower CI biofuels.

Table 6-4. California scenario ranking based on four criteria

	GHG Reduction	Cost	Vehicle Technology Risk	Fuel Supply Risk	Overall Score
Scen 1 (BEV)	Medium	High	Medium	Low	3
Scen 1, 70% NF grid	High	High	Medium	Medium	3
Scen 1, 70% NF grid, low CI EtOH	High	High	Medium	High	2
Scen 2a (PHEV-E85 HEV)	Medium	Low	Medium	Low	5
Scen 2a, 70% NF grid	Medium	Low	Medium	Medium	4
Scen 2a, 70% NF grid, low CI EtOH	Medium	Low	Medium	High	3
Scen 2b (PHEV-CNG)	Medium	High	Medium	High	1
Scen 2b, 70% NF grid	High	High	Medium	High	2
Scen 3 (E85 PHEV)	High	Medium	Medium	Low	5
Scen 3, 70% NF Grid	High	Medium	Medium	Medium	4
Scen 3, 70% NF Grid, low CI EtOH	High	Medium	Medium	High	3
Scen 4 (E85 HEV)	Low	Low	Low	Medium	4
Scen 4, Low CI EtOH	Medium	Low	Low	High	4

Several scenarios receive a ranking of 4: the PHEV scenarios (2a and 3) with 70% non-fossil grid and Scenario 4 (E85 HEV) with and without low CI ethanol. As stated previously, Scenario 4 is attractive despite modest GHG reductions because of its low cost. However, Scenario 4's score is reduced because of the risk associated with the large increase in ethanol demand. As noted in Section 5, it is estimated that there is enough cellulosic feedstock to produce sufficient ethanol for Scenario 4, it is just a question of technical and commercial feasibility. Natural gas could also be used as an ethanol feedstock, but the CI value is not attractive.

7. Conclusions

The purpose of this analysis was to determine whether it is possible to dramatically reduce light duty well-to-wheel GHG emissions by 2050, and to quantify the corresponding impact on incremental vehicle and fuel spending and petroleum consumption. For the U.S. analysis, the target GHG reduction is 80% below 2005 levels by 2050 while the California goal is 80% below 1990 levels by 2050. A scenario analysis maximizing new vehicle sales of promising advanced technology vehicles and fuels was performed. Four scenarios were considered with aggressive market share ramp up rates beginning in 2025 at the expense of gasoline ICE vehicles, with very few gasoline ICE vehicles sold by 2050. The scenario emissions, costs and petroleum consumption were then compared to the business-as-usual (BAU) results. The scenarios considered were:

Scenario 1 – Maximum market shares of BEVs and E85 HEVs
Scenario 2a – Maximum market shares of E10 PHEVs and E85 HEVs
Scenario 2b – Maximum market shares of E10 PHEVs with LDA E85 HEVs and LDT CNG
Scenario 3 – Maximum market shares of E85 PHEVs and E85 HEVs
Scenario 4 – Maximum market shares of E85 HEVs

Note that for Scenarios 1-3, the maximum 2050 market share for LDAs is 70% for BEVs and 80% for PHEVs. For LDTs, the maximum BEV/PHEV market share is assumed to be 45%. To drive gasoline ICE market share down, Scenarios 1-3 also include significant quantities of E85 HEVs to drive gasoline ICE sales down to minimal levels. GHG emissions and costs through 2050 were based on projections of: fuel economy and incremental vehicle cost for each technology type, total annual sales of light autos and light trucks, annual VMT per vehicle, fuel carbon intensity, and fuel prices. Projected values for all of these variables were carefully considered and are documented in this report. These variables were assumed to be constant across scenarios and the BAU case. Therefore, the only difference between the four scenarios and the BAU is advanced technology market shares each year.

For the U.S. analysis, none of the scenarios achieve the 80% reduction from 2005 level goal despite aggressive technology roll-in rates. The basic scenarios reduce 2050 emissions by more than 50% (relative to the BAU case) to approximately 600 billion tonnes compared to the goal of 330 billion tonnes. The scenarios with low CI ethanol and/or low CI grid reduce emissions to 430-530 billion tonnes, still significantly above the goal. All scenarios assume that the low GHG vehicle penetration rates begin ramping up in 2025. To achieve the goal, the low GHG technologies must begin their aggressive ramp up before 2025 or ramp more quickly.

Cumulative GHG reduction for the analysis period is shown in
Table 7-1. The base scenarios provide 4.7 to 5.1 billion tonnes of cumulative reduction with the BEV and E85 PHEV scenarios providing slightly more reduction than the E10 PHEV and E85 HEV scenarios. When low CI ethanol and a 70% non-fossil grid are added, the reductions increase by as much as 40%. The BEV case benefits the most from low CI fuels while the E85 HEV scenario benefits the least due to significantly lower electricity use.

Table 7-1. Summary of U.S. Analysis Cumulative GHG Reduction

Billion Tonnes	Base Scenarios	Low CI Options	Delta
Scen 1 (BEV/E85 HEV)	5.0	6.9	1.9
Scen 2a (PHEV/E85 HEV)	4.7	6.3	1.6
Scen 2b (PHEV/CNG)	3.6	4.2	0.7
Scen 3 (E85 PHEV/E85 HEV)	5.1	6.7	1.6
Scen 4 (E85 HEV)	4.7	5.9	1.2

For the California analysis, while none of the scenarios achieved the 2050 goal (30 million tonnes), they are all close at approximately 40 million tonnes, with over 75% reduction from 2015 levels. Cumulative reductions are summarized in Table 7-2. It is interesting to note that the benefit of adding more low CI ethanol and a 70% non-fossil grid is much smaller for the California analysis compared to the U.S. analysis (5% benefit vs 40%). This is because the base case electricity CI is nearly as low as the 70% non-fossil CI. Also, Scenario 2b with light truck CNG vehicles provides significantly more reduction in California than in the U.S. analysis because there is significantly more RNG in the CNG (due to the LCFS) and secondarily because the ratio of light trucks to light autos is slightly higher in California than in the U.S..

Table 7-2. Summary of California Analysis Cumulative GHG Reduction

Million Tonnes	Base Scenarios	Low CI Options	Delta
Scen 1 (BEV/E85 HEV)	646	680	34
Scen 2a (PHEV/85 HEV)	595	625	30
Scen 2b (PHEV/CNG)	660	678	18
Scen 3 (E85 PHEV/E85 HEV)	667	703	36
Scen 4 (E85 HEV)	572	602	30

Turning to costs, the scenarios all provided cumulative fuel savings (not discounted) that nearly balance increased cumulative vehicle and EVSE spending (EVSE spending is an order of magnitude lower than vehicle spending). For both the U.S. and California analyses, Scenario 2a (PHEV/E85 HEV) and Scenario 4 (E85 HEV) without low CI fuels provide a net cost savings relative to the BAU.

One key metric is cost effectiveness, defined here as the cumulative cost divided by the cumulative GHG reduction.

Table **7-3** provides the cost effectiveness values for the U.S. analysis. For the base scenarios, Scenario 4 (E85 HEV) has the best cost effectiveness due to very low incremental vehicle costs, with the same cumulative GHG reduction as the base PHEV scenario. The base E85 PHEV scenario has the most reduction at very low cost; without low CI fuels, this is the best option. If low CI fuels are available, the BEV scenario provides the most cumulative reduction, but the base E85 PHEV scenario provides almost as much reduction at 20% lower cost per tonne.

Table 7-3. Summary of U.S. Analysis Cost Effectiveness

	Base Scenarios		Low CI Options	
	Cost Effectiveness ($/tonne)	Cumulative Reduction (Billion tonnes)	Cost Effectiveness ($/tonne)	Cumulative Reduction (Billion tonnes)
Scen 1 (BEV/E85 HEV)	34	5.0	52	6.9
Scen 2a (PHEV/E85 HEV)	-12	4.7	19	6.3
Scen 2b (PHEV/CNG)	34	3.6	108	4.2
Scen 3 (E85 PHEV/E85 HEV)	11	5.1	41	6.7
Scen 4 (E85 HEV)	-90	4.7	-14	5.9

Cost effectiveness for the California analysis is summarized in Table 7-4. California cost per tonne values are generally higher than the U.S. values, though not unreasonable. Although the cumulative emission reductions for the California scenarios are similar to the U.S. analysis on a percentage basis, the reduction in fuel costs is lower, resulting in a higher cost per tonne. Consistent with the U.S. analysis, the PHEV and E85 HEV base scenarios are the most cost effective. In contrast to the U.S. analysis, Scenario 2b (PHEV-CNG) provides large cumulative reductions because the base case assumes a large fraction of RNG in the CNG supply due to LCFS compliance. The cost effectiveness for this scenario is on the high side because of high incremental vehicle cost and the cost of RINS for the RNG. Of the base scenarios, the E85 PHEV scenario provides the highest reduction at a low cost. For California, when low CI fuel options are considered, the reductions do not substantially increase because the base case 2050 grid is close to 70% non-fossil.

Table 7-4. Summary of California Analysis Cost Effectiveness

	Base Scenarios		Low CI Options	
	Cost Effectiveness ($/tonne)	Cumulative Reduction (Million tonnes)	Cost Effectiveness ($/tonne)	Cumulative Reduction (Million tonnes)
Scen 1 (BEV/E85 HEV)	87	646	87	680
Scen 2a (PHEV/E85 HEV)	-9	595	-3	625
Scen 2b (PHEV/CNG)	62	660	61	678
Scen 3 (E85 PHEV/E85 HEV)	22	667	28	703
Scen 4 (E85 HEV)	-78	572	-59	602

Finally, in terms of petroleum reduction, all of the U.S. scenarios decrease petroleum consumption by 71-78% in 2050 relative to the BAU. For California, the petroleum consumption decreases by 82 -87% in 2050 relative to the BAU. These are seismic changes that would have wide ranging economic impacts.

Several sensitivity cases were run for the U.S. analysis. First, the assumed share of PHEV miles on electricity was evaluated. Reducing eVMT by 15% points reduced cumulative GHG emissions by 6% and increases costs from a savings of -$12 per tonne to a cost of $13 per tonne for

Scenario 2a of the U.S. analysis. This is a modest GHG impact, but a large cost impact. Work should continue to better quantify the share of PHEV miles that are driven in electric mode, particularly for LDTs.

There is some uncertainty surrounding projections of BEV fuel economy for 2025-2050, with the estimate used in this analysis possibly being conservative (low). Increasing the 2025-2050 BEV fuel economy by 7% had less than 1% impact on cumulative GHG emission reductions and a 4% increase in cumulative cost effectiveness. Therefore, the results are not strongly affected by uncertainty in out-year fuel economy assumptions for the alternative fuel vehicles.

Finally, for electricity grid mix, this analysis utilized the AEO2016 projection with EPA's Clean Power Plan (CPP). There is currently some uncertainty about whether the CPP will be implemented as adopted, so Scenario 1 (BEV) was run with and without the Clean Power Plan (CPP). For Scenario 1, the scenario most dependent on the electricity grid, the CPP provides 0.5 billion tonnes of cumulative reduction relative to a BAU without the CPP, a 10% effect. By extension, the PHEV base scenarios will have a less than 10% effect. The low CI scenarios will have a larger reduction relative to a BAU without a CPP.

Arguments have been made that a low CI grid will result in higher and lower electricity prices. For this analysis, it was assumed that the low CI grid prices are the same as the high CI prices. A sensitivity test was performed to quantify the impact of a 20% increase and a 20% decrease in electricity prices due to decarbonization. A 20% increase in electricity price increases cumulative cost by 18 $/tonne or 65% for the BEV scenario. Cumulative cost is fairly sensitive to electricity prices.

Cellulosic RIN prices were assumed constant throughout the analysis period. If large quantities of cellulosic fuel are produced in response to an orderly increase in demand, it would be expected that production costs (the RIN premium) for cellulosic fuels would decrease. Reducing the RIN premium to $0.50 from $1.00 improves the cost effectiveness of the low CI ethanol E85 HEV scenario from -$14 per tonne to -$45 per tonne, further improving the attractiveness of this scenario.

In summary, the following conclusions may be drawn for the U.S. analysis:

- With low CI fuels, the BEV, PHEV and E85 scenarios can achieve the 2050 goal if technology roll-in rates increase above the BAU before 2025 as modeled, if roll-in rates are even more aggressive than assumed, or if the grid decarbonizes (BEV and PHEV scenarios) more than assumed.
- Without grid decarbonization to approximately 70% non-fossil levels, the BEV, PHEV and E85 PHEV scenarios are unlikely to achieve the goal (even after 2050)
- Without very large quantities of advanced low CI ethanol, the E85 HEV scenario will not achieve the goal (even after 2050)
- Limits on market share potential for BEVs and PHEVs (especially for LDTs) requires replacement of the remaining gasoline ICE vehicles with E85 HEVs in the electrification

scenarios. Use of advanced low CI ethanol in these vehicles is needed to help achieve the 2050 goals.
- Earlier and/or more compressed transition to lower carbon fuels and advanced vehicles provides more cumulative reduction for the analysis period, reducing atmospheric GHG concentrations.
- The cost per tonne abated for the low CI options is modest (aside from the CNG scenario), ranging from a cost savings of 14 $/tonne for the E85 HEV scenario to 52 $ per tonne for the BEV scenario.
- All scenarios provide ~75% reduction in petroleum consumption in 2050 relative to the BAU

For California the conclusions are somewhat different:

- The base scenarios have only slightly lower cumulative reductions than the low CI cases because the low CI grid mix (70% non-fossil) is similar to the BAU and because the LCFS requires modest quantities of advanced ethanol.
- All four scenarios come close to the goal by 2050, but do not achieve it. More time is needed for advanced vehicles to roll-in or technology roll-in rates must increase above the BAU before 2025 as modeled
- Without electrification beyond ZEV Mandate levels, the E85 HEV scenario will require large quantities of advanced ethanol to meet the goal.
- Limits on market share potential for BEVs and PHEVs (especially for LDTs) requires replacement of the remaining gasoline ICE vehicles with E85 HEVs in the electrification scenarios. Use of advanced low CI ethanol in these vehicles is needed to help achieve the 2050 goals.
- Because California's LCFS has encouraged significant quantities of RNG, CNG vehicles are an interesting complement to BEVs/PHEVs in the light truck category.
- Earlier and/or more compressed transition to lower carbon fuels and advanced vehicles provides more cumulative reduction for the analysis period, reducing atmospheric GHG concentrations.
- The cost per tonne abated for the low CI options ranges from a cost savings of -$59 per tonne for the E85 HEV scenario to $87 per tonne for the BEV scenario.
- All scenarios provide ~85% reduction in petroleum consumption in 2050 relative to the BAU

If the U.S. decides that reducing GHG emissions is an important national goal, the free market on its own will not be sufficient. Success will depend on regulatory efforts in the following areas:

Continued downward pressure on vehicle fuel consumption (CAFE). The 2022-2025 CAFE standards should be kept in place and more stringent standards should be developed for 2026-2050. Moreover, since there are separate standards for LDA and LDT, consumers should be encouraged/incentivized to purchase LDAs where possible.

The electric grid, which has steadily moved away from coal in the last 15 years due to lower cost natural gas and renewable generation, needs to continue to decarbonize. The CPP should be implemented and new policies/regulations to further accelerate our grid's transition from fossil fuel to low carbon fuels must be adopted.

Continue and extend the life of the RFS beyond 2022 to ensure a steady supply of conventional biofuels. In addition, strong and consistent regulatory signals are needed on cellulosic biofuel volumes to allow biofuel developers to attract financing for production plants. Because tax credits need to be renewed by Congress every few years, this is not a reliable means to support the financing of low CI biofuel plants. A robust biofuel industry has the potential side benefit of economic growth in rural areas. Promote sales of high level ethanol blends to offload reliance on fleet electrification.

To ensure rapid transition to advanced vehicles, implement a nationwide mandate to ensure a transition to BEVs, PHEVs, E85 PHEVs and/or E85 HEVs. The existing ZEV Mandate has resulted in large scale manufacturing of vehicle batteries such that commercial production volumes and associated cost reductions will be achieved by 2025.

This analysis evaluated the bounding scenarios with maximum feasible penetration of vehicle technologies and low carbon fuels. Emission reductions with more moderate vehicle penetration rates will be lower, with lower vehicle costs and reduced savings on fuel.

Appendix A Fuel Economy and Incremental Cost Forecasts

Two key assumptions in this analysis are projected LDA and LDT fuel economy for the range of technologies considered and their corresponding incremental cost (compared to a MY 2015 gasoline ICEV). Several studies were utilized to inform the development of fuel economy and incremental cost values for the present analysis. These studies include:

- Energy Information Administration Annual Energy Outlook 2016 (AEO2016)
- VISION2015 Default Values (same as AEO2015)
- NAS Transitions Report[56]
- NAS Phase 2 Report[57]
- Argonne C2G Analysis[58]
- Draft TAR (EPA and NHTSA separate analyses)[59]
- EPA Fuel Economy Guide[60]
- ARB[61]

Each year, Argonne National Laboratory updates its VISION model with the most recent version of AEO data. At the time this analysis began, VISION2015 with AEO2015 data was available. LCA has updated VISION2015 inputs as described here. The VISION model divides the light duty sector into two categories: autos and light trucks[62]. The model employs composite new vehicle fuel economy values for these two categories. The composite value is a sales-weighted average (based on AEO2015 sales projections) of corporate average fuel economy (CAFE) certification values by sub-class. Table A-1 provides the AEO2016 market share projections.

Table A-1. AEO2016 subclass market share forecasts

Light Auto				Light Truck			
Class	2016	2025	2040	Class	2016	2025	2040
Minicompact	1%	1%	1%	Small Pickup	5%	4%	4%
Subcompact	10%	12%	12%	Large Pickup	23%	23%	23%
Compact	33%	37%	37%	Small Van	1%	1%	1%
Midsize	44%	40%	40%	Large Van	8%	8%	9%
Large	12%	10%	10%	Small Utility	40%	40%	40%
Two Seater	1%	1%	1%	Large Utility	23%	24%	23%

[56] Transitions to Alternative Vehicles and Fuels, National Research Council of the National Academies, 2013.
[57] "Cost, Effectiveness and Deployment of Fuel Economy Technologies for Light Duty Vehicles", National Academy of Sciences, 2015
[58] Cradle-to-Grave Lifecycle Analysis of U.S. Light Duty Vehicle Fuel Pathways: A GHG Emissions and Economic Assessment of Current (2015) and Future (2025-2030) Technologies, Argonne National Laboratory, June 2016
[59] Draft Technical Assessment Report: Midterm Evaluation of Light Duty GHG Emission Standards and Corporate Average Fuel Economy Standards for Model Years 2022-2025, U.S. Environmental Protection Agency, California Air Resources Board, National Highway Traffic Safety Administration, EPA-420-D-16-900, July 2016.
[60] www.fueleconomy.gov
[61] California Air Resources Board projection based on EMFAC and VISION2.1 fuel consumption and VMT projections
[62] The light truck category includes class 2a (up to 8500 lb GVWR); class 2b trucks are not included.

Certification fuel economy is degraded in VISION[63] to reflect on-road performance by a factor of 0.817 for gasoline, diesel, flexible fuel vehicles (FFVs), compressed natural gas (CNG) vehicles and the gasoline portion of plug-in hybrid electric vehicle (PHEV) operation. The degradation factor for hybrid electric and hydrogen fuel cell vehicles is 0.85 while the degradation factor for electric vehicles is 0.70.

The NAS Transitions study developed fuel economy and incremental cost forecasts for LDAs based on the Toyota Yaris (compact), Toyota Camry (midsize), and Chrysler 300 (large car). For the LDT category, fuel economy and cost estimates were developed based on the Saturn Vue (compact SUV), Dodge Grand Caravan (minivan), and the Ford F-150 (standard pickup). We assume here that the average of these three autos is comparable to the AEO2016 light auto category and the average of the three light trucks is comparable to the AEO2016 light truck category. This three-car auto average is thought to be slightly lower than the actual fleet because it emphasizes larger cars. Similarly, the light truck average is likely slightly higher than the actual average because minivans have higher FE than other light trucks and represent much less than 33% of the fleet.

The NAS Transitions forecasts assume that the 2025 CAFE standard is fully implemented in 2030 and then projects that fuel economy continues to improve through 2050 at half the rate of the improvement from 2015-2030. The corresponding costs for this improvement only takes into account further light-weighting. The 2030-2050 fuel economy projections seem to be more aspirational rather than a response to market or regulatory drivers.

The Argonne C2G study developed fuel economy and cost projections for a midsize auto; it was assumed this could be compared to the AEO2016 LDA category. No projections for light trucks were made.

The Draft TAR provides two different sets of numbers: numbers developed by EPA for compliance with the GHG standard and numbers developed by NHTSA for compliance with the CAFE standard. The EPA analysis provides projected fuel economy for several technologies and a range of vehicle subclasses. LCA utilized the AEO2016 projected subclass sales provided in the table above to estimate composite LDA and LDT fuel economy values. The EPA Draft TAR incremental costs for plug-in vehicles includes the cost of EVSE ($1500). LCA reduced the cost of the EPA plug-in vehicles by $1500. The NHTSA analysis provides composite LDA and LDT fuel economy values and incremental costs.

The EPA fuel economy guide (FEG) provides “fuel economy label” values. According to EPA, the label values are 20% lower than certification values. When comparing label values to certification values, a factor of 1.2 has been applied.

[63] On-road degradation factors were provided to Argonne modelers by EIA

ARB fuel economy values are calculated from EMFAC and CA-VISION2.1 projections of fuel consumption and VMT. These calculated values are on-road fuel economy values. These values are divided by the VISION default degradation values to allow comparison with the other certification values. It appears that ARB's future BEV and FCV fuel economy values match the NAS Transitions values[64]; the calculated degradation factor used by ARB is 0.75 rather than 0.70 used by Argonne in VISION.

The following sections compare certification fuel economy and incremental cost projections for LDA and LDT vehicles for the range of technologies considered in the analysis. A summary of the values utilized in the present analysis is provided at the end. Two sets of fuel economy forecasts are utilized: one that maintains fuel economy at 2025 levels for 2025-2050 and another that assumes manufacturers will have to continue to improve their products in 2025-2050 to meet future standards. Specifically, we assume that the ICE improves by 0.5% per year, the HEV improves by 1% per year and that BEV/PHEV/FCV continues at 1.5% per year. It is further assumed that these increases do not have an associated incremental cost but are achieved by increased manufacturing volumes of technology and learning improvements. This assumption is supported by considering the improvements in HEV fuel economy and change in MSRP over time. Figure A-1 provides the Toyota Prius EPA label fuel economy and MSRP from its introduction in 2001 through MY2017. The fuel economy improved by 1.7% per year while the MSRP actually decreased by 0.6% per year.

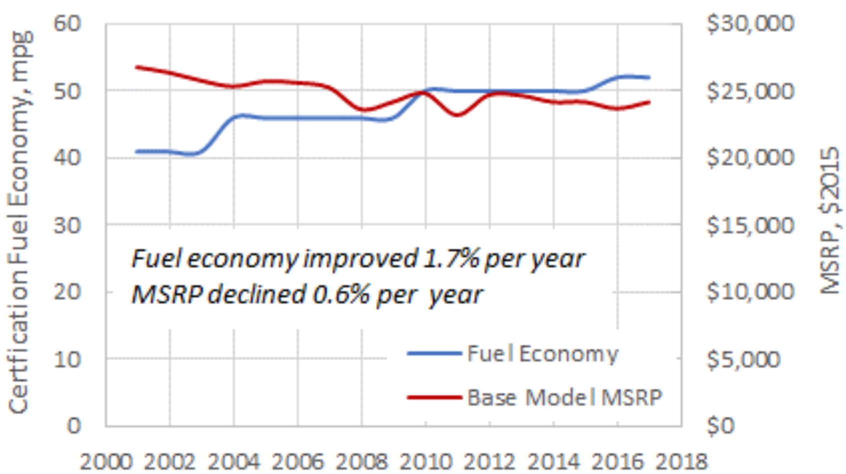

Figure A-1. Toyota Prius EPA Label fuel economy and MSRP ($2015).

[64] Phone and email conversations with Kathy Jaw, ARB

Light Duty Auto Fuel Economy and Incremental Cost Forecasts

Figure A-2 provides the various projections for LDA gasoline internal combustion engine (ICE) vehicles. There is close agreement between the various studies through 2025 with the NAS Transitions values higher than the others. This analysis utilizes the AEO2016 projection for the base case fuel economy. Incremental cost relative to a 2015 ICE is provided in Figure A-3. Since the NAS Transitions study assumes that the 2025 standard is fully adopted in 2030, the 2030 incremental cost value agrees will with the 2025 values from the other studies. This analysis assumes a linear increase to the 2025 Argonne C2G and AEO2016 incremental cost value and then flat through 2050.

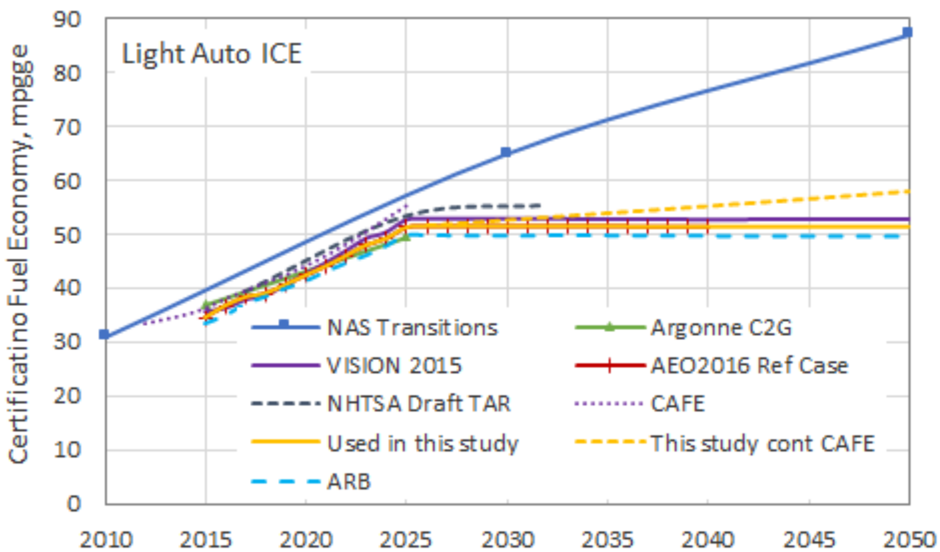

Figure A-2. Certification fuel economy forecasts for LDA gasoline ICE vehicles.

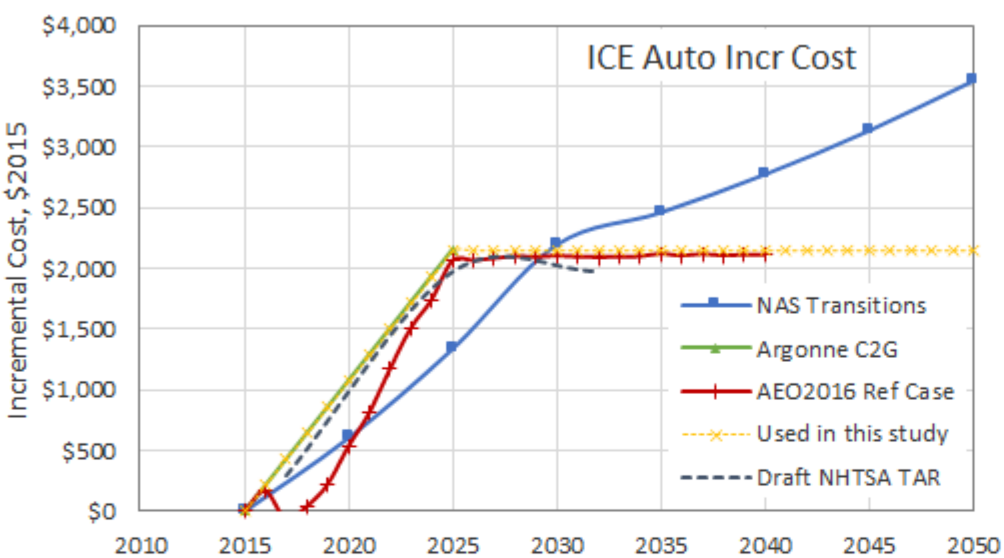

Figure A-3. Incremental cost forecasts for LDA gasoline ICE vehicles.

Figure A-4 and Figure A-5 provide the fuel economy and incremental cost projections for LDA diesel vehicles. The NHTSA and ARB fuel economy projections are significantly higher than the others, and seem to have the same slope as the gasoline ICE. Because improvements in gasoline ICE fuel economy are not all translatable to diesel vehicles, LCA has chosen to use the AEO2016/Argonne C2G forecast in this analysis. Since the LDA market shares are extremely low, the impact of this assumption is negligible. Diesel incremental costs are assumed to start at $3,000 currently, increasing linearly to $3,750 in 2025 and remaining constant thereafter. Because diesel vehicle shares are not increased in any of the scenarios considered, the incremental cost assumption does not impact the analysis.

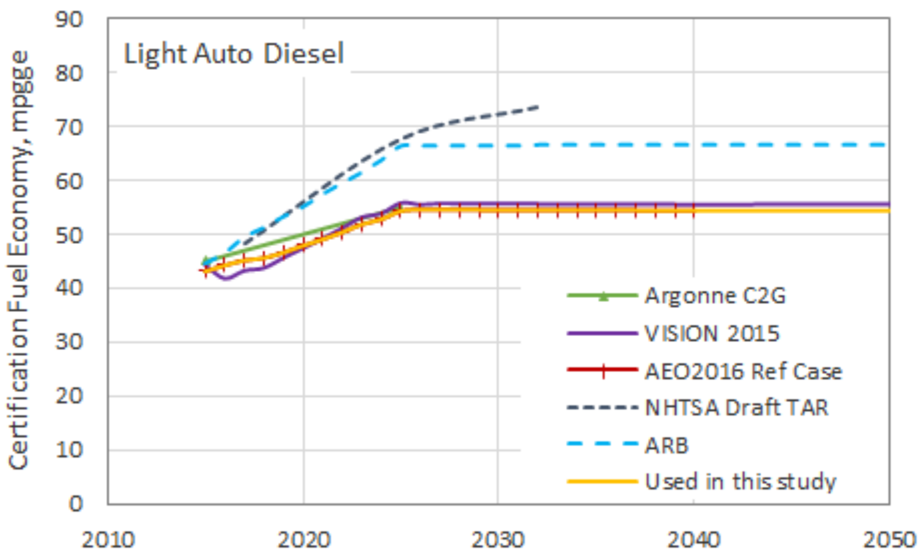

Figure A-4. Certification fuel economy forecasts for LDA diesel vehicles.

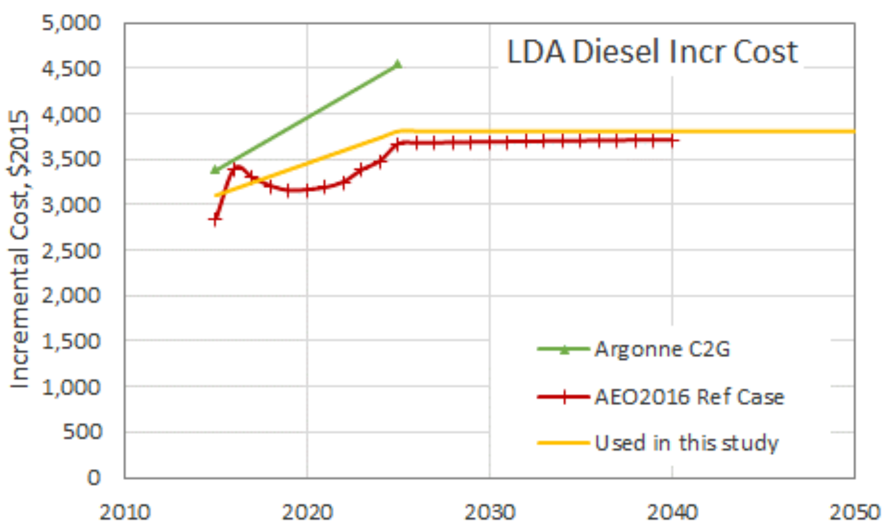

Figure A-5. Incremental cost forecasts for LDA diesel vehicles.

For ethanol FFVs, the default energy economy ratio (EER) utilized in VISION2015 is 1.01 for operation on both E10 and E85. EER is the ratio of alternative vehicle fuel economy to base vehicle fuel economy. A review of new vehicle fuel economy ratings[65] for light autos indicates that the current EER for operation on E85 is 1.03. We have modified the VISION model such that the EER on gasoline is 1.0 and the EER on E85 is 1.03 for light autos and light trucks. The cost associated with adding fuel flexibility is assumed to be $100 for light autos and $125 for light trucks (NAS Phase2 report). A 30% manufacturer markup is added with an additional 16% dealer markup.

The EPA Fuel Economy Guide and vehicle manufacturer websites were utilized to generate the plot of incremental vehicle price vs EER for gasoline hybrid electric vehicles (HEVs) in Figure A-6. The average current EER is 1.4; this was applied to the current average gasoline ICE certification fuel economy to arrive at the 2016 HEV value used in this analysis (52 mpg). Excluding the two luxury models (Acura RLX and Nissan Murano), the current average incremental cost is $4,480. If the two luxury models are included, the average increases to $5,580. LCA believes the sales weighted average incremental cost is likely closer to the $4,480 estimate.

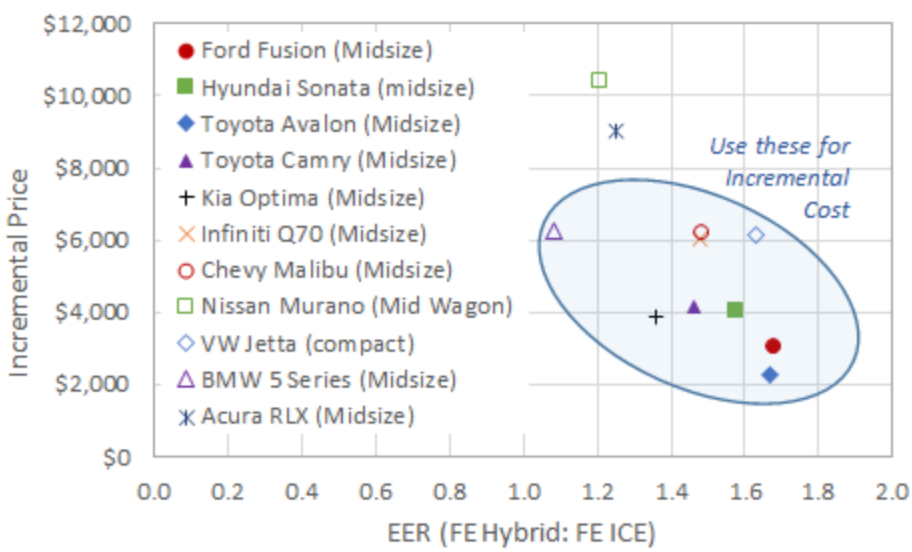

Figure A-6. Current EER and incremental cost for LDA HEVs.

The certification fuel economy forecasts for LDA HEVs are summarized in Figure A-7. The average MY2016 value from the Fuel Economy Guide (corrected to certification fuel economy values) matches all of the estimates with the exception of the NHTSA Draft TAR values which actually decrease from 2017-2025. For 2017, NHTSA assumed 43% of sales would be Toyota Prius with a fuel economy of 77 mpg (the 2016 Prius certification value is ~ 62 mpg). In this analysis, LCA has utilized the AEO2016 forecast. The Argonne C2G estimates are also slightly higher in 2025, but their 2025 estimates assume full commercialization (>500,000 units). If full commercialization is delayed to 2030 then their results are line with the other estimates.

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[65] US DOE and US EPA Fuel Economy estimates, www.fueleconomy.gov

Figure A-8 provides a comparison of the LDA HEV incremental cost forecasts. The MY2016 incremental price is similar to both the EPA and NHTSA Draft TAR estimates, and lower than the Argonne/AEO2016 estimate. We expect the Argonne costs to be higher since their analysis covered only a midsized vehicle and apparently AEO2016 over estimated costs. The EPA and NHTSA draft TAR values are lower than the Argonne/AEO values and their 2016 values are consistent with the current market offerings. For this analysis, we start at the current market increment, follow the Draft EPA and NHTSA TAR curves until crossing the NAS Transitions value in 2027 and holding at $3000 through 2050.

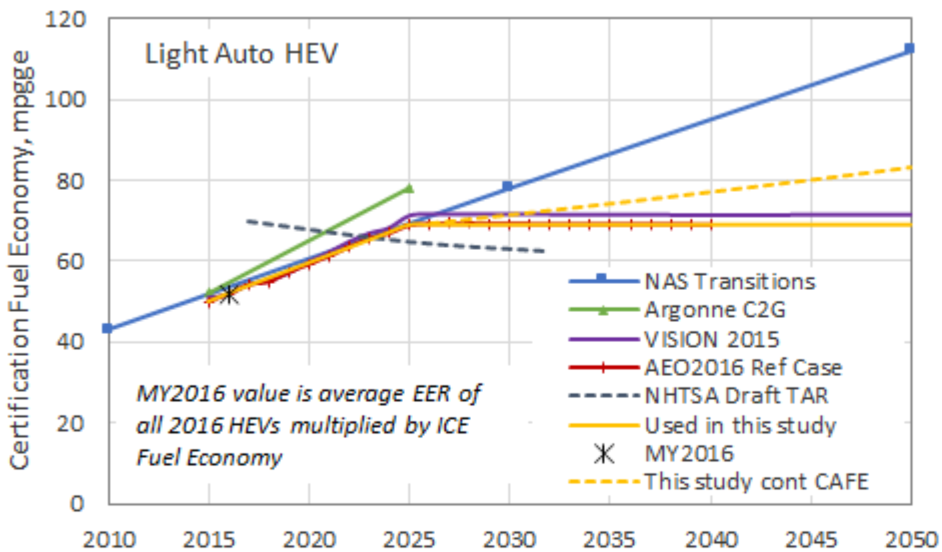

Figure A-7. Certification fuel economy forecasts for LDA HEVs.

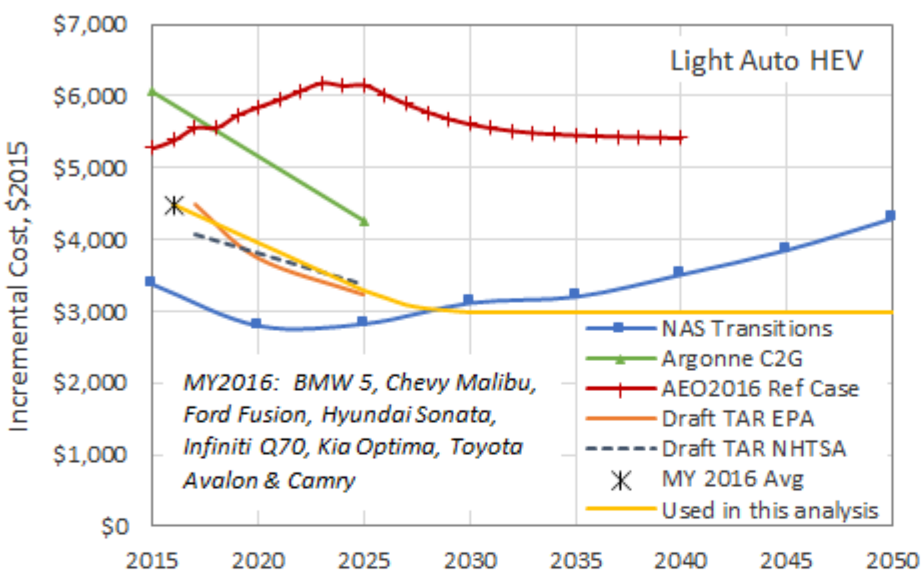

Figure A-8. Incremental cost forecasts for LDA HEVs.

For battery electric vehicles (BEVs) with 100 mile range, Figure A-9 provides current EPA fuel economy label data (20% lower than certification value). Excluding the Mercedes (much lower fuel economy and lower sales), the average fuel economy label is 113 mpgge which corresponds to ~ 136 mpgge certification. Four of these vehicles have ICE counterparts; by comparing to the ICE versions, EER and incremental price is calculated and provided in Figure A-10. The average EER is 3.8 which corresponds to a certification fuel economy of 138 mpgge when applied to the 2016 ICE average value. The average incremental price is $12,750.

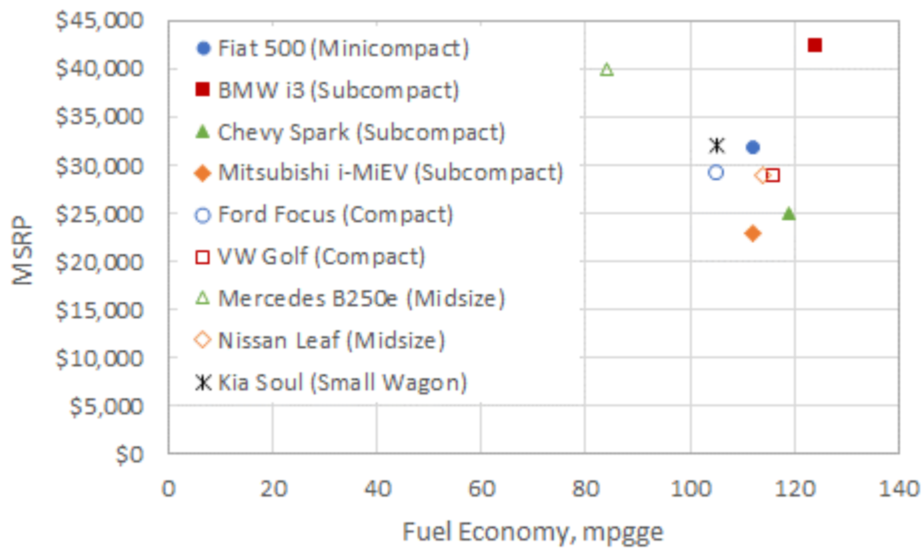

Figure A-9. MY2016 BEV100 MSRP vs EPA fuel economy label.

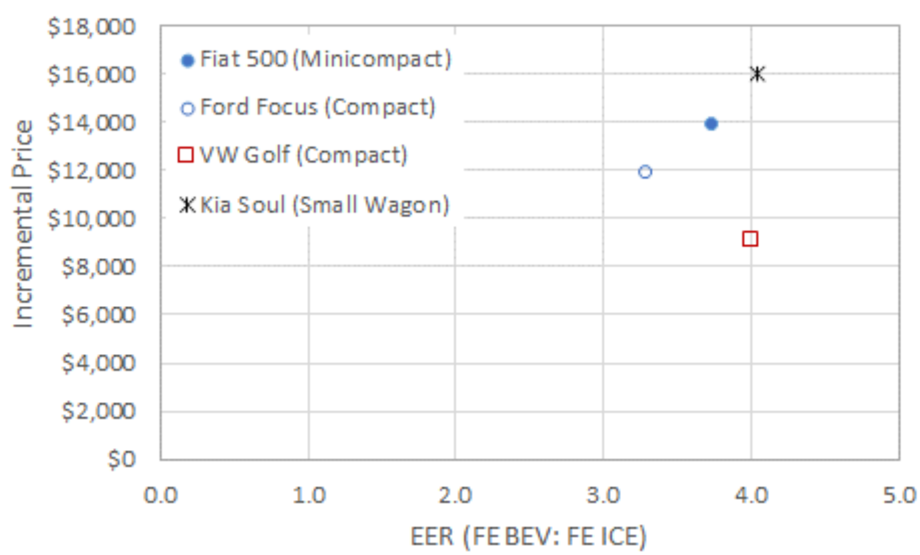

Figure A-10. MY2016 BEV100 incremental cost vs EER.

The BEV100 certification fuel economy projections are summarized in Figure A-11. The MY2016 value (136) is much lower than the NAS Transitions and ARB estimates and slightly lower than Argonne C2G and AEO2016 values. The ARB values shift to the NAS Transitions values for 2025-2050. These estimates appear too optimistic based on current technology. The VISION2015 estimates agree with current technology but show little improvement with time which seems unreasonable. For this analysis, we utilize the MY2016 value and increase along the slope of the Argonne C2G, AEO2016, and NAS studies through 2025. The dashed yellow line indicates the values for 2025-2050 used in the event that regulatory pressure on fuel economy continues. Because there is significant disagreement, a sensitivity case is run in which the fuel economy in 2016 is the current average value, but the 2025 value is the same as the Argonne C2G and AEO2016 value (172 mpgge).

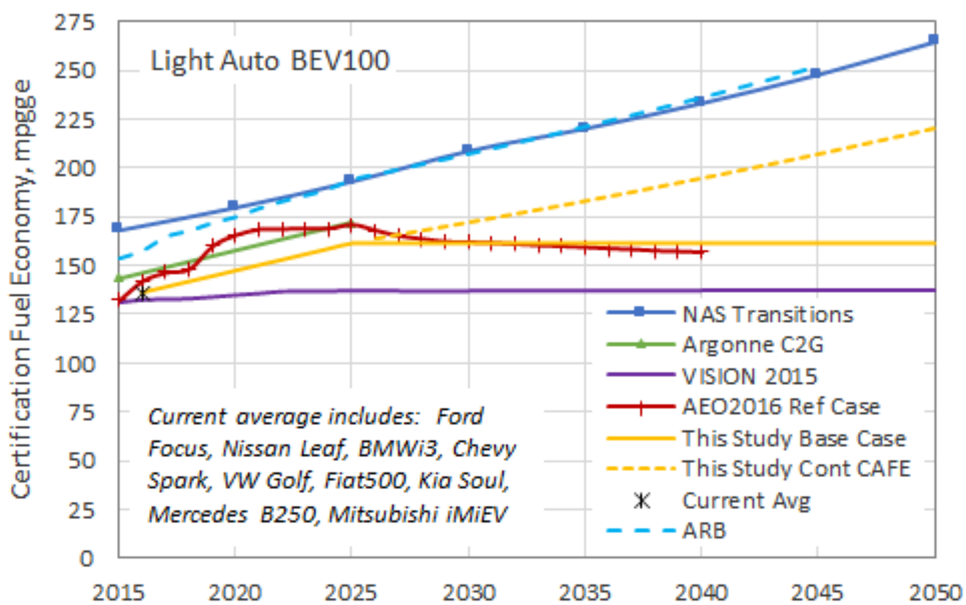

Figure A-11. Certification fuel economy forecasts for LDA BEV100.

Incremental cost forecasts are provided in Figure A-12. The MY2016 increment ($12,750) is similar to the EPA Draft TAR estimate (without charger), about 5% higher than the NAS and Argonne estimates, and approximately 30% lower than the AEO2016 estimate. NHTSA's TAR analysis does not provide a BEV100 cost increment. For this analysis, LCA utilizes the EPA TAR values through 2025 and then level out at $7200 through 2050. The 2016 values are similar to current values and appear conservative (higher) relative to the NAS and Argonne projections though significantly lower than the AEO2016 values. It is possible that the incremental cost could decrease to the NAS/Argonne levels, but unlikely that they would increase to the AEO2016 levels. As a sanity check on these values, LCA performed an analysis of battery pack and drive train costs as a function of projected production volume using Argonne National Laboratory's BatPaC model. The projected values were consistent with TAR values.

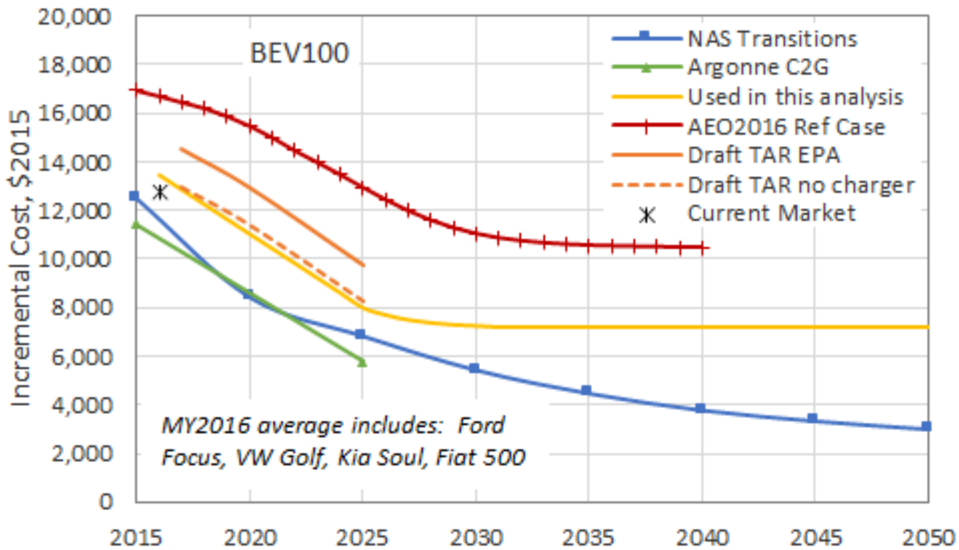

Figure A-12. Incremental cost forecasts for LDA BEV100.

For the BEV with 200+ mile range (BEV200), certification fuel economy forecasts are provided in Figure A-13. There are two Tesla models on the market with over 200-mile range, one with a 70 kWh battery and one with a 90 kWh battery. The NHTSA value is based on the Tesla model with more range (93 mpgge EPA label corrected to 116 mpgge certification) and projects minimal improvement over time. The Tesla value is valid for 2016, but new non-luxury (smaller) models will enter the market with higher fuel economy. In fact, the Chevy Bolt, introduced in early 2017, has a 238-mile range and an EPA label fuel economy of 119 mpgge (143 certification).

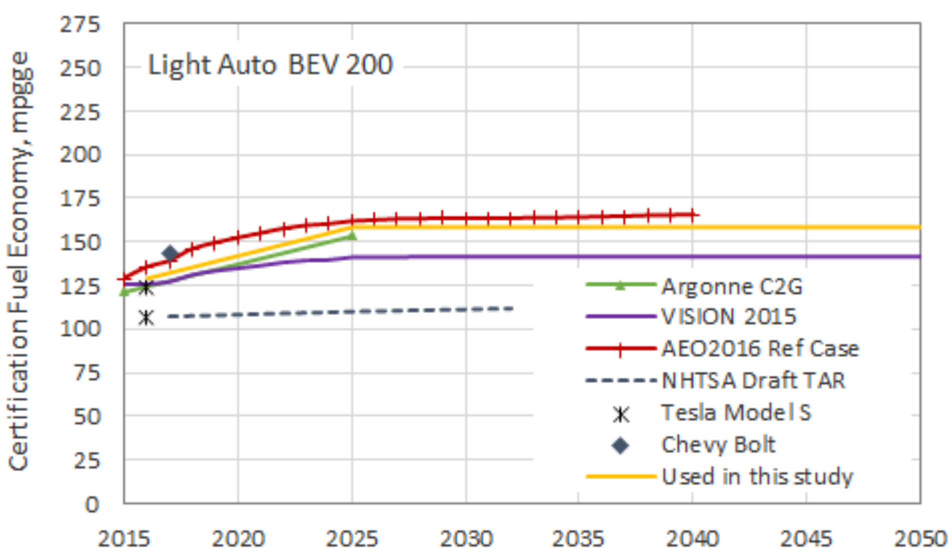

Figure A-13. Certification fuel economy forecasts for LDA BEV200.

For the present analysis, LCA has utilized the BEV100 fuel economy and added a penalty for the increased battery weight. To estimate the BEV200 fuel economy, we assume 233 Wh/kg battery weight[66], 30 kWh for the BEV100 and 60 kWh for the BEV200, a 3000 lb vehicle and 5.2% fuel economy penalty for every 10% change in vehicle weight[67]. The result is a 4.9% fuel economy penalty for the BEV200 relative to the BEV100. This forecast results in certification fuel economy estimates of 129 mpgge in 2016 and 158 mpgge by 2025. The 2016 analysis value is lower than the MY2017 Chevy Bolt (certification 143 mpgge), but the Bolt is a small car and does not necessarily represent a fleet average value.

BEV200 incremental cost forecasts are provided in Figure A-14. There are two groups: Argonne, NHTSA Draft TAR, and AEO2016 with very high incremental cost and EPA Draft TAR and NAS Transitions (estimated by doubling the battery costs for the BEV100) significantly lower. The Argonne/NHTSA/AEO2016 value is ~ 4 times higher than the BEV100 increment. If price is based on $125/kW battery cost and doubling capacity, the increment is similar to the EPA Draft TAR price. Moreover, the Chevy Bolt has a lower MSRP ($37,495) than the Argonne/NHTSA ***increment***, indicating that the lower estimate is much more in line with actual incremental costs. For this analysis, the EPA Draft TAR increment is used until crossing the NAS Transition curve in 2030 at $12,500.

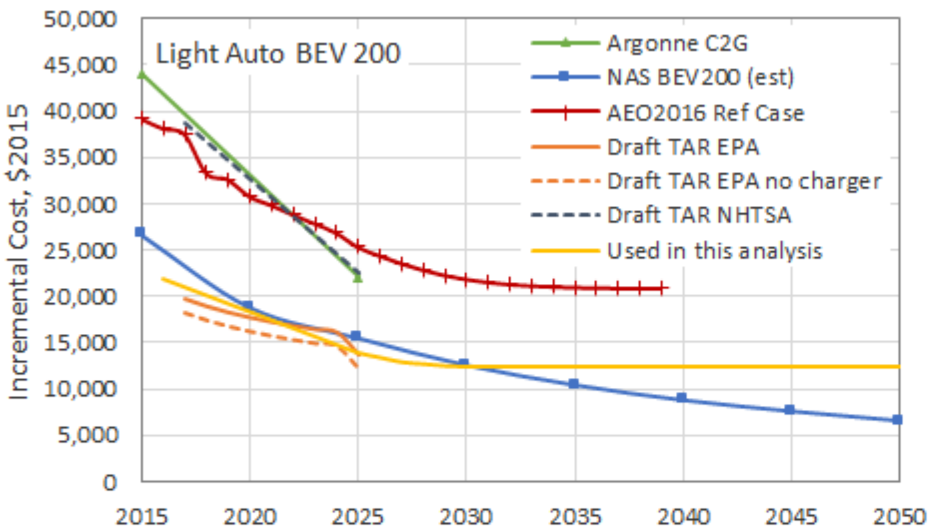

Figure A-14. Incremental cost forecasts for LDA BEV200.

There are currently 9 plug-in hybrid electric vehicles (PHEVs) on the market; their electric mode fuel economy (EPA label) and MSRP are provided in Figure A-15. The current average fuel economy is 84 mpgge (101 mpgge certification). Of the current offerings, 6 models have gasoline counterparts (Figure A-16), so EER and incremental cost can be calculated. Based on

[66] https://cleantechnica.com/2015/03/17/lighter-batteries-may-prove-tipping-point-electric-vehicles/
[67] EPA Draft TAR

these 6 models with gasoline counterparts, the average electric mode EER is 3.1 which corresponds to a certification fuel economy of 112 mpgge, lower than the BEV100 (136 mpgge, certification). However, this EER value is based on a small sample size and does not include one of the market leaders, the Chevy Volt. An EER for the Volt can't be calculated because it doesn't have a gasoline equivalent; it's electric mode certification fuel economy is 127 mpgge. For this analysis, we assume the PHEV electric mode fuel economy is the same as the BEV100. This assumption is consistent with the NAS transitions, Argonne, and other forecasts.

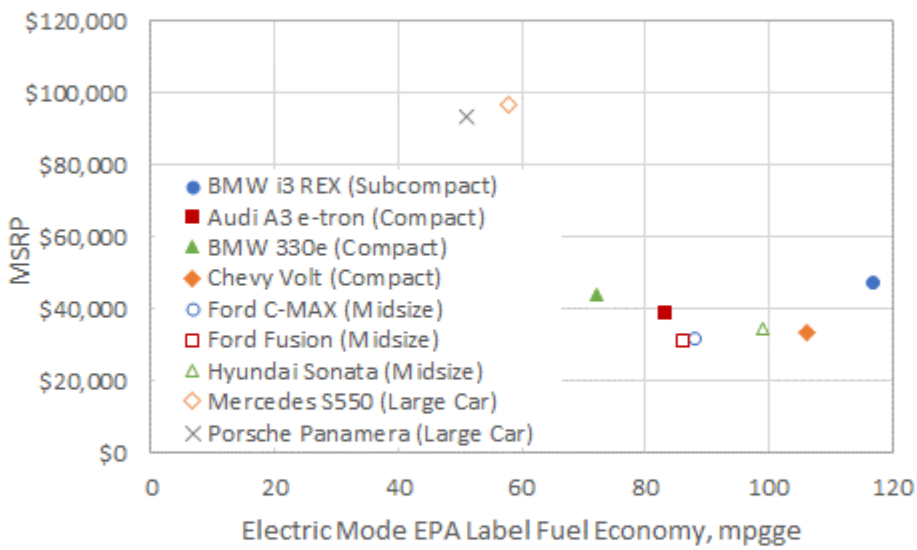

Figure A-15. MY2016 LDA PHEV electric mode EPA label fuel economy and MSRP.

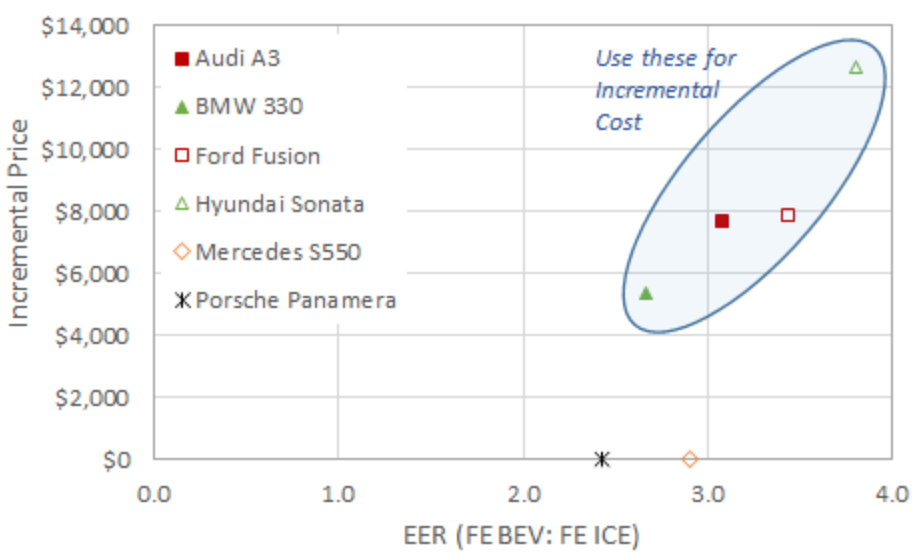

Figure A-16. Incremental cost vs EER for MY2016 LDA PHEV.

Figure A-17 provides the various PHEV electric mode certification fuel economy forecasts. The VISION2016 value is significantly lower than the other projections. The Argonne C2G and NHTSA Draft TAR values are similar to the BEV100 assumption. The NAS and ARB (same as NAS) forecasts are the same as their corresponding BEV100 values. The forecast used in this analysis is generally consistent with Argonne C2G and NHTSA. Note that the MY2016 value shown in the figure is based on the EER calculated from current vehicles with gasoline counterparts – as discussed above, this omits the Chevy Volt with certification fuel economy of 127 mpgge.

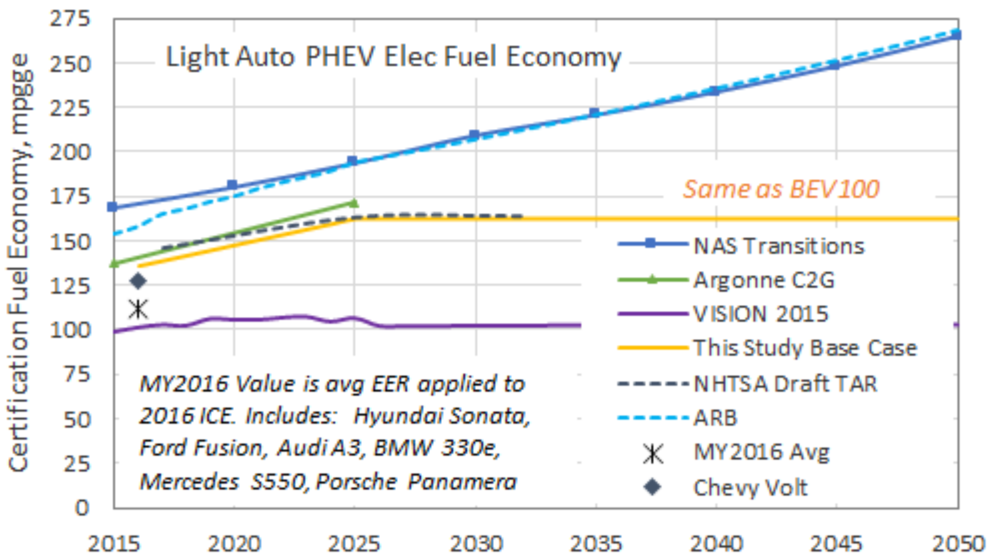

Figure A-17. Certification Fuel economy (electric) forecasts for LDA PHEV.

The current average PHEV MSRP is $50,000 (Figure A-15). The average MY2016 incremental cost (omitting the Mercedes and Porsche) is $8400 (Figure A-16). Incremental cost forecasts are summarized in Figure A-18 along with the MY2016 incremental cost. For this analysis, LCA is using the EPA Draft TAR incremental price, leveling out at $8,850 in 2025. The MY2016 incremental cost is low possibly because the electric range of the vehicles considered is approximately 20 miles or less (larger all electric range requires more battery capacity and increases cost). This analysis assumes PHEVs quickly move to 40 miles of electric range.

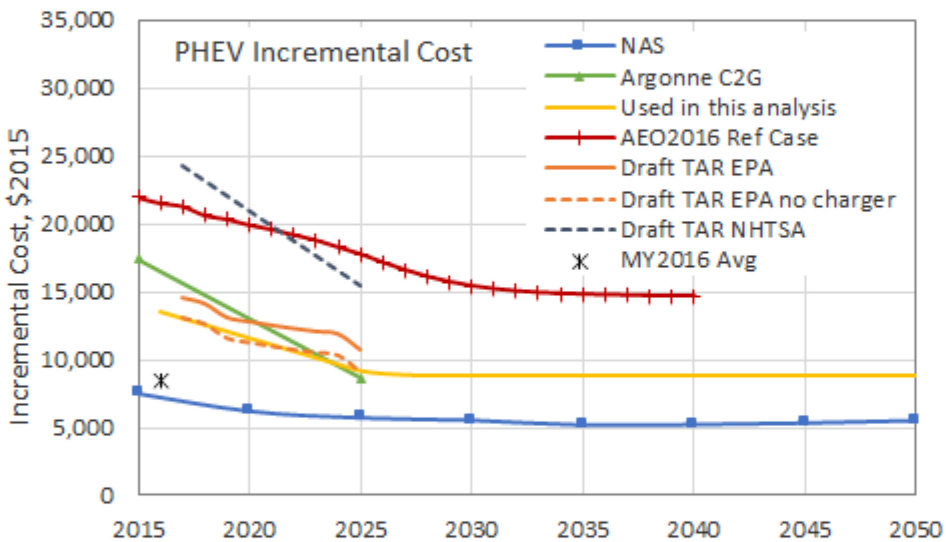

Figure A-18. Incremental cost forecasts for LDA PHEV.

For hydrogen fuel cell vehicles (FCVs), the Argonne C2G and ARB/NAS Transitions fuel economy forecasts (Figure A-19) are very close to the current model on the market (Toyota Mirai). The AEO2016 values are surprisingly low. For this analysis we follow the Argonne values to 2025. For incremental cost (Figure A-20), this analysis starts at the current value and decreases along the NHTSA Draft Tar line through 2025, continuing linearly through 2045 when it hits the Argonne C2G mature value. Because this analysis does not consider high volumes of FCVs over the analysis period, economies of scale are not fully achieved until 2045.

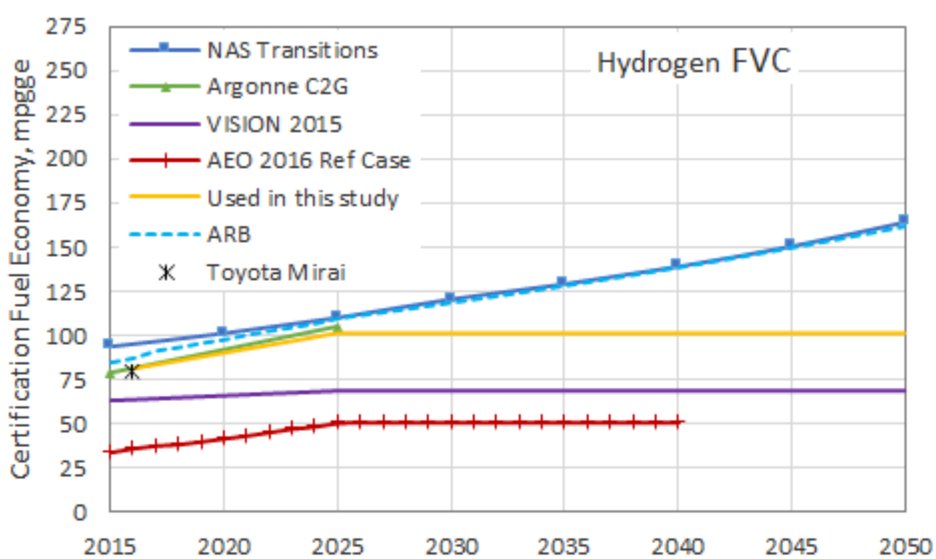

Figure A-19. Certification fuel economy forecasts for LDA H2 FCV.

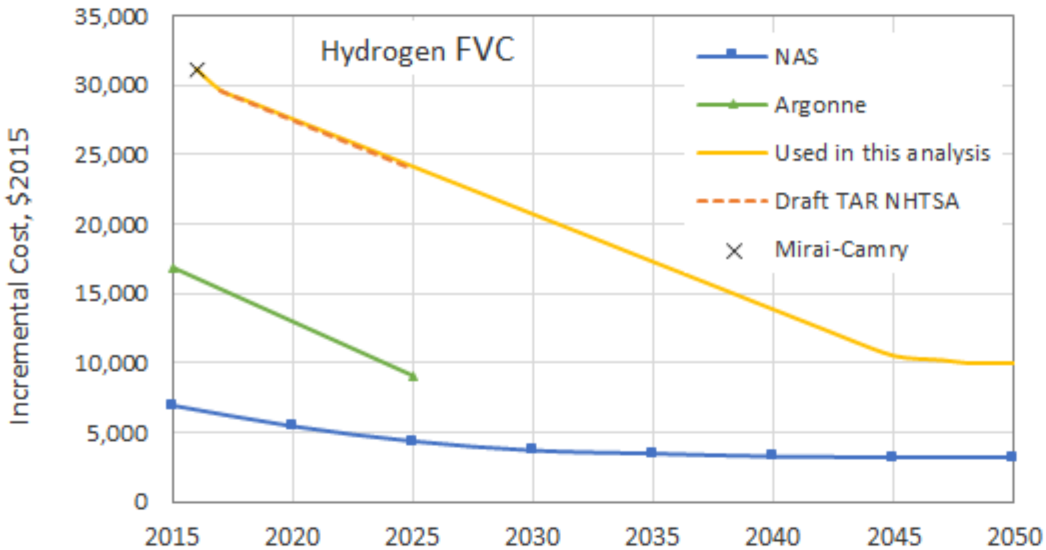

Figure A-20. Incremental cost forecasts for LDA H2 FCV.

A summary of the light auto certification fuel economy and corresponding EER values used in the analysis are provided in Table A-2. The EER values are relative to the gasoline ICE in the year considered, for example, the 2025 EER value is the alternative fuel vehicle fuel economy in 2025 divided by the gasoline ICE fuel economy in 2025. Also provided is the annual average improvement for the 2016-2025 period and the 2025-2050 period. Note that most of the fuel economy improvement occurs before 2025 with the exception of the electric drive technologies. The electric drive vehicles experience the most improvement in fuel economy between 2016-2025 and this improvement continues at only a slightly lower rate through 2050.

Table A-3 summarizes the values used in the analysis for incremental vehicle cost. The gasoline and diesel vehicles experience rising costs through 2025 while the other technology costs decrease dramatically. Note that the hydrogen FCV has much higher incremental cost through 2025 than the next most expensive technology (BEV200), with a significantly worse fuel economy.

Table A-2. Summary of LDA Certification Fuel Economy and EER Analysis Values

	Certification FE, mpgge			EER			Change, mi/gal/yr	
	2016	2025	2050	2016	2025	2050	2016-2025	2025-2050
Gasoline ICE	37	51	58	1.00	1.00	1.00	1.6	0.3
Diesel	44	54	62	1.21	1.06	1.06	1.1	0.3
FFV-Gasoline Mode	37	51	58	1.00	1.00	1.00	1.6	0.3
FFV-EtOH Mode	38	53	60	1.03	1.03	1.03	1.7	0.3
Gasoline HEV	52	69	83	1.42	1.35	1.43	1.9	0.6
PHEV-Gasoline Mode	52	69	83	1.42	1.35	1.43	1.9	0.6
PHEV-Electric Mode	136	162	221	3.71	3.16	3.80	2.9	2.4
BEV-100	136	162	221	3.71	3.16	3.80	2.9	2.4
BEV-200	129	158	216	3.53	3.09	3.72	3.2	2.3
Hydrogen FCV	81	101	138	2.22	1.97	2.37	2.2	1.5

Table A-3. Summary of LDA Incremental Costs (relative to 2015 gasoline ICEV)

	Incremental Cost, $2015			Annual Change	
	2015	2025	2050	2016-2025	2025-2050
Gasoline ICE	0	2,149	2,149	215	0
Diesel	3,100	3,800	3,800	70	0
Gasoline HEV	4,484	3,300	3,000	-118	-12
PHEV	13,500	9,200	8,850	-430	-14
BEV-100	13,500	8,000	7,200	-550	-32
BEV-200	22,000	14,000	12,500	-800	-60
Hydrogen FCV	31,190	24,159	10,000	-703	-566

Light Truck Fuel Economy Projections

Certification forecasts for light truck gasoline ICEVs are summarized in Figure A-21. Similar to the LDA, all the forecasts are in agreement, with the NAS Transitions estimate slightly higher than the rest. The incremental cost forecasts are provided in Figure A-22. The NAS study assumes the 2025 standard is fully adopted in 2030, so its 2030 incremental cost is similar to 2025 estimates of the others. The NHTSA TAR value is lower than the AEO2016 estimate for 2025. This analysis assumes a linear increase to the midpoint between the NHTSA and AEO2016 values, which is essentially the NAS Transitions 2030 value (which should actually be 2025).

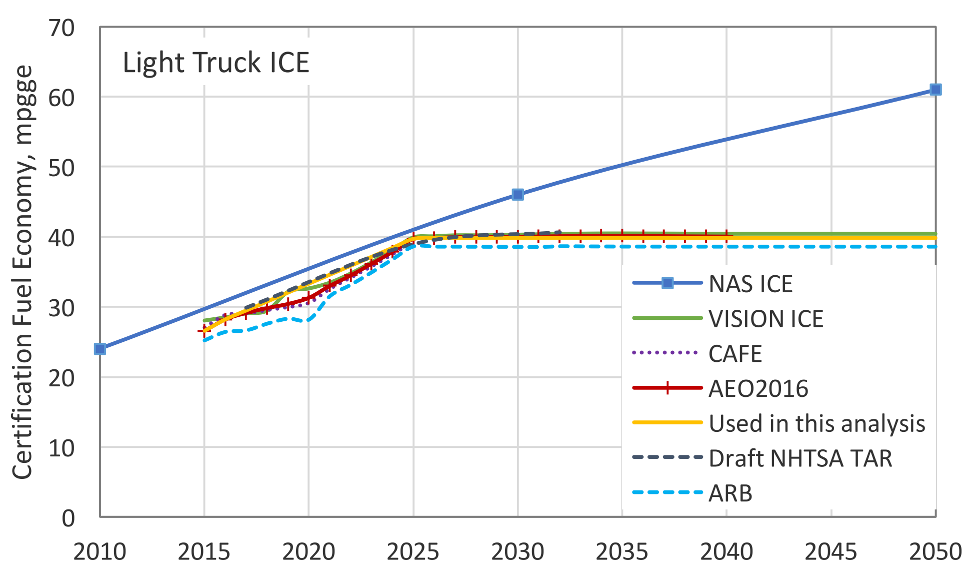

Figure A-21. Certification fuel economy forecasts for LDT gasoline ICEV

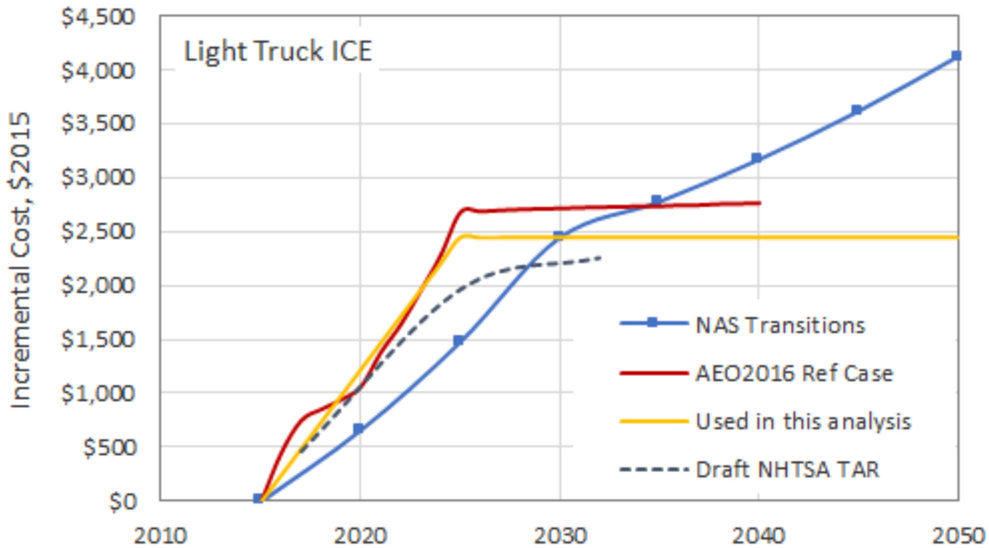

Figure A-22. Incremental cost forecasts for LDT gasoline ICEV

The forecasts for LT diesel fuel economy are illustrated in Figure A-23. For the U.S. analysis, the AEO2016 fuel economy values are used; for the CA analysis, the ARB forecast is used. The ARB and U.S. forecasts may be different due to different LDT1/LDT2/MDV market share assumptions. The AEO2016 forecasts for incremental cost is provided in Figure A-24. In the absence of any other incremental cost projections, the AEO2016 incremental cost is utilized.

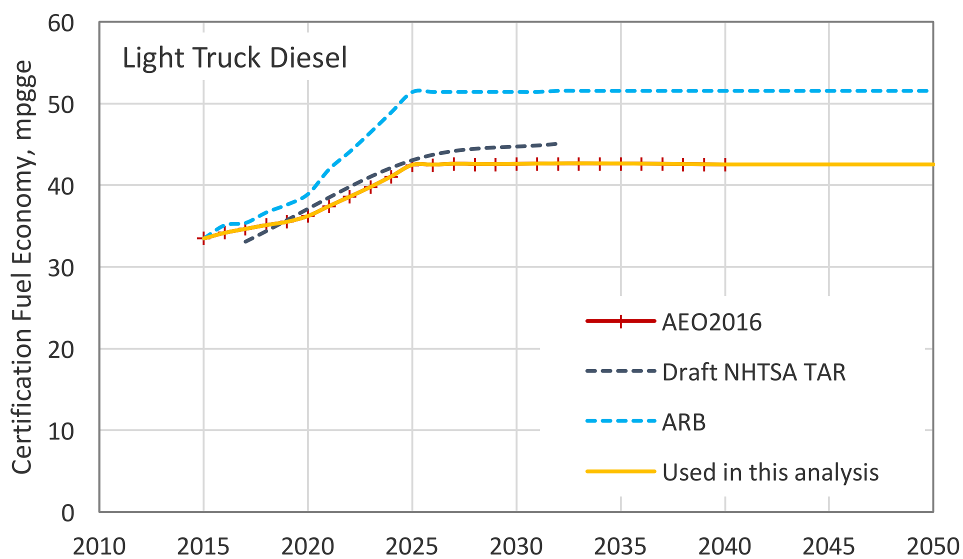

Figure A-23. Certification fuel economy forecasts for LDT diesel

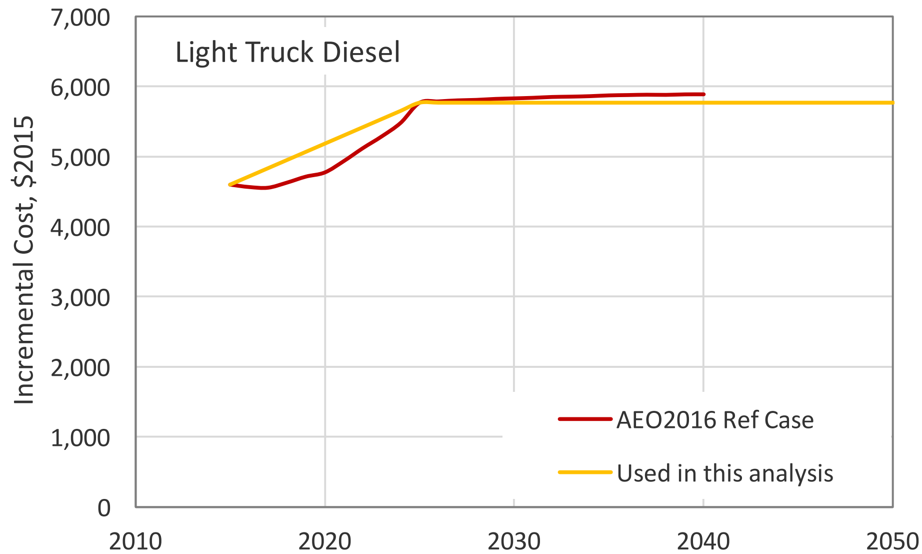

Figure A-24. Incremental cost forecasts for LDT diesel

There are 7 LDT hybrids on the market in 2016 (Figure A-25). The average EER is 1.26. Applying this EER to the gasoline ICE fuel economy, yields an average LDT HEV fuel economy of 35.4 mpg. The average incremental price is $7,100 for MY2016. The average without the luxury models is $4500, but more than half of the sales in 2015 were luxury models.

Figure A-26 summarizes the certification fuel economy forecasts. Most of the forecasts agree although the NHTSA Draft TAR values are difficult to understand with higher near-term fuel economy and lower or flat fuel economy in 2030. For this analysis, the current value(MY2016) is utilized for 2016, increasing linearly to the average of the AEO2016/NHTSA/NAS values in 2025.

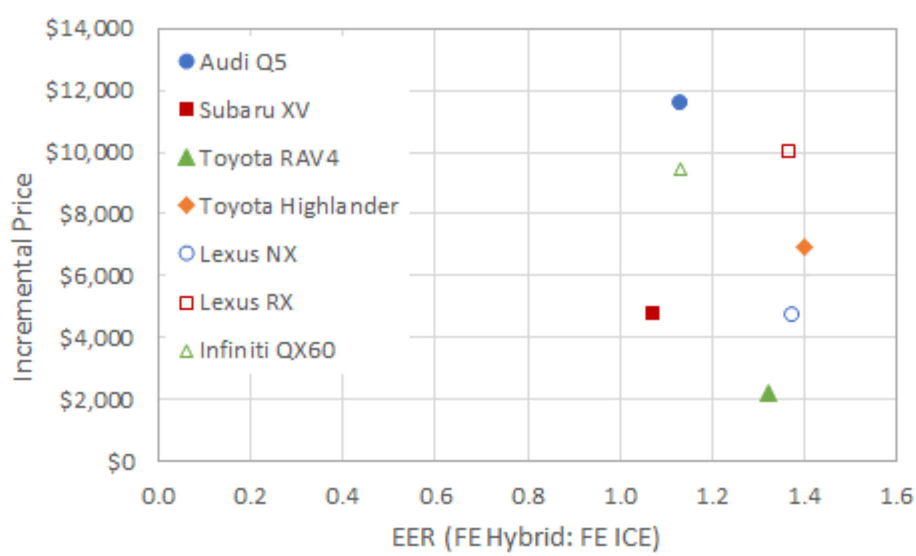

Figure A-25. Incremental cost vs. EER for MY2016 LDT HEV

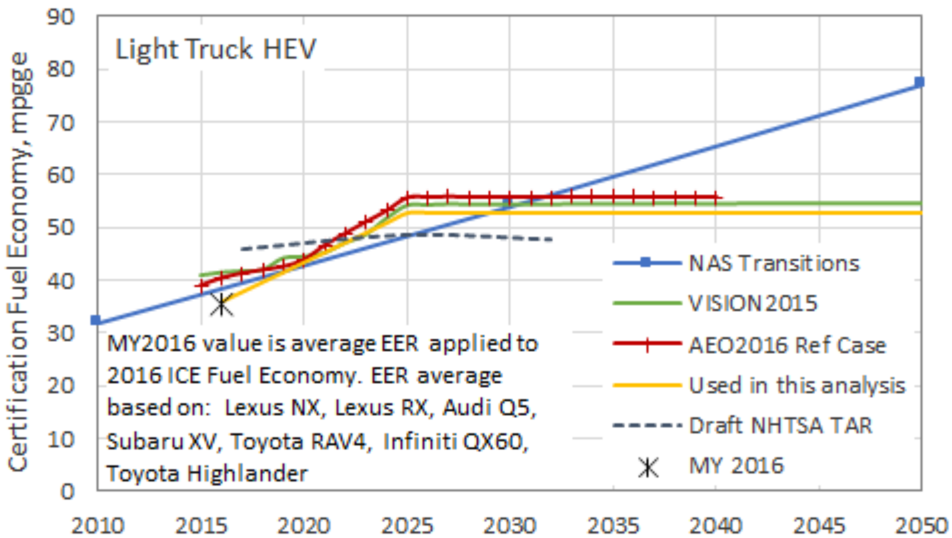

Figure A-26. Certification fuel economy forecasts for LDT HEV

Incremental cost forecasts are summarized in Figure A-27. The AEO2016 values are at the current average increment (with luxury models), but never decrease. The NHTSA and EPA Draft TAR forecasts are similar and seem to be more in line with the current average without the luxury models. For this analysis, the actual 2016 value (with luxury models) is used, with a rapid decrease to the NAS Transitions value in 2030, and remaining there through 2050. Although the assumed incremental cost for 2016-2018 may seem high, none of the analysis scenarios include increased sales of HEVs prior to 2018, so there is no impact on the analysis results.

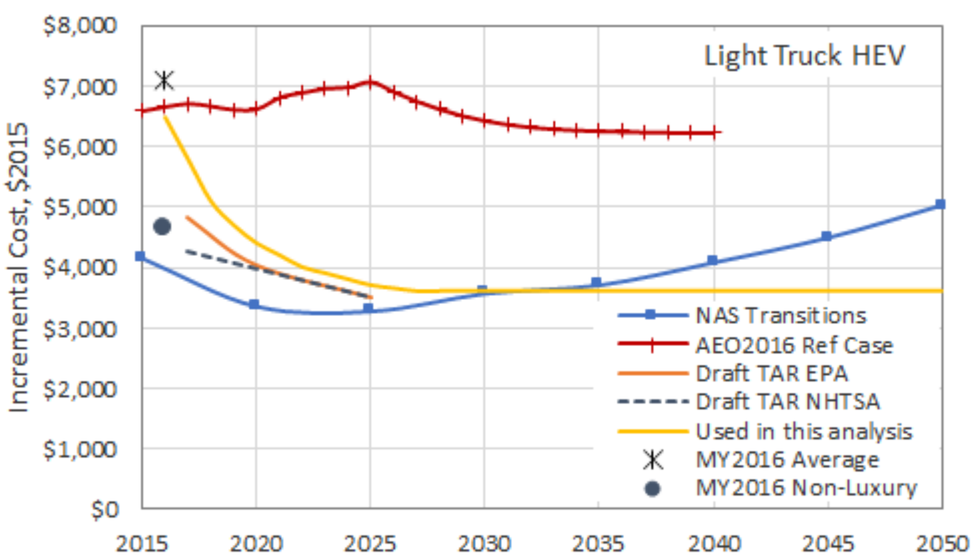

Figure A-27. Incremental cost forecasts for LDT HEV

The LDT BEV discussion starts with BEV200 because the only LDT BEV on the market is the Tesla Model X, which is a BEV200. Figure A-28 summarizes the LDT BEV200 certification fuel economy forecasts. The two Tesla models (different ranges) have similar fuel economy compared to the NHTSA and VISION2015 value for 2016. The NHTSA forecast is flat, in contrast to the AEO2016 value which increases rapidly to 200 mpgge in 2025. Strangely, the AEO2016 estimate for BEV200 is higher than their estimate for the BEV100 and also higher than their estimate for the light auto BEVs. For this analysis, we utilize the 2016 actual value and then increase along the NAS Transitions slope for the BEV100 (see Figure A-30).

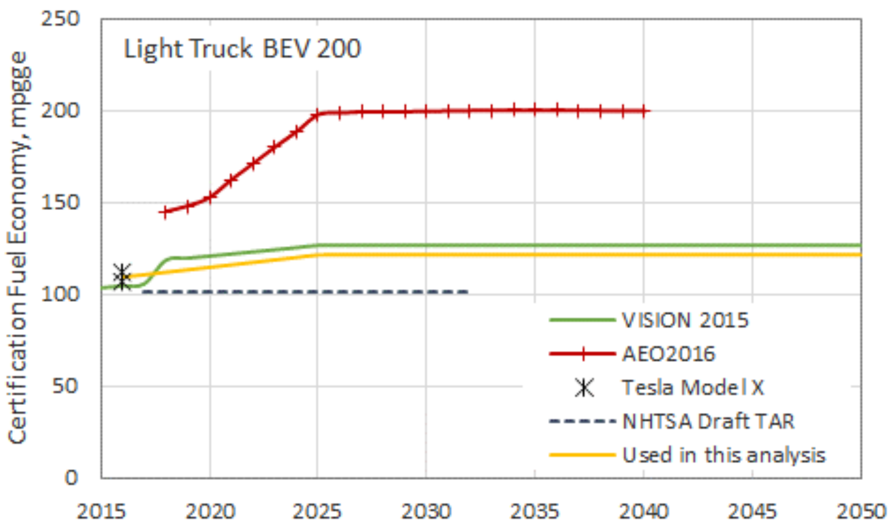

Figure A-28. Certification fuel economy forecasts for LDT BEV200

Incremental cost forecasts are shown in Figure A-29. The NHTSA Draft TAR and AEO2016 forecasts are higher than the EPA Draft TAR forecast. The NAS Transitions forecast is mid-way between the TAR estimates. Recalling that the light auto EPA TAR values are more realistic than the NHTSA values, this analysis utilizes the midpoint between the NHTSA and EPA Draft TAR values for 2016, decreases to the EPA values by 2025, and settles at $16,000 for 2030-2050.

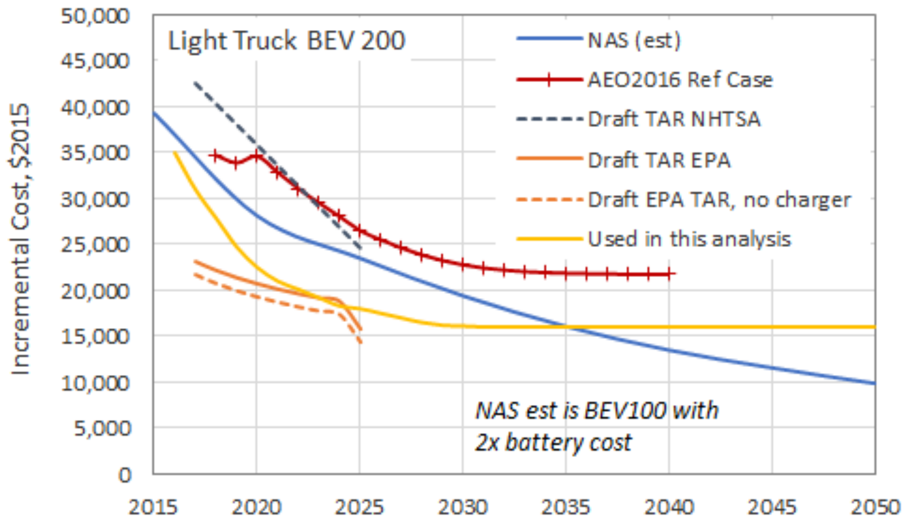

Figure A-29. Incremental cost forecasts for LDT BEV200

The BEV100 fuel economy forecasts are shown in Figure A-30. Note that there are no draft TAR fuel economy projections for LDT BEV100. The values used in this analysis are based on the BEV200 fuel economy projection (similar to the LDA BEV200 projection based on the BEV100). The BEV100 has 10% less weight than the BEV200 (assuming 233 Wh/kg, 45 kWh for the BEV100 and 95 kWh for the BEV200, and a 4600 lb vehicle), which corresponds to a 5.4% fuel economy benefit for the BEV100 relative to the BEV200. This correction applied to the BEV200 forecast lines up exactly with the NAS Transitions estimate.

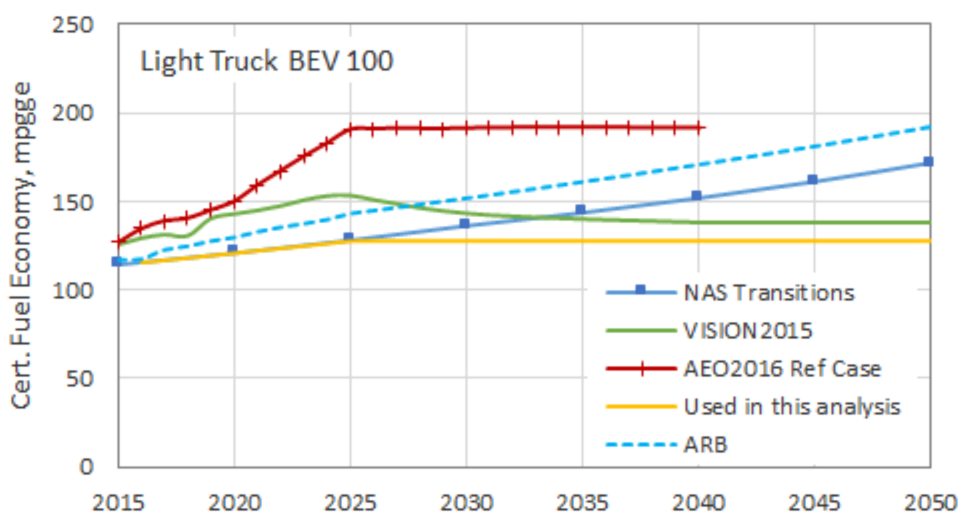

Figure A-30. Certification fuel economy forecasts for LDT BEV100

For BEV100 incremental cost (Figure A-31), this analysis utilizes the EPA Draft TAR forecast and NAS Transition forecasts through 2025, leveling out to $9200 for 2025-2050. There is no NHTSA TAR estimate for BEV100 light trucks.

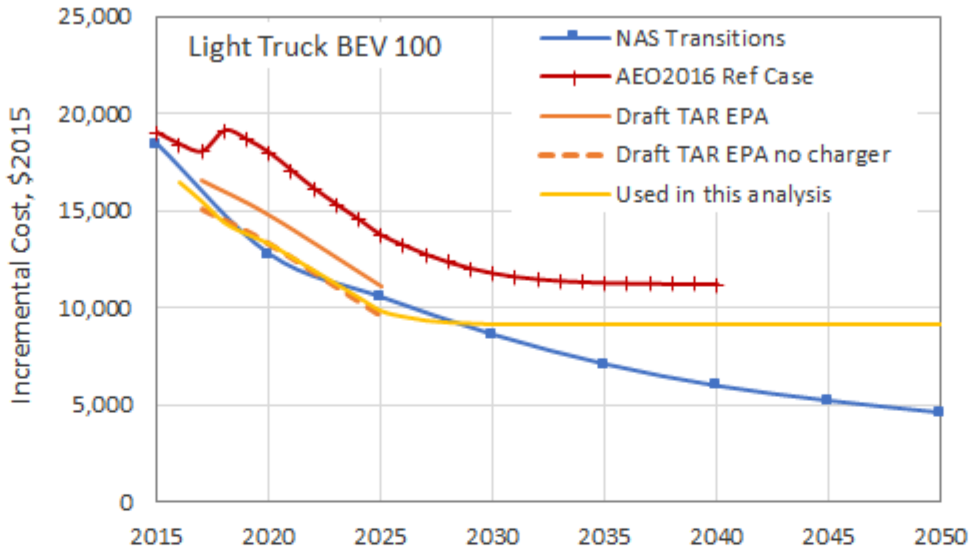

Figure A-31. Incremental cost forecasts for LDT BEV100

For MY2016, there are four LT PHEVs on the market with an average electric fuel economy of 50 mpgge sticker (~ 60 mpgge certification). Three of these models have ICE counterparts; their incremental price vs EER is shown in Figure A-32. The average EER is 2.5 and when this is applied to the ICE fuel economy, the result is 70 mpgge for electric mode. The average incremental price is $7,800 which is lower than the current LDA increment. Incremental price is difficult to discern in luxury vehicles.

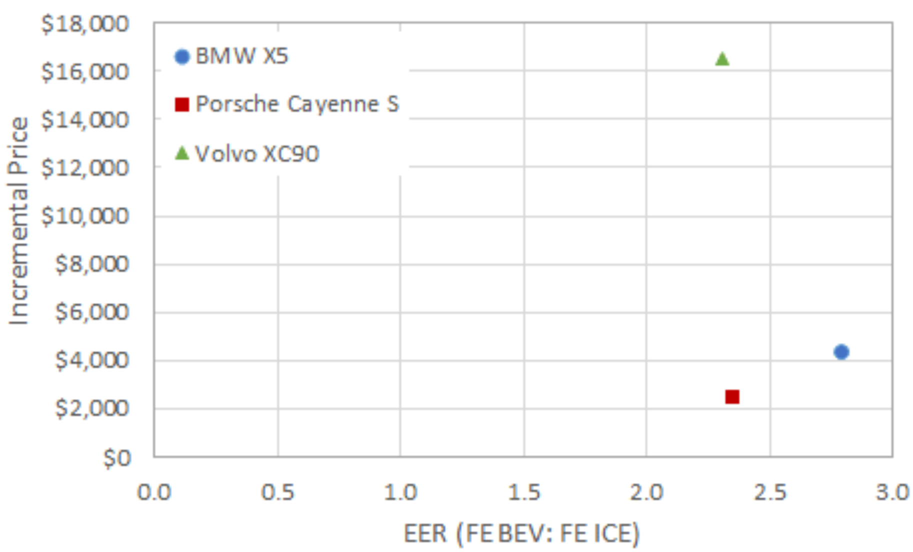

Figure A-32. Incremental cost vs electric mode EER for MY2016 LDT PHEV

Figure A-33 summarizes the electric mode fuel economy forecasts for light truck PHEVs. The NHTSA Draft TAR value is based only on the Porsche Cayenne. The NAS Transitions value is set equal to the BEV100 fuel economy (same as LDA). It is not clear why the current electric mode fuel economy in LDT PHEVs is so much lower than the BEV100 and BEV200 values. For this analysis, we start at the current value and increase linearly to the BEV100 estimate in 2025. Setting the electric mode fuel economy equal to the BEV100 values is consistent with the assumption for LDA that PHEV electric mode fuel economy is the same as the BEV100. It is also consistent with NAS Transitions and other studies.

Incremental cost estimates are shown in Figure A-34. The AEO2016 and NHTSA Draft TAR estimates are on the high side while the NAS Transitions estimate is significantly lower. The EPA Draft TAR forecast is between these two estimates and lines up well with the current Volvo increment. Note that the MY2016 LDA PHEV increment is higher than the BMW and Porsche increments. This analysis utilizes the EPA Draft TAR values, leveling out at $12,000 in 2030.

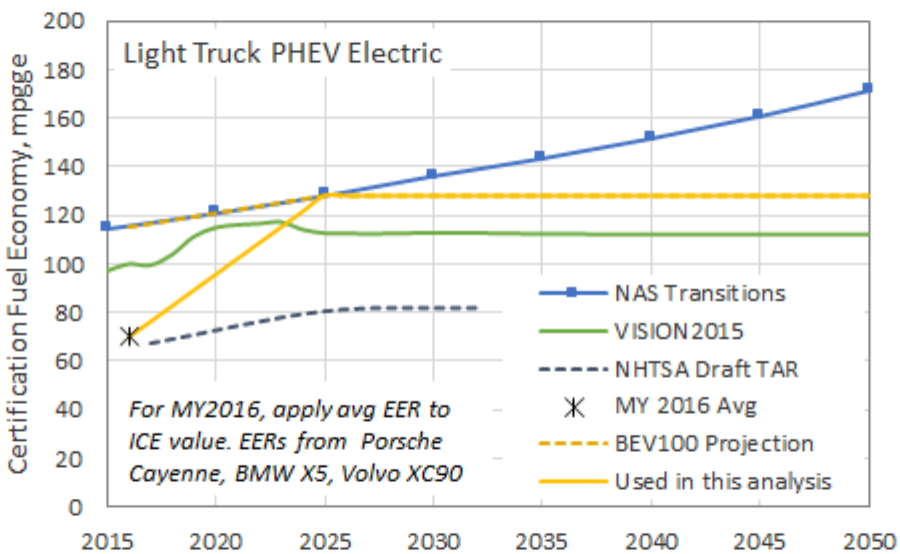

Figure A-33. Certification fuel economy forecasts for LDT PHEV

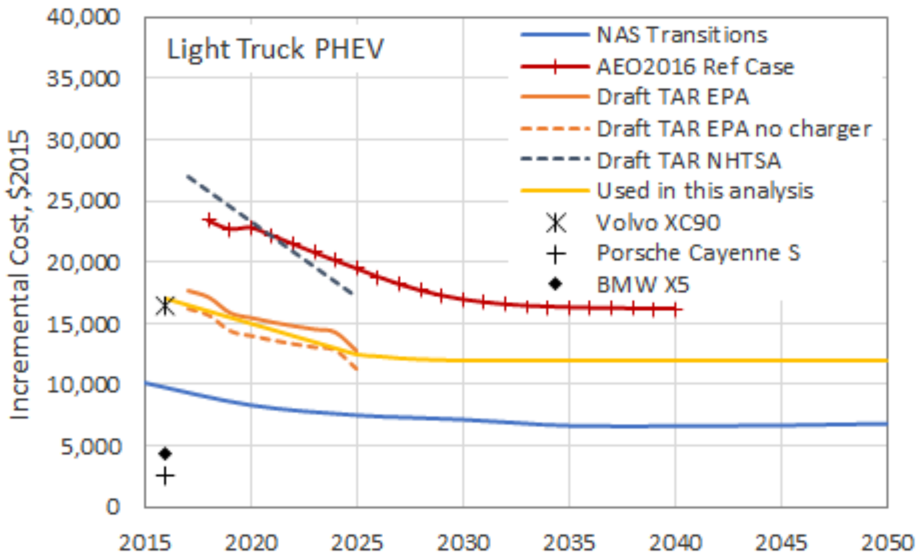

Figure A-34. Incremental cost forecasts for LDT PHEV

Figure A-35 presents the hydrogen FCV fuel economy forecasts. The MY2016 fuel cell Hyundai Tucson (small SUV) is close to the NAS Transitions estimate. The AEO2016 value is surprisingly low (same as gasoline ICE). For this analysis, fuel economy is set at the Tucson value, increasing linearly along the NAS slope until 2025 and leveling off there through 2050. Because our forecast is based on a small SUV, the projection could be biased on the high side. However, since our scenarios do not include increased penetration of FCVs during the analysis time frame, this bias does not affect the results.

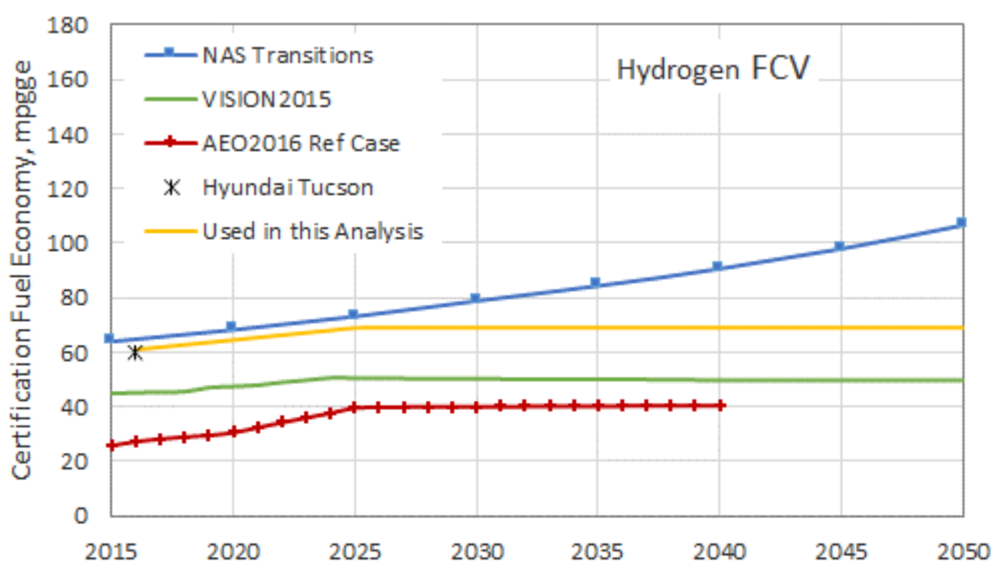

Figure A-35. Certification fuel economy forecasts for LDT H2 FCV

Incremental price estimates are provided in Figure A-36. Unfortunately, the Hyundai Tucson is only available for lease, so an actual incremental price is not available. The AEO2016 forecast is significantly higher than the NAS Transitions forecast, with the NHTSA Draft TAR forecast splitting the difference. Unfortunately, EPA did not provide an estimate for FCVs in the draft TAR. For this analysis, the NHTSA increment is utilized through 2025, decreasing linearly through 2040. Because this analysis does not consider scenarios with large market penetration of FCVs, it is assumed that economies of scale are achieved late in the analysis period.

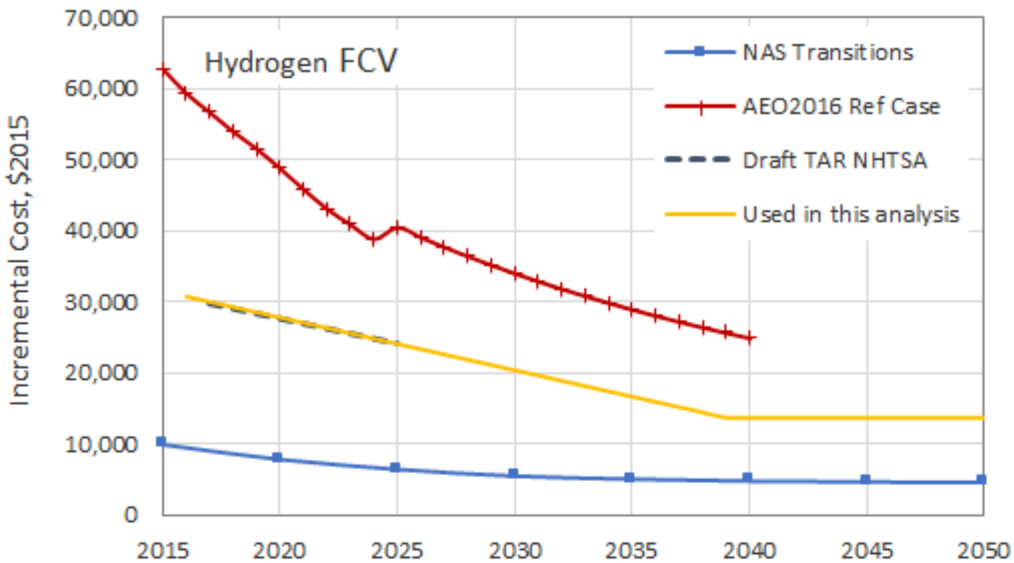

Figure A-36. Incremental cost forecasts for LDT H2 FCV

A summary of the light truck fuel economy and EER values used in the analysis are provided in Table A-4. The EER values are relative to the gasoline ICE in the year considered, for example, the 2025 EER value is the alternative fuel vehicle fuel economy in 2025 divided by the gasoline ICE fuel economy in 2025. Also provided is the annual average improvement for the 2016-2025 period and the 2025-2050 period. In contrast to the LDA fuel economy projections, the LDT electric drive fuel economy values do not improve significantly more on a mi/gal/year basis than the conventional vehicle fuel economy. One exception is the PHEV electric mode fuel economy – recall that the 2016 value is based on the three luxury models available today and then rapidly rises to the BEV100 fuel economy level by 2025. For this reason, the annual progress for 2016-2025 in mi/gal per year is much higher than the other technologies.

Table A-5 summarizes the values used in the analysis for incremental vehicle cost. The gasoline and diesel vehicles experience rising costs through 2025 while the other technology costs decrease dramatically. Note that the hydrogen FCV has much higher incremental cost through 2025 than the next most expensive technology (BEV200), with a significantly worse fuel economy.

Table A-4. Summary of LDT Certification Fuel Economy and EER Analysis Values

	Certification FE, mpgge			EER			Progress, mi/gal/yr	
	2016	2025	2050	2016	2025	2050	2016-2025	2025-2050
Gasoline ICE	28	40	45	1.00	1.00	1.00	1.3	0.2
Diesel	34	42	48	1.21	1.07	1.07	0.9	0.2
FFV-Gasoline Mode	28	40	45	1.00	1.00	1.00	1.3	0.2
FFV-EtOH Mode	29	41	46	1.03	1.03	1.03	1.3	0.2
CNG	27	37	42	0.94	0.94	0.94	1.2	0.2
Gasoline HEV	36	53	64	1.28	1.33	1.41	1.9	0.4
PHEV-Gasoline Mode	36	53	64	1.28	1.33	1.41	1.9	0.4
PHEV-Electric Mode	70	128	175	2.48	3.22	3.88	6.4	1.9
BEV-100	115	128	175	4.08	3.22	3.88	1.4	1.9
BEV-200	109	121	166	3.87	3.06	3.68	1.4	1.8
Hydrogen FCV	61	69	94	2.16	1.74	2.10	0.9	1.0

Table A-5. Summary of LDT Incremental Costs (relative to 2015 gasoline ICEV)

	Incremental Cost, $2015			Annual Change, $/yr	
	2015	2025	2050	2016-2025	2025-2050
Gasoline ICE	0	2,438	2,438	244	0
Diesel	4,600	5,770	5,770	117	0
CNG	9,500	11,938	11,938	244	0
Gasoline HEV	6,500	3,700	3,600	-280	-4
PHEV	17,000	12,500	12,000	-450	-20
BEV-100	16,500	9,800	9,100	-670	-28
BEV-200	35,000	18,000	16,000	-1700	-80
Hydrogen FCV	30,744	24,050	13,638	-669	-417

Dedicated High Octane Fuel (HOF) Vehicles

Potential fuel economy gains due to higher octane gasoline is explored in this analysis. Higher octane fuels with a research octane number (RON) of 100 compared to the current 91 RON for regular grade gasoline would result in small but measurable fuel economy improvements in the legacy fleet and larger improvements in vehicles designed to operate on these fuels. Many vehicles in the existing fleet have knock sensors that retard the spark under high load (knock inducing) conditions, which degrades efficiency. With RON 100 fuels, existing engines would need less spark retard at load, resulting in improved efficiency and power output. Several recent studies[68,69] have been conducted that indicate legacy vehicles may experience a ~1.5% improvement in fuel economy with an increase in RON from current levels to 100. If the spark advance map in the engine software of these legacy vehicles were recalibrated, more improvement would likely be realized.

68 Effects of High Octane Ethanol Blends on Four Legacy FFVs and a Turbocharged GDI vehicle, John Thomas, Brian West, Shean Huff, March 2015, ORNL/TM-2015/116

69 Ethanol and Air Quality: Influence of Fuel Ethanol Content on Emissions and Fuel Economy of FFVs, Carolyn Hubbard, James Anderson, Timothy Wallington, Ford Motor Company, ES&T 2014, 48, 861-867.

The primary reason dedicated HOF vehicles have improved fuel economy is because higher RON allows higher CR (without engine knock) which improves thermodynamic efficiency. Higher compression ratio in turn allows further engine downsizing for the same power output, resulting in additional fuel economy improvement. Aside from the compression ratio and downsizing effects, higher RON allows engines to run at lower speeds and consequently higher loads without engine knock, which improves efficiency. Finally, if the fuel's higher RON is achieved through the use of ethanol blending, further improvement in efficiency could be achieved due ethanol's higher heat of vaporization. More energy is required to vaporize the fuel in the cylinder, lowering cylinder temperatures, reducing heat losses and pumping work.

A recent analysis attempts to correlate improvements resulting from increased RON and ethanol content for new dedicated vehicles[70]. The correlation assumes a one-unit increase in compression ratio for every 3 units of RON increase. Additionally, a 0.5% efficiency improvement is achieved for every 10% increase in ethanol content. Table A-6 shows estimated efficiency improvement enabled by higher RON fuels. The estimated compression ratio for the E70 vehicle is extremely high – if a more modest estimate is used for new vehicle CR (13.2), the overall efficiency improvement is 7.7%. In addition, in this analysis, FFVs are assumed to have the same fuel economy as ICE vehicles while operating on gasoline, but while operating on E85, an EER of 1.03 was applied.

Table A-6. Estimated HOF Dedicated Vehicle Fuel Economy Improvement

Base Fuel	Base Vehicle CR	New Fuel	New Vehicle CR	Estimated Efficiency Improvement
E10, RON92	10.5	E10, RON100	13.2	4.5%
E10, RON92	10.5	E30, RON100	13.2	5.6%
E10, RON92	10.5	E70, RON103	16.4	8.8%
E10, RON92	10.5	E70, RON103	13.2	7.7%

Dedicated HOF vehicle incremental cost values are from the NAS Phase 2 report[71]. For high ethanol blend vehicles, costs are incurred for corrosion resistant injectors, with an estimated cost of $100 for a 6-cylinder auto. The incremental direct manufacturing cost of dedicated HOF vehicles is estimated to range from $75 to $150, depending on engine size. These manufacturing costs were marked up 30% for manufacturer markup and an additional 16% for the dealer markup. The resulting incremental cost projections are shown in Figure A-37 and Figure A-38.

[70] The Effect of Compression Ratio, Fuel Octane Rating, and Ethanol Content on S-I Engine Efficiency, Thomas Leone, James Anderson, Michael Shelby, Ford Motor Company, Richard Davis and William Studzinski, General Motors Powertrain, Asim Iqbal, Ronald Reese, FCA USA LLC (Chrysler), ES&T 2015, 49 10778-10789.
[71] *Cost, Effectiveness and Deployment of Fuel Economy Technologies for Light Duty Vehicles*, National Academy of Sciences, 2015.

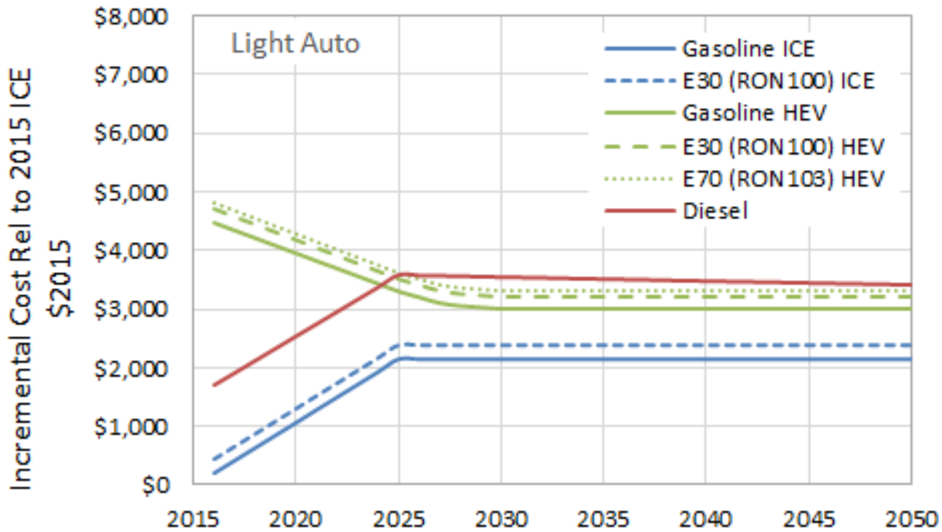

Figure A-37. Incremental cost of dedicated HOF light autos

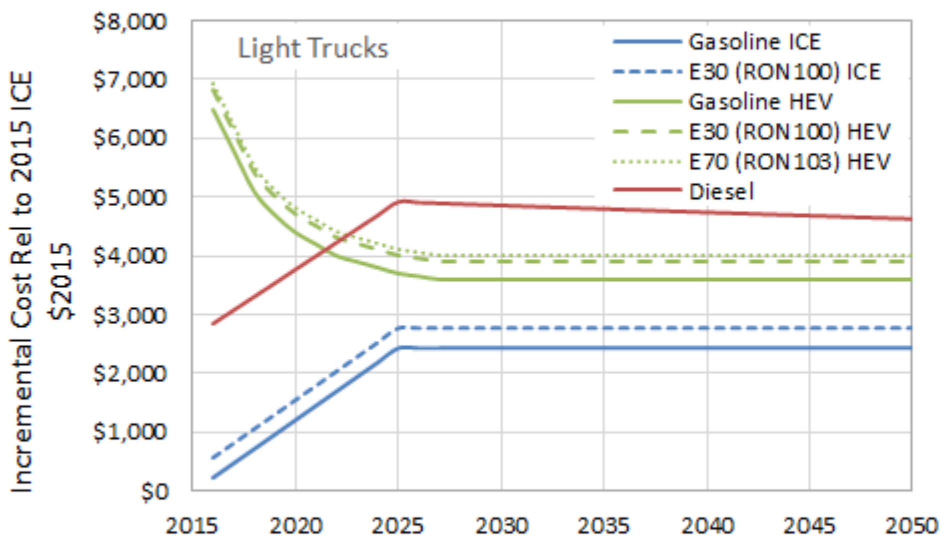

Figure A-38. Incremental cost of HOF light trucks

Appendix B Carbon Intensity Estimates for U.S. Analysis

To quantify GHG emissions in this wedge analysis, carbon intensity (CI) values for each fuel type were selected. CI is defined here as the mass of GHG emissions per unit energy of fuel. The GHG pollutants included are CO_2, CH_4, and N_2O[72] and emissions are quantified on a "well-to-wheel" basis which includes emissions from fuel production activities and vehicle emissions. Two sets of CI values were developed – one for California and one for the entire U.S. Because the wedge analysis extends to 2050, changes in CI over time are quantified. Key considerations for the time dependent estimates are crude oil origin and type, natural gas sources and leakage rates, and electricity generation resource mix. Table B-1 shows the fuel pathways for which CI values were developed.

Table B-1. Fuel and feedstock combinations for which CI values are quantified.

Finished Fuels	Feedstocks
Gasoline Blendstock for E10 Gasoline Blendstock for E10 RON100 Gasoline Blendstock for HOF E30	Petroleum Crude and Cellulose Petroleum Crude Petroleum Crude
Natural Gasoline (E85 Blendstock)	Natural Gas Recovery
Ultra Low Sulfur Diesel	Petroleum Crude and Cellulose
Ethanol (neat)	Corn, Brazilian Sugarcane, Cellulose, NG
Biodiesel	Soybeans, Canola, Corn, Waste Oil
CNG	Natural Gas, Renewable Natural Gas
Electricity	Grid Average
Hydrogen	Natural gas on-site reforming

The GREET[73] model was utilized to quantify CI values. In brief, for each step in a fuel's life cycle, the GREET model methodically calculates direct and upstream GHG and criteria pollutant emissions. The emissions for each step are calculated based on an assumed process efficiency that dictates the total amount of fuel consumed per unit of product produced. The total fuel consumption is split among different fuel types (e.g. crude oil, residual oil, gasoline, natural gas, electricity, etc). For each fuel type, the portion consumed in each different type of combustion equipment is also assumed. Non-combustion emissions such as venting are also included. With these assumptions (process efficiency, fuel shares, combustion device shares, other process emissions), the total direct emissions can be calculated.

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[72] GHGs = $CO_2 + GWP_{CH4}*CH_4 + GWP_{N2O}*N_2O$ where the GWP values are Global Warming Potential factors. GWP factors from the IPCC Fifth Assessment Report were used: 30 for CH_4 and 260 for N_2O. This set of factors is the default selection in GREET1_2015.

[73] Greenhouse Gases, Regulated Emissions and Energy Use in Transportation Model, Argonne National Laboratory. GREET1_2015 released Oct 2, 2015.

Upstream emissions are emissions produced in production and transport of the process fuels that are directly consumed. For example, a process might specify that an amount of natural gas is combusted in a boiler. The direct emissions of natural gas combustion in a boiler are quantified, and the upstream emissions associated with natural gas recovery, processing, transmission and distribution are added. Inclusion of the upstream emissions renders the calculations iterative and changes to one fuel pathway affect all pathways that utilize that fuel. For example, changes in assumptions about natural gas recovery affect not only the CI of the natural gas based fuels, but also the CI values for all fuels that utilize natural gas as a process fuel in their production.

Carbon intensity values utilized in the U.S. wedge analysis were estimated with the most recent version of the GREET model, GREET1_2015. Recently the GREET1_2016 version was released. Key differences between the version adapted for this analysis and the newly released version are noted. In many cases the model was updated with the new assumptions in GREET1_2016. CI values for 2016, 2020 and 2040 were calculated with the GREET1_2015 version of the model updated by LCA. CI values are assumed to change linearly for the periods 2016 to 2020 and 2020 to 2040; 2050 values are assumed to be equal to 2040 values. The following sections describe the underlying assumptions for the fuel pathways in Table B-1. A summary of the resulting CI values is provided at the end of this section.

Petroleum Fuel Assumptions

Petroleum fuel well-to-tank (WTT) CI values can be divided into the crude oil portion and the refining portion. The crude oil portion is the same for gasoline blendstock and diesel. The GREET model calculates crude oil recovery and transport emissions by assuming a crude slate based on EIA[74] projections. Table B-2 provides the GREET1_2015 and GREET1_2016 assumptions on crude origin. The GREET1_2016 values are taken from AEO2015 projections. Because 2020 is the last year in the GREET time series, the AEO2015 value for domestic crude share was used here. Note that EIA's NEMS model predicts a decrease in domestic production. The GREET default shares for the other crude sources were renormalized as shown. The GREET model utilized for this analysis has been updated with the GREET1_2016 values for crude origin.

Table B-2. Crude Oil Source Time Series (vol%)

Crude Source	GREET1_2015		GREET1_2016		EIA[75]	Analysis Values		
	2016	2020	2016	2020	2040	2016	2020	2040
US Domestic	54.3%	65.8%	56.7%	61.9%	51.7%	56.7%	61.9%	51.7%
Canadian Oil Sands	9.8%	12.0%	10.3%	12.9%		10.3%	12.9%	14.7%
Canadian Conv	8.4%	7.0%	9.2%	7.5%		9.2%	7.5%	8.5%
Mexico	4.6%	2.5%	3.4%	3.1%		3.4%	3.1%	3.6%
Middle East	11.5%	6.3%	8.9%	8.1%		8.9%	8.1%	9.2%
Latin America	8.9%	4.9%	9.5%	8.7%		9.5%	8.7%	9.8%
Africa	1.9%	1.0%	1.7%	1.6%		1.7%	1.6%	1.8%
Other	0.6%	0.3%	0.7%	0.7%		0.7%	0.7%	0.8%

[74] DOE's Energy Information Administration

[75] AEO2015 Reference Case, Petroleum Supply and Disposition.

Table B-3 provides the GREET default time series for U.S. crude oil by type. These values have not been updated in GREET1_2016. Default crude oil transport modes and distances, based on crude slate were utilized.

Table B-3. GREET Default Time Series for US Domestic Crude Sources (vol%)

	Bakken Shale	Eagle Ford Shale	Other U.S. Domestic
2016	14.3%	17.6%	68.2%
2020	14.7%	18.1%	67.2%
2030	13.4%	16.5%	70.2%

The GREET model quantifies CI for three gasoline blendstocks:

- Blendstock for gasoline with denatured ethanol content of 10% by volume (E10),
- Blendstock for high octane fuel with 30% denatured ethanol content (HOF E25)
- Blendstock for high octane fuel with 70% denatured ethanol content (HOF E40)

For E10, the model calculates refining efficiency based on crude slate API, sulfur content, refinery heavy product yield, and Nelson complexity index[76]. Because the slate changes over time, the gasoline and diesel refining efficiencies vary over time as shown in Table B-4. The table also provides the refining efficiencies for the two HOF blendstocks. GREET1_2016 provides refining efficiency for each of the PADDs; the values shown in the table and utilized in the analysis are an average of the PADD values. The linear programming analysis used to estimate the HOF refining efficiency values is documented in a recent ANL publication.[77] For this analysis, we will utilize one HOF fuel with 30% ethanol content (HOF E30), which was determined by scaling the GREET HOF E25 and HOF E40 results.

Table B-4. Petroleum Fuel Refining Efficiencies

Fuel	2016	2020	2040
E10 Blendstock	88.6%	88.6%	88.4%
HOF E25 Blendstock		89.0%	
HOF E40 Blendstock		87.8%	
Ultra Low Sulfur Diesel	90.9%	90.9%	90.7%

A relatively new addition to the GREET model is a factor called "Energy Ratio of Crude Oil Feed to Product". This factor allocates the amount of crude recovery and transport emissions to the different refinery products and is based on refinery modeling performed by Argonne National

[76] *Analysis of Petroleum Refining Energy Efficiency of U.S. Refineries*, Argonne National Lab (Cai, Han, Forman, Divita, Elgowainy, Wang), Sasol, and Jacobs Consultancy, 2013.
[77] *Well-to-Wheels Greenhouse Gas Emissions Analysis of High Octane Fuels with Various Market Shares and Ethanol Blending Levels*, Argonne National Lab (Han, Elgowainy, Wang) and Jacobs Consultancy, July 2015.

Laboratory[78]. The units are MJ of crude oil per MJ of product. Previous versions of the model assumed a ratio of 1.0 for all refinery products. Table B-5 provides the GREET1_2016 values for this energy ratio. The E10 and diesel ratios are unchanged from the previous GREET version, but the HOF ratios are much lower compared to the previous values. Lower ratios of crude to product result in lower CI values. Natural gasoline is the assumed blendstock for higher level ethanol blends (E85) in FFVs because this is typically used at present. However, the supply of natural gasoline may be limited, so the scenarios with high penetration rates of E85 HEVs and E85 PHEVs employ gasoline blendstock rather than natural gasoline. Carbon intensity assumptions for natural gasoline blendstock is described several sections **Error! Reference source not found.**.

Table B-5. Ratio of crude use per unit feedstock.

Fuel	MJ Crude per MJ product
E10 Blendstock	0.863
HOF E25 Blendstock	0.916
HOF E40 Blendstock	0.920
Ultra Low Sulfur Diesel	1.001

Natural Gas Production Inputs

This section provides the key assumptions in the natural gas production, distribution and transmission emissions. Table B-6 provides the GREET default values for domestic natural gas recovery efficiency, processing efficiency, and the share of the domestic supply that is produced from shale. These values have not been updated in GREET1_2016. We assume in this analysis that all of the natural gas consumed is domestic.

Table B-6. GREET Default Values for NG recovery and processing

	Portion of NG Supply from Shale	Recovery Efficiency		Processing Efficiency
		Conventional	Shale	
2016	51.5%	97.5%	97.6%	97.4%
2020	53.6%			
2040	55.2%			

One significant issue for natural gas is the quantity of methane that leaks and is vented during recovery, processing, transmission, and distribution. For the most recent version of GREET, ANL updated the leak rates to be consistent with the 2015 EPA GHG inventory (based on 2013

[78] *Energy Efficiency and Greenhouse Gas Emission Intensity of Petroleum Products at U.S. Refineries*, Argonne National Lab (Elgowainy, Han, Cai, Wang) Sasol (Forman), and Jacobs Consultancy (DiVita), May 2014.

data)[79]. The Environmental Defense Fund (EDF) has recently commissioned a suite of studies to try to better quantify the natural gas industry methane emissions. Table 5 of the ANL study provides a comparison of the EPA Greenhouse Gas Inventory (GHGI) values and those from the EDF studies. The EDF sponsored reports include one for gas field emissions by Allen[80], another for gathering and processing emissions by Marchese[81], a report by Zimmerle[82] on methane emissions in transmission, and another by Lamb[83] on distribution emissions. To compare the emission estimates, ANL divided the emission estimates in these reports by EIA estimated total withdrawals to arrive at an emission rate normalized to gas throughput.

Table B-7 provides the values from ANL's table along with those from Tong[84] and the EPA GHGI; default values in GREET1_2015 and GREET1_2016 are also shown. The EPA GHGI gas field emission estimate is similar to the value estimated by Allen, but lower than those estimated by both by EDF studies (Marchese and Tong). Note that the GREET1_2015 estimates for processing, transmission and distribution in GREET are higher than the EDF study values and similar to those estimated by Tong. The GREET1_2016 values are markedly different from the prior model version. Gas field emissions have more than doubled while distribution emissions have decreased. Total leakage has increased and appears to be higher than the other estimates shown. For this analysis, updated GREET1_2016 values were used.

Table B-7. Summary of recent upstream natural gas methane leakage estimates

Activity	GREET1_2015		GREET1_2016		EPA GHGI, 2015	Allen, 2013*	EDF Studies 2015*	Tong, 2015**
	Shale	Conv	Shale	Conv				
Gas Field	0.34%	0.30%	0.77%	0.70%	0.31%	0.38%	0.58%	0.49%
Processing	0.13%		0.13%		0.15%	n/a	0.09%	0.04%
Transmission	0.41%		0.36%		0.36%	n/a	0.25%	0.46%
Distribution	0.33%		0.09%		0.22%	n/a	0.07%	0.31%
Total	1.18%	1.22%	1.28%	1.34%	1.04%		0.99%	1.30%

*Taken from ANL report Table 5 – ANL divided reported methane emission values by EIA gross withdrawals. The Gas Field value utilizes EPA's value for gas field emissions (0.31%) and Marchese's value for gathering (0.27%). The processing value is a combination of EPA's value for routine maintenance and Marchese's processing value.

** Gas field estimate also includes road construction, well drilling, and fracking emissions

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79 *Updated Fugitive Greenhouse Gas Emissions for Natural Gas Pathways in the GREET1_2015 model*, ANL (Burnham, Elgowainy, Wang), October 2015.

80 *Measurements of methane emissions at natural gas production sites in the United States*, David Allen et al, 2013 sponsored by Environmental Defense Fund.

81 *Methane Emissions from United States Natural Gas Gathering and Processing*, Marchese et al, 2015

82 *Methane Emissions from the Natural Gas Transmission and Storage System in the United States*, Daniel Zimmerle et al, July 2015

83 *Direct Measurements Show Decreasing Methane Emissions from Natural Gas Local Distribution Systems in the United States*, Brian Lamb et al, March 2015

84 A Comparison of Life Cycle Greenhouse Gases from Natural Gas Pathways for Medium- and Heavy-duty Vehicles, Fan Tong et al, 2015

GREET maintains constant methane leakage rates over time. In August of 2015, EPA proposed New Source Performance Standards (NSPS) for new and modified equipment in the oil and gas sector. EPA estimates that if the proposed rule is adopted, methane emissions from oil and gas production will decrease by 170,000 short tons in 2020 and 340,000 short tons in 2025. A rough allocation of these emissions reductions between oil and gas production results in approximately 9 percent reduction in gas field methane emissions and a 4% reduction in processing emissions in 2025 with negligible reductions in T&D emissions.

President Obama and Canadian Prime Minister Trudeau pledged to reduce methane emissions from the oil and gas industry by 40% from 2012 levels over the next decade. President Obama's EPA administrator, Gina McCarthy has stated that to meet this goal, new regulations targeting existing sources will need to be promulgated. Because the NSPS standards for new sources and regulations targeting existing source have not been finalized and because the new President opposes environmental regulation, these reductions are not included in this analysis. These controls would reduce the gasoline CI by 0.3% and the CNG CI by 4% in 2040. The vehicle emissions are a large part of the CI for these fuel pathways.

Natural Gasoline Assumptions

Natural gasoline is collected as a condensate at oil and natural gas wells and is currently used as a blending agent for high ethanol blends (E70-E85) (ASTM D5798-13a) for FFVs. Natural gasoline is composed mainly of pentanes with some butanes and hexanes. Natural gasoline is separated from natural gas at the NG recovery processing facility via condensation or distillation. Although the GREET model does not explicitly model natural gasoline, the natural gasoline pathway CI can be estimated using the NG recovery and processing components in GREET combined with the default fuel transport assumptions (mode share and miles) of methanol (correcting for the heating value and density of natural gasoline compared to conventional gasoline[85]). The resulting CI for natural gasoline is 92.1 gCO2e/MJ in 2020.

Electricity Inputs

One key input for the CI calculation of most fuels is the resource mix that is utilized to generate electricity. Table B-8 shows the AEO2016[86] reference case projection. The reference case assumes implementation of EPA's Clean Power Plan (CPP) which was finalized but stayed by the U.S. Supreme Court in February of 2016 while the U.S. Court of Appeals for the District of Columbia reviews it. The lower court will make its ruling in early 2017 and it appeared in September 2016 that the CPP would go forward albeit with a late start.[87] However, on the campaign trail, the new President vowed to undo the CPP and every indication early in his

[85] A ratio of motor gasoline blend component to natural gasoline of 0.885, taken from EIA's Monthly Energy Review - Section 13, is utilized to estimate natural gasoline lower heating value.
[86] U.S. Energy Information Administration Annual Energy Outlook (AEO2016).
[87] "EPA's Clean Power Plan Does Well in Court: Both sides in the fierce legal battle acknowledge that EPA has the early edge", Emily Holden, September 2016, Scientific American. https://www.scientificamerican.com/article/epa-s-clean-power-plan-does-well-in-court/

presidency indicates that CPP will likely not be implemented. There is an AEO2016 side case without the CPP. Both electricity grid mix forecasts are shown in Table B-8. Without the CPP, the coal share in 2040 is projected to be 50% higher than it would be with the CPP.

Three different electricity grid mixes are utilized in this analysis: AEO2016 reference case, AEO2016 reference case without CPP, and low CI mix with 70% non-fossil generation by 2040. Table B-9 provides the 70% non-fossil mix over time. Figure B-1 illustrates the 2040 resource mix for each case considered here. Note that changing electricity grid mix affects all fuel pathways that utilize electricity in their production.

Table B-8. Projections of U.S. average electricity generation resource mix.

	AEO2016 Reference					AEO2016 Reference w/o CPP				
	Oil	NG	Coal	Nuclear	Renew -able	Oil	NG	Coal	Nuclear	Renew -able
2015	1%	26%	37%	22%	14%	1%	26%	37%	22%	14%
2020	0%	22%	37%	21%	20%	0%	22%	38%	21%	19%
2025	0%	24%	31%	21%	23%	0%	23%	37%	20%	20%
2030	0%	29%	25%	21%	25%	0%	24%	35%	20%	20%
2035	0%	28%	24%	20%	27%	0%	25%	34%	19%	22%
2040	0%	29%	22%	20%	28%	0%	26%	32%	19%	23%

Table B-9. Projections of U.S. average electricity generation resource mix.

	70% Non-Fossil Grid Mix				
	Oil	NG	Coal	Nuclear	Renew
2015	0.7%	26%	37%	22%	14%
2020	0.4%	22%	30%	21%	27%
2025	0.3%	24%	23%	21%	32%
2030	0.3%	29%	15%	21%	35%
2035	0.2%	28%	8%	20%	43%
2040	0.1%	30%	0%	20%	50%

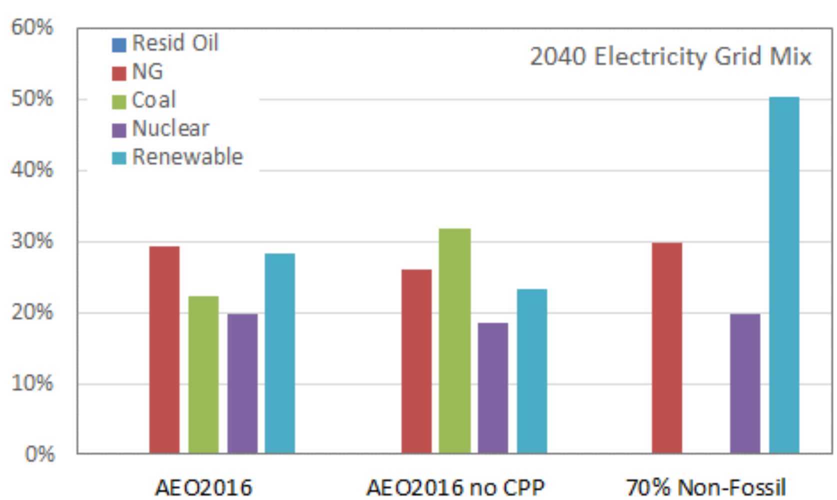

Figure B-1. Comparison of three analysis grid mixes.

GREET also assumes that 3% of coal fired generating capacity would be integrated gasification combined cycle (IGCC) by 2020. According to EIA, total coal generating capacity decreased from 318 GW in 2011 to 281 GW in 2015[88]. Assuming that the aging coal fleet continues to retire in the face of inexpensive natural gas at the same rate, coal capacity in 2020 will be 235 GW. A review of the EPA Clean Air Markets Database indicates that Polk, the first coal fired IGCC unit is currently not operating. Wabash is operating but not on coal. The only IGCC plant currently operating on coal is Edwardsport with a total capacity of 618 MW. Currently two IGCC plants are nearing commercial operation: Kemper City Ratcliffe plant (operating on pipeline NG in 2015) and the Texas Clean Energy project. If all four plants were operational in 2020, they would represent approximately 0.7% of total projected coal capacity. For this analysis, the GREET default of 3% IGCC was reduced to 0.7%.

Corn Ethanol Assumptions

For the wedge analysis, a U.S. average corn ethanol CI value is utilized. Corn ethanol CI consists of farming emissions, corn transport emissions, ethanol production emissions, credits for co-products displacing other products, and ethanol transport. Table B-10 provides the GREET default farming energy use and chemical use. All inputs are assumed to decline to 2020. For this study, the 2040 farming inputs are assumed to be the same as 2020 inputs.

GREET calculates CI values for three types of corn ethanol plants: dry mill plants, dry mill plants that co-produce corn oil, and wet mill plants. Each type has different ethanol yields, fuel consumption, and byproduct yields. Table B-11 summarizes the default yield values in GREET along with total process fuel use estimates. This analysis utilizes the GREET values. Ethanol yield values in 2040 are assumed to be the same as the yield in 2020.

Table B-10. Projected Corn Farming Inputs

GREET Default Values	Units	2015	2020
Farming Energy Use	Btu/bu	9,142	8,698
Nitrogen Use	gN/bu	403	383
Phosphorus Use	g P_2O_5/bu	139	132
Potassium Use	g K_2O /bu	144	137
Calcium Use	g $CaCO_3$ /bu	1,094	1,041
Insecticide Use	g/bu	0.06	0.06
Herbicide Use	g/bu	7	7

Table B-11. GREET Default Ethanol Plant Yields and Energy Use

	Ethanol Yield, gal/bu		Dry DGS	CGF	CGM	Oil	Fuel Use
	2015	2020	lb/gal	lb/gal	lb/gal	lb/gal	Btu/gal
Dry Mill no Oil Extraction	2.86	2.93	5.63				26,856
Dry Mill – with Oil Extraction	2.88	2.95	5.39			0.19	26,421
Wet Mill	2.67	2.74		5.28	1.22	0.98	47,409

[88] EIA Table 4-3 “Existing Capacity by Energy Source” and Form EIA-860.

The distribution of plants between wet and dry mill are summarized in Table B-12. GREET projects a drop in older less efficient wet mill plants from 2015 to 2020. This study assumes that the trend continues such that by 2040, only 5% of plants are wet mill. GREET assumes an 80/20 split of dry mill plants between those that co-produce corn oil and those that don't. GREET also assumes that the share of process fuel that is coal is 8% for dry mill plants and 27.5% for wet mill plants. This study assumes that by 2040, coal use decreases to 2% for dry mill plants and 15% for wet mill plants.

Table B-12. Corn ethanol plant types and fuel share projections

	Plant Shares			% Coal as Process Fuel		
	2015	2020	2040*	2015	2020	2040*
Dry Mill no Oil Extraction	17.7%	18.2%	19%	8%	8%	2%
Dry Mill – with Oil Extraction	70.9%	72.9%	76%	8%	8%	2%
Wet Mill	11.4%	8.9%	5%	27.5%	27.5%	15%

* No GREET default value for 2040. Estimate for this study.

Sugarcane Ethanol Assumptions

For the wedge analysis, an average Brazil sugarcane CI value is utilized. Sugarcane ethanol CI consists of emissions from farming, field burning, sugarcane transport, ethanol production emissions, a credit for exported electricity and ethanol transport. GREET defaults for sugarcane farming inputs are shown in Table B-13. These values are utilized in the present analysis for all analysis years. Table B-14 provides assumptions regarding sugarcane harvesting. It is assumed that by 2020, the practice of field burning will be eliminated and the share of sugarcane left in fields with mechanized harvesting will decrease from 64% to 60% by 2020. For this analysis, the default values for field burning were used; additionally, the share of cane left in unburned fields is assumed to remain constant from 2020 to 2050.

Table B-13. GREET1_2015 Default sugarcane farming inputs

GREET Default Values	Units	2015-2040
Farming Energy Use	Btu/wet tonne	95,000
Nitrogen Use	g N/wet tonne	800
Phosphorus Use	g P_2O_5/wet tonne	300
Potassium Use	g K_2O /wet tonne	1,000
Calcium Use	g $CaCO_3$ /wet tonne	5,200
Insecticide Use	g/wet tonne	45
Herbicide Use	g/wet tonne	2.5

Table B-14. Assumptions regarding sugarcane harvesting

GREET Default Values	2015	2020
Share of fields with manual cutting	15%	0%
Share of fields with field burning	15%	0%
Share of cane left in unburned fields	64%	60%

Sugarcane ethanol plants utilize bagasse to generate steam and electricity to run the plant. Excess electricity is exported to the grid; we assume a credit for this electricity equivalent to the average Brazil electricity resource mix. Table B-15 provides ethanol plant operating assumptions. The GREET default electricity export quantities might be considered aggressive, especially since they are an average value for all sugarcane ethanol plants in Brazil. The Table provides slightly lower values utilized in this study.

Table B-15. Ethanol plant operating assumptions

Values	Units	2015	2020	2040
Ethanol Yield	gal/wet tonne	21.4	21.4	21.4
Energy Use	Btu/gal	300	300	300
Exported Electricity (GREET)	kWh/gal	3.5	4.7	4.7
Exported Electricity (this analysis)	kWh/gal	3	4	4

Cellulosic Ethanol Inputs

The federal Renewable Fuel Standard (RFS2)[89] requires an increasing portion of ethanol sales to be produced from cellulosic feedstocks. Several fuel feedstocks are potential options for cellulosic ethanol. These include corn stover and other crop residues, energy crops such as switch grass, forest residues, municipal solid waste, and other cellulosic materials. Because the cellulosic feedstock with the most commercial interest to date is corn stover, the corn stover fermentation pathway was selected for use in the wedge analysis. The corn stover pathway emissions consist of emissions from collection, makeup fertilizer application, transport, ethanol production and distribution. A 30% field collection rate is assumed with 14% loss from field to plant. Conventional till with a cover crop of rye is assumed for land management practices. **Error! Reference source not found.** provides the GREET1_2015 default field emission parameters that are utilized in the analysis. Table B-17 provides the GREET default ethanol production assumptions that are utilized in this analysis. These assumptions yield CI estimates of less than 10 g CO_2e/MJ.

A review of the cellulosic ethanol pathways submitted to ARB for Low Carbon Fuel Standard (LCFS) compliance indicate that a more realistic average value at present is 25 g CO_2e/MJ. Actual yields and the amount of exported electricity are lower than the GREET values. This analysis assumes that cellulosic ethanol has a CI of 25 g CO_2e/MJ.

Table B-16. GREET1_2015 Default field assumptions for stover

GREET Default Values	Units	2015-2040
Collection Energy Use	Btu/dry ton	192,500
Transport Energy Use	Btu/dry ton	4,200
Rye Farming Energy Use	Btu/dry ton	51,924
Replacement Nitrogen	g N/dry ton	7,000
Replacement Phosphorus	g P_2O_5/dry ton	2,000
Potassium Use	g K_2O /dry ton	12,000

89 Federal Register Citation 75 FR 14670

Herbicide Use (rye)	g/dry ton	582

Table B-17. GREET1_2016 Ethanol plant operating assumptions

Values	Units	2015	2020	2040
Ethanol Yield	gal/dry ton	85	90	90
Fuel Use	Btu/gal	180	180	180
Exported Electricity (GREET)	kWh/gal	2.4	2.3	2.3

Indirect Land Use Change Emissions

An additional source of emissions for biofuel pathways is referred to as indirect land use change (ILUC). ILUC emissions must be quantified for biofuels derived from grown crops. The emissions arise when land used to grow a crop for uses other than biofuel production is converted to grow feedstock for biofuel production. The indirect impacts of this change (increased cultivation of the displaced crop elsewhere) are accounted for. It is very difficult to accurately quantify ILUC emissions; general equilibrium models of world trade are used to evaluate the impact of changes in corn, sugarcane and soybean cultivation to determine where land use change occurs. Additional modeling is done supplemented by satellite photography to determine the carbon emissions associated with the predicted land use change.

A recent study by ICF[90] for the USDA estimates an ILUC value for corn ethanol of 1.3 to 16.9 gCO2e/MJ. Their result is based on GTAP2013 model runs and a variety of different land use change emission factors. This study utilizes the indirect land use change (ILUC) estimates developed by the California Air Resources Board (ARB) and provided in the LCFS Final Regulation Order dated November 16, 2015[91]. Table B-18 provides the ILUC values for the four biofuels utilized in the present analysis.

Table B-18. ARB ILUC values

Fuel	ILUC (gCO_2e/MJ)
Corn Ethanol	19.8
Sugarcane Ethanol	11.8
Soybean Biodiesel	29.1
Canola Biodiesel	14.5

Ethanol from NG

The current abundant supply of low cost natural gas might make it an attractive potential feedstock for ethanol production. Coskata and Celanese have pursued this fuel pathway which consists of converting natural gas to synthesis gas (carbon monoxide and hydrogen) followed by conversion of carbon monoxide and hydrogen directly to ethanol over a catalyst. The natural gas feedstock results in an excess of hydrogen gas that provides either process heat for the production of synthesis gas or potentially a co-product hydrogen stream. The process is

[90] "A Life-Cycle Analysis of the Greenhouse Gas Emissions of Corn-Based Ethanol", January 12, 2017, ICF.
[91] California Code of Regulations, Chapter 17 Part 95480

analogous to methanol production from natural gas, which is produced at world scale with either steam reforming or combined auto-thermal and steam reforming as the means of synthesis gas production. The net stoichiometric reactions are shown below:

$$2CH_4 + 2H_2O \rightarrow 6H_2 + 2CO$$

$$2CO + 4H_2 \rightarrow CH_3CH_2OH + H_2O$$

$$2CH_4 + H_2O \rightarrow CH_3CH_2OH + 2H_2$$

The net reaction for ethanol production results in net products where half of the fuel energy is hydrogen[92]. The net overall reaction for methanol production results in a similar overall stoichiometry where

$$CO + 2\,H_2 \rightarrow CH_3OH$$

In the case of ethanol production, the additional oxygen molecule is converted to water vapor. The overall carbon efficiency for ethanol production is 77%[93] while the efficiency for methanol production[94] is 80%. Thus, the catalytic production of ethanol should be slightly less efficient than methanol production based on the same synthesis gas production route.

This expectation is consistent with preliminary processing data from fuel developers. Without actual yield data, LCA has inferred an ethanol production yield of 0.14 MCF of natural gas per gallon of ethanol from proprietary economic assessments. A separate analysis[95] approximately confirms this yield. This yield is consistent with an overall energy efficiency of 58.6%; for reference, world scale corn ethanol plants have efficiencies ranging from 69 to 71%. With greater thermal integration and on-site power generation from waste synthesis gas an efficiency of 63.7% was assumed and used in the GREET model to estimate the CI for natural gas based ethanol. Table B-19 provides the GREET default values for the production of ethanol from both natural gas and biogas; methanol produced from natural gas is also provided for reference. Because the CI of ethanol produced from NG is higher than the CI of gasoline, it is not considered further in our analysis.

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[92] 46 kg of ethanol x 26.8 MJ/kg ethanol compared with 4 kg of hydrogen x 120 MJ/kg of hydrogen.

[93] 46 kg ethanol x 26.8 MJ/kg/(2 x 16 kg CH_4 x 50 MJ/kg) = 77.1%

[94] 32 kg methanol x 19.9 MJ/(16 kg CH4 x 50 MJ/kg) = 79.6%

[95] "Comparative Economic and Environmental Impacts of Alternative Light Duty Liquid Fuels Produced from Natural Gas", Carnegie Mellon University.

Table B-19. GREET inputs for Natural Gas to Ethanol

Pathway Syngas Source	NG Methanol NG SR	NG Ethanol NG SR	BioGas Ethanol NG SR
Energy Efficiency	70.0%	63.7%	63.7%
Fuel Product			
LHV (MJ/kg)	20	26.8	26.8
Energy (MJ)	35	31.87	31.87
Mass (kg)	1.75	1.19	1.19
Carbon (kg)	0.656	0.621	0.621
Carbon eta	89.9%	85.0%	85.0%
CI (g CO_2/MJ)	98.1	107.7	38.6
MCF/gal	0.118	0.130	0.130

Biogas is also a potential source of ethanol production. Ethanol production facilities could be built at landfills or the biogas could be transmitted by pipeline. Currently much of this biogas is used for CNG applications because biogas to CNG yields a cellulosic RIN credit. The CI of natural gas to ethanol can be as low as 108 g CO_2/MJ and biogas derived ethanol could have a CI below 40 g CO_2/MJ. Potential technology improvements that take advantage of the CO_2 in landfill gas could result in a lower CI.

Summary of CI Values for Each Electricity Grid Mix

With the assumptions described above, the modified GREET model was exercised for three different analysis years (2016, 2020, 2040) and three different electricity grid mixes: AEO2016 with the Clean Power Plan, AEO2016 without the Clean Power Plan, and a 70% non-fossil grid mix. The results are provided below in Table B-20 , Table B-21, and Table B-22, with the relative contribution from the WTT, TTW and ILUC components shown. Note that the values shown in the Tables for cellulosic (stover) ethanol are the values emerging from the modified GREET models. As discussed above, a CI value of 25 g CO_2e/MJ is utilized for cellulosic ethanol in the scenario analysis. The higher value is consistent with actual values from the California LCFS program for several cellulosic fuel producers.

For most fuels, the CI values decrease over time due to decreases in electric power carbon content. One exception to this rule is petroleum fuels; gasoline and diesel values increase over time mainly due to default GREET assumptions regarding crude oil source and resulting impacts on refining efficiency.

Fuels that are a mixture of different feedstocks such as biodiesel, ethanol, and CNG have composite CI values based on assumed feedstock share profiles over time. These feedstock shares are provided in the *Fuel Blend Assumptions* section of the main report.

Table B-20. CI Values for AEO2016 Reference Case with CPP

Base Case	2016			2020			2040			WTW CI, gCO_2e/MJ		
	WTT	TTW	ILUC	WTT	TTW	ILUC	WTT	TTW	ILUC	2016	2020	2040
Gasoline Blendstock	19.2	74.0	0.0	19.6	74.0	0.0	19.5	74.0	0.0	93.1	93.6	93.5
HOF 30 Blendstock	20.2	74.0	0.0	20.5	74.0	0.0	20.2	74.0	0.0	94.1	94.5	94.2
E70 Blendstock	11.5	80.7	0.0	11.5	80.7	0.0	11.4	80.7	0.0	92.2	92.1	92.0
ULSD	15.6	75.6	0.0	16.1	75.6	0.0	16.0	75.6	0.0	91.2	91.7	91.6
Ethanol MW Corn Avg	50.7	0.1	19.8	47.7	0.1	19.8	44.9	0.1	19.8	70.6	67.6	64.8
Ethanol Sugarcane	26.7	0.1	11.8	25.5	0.1	11.8	25.5	0.1	11.8	38.6	37.4	37.4
Ethanol Stover	4.0	0.1	0.0	4.7	0.1	0.0	6.8	0.1	0.0	4.0	4.8	6.9
Biodiesel Soybean	23.0	3.9	29.1	22.6	3.9	29.1	22.1	3.9	29.1	56.0	55.6	55.1
Biodiesel Canola	31.2	3.9	14.5	30.8	3.9	14.5	30.3	3.9	14.5	49.6	49.2	48.7
Biodiesel Tallow	29.1	3.9	0.0	28.3	3.9	0.0	27.2	3.9	0.0	33.0	32.3	31.1
Biodiesel Corn Oil	11.7	3.9	0.0	11.2	3.9	0.0	10.5	3.9	0.0	15.7	15.1	14.4
Renew Diesel Soy	23.3	0.0	29.1	23.1	0.0	29.1	22.6	0.0	29.1	52.4	52.2	51.7
Renew Diesel Canola	31.2	0.0	14.5	31.0	0.0	14.5	30.4	0.0	14.5	45.7	45.5	44.9
Renew Diesel Corn Oil	12.5	0.0	0.0	12.1	0.0	0.0	11.4	0.0	0.0	12.5	12.1	11.4
CNG	19.4	62.2	0.0	19.0	62.2	0.0	18.2	62.2	0.0	81.6	81.1	80.4
Electricity	154.0	0.0	0.0	136.4	0.0	0.0	104.3	0.0	0.0	154.0	136.4	104.3
Hydrogen-NG	119.8	0.0	0.0	115.8	0.0	0.0	110.2	0.0	0.0	119.8	115.8	110.2
Hydrogen-Elec	246.3	0.0	0.0	201.9	0.0	0.0	154.4	0.0	0.0	246.3	201.9	154.4

Table B-21. CI Values for AEO2016 Reference Case without Clean Power Plan

AEO2016 no CPP	2016			2020			2040			WTW CI, gCO_2e/MJ		
	WTT	TTW	ILUC	WTT	TTW	ILUC	WTT	TTW	ILUC	2016	2020	2040
Gasoline Blendstock	19.2	74.0	0.0	19.7	74.0	0.0	19.9	74.0	0.0	93.1	93.6	93.8
HOF 30 Blendstock	20.2	74.0	0.0	20.5	74.0	0.0	20.6	74.0	0.0	94.1	94.5	94.6
E70 Blendstock	11.5	80.7	0.0	11.5	80.7	0.0	11.4	80.7	0.0	92.2	92.1	92.1
ULSD	15.6	75.6	0.0	16.1	75.6	0.0	16.4	75.6	0.0	91.2	91.7	91.9
Ethanol MW Corn Avg	50.7	0.1	19.8	47.8	0.1	19.8	45.8	0.1	19.8	70.6	67.7	65.7
Ethanol Sugarcane	26.7	0.1	11.8	25.5	0.1	11.8	25.5	0.1	11.8	38.6	37.4	37.4
Ethanol Stover	4.0	0.1	0.0	4.6	0.1	0.0	5.3	0.1	0.0	4.0	4.7	5.4
Biodiesel Soybean	23.0	3.9	29.1	22.6	3.9	29.1	22.4	3.9	29.1	56.0	55.6	55.5
Biodiesel Canola	31.2	3.9	14.5	30.8	3.9	14.5	30.6	3.9	14.5	49.6	49.2	49.1
Biodiesel Tallow	29.1	3.9	0.0	28.4	3.9	0.0	28.0	3.9	0.0	33.0	32.3	32.0
Biodiesel Corn Oil	11.7	3.9	0.0	11.2	3.9	0.0	11.0	3.9	0.0	15.7	15.2	14.9
RD Soybean	23.3	0.0	29.1	23.1	0.0	29.1	22.9	0.0	29.1	52.4	52.2	52.0
RD Canola	31.2	0.0	14.5	31.0	0.0	14.5	30.8	0.0	14.5	45.7	45.5	45.3
RD Corn Oil	12.5	0.0	0.0	12.1	0.0	0.0	11.9	0.0	0.0	12.5	12.1	11.9
CNG	19.4	62.2	0.0	19.0	62.2	0.0	18.8	62.2	0.0	81.6	81.2	80.9
Electricity	154.0	0.0	0.0	137.9	0.0	0.0	126.9	0.0	0.0	154.0	137.9	126.9
Hydrogen-NG Reforming	119.8	0.0	0.0	116.0	0.0	0.0	114.1	0.0	0.0	119.8	116.0	114.1
Hydrogen-Electrolysis	246.34	0	0	204.11	0	0	187.78	0	0	246.3	204.1	187.8

Table B-22. CI Values for 70% Non-Fossil Case

70% Non-Fossil by 2040	2016			2020			2040			WTW CI, gCO_2e/MJ		
	WTT	TTW	ILUC	WTT	TTW	ILUC	WTT	TTW	ILUC	2016	2020	2040
Gasoline Blendstock	19.2	74.0	0.0	19.3	74.0	0.0	18.4	74.0	0.0	93.1	93.3	92.4
HOF 30 Blendstock	20.2	74.0	0.0	20.1	74.0	0.0	19.0	74.0	0.0	94.1	94.1	92.9
E70 Blendstock	11.5	80.7	0.0	11.4	80.7	0.0	11.2	80.7	0.0	92.2	92.1	91.8
ULSD	15.6	75.6	0.0	15.8	75.6	0.0	15.0	75.6	0.0	91.2	91.4	90.6
Ethanol MW Corn Avg	50.7	0.1	19.8	46.9	0.1	19.8	42.4	0.1	19.8	70.6	66.8	62.2
Ethanol Sugarcane	26.7	0.1	11.8	25.4	0.1	11.8	25.3	0.1	11.8	38.6	37.3	37.2
Ethanol Stover	4.0	0.1	0.0	6.0	0.1	0.0	10.8	0.1	0.0	4.0	6.0	10.8
Biodiesel Soybean	23.0	3.9	29.1	22.3	3.9	29.1	21.1	3.9	29.1	56.0	55.3	54.2
Biodiesel Canola	31.2	3.9	14.5	30.4	3.9	14.5	29.2	3.9	14.5	49.6	48.9	47.7
Biodiesel Tallow	29.1	3.9	0.0	27.6	3.9	0.0	24.9	3.9	0.0	33.0	31.6	28.8
Biodiesel Corn Oil	11.7	3.9	0.0	10.7	3.9	0.0	9.1	3.9	0.0	15.7	14.7	13.0
RD Soybean	23.3	0.0	29.1	22.7	0.0	29.1	21.6	0.0	29.1	52.4	51.8	50.7
RD Canola	31.2	0.0	14.5	30.6	0.0	14.5	29.4	0.0	14.5	45.7	45.1	43.9
RD Corn Oil	12.5	0.0	0.0	11.6	0.0	0.0	9.9	0.0	0.0	12.5	11.6	9.9
CNG	19.4	62.2	0.0	18.5	62.2	0.0	16.7	62.2	0.0	81.6	80.7	78.9
Electricity	154.0	0.0	0.0	116.4	0.0	0.0	41.7	0.0	0.0	154.0	116.4	41.7
Hydrogen-NG Reforming	119.8	0.0	0.0	112.3	0.0	0.0	99.4	0.0	0.0	119.8	112.3	99.4
Hydrogen-Electrolysis	246.34	0	0	172.19	0	0	61.66	0	0	246.3	172.2	61.7

Appendix C Carbon Intensity Estimates for the California Analysis

For the California analysis, CI values were taken directly from ARB's most recent LCFS compliance scenario.[96] In addition to CI values for a range of fuel/feedstock combinations, ARB also provides projected volumes of different types of ethanol, biodiesel and CNG so that composite CI values can be calculated. LCA used CA-GREET2 to calculate electricity and hydrogen CI values.

Table C-1 provides the CI values for California reformulated blendstock for oxygenate blending (CARBOB), ultra low-sulfur diesel (ULSD), Fossil CNG, renewable natural gas (RNG), average biodiesel (BD), and renewable diesel (RD). Note that CARBOB's CI is ~ 7 gCO2e/MJ higher than the U.S. blendstock value. ARB employs the OPGEE model to calculate the emissions from crude recovery and transport. The crude portion of the CARB pathway is approximately 12 g/MJ as in contrast to 6.5 g/MJ for the U.S. average blendstock. ARB's compliance scenario assumes that the current share of RNG in CNG is 44% followed by a steady increase to 93% by 2025. In this analysis, it is assumed that the 93% share is maintained through 2050.

Table C-1. ARB projected CI values for petroleum, BD, RD and CNG

	ARB Illustrative Compliance Scenario CI Values, gCO2e/MJ					
	CARBOB	ULSD	Average BD	Average RD	Fossil CNG	Renew CNG
2015	99	98	20	35	71	20
2016	101	103	20	30	78	20
2017	101	103	20	30	78	20
2018	101	103	19	30	78	20
2019	101	103	19	30	78	19
2020	101	103	18	30	78	19
2021	101	103	18	30	78	19
2022	101	103	17	30	78	19
2023	101	103	17	30	78	18
2024	101	103	16	30	78	18
2025	101	103	16	30	78	18

ARB's CI values for the different types of ethanol are shown in **Error! Not a valid bookmark self-reference.**. The "corn+" category is for ethanol derived from corn/sorghum and corn/sorghum/wheat mixtures. Table C-3 provides ARB's projected volumes of ethanol by feedstock type through 2025. It is assumed for the base case that the 2025 shares are maintained through 2050. A low CI ethanol case is also considered. Figure C-1 provides the relative shares of the different ethanol feedstocks for this case. For 2015-2025, the shares are the same as in the BAU case; after 2025, cellulosic shares steadily increase to 70% of the total. It is assumed that corn and corn+ provide a minimum of 30% of the ethanol through 2050. The result is decreasing shares of imported sugarcane and molasses.

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96 ARB LCFS Illustrative Compliance Scenario, 4-1-15.

Table C-2. ARB projected CI values for ethanol (with ILUC)

	ARB Ethanol CI Values, gCO2e/MJ				
	Corn	Cane	Corn+	Cellulosic	Molasses
2015	83	70	74	20	23
2016	70	44	68	20	33
2017	69	44	67	20	33
2018	67	43	66	20	36
2019	66	43	65	20	36
2020	65	42	64	20	36
2021	64	42	63	20	35
2022	63	41	62	20	35
2023	62	41	61	20	35
2024	61	40	61	20	34
2025	60	40	60	20	34

Table C-3. ARB projected ethanol shares

	ARB Projected Ethanol Shares				
	Corn	Cane	Corn+	Cell	Molasses
2015	79%	10%	10%	0%	1%
2016	74%	13%	10%	0%	3%
2017	68%	17%	12%	1%	3%
2018	57%	24%	12%	3%	4%
2019	51%	27%	12%	5%	4%
2020	47%	30%	12%	7%	4%
2021	39%	33%	11%	13%	4%
2022	36%	33%	11%	16%	4%
2023	31%	33%	12%	20%	4%
2024	27%	34%	12%	24%	4%
2025	22%	34%	12%	27%	4%

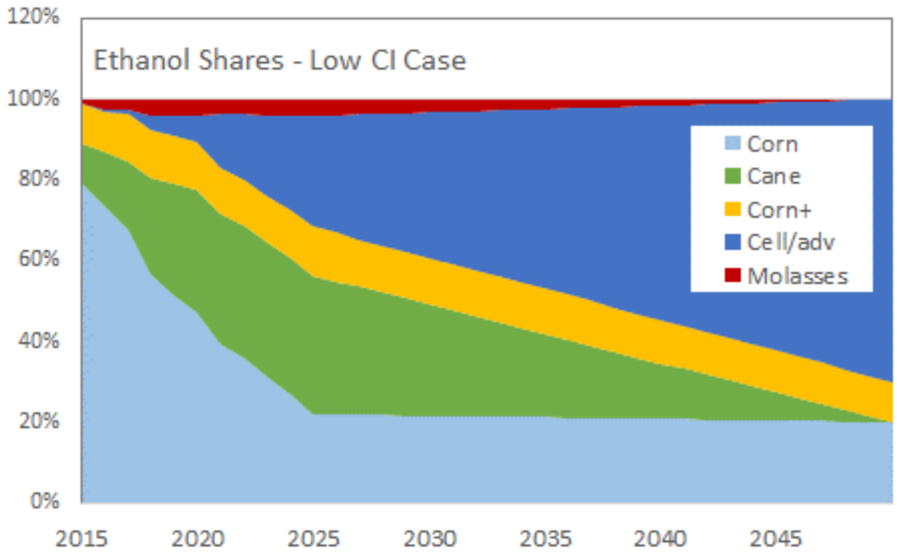

Figure C-1. Ethanol shares through 2050 for the low CI ethanol case.

LCA utilized the CA-GREET2 model to calculate CI values for electricity over time. The first step was to project the grid resource mix. CEC's total system power report[97] for 2015 was utilized; it was assumed that the 2016 mix was the same as the 2015 mix. In 2025, PG&E's Diablo Canyon is slated to shut down, bringing California's nuclear generation to 0. PG&E (44% of total supply) has pledged to replace this power with 55% renewables. In 2030, the grid is to be 50% renewable (PG&E at 55%). For the base case, we assume 2050 is the same as 2030. For the low CI case, it is assumed that the grid is 70% non-fossil. These grid mix projections are tabulated in Table C-4 and provided graphically in Figure C-2. Note that the 70% non-fossil case provides a 22% decrease in CI relative to the base case in 2050. Table C-5 provides a comparison of California and U.S. electricity CI values. Without the CPP, the U.S. electricity CI is double the CA base case value by 2030.

Table C-4. Assumed California electricity resource mix

	Oil	Gas	Coal	Nuclear	Biomass	Other Renew
2016	0%	49%	7%	11%	3%	30%
2025	0%	42%	2%	0%	3%	53%
2030	0%	40%	0%	0%	3%	57%
2050 (70% NF)	0%	30%	0%	0%	3%	67%

[97] http://www.energy.ca.gov/almanac/electricity_data/total_system_power.html

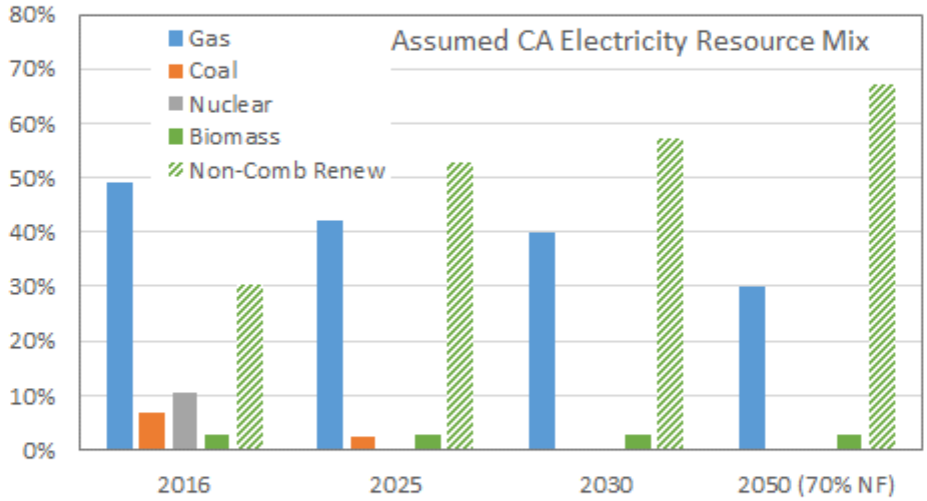

Figure C-2. Electricity grid mix assumption.

Table C-5. Electricity CI Values

	California gCO_2e/MJ	California, 70% NF gCO_2e/MJ	U.S. w/CPP gCO_2e/MJ	U.S. no CPP gCO_2e/MJ
2016	99	99	154	154
2025	74	74	136	138
2030-2050	64	50		
2040-2050			104	127

State law[98] requires that 33% of all hydrogen sold be produced from renewable resources. For this analysis, it is assumed that 33% is produced via electrolysis using 100% renewable electricity. The balance is assumed to be on-site natural gas steam reforming. Table C-6 provides the CA-GREET2 results for these two pathways and the resulting composite CI.

Table C-6. Assumed Hydrogen CI Values.

CI, gCO2e/MJ	100% Renewable Electrolysis	On-Site NG Steam Reforming	Composite Hydrogen
2016	12.8	109.3	77.4
2025	9.7	106.5	74.5
2030-2050 (base case)	8.3	105.3	73.3
2050 (70% NF)	6.4	103.6	71.5

[98] CA Senate Bill 1505, 2006

Appendix D Vehicle Market Shares for U.S. Scenario Analysis

Four main scenarios were evaluated and compared to a business-as-usual (BAU) case. There is one scenario for each key vehicle technology (BEV, PHEV, dedicated E85 PHEV, and dedicated E85 HEV). Note that the dedicated E85 vehicles are designed to take advantage of the octane boost associated with high ethanol blends so have a better fuel economy than an FFV. These vehicles are fueled exclusively with E85. Table D-1 Summarizes the scenarios considered.

Table D-1. New vehicle market share assumptions for U.S. analysis scenarios.

Scenario	2050 LDA Market Share	2050 LDT Market Share
BAU	85% Gasoline ICE 1% Diesel 6% HEV 3% PHEV 4% BEV 1% H2 FCV	94% Gasoline ICE 2% Diesel 1% HEV 1% PHEV 1% BEV 1% FCV
1. Max BEV	70% BEV 15% E85 HEV 4.3% Gasoline ICE All others BAU	45% BEV 45% E85 HEV 4.6% Gasoline ICE All others BAU
2a. Max PHEV/E85 HEV	80% PHEV 4.4% E85 HEV 4.3% Gasoline ICE All others BAU	45% PHEV 45% E85 HEV 4.6% Gasoline ICE All others BAU
2b. Max PHEV/CNG	Same as 2a	45% PHEV 46% CNG 4.6% Gasoline ICE All others BAU
3. Max E85 PHEV	81% E85 PHEV 4.3% Gasoline ICE All others BAU	45% E85 PHEV 45% E85 HEV 4.6% Gasoline ICE All others BAU
4. Max E85 HEV	81% E85 HEV 4.3% Gasoline ICE All others BAU	90% E85 HEV 4.6% Gasoline ICE All others BAU

The following guidelines were used to adjust new vehicle market shares:

- To ensure a fair comparison between scenarios, gasoline ICE market shares in each scenario were decreased to 1.8% for LDA and 2.4% for LDT.
- All other technology shares were maintained at BAU levels except LDT FFV. The 2050 BAU market share for LDT FFVs is 19%. This was decreased to 3% to allow significant penetration of alternative vehicles.
- Because BEV market share is limited by homes with EVSE access, for LDA the maximum possible market share is set at 70% for BEVs and 80% for PHEVs.

- For LDTs, BEVs do not provide towing capability. It was assumed that maximum LDT market share for BEVs and PHEVs is 45%. Dedicated E85 HEVs and NGVs are also sold.
- It is assumed that dedicated E85 HEVs have a faster ramp up to goal market penetration than electrification options because they are less expensive

Figure D-1 and Figure D-2 illustrate the market shares of new light auto and light truck sales for Scenario 1 (Max BEV). The primary LDA sales are BEVs, followed by dedicated E85 HEVs since 100% market share is not realistic. As noted above, maximum LDT BEV market share was limited to 45%. The 2050 market share for BEVs is the same as the assumed market share of LDT E85 HEVs.

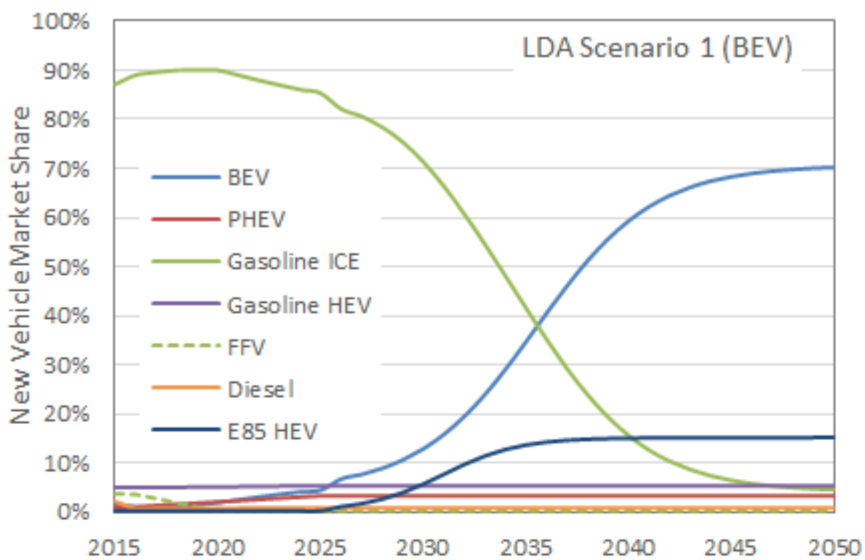

Figure D-1. LDA assumed new vehicle market shares for U.S. Scenario 1.

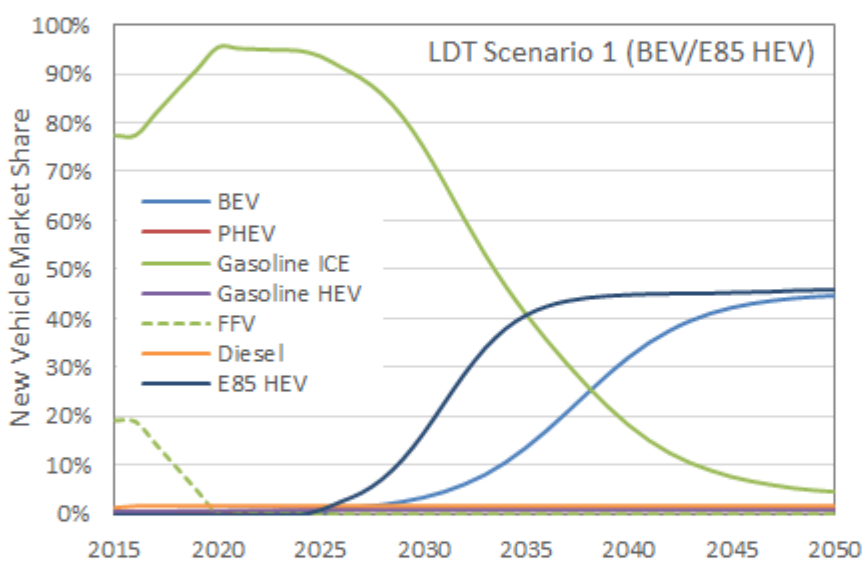

Figure D-2. LDT assumed new vehicle market shares for U.S. Scenario 1.

Scenario 2 is the Max PHEV scenario. The new vehicle market share assumptions for LDAs are provided in Figure D-3 while the LDT assumptions for Scenario 2a and Scenario 2b are shown in Figure D-4 and Figure D-5, respectively. As mentioned above, the maximum PHEV market share for LDTs is limited to 45%. In Scenario 2a, LDT PHEVs are supplemented with dedicated E85 HEVs while in Scenario 2b the PHEVs are supplemented with CNG vehicles.

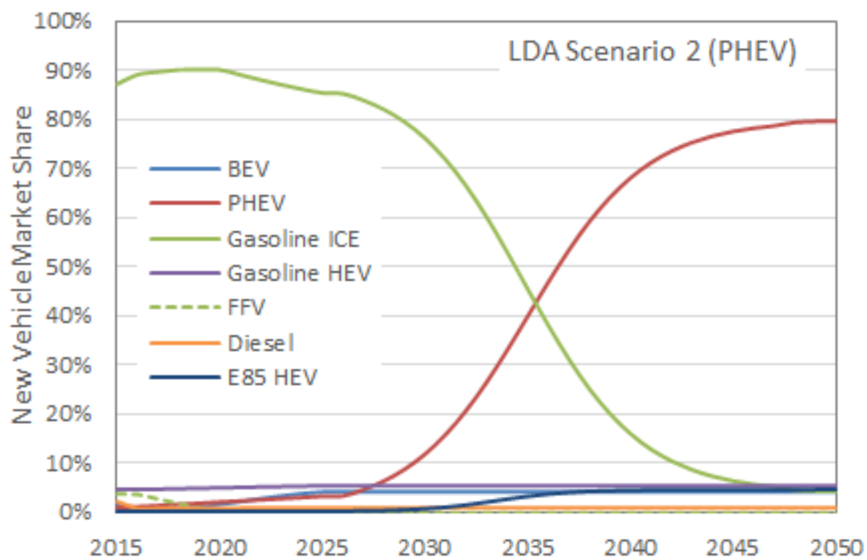

Figure D-3. LDA assumed new vehicle market shares for U.S. Scenario 2a and 2b.

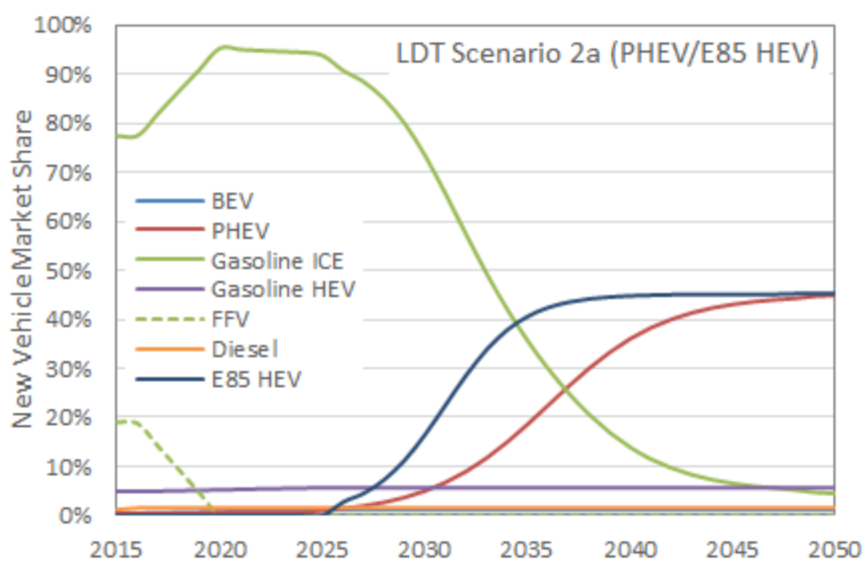

Figure D-4. LDT assumed new vehicle market shares for U.S. Scenario 2a.

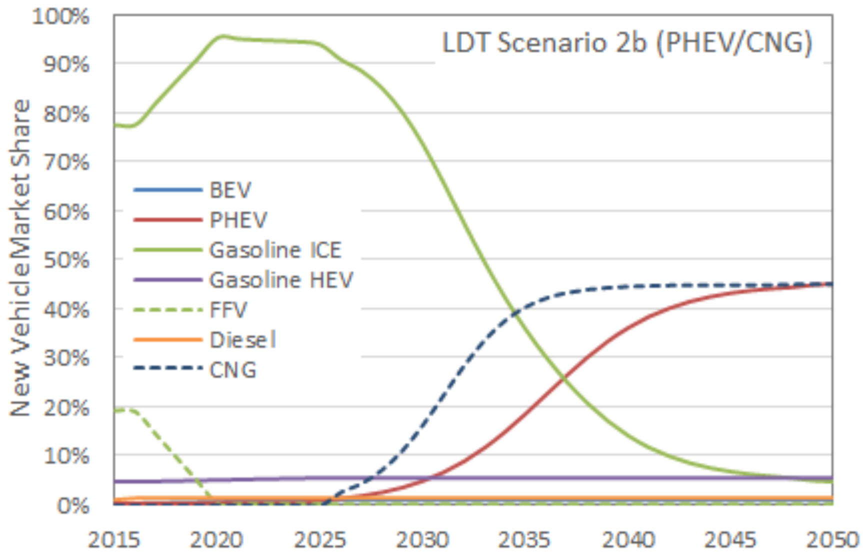

Figure D-5. LDT assumed new vehicle market shares for U.S. Scenario 2b.

Scenario 3 is similar to Scenario 2 except that it focuses on dedicated E85 PHEVs rather than gasoline PHEVs. Figure D-6 illustrates the assumed market share assumptions for LDAs while Figure D-7 provides the LDT assumptions.

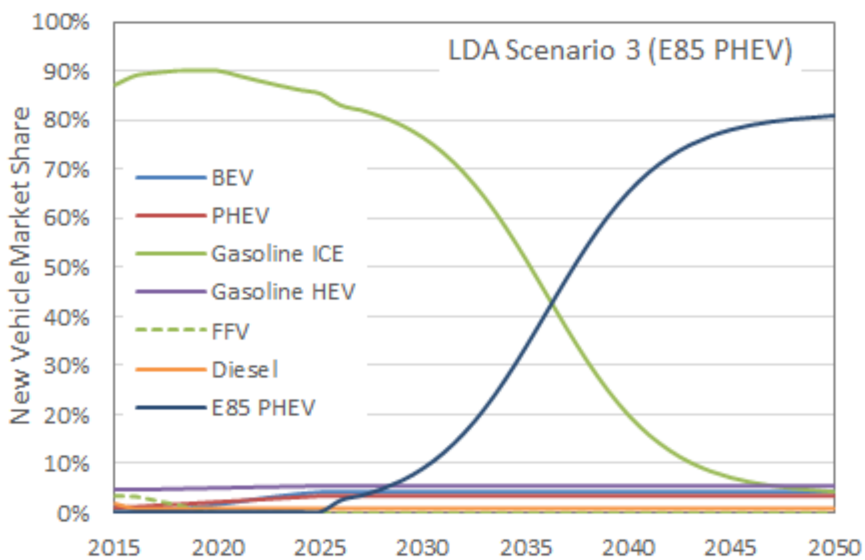

Figure D-6. LDA assumed new vehicle market shares for U.S. Scenario 3.

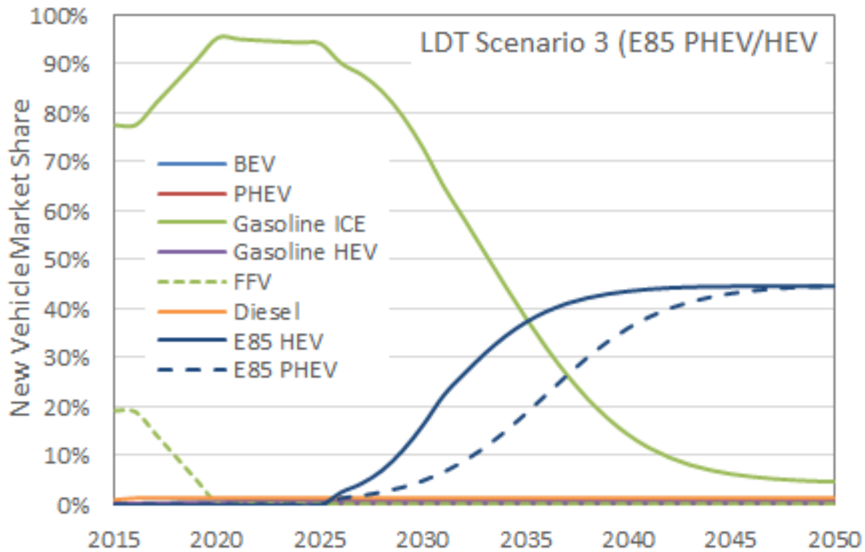

Figure D-7. LDT assumed new vehicle market shares for U.S. Scenario 3.

Scenario 4 focuses on maximum penetration of dedicated E85 HEVs. The assumed market shares of new LDAs are provided in Figure D-8 while the LDT market shares are illustrated in Figure D-9.

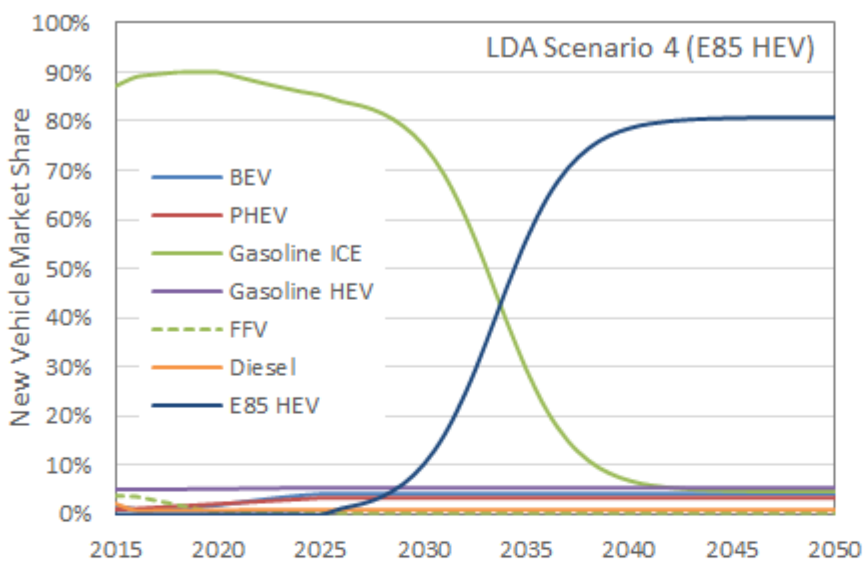

Figure D-8. LDA assumed new vehicle market shares for U.S. Scenario 4.

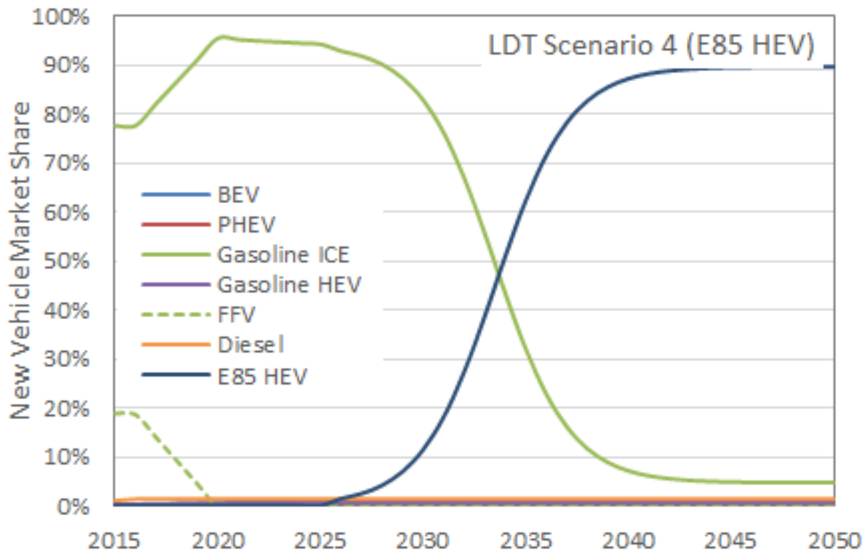

Figure D-9. LDT assumed new vehicle market shares for U.S. Scenario 4.

Appendix E Vehicle Market Shares for CA Scenario Analysis

Consistent with the U.S. analysis, the California analysis considers four main scenarios. There is one scenario for each key vehicle technology: BEV, PHEV, dedicated E85 PHEV, and dedicated E85 HEV. Table E-1 provides the new vehicle market share values in 2050 for each scenario.

Table E-1. New vehicle market share assumptions for California analysis scenarios.

Scenario	2050 LDA Market Share	2050 LDT Market Share
1. Max BEV	70% BEV 2% Gasoline ICE All others BAU	43% BEV 43% E85 HEV 2% Gasoline ICE All others BAU
2a. Max PHEV/E85 HEV	75% PHEV 2% Gasoline ICE All others BAU	45% PHEV 45% E85 HEV 2% Gasoline ICE All others BAU
2b. Max PHEV/CNG	Same as 2a	45% PHEV 46% CNG 2% Gasoline ICE All others BAU
3. Max E85 PHEV	65% E85 PHEV 2% Gasoline ICE All others BAU	43% E85 PHEV 43% E85 HEV 2% Gasoline ICE All others BAU
4. Max E85 HEV	65% E85 HEV 2% Gasoline ICE All others BAU	83% E85 HEV 2% Gasoline ICE All others BAU

The following guidelines were used to adjust new vehicle market shares:

- To ensure a fair comparison between scenarios, gasoline ICE market shares in each scenario were decreased to 2% for LDA and LDT.
- All other technology shares were maintained at BAU levels.
- Because BEV market share is limited by homes with EVSE access, it is assumed that maximum possible BEV market share is 70%, and maximum PHEV market share is 80% for LDA.
- Because electrification is not currently compatible with towing capability, it was assumed that maximum LDT market share for BEVs and PHEVs is 45%. To maximize LDT alternative vehicles, PHEVs and BEVs were supplemented with E85 HEVs or NGVs.
- It is assumed that E85 HEVs and NGVs have a faster market penetration than electrification options

Figure E-1 and Figure E-2 illustrate the assumed LDA and LDT new vehicle market shares for Scenario 1. Our guidelines limit the maximum BEV penetration to 45%, but the California BAU PHEV shares were higher than in the U.S. analysis. To limit total electric drive market share to 45% for LDTs, the maximum BEV market share was limited to approximately 42%. As in the U.S. analysis, LDT market shares were supplemented with dedicated E85 HEVs.

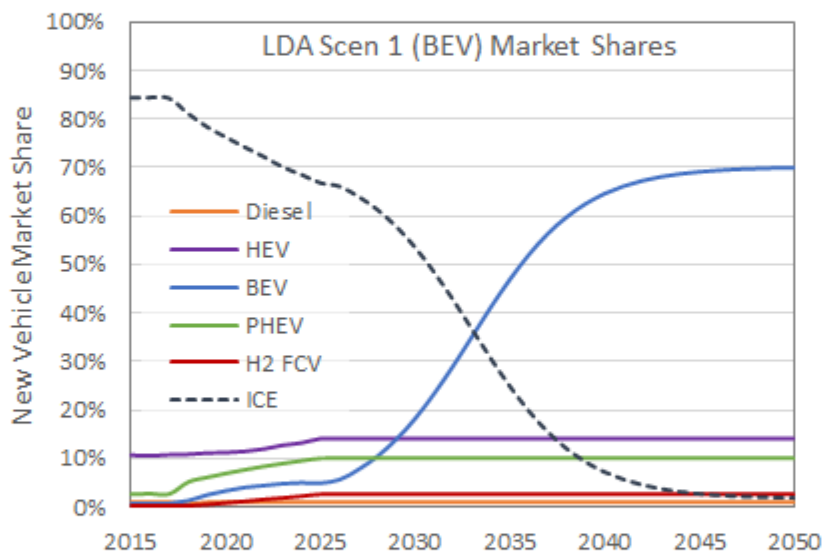

Figure E-1. LDA assumed new vehicle market shares for CA Scenario 1.

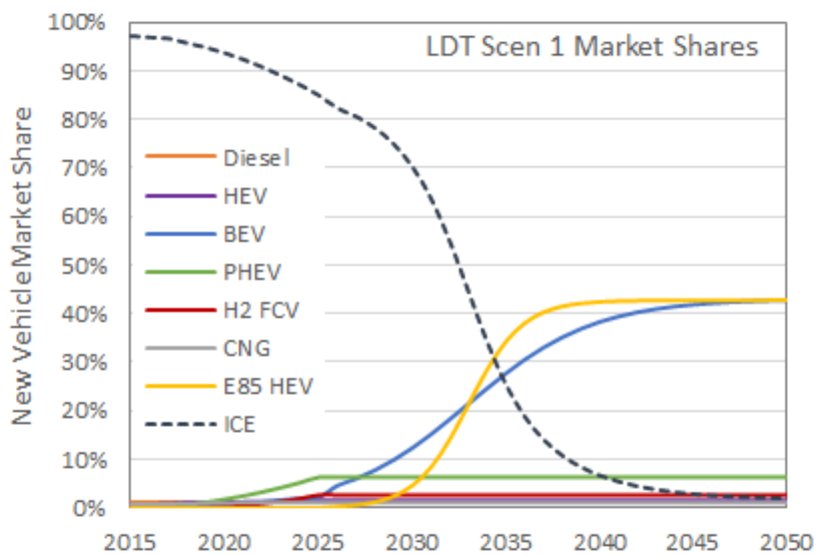

Figure E-2. LDT assumed new vehicle market shares for CA Scenario 1.

Figure E-3 provides the LDA market shares for Scenario 2 (max PHEV). Note that in the U.S. analysis, additional shares of dedicated E85 HEVs were assumed to maximize the number of alternative vehicles sold. However, because the California BAU has so many HEVs in the out years, it wasn't possible to add more alternative vehicle market share. The LDT market share assumptions for Scenario 2a (Max PHEV/Max E85 HEV) are provided in Figure E-4 while market share assumptions for Scenario 2b (Max PHEV/Max CNG) are provided in Figure E-5.

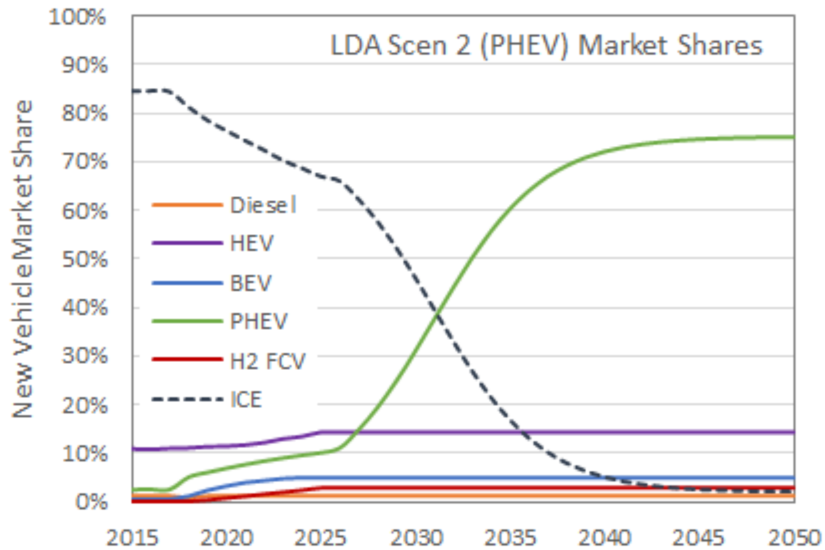

Figure E-3. LDA assumed new vehicle market shares for CA Scenario 2a and 2b.

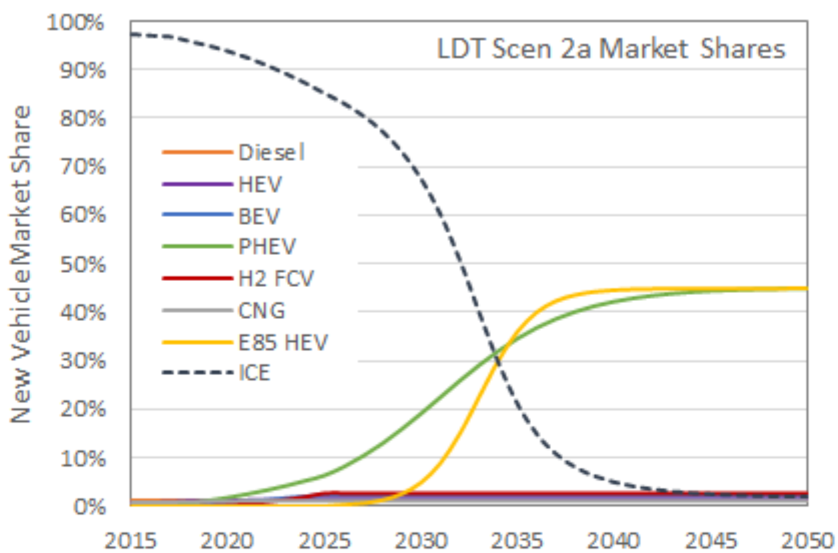

Figure E-4. LDT assumed new vehicle market shares for CA Scenario 2a.

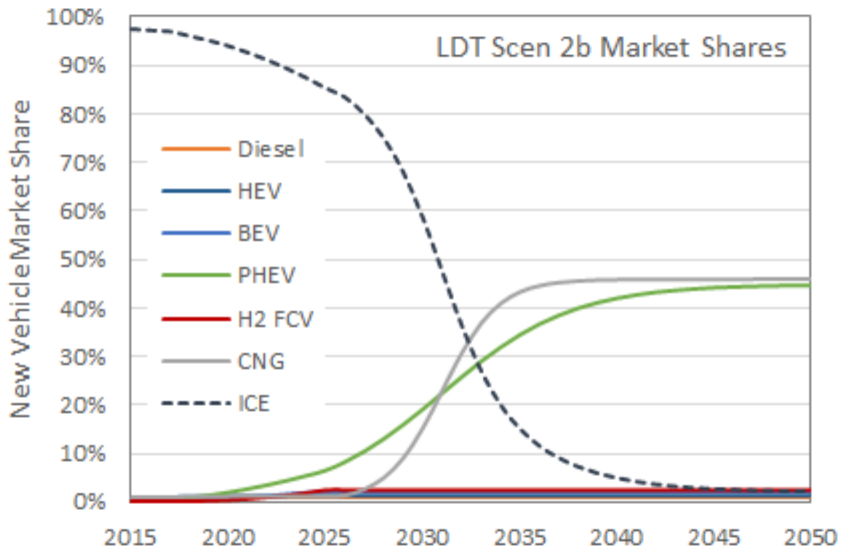

Figure E-5. LDT assumed new vehicle market shares for CA Scenario 2b.

Scenario 3 assumes the maximum number of dedicated E85 PHEVs are sold. For LDA (Figure E-6), gasoline PHEVs are maintained at BAU levels while E85 PHEVs are increased until the combined total reaches 75% by 2050. Similarly, total LDT PHEV market share (Figure E-7) is not allowed to exceed 45%.

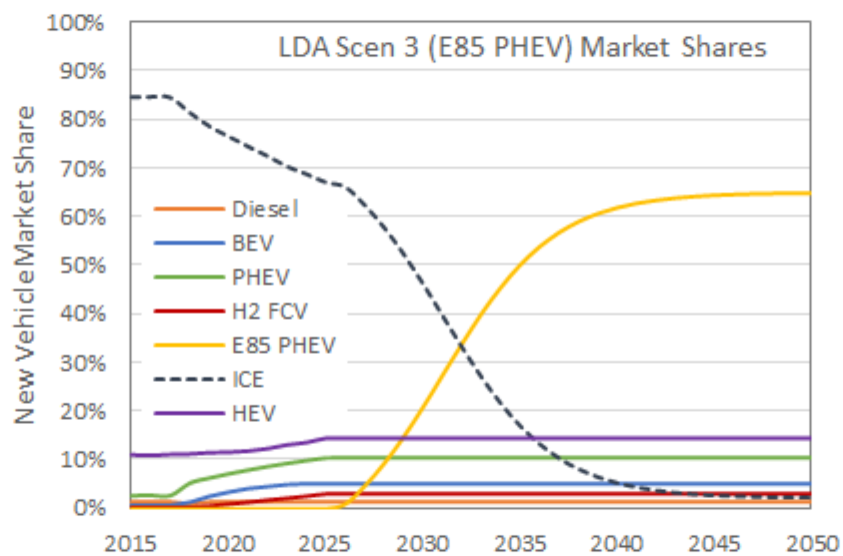

Figure E-6. LDA assumed new vehicle market shares for CA Scenario 3.

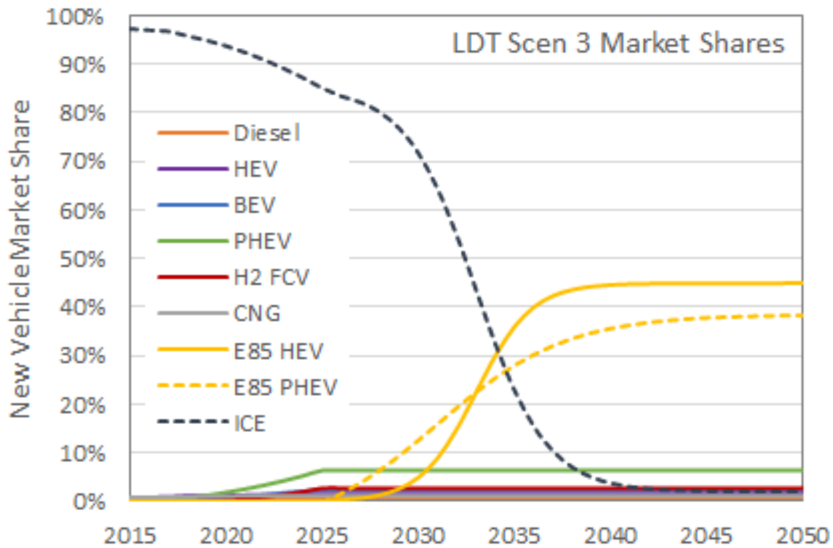

Figure E-7. LDT assumed new vehicle market shares for CA Scenario 3.

Scenario 4 features the maximum penetration of dedicated E85 HEVs. BAU levels of HEV, BEV and PHEV are maintained with gasoline ICEs reduced in place of E85 HEVs. For LDA (Figure E-8), 65% E85 HEV is achieved by 2050 and for LDT (Figure E-9), more than 80% new vehicle market share is assumed.

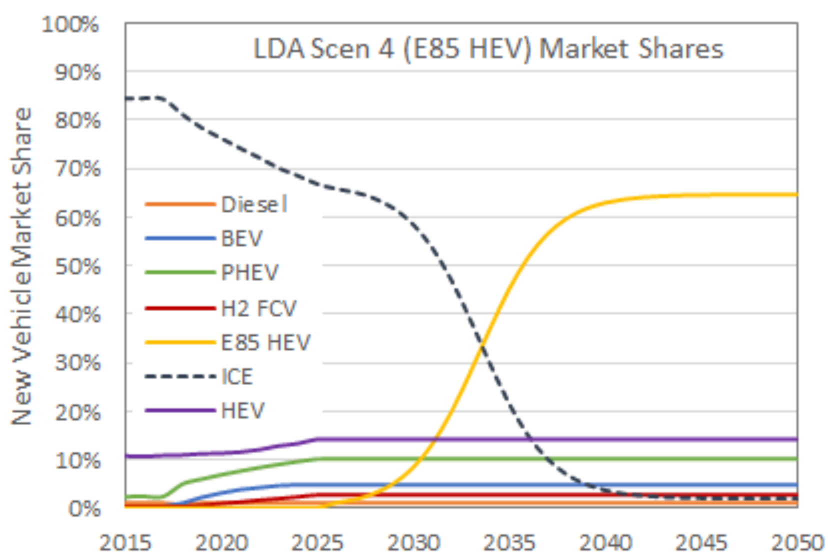

Figure E-8. LDA assumed new vehicle market shares for CA Scenario 4.

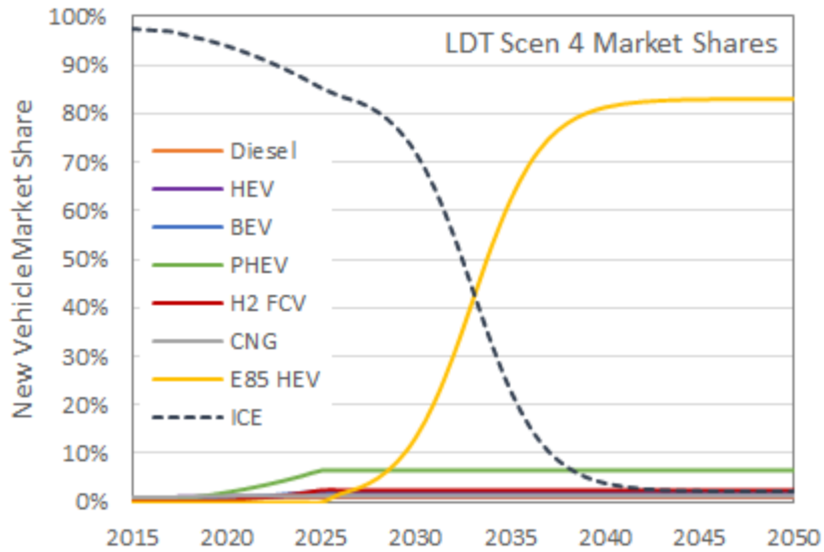

Figure E-9. LDT assumed new vehicle market shares for CA Scenario 4.