Pathways Towards a Near-Zero Heavy Duty Sector

FINAL REPORT

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Disclaimer

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Abstract

Achieving California's climate and air quality goals requires significant transformation of the heavy duty sector. While electrification can help decarbonize vehicle energy demands, it may not be suitable or the least-cost option for all applications. Alternatively, biofuels can also reduce greenhouse gas (GHG) emissions and provide a drop-in fuel substitute; however, they are limited in supply and may not reduce criteria pollutant emissions as much as zero emission vehicles (ZEVs). This study develops long-term scenarios for least-cost uses of renewable fuel feedstocks, fuel production technologies, and powertrains for the heavy duty sector, given technology and emission constraints, to inform investments and policy development so California can achieve climate and air quality goals. Results from the techno-economic optimization show electricity and biomass-derived renewable diesel, natural gas, and hydrogen are viable pathways towards fleet mixes that can meet climate and air quality goals, but increasing ZEV adoption yields lower GHG emissions in the long-term at nearly the same cost. Additionally, constraints on biomass availability and uncertainty regarding competing demands from other sectors may require electrolytic fuel pathways play a prominent role long-term if hydrogen and renewable natural gas meet a substantial portion of fleet fuel demands. Fleet barriers to achieving these future scenarios were investigated to create a guidance document incorporating strategies that help overcome identified constraints. The most effective policies and economic mechanisms to encourage zero and near-zero pathways are identified through analyzing existing policies and potential barriers to using advanced technologies.

Executive Summary

Background

The state of California has ambitious environmental goals, including but not limited to a 40% reduction in GHG emissions compared to 1990 levels by 2030, an 80% reduction by 2050, and economy-wide carbon neutrality by 2045. Transportation-specific carbon goals include a reduction in carbon in transportation fuel by 20% in 2030. Criteria pollutants, predominantly related to heavy duty vehicle (HDV) activity, are also of critical importance due to their negative impacts on human health. Transitioning to biofuels can result in reduced GHG emissions but does not necessarily reduce criteria pollutant emissions as much as a fully ZEV fleet with electricity and electrolytic hydrogen fuel. Given these constraints, a holistic approach is needed to assess which alternative fuel and energy sources can be generated in the future. A more accurate assessment of the best uses of California's feedstocks for the support of HDV emissions goals will help inform optimal HDV fleet choices in the long-term.

Objectives and Methods

The goals of this study are to determine optimal fuel pathways for the heavy duty sector in California and provide guidance on policy and economic mechanisms that should be implemented to help overcome barriers to zero and near-zero emission heavy duty vehicle adoption from both a technical and a fleet perspective. For this study, on-road vehicles between class 2B and 8 are considered. These goals are met by (1) determining the best use of renewable feedstocks in California, (2) quantifying the potential reductions in the emission of GHGs and criteria pollutants through the use of a broad range of connected and automated vehicle (CAV) technologies and efficiency upgrades in the heavy duty sector, (3) creating multiple long-term heavy duty fleet mix scenarios, (4) developing a guidance document for fleets transitioning to alternative fuels, and (5) providing guidance on overcoming barriers to implementing zero and near-zero emission heavy duty pathways.

Investigating optimal use of renewable feedstocks in California was accomplished through a techno-economic analysis to determine resource potential, costs, conversion yields, and viable pathways for biofuels, electricity, and electrolytic power-to-gas technologies for the production of renewable natural gas (RNG) and hydrogen. These data are compiled through a literature review in order to establish existing and near-term fuel pathways for the heavy duty sector, and Wright's Law was used to project fuel production costs into the future. The impact of electricity use and electrolytic hydrogen production for HDVs on the electric grid was modeled using the Holistic Grid Resource Integration and Deployment tool to determine probable impacts on renewable utilization, transportation and grid emissions, and levelized cost of energy. A heavy duty vehicle charging model was developed for this study based on California HDV travel patterns to examine a range of vehicle-grid integration scenarios including vehicle-to-grid.

For this study, an extensive literature review was also conducted to determine the impact of CAV and efficiency upgrades on the heavy duty sector. Potential costs, barriers to use, GHG and criteria pollutant reductions, and impacts on disadvantaged communities from CAV adoption were compiled. Disadvantaged communities (DACs) were identified with the use of CalEnvironScreen 3.0. Fuel savings at the state level were calculated out to the year 2050 for different scenarios spanning the range of fuel changes reported in literature and examining different adoption timeframes. The baseline fuel consumption, vehicle miles traveled, and vehicle turnover come from CARB's Vision model.

The fuel pathways and associated costs, vehicle miles traveled data from EMFAC, and future vehicle characteristics including fuel efficiency, range, and powertrain costs were then incorporated to develop multiple heavy duty fleet mix scenarios that will allow California to meet its long-term climate and air quality goals. The model projections consider improvements in vehicle efficiency and the impacts of the availability and costs of fuel and infrastructure.

The guidance document developed for this project is based on the feedback gathered from fleet managers, and researchers, as well as a review of other published reports and peer-reviewed literature. Questions directed to fleet managers and other relevant experts were focused on identifying challenges, costs, barriers, and tradeoffs, and potential solutions to overcome barriers, associated with investing in low carbon fuels and advanced technology. This included timeframes for technology diffusion within fleets, and discounting decisions applied to fuel costs versus capital costs. The results of the literature review and interviews were distilled with the intent to provide easy guidance for fleets that are considering transitioning to alternative vehicles and/or fuels, or that have already begun that transition. Complementary to the fleet guidance document is a review of current policies, focusing on federal and state incentive programs, in order to provide guidance on implementing effective future policies and programs that support zero and near-zero emission heavy duty pathways.

Results

The cost of electricity as an HDV fuel is greatly affected by infrastructure cost, which in turn is greatly affected by the assumed charging power, i.e., Level 1, Level 2, or Level 3. In addition, the use of intelligent charging strategies (e.g. smart charging and vehicle-to-grid) can allow vehicle operators to schedule charging to correspond with lower electricity cost periods. This is limited by access to infrastructure, such as availability along routes or at home base locations. The infrastructure then directly impacts the feasibility of heavy-duty BEVs. Generally, hydrogen costs are slightly above level 3-dispensed electricity. Electrolysis is a relatively efficient production method but requires cost reductions and a low carbon electric grid to facilitate deep GHG reductions. Conversely, the gasification of biomass allows for the use of very low or negative carbon intensity (CI) biomass which can be a cost-effective method of producing renewable hydrogen in the near- to mid-term. RNG is most efficiently and cost-effectively produced by gasification of biomass feedstock unless a cheap source of carbon can be obtained for use in methanators to facilitate electrolytic pathways. Renewable diesel has a moderate cost compared to other renewable HDV fuels. Because it is a drop-in fuel for current infrastructure and vehicles, using renewable diesel can be a cost-effective method of meeting GHG goals if negative CI biomass such as manure and food waste are used. Additional revenue streams can provide important cost reductions for certain fuels but not others, e.g., the Low Carbon Fuel Standard (LCFS) and Renewable Fuel Standard (RFS) can offer significant cost reductions to renewable diesel and electricity, both of which see reductions of approximately 30-60% depending on pathway. The cost of hydrogen and RNG fuel is not as impacted, though reductions of up to 15% are realized for hydrogen and 19% for anaerobic digestion.

Demonstrations of CAV technologies in the HDV sector have shown significant fuel savings associated with eco-driving and platooning strategies. However, there is limited literature on CAV impacts on DACs and the state as a whole. When constrained by existing GHG and criteria pollutant emissions legislation and goals, renewable diesel and hydrogen, produced from electricity and various biomass sources, along with electricity are the primary fuels projected to be used. Heavy use of negative CI biomass is needed to meet GHG constraints. When constrained by increasingly strict ZEV mandates, electricity and hydrogen are the only renewable fuels considered in the long-term, although RNG is used in the short- and medium-term as a transitory fuel. It is important to note that the overall cost is only slightly higher for the high ZEV assumption and that scenario attains other benefits including lower pollutant emissions and lower annual costs until 2040. Fossil diesel is projected to be used in decreasing amounts in the near-future, and fossil natural gas is used in the mid-future. A ZEV scenario uses electricity as a primary fuel and fuel feedstock, while waste, agriculture, and forestry biomass are used in gasifiers to produce hydrogen. While this scenario does not meet 2030 GHG goals, the resulting 2050 GHG emissions are significantly lower than an 80% reduction. Policies (e.g., incentives and pricing) can support the use of zero and near-zero emission, heavy duty vehicles, infrastructure and fuels, as well as promote the responsible use of CAV technologies, to achieve the State's long-term climate and air quality goals.

Conclusions

Renewable HDV fuel availability is limited by biomass availability but far less limited by electricity availability. An enhanced understanding of biomass allocation is needed to determine the actual availability of HDV fuel production relative to other sectors including aviation, marine, off-road, etc. Given the limited quantities of biogas and biomass feedstocks, as well as potential demands from competing sectors, electrolytic fuels will very likely be required in large scale transitions to hydrogen or RNG in the HDV sector. Support for electrolytic fuels will likely be required across the full fuel pathway (production, distribution, and dispensing) including novel mechanisms for the provision of cost-effective electricity (e.g. developing electric rate structures specific to transmission-connected renewable fuels facilities).

Planning for the allocation of California's biomass resources should be a high priority as biomass availability for HDV renewable fuel production affects resulting fuel pathway and vehicle powertrain projections. Heavy use of net negative or very low CI biomass to meet GHG goals reduces the near- to mid-term ZEV adoption rate which could result in higher GHG emissions long-term compared to a scenario characterized by aggressive adoption of ZEV despite similar total costs. Also, altering the negative CI value of biomass to reflect a change in standard practices (e.g. SB 1383) can yield challenges in meeting long term goals. More clarity on how California's GHG laws and goals will be implemented on a sector-by-sector basis is needed to determine what emissions reductions should be targeted by each sector. The fleet guidance document developed for this project can provide step-by-step guidance for fleets transitioning to alternative fuels. Additionally, simplifying and consolidating incentive programs to create a "one-stop shop" where fleets can acquire both vehicles and supporting infrastructure can accelerate zero and near-zero emission vehicle adoption.

1. Technology Options for Alternative Heavy-Duty Vehicle Fuel Production and Resulting Fuel Prices and Availability

1.1 Overview

The goal of Task 1 is to determine the best production pathways and use of renewable fuels in the heavy duty vehicle (HDV) sector. Within this goal, four key topics are addressed: (1) determining the optimal use of State biomass and biogas resources for HDVs, (2) characterize and assess power-to-gas fuels to support HDV and renewable goals, (3) determine energy and emission benefits of vehicle-to-grid services for electric drive HDVs, and (4) determine costs for alternative fuels. Discussions with the ARB identified electrolytic fuels as the foremost research need for Task 1 and this is reflected in a thorough techno-economic characterization of power-to-gas (P2G) fuel pathways in Task 1.

The approach includes, first, a techno-economic characterization of the entire fuel pathway, including fuel feedstock, production technology, distribution, and dispensing. The second part of the analysis is the development of a vehicle charging model that will be integrated into an existing electric grid model in order to determine vehicle-grid integration impacts on the electric grid.

For the techno-economic characterization, each step is analyzed for its efficiency and cost, and emissions data are gathered for the feedstocks and extrapolated to represent the entire pathway using primary energy efficiency. Projections are then made, focusing on the production technologies as these are areas where most of the efficiency and cost improvements are expected to be made. The literature is consulted to guide efficiency projections, and Wright's Law is used to project cost based on technology adoption. The culmination of these data allows for calculation of the dispensed cost of alternative fuel. Both Low Carbon Fuel Standard (LCFS) and Renewable Fuel Standard (RFS) incentives are projected and applied to determine an effective reduced cost with the incentives. Fuel availability is determined using fuel feedstock availability projections and overall fuel pathway efficiencies.

A summary of each fuel pathway step efficiency as well as the total pathway efficiency for the year 2020 is shown in Table 1. Electricity represents the most efficient fuel due to the avoidance of production losses and the relatively high efficiencies associated with distribution. However, it should be noted that no storage step was assumed and future management of a high renewable grid in California may require some form of storage which would reduce efficiencies. The gasification of biomass to produce RNG and the liquefaction of biomass to produce renewable diesel are also possible with notably high efficiencies. While electrolytic production of hydrogen or RNG results in lower efficiencies overall, the use of otherwise curtailed renewable electricity represents a beneficial production pathway overall.

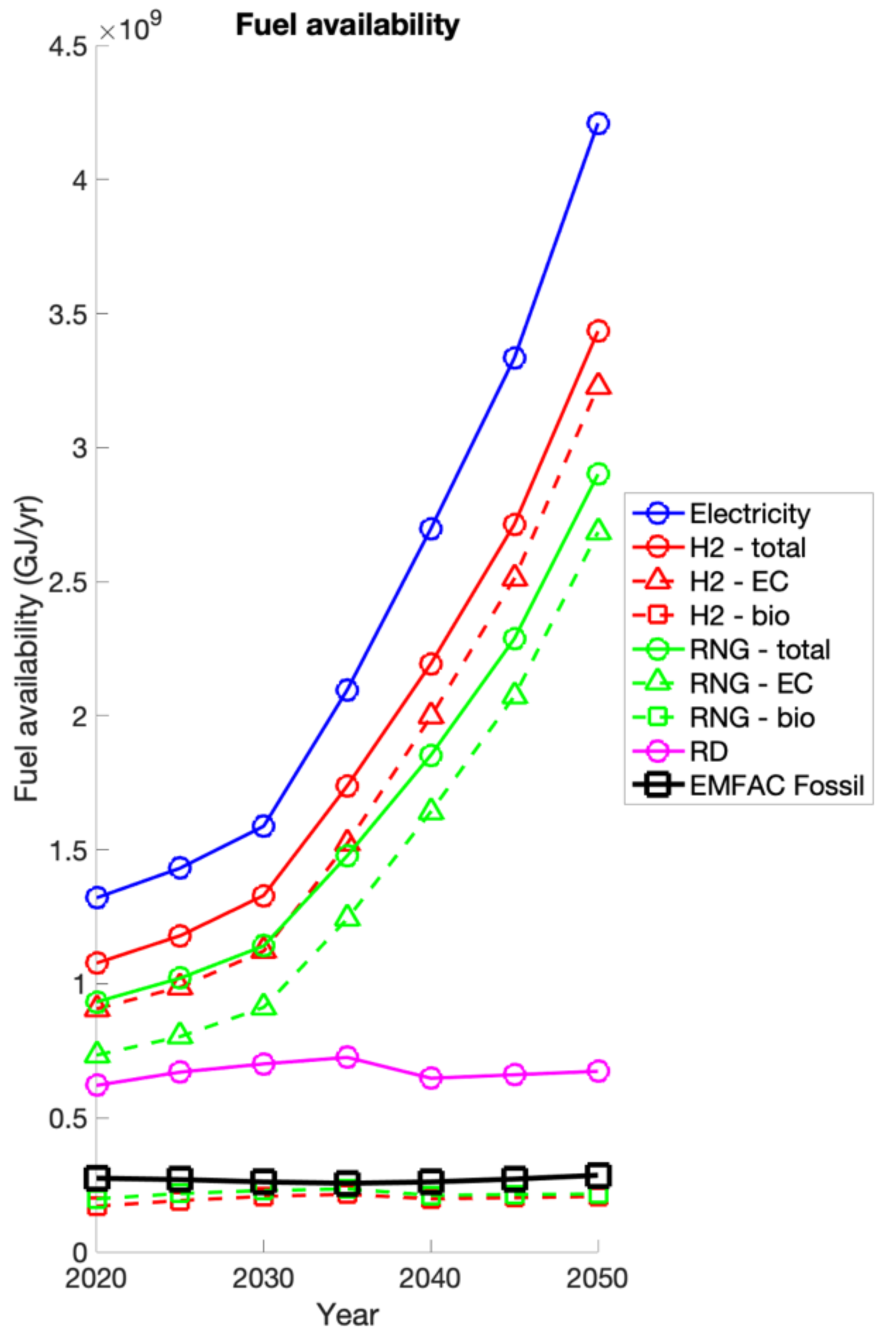
Table 1. Summary of fuel pathway efficiencies in 2020. It should be noted that the electrolyzer efficiencies are representative of conservative values reported in the literature.

Fuel	Production method	Production efficiency (%)	Distribution efficiency (%)	Dispensing efficiency (%)	Total pathway efficiency (%)
Electricity	CA grid mix	-	95	92	87.4
Hydrogen	AEC	70	82	96.5	55.4
	PEMEC	66	82	96.5	52.2
	SOEC	70	82	96.5	55.4
	Gasifier	54	82	96.5	44.3
RNG	AEC - methanator	55.3	100	100	55.3
	PEMEC - methanator	52.2	100	100	52.2
	SOEC - methanator	59.3	100	100	59.3
	Gasifier	67	100	100	67
	AD (manure)	37	100	100	37
	AD (organics)	50	100	100	50
Renewable diesel	Liquefaction	64	100	100	64
	Gasifier - FT	55	100	100	55
	Hydrolysis	55	100	100	55
	Pyrolysis	60	100	100	60
	Hydrotreated Vegetable Oil	87	100	100	87

Figure 1 shows the HDV fuel availability with categorization for biomass-derived and electrolytic production where appropriate (i.e., hydrogen and RNG). Fuel availabilities for non-electrolytic pathways are determined by taking the biomass feedstock availabilities and adding the total pathway efficiencies including fuel production, distribution, and dispensing. For electricity availability it is assumed that approximately 40% of California's total electricity capacity projected in Energy and Environmental Economics (E3)'s PATHWAYS model is available as a vehicle fuel or fuel feedstock allowing for a moderately aggressive expansion of the electric grid. Projections from EMFAC for the total projected amount of fuel energy used by the baseline HDV sector is also included demonstrating that quantities of renewable fuel are sufficient to meet demands, although more information is needed on competing demands in additional sectors with electrification challenges [1].

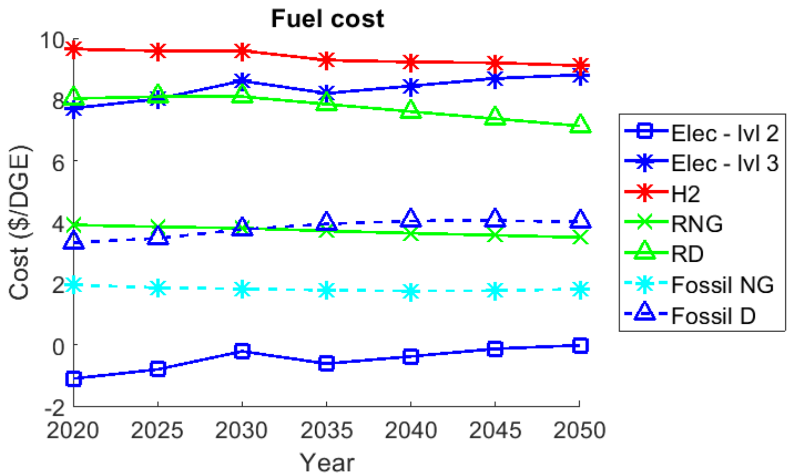
Despite benefits in GHG emissions due to net negative or very low carbon feedstock, biomass feedstock availability limits the availability of bio-derived renewable fuels and raises concerns over allocation decisions for the production of fuels for other end-use sectors including aviation, marine, off-road equipment, etc. Conversely, electricity and electrolytic fuels are expected to be available in much larger quantities as the renewable generation of electricity expands.

Figure 1. Heavy-duty vehicle fuel availability accounting for feedstock constraints and pathway efficiencies accounting for fuel production, distribution, and dispensing



The dispensed fuel costs normalized to diesel gallon equivalent (DGE) and averaged across different production pathways are shown in Figure 2, excluding electrolytic RNG pathways as they are significantly more expensive due to the high cost of carbon capture (especially some of the renewable sources of carbon). It should be noted that these costs include the assumption of LCFS revenue, valued at $100 per credit (a conservative estimate compared to the $142 average of 2015-2019), and RFS revenue, assuming recent historical trends for appropriate credit prices, are applied; the fuel costs without incentive revenue are presented and discussed in further detail in the report. Note that, unless otherwise specified, real dollars are used for projections out to 2050.

Figure 2. Heavy-duty vehicle fuel cost projections, conservative electrolytic assumptions, with LCFS revenue of $100 per credit and RFS revenue



Electricity is the most energy-efficient fuel of those analyzed in this work, with the assumption that no electricity storage is needed. Cost of dispensed electricity is greatly affected by the level of power charger used; level 3-dispensed electricity is the second most expensive fuel modeled while level 2-dispensed electricity is the least expensive (and even slightly negative in the near- to mid-term due to the revenue streams being higher than the electricity feedstock and required infrastructure. However, many issues surround the charging of electric vehicles which could complicate deployment and increase costs including technical feasibility, charging logistics and associated labor cost, route management to account for reduced vehicle range and charger locations, and reduced carrying capacity due to increased BEV powertrain weight. These issues require further study to better understand the implications for total cost and emissions.

Hydrogen costs are projected on average to be slightly above those of level 3-dispensed electricity and higher than level 2-dispensed electricity. While hydrogen costs are relatively high, if the use of zero emission vehicles (ZEV) are pursued, fuel cell electric vehicles (FCEV) are needed for applications in which battery electric vehicles (BEV) are not able to meet technical demands due to range limitations, etc. [2]. These limitations are explored in Section 1.4.3 and applied in the analyses presented in Chapter 3. Electrolysis is a relatively efficient method of producing hydrogen, but gasification of biomass allows for the use of very low or negative carbon intensity biomass which can be a cost-effective method of producing renewable hydrogen in the near- to mid-term while the electric grid continues to become cleaner over time. In 2050, electrolysis and gasification will be the predominant technologies for in-state production of renewable hydrogen as feedstock supply constraints will limit the role of biomethane by the 2030s. The cost of gasification and electrolysis reaches $5 to $6 per kilogram without carbon credit revenue, although reaching that target requires technology progress on the high end of the range. The use of a secondary revenue stream such as the LCFS can potentially reduce the net delivered cost by approximately $2 per kg, which roughly approximates to the Department of Energy's long-term target for hydrogen to achieve parity with fossil fuels of $6 to $8 per kilogram [3].

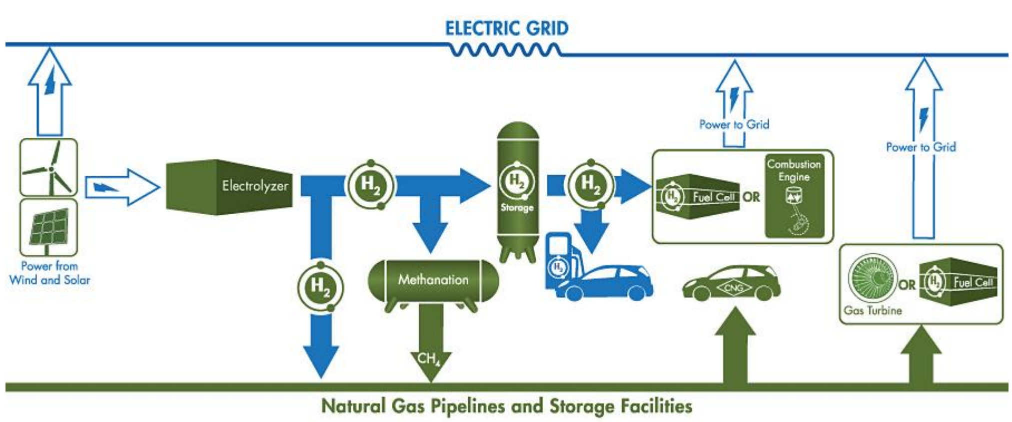
Given the same constraints on biomethane feedstocks, renewable natural gas (RNG) is best served by gasification of biomass feedstocks, unless a cheap source of carbon can be obtained for use in methanator along with electrolytic hydrogen. Biomass-derived RNG is on average the second least expensive renewable fuel considered, and it benefits by being a drop-in fuel for existing compressed natural gas (CNG) HDVs. However, despite advances in engine technology which allow for very low NO_x-emissions the use of RNG may result in direct vehicle emissions that prevent long-term environmental quality targets from being met and this trade-off is explored further in Task 3.

Renewable diesel, a drop-in fuel for diesel HDVs, is a moderately energy efficient fuel to produce with costs between those of RNG and level 3-dispensed electricity and hydrogen on average, though specific pathways such as hydrotreatment of vegetable oils and biomass liquefaction produce renewable diesel at costs similar to that of fossil diesel. Again, however, biomass feedstocks are limited.

Power-to-Gas (P2G) HDV Fuels

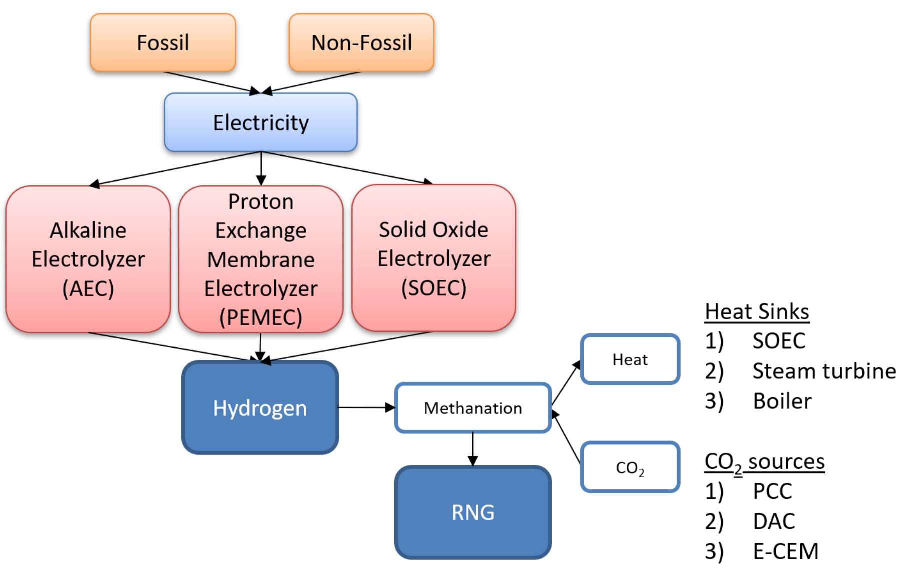
P2G is characterized by electrolysis fuel pathways that convert 1) electricity to hydrogen or 2) electricity to hydrogen and then converted to methane when hydrogen is combined with a source of CO_2. P2G is gaining interest as a flexible mechanism to facilitate increasing amounts of intermittent renewable resources being integrated into the California electrical grid (Figure 3). A particularly attractive use of P2G is the use of curtailed electricity from renewable energy sources. P2G can be used as a form of energy storage in that produced fuels can be stored using various methods potentially including injection into the natural gas grid to take advantage of the inherent large-scale storage capacity. However, the use of the natural gas grid to store and transmit hydrogen for vehicle fueling is not considered here as extraction downstream would likely require processes that reduce overall fuel pathway efficiencies. In the future, the complete conversion of the natural gas grid to a renewable hydrogen grid may represent a beneficial outcome for California and would facilitate fuel cell vehicle fueling [4]. Achieving a high concentration of hydrogen or a 100% hydrogen network using the existing natural gas system will require higher pressure components and portions of the natural gas grid such as the compressors could be retrofitted to reduce hydrogen leakage. Higher concentration of hydrogen in the infrastructure could lead to hydrogen embrittlement of steel pipeline [5]. Methane leakage from the California natural gas network transmission, storage, and distribution are under 1% [6]and recent work comparing the leakage of natural gas and hydrogen in low-pressure gas infrastructure found that there is indeed no measured difference in leakage rate [7].

Figure 3. Schematic of P2G Pathways, from the Advanced Power and Energy Program [8]



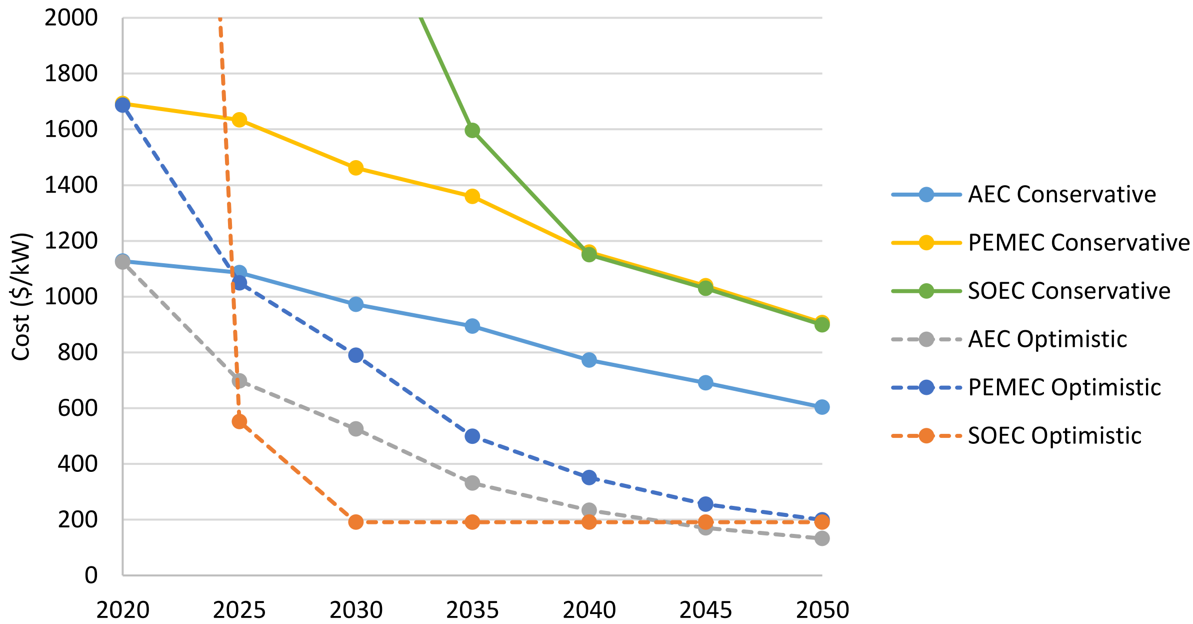
Various P2G technologies are considered in the academic literature, industry reports, and other documentation and these are reviewed in more detail in the body of the report as well as in the Appendix A. For this work, technologies were selected based on the related environmental characteristics, including emissions and ability to accept renewable feedstocks as inputs. Key technology choices are the type of electrolyzer, and for methanator the CO_2 and heat source (see Figure 4). Electrolysis is currently accomplished using electrolyzers of three main varieties: alkaline electrolytic cells (AECs), proton exchange membrane electrolytic cells (PEMECs), and solid oxide electrolytic cells (SOECs), all with varying technological maturities, efficiencies, costs, and other relevant techno-economic metrics. AECs and PEMECs are common today, while SOECs have the highest efficiency and the greatest potential for price reduction with increased scale, even though they are significantly more expensive today. Given the range of values reported in the literature for current and future electrolyzers, cost projections are developed using learning-curve forecasts under both conservative and optimistic assumptions to account for the impact of scale on efficiency and cost. It is also assumed that P2G plants are central scale (50 MW), and distributed or on-site electrolysis is not considered. Pathways considered for P2G include California grid electricity and, as appropriate, carbon sources for methanation from both renewable sources as well as existing fossil fuel combustion power plants (with fossil fuel-associated carbon generally being much cheaper than renewable sources).

Figure 4. Overview of Analyzed P2G Pathways



The cost projections for electrolyzers in the present work are shown in Figure 5, demonstrating significant reductions to 2050 resulting from increases in scale, efficiencies, and other factors. The conservative and optimistic assumptions refer to (1) the installed capacities of the technologies and (2) the learning rates for the P2G technologies. Electrolyzer costs represent an important fraction of total electrolytic fuel cost (e.g., 11-82% currently and 2-30% in 2050) and the results demonstrate the need for support and adoption of P2G technologies to reduce electrolyzer costs and resulting renewable hydrogen and natural gas costs, as well as the impact that electricity cost has on electrolytic fuels which can counteract much of the electrolyzer costs in later years should electricity costs increase as projected.

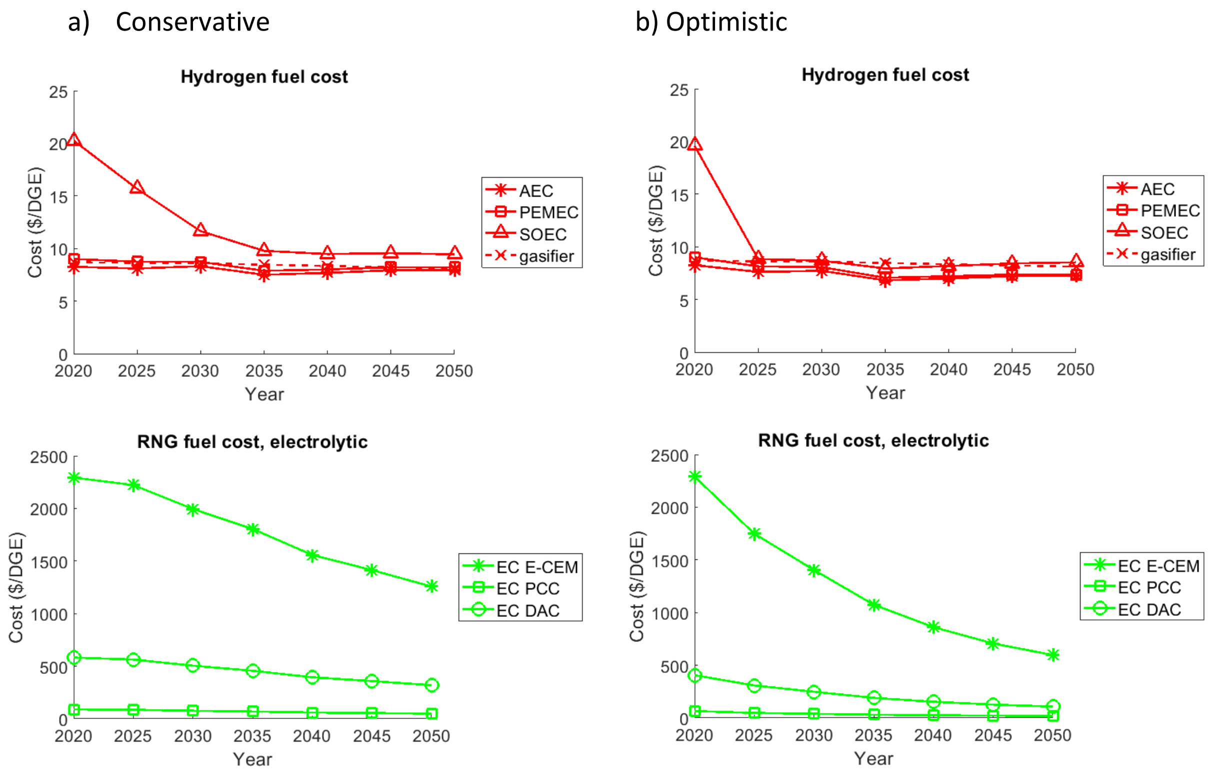
Figure 5. Electrolyzer cost projections to 2050 for optimistic and conservative assumptions



The costs incurred from the point of production through the hydrogen refueling station were analyzed using the HDSAM 3.1 tool developed by Argonne National Laboratory augmented with a learning-curve forecast of cost-reduction potential. The analysis projects costs to decline from around $16 per kg to a low-end estimate of $4 per kg in 2050 due to increased station utilization, economies of scale and technology progress. In this work a representative distribution and dispensing combined cost of $4.50 per kg is used to account for variability of station cost with size. For RNG refueling it is assumed that distribution occurs through existing pipeline at a cost of $0.20 per-BTU and dispensed via a high capacity station at $0.32 per GGE.

Cost forecasts for all elements in the production, delivery, and dispensing chain are then integrated to determine the full dispensed cost of electrolytic hydrogen and RNG as shown in Figure 6. The optimistic scenario projects greater cost reduction of P2G fuels, primarily for SOEC hydrogen and electrolytic RNG. Increasing cost of electricity in the later years of analysis negates much of the cost reduction from Wright's Law on the electrolyzer technologies. When assuming LCFS revenue, valued at $100 per credit, and RFS revenue, assuming recent historical trends for appropriate credit prices, the costs for electrolytic hydrogen in 2030 range from $8.31/DGE to $20.27/DGE and in 2050 from $7.26/DGE to $9.44/DGE. On a per kilogram basis, these costs translate to $7.42-18.10 in 2030 and $6.48-8.43 in 2050 which approach long-term targets established by the U.S. Department of Energy for hydrogen to achieve cost parity with fossil fuels, though presently modeled electricity costs are higher [9]. Conversely, the costs for electrolytic RNG is significantly higher than hydrogen due to the high cost for the sources of required CO_2 considered in this work.

Figure 6. Hydrogen and electrolytic RNG fuel costs for a) conservative (left) and b) optimistic (right) scenarios with LCFS credit of $100 and RFS revenue included



Emissions associated with the fuel pathways are dependent on the feedstock, production equipment, distribution, and dispensing. Present modeling uses feedstock emissions and total pathway efficiency (with production efficiency in terms of primary energy input) to calculate total fuel pathway emissions. Greenhouse gas (GHG) and several criteria air pollutant (CAP) emissions (NO_x, and PM_{10}) are calculated. The total emissions associated with the production of P2G fuels are heavily impacted by the electricity used by the electrolyzer. Electricity and electrolytic fuels have relatively high GHG emission factors when compared to most biomass fuel pathways up to 2040. By 2045 all electricity is zero carbon, so GHG emission factors are zero. While biomass fuel pathways generally have lower GHG emission factors up to 2040, they do not decline to zero by 2045, giving the comparative advantage to electricity and electrolytic fuels. There are two exceptions: both manure and food waste have negative carbon intensities because their use as a fuel results primarily in carbon dioxide rather than natural emission of methane, so using these two biomass feedstocks can have a significant GHG benefit until SB 1383 limits that benefit by 2040 at the latest [10]. The impact of these negative carbon intensity feedstocks is investigated further in Task 3.

For CAPs as modeled, NO_x emissions are generally in the same range between electrolytic fuels and biomass fuels, Emissions of PM_{10} are projected to be somewhat lower for electrolytic fuels than for biomass fuels. However, further review of and work on CAP emissions from the various biomass fuel production technologies would add helpful resolution in this area.

Conclusions

- **The cost of electricity as an HDV fuel is greatly affected by infrastructure cost, which in turn is greatly affected by the assumed charging power, i.e., Level 1, Level 2, or Level 3. The infrastructure then directly impacts the feasibility of heavy duty BEVs.** The difference in cost of delivered electricity as a fuel for HDVs when using either level 2 or level 3 charging is approximately $8 per diesel gallon equivalent (DGE), due to the dramatic increase in electric charger cost for the higher power capacity. When applying LCFS credits, the cost for level 2-delivered electricity is very low, even slightly negative, while the cost for level 3-delivered electricity is the second-most expensive renewable fuel as modeled when assuming a conservative $100 per credit. The impact of altering the LCFS program to increase incentives for higher levels of electric charging would change the relative fuel cost between BEVs and FCEVs, and thus could have a substantial impact on resulting BEV and FCEV adoption. Furthermore, electric utilities have the ability to alter electricity prices through means such as time of use (TOU) rate structures, something that could be used to achieve a similar effect.

- **Further work is needed to determine a cost for logistics and labor of charging heavy duty BEVs as this could significantly impact the overall cost of electricity as an HDV fuel.** Adopting a BEV can be cost effective for some fleets due to fuel costs. However, something not included in the present analysis is a quantitative cost associated with fleets working through the logistics of rearranging routes and the cost of labor for managing charging of the HDVs when adopting BEVs. The rearranging of routes is particularly a factor for BEVs due to their limited driving range.

- **Renewable HDV fuel availability is limited by biomass availability but far less limited by electricity availability. An enhanced understanding of biomass allocation to various end-use sectors is needed to determine the actual biomass availability for the HDV sector (relative to other sectors including aviation, marine, off-road, etc.).** The availability of biomass is well-documented by the Billion Ton Report, but there is not agreement on how that biomass will be used in the different sectors of California. Such planning is needed and will have a direct effect on how much renewable HDV fuel can be made from these biomass resources. For electricity and electrolytic HDV fuel, limitations are much less stringent on electricity than biomass due to the ability to add renewable electricity generation at much larger scales than biomass farming for fuel production purposes.

- **Given the limited quantities of biogas and biomass feedstocks, as well as potential demands from competing sectors, electrolytic fuels will very likely be required in large scale transitions to hydrogen or RNG in the HDV sector.** Electricity is generally easier to install production capacity for than biomass, which requires farming, more land, and other logistical and environmental challenges. Having greater surplus feedstock can lead to more stable and lower electrolytic fuel costs in the long-term. Additionally, the dispatchable load characteristics of electrolytic fuel production can provide a significant benefit to the California electric grid and additional renewable generation is added.

- **RNG is best served by biomass feedstocks and the corresponding RNG production technologies from a cost perspective, unless an inexpensive source of carbon can be obtained**

for use in methanators to facilitate electrolytic pathways. Carbon capture technologies post-combustion capture (PCC), direct air capture, and electrolytic cation exchange module (E-CEM) lead to much more costly RNG than the biomass-derived options. Methods of sourcing cheaper carbon should be investigated and developed to make electrolytic production of RNG more cost-effective. Producing RNG from biomass costs \$3.40 to \$5.60 per diesel gallon equivalent (DGE), depending on the feedstock and production technology used. Producing RNG from electrolytic hydrogen and captured carbon costs \$86.50 to \$2500 per DGE, with most of that cost coming from the carbon capture technology used. Cheaper sources of carbon dioxide, such as integration with chemical processing plants or other industrial processes, are needed to make electrolytic production of RNG more cost-effective. This becomes increasingly valuable as the electric grid gets cleaner into the future.

- **LCFS and RFS can offer significant cost reduction to renewable diesel, particularly when using cellulosic biomass, as well as electricity fuel cost, both of which see reductions of roughly 30-60% depending on pathway. The cost of hydrogen and RNG fuel is not impacted as much, though reductions of up to 15% are realized for hydrogen and 19% for anaerobic digestion.** With an LCFS credit price of \$100 and an RFS D3 RIN price of \$1.5 yields a total incentive of \$7-8 per DGE. These incentives can make some renewable diesel production methods similar in cost to fossil diesel and the hydrotreated vegetable oil method often used for producing renewable diesel currently. This allows drop-in use of low or negative carbon intensity fuels in vehicles with conventional powertrains that are already on the road, a cost-effective method of meeting GHG legislation in the near-term.

- **Hydrogen costs are slightly above level 3-dispensed electricity. Electrolysis is a relatively efficient production method but requires the electric grid get cleaner over time to facilitate deep GHG reductions. Conversely, the gasification of biomass allows for the use of very low or negative carbon intensity biomass which can be a cost-effective method of producing low-carbon renewable hydrogen in the near- to mid-term.** Due to the relatively low installed base of electrolyzers, their cost can be dramatically reduced with support and increasing adoption. This would lead to reducing the cost of electrolytic hydrogen to the point that it becomes the cheapest method of producing hydrogen. As the electric grid reduces its emissions impact, this electrolytic hydrogen becomes a more cost-effective and clean fuel option.

- **RNG is most efficiently and cost-effectively produced by gasification of biomass feedstocks. Unless a more cost-effective source of CO_2 can be obtained for use in methanators to facilitate electrolytic pathways, electrolytic RNG is prohibitively expensive.** RNG produced from gasifiers is the most efficient pathway for RNG production studied, and it uses relatively low carbon intensity biomass as its feedstock. Furthermore, the dramatically high cost of carbon capture technology would need significant cost reduction before electrolytic RNG can be cost-competitive with biomass-derived RNG.

- **Electrolyzers, gasifiers, and anaerobic digesters are expected to have the greatest improvements in efficiency by 2050. At 2050, solid oxide electrolyzers (SOECs) are expected to be the most efficient method of producing hydrogen and both gasifiers and SOECs are expected to be the most efficient methods of producing RNG with similar efficiency.** SOECs are a relatively new electrolyzer technology that scientists and engineers are working hard to commercialize. This technology is already one of the most efficient electrolyzer technologies and it has more room to improve than most as well. Gasifiers are also a relatively new technology that have promisingly high efficiency, particularly for RNG production.

- **Support for electrolytic fuels will likely be required across the full fuel pathway (production, distribution, and dispensing) including novel mechanisms (e.g. rate structures, raising hydrogen blending limits on the natural gas grid, etc.) for the provision of cost-effective electricity.** The cost of electricity is a critical determinant of electrolytic fuel pathways and requires consideration. For example, developing electric rate structures specific to transmission-connected renewable fuels facilities (e.g., electrolyzers and hydrogen liquefaction facilities) such as whole power market access and transmission charge would benefit both electrolytic hydrogen and RNG production.

1.2 Introduction and Background

1.2.1 Motivation

The heavy duty transportation sector is amidst a time of major changes in various regards. Numerous factors such as air quality, climate change, more renewable electricity production, and pieces of legislation aimed at heavy duty transportation and emissions are forcing the fuels and powertrains of heavy duty vehicles (HDVs) to evolve. This has caused HDV manufacturers to develop and offer a wider variety of vehicles that are powered by different, sometimes multiple, fuels and unconventional powertrains, such as batteries and fuel cells. This wide variety of options is only increasing as research into other carbon-free or carbon-neutral fuels, new fuel production pathways, and advanced powertrains all improve their viability and marketability. The wide array of potential options is vast compared to the traditional use of diesel fueled HDVs.

With all the fuel and powertrain options becoming available, it is impossible for the average fleet manager to judge what might be best for their fleet in terms of fuel cost and driving characteristics. It is even more challenging for the average fleet manager to judge what is best for society, considering the intricacies of cost, efficiency, emissions, and technological constraints of various kinds at the many stages of fuel production and vehicle use.

At the same time as options for vehicle fuels and powertrains are increasing dramatically, the world is facing growing issues of climate change and air quality. Transportation accounts for over a quarter of greenhouse gas (GHG) emissions in the U.S., and 14% of GHG emissions worldwide, as shown in Table 2 [11], [12]. Focusing on California, transportation is the largest emitter of GHG emissions, responsible for 41% of GHG emissions. Furthermore, HDVs are responsible for roughly 22% of transportation GHGs, second only to light-duty vehicles (LDVs) [13]. These GHGs exacerbate climate change. Transportation is also responsible for 38% of criteria air pollutants (CAPs) in the U.S. [14]. These CAPs are what lead to poor air quality, respiratory issues, and a number of other health hazards for those that breathe them [15]–[17].

As a politically progressive state with some areas burdened by poor air quality, California has many pieces of legislation as well as goals relating to the environment. Table 2 lists a variety of legislation and goals either directly or indirectly relating to transportation.

Table 2. California transportation legislation and goals

Climate Change		
	AB 32: Global Warming Solutions Act [18]	Reduce GHG emissions to 1990 amounts by 2020
	SB 32: California Global Warming Solutions act of 2006 [19]	Reduce GHG emissions to 40% below 1990 amounts by 2030
	California Governor's Executive Order # S-03-05 [20]	Reduce GHG emissions to 80% below 1990 amounts by 2050
	SB 2: Renewable Energy Resources [21]	33% of electricity is renewable by 2020
	SB 350: Clean Energy and Pollution Reduction Act of 2015 [22]	50% of electricity is renewable by 2030
	SB 100: California Renewables Portfolio Standard Program [23]	100% of electricity is zero-carbon by 2045
	SB 375: Sustainable Communities [24]	Reduce GHG emissions by community planning for transportation and land use
Transportation Fuel		
	Low Carbon Fuel Standards [25]	Reduce carbon in transportation fuel by 10% in 2020
	AB 1007: State Alternative Fuels Plan [26]	Plan to use more alternative fuels in CA, including details on how to increase hydrogen use
	AB 118: California Alternative and Renewable Fuel, Vehicle Technology, Clean Air, and Carbon Reduction Act [27]	Provides funding for technologies that improve local air quality
	Zero Emissions Vehicle Action Plan[28]	Plan to achieve 1.5 million ZEVs in CA by 2025
	AB 8: Alternative Fuel and Vehicle Technologies [29]	Allocates $20 million each year for hydrogen fueling stations until 100 are built
	SB 1505: Environmental Standards for Hydrogen Production [30]	Requires that hydrogen be 33.3% renewable, and have 30% lower GHG and 50% lower CAP emissions than gasoline
Heavy Duty Vehicles		
	AB 739: State vehicle fleet: purchases [31]	A minimum of 15% of certain state-purchased heavy duty vehicles must be ZEVs by 2025 and 30% by 2030
	AB 1073: California Clean Truck, Bus, and Off-Road Vehicle and Equipment Technology Program [32]	Extended funding for heavy duty trucks, according to California's Clean Truck, Bus and Off-Road Vehicle program
	Goods Movement Emission Reduction Plan [33]	$1 billion allocated to a collaboration between California Air Resources Board and local agencies to reduce pollutant emissions in freight corridors
	California Sustainable Freight Action Plan [34]	Creates 2050 goals for cleaner freight system, targets for 2030, and assistance in starting pilot projects
	San Pedro Bay Ports Clean Air Action Plan, 2018 Update [35]	Newly registered trucks at the Ports of Long Beach and Los Angeles must be model year 2014 or newer

1.2.2 Objective

The work of this chapter, corresponding to Task 1 of the project, is to characterize HDV fuel production methods. This includes a thorough techno-economic analysis of the various fuel production technologies and the corresponding fuel feedstock, distribution, and dispensing methods. The resulting HDV fuel cost and availability are also analyzed. Results of this work feed into Task 3, which projects the evolution of the HDV fuel and powertrain fleet mix.

1.2.3 Background: Heavy-Duty Vehicle Fuel

Four alternative fuels are likely to be used in the next few decades in HDVs. These fuels are electricity, hydrogen, renewable natural gas, and renewable diesel [36]–[39].

Each of the above fuels can be produced in a variety of manners. Some constraint on the scope of this work is used to focus on pathways that are, according to the state of the art of this writing, more likely to be viable from cost and efficiency perspectives. This does not preclude the fact that future technology advancements may introduce new fuels or pathways. It is important to note that while these potential future advancements could mean reality may be different from the projections of the present work, the advancements can be integrated into the methodology introduced herein at the time that they are discovered. It is recommended that the current state of the art be updated from time to time to ensure the most accurate data are used.

Fuel Feedstocks

A fuel feedstock is an input that is converted to a fuel through one of a multitude of fuel production technologies that are available. For the five alternative fuels introduced, there are two broad feedstock categories: electricity which can be used directly or converted to hydrogen or methane through electrolytic pathways, and biomass which can be converted to gaseous or liquid fuels through a range of different technological pathways.

Fuel Feedstocks: Electricity

For some alternative fuels, electricity is a main feedstock. Furthermore, certain kinds of vehicles, known as plug-in electric vehicles (PEVs), which includes plug-in hybrid vehicles and BEVs, use electricity directly as a fuel.

As a fuel feedstock, electricity is primarily used to convert water into hydrogen in a process known as electrolysis. In a further step, hydrogen can be converted to methane (CH_4) to serve as a natural gas substitute using a CO_2 source. The resulting fuels are known as electrolytic fuels. Water is also a co-feedstock along with electricity for these electrolytic fuels. However, given the techno-economic nature of this work, and the fact that water costs will likely stay a small fraction of overall fuel costs, which will be discussed in more detail in Appendix A, the water feedstock is not further considered. It should be noted, however, that future electrolytic fuel production should be in an area with water availability to increase efficiency and cost-effectiveness.

Fuel Feedstocks: Biomass

Biomass comes from both plant and animal sources. In the scope of the present work, biomass can be used for producing either electricity or gaseous, liquid, or solid fuel. Biomass is therefore quite flexible as a feedstock category.

Biomass availability, for both the U.S. and California in particular, is sourced from the U.S. Department of Energy's Billion Ton Report [40]. Biomass is separated into seven crop type categories in the Billion Ton Report, as follows: (1) agriculture residues, (2) energy crops, (3) food waste, (4) forest residue, (5) manure, (6) municipal solid waste (MSW), and (7) tree. The individual feedstocks that compose each of these crop types are listed in Table 3.

Table 3. Biomass feedstocks by crop type according to Billion Ton Report [40]

Agriculture residues	**Energy crops**	**Food waste**	**Forest residue**	**Manure**	**MSW**	**Tree**
Barley straw	Miscanthus	Food waste	Hardwood, lowland, residue	Hogs, 1,000+ head	Construction and demolition waste	Hardwood, lowland, tree
Citrus residues	Poplar	---	Primary mill residue	Milk cows, 500+ head	MSW wood	Hardwood, upland, tree
Corn stover			Secondary mill residue		Other	Softwood, natural, tree
Cotton gin trash			Softwood, natural, residue		Paper and paperboard	Softwood, planted, tree
Cotton residue			Softwood, planted, residue		Plastics	
Non-citrus residues					Rubber and leather	
Rice hulls					Textiles	
Rice straw					Yard trimmings	
Tree nut residues						
Wheat straw						

Note that one defining factor of these biomass feedstocks that will play a role in determining which fuel production technologies that can be used is moisture content. Both food waste and manure categories are high-moisture biomass categories, whereas the rest are typically dry.

Additionally, the non-organic portions of the MSW, which include plastics, rubber, and leather, are not included in this analysis as potential fuel production feedstocks. The feedstock quantities that will later be shown reflect this removal of the non-organic MSW from the original Billion Ton Report data.

Fuel Production

What follows are descriptions of the various methods of fuel productions for the five fuels considered in this work, categorized first by the fuel being produced and then by the specific fuel production technology adopted.

Fuel Production: Electricity

From the perspective of PEVs, electricity is the fuel itself, and not simply a feedstock as introduced previously. This work assumes the electricity production feedstocks and methods as projected by entities such as Energy and Environmental Economics (E3) [41] and Argonne National Laboratory's GREET Model [42]. The reasoning for this is that the electricity sector is larger than simply the demand for transportation. There are legislation and goals for the electric grid, and therefore it is reasonable to assume that a transportation analysis will not dramatically impact the evolution of the feedstock portfolio for electricity generation. However, it is important to note that transportation and electricity generation are increasingly intertwined as vehicle electrification increases.

Electricity is generated from a wide variety of sources, ranging from fossil fuels such as natural gas used in gas turbines to renewable sources such as solar panels. Due to the wide variation in the production of electricity that is beyond the scope of this work, the PATHWAYS model by E3 is used to determine how the electricity grid composition will change with time [41]. This model shows the projected evolution of the electric grid from 2015 to 2050 along various evolution scenarios. The one used for this work is the "Straight Line" scenario which assumes a linear reduction in emissions to reach emissions reductions goals in 2050, but is modified to have zero carbon intensity by 2045 to comply with the recent SB 100 legislation that was introduced in Table 2.

Fuel Production: Hydrogen

Hydrogen is a gaseous fuel at ambient temperature and pressure, though it is often stored at higher pressures to increase volumetric energy density. Hydrogen can be combusted like current fossil fuels in vehicles, but in this work, it is assumed that hydrogen is a fuel only for fuel cells. Fuel cells are electrochemical conversion devices, and more detailed information about them will come later in the section discussing the various vehicle powertrain configurations. Fuel cells are an alternative to combustion engines which do not have any emissions of pollutants or GHG when fueled by hydrogen.

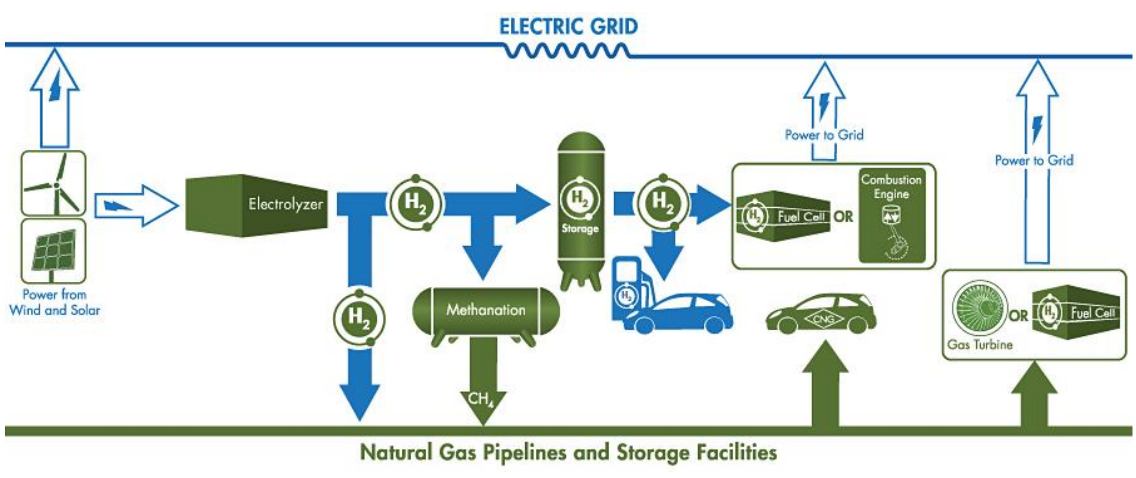
Hydrogen can be made from one of three major production methods. First, hydrogen can be produced from electrolysis of water, meaning production efficiency and associated emissions are heavily dependent on those of the electricity used. Second, hydrogen can also be produced from biomass gasification. Gasification involves heating dried biomass without an oxidant (air) to produce bio-oils, a process known as pyrolysis. Next, the bio-oils are further heated with an oxidant (such as air) and water. Fuels produced from biomass feedstocks, such as hydrogen from biomass gasification, are known as biofuels. Thirdly, hydrogen can be produced from steam methane reformation (SMR). SMR is a process in which methane and water react at high temperatures to produce hydrogen. It should be noted that SMR can be applied to both fossil and renewable sources of methane.

Electrolysis splits water with electricity to produce hydrogen and oxygen using electrolyzers of three main varieties: alkaline electrolytic cells (AECs), proton exchange membrane electrolytic cells (PEMECs), and solid oxide electrolytic cells (SOECs). AECs are the most mature form of electrolyzers of these three in that they have been available commercially for the longest time. PEMECs are the next most mature. SOECs are the least mature electrolyzer, with no commercially available examples available and a technology readiness level (TRL) of 2-4 in 2014 [43].

Power-to-gas (P2G) is an emerging technology that transforms energy in the form of electricity to energy in the form of a gaseous fuel such as hydrogen (or methane, which will be detailed shortly). This is useful due to the increasing amount of renewable energy such as wind and solar which are intermittent and not easily predictable. P2G can be used as a form of energy storage in that the gas that is produced from electricity can be stored in containers or even the natural gas grid for later use either as a vehicle fuel or fuel for other purposes.

P2G is flexible due to the numerous possible pathways for energy to flow. These pathways are depicted in Figure 7. P2G can connect the electric grid and the natural gas grid, two large energy distributors of the modern day. This allows the benefits of both grids to be utilized while downplaying their characteristic issues. For example, P2G can use the highly efficient electric grid when possible (meaning there is demand for more electricity), but also use the natural gas grid when there is not an immediate demand for power (making use of the natural gas grid's inherent storage ability). P2G also enables other transfers of energy, such as fueling vehicles that run on hydrogen, natural gas, or electricity.

Figure 7. Schematic of P2G Pathways, from the Advanced Power and Energy Program [8]

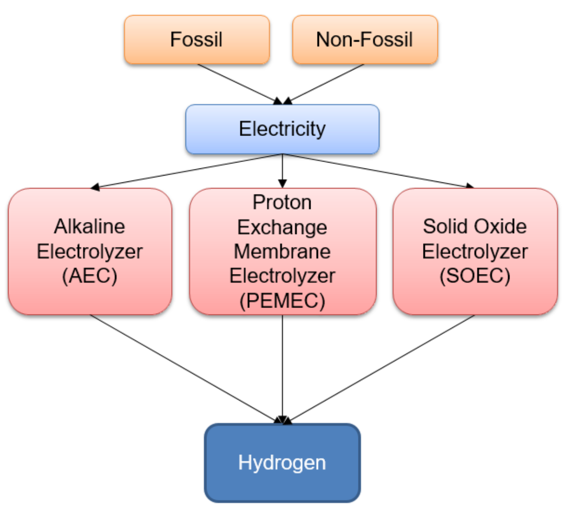


As seen from Figure 7, the first step in P2G, no matter which pathway is being followed, is using electricity in an electrolyzer to produce hydrogen. Therefore, the emissions associated with P2G are directly tied to the emissions associated with the production of the electricity used by the electrolyzer. While Figure 7 only shows renewable sources of electricity, P2G can also use fossil sources of electricity which do have emissions.

A particularly attractive use of P2G comes from using what would be curtailed, or wasted, electricity from renewable energy sources such as solar panels and wind turbines [44]. As mentioned above, both wind and solar power are intermittent and hard to predict precisely. P2G is able to use electricity from these renewable sources at times when the electric grid might not be able to accept them, which is brought about by the fact that electricity must continually be used at the same time as it is generated. This means more of the renewable electricity generated would be used in other areas such as making renewable hydrogen for vehicle fuel. Increasing renewable energy usage will decrease the emissions associated with both the electric grid and the natural gas grid, which are both intertwined with the advent of P2G.

To focus on the work conducted within this work, it is beneficial to summarize the pathways and technologies used herein. Figure 8 is a flowchart that includes all such pathways for electrolytic hydrogen production. The overall idea of these pathways is to use electricity (produced from either fossil fuels or non-fossil fuels such as solar and wind power) to produce hydrogen from water. This gaseous fuel can be made by any of the three electrolyzer technologies displayed below.

Figure 8. Flowchart of analyzed electrolytic hydrogen production pathways



Gasification is a thermochemical process in which solid biomass is heated in the absence of oxygen to produce a gaseous mixture known as syngas [45]. This syngas is composed primarily of hydrogen and carbon monoxide. Hydrogen can then be separated from this mixture [46][47][48], [49][50]–[57].

Note that gasification is most efficient with dry biomass [45]. Drying would be required for higher moisture content biomass, and the efficiency loss there would make gasification less attractive than an alternative process such as anaerobic digestion, which will be introduced later. Therefore, this work assumes only dry biomass as potential feedstocks for gasification, including agricultural residues, MSW, forestry residues, trees, and energy crops. Food waste and manure are not considered feedstocks for gasification in this work as they would require significant drying which would decrease overall efficiency.

Steam methane reformation (SMR) is a chemical reaction in which methane (CH_4) is converted to hydrogen (H_2) according to the following reaction in Equation 1.

Equation 1. Steam methane reformation reaction

$$\mathrm{CH_4 + H_2O \rightarrow CO_2 + 4H_2}$$

This process is currently used on natural gas, a fossil fuel, to make 95% of hydrogen in the U.S. [58]. Additionally, some biogas is put through SMR to meet SB 1505, the requirement that one-third of hydrogen sold at fueling stations is renewable.

Due to this work's focus on increasing adoption of renewable fuels and the roundabout method of production using SMR which lowers efficiency by about 70% [59] (first biogas would need to be produced from the primary biomass by one of the methods to be introduced shortly, and then that biogas would be converted to hydrogen), this production method is not considered in this work.

Fuel Production: Renewable Natural Gas

Renewable natural gas (RNG) is a drop-in fuel, meaning it can be integrated into current natural gas infrastructure, including pipelines and dispensing stations, and be used in current vehicles that are fueled by natural gas. Being a drop-in fuel allows for easy integration of a fuel that can be made in a more environmentally friendly manner and using resources that may be more prevalent in any given area. One potential benefit of drop-in fuels such as RNG is time of transition: it may take less time to reduce emissions by changing the fuel than by changing the vehicle, either with efficiency improvements or alternative powertrain technologies.

Three methods of producing RNG are considered in this work: (1) electrolytic methanation and biomass conversion by either (2) anaerobic digestion or (3) gasification. Electrolytic production of RNG uses electricity as its feedstock. This process begins the same as electrolytic hydrogen production and is followed by a methanation step to convert that hydrogen into methane using carbon dioxide. Anaerobic digestion (AD) is a biochemical process that uses microbes to break down organic matter to methane and carbon dioxide. Gasification for RNG production, as for hydrogen mentioned previously, requires lower moisture biomass. Again, these dry biomass feedstocks are agricultural residues, MSW, forestry residues, trees, and energy crops.

Electrolytic methanation starts in the same way as electrolytic hydrogen, but there is a following methanation step. This production method also belongs to the umbrella term P2G introduced previously.

Methanation is the chemical reaction that turns hydrogen and carbon dioxide into methane and water. This chemical reaction is also known as the Sabatier reaction, and it is exothermic, meaning heat is a product. The chemical equation is listed below with the correct stoichiometric coefficients in Equation 2. Each mole of reaction gives off 165 kilojoules of heat [60].

Equation 2. Sabatier reaction

$$CO_2 + 4H_2 \rightarrow CH_4 + 2H_2O$$

Literature was consulted for technologies that provide carbon dioxide for making RNG from hydrogen as well as technologies to make use of the heat produced during the methanation process. Both of these technologies are needed because the Sabatier reaction (1) is an exothermic reaction that requires a heat sink for sustained reaction without overheating equipment, and (2) requires carbon dioxide as input to convert hydrogen into methane [61].

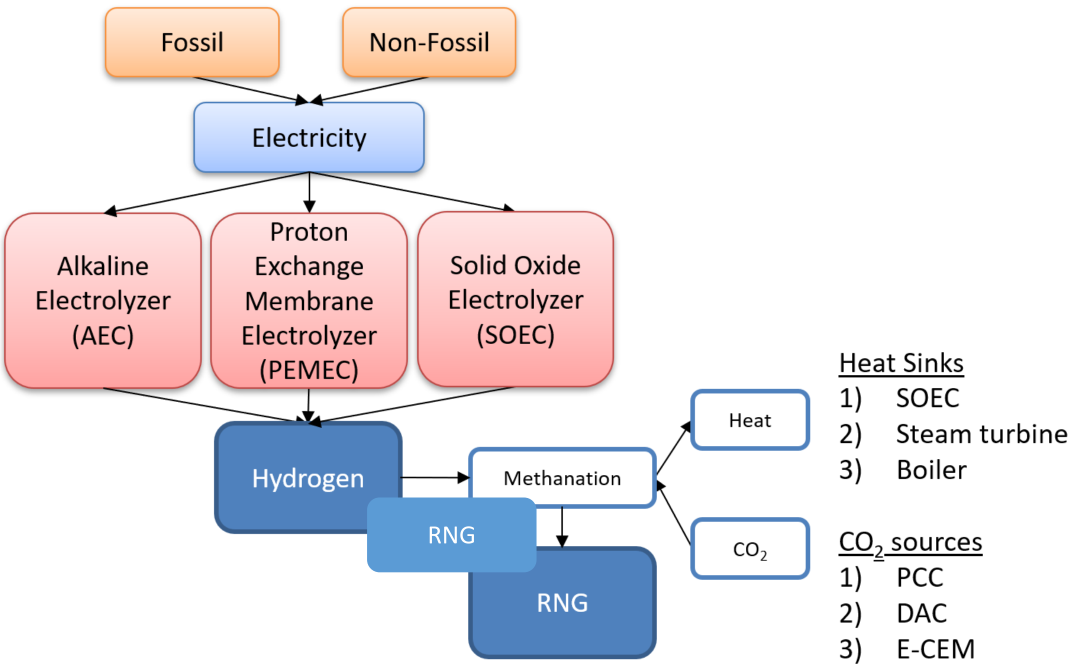
The primary benefit of methanation is the ability to take advantage of the natural gas infrastructure. Without methanation, hydrogen is the main product of P2G. However, there is not much infrastructure in the U.S., or even the world, for hydrogen. Therefore, the extra step of methanation makes P2G much simpler to integrate into the power grid of today and transport to areas of demand. Use of natural gas pipelines and storage throughout the country and much of the rest of the world make P2G more practical today. The tradeoff for this practicality is the loss of efficiency by adding the extra step of methanation as well as the additional emission of carbon whenever the RNG is eventually used.

A diagram showing the various electrolyzers, heat sinks, and carbon dioxide sources analyzed in this work for electrolytic RNG production is shown below in Figure 9.

The three electrolyzer types have already been introduced in the discussion of electrolytic hydrogen production. As for the heat sinks of the methanation reaction, it is assumed that increasing the efficiency of the SOEC is prioritized if using such an electrolyzer [62], [63]. Otherwise, it is assumed that the plant has other heat needs and further consideration of the heat rejection is neglected. What follows are the various heat sink and carbon dioxide source technologies.

Post-combustion capture (PCC) pulls carbon dioxide from the exhaust stream of a power plant, a stream that is relatively dense in carbon dioxide compared to ambient air. Various solvents, sorbents, and membranes are used to capture the carbon dioxide from the exhaust stream as the carbon dioxide-containing exhaust flows through the PCC system. [64], [65].

Figure 9. Flowchart of analyze electrolytic RNG production pathways



Direct air capture also involves a sorbent to capture carbon dioxide from the ambient air [66]. Because of the lower density of carbon dioxide in ambient air compared to the exhaust stream of a power plant, DAC is not as efficient as PCC. Due to the nature of carbon dioxide's effect on climate change, DAC units can be placed anywhere and have the same impact.

The electrolytic cation exchange module (E-CEM) technology is being pursued by the U.S. Navy and is promising due to its ability to capture both carbon dioxide and hydrogen from seawater [67]. Here, the carbon dioxide would be used as an input to the Sabatier reaction, and the hydrogen again is useful as a fuel or as more reactant for the Sabatier reaction. E-CEM was originally developed for jet fuel production in the sea to overcome the need for resupply of fuel on military missions involving aircraft carriers. The technology readiness level for E-CEM is low and therefore the option may not be ready in time for use in 2030 or 2050.

RNG can also be produced using a biochemical process known as anaerobic digestion. Anaerobic digestion involves microbes (hence biochemical), in the absence of oxygen, breaking down organic matter to methane and carbon dioxide. This process works with high moisture biomass, so only the moist biomass sources including manure and food waste can be used in AD [68]–[71]. The gas mixture of mostly methane and carbon dioxide can be cleaned to improve the purity of methane using methods previous introduced, creating RNG. The wet material remaining after AD, known as digestate, can be used as a fertilizer for farming applications [72].

Gasification was previously introduced as a method of producing hydrogen from dry biomass. Again, the actual product of gasification is termed syngas, which is composed primarily of hydrogen and carbon monoxide. This syngas can be turned into RNG by the same methanation process described previously to convert electrolytic hydrogen and carbon dioxide into methane [73]–[91][92]–[103]. Just as before with hydrogen gasification, producing RNG by gasification is also most appropriate with a relatively dry biomass, which saves energy on the drying process. Therefore, this work assumes only dry biomass as potential feedstocks for gasification, including agricultural residues, MSW, forestry residues, trees, and energy crops. Food waste and manure are not considered feedstocks for gasification in this work as they would require significant drying which would decrease overall efficiency.

Fuel Production: Renewable Diesel

Renewable diesel is a drop-in fuel, just as RNG is. Therefore, renewable diesel can be used in the current diesel infrastructure, including the many dispensing stations open today, as well as the vehicles that are fueled by diesel. Taking advantage of the vast incumbent gasoline and diesel infrastructure and vehicles provides a significant timing and cost benefit to the renewable gasoline and renewable diesel.

Renewable diesel can be produced from biomass using one of four processes: liquefaction, gasification followed by Fischer-Tropsch, pyrolysis, and hydrolysis. The three former production methods are thermochemical, whereas hydrolysis is biochemical. These production methods will be discussed in further detail shortly. Also, important to note is that each of these four fuel production methods use the nearly the same biomass feedstocks, which are relatively dry: agriculture, waste, forestry, tree, and energy crops. However, liquefaction can also use moist biomass, so food waste and manure are included as feedstocks for liquefaction [68], [104]–[106].

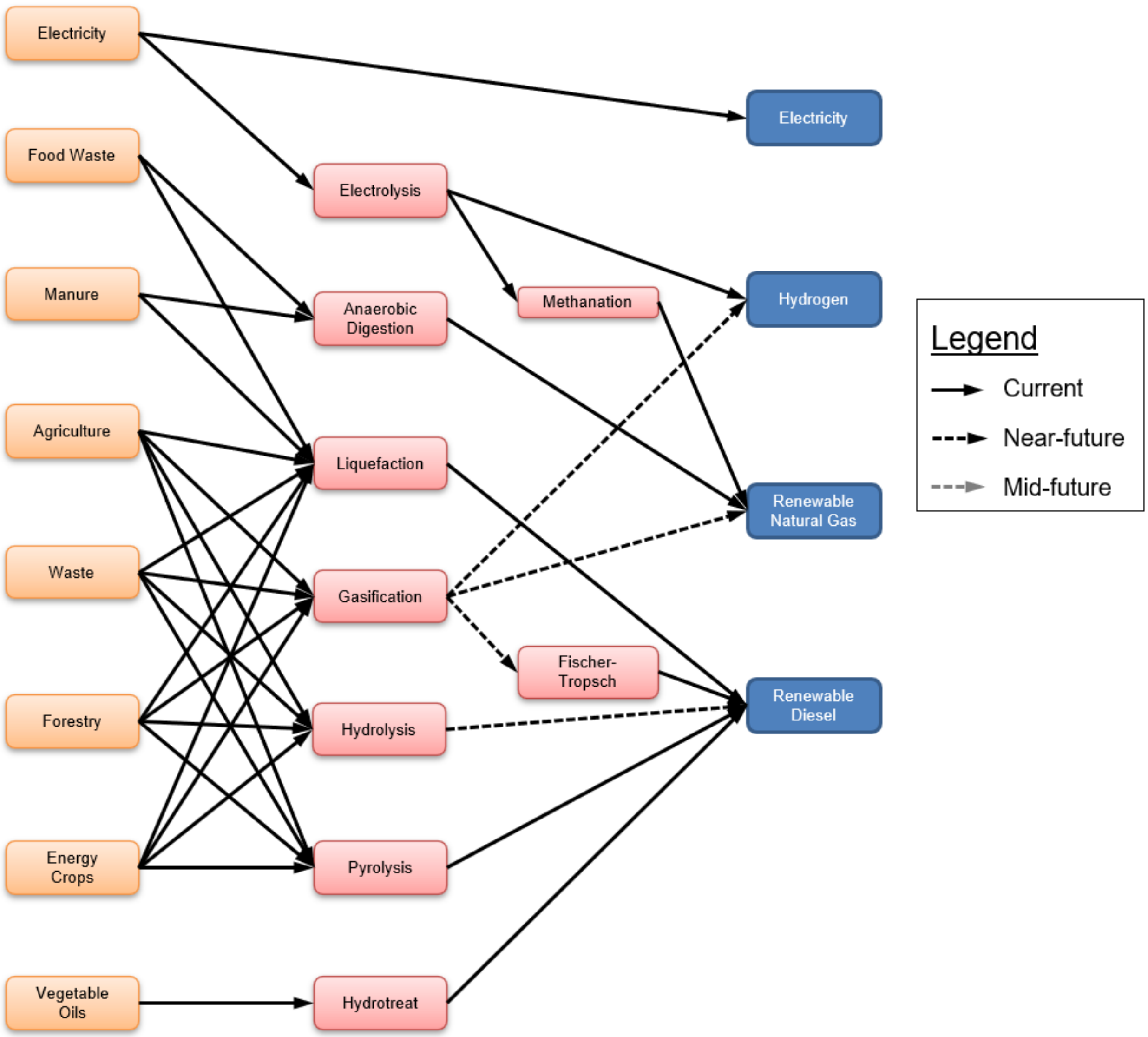
In addition to using biomass as a feedstock, vegetable oil can be a feedstock for renewable diesel production as well, commonly known as hydrotreated vegetable oil (HVO). The vegetable oil is hydrotreated, meaning it is processed using hydrogen to convert the vegetable oil into the various hydrocarbon chains that make up diesel. Note that this process is one of the final stages of some of the various biomass to renewable diesel technologies introduced above.

Further details on these renewable diesel production technologies can be found in Appendix A.

Fuel Production: Summary of Production Technologies Modeled

Having finished the introduction of each of the fuel pathways to be considered in this work, Figure 10 summarizes them. Note the many pathways options, particularly with respect to some of the biomass feedstocks that have several process options available. Arrows pointing from fuel production technologies to fuels that are dashed signify a technology that is being developed but not yet commercial.

Figure 10. Flow diagram of HDV fuel production pathways



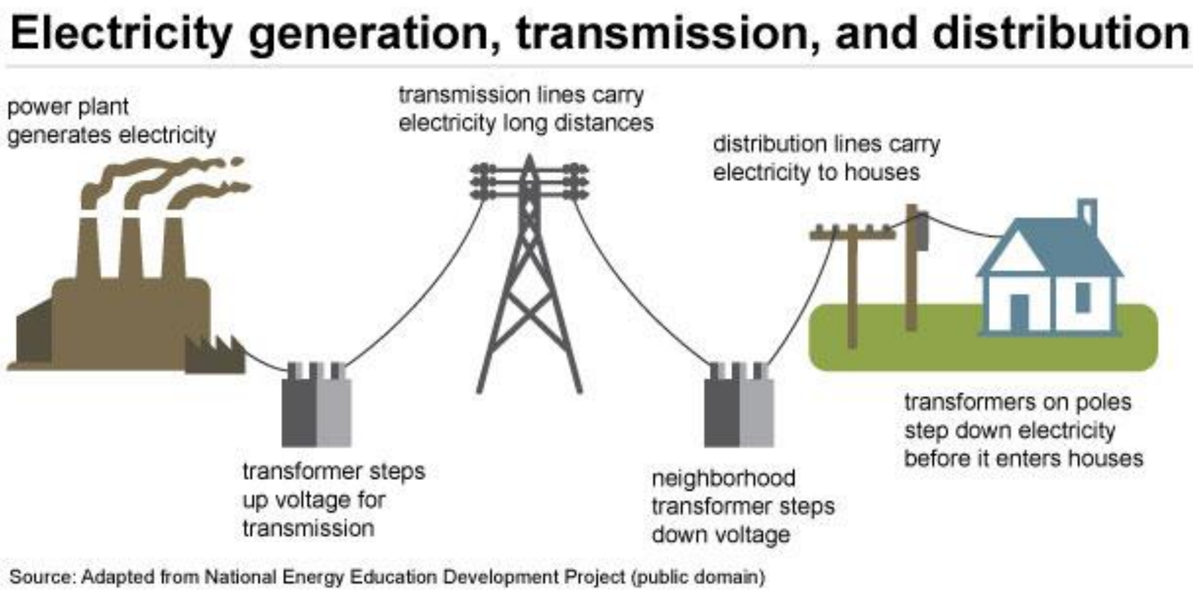
Fuel Distribution

Once the fuels have been produced, it is then necessary to distribute them to locations at which drivers can refuel their vehicles. Due to the physical differences between these fuels, there are also major differences in how these fuels may be distributed.

Fuel Distribution: Electricity

Electricity is distributed on the electric transmission and distribution grid, as shown in Figure 11. Transmissions lines move electricity long distances at high voltages to reduce electric losses, making the transmission more efficient. Distribution lines move electricity at lower voltages for shorter distances, typically around neighborhoods and office areas. While moving the electricity at lower voltages in distribution lines is less efficient, the distances covered by distribution lines is much lower than transmission lines and therefore the lower efficiency is acceptable. The lower voltage is then easier to handle for end-uses such as homes, business, and industrial facilities.

Figure 11. Diagram of electricity transmission and distribution network, from U.S. Energy Information Administration [107]



Equipment for the electric grid includes the transmission and distribution network of the electric grid, substations , individual transformers at the distribution level, and electric lines that carry the electricity from one place to another. Depending on the power of charging for PEVs as well as the PEV population, some or all of this distribution equipment may need upgrading to handle the increased electric load on the grid [108][109].

Fuel Distribution: Hydrogen

Hydrogen is a gaseous fuel, and being a gaseous fuel means it is less energy dense by volume than a liquid fuel. Therefore, distribution of hydrogen has a challenge of keeping cost-effectiveness high.

A dedicated hydrogen pipeline to distribute hydrogen is a consideration, as is blending hydrogen into the natural gas grid. A dedicated hydrogen pipeline is a serious technical feat that would take decades to roll out with significant logistical challenges such as securing rights to dig and implement the pipeline. Blending hydrogen into the natural gas pipeline is an option, with a practical limit of about 15% of the pipeline by volume, or 5% by energy, before there are any serious concerns of safety or integrity [110], [111]. Blending hydrogen into the natural gas grid would also require interconnections to be built to connect to the grid itself, increasing cost significantly [112]. Lastly, blending hydrogen into the natural gas grid for distribution would then require extracting that hydrogen out of the grid downstream. This would most likely be done by SMR, which as previously mentioned lowers efficiency to the point that it would not be competitive with the other pathways considered herein [59]. Therefore, pipeline delivery of hydrogen, either through a dedicated pipeline or through the natural gas pipeline, is not considered in this work.

The remaining option for hydrogen delivery is trucking. One could consider trucking either as a compressed gas, or first liquefying the hydrogen and then trucking that. The benefit of liquefying is increasing the density, but that comes with the tradeoff of energy input to liquefy the hydrogen.

There are two key components of hydrogen distribution: the terminal, and the delivery. The terminal is the point from which hydrogen is to be collected and then delivered to the dispensing stations. Terminals are needed to ensure smooth logistics in moving hydrogen from production location to dispensing stations [111].

Fuel Distribution: Renewable Natural Gas

RNG, like hydrogen, is a gas at ambient temperature and pressure. Because it is chemically comparable to natural gas (RNG is simply the methane molecule that has been produced either electrolytically or from biomass), RNG can be injected into the natural gas pipeline without any limitation or blending requirement. Due to the robust natural gas infrastructure in place, with nearly all homes, offices, and buildings already connected to the natural gas grid in the U.S., the distribution method for RNG in this work is assumed to be the natural gas pipeline.

Another option for RNG is to truck it, either as a compressed gas or as a liquid, similar to hydrogen. However, the efficiency and cost-effectiveness of the ability to take advantage of the robust natural gas infrastructure makes trucking RNG generally less cost effective. Therefore, RNG can be assumed to be distributed using the natural gas pipeline infrastructure.

Fuel Distribution: Renewable Diesel

Renewable diesel is effectively the same product as fossil diesel. Therefore, it is safe to assume that distribution of renewable diesel will take the same form as fossil diesel. This method is trucking. Because diesel is a liquid fuel, it is relatively energy dense and therefore trucking is an effective method of distribution.

Fuel Dispensing

Once each of the fuels has been distributed from the point of production, there needs to be some station to allow for fueling of the corresponding vehicle types. This is the role of the dispensing infrastructure. While each of the following dispensing infrastructure currently exists, there is a wide gap between them in terms of availability and maturity.

Fuel Dispensing: Electricity

Electricity dispensing takes the form of electric chargers for PEVs. These electric chargers come in a range of powers, with higher power electric chargers refueling PEVs faster. The PEV charging equipment is often referred to as electric vehicle supply equipment (EVSE). While there are many factors such as vehicle battery capacity and the power of electric chargers, typical charging times are on the order of a few hours for a BEV. Therefore, it should be noted that the relatively short refueling times of current vehicles would be much longer for BEVs.

The lowest power charger is known as level 1, with power output of 1.44-1.9 kilowatts (kW). Level 1 charging is done at 120 volts (V), which is the same as is commonly available at homes and commercial locations. Therefore, conventional wall power outlets are able to support PEVs with level 1 charging, and no special equipment must be installed. Typically, level 1 charging is not appropriate for HDVs due to constraints associated with their inherently large batteries. Next is level 2 charging, which is done at 240 V or 208 V, depending on what is available at the site, with power output of 3-19.2 kW. Level 2 charging does require additional equipment, which increases the cost of this charging compared to level 1. Last is level 3 charging, often known as DC fast charging, with power output of 25 kW and above. Level 3 charging operates at 480 V, which make these chargers most appropriate for dedicated charging stations or depots [113]. Both level 1 and level 2 charging share the same connector, while level 3 uses a more robust connector to handle the higher charging powers.

For PEV that include an additional powerplant on board (e.g., diesel engine or fuel cell) level 2 charging may be appropriate due to the extended range provided (although level 3 charging may be desirable to decrease charging times when needed. Conversely, it is likely that a BEV will require level 3 charging to feasibly reach required vehicle ranges with reasonable charging times. Therefore, the present work assumes all heavy duty BEVs use level 3 charging while PEVs with a range extender use level 2 charging. It should be noted however, that the use of a mix of different charging levels could be utilized to support the real-world deployment of PEV and BEV.

Fuel Dispensing: Hydrogen

Hydrogen dispensing stations, often called hydrogen refueling stations (HRSs), are currently under development in California. There are 40 public stations open in California as of April 2020. Three under construction will support heavy duty trucks and four will support heavy duty buses [114]. There are some stations on the east coast [115], but otherwise hydrogen dispensing stations are not common in the rest of the U.S. Current small-scale hydrogen stations cost on the order of one to a few million dollars each [116], [117].

Note that the hydrogen station schematic is quite similar to that of the RNG station, as seen in Figure 12. One major difference is that because pipeline distribution of hydrogen is not modeled in this work, the “gas line” of the RNG station would be a tube trailer of liquid hydrogen that is delivered by truck.

Fuel Dispensing: Renewable Natural Gas

RNG is distributed just like compressed natural gas (CNG). CNG stations, while mature like gasoline and diesel stations, are not nearly as common. There are 116 public CNG stations that can support fueling for HDVs as of June 2019 [118]. Therefore, any significant future adoption of RNG vehicles will require fueling station construction [119].

Fuel Dispensing: Renewable Diesel

Renewable diesel is a drop-in fuel, and therefore can be used in existing diesel dispensing infrastructure. Diesel is the primary fuel HDV today, and its fueling infrastructure is prevalent. Therefore, no significant infrastructure would need to be built for renewable diesel into the future.

Fuel Emissions

Emissions from fuel for this work are considered only from the feedstock, whether electricity or biomass, and the overall pathway efficiency. Each production technology will be characterized by its primary energy efficiency. Additionally, distribution and dispensing efficiencies are considered and therefore affect the emissions associated with the vehicle fuel.

Not included are leakage emissions from distribution, particularly applicable for gaseous fuels such as hydrogen and RNG. GREET notes that 1.3% of US natural gas throughput is emitted into the air as methane, although this number may be overestimated [120]. This methane comes from both leakage from extraction, processing, and distribution, as well as some combustion used for heat for any needed process. GREET also notes that about 0.2% of natural gas is leaked in transmission from the natural gas processing plant to electric generators that run on natural gas. Therefore, the leakage that can be assumed for the distribution of RNG falls somewhere between the above two numbers. Overall, this value is negligible and will not be considered a loss in this work. The same is assumed for hydrogen, which has been shown to leak at similar rates despite inherent differences in chemical and molecular properties [7]. Similarly, distribution of renewable diesel is assumed to be leak-free. Electricity is not leaked, but distribution efficiency is included.

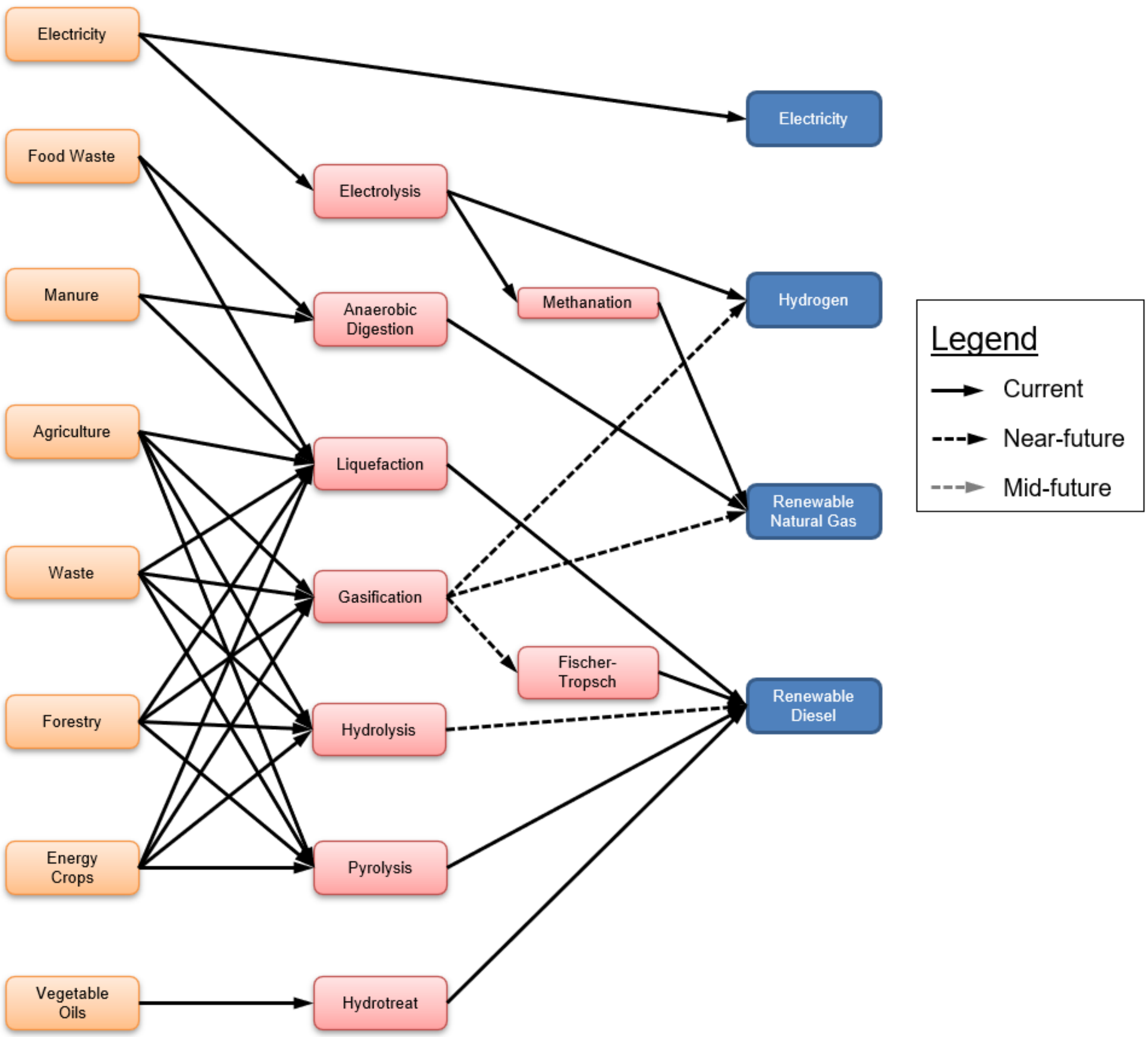
1.3 Methods

First, literature is consulted to determine which HDV fuels should be considered as renewable options looking out to 2050. For fuels, each of the major pathway options are characterized from fuel feedstock to dispensing infrastructure. Relevant techno-economic data including cost and efficiency are gathered from a literature review and used to develop projections to 2050 using Wright’s Law based on adoption of each technology.

1.3.1 Fuel Pathway Analysis

First, literature is consulted to determine which HDV fuels should be considered as renewable options looking out to 2050. For fuels, each of the major pathway options are characterized from fuel feedstock to dispensing infrastructure. The summary of analyzed pathways is shown in Figure 12.

Figure 12. Flow diagram of HDV fuel production pathways



Relevant techno-economic data including cost and efficiency, availability, and emissions are gathered from a literature review and used to develop projections to 2050 using Wright's Law based on adoption of each technology. Wright's law projects future capital costs based on the cumulative capacity produced (rather than using time as in the case of Moore's law). The equation for Wright's law can be written as shown in Equation 3 according to [121].

Equation 3. Wright's law

$$C(p_t) = C(p_i)\left(\frac{p_t}{p_i}\right)^{-b}$$

Here, p_i is the initial production volume, p_t is the production volume at time *t*, $C(p_t)$ is the cost at production volume at time *t*, $C(p_i)$ is the cost at the initial production volume, and *b* is an exponential learning parameter related to the learning rate (LR) by the equation.

Equation 4. Learning rate

$$LR = 1 - 2^{-b}$$

The above Wright's law analysis is used to project cost reduction of fuel production equipment, and the total fuel cost incorporates all steps from fuel feedstock, fuel production, fuel distribution, and fuel dispensing. A particularly in-depth analysis is conducted for electrolytic pathways, beyond the detail of any such analysis in the literature, from the perspective of the authors.

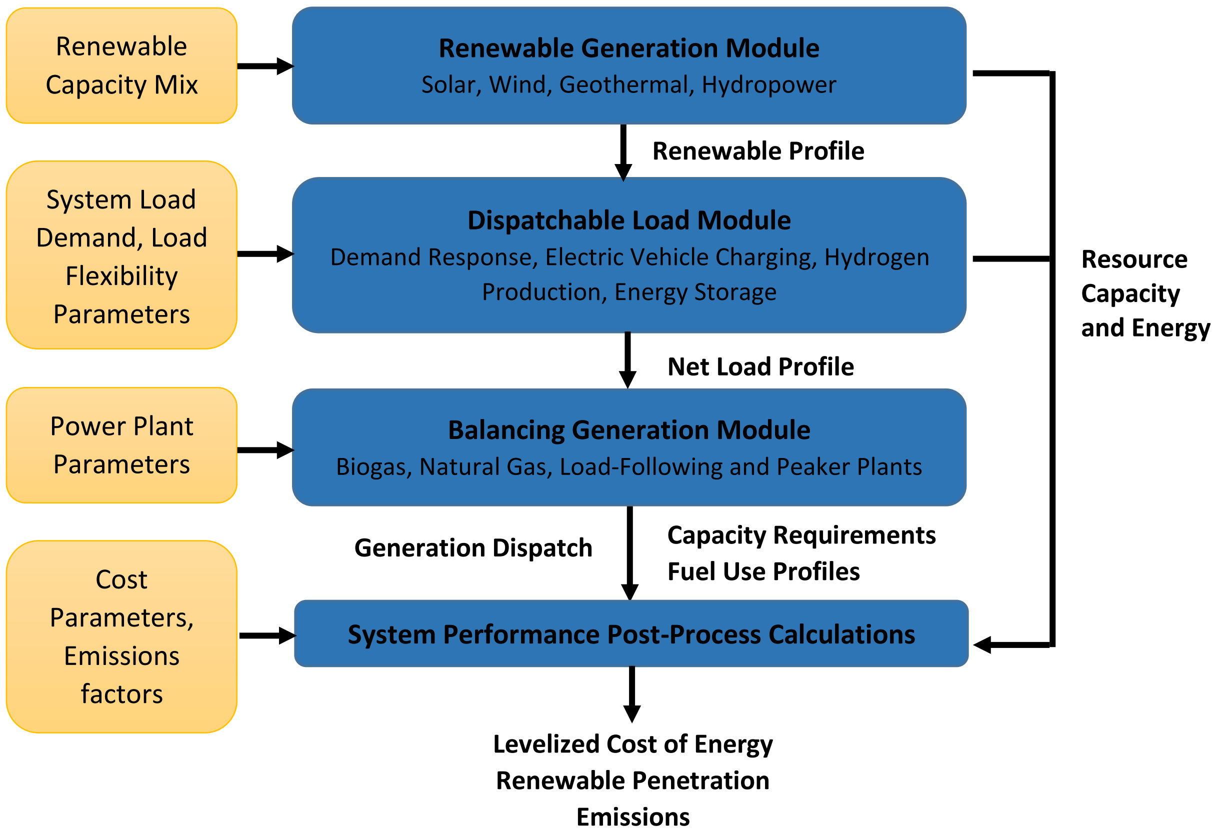
The HDV fuel efficiency is calculated using each of the individual pathway steps' efficiencies. Resulting HDV fuel availability is calculated using fuel feedstock availability and the full fuel pathway efficiency. Resulting emissions associated with the fuels incorporate feedstock emissions and full pathway efficiency.

1.3.2 Vehicle-to-Grid Analysis

Electric Grid Modeling

This analysis applies the Holistic Grid Resource Integration and Deployment (HiGRID) tool to simulate the impact of vehicle integration onto the future California electric grid. A flowchart of HiGRID's structure is presented in Figure 13. HiGRID, developed by the Advanced Power and Energy Program (APEP) at the University of California, Irvine, is a temporally resolved platform that simulates the dispatch of defined grid resources to meet the electric load profile. The flexible structure of this tool allows for new and advanced technologies to be evaluated for their impact on the grid, including changes to grid operations and the dynamic dispatch of balancing generation resources. This makes it especially valuable in answering questions regarding the future integration of zero-emission vehicles. Previously, this model has been applied to related research questions, such as examining the impact of deploying renewable generation on grid GHG emissions, the role of hydropower for helping to integrate renewable generation, the GHG emissions impact of vehicle integration, and the air quality impacts of stationary fuel cells [122]–[124].

Figure 13. HiGRID model flowchart



The electric grid parameters and inputs for this study are informed by California state agencies' PATHWAYS project, ordered by the California Energy Commission, the California Public Utilities Commission, and the California Air Resources Board, and conducted by Energy + Environmental Economics, Inc. (E3) to evaluate pathways to meet California's 2050 GHG emissions reduction goals [125]. The assumptions taken from PATHWAYs are detailed in the section Future Grid Scenarios with Heavy-Duty Zero Emission Vehicle Integration. The heavy duty module built as a part of this work has been designed to provide insight into the potential of grid-connected vehicles to balance variable renewable generation. Factors affecting vehicle flexibility to balance the grid include: vehicle state of charge, EVSE charging rate, dwell time, charging intelligence, and travel constraints [126], [127].

Transportation Modeling

Zero-emission HDVs, encompassing FCEVs and BEVs, are an emerging market with some automakers offering select vehicle models and several automakers developing the drivetrains and vehicle body designs for future models. Reported fuel economy for these zero-emission HDV varies by make and vehicle class, see Appendix A. Future improvements and new vehicle models for all ZEV classes are expected in the coming years as ZEV technologies mature and legislation pushes for greater deployment of ZEVs [128], [129]. Future ZEV population levels are dependent on which vehicle classes and body configurations are offered as ZEVs as well as what the technical specifications of vehicles offered are, specifically fuel efficiency and range, because ZEVs will only replace ICE vehicles if vehicle demands can be met. Assuming vehicle availability, ZEV adoption rates are dependent on fleet turnover rates and economic drivers [130]. Several studies have projected likely ZEV population growth to 2050 [131], [132]. This work will use the scenarios developed for the E3 PATHWAYS project to explore a range of possible ZEV penetration levels [129].

The HDV population is diverse, ranging in weight (8,501 – 33,000+ lbs.) and use (agriculture to public transit to work-site operations). A few models have been developed to simulate heavy duty vehicle sector in California. Previous work investigating heavy duty vehicle activity have employed a range of methods for grouping HDVs into different categories and characterizing their activities. A list of relevant work is listed in Appendix A. For this study, four categories were devised in line with the California Air Resources Board's general categories: private light-heavy (8,501-14,000 lbs.), commercial light-heavy (8,501-14,000 lbs.), (medium-heavy (14,001-33,000 lbs.), and heavy-heavy (>33,000 lbs.), see Table 4.

Table 4. Vehicle Weight Classifications Including Current Study

<table>
<tr><th rowspan="2">Gross Vehicle Weight Rating (lbs.)</th><th colspan="5">Vehicle Classifications</th></tr>
<tr><th>Class</th><th colspan="2">California ARB (EMFAC2011) [133]</th><th>U.S. FHWA [134]</th><th>Current Study</th></tr>
<tr><td>0-6,000</td><td>1</td><td>Light-duty cars and trucks (LDA, LDT1, LDT2)</td><td rowspan="2"></td><td rowspan="2">Light truck</td><td rowspan="2">Light duty vehicles</td></tr>
<tr><td>6,001 – 8,500</td><td>2a</td><td>Medium-duty cars and trucks (MDV)</td></tr>
<tr><td>8,501-10,000</td><td>2B</td><td>Light-heavy duty trucks (LHD1)</td><td rowspan="8">Buses (SBUS, Motor Coach, UBUS, OBUS, All Other Buses)</td><td>Light/Medium duty truck</td><td rowspan="2">Light-heavy duty (private, commercial)</td></tr>
<tr><td>10,001 – 14,000</td><td>3</td><td>Light-heavy duty trucks (LHD2)</td><td rowspan="4">Medium Duty Truck</td></tr>
<tr><td>14,001 – 16,000</td><td>4</td><td rowspan="3">Medium-heavy duty trucks (T6 Small)</td><td rowspan="4">Medium-heavy duty</td></tr>
<tr><td>16,001 – 19,500</td><td>5</td></tr>
<tr><td>19,501 – 26,000</td><td>6</td></tr>
<tr><td>26,001 – 33,000</td><td>7</td><td>Medium-heavy duty trucks (T6 Heavy)</td><td rowspan="3">Heavy Duty Truck</td></tr>
<tr><td>33,001 – 60,000</td><td>8a</td><td rowspan="2">Heavy-heavy duty trucks (T7)</td><td rowspan="2">Heavy-heavy duty</td></tr>
<tr><td>>60,000</td><td>8b</td></tr>
</table>

Private light-heavy duty vehicles were modeled using the 2017 National Household Travel Survey-California Add-on [135]. For the three commercial vehicle categories, while there have been a few previous studies that have collected California-specific statewide trip data, most recently and relevantly the 2017 CA-VIUS, data from these studies are confidential, and therefore, unavailable for use. Additionally, Caltrans is currently revising its heavy duty vehicle model [136]. A complete and representative dataset for all trip lengths, therefore, could not be aggregated from the Caltrans models.

After reviewing available datasets, the trip data from the 2007/2008 Texas Commercial Vehicle Survey, provided by the Transportation Planning and Programming Division of the Texas Department of Transportation [137], were selected to be used as the base input for this study, to be calibrated to align with known California statistics on heavy duty vehicle travel. The sample data applied in this study had limited bus data (less than 10 vehicles of varying bus types) and therefore these vehicle trips were removed and the resulting dataset accounts only for trucks (straight and tractor configurations). Instead, a static charging profile from E3's PATHWAYS model was applied for light-duty and bus populations for the electric grid analysis.

In addition to the three weight classifications, it is important to clarify that the heavy duty vehicle charging model developed for this study is intended to represent statewide travel by heavy duty vehicles registered and traveling within California. It is assumed that vehicles registered within the state are subject to California regulations and will be the first to be converted to zero-emission vehicles. According to the 2017 CA-VIUS, this encompasses roughly 95% of all light-heavy and medium-heavy duty VMT within California and 72% of heavy-heavy duty VMT. The survey also found that in-state registration also indicates an in-state home base location [138]. Home base location is critical in the deployment and operation of BEVs, as well as grid impacts of electrification. If vehicles tend to dwell outside the state, they would be unlikely to contribute to grid services within the state.

There are several challenges in determining the potential BEV feasibility of out-of-state vehicles and their impact on the California electric grid given the available datasets. First, the 2017 CA-VIUS recorded trip distance as a measurement from home base. However, it is unclear how frequently these vehicles return to home base as a representative group. Following the assumption that registration state correlates strongly with home base state, few to none of the out-of-state vehicles will have access to charging within the state if EVSE equipment is constrained to home base locations. Since this analysis is focused on California grid impacts, out-of-state vehicles charging at out-of-state home bases would not impact the California grid. Due to the far distances these vehicles travel from home base, sometimes across multiple states, it follows that, for a significant portion of out-of-state vehicles to be electrified, they must have access to publicly available charging stations. Establishment of publicly available charging stations or battery swapping locations, as mentioned by [139], would take the coordination of multiple stakeholders including trucking companies as well as local and state governments.

BEV Charging Model

The heavy duty vehicle charging model developed for this work generates an aggregated, scaled charging profile that will be applied within HiGRID to determine the impact of vehicle charging on the electric grid. The heavy duty vehicle charging algorithms for immediate and smart charging are from the centralized electric vehicle charging model developed by Zhang (2014) [140]. The vehicle-to-grid charging model algorithm is from Tarroja (2016) [141]. Whereas light-duty vehicle applications of this algorithm had the equality constraint be applied for a 24-hour period, this analysis used a 72-hour period to account for the multiday travel of some heavy duty vehicles. The cost function is as follows [140]:

Equation 5. Cost function

$$min\left(\sum_{j=1}^{q} f_j \times x_j\right)$$

where, f is electricity cost per kWh, x is charging rate (kW), j is dwell segment, and q is total number of dwell segments.

Equation 6. Equality constraint

$$\sum_{j=1}^{q} x_j + \sum_{i=1}^{m} y_i = 0$$

where, i is trip number, y is discharged energy (kWh), and m is total number of trips.

Equation 7. Inequality constraint 1

$$y_1 > -c$$

Equation 8. Inequality constraint 2

$$y_1 + \sum_{j=1}^{q} x_{1j} + y_2 + \cdots + \sum_{j=1}^{m-1} x_{(m-1)j} + y_m > -c$$

where, c is battery energy capacity.

Equation 9. Bounds for smart charging

$$0 \le x_j \le p_j \times \Delta t_{ij} \times \eta$$

Equation 10. Bounds for Vehicle-to-Grid

$$-p_j \times \Delta t_j \times \eta \le x_{ij} \le p_j \times \Delta t_j \times \eta$$

where, η = charging efficiency and p is rated power capacity (kW) of EVSE.

The hourly net load profile entering the energy storage model serves as the “electricity price” for the smart and V2G charging algorithms. Selecting for the least cost periods to charge will result in valley-filling of the net load, and V2G discharging during peak cost periods will result in peak shaving. The new load profile, including vehicle charging and discharging, is then applied to the next module: the hydrogen demand model.

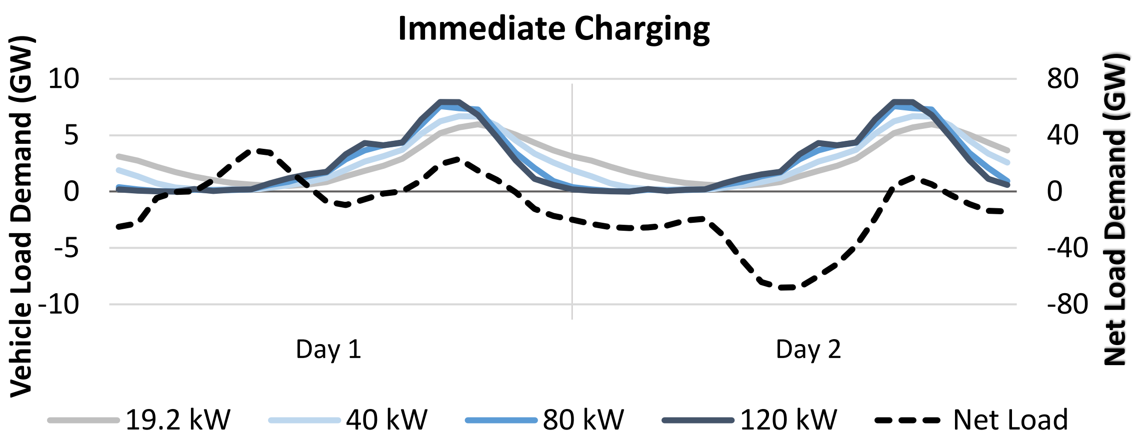
The heavy duty vehicle electric load demands generated by the vehicle charging module depend on the vehicle, EVSE parameters, and charging intelligence set for the model. Based on information on dwell periods of heavy duty vehicles, there are two general categories of locations that vehicles can charge at: home base and other (not home base) locations [137]–[139]. Charging at home base would require fleet owners to install EVSE equipment at their home base location(s). Charging at other locations would require private and/or public installation of EVSE across a diverse set of locations accessible to heavy duty vehicles along their routes. Selecting home base charging versus all-stop charging will result in vehicles charging at different periods of the day, see Figure 14 and 15. The timing of electric vehicle charging demand is compared to the year 2050 net load profile from the CPR base case.

Home base only charging with immediate charging results in a peak load demand around 7-9 pm. This indicates that immediate, home base only charging of heavy duty vehicles will result in a higher peak electric load demand. The simultaneous occurrence of vehicle and stationary peak loads can result in increased demand for fossil fuel generation capacity and increased ramping demands. The minimum charging load demand occurs between 9 am and noon. This indicates that the heavy duty vehicle charging profile with home base only charging does not align well with solar electricity generation. In comparison, all-stop charging results in a portion of the electric load demand shift from evening to earlier in the day. The net impact is a reduced contribution to load demand during the peak period and increased charging during the solar over-generation period in the middle of the day.

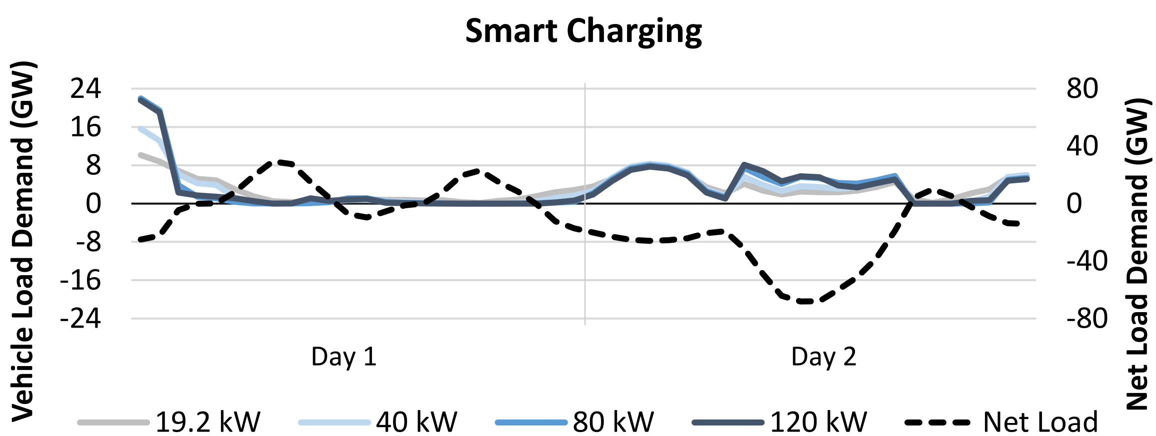
The peak charging demand also decreases, as the vehicle load is spread more evenly across the day. In addition, all-stop charging increases charging (and discharging) flexibility for vehicles with intelligent charging. For the smart charging cases, all-stop charging is more effective in filling the midday valley compared to home base only charging due to the low percentage of HDVs that return to home base throughout the day. More common is vehicles dwelling at different locations along their route. Most vehicles dwell overnight, making home base only charging effective in filling overnight valleys that occur.

Heavy-duty BEV load demand is also dependent on the assumed EVSE charging rate. With immediate charging, higher charging rates result in faster charging of the vehicles, which in turn increases the peak demand and reduces overnight charging. Increasing charging rate with intelligent charging strategies also results in increased peak vehicle load demand, however, with intelligent charging these peaks are coordinated with “valleys” in the net load. The result is improved load smoothing. Increasing the charging rate for V2G-enabled vehicles increases the peak vehicle load and the peak vehicle discharge power, resulting in a greater capture and shifting of renewable energy.

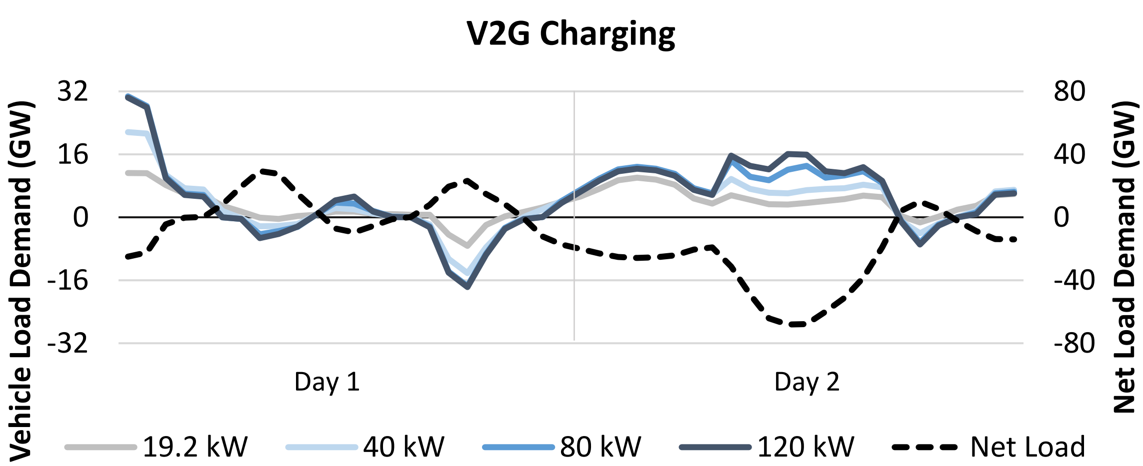
Figure 14. Cumulative Charging Profile for at Home Base Charging with Increased Charging Rate: a) Immediate, b) Smart, and c) V2G Charging Strategies



a)

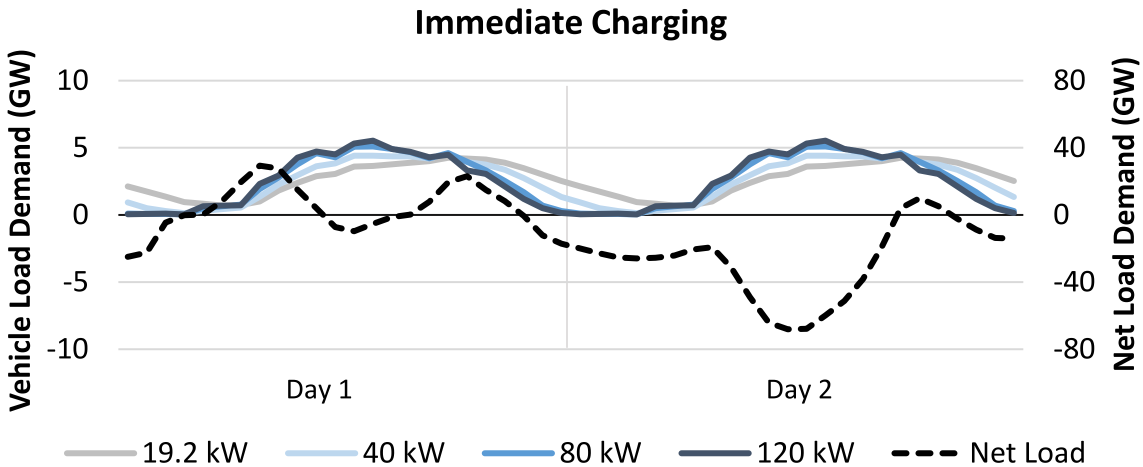


b)

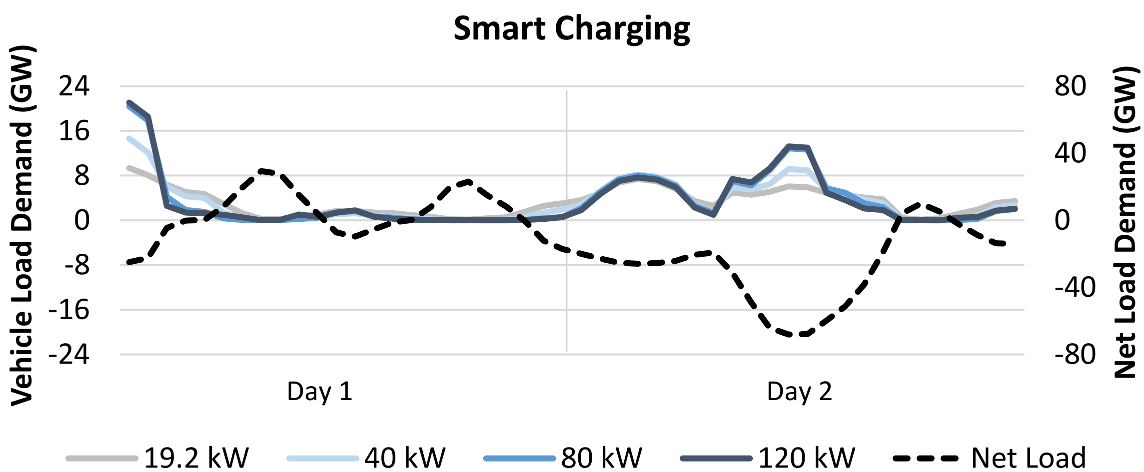


c)

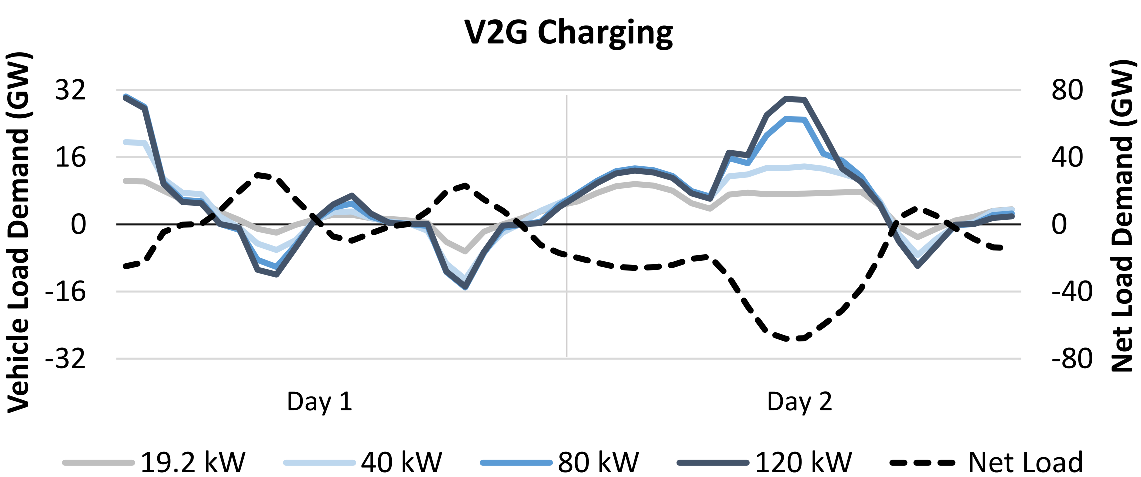
Figure 15. Cumulative Charging Profile for All-Stop Charging with Increased Charging Rate: a) Immediate, b) Smart, and c) V2G Charging Strategies



a)



b)



c)

1.4 Results and Discussion

1.4.1 Heavy-Duty Vehicle Fuel Pathways Techno-Economics

This section summarizes the vehicle fuel production, distribution, and dispensing techno-economic projections that are carried out. Note that for brevity, many of the details of the analysis are saved for Appendix A.

Because the timescale of the present work is long (30 years from 2020 to 2050), inflation must be considered. This work assumes a 2% rate of inflation, which is in line with recent historic data from the U.S. [142].

Also needed due to the long timescale and the high capital costs of creating large fuel production plants, the idea of a capital recovery factor (CRF) is introduced. A CRF is a method of capturing various economic data such as interest rates, depreciation, lifetime of equipment, and others to convert a single bulk capital cost into recurring payments. The present work assumes a CRF of 0.12 for all equipment to calculate yearly payments from a single capital cost. The precedent for this value is work from the U.S. Department of Energy using such a CRF for its coal power plants for low-risk scenarios [143]. Inherent in using this CRF is the assumption that the proceeding fuel production plants will be low risk. This would mean that large entities such as utilities would be the ones creating these plants, a valid assumption for a high-capital plant. Also assumed is a lifetime of 30 years, which is the time of interest for this work. Therefore, when a fuel production plant is built, it will be used until the end of the model run.

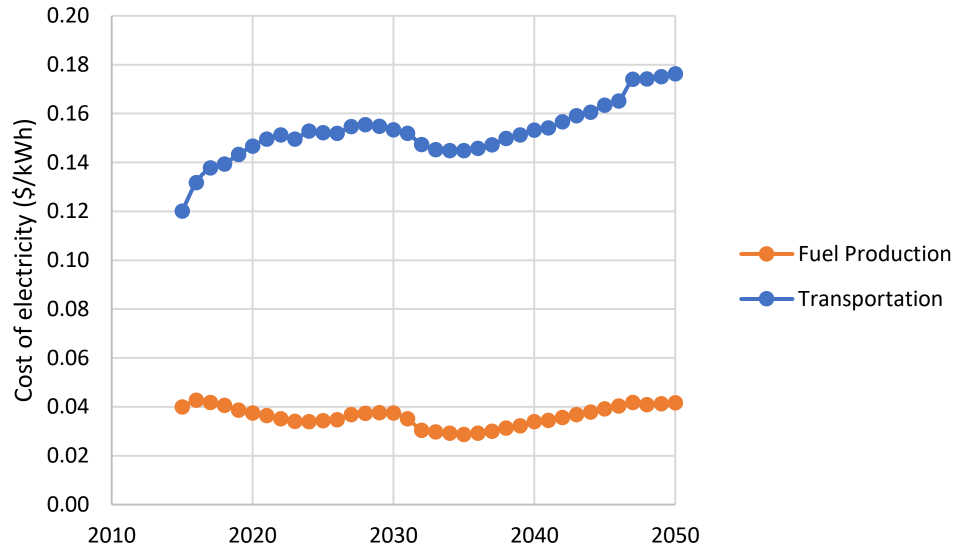
Fuel Feedstocks

Here, the cost of both electricity and biomass feedstocks is detailed. Emissions results are presented at the end of this section, at which point both the feedstock emissions as well as the total fuel pathway emissions up to the vehicle will be detailed.

Fuel Feedstocks: Electricity

Electricity cost is sourced from E3's PATHWAYS model that projects demand of electricity and how that demand can be met most cost-effectively while meeting emissions legislation of California [41]. Note that there are different prices associated with different end uses. Fuel production is the lowest, and that is associated with using electricity as a feedstock for other fuels, such as electrolytic hydrogen or RNG. Transportation rates are higher, and these are the rates that would be in place to charge a PEV with electricity. Some utilities already have lower PEV charging rates in their contracts [144]. Other electricity rates are projected as well, such as for commercial and industrial sectors, but those are not relevant in the context of fuel production so they are not shown in Figure 16. The present work uses E3's fuel production rates for the electricity feedstock and adds cost for the additional distribution infrastructure.

Figure 16. Electricity price projections, current policy reference scenario with SB 100, data from [41]



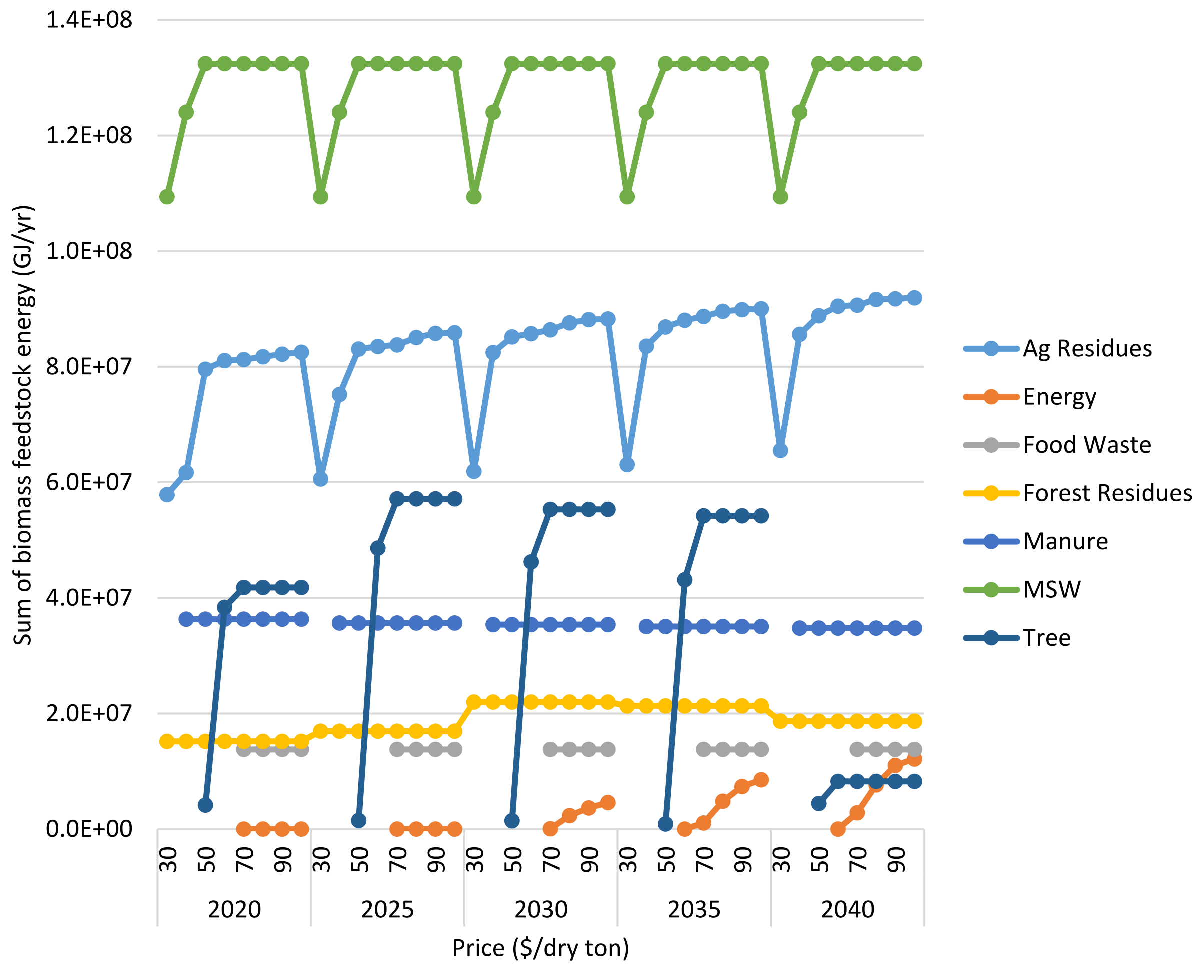
The electricity prices are assumed to be constant over the range of availabilities to be described later, an assumption that is most accurate if the modeled electricity demand of this work is like that of E3's. Given the assumptions to be made, these prices should be appropriate.

Fuel Feedstocks: Biomass

Prices for biomass feedstocks are found in the U.S. Department of Energy's Billion Ton Report [40]. Figure 17 shows the quantity of each of the categories of biomass available at various selling prices. These quantities are given every 5 years from 2020 to 2040. Selling prices start at $30/dry ton and increase by $10/dry ton increments up to $100/dry ton.

For vegetable oil costs, two costs are modeled: (1) crop vegetable oil, and (2) waste vegetable oil. Crop vegetable oil is modeled as $20.25 per GJ and waste vegetable oil is modeled as $5.79 per GJ, both from CARB's Biofuel Supply Module [145].

Figure 17. Current and potential biomass production for energy use in California based on medium housing, medium energy use, and base case energy crop growth scenario with non-organic MSW removed, data from [40]



Fuel Production

This section details the efficiency and cost of fuel production for four fuels considered in this work (hydrogen, RNG, renewable gasoline, and renewable diesel). Electricity production is outside the scope of this work, and costs for electricity have already been detailed. ***Note that the electrolysis pathways for both hydrogen and RNG include the most detail as this was the area with least information and agreement in the literature.*** The methodology developed for these electrolytic fuels is then applied to the other fuel production methods.

Many methods have been proposed for estimating technological progress and the effects on cost. These include Moore's law [146], Wright's law [147], and various other variants [148]. Nagy et al. tested these different methods for estimating technological progress based on a database of 62 different technologies and showed that Wright's law and Moore's law perform essentially the same with a slightly better performance by Wright's law. When applying Wright's law on time horizons of 30 years and less, estimates are generally off by a factor of 3 or less, though one technology was an order of magnitude off [148]. It is important to keep in mind this uncertainty when making projections, especially as far out as 30 years. Also, a reminder here that for the results of the Wright's law projections, real dollars are used out to 2050, and generally a 2% annual rate of inflation is assumed.

In the coming sections, it will be shown that there is a wide range of current costs and cost projections for electrolyzer technologies. Therefore, a conservative and an optimistic scenario are proposed in this work for the cost projections of P2G equipment. The conservative scenario assumes a constant 14% learning rate for electrolyzers and 10% for the remaining P2G equipment throughout the timeframe considered. The optimistic scenario assumes a 25% learning rate until 2030, 15% learning rate until 2035, and then 10% learning rate until 2050 for the electrolyzers and a constant 14% learning rate for remaining P2G equipment. The rest of the equipment considered in this work are less technologically complicated and therefore have lower associated learning rates because costs should not be expected to decrease as drastically. Therefore, a learning rate of 10% is applied for non-P2G fuel production equipment.

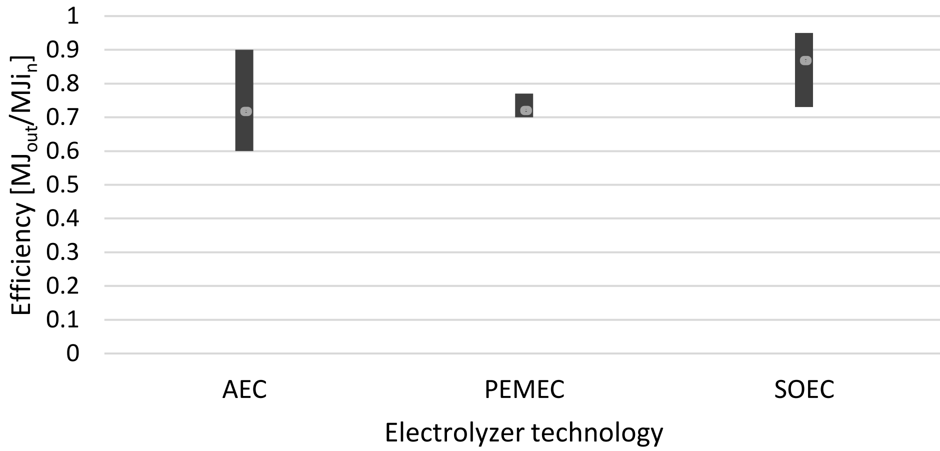
Fuel production equipment has a dependence on scale for both efficiency and cost. Therefore, for each type of equipment, the scale of plant used for the techno-economic data presented is noted. Significant deviation in plant size from that scale could result in inaccuracies. Generally, electrolyzers are less affected by scale than other fuel production equipment [149].

Note that while the following sections include cumulative installed capacities for each of the fuel production technologies (in cumulative GW in the corresponding years shown), these numbers should only be considered hypothetical examples at this point to give an idea of how cumulative installed capacities of these technologies affect cost. The capacities shown will be further detailed in Chapter 3, and the actual projected cumulative installed capacities of the modeling will be determined by a methodology explained in Chapter 3.

Fuel Production: Hydrogen

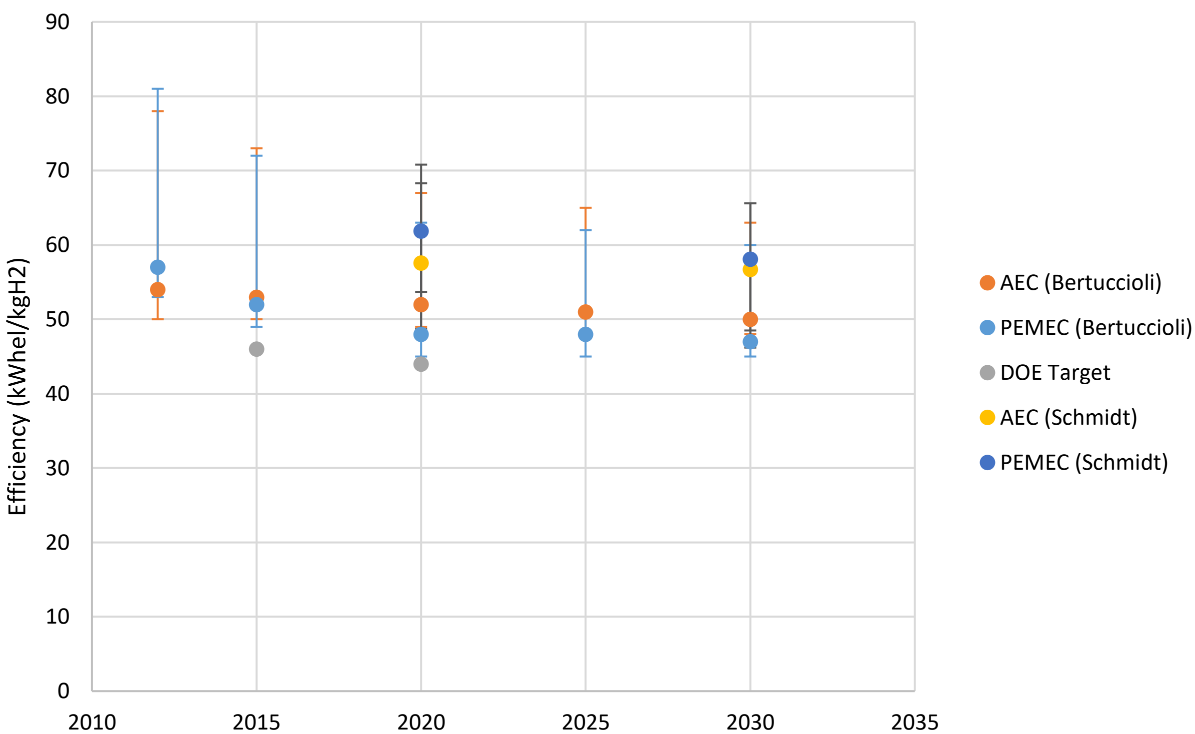
Hydrogen can be produced by electrolysis or gasification in the context of this work. Both the electrolyzers and gasifiers are taken to be 50 MW in size. Electrolytic hydrogen uses electricity as its feedstock and electrolyzers as the fuel production equipment. As noted, before, water costs are negligible and will therefore not be considered in the proceeding work. Literature values for electrolyzer efficiency give a range of efficiencies both now and into the coming decades. Figure 18 shows recent and current values for electrolyzer efficiency from the literature sources with data as cited from Table 9.

Figure 18. Range of electrolyzer efficiencies found in the literature, from sources of Table 9



Also necessary is determining the evolution of electrolyzer efficiency with time. See Figure 19 for projections of various electrolyzer efficiency projections from standout studies in the literature.

Figure 19. Electrolyzer system efficiency projections from [9], [43], [150]

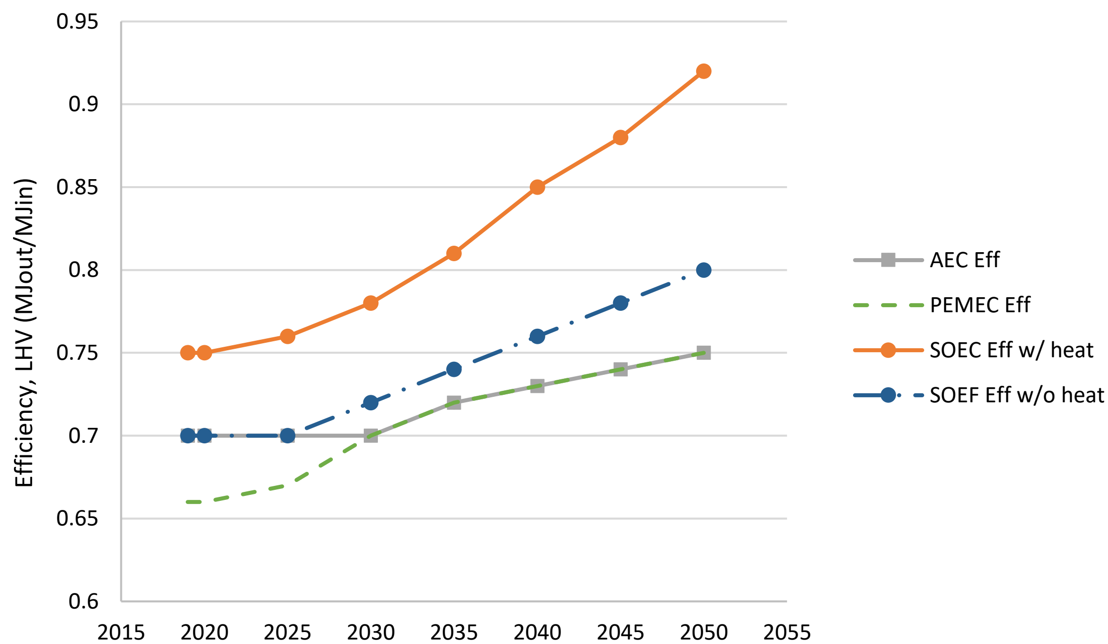


There is clearly a wide range of values in this set, so some work must be done to simplify the data into more usable values. To distill efficiency information from the literature into values to use for this analysis, two efficiency scenarios are introduced. The first is the conservative scenario, which uses efficiency numbers on the lower end of the spectrum of the literature data. The second is the optimistic scenario, which uses efficiency numbers on the higher end of the literature data. Note that these efficiency projections are to align with the conservative and optimistic learning rate scenarios introduced previously.

In addition to the initial values used for efficiency, as well as some long-term efficiency estimates from the literature, intuition, and an understanding of general technology learning assisted in creating curves for the evolution of electrolyzer efficiency. One detail that stands out for the efficiency evolution is for SOECs. SOECs are unique among the electrolyzer technologies selected in that they are high temperature and get more efficient as their temperature increases. This means that they are able to use the waste heat of methanation, which is an exothermic reaction, to increase their efficiency instead of any other potential use of heat. Therefore, two SOEC scenarios are considered: (1) lower efficiency SOECs without methanation where the end product is hydrogen, and (2) higher efficiency SOECs with methanation where the end product is RNG.

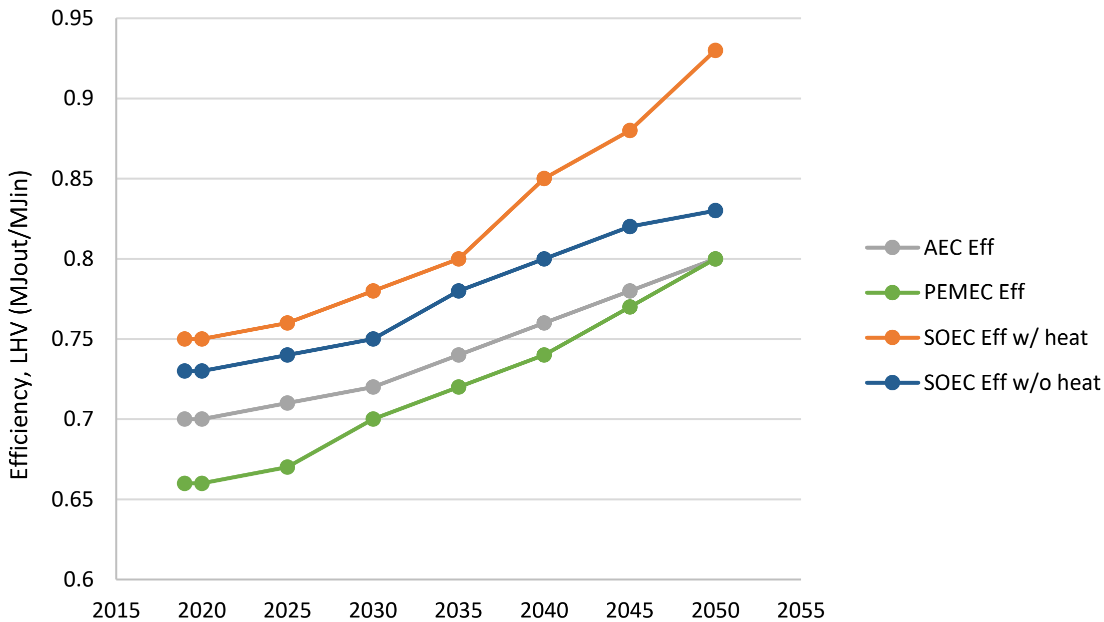
Plots for the efficiencies of the three electrolyzer technologies for the conservative scenario and the optimistic scenario are found below in Figure 20 and Figure 21, respectively.

Figure 20. Conservative estimate on electrolyzer efficiency projection



Given the literature data gathered, the following starting costs are taken for three electrolyzer technologies as they represent a middle-ground of the most comprehensive work from the literature: \$1,000/kW for AEC, \$1,320/kW for PEMEC, and \$9,324/kW for SOEC. Note that economies of scale are a factor in electrolyzer technology, and even more so for the other fuel production methods, so it is important to also include a reference to scale when noting the efficiency and cost. For electrolyzer technologies, a 50 MW scale is used as it is projected to be the P2G plant size.

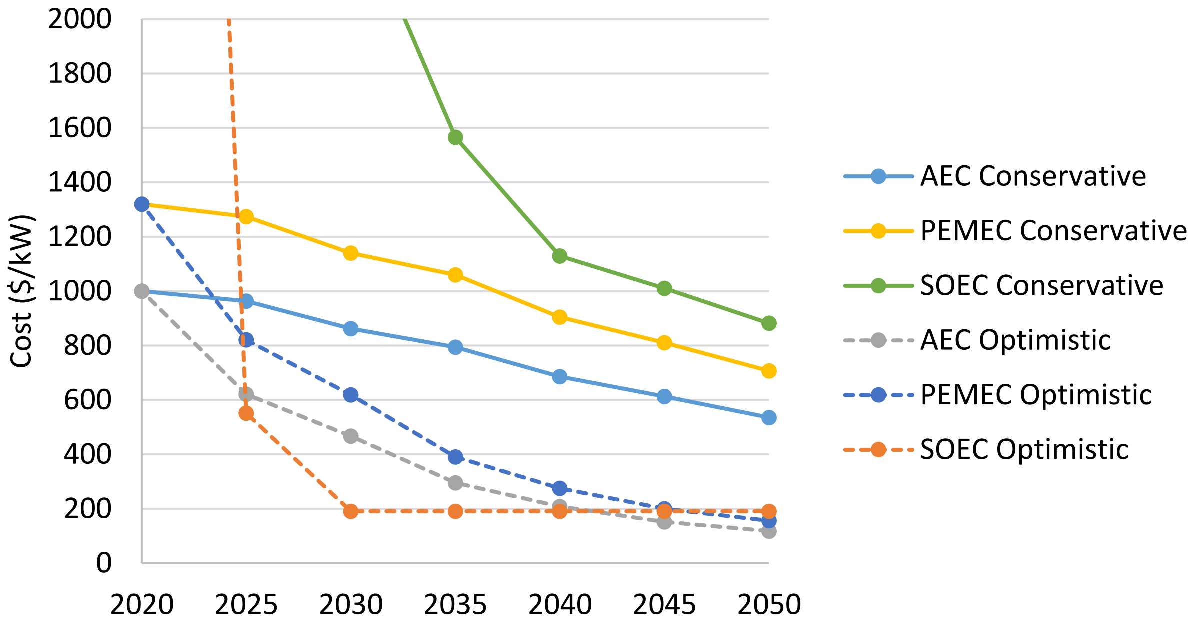
Figure 21. Optimistic estimate on electrolyzer efficiency projection



Combining the starting values for electrolyzer cost, projections for electrolyzer cumulative production capacity, and Wright's law gives a method for projecting the cost of electrolyzer technology into the future. A reminder that the representative electrolyzer production growth numbers (in cumulative GW in the corresponding years shown) are merely to give an idea of how cumulative installed capacities of these technologies affect cost. The costs in both the conservative and optimistic scenarios group around similar values relative to the starting costs for each of the three technologies, so it is helpful to include a chart focused on the costs in later parts of the analysis. Such a detailed view can be seen in Figure 22. Further figures and tables detailing the cost projections of the electrolyzers can be found in the Appendix A.

Operations and maintenance (OM) costs for electrolyzers are taken to be 1.75% of the capital costs [150], [151][152][153] [154]–[157]. This is a fixed OM (FOM) cost, as it depends solely on the size of the plant. There is also variable OM (VOM) which depends on the quantity of fuel being produced, and some of the technologies that will be detailed shortly have associated VOM, but no VOM is modeled in the present work. Note that Wrights Law is not applied to these OM costs as they are typically composed of labor, fuel, and workplace requirements such as lighting, and these do not lend themselves to improvements over time like the capital costs do.

Figure 22. Electrolyzer cost projections to 2050 for optimistic and conservative assumptions



Fuel Production: Summary of All Fuels

Having developed a methodology for projecting efficiency and cost for electrolyzer technologies, those same methodologies are carried out for the remaining fuel production technologies. The following is a summary of the results of that work. Further details can be found in the Appendix A.

Table 5 shows efficiency projections to 2050 for the various fuel production technologies of the present work. For electrolytic technologies, which the literature has several sources for projections to 2030, those projections are carried out further to 2050 using similar trends. For technologies with moderate efficiency and projection data, such as gasifiers and AD, the average of the literature values is used for 2020 and the high reasonable efficiency data are assumed for 2050, with roughly half of that progress reached by 2035. Note that for technologies with scarce literature, particularly liquid fuel production, an efficiency improvement of 2% every 5 years is assumed.

The HVO technology efficiency is modeled as 285 GGE per ton of feedstock from CARB's Biofuel Supply Module [145].

Table 6 summarizes the various parameters used in Wright's Law to project costs. Initial capital costs are from sources as cited. The fixed operation and maintenance (FOM) and variable operation and maintenance (VOM) costs are from sources as cited as well, if available. Otherwise, values from most-similar technologies are used as an approximation. Learning rates and initial capacities are assigned values from literature where possible, or most appropriate approximations when not.

The starting cost for HVO technology is modeled as $314 per ton of oil converted with an efficiency of 285 GGE per ton of feedstock from CARB's Biofuel Supply Module [145], and the learning rate is taken to be 10% with an initial capacity of 3.15e8 GJ per year.

Table 5. Fuel production technology efficiency projections

Production Technology	Fuel	Efficiency							Sources
		2020	2025	2030	2035	2040	2045	2050	
Alkaline electrolytic cell (AEC)	Hydrogen, Renewable natural gas	0.70	0.70	0.70	0.72	0.73	0.74	0.75	[150], [151][158] [159] [160]
Proton exchange membrane electrolytic cell (PEMEC)	Hydrogen, Renewable natural gas	0.66	0.67	0.70	0.72	0.73	0.73	0.74	[150], [151] [161] [162] [163] [160]
Solid oxide electrolytic cell (SOEC)	Hydrogen	0.70	0.70	0.72	0.74	0.76	0.78	0.70	[164][165][62][160]
SOEC w/ heat from Methanator	Renewable natural gas	0.75	0.76	0.78	0.81	0.85	0.88	0.92	[164][165][62][160]
Methanator	Renewable natural gas	0.79	0.79	0.79	0.79	0.79	0.79	0.79	[166]–[168]
Gasifier	Hydrogen	0.54	0.58	0.62	0.63	0.65	0.67	0.68	[46]–[57]
Gasifier	Renewable Natural Gas	0.67	0.70	0.72	0.73	0.74	0.74	0.75	[73]–[91][92]–[103]
Anaerobic digestion (manure)	Renewable Natural Gas	0.37	0.39	0.41	0.42	0.43	0.44	0.45	[71], [169]–[183]
Anaerobic digestion (organics)	Renewable Natural Gas	0.50	0.53	0.56	0.58	0.60	0.62	0.63	[71], [169]–[183]
Liquefaction	Renewable diesel	0.64	0.66	0.67	0.68	0.69	0.71	0.72	[51]
Gasification with Fischer-Tropsch	Renewable diesel	0.55	0.56	0.57	0.58	0.60	0.61	0.62	[51]
Hydrolysis	Renewable diesel	0.55	0.56	0.57	0.58	0.60	0.61	0.62	[51]
Pyrolysis	Renewable diesel	0.60	0.61	0.62	0.64	0.65	0.66	0.68	[51], [184]

Table 6. Fuel production technology cost projection parameters

Production Technology	Fuel	Initial Capital Cost ($/kW)	FOM ($/kW-yr)	VOM ($/kWh)	Learning Rate	Initial Capacity (GJ/yr)	Sources
Alkaline electrolytic cell (AEC)	Hydrogen, Renewable natural gas	1000	17.5	0	0.14	2.40e8	[43], [150]–[157], [185]–[188]
Proton exchange membrane electrolytic cell (PEMEC)	Hydrogen, Renewable natural gas	1320	23.1	0	0.14	1.61e8	[43], [150]–[157], [189], [190]
Solid oxide electrolytic cell (SOEC)	Hydrogen, Renewable natural gas	9324	163	0	0.14	3.47e4	[150]–[157], [191]–[193]
Methanator	Renewable natural gas	339	10	0.01	0.10	2.40e8	[194]
Direct air capture	Renewable natural gas	456,250	10	0.01	0.10	7.06e6	[154], [195]
Post-combustion capture (PCC)	Renewable natural gas	63,630	10	0.01	0.10	7.06e6	[154], [195]
Electrolytic cation exchange modules (E-CEM)	Renewable natural gas	1,820,412	10	0.01	0.10	7.06e6	[196]
Gasifier	Hydrogen	1200	40	0.006	0.10	3.15e8	[46]–[57]
Gasifier	Renewable natural gas	1400	40	0.013	0.10	3.15e8	[73]–[91][92]–[103]
Anaerobic digestion	Renewable natural gas	2000	10	0.01	0.10	3.15e8	[71], [169], [176]–[179], [197]–[200]
Liquefaction	Renewable diesel	1440	108	0.0067	0.10	3.15e8	[201]
Gasification with Fischer-Tropsch	Renewable diesel	4093	0	0.15	0.10	3.15e8	[201]
Hydrolysis	Renewable diesel	4680	283	0.15	0.10	3.15e8	[202]
Pyrolysis	Renewable diesel	812	60	0.15	0.10	3.15e8	[203]

Fuel Distribution

Having detailed the techno-economics of the production of the five fuels included in the present work, this section discusses the distribution of each of those fuels.

Fuel Distribution: Electricity

Electricity distribution efficiency comes from losses in the electricity lines. The efficiency modeled is 95% [204] and is held constant throughout the time of analysis.

Cost of electricity distribution depends on the level of charging required. For light-duty plug-in hybrid electric vehicles (PHEVs) and plug-in fuel cell electric vehicles (PFCEVs), which have both batteries and range extenders to power the vehicle, only level 1 charging is needed [140][205][206]. For light-duty BEVs and all HDVs using electricity as a fuel, some electric grid upgrades will be required to support the additional throughput.

Prior work by Lane [206] calculates the infrastructure costs for the electric grid upgrades needed to support level 1 and level 2 charging of vehicles throughout California. Dividing those costs by the amount of electricity the infrastructure supports as fuel for vehicles and using a CRF of 0.12 again to annualize costs, this leads to a cost of $2.21 per GJ of electricity distributed when using charging greater than level 1, which all plug-in HDVs would need.

Fuel Distribution: Hydrogen

As introduced previously, hydrogen distribution can be categorized into two segments: from production facility to a terminal and delivery from the terminal to the dispensing station.

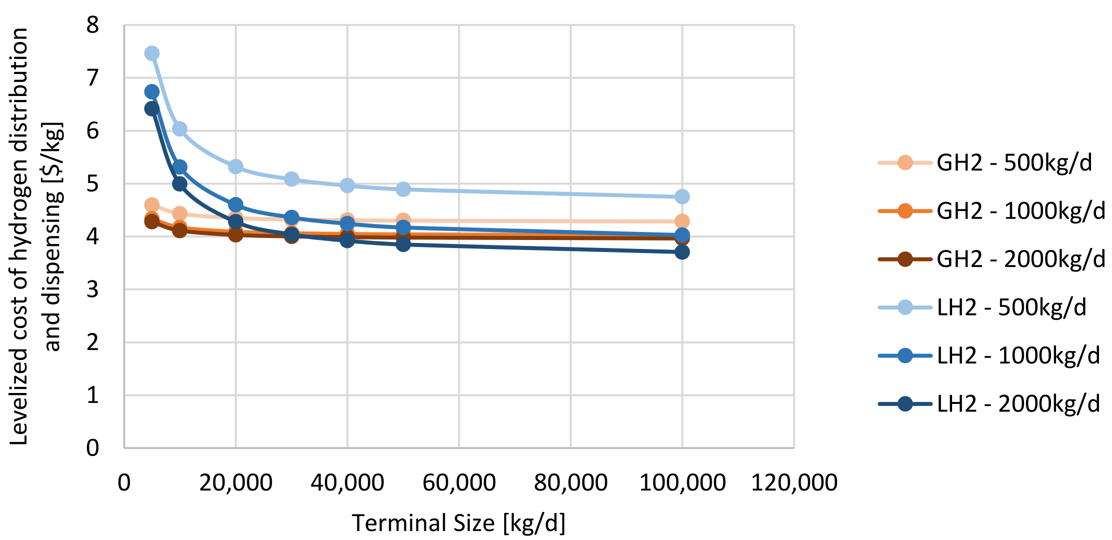
The efficiency of hydrogen distribution is calculated from three components: liquefying the hydrogen, trucking the hydrogen to the dispensing station, and any leakage that occurs during the distribution. Liquefying is taken to be 82% energy efficient [207]. Hydrogen leakage is assumed to be negligible as previously mentioned. Prior work shows distribution of hydrogen by a hydrogen-powered HDV requires under 0.2% of the amount of hydrogen that is being distributed [206], so the trucking portion of distribution is assumed to have negligible impact on the efficiency of the process. Therefore, hydrogen distribution is modeled as 82% efficient overall.

Previous work shows that there is a slight dependency on hydrogen production plant size for the cost of distributing hydrogen from production plant to dispensing site. The maximum change in distribution cost was about $0.02 per kilogram of hydrogen [208]. The range of plants considered in this work is from 21.4 MW to 500 MW. Perhaps if the range was extended, there could be some impact of production plant scale on distribution cost, but it is assumed in the present work that distribution cost is independent of scale of production plant.

Working with the U.S. Department of Energy's H2A Delivery Analysis model yields costs for the distribution and dispensing of hydrogen. Due to the way the results are displayed, the aggregate cost of both distribution and dispensing are given here. Figure 23 shows the sum cost of hydrogen terminals, delivery to hydrogen dispensing station, and hydrogen dispensing station cost. The plot shows insight into factors that affect the cost of hydrogen distribution. One is that terminal size has a significant impact on the cost of hydrogen. Increasing terminal size decreases the cost of hydrogen. Second, the impact of terminal size diminishes as the size continues increasing. At low terminal size (up to about 30,000 kg/day), increasing terminal size has a dramatic decrease in cost. After about 50,000 kg/day terminal size, the effect becomes nearly negligible.

Figure 23 also shows the difference in cost between gaseous hydrogen and liquid hydrogen. At lower terminal sizes, liquid hydrogen is significantly more expensive than gaseous hydrogen. This trend stays true for low-capacity stations no matter the terminal size. However, mid- and high-capacity hydrogen stations, liquid hydrogen becomes cheaper than gaseous hydrogen for larger terminal size. Recall that the present work assumes liquid hydrogen distribution as it is assumed that mid- and high-capacity stations will be necessary to support MDV and HDV fueling. Taken as a whole, a representative distribution and dispensing combined cost of $4.50 per kilogram of hydrogen is used to account for variability of station cost with size.

Figure 23. Levelized cost of hydrogen distribution and dispensing, data from [209]



Fuel Distribution: Renewable Natural Gas

RNG distribution is assumed to take the form of pipeline distribution, making use of the prevalent pipeline infrastructure that natural gas uses today.

RNG distribution using the natural gas pipeline is 99% efficient from a primary energy input basis [210]. This slight efficiency loss is assumed negligible in the present work, and therefore RNG distribution is modeled as 100% efficient.

RNG distribution costs are from Southern California Gas Company and San Diego Gas & Electric Company, which have a customer charge of $65 each month and $0.20 per therm of natural gas delivered [211][212]. Even if a high estimate of 1,000 RNG stations would be created to support HDVs in the future (a number that is one-tenth the number of gasoline stations in California), this would yield a customer charge of $780,000 for distribution spread among all stations. This cost is significantly less than the cost of a single RNG station, which will be detailed shortly. Therefore, the customer charge will be neglected and only the per-therm charge of $0.20 will be considered in this analysis.

Fuel Distribution: Renewable Diesel

Distributing renewable diesel is assumed to be carried out in the same manner as fossil diesel, which is by trucking.

Renewable liquid fuels have negligible energy losses in distribution compared to the amount of energy distributed, so it is assumed to be 100% efficient in the present work [210].

According to the U.S. Energy Information Administration, approximately $0.40 to $0.60 of every gallon of diesel sold goes to distribution and marketing [213]. It is assumed for the present work that $0.20 of each gallon goes to distribution of the diesel, after removing the marketing costs included in the reference.

Fuel Dispensing

Fuel Dispensing: Electricity

Electricity dispensing is categorized by the power output as mentioned previously. For passenger vehicles, PHEVs and PFCEVs generally use level 1 charging, and BEVs generally use level 2 charging [140][205][206]. HDVs have larger battery capacities due to their lower efficiencies; therefore, higher charging powers are needed to meet driving demands. For HDVs, the present modeling assumes PHEVs use level 2 charging and BEVs use level 3 charging, although in reality a mix of level 2 and level 3 charging could be used by both vehicle types.

The efficiency of electric chargers does vary somewhat depending on what level the charger is. An average value of 92% from Apostolaki-Iosifidou et al. [214] and Sears et al. [215] is used for the present modeling.

Just as for efficiency, the cost of electric chargers depends on the level of charging as well. Additionally, the number of chargers that are to be added depend on the level of charging. Using prior work by Lane [206] which determined level 2 charging costs for California and dividing by electricity dispensed by those chargers as well as using a CRF of 0.12 to annualize payments, the cost of level 2 charging is determined. For level 3 charging, the same methodology of Lane [206] is used with the updated cost for the level 3 chargers found in [216]. The costs used for chargers as well as the levelized cost of the various levels of chargers is shown in Table 7.

Table 7. Electricity dispensing levels and costs

Level of charging	HDV powertrains applicable	Charger cost ($)	Levelized cost of dispensing ($/GJ)
2	PHEV	10,000	15.01
3	BEV	50,000	72.27

Fuel Dispensing: Hydrogen

Hydrogen dispensing infrastructure is in a nascent state in California as of the time of this writing, so any significant adoption of hydrogen-fueled vehicles would require further buildout and therefore capital investment.

Efficiencies for liquid hydrogen dispensing stations are quite high, with values ranging from 96% from U.S. Department of Energy [209] to 97% from Hänggi et al. [210]. The average of 96.5% efficiency is used in the present work.

A reminder here that the cost of hydrogen dispensing was incorporated with the cost of hydrogen distribution previously. The present work is not spatially resolved, so detailed station size for individual locations is beyond the scope of this work. Therefore, a representative distribution and dispensing combined cost of $4.50 per kilogram of hydrogen are used to account for variability of station cost with size [209].

Fuel Dispensing: Renewable Natural Gas

RNG is a drop-in fuel, so it can be used in existing natural gas infrastructure. However, as previously noted before, any significant adoption of RNG-fueled HDVs would require building out the RNG dispensing infrastructure, which is the same as compressed natural gas (CNG) dispensing infrastructure [118][119].

RNG dispensing efficiency losses are negligible according to Hänggi et al. [210], so it is modeled as 100% efficient.

Just as for hydrogen dispensing, RNG dispensing costs depend on the size of dispensing station. For this work, assume a large station size of 1,500-2,000 GGE per day capacity, which costs $1.8 million [217]. This large station assumption is made as the present modeling is not spatially resolved, so a larger station size is most economical. Again, using a CRF of 0.12 to annualize payments, this leads to $0.32 per GGE for RNG dispensing.

Fuel Dispensing: Renewable Diesel

Renewable diesel is a drop-in fuel, so it can use the existing and prevalent diesel infrastructure.

Renewable liquid fuels have negligible energy losses in dispensing [210], so it is assumed to be 100% efficient in the present work.

Cost is negligible because diesel dispensing infrastructure has been built in abundance and it is unreasonable to expect fleets to switch from alternative fuel to renewable diesel, so no new dispensing infrastructure will need to be built if renewable diesel vehicles are projected. While in reality there is still some cost to run the stations, these costs are assumed negligible compared to the capital of creating new stations and compared to the dispensing costs of other fuels such as for electric chargers or constructing RNG stations.

Total Fuel Pathway Efficiency and Emissions

Emissions associated with the fuel pathway are dependent on the feedstock, production equipment, distribution, and dispensing. The method proposed for calculating the overall emissions is using the feedstock emissions and applying efficiencies at each step of the above-detailed pathway chain. The efficiencies associated with each of the pathway steps have been detailed. Multiplying the total pathway efficiency with the feedstock emissions will result in the total fuel emissions.

Fuel Pathway Efficiency

Efficiencies of production equipment have projected improvements as detailed previously. For brevity, only the starting year efficiencies will be shown in the following calculations for total pathway efficiency. The same methodology is applied throughout this analysis, with the further years having efficiency improvements to the production only. Similarly, only the conservative electrolyzer efficiencies are shown, as those are the default values used in Task 3 work. See a summary of each pathway step efficiency as well as the total pathway efficiency for the year 2020 in Table 8 and the year 2050 in Table 9, both of which use the conservative electrolytic efficiency scenario. Furthermore, plots showing the efficiency projections over time are shown for renewable hydrogen in Figure 24, renewable natural gas in Figure 25, and renewable diesel in Figure 26, and the former two include both conservative and optimistic assumptions for electrolytic pathways. The fuel production efficiencies improve with time (while distribution and dispensing are assumed constant), so the total pathway efficiencies improve as well. Note also that while references are not repeated here for simplicity, they are given in the corresponding sections of this chapter.

It is important to note that the proceeding fuel pathway efficiencies are not necessarily of the entire transportation pathway (which could be considered as energy needed per mile traveled) because the vehicle efficiency must be accounted for as well. The vehicle efficiencies will be analyzed in Chapter 3. Nonetheless, the fuel pathway efficiencies are an important piece of the total transportation efficiency.

Table 8. Summary of fuel pathway efficiencies in 2020

Fuel	Production method	Production efficiency (%)	Distribution efficiency (%)	Dispensing efficiency (%)	Total pathway efficiency (%)
Electricity	Electricity	-	95	92	87.4
Hydrogen	AEC	70	82	96.5	55.4
	PEMEC	66	82	96.5	52.2
	SOEC	70	82	96.5	55.4
	Gasifier	54	82	96.5	44.3
RNG	AEC - methanator	55.3	100	100	55.3
	PEMEC - methanator	52.2	100	100	52.2
	SOEC - methanator	59.3	100	100	59.3
	Gasifier	67	100	100	67
	AD (manure)	37	100	100	37
	AD (organics)	50	100	100	50
Renewable diesel	Liquefaction	64	100	100	64
	Gasifier - FT	55	100	100	55
	Hydrolysis	55	100	100	55
	Pyrolysis	60	100	100	60
	HVO	0.87	100	100	0.87

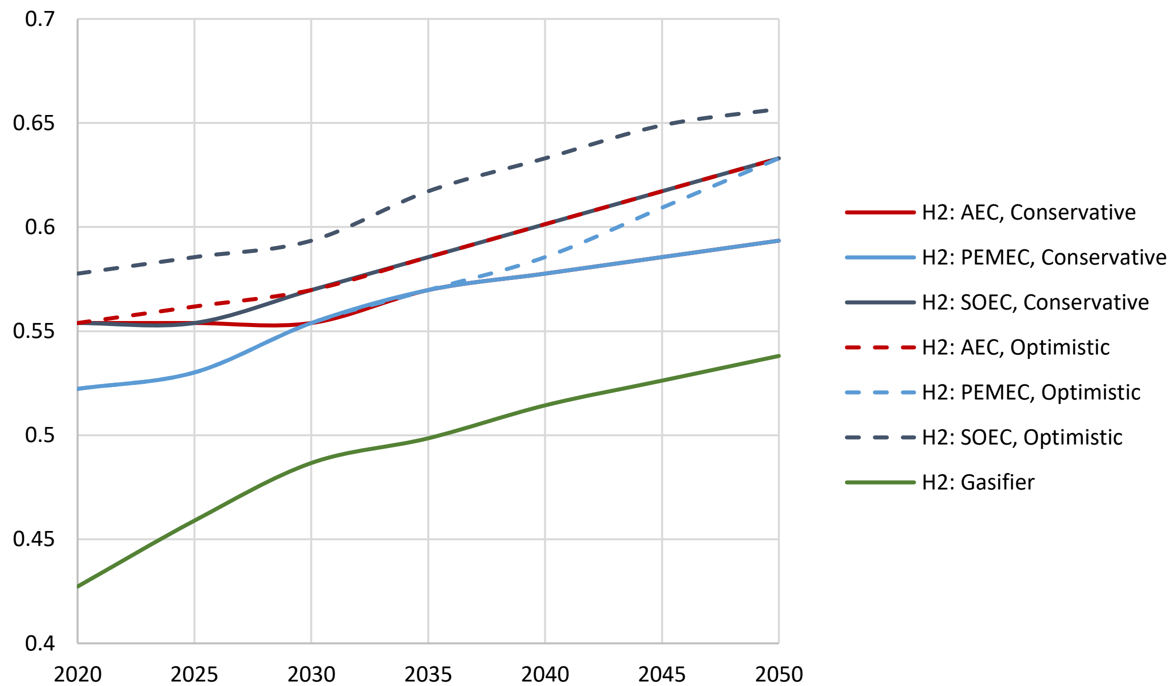
Table 9. Summary of fuel pathway efficiencies in 2050

Fuel	Production method	Production efficiency (%)	Distribution efficiency (%)	Dispensing efficiency (%)	Total pathway efficiency (%)
Electricity	Electricity	-	95	92	87.4
Hydrogen	AEC	75	82	96.5	59.3
	PEMEC	75	82	96.5	59.3
	SOEC	80	82	96.5	63.3
	Gasifier	68	82	96.5	53.8
RNG	AEC - methanator	59.3	100	100	59.3
	PEMEC - methanator	59.3	100	100	59.3
	SOEC - methanator	72.7	100	100	72.7
	Gasifier	75	100	100	75
	AD (manure)	45	100	100	45
	AD (organics)	63	100	100	63
Renewable diesel	Liquefaction	72.1	100	100	72.1
	Gasifier - FT	61.9	100	100	61.9
	Hydrolysis	61.9	100	100	61.9
	Pyrolysis	67.6	100	100	67.6
	HVO	87	100	100	87

Of the three electrolyzer technologies, we project AECs to improve in efficiency the least due to their relative maturity. SOECs are expected to improve in efficiency the most due to their relative immaturity, and they are expected to be the most efficient electrolyzer technology in the mid- to long-term. The optimistic scenario includes higher efficiency improvements for PEMECs to reflect the substantial backing of this technology in motive applications. This suggests early support of PEMEC and SOEC technologies to increase installed capacities could advance efficiency improvements and thereby improve renewable hydrogen production efficiency.

Compared to electrolyzer technologies, gasifiers are projected to have a greater increase in efficiency as they are relatively low in current installed capacity but expected to increase prevalence in the coming decade and thereby achieve improvements in efficiency. However, as shown in Figure 24, electrolyzers are expected to be significantly more efficient at producing hydrogen due to their electrochemical conversion process rather than the thermochemical process of gasification, so inefficiencies due to heat generation are lower.

Figure 24. Renewable hydrogen pathway efficiency projections

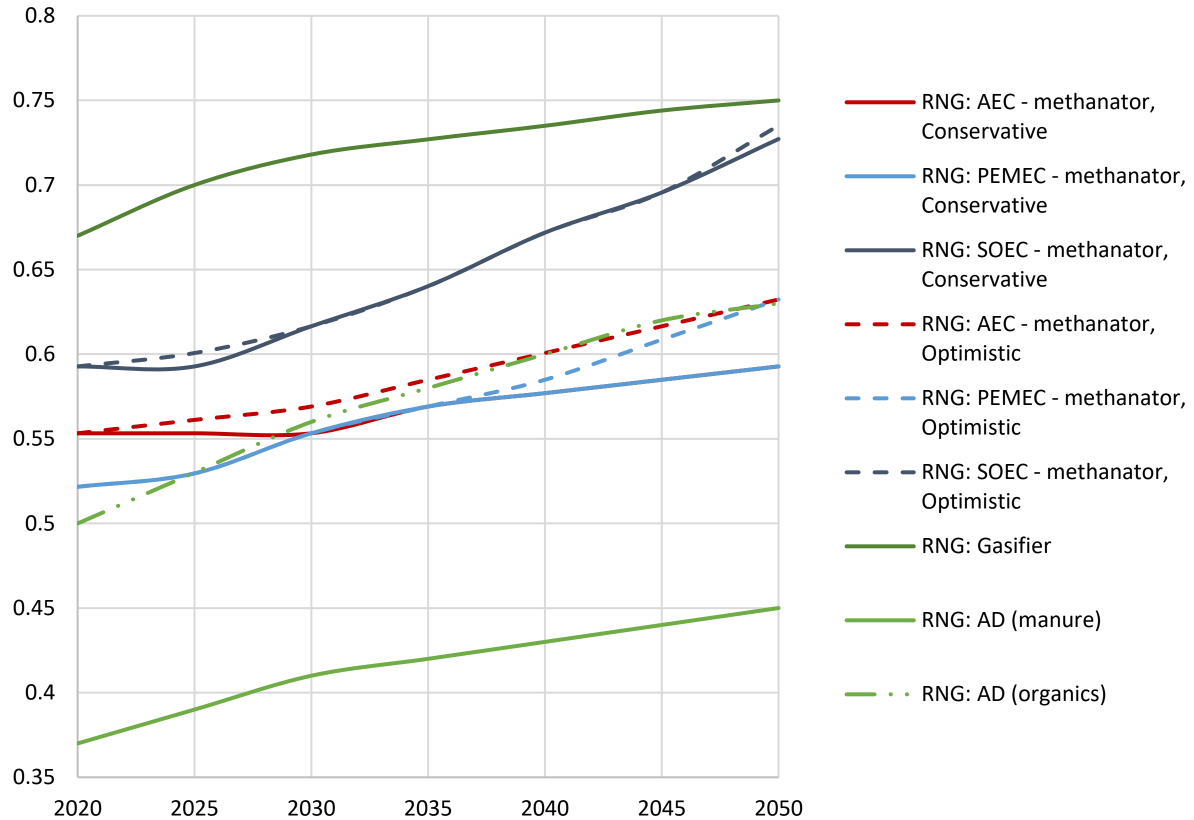


For RNG production, gasifiers are not expected to improve in efficiency as much as for hydrogen production because the process is more efficient currently and the underpinning technology is much the same. However, gasifiers are the most efficient method of producing RNG currently and through 2050.

AD, a budding fuel production technology with relatively low efficiency currently, is expected to achieve efficiency improvements that are significant, comparable to those of gasifiers producing hydrogen.

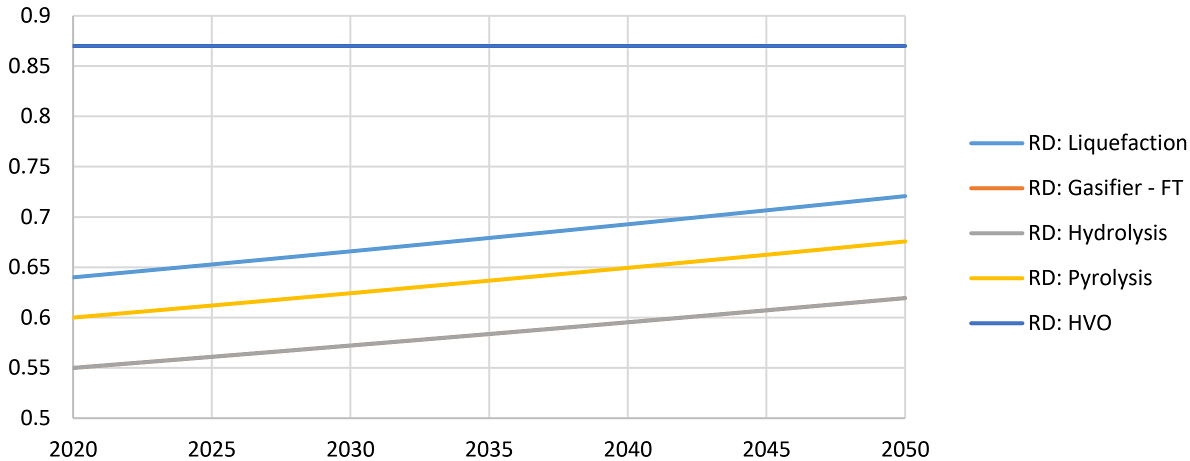
Electrolyzers are a relatively efficient method of producing RNG, but they do have an efficiency drop due to the methanation step, which results in an efficiency lower than that of gasifiers as previously stated. These electrolytic RNG pathways are expected to achieve similar efficiency improvements to those for hydrogen. Note that efficiencies of methanators are assumed constant due to the simplicity and maturity of the technology. Efficiency of carbon capture technology is not considered in this work, though different technologies are expected to vary in efficiency both in terms of electricity and heat input.

Figure 25. Renewable natural gas pathway efficiency projections



Efficiency projections for various renewable diesel production technologies were less available in the literature than those for hydrogen and RNG. Therefore, it is assumed that each of these technologies will attain a 2% efficiency improvement every 5 years, something that is on the low- to mid-range of the other technologies. The one exception is for hydrotreating vegetable oils (HVO), for which the efficiency is modeled as 285 GGE per ton of oil feedstock from CARB's Biofuel Supply Module [145], which is a high percentage when considering the energy density of vegetable oil, but does not account for the efficiency of producing the oil from the biomass feedstock. This HVO technology is assumed to stay constant as it is already remarkably high and significant further efficiency improvements are not expected. Interesting to note, the hydrotreating process is one of the processing steps of some of the other RD production methods, so it is appropriate to expect the efficiency of HVO to be higher than those other methods.

Figure 26. Renewable diesel pathway efficiency projections



Gasifier-FT and hydrolysis have same efficiency

Fuel Pathway Emissions

A common method of comparing the environmental impacts of various processes and equipment is by comparing emission factors. Emission factors give the emission intensity by the ratio of the quantity of emissions released per the amount of activity. The amount of activity can be number of units, miles driven, or the amount of energy associated with a process. In this work, emission factors generally take the form of quantity of emissions released per the amount of associated energy.

Emission factors in this work are separated into two categories: (1) fuel emission factors and (2) vehicle emission factors. Fuel emission factors consider farming, land use change by removing the biomass to harvest for fuel and transporting the biomass to a fuel production facility. Note that these emissions are held constant independent of this work's results of how many fuel production facilities should be made and how large they should be. There is no spatial consideration to affect the amount of biomass transportation emissions for fuel production. Vehicle emission factors will be discussed in the following chapter.

Fuel emissions can be separated into two categories: electricity and biomass. In general, the emissions associated with the fuel portion of the transportation pathway are dependent on the feedstock (electricity or a type of biomass) and the efficiency of that pathway. While this may be obvious for the electricity feedstock, it may not be as obvious for the biomass feedstocks. For pathways using biomass as a feedstock, the main inputs to the fuel production processes for the various equipment are the feedstock itself, heat, and pressure. Both heat and pressure can be produced by simply burning some of the biomass feedstock used for fuel production. Because the efficiencies cited in previous sections are in terms of primary energy input, this efficiency along with the emission factor of the biomass feedstock are all that are necessary for calculating the emissions associated with fuel production.

The present modeling assumes other emissions from the various pathway processes (for example, the partial oxidation of pyrolysis) are negligible compared to the feedstock itself. Also, important to note is that for a given fuel production method, emissions are the same whether producing renewable gasoline or diesel. This is due to the use of only feedstock and pathway efficiency to calculate emissions, and efficiencies for renewable gasoline and diesel production are modeled to be the same.

The majority of the feedstock emission factors used in this work are from Argonne National Laboratory's GREET 2016 [42]. More up-to-date data for electricity GHG emission factors are sourced from E3's PATHWAYS work and in particular their reference scenario [41], which projects lower GHG emissions in later years compared to GREET; however, these numbers are altered to include consideration for SB 100 goals of zero-carbon electricity by 2045. The CAP emission factors for electricity are sourced from GREET.

Due to a lack of emission factors for some biomass feedstocks, some assumptions are made for the feedstocks that do not have data available to link them to types of biomass that they are most similar to which do have emission factor data available. All straw biomass (barley straw, rice hulls, rice straw, and wheat straw) are assumed to have the same emission factors as corn stover. Residues (cotton gin trash, cotton residue, non-citrus residues, primary mill residue, secondary mill residue, paper, paperboard, plastics, rubber, leather, textiles, yard trimmings, and other) are all assumed to have the same emission factors as citrus residues. Both hardwood and softwood variations are assumed to have the same emission factors as forestry. Lastly, MSW wood is assumed to have the same emission factors as construction and demolition waste.

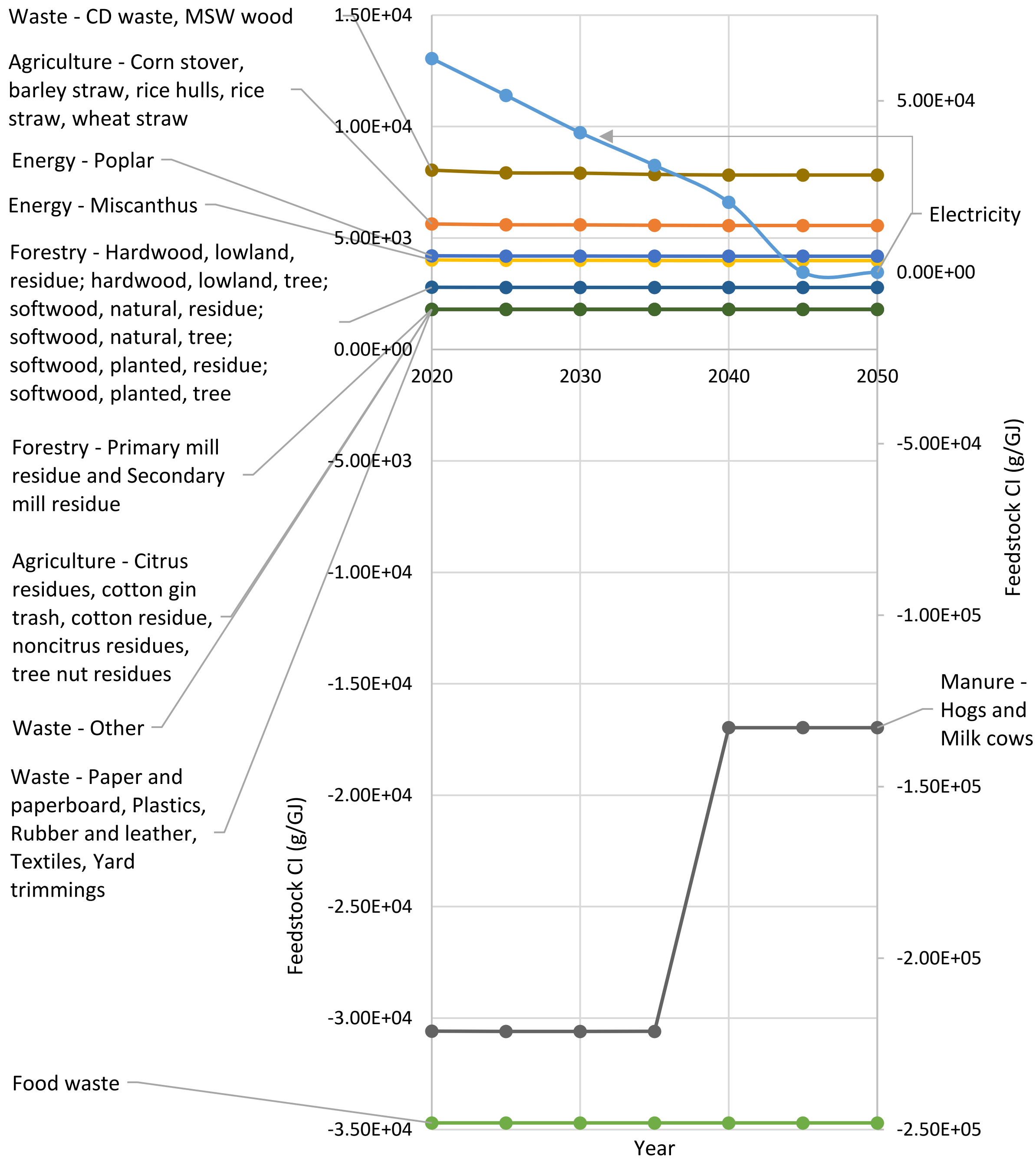
Two biomass categories are not present in GREET and therefore other sources were consulted. For citrus residues (and the other biomass types that are approximated to have the same emission factors), emission factors are sourced from Pourbafrani et al. [218]. Food waste emission factors are taken from the California Air Resources Board [219].

Note also that GREET emission factors are projected into 2040. For the present work, these projections are carried out to 2050, assuming emission factors stay the same after 2040. For the emission factors sourced from Pourbafrani et al. [218] and the California Air Resources Board [219], they are assumed constant throughout the timeframe of this work as there is no indication of changing values. It should be noted that this is a valid assumption as most emission factors are nearly constant, as will be shown shortly.

CAP emission factors for electricity are specifically for California from the "Fuel" category of the "Electric" tab of GREET. Emission factors for the various biomass feedstocks found in GREET are sourced from the feedstock emissions section of the various production pathways detailed using each of the included feedstocks.

GHG emission factors, also known as carbon intensities (CIs), for the feedstocks are shown in Figure 27. There are a wide range of biomass varieties with a wide range of CI values. Note that both manure and food waste biomass feedstocks have negative CIs. This is because both of these categories of biomass naturally release methane into the atmosphere, which has a greater GHG impact than carbon dioxide. Turning these feedstocks into fuels stops them from emitting methane into the atmosphere and converts most of that methane into carbon dioxide (depending on the method of conversion). Important to note is that the CIs for electricity and manure are on the secondary y-axis on the right side, which has a much greater magnitude of values. The rest of the feedstocks have CIs detailed by the primary y-axis on the left side.

Figure 27. Feedstock carbon intensities, data from sources as cited in-text



The highest CI is for electricity up to roughly 2035, which is close to ten times higher than the next-highest CI in early years of modeling. It should be noted that electricity is the only fuel feedstock with a CI that decreases significantly with time. This is due to an increasing amount of carbon-free renewable electricity generation being installed on the electric grid, more-efficient fossil generation, and, perhaps most importantly, legislation such as SB 100 which require cleaner electricity production into the future culminating in zero carbon electricity in 2045. The lowest CI is for manure, which has a very negative value, though that value becomes significantly less negative in 2040 due to SB 1383 [10]. Compared to these two extremes, all other feedstocks considered (besides food waste) have a relatively low spread between their CIs.

Biomass feedstocks' emission factors stay relatively constant as the emission factors come from farming, land use change by removing the biomass to harvest for fuel and transporting the biomass to a fuel production facility. Both farming and land use change emissions do not change much with time. Additionally, GREET likely assumes conventional transport of the biomass feedstock to fuel production facilities (which will likely change). While vehicles are assumed to be more efficient as time progresses, there is not a drastic difference in these transportation emissions. Therefore, the overall feedstock emission factors are nearly constant for most biomass feedstocks.

An important concept to keep in mind is that the feedstock emission factors are not the only data that matter when determining the climate change and air quality impacts of a fuel. Also important are the efficiency of the fuel production pathway as well as the emissions from the vehicles themselves. Consider the following: if one feedstock has particularly low emission factors, but it must be made using in an inefficient process and it must be used in an inefficient vehicle, the overall emissions associated with that process may be much higher than using a feedstock with higher emission factors but that can be made into a fuel more efficiently and used in a more efficient or zero emission vehicle.

However, there is a situation where the above is not true. Consider now a focus on GHG emissions and CIs. For feedstocks with negative CIs, by definition, using more of the feedstock to produce fuel would effectively be decreasing the climate change-inducing species in the air. Therefore, a less-efficient fuel production process and less-efficient vehicle could be considered better for the environment from a climate change perspective because more of the negative CI feedstock is being used. However, consider the fact that a less-efficient process would be using more of the feedstock. So, while lower efficiency would mean a single vehicle could be helping to provide larger emission reductions, this also means fewer vehicles can be fueled by that feedstock. Additionally, there is only a limited amount of feedstock available (while the biomass feedstocks considered will replenish with time, that amount of time is not negligible). Therefore, while negative CI feedstocks may seem to promote the pursuit of lower efficiency production methods to maximize emission reductions, it does not represent an appropriate use of limited feedstocks. The GHG and CAP emission factors for electricity and the biomass feedstocks are shown in the Appendix A.

Next, it is necessary to determine a representative set of emission factors for each of the main biomass feedstock categories using the emission factors of the individual feedstocks and the relative quantity of each feedstock. It is assumed that the relative quantities of each individual feedstock within a category stay constant. For agriculture residue, there is a relatively homogenous mixture of each individual feedstock, so the average is used. For energy crops, poplar vastly outweighs miscanthus in the energy crops availability, so emission factors for poplar are used. For food waste, there is only one feedstock. For forestry and tree, there is a mixture of each individual feedstock, so the average is used. For manure, there is only one feedstock. For MSW, there is a mixture of each individual feedstock, so the average is used.

For feedstocks that do not have CAP emission factor data from the literature, those of the closest resembling feedstock are used. For example, only half of the agriculture residues have CAP emission factor data gathered from the literature, so the other half are assumed to have the same as those in the same category for which there are data available. For food waste, the CAP emission factors are taken from manure as that is the closest data that could be found.

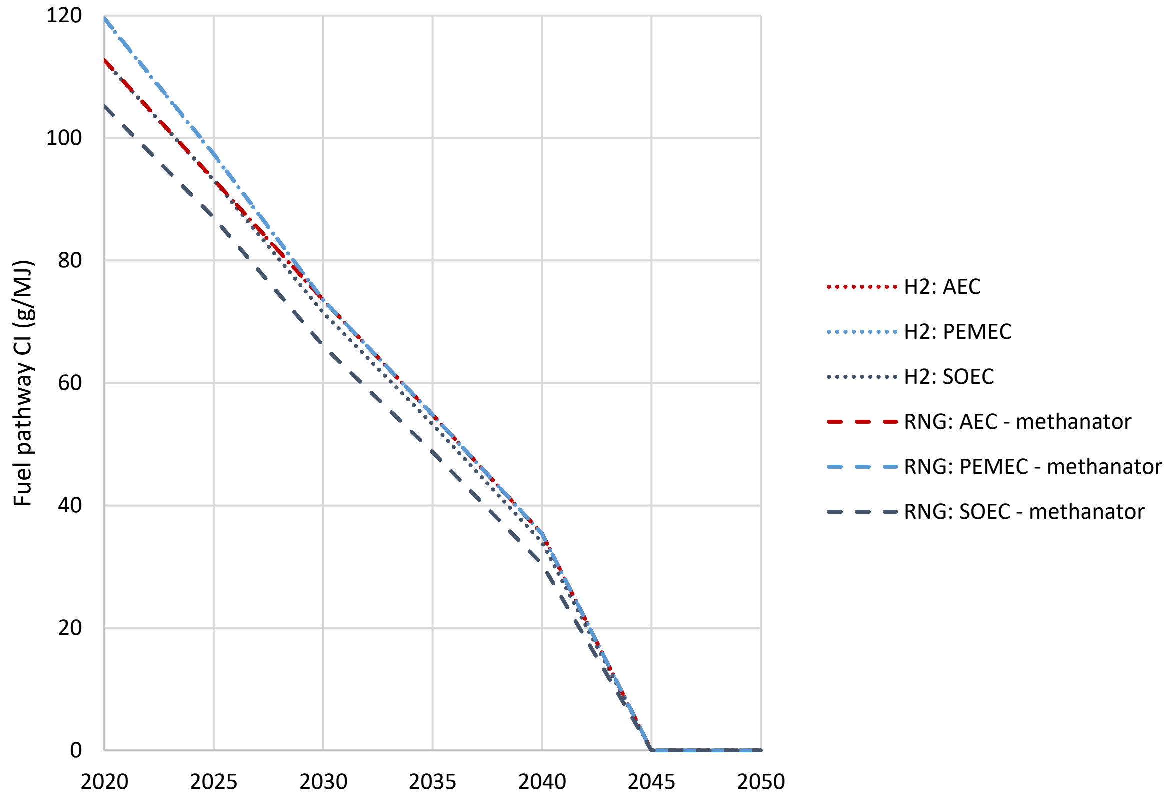
With the feedstock emissions as detailed and the total fuel pathway efficiencies from Table 8, the emission factors associated with fuel feedstock, production, distribution, and dispensing can be calculated for each of the feedstocks by simply multiplying the two (total fuel pathway efficiency and emission factors) together. The resulting plots for electrolytic, gasifier, and anaerobic digestion fuel pathways are shown in Figure 28, Figure 29, and Figure 30, respectively. These three technologies were selected as they were the primary technologies selected in Task 3 work for zero- and low-emission HDVs.

The electrolytic fuel pathway carbon intensities shown in Figure 28 are for the conservative efficiency projections. Results for the optimistic pathways are generally very similar, with up to 5.4% lower carbon intensity.

A general trend is that the carbon intensities for all electrolytic fuel pathways, whether they are producing hydrogen or RNG, are within 15% of each other. The efficiency loss during the RNG fuel production stage of the methanator is generally compensated by the higher efficiency of RNG distribution and dispensing when compared to that of hydrogen.

Also, important to note is the relatively rapid downward trend for all electrolytic pathways due to efficiency improvements, but more importantly the reduction in carbon intensity of the California electric grid, culminating with a zero carbon grid by 2045 (and the resulting zero carbon electrolytic fuels).

Figure 28. Electrolytic fuel pathway carbon intensities



Recall that gasifiers are significantly more efficient at producing RNG than hydrogen. This trend manifests itself in the fuel pathway carbon intensities with the RNG produced by gasifiers generally having lower carbon intensity than the hydrogen. Note that forestry biomass leads to a relatively low carbon intensity for both hydrogen and RNG.

When compared to the electrolytic methods of producing hydrogen and RNG, the gasifier pathways generally have significantly lower carbon intensity until roughly 2043, and by 2045 the electrolytic pathways have zero carbon intensity due to California electric grid targets.

Anaerobic digesters are an effective method of producing RNG from biomass with high moisture content, such as manure and food waste. These two biomass feedstocks also have significantly negative carbon intensity, though that is not expected to be true indefinitely due to SB 1383 [10].

However, until the carbon intensities are formally reduced due to SB 1383, anaerobic digesters fed by manure and organic waste (e.g. food waste) can be a very effective method of leveraging negative carbon intensity biomass and relatively low emission CNG-fueled HDVs to offer an attractive low emission supplement to ZEVs such as battery and fuel cell electric HDVs.

Figure 29. Gasifier fuel pathway carbon intensities

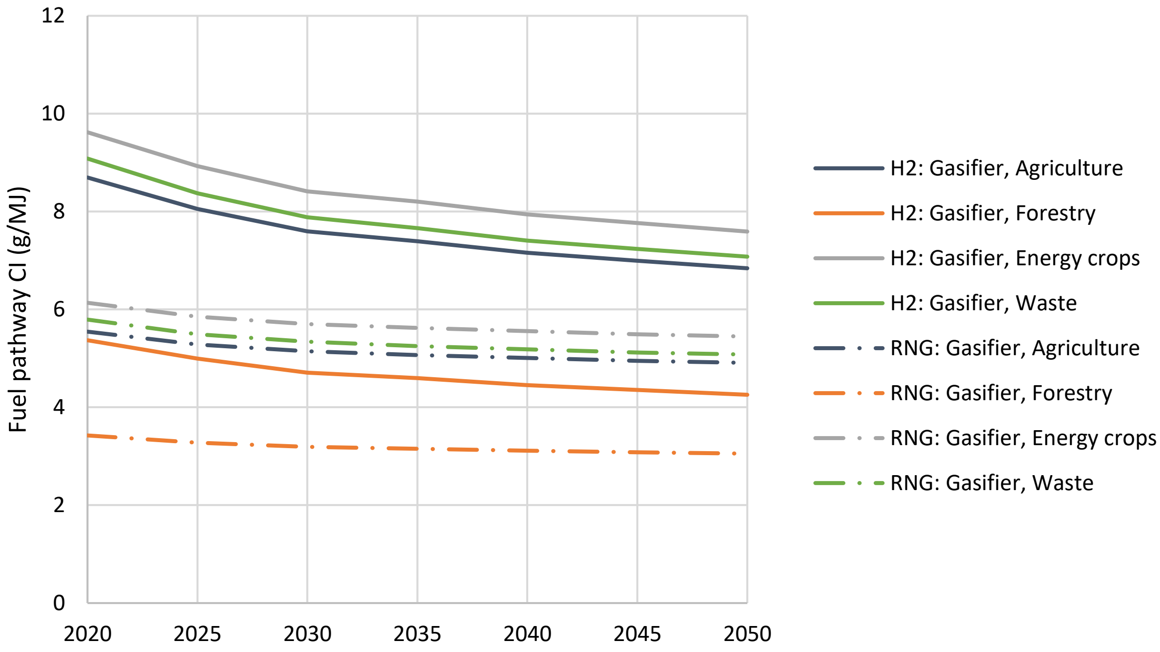
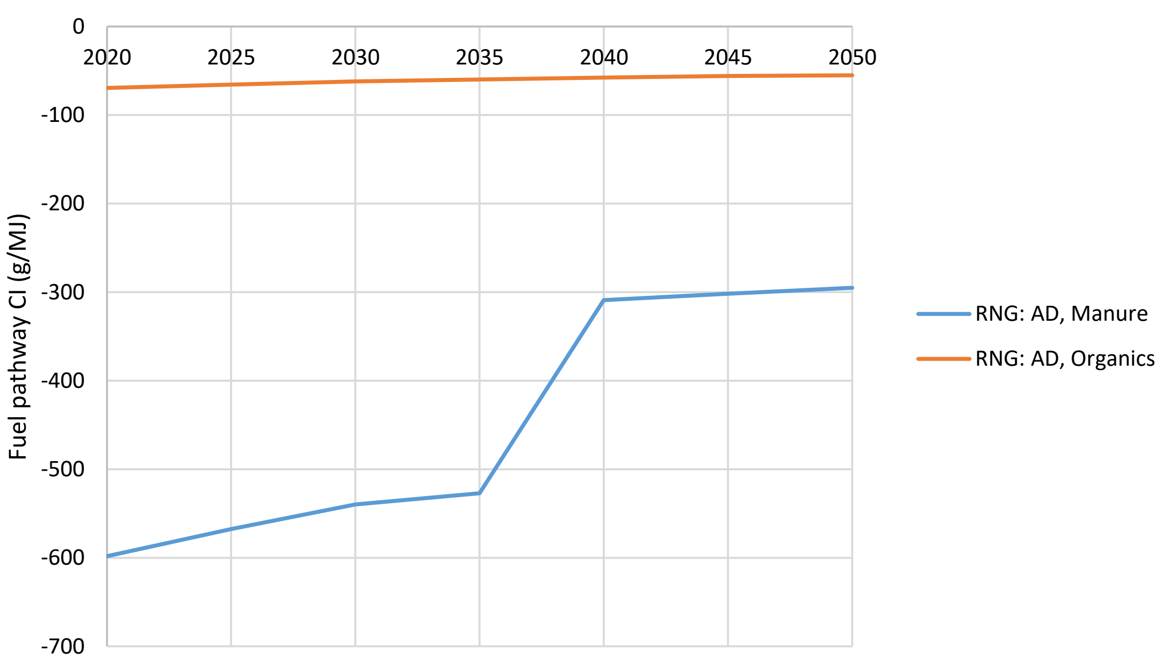


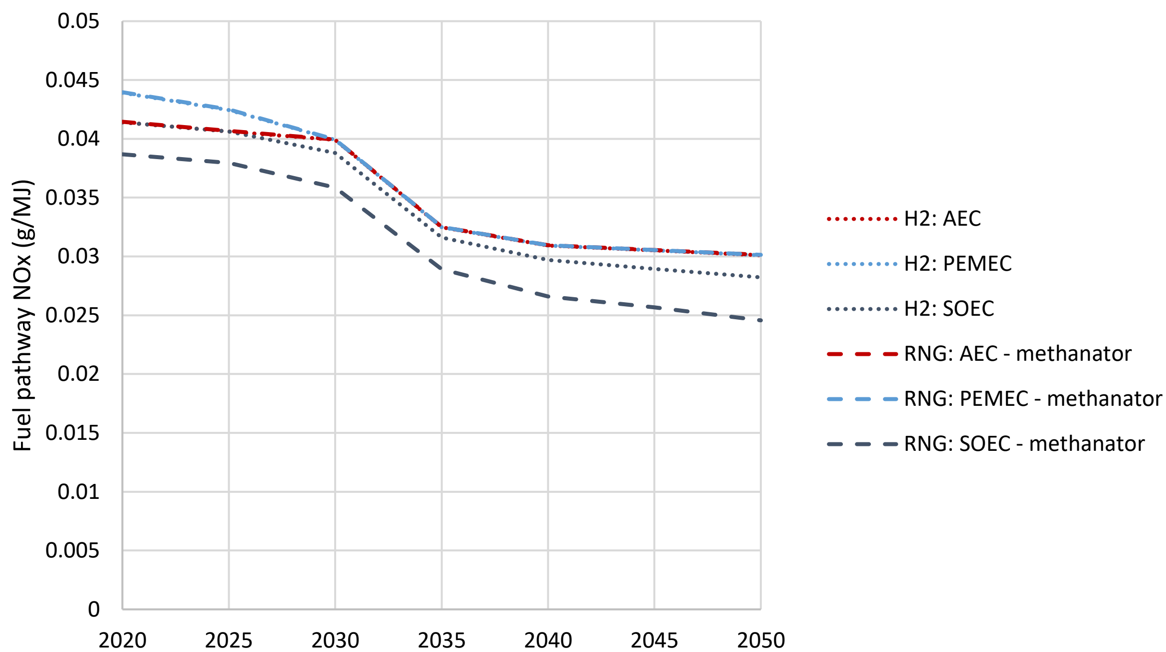
Figure 30. Anaerobic digester fuel pathway carbon intensities



In addition to the carbon intensities for various fuel pathways, the NO_x emission factors for the electrolytic, gasifier, and AD production technologies are shown in Figure 31, Figure 32, and Figure 33, respectively. The electrolytic fuel pathway NO_x emission factors shown in Figure 31 are for the conservative efficiency projections. Results for the optimistic pathways are generally very similar, with up to 6.3% lower NO_x.

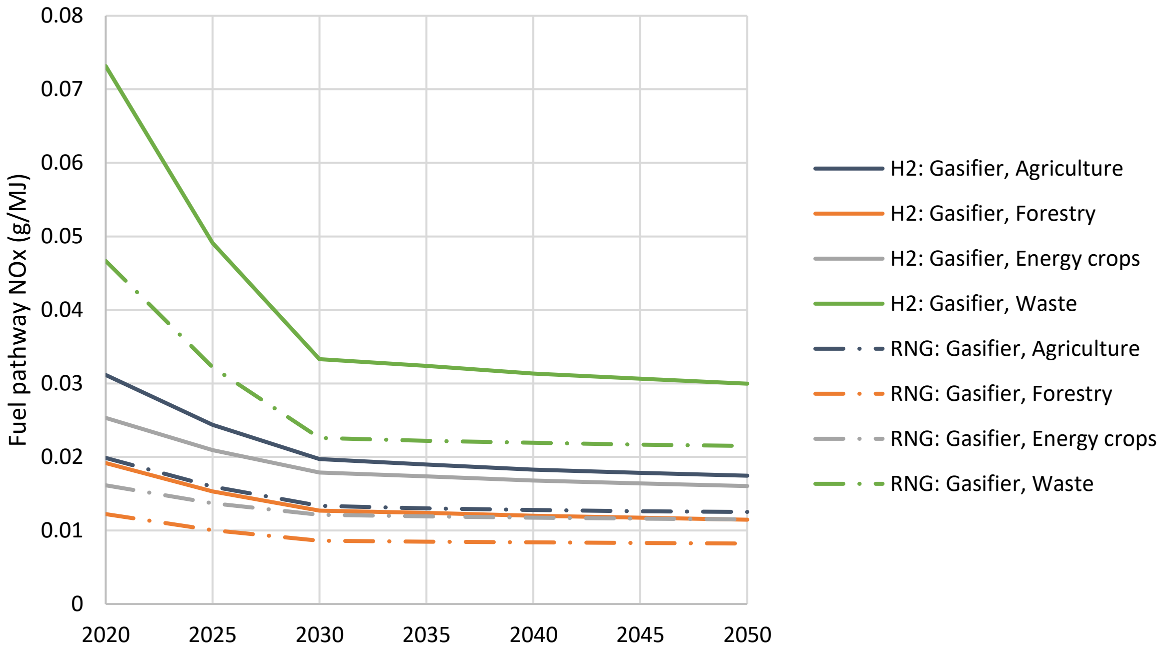
For electrolytic fuel pathways, unlike for carbon, there is no corresponding requirement for zero NO_x emissions by 2045. However, significant NO_x reduction is projected by 2035, due primarily to reductions in from the electric grid rather than electrolyzer efficiency improvements.

Figure 31. Electrolytic fuel pathway NO_x emission factors



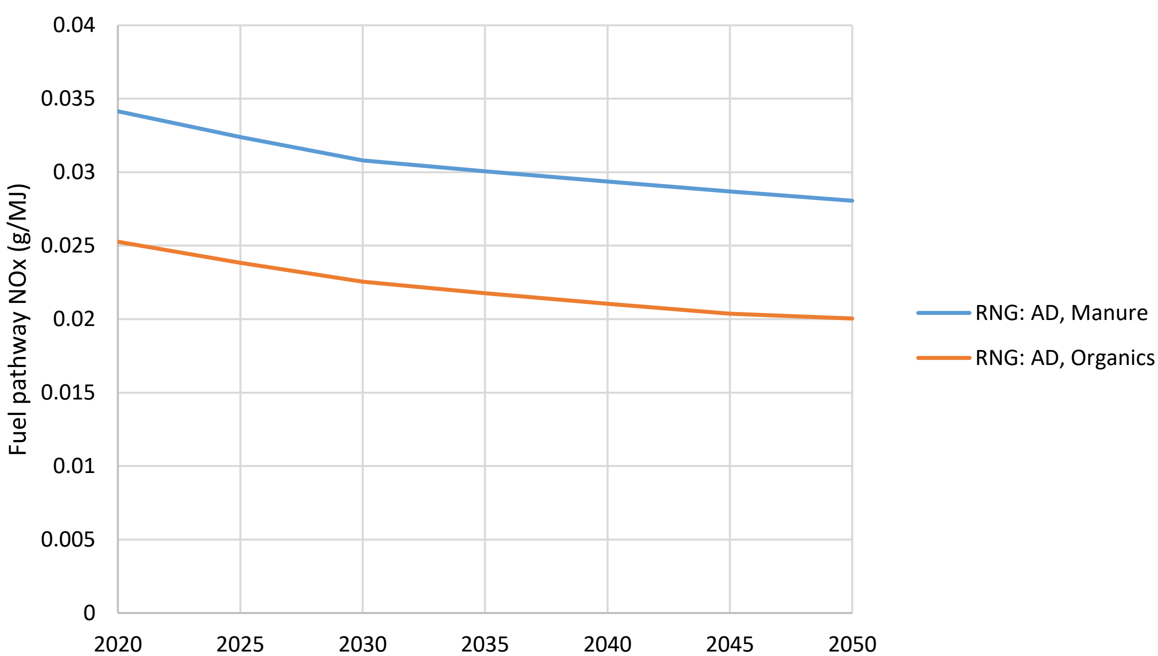
For gasifier fuel pathways, all pathways generally follow the same trend in NO_x reduction over time, with most improvements occurring between 2020 and 2030, but the waste feedstock in particular is projected to have dramatic reductions by 2030. The more significant reductions from 2020 to 2030 are due primarily to improvements in biomass feedstock processes, while the more modest improvements from 2030 and beyond are due to gasifier efficiency improvements.

Figure 32. Gasifier fuel pathway NO_x emission factors



For anaerobic digester both manure and organics feedstock pathways follow the same trend in NO_x improvements, and both are realized by anaerobic digester efficiency improvements.

Figure 33. Anaerobic digester fuel pathway NO_x emission factors



Plots and discussion for PM10 emissions from the electrolytic, gasifier, and AD production technologies are in the Appendix A.

1.4.2 Heavy-Duty Vehicle Fuel Availability and Cost

From the fuel pathway techno-economics introduced in the previous section, the total HDV fuel availability and cost can be calculated. Fuel availability is tightly linked to feedstock availability and total fuel pathway efficiency. Fuel cost is presented for multiple scenarios, both with and without alternative fuel credit revenue streams.

Fuel Availabilities

To calculate fuel availability, limits on fuel feedstock, production technology, distribution equipment, and dispensing equipment are considered. Of these four, availability of fuel feedstock and production technology have been determined to be the primary limitations on fuel availability. The present work focuses on fuel feedstock availability as the most stringent constraint on fuel availability, but technology availability is further considered in the work of Task 3.

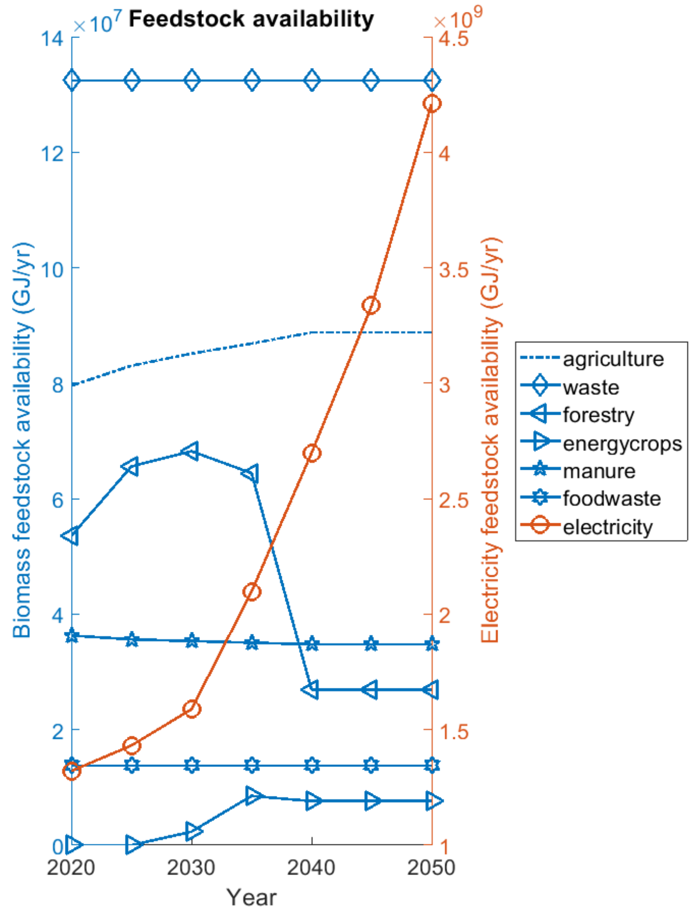
Generally, there are two mostly independent constraints on fuel availability: (1) electricity feedstock availability and (2) biomass feedstock availability. These are shown in Figure 34, with biomass availability depicted on the left axis and electricity availability on the right axis, Note the difference in magnitude of availability indicating the significantly higher availability of energy in the form of electricity for vehicle fuels and fuel feedstocks.

For electricity availability, it is assumed that approximately 40% of the total electricity capacity projected in E3's PATHWAYS model is available as a vehicle fuel or fuel feedstock. The 40% assumption is higher than what is assumed by E3 [41], but it allows for a more aggressive expansion of the electric grid should that expansion be recommended by the Task 3 fuel and powertrain rollout optimization results. The more aggressive expansion is also accounted for in the modeled cost of electricity distribution.

Biomass feedstock availability is sourced from U.S. DOE's Billion Ton Report [40], which projects out to 2040, and assumes constant availability from 2040 to 2050.

Note the lack of biogas from places such as landfills and wastewater treatment plants. The sources of biogas are much more limited than the biomass sources presented, and the rights to those sources are generally already allocated, hence the focus on biomass rather than biogas [3].

Figure 34. Electricity and biomass feedstock availabilities, data from E3 [41] *and U.S. DOE* [40]



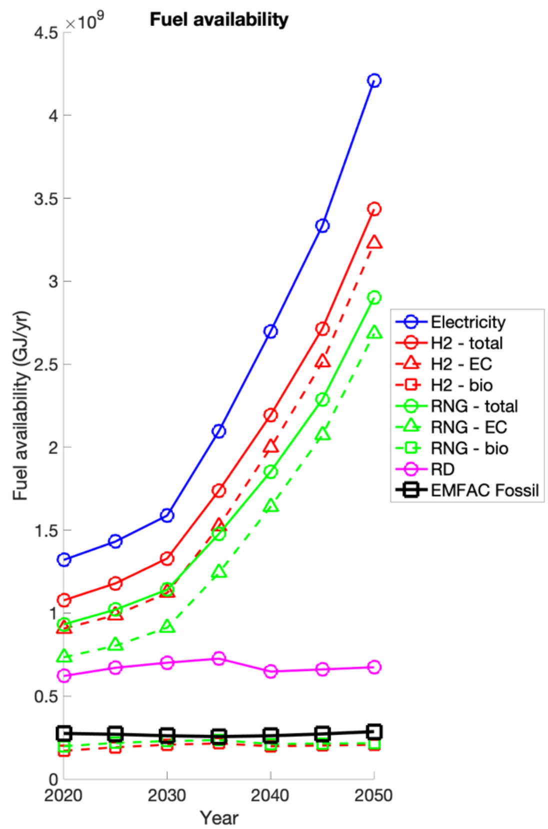
From these two feedstock constraints, each fuel is further limited by pathway efficiency. The resulting fuel availability shown in Figure 35 uses the average of production pathways should more than one be available to produce a fuel (e.g. renewable diesel can be produced from several technologies and many overlapping biomass categories, so the sum of biomass available that can be used in a given set of renewable diesel technologies is multiplied by the average efficiency of the different production technologies).

Hydrogen and RNG can be produced by both electricity and biomass feedstocks, and thereby have increased availabilities and more diverse feedstock options which is a strong strategic benefit. Availability by the two feedstock classes as well as the total are displayed in Figure 46.

Projections from EMFAC for the total amount of fuel energy used by the baseline HDV sector is also included demonstrating that quantities of renewable fuel are sufficient to meet projected baseline demands [1].

Note that these fuel availabilities shown in Figure 35 assume all biomass is potentially available for heavy duty vehicle fuels. In reality, this will likely not be how California decides to allocate its biomass resources, but no specific plans for allocation are available. Further consideration must be given to what sectors of the economy these biomass feedstocks should be apportioned to. It may later be determined that only a fraction of the California-available biomass and electricity should be available to make fuel for heavy duty vehicles, which would yield lower fuel availabilities. The impacts of feedstock constraints are explored further in the fleet transition scenarios presented in Chapter 3.

Figure 35. Heavy-duty vehicle fuel availability accounting for feedstock constraints and pathway efficiencies accounting for fuel production, distribution, and dispensing



Electricity is much more available than biomass, and additions to the electric grid to further expand availability, should it be needed for California as a whole, are arguably easier to achieve than expanding biomass availability due to the necessary increased land usage, seasonality and uncertainty of crops, etc. There is a difficult to quantify benefit of having a surplus of availability, but both electricity and electrolytic fuels share that benefit due to much greater availability than biomass. Fuel costs can be expected to be less volatile (and especially fewer spikes of increased price) when a surplus of feedstock exists. This would also improve energy independence of California as there is less likelihood of needing to source feedstock out of state or internationally.

Another benefit of electricity as a fuel and electrolytic fuels is the addition of dispatchable loads to the electric grid. As California continues to add more renewables to the electric grid, variance in the generation (caused by variance in solar power, wind power, etc.) will continue to make managing the electric grid more challenging. To help with that variability in electricity production, electricity and electrolytic fuels can provide variable and dispatchable electric loads. For electricity as a fuel, this would require smart charging, which times and varies power of charging plug-in electric vehicles based on grid characteristics. For electrolytic fuels, this dispatchability is simpler as the fuels produced (hydrogen and RNG) can be easily stored for later use, unlike electricity which requires batteries (conventional or hydrogen) that are much more expensive.

The above two benefits are quantified in the following section for a limited number of future scenarios. The present fuel cost work and the Chapter 3 fuel and vehicle projection optimization do not elaborate on these benefits, but are additional benefits that should be considered when planning support for renewable fuel technologies and further demonstrate the need for California to support the technologies of electrolytic fuel production.

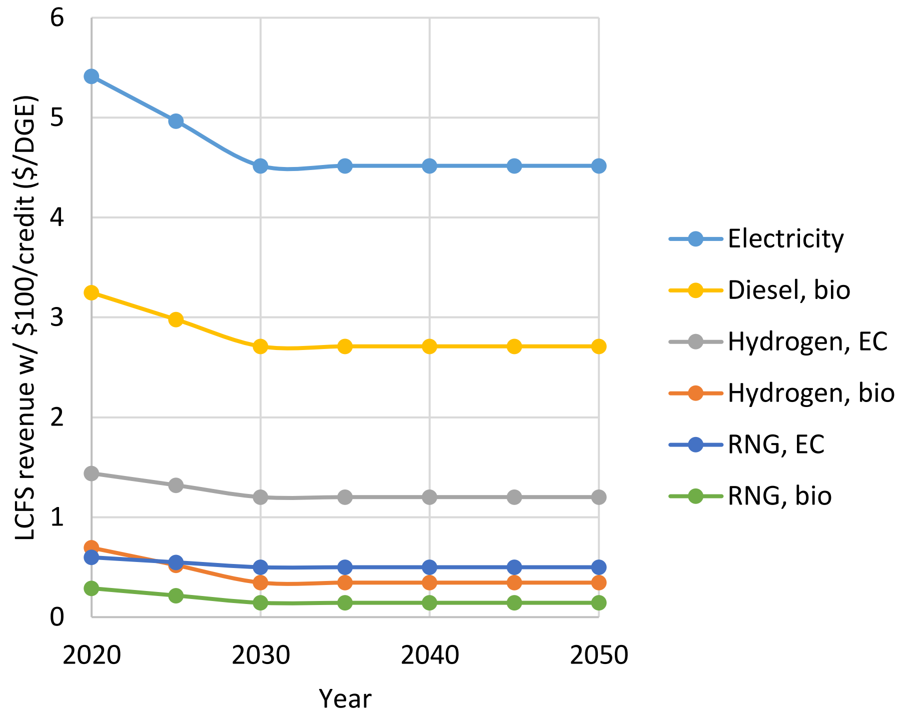
Alternative Fuel Credit Revenue Streams

One important contributing factor to fuel cost are available revenue streams designed to accelerate the use of alternative fuels. Several of these are detailed in Task 5, and two prominent ones are included in the work of Tasks 1 and 3. These two are the Low Carbon Fuel Standard (LCFS) and the Renewable Fuel Standard (RFS).

LCFS is a program designed and administered by the CARB to reduce the carbon intensity of fuels, often using renewable fuels. LCFS brings in revenue for fuel producers based on the carbon intensity of the fuel pathway. Each fuel pathway must be individually certified. Due to the wide variety of modeled fuel pathways, the LCFS revenue modeled in this work is based on values from the literature and extractions thereof. Revenue for electricity, which is used in BEVs and PHEVs, is taken from CARB Advanced Clean Trucks work. These values are used for electrolytic hydrogen production and RNG production as well, using the appropriate fuel production efficiencies and vehicle energy economy ratios (EER) for the FCEVs and CNG ICVs, respectively. Revenue for bio-derived hydrogen is also taken from this CARB work, which has data specifically for landfill gas feedstock but is here used for bio-derived hydrogen in general. This bio-derived hydrogen revenue is extrapolated RNG using the methanation efficiency and appropriate vehicle EER [220]. LCFS revenue for renewable diesel production is taken from CARB's generic renewable pathway carbon intensity of 32.23 gCO_2e/MJ and calculating the revenue from that using the appropriate EER for diesel ICVs [221].

The resulting LCFS revenues for the various fuel pathways are shown in Figure 36. Note that it is assumed that LCFS credits are valued and $100 per credit, a conservative assumption compared to the 2015-2019 average of $142, and the program will continue to 2050 as there is no sunset date.

Figure 36. LCFS revenue modeled assuming $100 per credit



The Renewable Fuel Standard (RFS) program is like LCFS in that it provides revenue for producing renewable fuels using certain pathways. RFS is designed and administered by the U.S. federal government. A notable difference between RFS and LCFS is that RFS does not include any approved hydrogen production pathways. Determining potential revenue from RFS is primarily a matter of multiplying the value of the Renewable Identification Number (RIN), a credit assigned to each gallon (or equivalent) of renewable fuel produced, by that fuel's Equivalence Value (EV).

Like LCFS, RFS revenue is pathway specific. However, RFS is somewhat more constrained in the types of pathways that have been approved, at least when applied to the pathways modeled in the present work. While there are two approved RFS pathways to produce electricity, both are only applicable for the portion of electricity produced from biomass. The present work uses electricity projections from E3, which includes only a negligible portion of electricity produced from biomass. Therefore, RFS does not substantially apply to the electricity fuel use here. For bio-derived RNG, only RNG produced from digesters are approved pathways, and the present work only includes non-cellulosic feedstocks for these digesters. There is no pathway for electrolytic RNG pathway. There are pathways for cellulosic renewable diesel production and for hydrotreating oils.

The U.S. Environmental Protection Agency posts RIN prices for the various categories of the program. There is some volatility in the prices, so the average of the prices in the last 5 years is used in this work [222]. RIN prices for each of the "D" codes used in modeling are in Table 10. Note that D3 RINs have a substantially higher average price than the others, which leads to a larger incentive to produce renewable fuels from cellulosic biomass feedstocks.

Table 10. RIN prices modeled by D code, data from [222]

D code	RIN price ($)
D3	1.5
D4	0.5
D5	0.5
D6	0.5

The EV is 1.0 for each 77,000 Btu, by lower heating value (LHV) of compressed natural gas (or RNG in the present work) and 1.7 for each gallon of renewable diesel [223].

Using the above RIN prices and EVs, the amount RFS revenue per gallon of diesel equivalent is shown in Table 11. Note that RFS only applies to the following pathways modeled in the present work: (1) RNG from anaerobic digestion of non-cellulosic biomass (food waste and manure) with D5 RINs, and (2) renewable diesel from cellulosic biomass (all biomass but food waste and manure) with D3 RINs [224].

Table 11. RFS revenue modeled

Fuel and pathway	RFS revenue ($/DGE)
RNG - Anaerobic digestion, non-cellulosic feedstock	0.834
Renewable diesel - Cellulosic feedstock	2.55

Total Fuel Costs

This section details and analyzes the dispensed fuel costs for each of the four HDV fuels considered in this work. Three scenarios are included, and each is presented both with and without LCFS and RFS revenue, yielding a total of six sets of results.

1. Fuel costs with conservative electrolytic projections, with LCFS and RFS revenue
2. Fuel costs with conservative electrolytic projections, without LCFS and RFS revenue
3. Fuel costs with optimistic electrolytic projections, with LCFS and RFS revenue
4. Fuel costs with optimistic electrolytic projections, without LCFS and RFS revenue
5. Fuel costs resulting from optimized fuel and vehicle rollout, with LCFS and RFS revenue
6. Fuel costs resulting from optimized fuel and vehicle rollout, without LCFS and RFS revenue

For sets 1-4, the previously introduced conservative and optimistic sets of assumptions are applied for all electrolytic fuel production technologies (including efficiencies, installed capacities, and learning rates.

For sets 5 and 6, the efficiencies and learning rates of the electrolytic technologies are based on the conservative scenario, but the installed capacities of the electrolytic technologies are determined by the optimal fuel production schedule of the scenarios presented in Chapter 3.

The use of Wright's law to calculate fuel cost (specifically in the fuel production step) means each of the three different scenarios (i.e. conservative, optimistic, and "Task 3 optimal") will have different electrolytic fuel costs directly related to the installed capacities of the different technologies prescribed by the different scenarios. The extent to which costs are different will be analyzed here. For all six sets of results, non-electrolytic fuels are determined using the efficiencies and learning rates previously presented, and installed capacities are all determined by the "Task 3 optimal" scenario.

For all six sets of results, LCFS revenue is projected assuming $100 per credit is sustained, and RFS revenue is projected assuming recent historical credit price trends continue.

Lastly, it is important to note that fuel costs should not be considered in isolation. Rather, the associated vehicle efficiency and vehicle cost are important to consider alongside the fuel cost. Combining these three factors yields a total cost per mile traveled, which is a more comprehensive factor to consider than fuel cost alone. This cost per mile is calculated in Chapter 3. Nonetheless, fuel costs are an important factor to consider.

Fuel costs with conservative electrolytic projections, with LCFS and RFS revenue

The dispensed fuel costs normalized to diesel gallon equivalent (DGE) and averaged across different production pathways are shown in Figure 37, excluding electrolytic RNG pathways as they are significantly more expensive due to the high cost of carbon capture. The cost for level 2 electric charging is slightly negative due to the revenue streams being higher than the modeled cost of the electricity feedstock and required infrastructure. Additionally, the fuel costs by production technology are presented in Figure 38.

Figure 37. Average heavy duty vehicle fuel cost projections, conservative electrolytic assumptions, with LCFS revenue of $100 per credit and RFS revenue

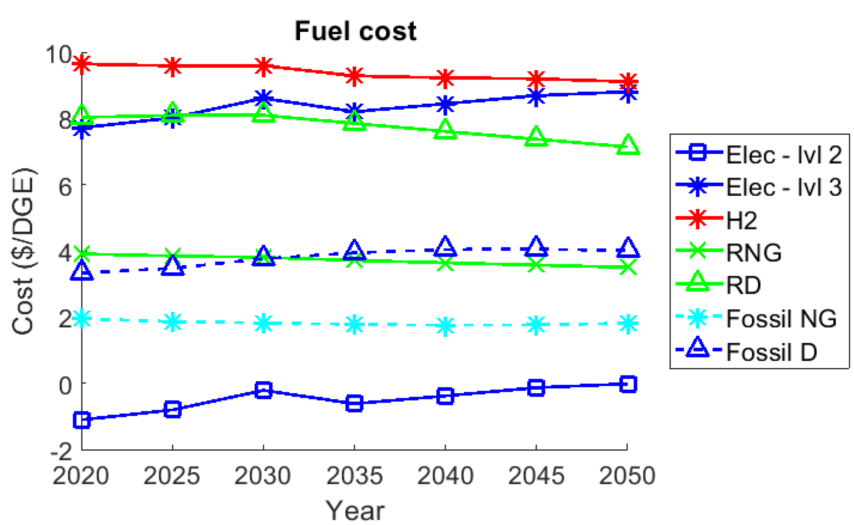
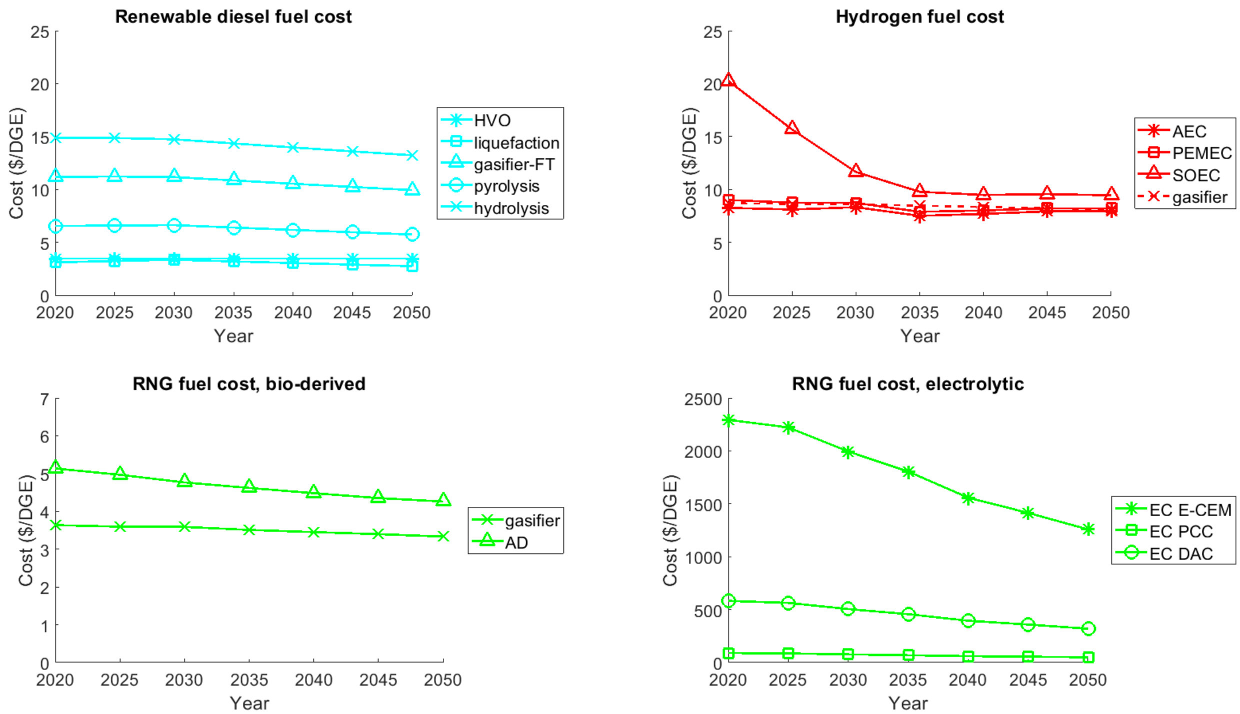


Figure 38. Production technology specific heavy duty vehicle fuel cost projections, conservative electrolytic assumptions, with LCFS revenue of $100 per credit and RFS revenue



For biomass-derived fuels, fuel costs are affected more by the conversion technology used than by the biomass feedstock used. Biomass feedstock type affects fuel cost by 5% to nearly 20% in general, except for manure and food waste for liquefaction which roughly double the fuel cost. HVO cost is nearly doubled when going from waste vegetable oil to crop vegetable oil. Conversely, the conversion technology impacts the cost of the fuel by an order of magnitude, e.g., considering woody biomass the cost for renewable diesel from hydrolysis is 132% more expensive than using pyrolysis, and producing electrolytic RNG with carbon from E-CEM is 2447% more expensive than when using carbon from PCC in the extreme case.

Overall, the most cost-effective method of utilizing biomass resources in California for HDV fuel is using liquefaction to produce renewable diesel. Next would be both HVO to produce renewable diesel and gasification to produce RNG, as both pathways produce fuels of similar cost. Note that each of these three technologies generally use different biomass feedstocks, though there is some overlap: liquefaction is most effective with moist biomass, HVO uses vegetable oils, and gasification is most effective with dry biomass. That is to say each category of biomass has its own associated production technology that most effectively converts that biomass feedstock to renewable fuel. Biomass is considerably less cost effective to produce hydrogen than it is to produce either renewable diesel or RNG. This is due to the relatively high efficiency of liquefaction and HVO to produce renewable diesel and gasification to produce RNG.

In general costs for hydrogen are higher than other fuels, although similar to electricity if level 3 charging is assumed and both LCFS and RFS credits are available. Highlighting the importance of not only production equipment but also electricity feedstock, increasing cost of electricity in the later years of analysis negates much of the cost reduction from Wright's Law on the electrolyzer technologies. High initial hydrogen cost from SOECs is due to low installed capacity of the technology at the present, but Wright's Law projects significant reduction in technology cost by 2035.

Given the limitations of biomethane resources, the production of hydrogen via biomass gasification pathways offers a reasonably cost-effective method of producing renewable hydrogen as well. Variability in cost by feedstock type for hydrogen from gasifiers is small.

RNG has a wide range of cost depending on which method is used, and electrolytic RNG is far more expensive than biomass-derived RNG. Very high cost in carbon capture technology means total electrolytic RNG costs are much more dependent upon the carbon capture technology than the electrolyzer technology; therefore, electrolytic RNG costs are categorized by carbon capture technology only with the average of the three electrolyzer technologies. Post-combustion capture is the cheapest carbon capture source modeled but resulting RNG costs are still an order of magnitude higher than biomass-derived RNG. Note that PCC may not be considered renewable as the carbon is generally coming from fossil fuel power plants, but co-location of RNG plants with a bio-refinery could make use of PCC technology with a renewable source of carbon. Renewable sources of more cost-effective CO_2 are needed to make electrolytic RNG competitive with biomass-derived RNG. Gasifiers producing RNG lead to nearly 30% lower fuel cost than AD at first, though that cost difference drops to about 20% by 2050.

In terms of renewable diesel production, both HVO and liquefaction are comparable in cost to fossil diesel when taking advantage of LCFS and RFS revenue. As fossil diesel is projected to increase in cost over time due to scarcity, regulations, geopolitics, etc. renewable diesel will likely be cheaper than diesel before 2050 especially as technology advancements continue. Note, however, that limited biomass and resulting biofuel availability (see Figure 35) and competing sectors are potential constraints that could limit widespread adoption of biofuels for HDVs. Further analysis of these constraints is presented in Chapter 3.

Although beyond the scope of work to analyze, it is prudent to consider the rate structure of electricity in producing electrolytic fuels as resulting fuel costs are highly dependent upon electricity input costs and rate structures for these fuels are not yet firmly established. Projections used for the present work have electrolyzer input electricity costs of $0.038 per kilowatt-hour for 2020, a low of $0.029 per kilowatt-hour in 2035, and then an increase to $0.042 per kilowatt-hour by 2050 due to, in part, additional storage requirements for high renewables [41]. Currently, electrolyzers consuming grid electricity pay retail rates on tariff schedules and service on a standard commercial or industrial rate in California would be approximately $0.11 to $0.14 per kilowatt-hour for grid electricity, which currently has a renewable fraction of about 35% [3]. For electrolyzers interconnected at the transmission level, time-of-use rates would provide a reasonable proxy to wholesale electricity rates but would require the electrolyzer to receive grid-average blends of renewable and conventional electricity with implications for efficiency, emissions, generated fuel revenue credits, etc. In contrast, the use of wind or solar electricity would incur a cost of about $0.03 per kilowatt-hour for 100 percent renewable energy, although at the expense of siting flexibility and lower capacity factors.

Fuel costs with conservative electrolytic projections, without LCFS and RFS revenue

When removing both the LCFS and RFS revenue, which is depicted in Figure 39 and Figure 40, general fuel cost evolution trends stay largely the same, but some fuels and fuel production methods are impacted more than others.

Electricity (with both level 2 and level 3 charging) becomes significantly more costly without incentive revenue. Electricity with level 2 charging and renewable natural gas are similar in cost to fossil diesel.

With major implications for the deployment of ZEV pathways, renewable hydrogen becomes more cost effective than electricity with level 3 charging.

Along with electricity, renewable diesel is also significantly impacted by the lack of LCFS and RFS revenue. Renewable diesel production using cellulosic biomass (i.e. all potential biomass for renewable diesel considered excluding manure, food waste, and vegetable oil) receive a \$5.80/DGE to \$5.26/DGE benefit from the LCFS and RFS incentive programs, with the larger benefit slightly declining over time. Renewable diesel from non-cellulosic biomass (i.e. manure, food waste, and vegetable oil) does not benefit from RFS credits due to that incentive's focus on cellulosic biomass feedstocks for renewable diesel production, but it does benefit from LCFS with \$3.25/DGE to \$2.71/DGE reduction in cost, again starting with the larger benefit which then declines over time. Without the incentives, HVO becomes the cheapest method for producing renewable diesel.

Hydrogen costs are increased 6-15% when no incentive revenue is available, a relatively modest increase when compared to up to 70% for electricity and up to 175% for renewable diesel. Among hydrogen production pathways, electrolytic hydrogen production is generally impacted more than biomass-derived hydrogen from gasifiers.

For RNG, gasifier pathways are least impacted, with costs increasing up to 8% while anaerobic digester RNG increases up to 23% in cost. Electrolytic RNG pathways are impacted less than 1% due to their very high cost of carbon capture.

Figure 39. Average heavy duty vehicle fuel cost projections, conservative electrolytic assumptions, without LCFS and RFS revenue

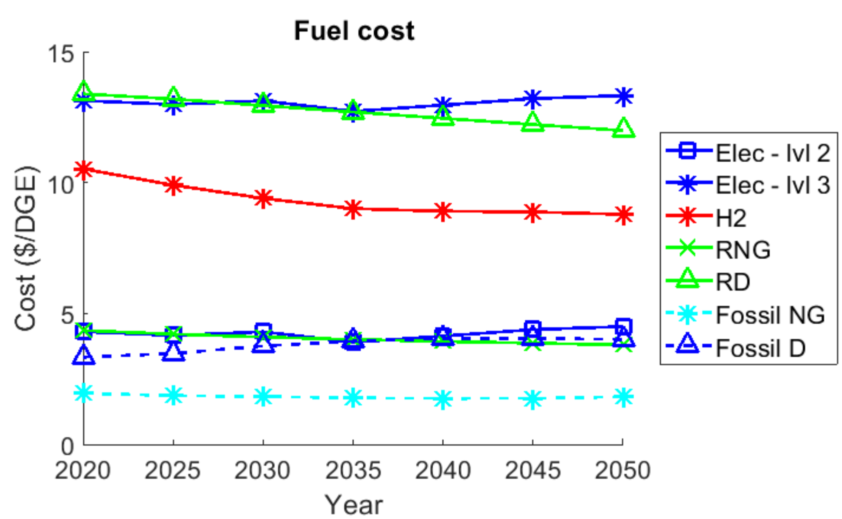
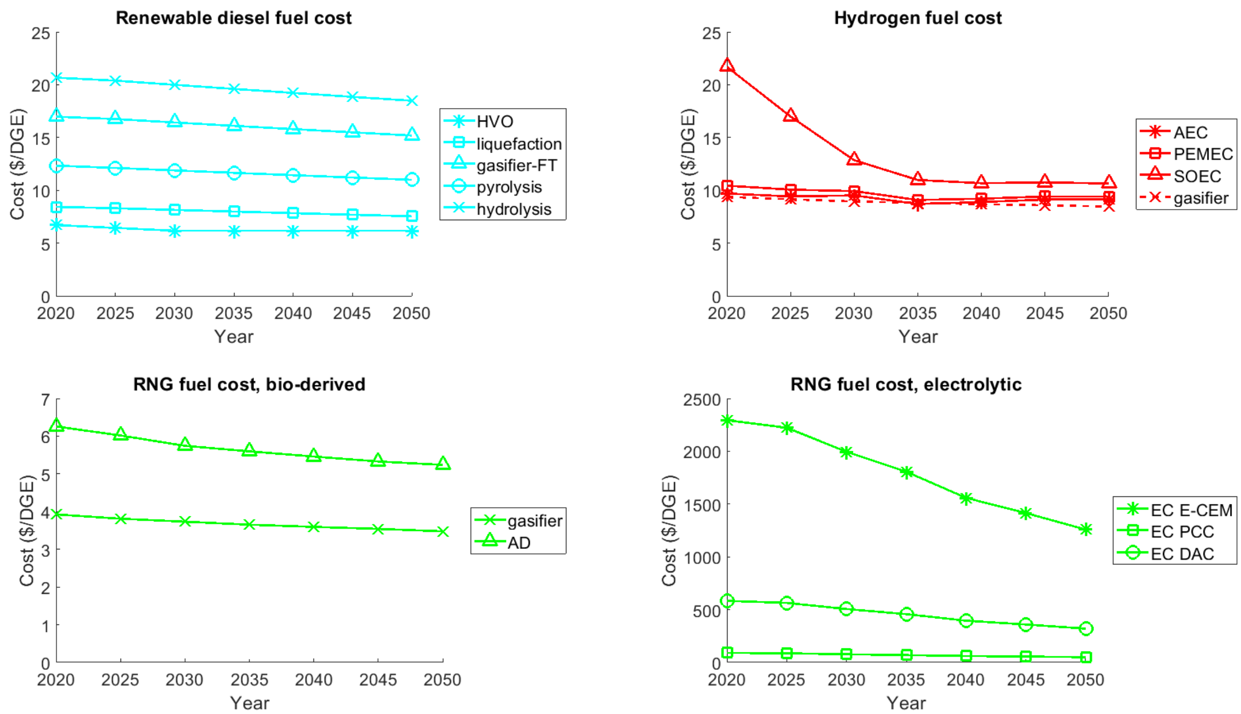


Figure 40. Production technology specific heavy duty vehicle fuel cost projections, conservative electrolytic assumptions, without LCFS and RFS revenue



Fuel costs with optimistic electrolytic projections, with LCFS and RFS revenue

As mentioned at the beginning of this fuel costs section, only the electrolytic pathways are affected by the conservative, optimistic, and "Task 3 optimal" scenarios. Therefore, in the following discussion for the present optimistic scenario and the proceeding "Task 3 optimal" scenario, focus will be placed on the electrolytic pathways.

For the average fuel cost projections, the key difference between the conservative and optimistic scenario with incentives is the cost reduction of hydrogen, which becomes competitive with electricity from level 3 charging by 2030 and undercuts it in cost by 2040.

Electrolytic hydrogen is about $0.80/DGE cheaper with the optimistic assumptions by 2050, with both PEMEC and SOEC pathways benefiting slightly more than AECs due to their being newer to the market and therefore more likely to have greater improvement.

Electrolytic RNG cost is cut by more than half with the optimistic assumptions, but costs are still (likely) prohibitively expensive, dropping as low as $19.15/DGE through PCC carbon capture technology by 2050.

Figure 41. Average heavy duty vehicle fuel cost projections, optimistic electrolytic assumptions, with LCFS revenue of $100 per credit and RFS revenue

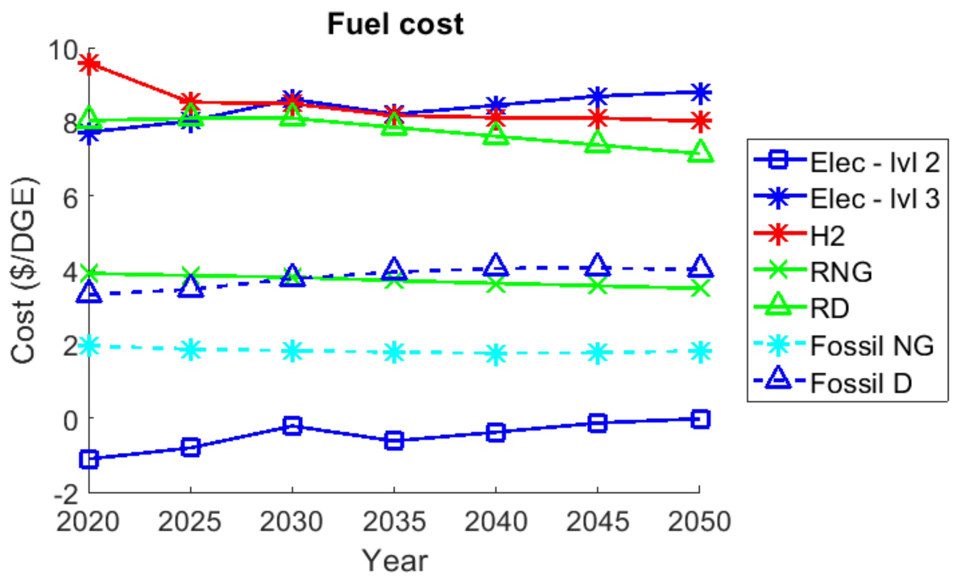
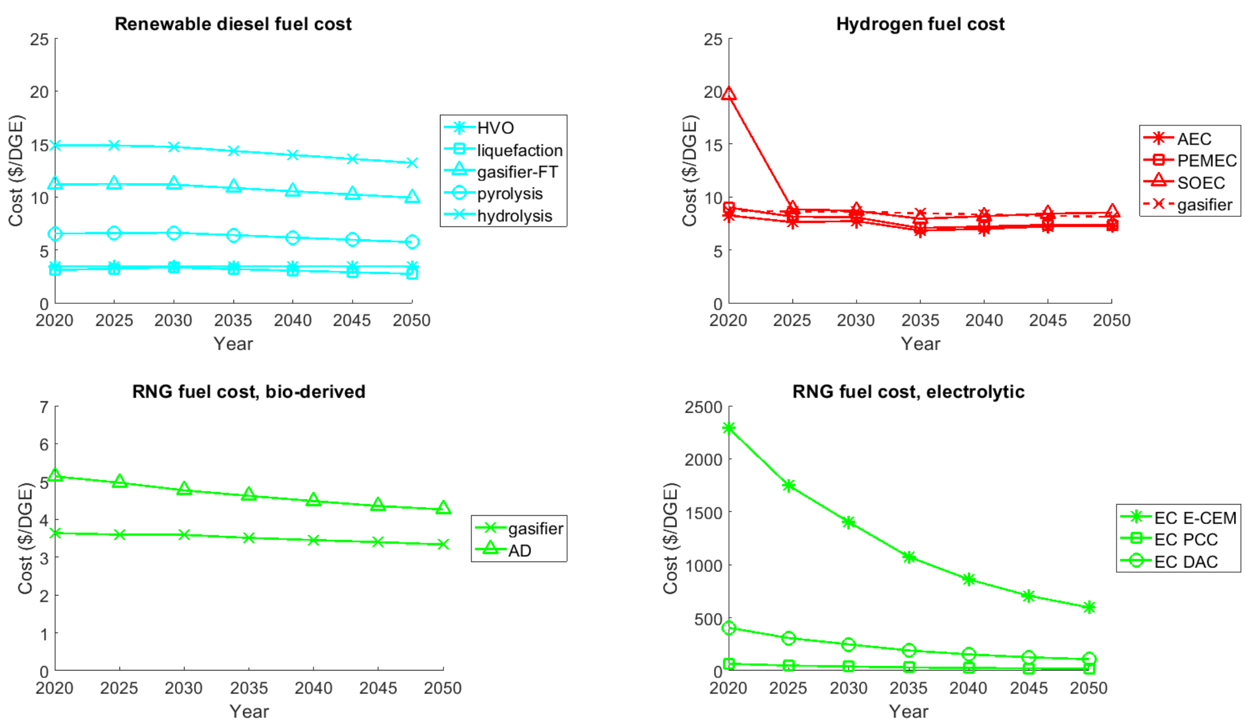


Figure 42. Production technology specific heavy duty vehicle fuel cost projections, optimistic electrolytic assumptions, with LCFS revenue of $100 per credit and RFS revenue



Fuel costs with optimistic electrolytic projections, without LCFS and RFS revenue

Without incentives, as with the conservative scenario, the optimistic scenario has hydrogen in the middle of the pack of renewable fuels in terms of cost. The major difference in the optimistic scenario is there is greater cost reduction achieved, particularly by 2025 with much more rapid decline in SOEC costs.

Figure 43. Average heavy duty vehicle fuel cost projections, optimistic electrolytic assumptions, without LCFS and RFS revenue

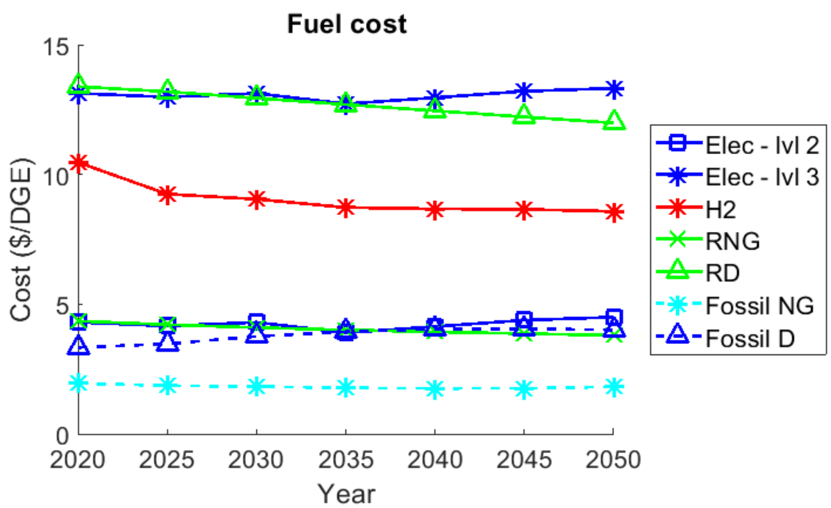
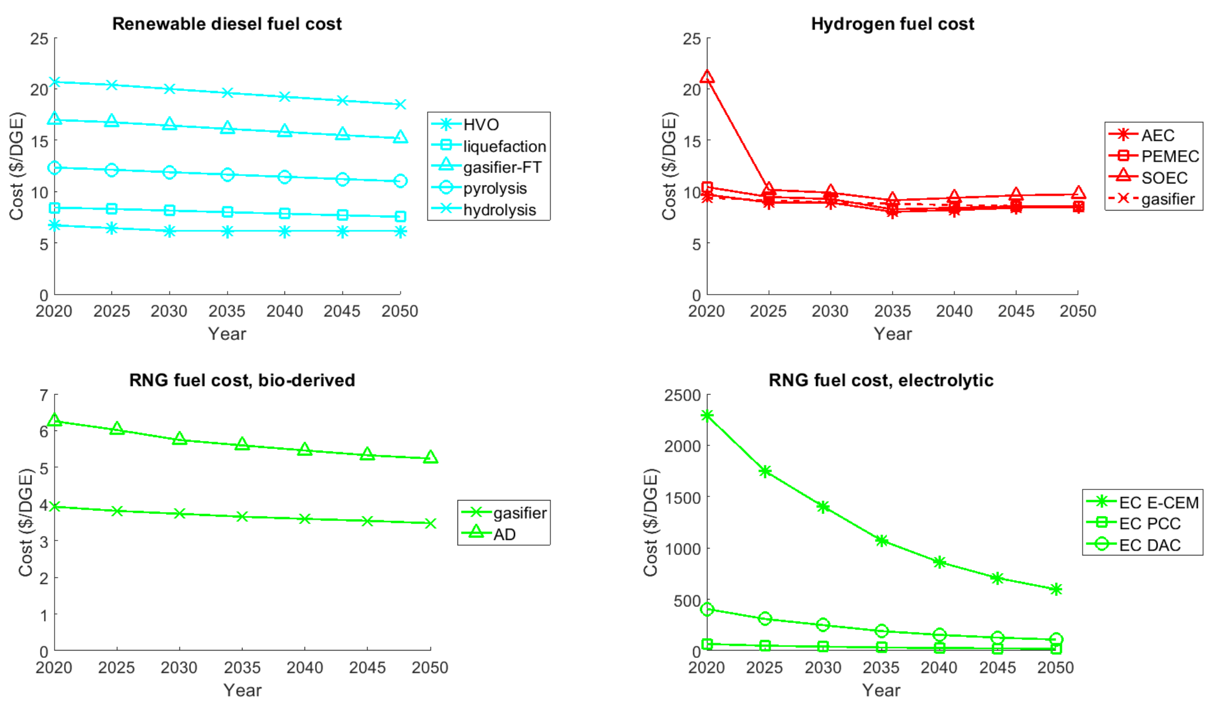


Figure 44. Production technology specific heavy duty vehicle fuel cost projections, optimistic electrolytic assumptions, without LCFS and RFS revenue



Fuel costs resulting from optimized fuel and vehicle rollout, with LCFS and RFS revenue

The third and final scenario assumes installed capacities for all technologies based on the optimal fuel and vehicle rollout of Task 3 work. These installed capacities directly affect the projected fuel costs through Wright's law. As was stated for the optimistic scenario results, the key difference between the three scenarios is in how much of the electrolytic fuel production pathways are prescribed, so those are the results that will be focused on in this section. Fuel costs for biomass-derived fuels are the same as for the conservative and optimistic scenarios already detailed.

The average fuel costs of this scenario are similar to those of the conservative scenario, in part due to the moderate adoption of electrolytic hydrogen production (rather than the heavy adoption prescribed by the optimistic scenario), but adoption of SOEC technology is absent so average electrolytic hydrogen costs are 41% higher.

While average hydrogen costs are similar to those of the conservative scenario, the SOEC production pathway of hydrogen remains much higher in the "Task 3 optimal" due to the lack of SOEC adoption in this scenario. Without increasing adoption of the technology, Wright's law projects costs to remain high through 2050, leading to the significantly higher average electrolytic hydrogen cost noted above. As previously stated, SOEC pathways offer the highest efficiencies and this result demonstrates that early support for SOEC may be warranted to support the long-term development of electrolytic pathways.

Figure 45. Average heavy duty vehicle fuel cost projections, optimized fuel and vehicle rollout assumptions, with LCFS revenue of $100 per credit and RFS revenue

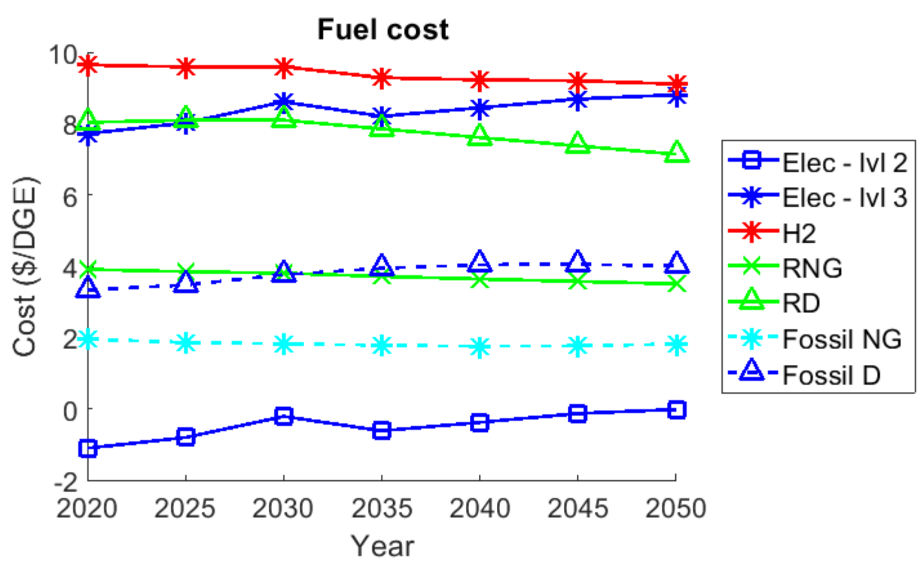
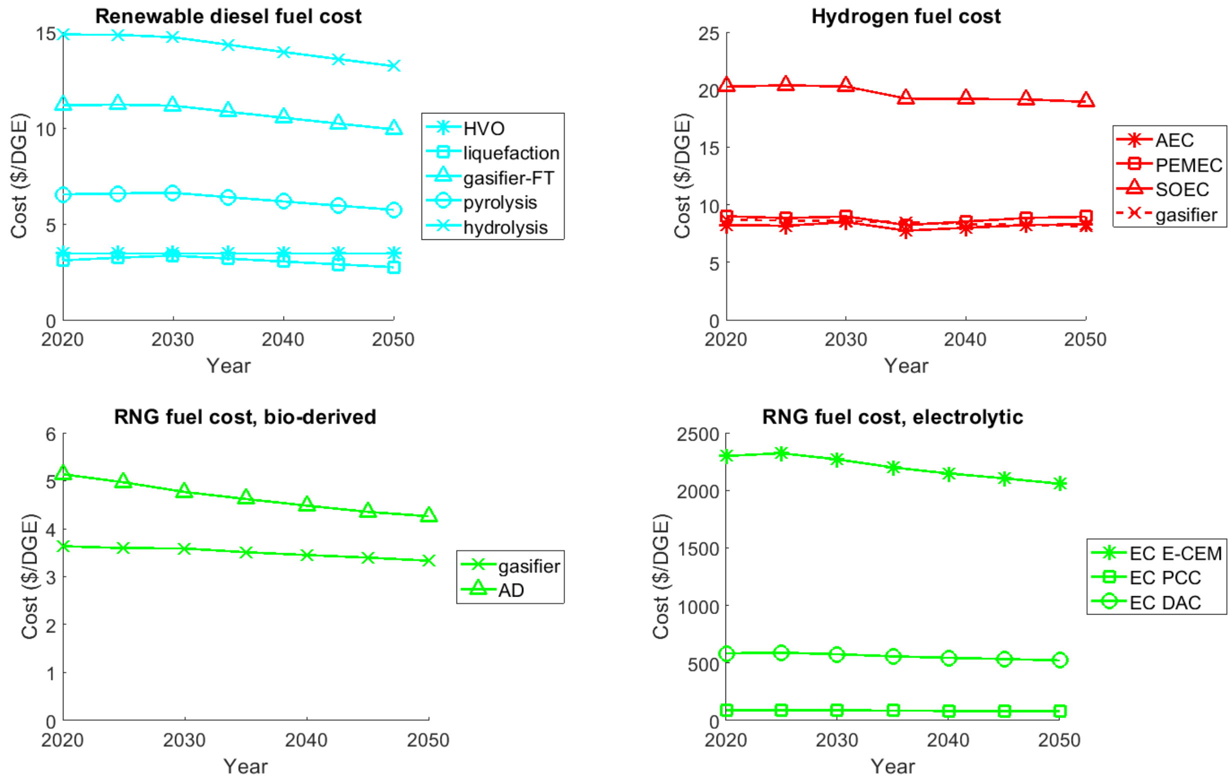


Figure 46. Production technology specific heavy duty vehicle fuel cost projections, optimized fuel and vehicle rollout assumptions, with LCFS revenue of $100 per credit and RFS revenue



Fuel costs resulting from optimized fuel and vehicle rollout, without LCFS and RFS revenue

Lastly, when comparing the “Task 3 optimal” scenario results to the conservative results, both without incentive revenue, the key difference is again higher hydrogen costs in the mid- and long-term to 2050 due to primarily no SOEC adoption. Without incentives, however, hydrogen is again on average in the middle of the other renewable fuels in terms of price, the same as for both the conservative and optimistic scenarios when not including incentive revenue.

Figure 47. Average heavy duty vehicle fuel cost projections, optimized fuel and vehicle rollout assumptions, without LCFS and RFS revenue

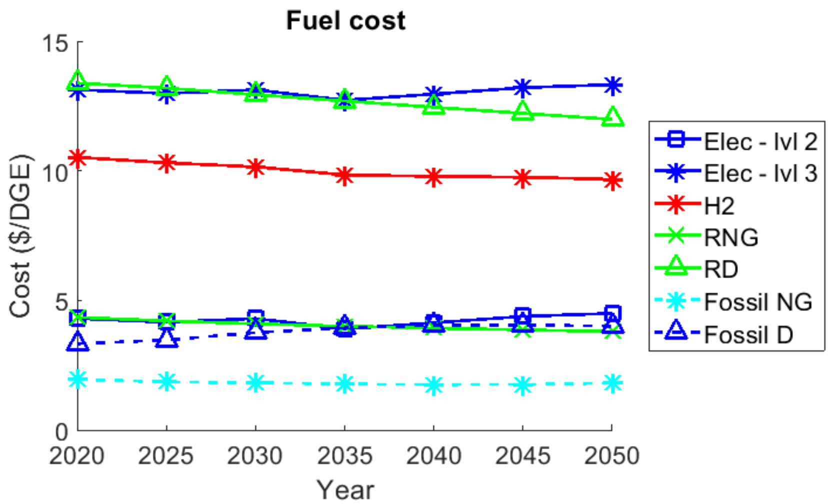
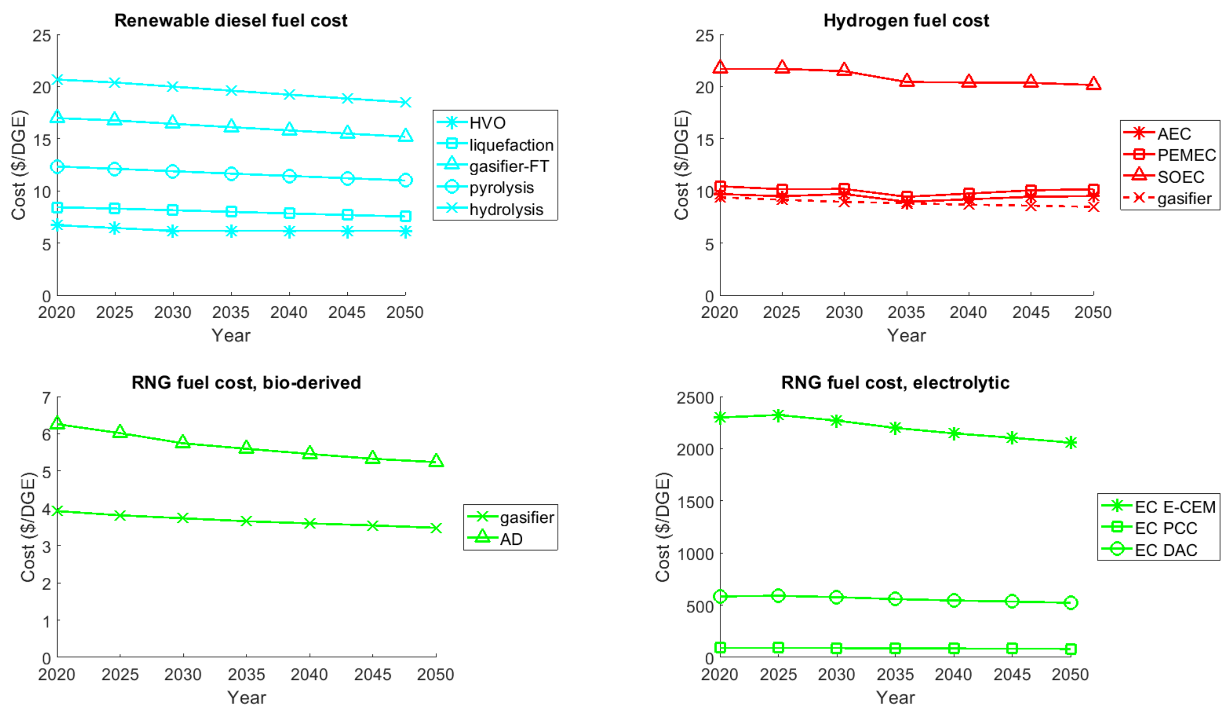


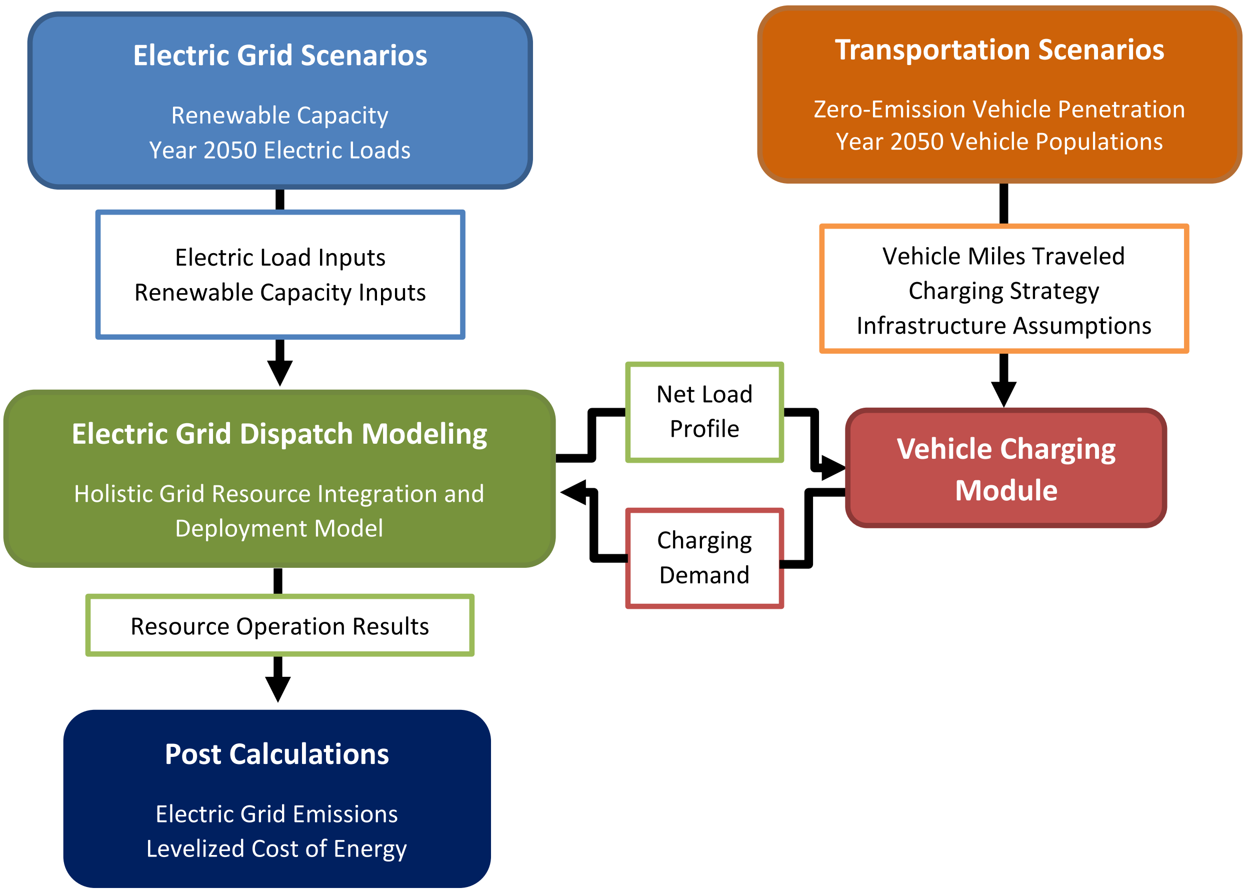
Figure 48. Production technology specific heavy duty vehicle fuel cost projections, optimized fuel and vehicle rollout assumptions, without LCFS and RFS revenue



1.4.3 Energy and Emissions Benefits of V2G Services for Electric Drive HDVs

The goal of this sub-task is to identify energy and emissions benefits of vehicle-to-grid (V2G) services for electric drive heavy duty vehicles (HDV). To meet this goal, this sub-task 1) assesses charging infrastructure configurations and management strategies to support HDV electrification and 2) quantifies the impacts of V2G services on renewable utilization, balancing fleet operation, emissions, and levelized cost of energy. An overview of the methodology used to analyze the impact of electric vehicle integration onto the grid is presented in Figure 49.

Figure 49. Vehicle-to-Grid methodology overview



Future grid trajectories were developed for the California electric grid for the year 2050, scaling the baseline 2050 capacity established in E3 PATHWAYS [2]. The renewable capacities for the three electric grid configurations are presented in Table 12. The trajectories examined in this section are as follows:

- *Current Policy Reference (CPR) (80% Reduction in Grid GHG Emissions)*—used here as the base case. The CPR is directly from the E3 PATHWAYS Project and includes the E3 baseline 2050 electric load profile including load demand for light-duty vehicles and buses [129]. It assumes an 80% reduction in GHG emissions from the electric grid.

- *100% Clean Electric Grid*—renewable capacity is increased by 20% compared to the CPR base case and the 80% reduction scenarios in order to support a target of zero GHG emissions from the electric grid.

- *100% Clean Electric Grid-Renewable Energy Overbuild*—renewable capacity is increased by 50% compared to the CPR base case. This overbuild trajectory increases renewable availability, and therefore, flexibility for the transportation sector to utilize clean electricity.

Table 12. Resource generation capacities applied in analysis from E3 PATHWAYS [129]

Technology	CPR Base Case (80% Reduction) (GW)	100% Clean Electric Grid	100% Clean Electric Grid-Overbuild
Rooftop PV	41.5	50.8	62.2
Solar	66.0	80.8	99.0
Wind	99.7	122	157
Geothermal	4.86	4.86	4.86
Hydropower	15.1	1.29	1.29

Under the three future grid scenarios, a few different ZEV futures are examined to assess the potential impact of V2G services. The ZEV scenarios explore the sensitivity of grid impacts to the level of vehicle penetration and fuel/charging assumptions. The base case for ZEV deployment is the same as the CPR assumptions from E3. The additional ZEV deployment scenarios are also based on scenarios from PATHWAYS, taking the zero-emission vehicle VMT from different portfolio scenarios [129]. A summary of the overall scenarios is outlined in Table 13.

Table 13. Transportation scenarios investigating Vehicle-to-Grid services

Transportation Assumptions	Renewable Assumptions	Light Duty Charging Strategy	Heavy Duty Charging Strategy	Energy Storage
Current Policy Reference	80% Reduction in GHG Emissions	Immediate, at home and work	Immediate	1.3 GW energy storage
			Smart	
			V2G	
80% Reduction in GHG Emissions		Immediate, at home and work	Immediate	
			Smart	
			V2G	
			FCEV	
	100% Clean Electric Grid	Immediate, at home and work	Immediate	Scaled to meet 100% clean electric grid target
			Smart	
			V2G	
	100% Clean Electric Grid-Overbuild	Immediate, at home and work	Immediate	
			Smart	
			V2G	
		Smart	V2G	
Expanded HDV Electrification	80% Reduction in GHG Emissions	Immediate, at home and work	Immediate	1.3 GW energy storage
			Smart	
			V2G	

The reduction in heavy duty vehicle emissions is achieved by switching to lower carbon fuels including compressed natural gas, electricity, and hydrogen. The 80% reduction scenarios examine an 80% reduction in GHG emissions from the transportation sector compared to 1990 levels, examining BEVs with. The Expanded HDV Electrification scenario examines greater BEV adoption in the heavy duty sector with increased vehicle range and charging availability.

Vehicle populations and corresponding vehicle miles traveled were scaled to the year 2050 based on EMFAC assumptions and E3 PATHWAYS scenarios [129], [133]. Fuel economy assumptions reflect reasonable efficiency improvements informed by current tests of new vehicle technologies and supported by literature [225]–[227]. Both battery electric and fuel cell vehicles were deployed to simulate different ZEV deployment scenarios.

The BEV and EVSE infrastructure assumptions for the scenarios are presented in Table 14. These are informed by the sensitivity analyses conducted. Incorporated are the conversion losses applied for both charging and discharging. Transformer losses are applied for discharging back to the grid. Transformer losses on the charging side are already accounted for in the transmission and distribution losses applied on the generation side.

Table 14. BEV vehicle and infrastructure assumptions for year 2050

Vehicle Scenario	HD ZEV VMT Penetration	Vehicle Range (mi)	Charging/ Fueling Rate	Charging/ Fueling Locations	Charging/ Discharging Efficiency
CPR base case	14%	200	120 kW	Home base (BEV), All Stops (FCEV)	0.95/0.85
80% Reduction-BEV	40%	200	120 kW	Home base (BEV)	0.95/0.85
80% Reduction-FCEV	40%	200	3.6 kg/min	All Stops (FCEV)	N/A
Expanded HDV Electrification	75%	500 (LHDV/ MHDV) 400 (HHDV)	120 kW	All Stops (BEV, FCEV)	0.95/0.85

Sensitivity Analysis for Battery Electric Vehicle Feasibility

A sensitivity analysis was conducted to examine the impact of fuel efficiency, vehicle range, and EVSE assumptions on BEV feasibility. BEV feasibility can be measured in terms of either the percent of VMT that can be met by a specific BEV/EVSE configuration without modifying vehicle travel patterns. Another, equivalent measurement is the percent of vehicles that can be operated as BEVs under the same assumptions. The values presented in the analysis are percent of VMT and vehicle population for in-state vehicles. Out-of-state vehicles are not accounted for in total percentages. As previously stated, out-of-state vehicles account for 5% of light-heavy and medium-heavy duty vehicle miles traveled in California and 28% of heavy-heavy duty vehicle miles traveled in California. A reasonable range of current and near future fuel efficiencies is presented in Table 15 based on literature values as well as assumptions made in the Vision model and E3 PATHWAYS study [125], [228].

Current and near future BEV models report fuel efficiencies ranging from approximately 0.5 to 2.5 kWh/mi, depending on vehicle class and vehicle configuration. While there are limited data on current heavy duty FCEV models, Kast et al. (2017) simulated potential vehicle configurations for various vocations given known drive cycle behavior [227]. These vehicle results indicate that fuel efficiency is dependent on both a vehicle's gross vehicle weight rating and vocation, and for the purposes of this study a general average for vehicle category (light-heavy, medium-heavy, and heavy-heavy) can be determined. Additionally, Kast et al. (2017) calculated that on-board hydrogen capacity can meet 40% - 100% travel demands of the given vocations [227], based on the travel data used [229].

Current and projected vehicle fuel efficiencies are presented in Table 15. It is important to note that some values gathered are based on laboratory tests or simulations versus on-road driving. The values from on-road tests are noted in. Additionally, fuel efficiency is affected by payload carried. The scenarios developed will use the average fleet values calculated in previous work that take into account payload and varying fuel efficiency based on drive cycle [129], [228].

Table 15. Fuel Efficiencies and Vehicle Ranges Reported in Literature and Future Projections

Vehicle Category	**Current/Near Future Range Reported (mi)**	**Current Fuel Efficiency Reported (kWh/mi)**	**Vision Individual and Fleet Average Values** [228]	**E3 Pathways Values** [129]	
			Year 2050	**Year 2030**	**Year 2050**
Light-Duty	100 – 310	0.25 – 0.51	0.16 – 0.58 Avg. 0.20	0.22 (auto), 0.30 (truck)	0.17 (auto), 0.24 (truck)
Light-Heavy	25 – 145	0.55 – 0.74	0.76 – 1.37 Avg. 0.95	1.03 (combined), 1.85 (buses)	0.97 (combined), 1.45 (buses)
Medium-Heavy	80 – 300	1.34 – 1.90	1.62 – 2.09 Avg. 1.80		
Heavy-Heavy	102 – 500	1.97 – 2.47	2.11 – 6.61 Avg. 2.42	2.06	1.96

Conversion assumptions for table are: 1 kWh = 0.030 Gallons Gasoline Equivalent (GGE), 1 Diesel Gallon = 1.155 GGE, 1 GGE = 0.112 MMBTU, 1 kWh = 0.026 Diesel Gallon [230]

This analysis calculates the upper and lower bound for BEV feasibility, given the range of projected fuel efficiency values for a selection of vehicle range and EVSE assumptions. BEV feasibility is calculated as a percent of in-state vehicles only. The different configurations are listed in Table 16. Charging efficiency is assumed to be 0.85 for level 1 (<1.9 kW), 0.9 for level 2 charging (>1.9 kW, <= 19.2 kW) and 0.95 for level 3 charging (>19.2 kW). The results of the sensitivity analysis are summarized in Figure 50.

Table 16. Parameters for BEV Sensitivity Analysis

Vehicle Category	Low Fuel Efficiency (kWh/mi)	High Fuel Efficiency (kWh/mi)	Charging Locations	Charging Rates (kW)	Vehicle Range
Light-heavy	1.37	0.55	Home base, All Stops	1.33 - 200 kW	100, 200, 500
Medium-heavy	2.09	1.34	Home base, All Stops	1.33 - 200 KW	100, 200, 500
Heavy-heavy	6.61	1.97	Home base, All Stops	1.33 -200 kW	100, 200, 500

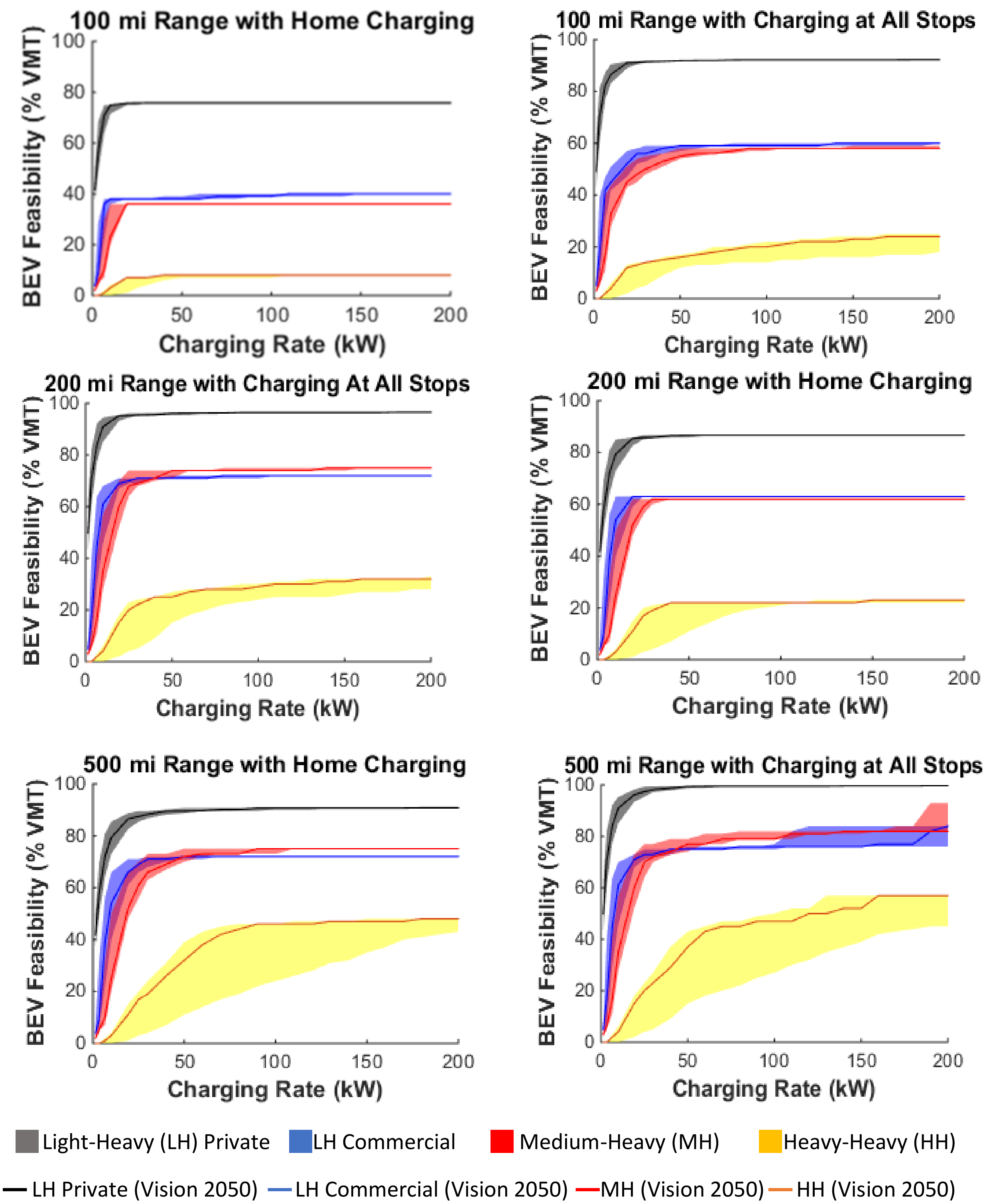
Comparing the different vehicle categories, the trip distribution for each vehicle category drives what the maximum BEV feasibilities are for different vehicle range configurations. Despite an overlap in fuel efficiency values between low efficiency MHDV and high efficiency HHDV categories, HHDVs have much lower BEV feasibility compared to MHDVs. This difference is the direct result of HHDVs having a much greater percentage of long-distance trips compared to MHDVs. Conversely, LHDVs and MHDVs also have overlap between their lower and upper bounds of fuel efficiency, respectively, and at lower ranges and charging rates, have very similar levels of BEV feasibility. This is due to their similar proportion of trips under 200 miles from home base. This trend shifts at higher vehicle ranges and charging rates. In fact, despite a greater energy demand per mile, because MHDVs have a smaller percentage of long-distance trips (>500 miles from home base) (1% versus 3% for LHDVs), MHDVs have a higher BEV feasibility than LHDVs under certain configurations with higher level 3 charging rates.

Examining BEV feasibility in terms of percentage of vehicles converted to BEVs shows that a relatively large percentage of vehicles can be electrified with vehicle ranges of 100-200 miles and home base charging. However, these are the vehicles traveling short distances and therefore, they make up a smaller percent in terms of total VMT, for example: 76% of the light-heavy duty vehicle population can be electrified with 100-mile range BEVs with home base charging at a peak level 2 rate, but this encompasses only 40% of the VMT from in-state vehicles.

As demonstrated in this sensitivity analysis, BEV feasibility is strongly dependent on travel patterns, vehicle range, fuel efficiency achieved, and EVSE available. In general, BEV feasibility increases with greater vehicle range, higher charging rates, and increased access to EVSE—home base versus all-stops (all dwell locations). As charging rate increases, the difference between high and low fuel efficiency decreases; trip distance becomes a limiting factor in BEV feasibility. For this reason, increasing the charging rate to higher level 3 capacities does not always yield improved feasibility.

For at home charging, there are only marginal improvements in BEV feasibility after level 2 – 19.2 kW with a vehicle range of 100 miles and after level 3 – 80 kW with a 200 to 500 mile range except for least efficient heavy-heavy duty vehicles with a 500 mile range, which see similar levels of improvement up to the maximum charging rate tested of 200 kW. Once route distance becomes a limit to BEV deployment, charging other locations beyond home base are required to increase BEV feasibility. Allowing heavy duty vehicles to charging anywhere they dwell for 15 minutes or longer increased the BEV feasibility of all vehicle categories, with level 3 charging rates up to 200 kW continuing to increase the percent of VMT electrified, especially for heavy-heavy duty vehicles. Charging at all stops increased the maximum BEV feasibility most significantly compared to home base charging for short range vehicles.

Figure 50. Sensitivity analysis on parameters affecting BEV feasibility: a) 100 mi range with home base charging, b) 100 mi range with charging at all stops, c) 200 mi range with home base charging, d) 200 mi range with charging at all stops, e) 500 mi range with home base charging, and f) 500 mi range with charging at all stops



Comparing the two different charging location strategies—home base only and all-stops—the increased access to charging stations with all-stop charging results in an increase in BEV feasibility. For vehicles with a range of 100 miles, LHDVs had a 50% increase in VMT electrified with all-stop charging compared to home base only charging, MHDVs, a 64% increase, and HHDVs, a 175-238% increase depending on fuel efficiency. There remains to be a benefit to all-stop charging in terms of BEV feasibility at higher vehicle ranges, but there are diminishing returns. For vehicles with a range of 500 miles, the increase in VMT electrified for LHDVs is 17%, for MHDVs, 12-24%, and HHDVs 6-21%.

Sensitivity Analysis for Fuel Cell Electric Vehicle Feasibility

FCEV refueling frequency depends on vehicle technical specifications assumed. Refueling frequency depends on vehicle miles traveled. In the cases that a trip distance exceeds the vehicle's range, it may be assumed that the vehicle cannot be a FCEV. This assumption is to maintain the same operational constraints as for the BEV sensitivity analysis. For this sensitivity analysis, it is assumed that the vehicle is able to refuel during a dwell period if it is 15 minutes or more. The FCEV parameters for the sensitivity analysis are in Table 17.

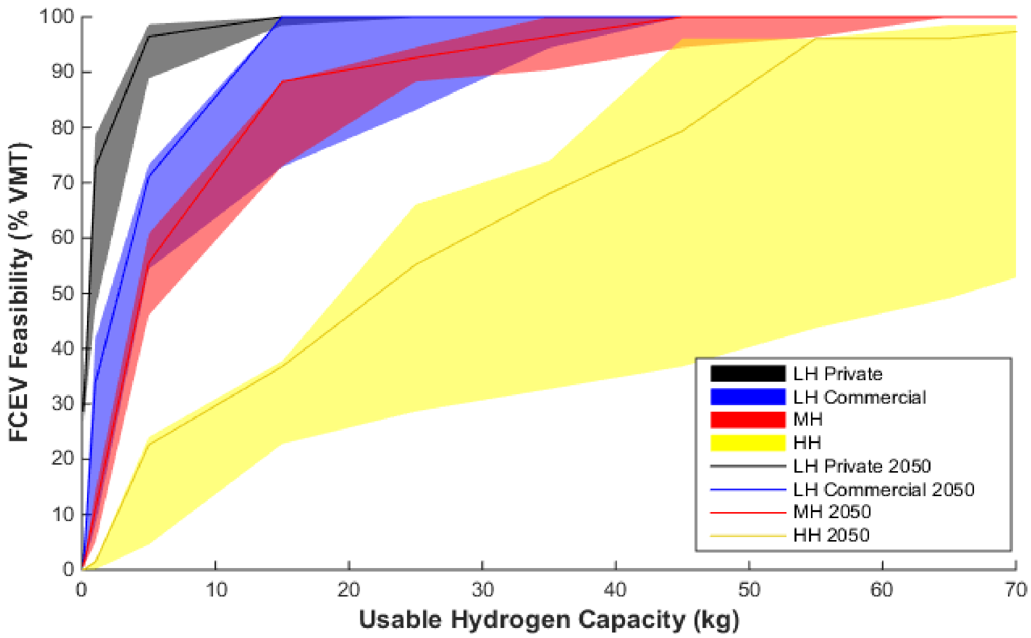
Table 17. Parameters for FCEV Sensitivity Analysis

Vehicle Category	Low Fuel Efficiency (mi/kg H_2)	High Fuel Efficiency (mi/kg H_2)	Vehicle H_2 Capacity (kg)
Light-heavy	15**	23.6*	1 - 70
Medium-heavy	11.1*	15**	1 - 70
Heavy-heavy	4.79+	11.2**	1 - 70

* Values from Kast et al. (2017) [227], ** Values from E3 PATHWAYS [129], + Value from Chandler and Eudy (2008) [231]

The results of the sensitivity analysis are in Figure 51. A 100-mile range is equivalent to a tank capacity of 4.2 – 6.7 kg H2 for light-heavy duty vehicles, 6.7 – 9 kg H2 for medium-heavy duty vehicles, and 8.9 – 20.9 kg H2 for heavy-heavy duty vehicles. The wide span of potential hydrogen capacity requirements for heavy-heavy duty vehicles is due to the wide range in fuel efficiency values found in the literature. A 200-mile range is equivalent to doubling the tank size of the 100-mile range results, and a 500-mile range is equivalent to increasing the 100-mi tank size 5x.

Figure 51. FCEV Feasibility Assuming No Trip Interruption for Different H_2 Capacities



Like the results for BEV feasibility, medium-heavy duty vehicles see an increase in FCEV feasibility as a percent of total VMT compared to low-efficiency light-heavy duty vehicles. Again, this is driven by the varying trip distributions for each vehicle category. Medium-heavy duty vehicles have fewer long trips (+500 miles from home base) compared to light-heavy duty vehicles. Fewer longer distance trips which cannot met by short-range ZEVs results in a greater percent of total VMT met.

A comparison of ZEV feasibility for different vehicle range assumptions is presented in Table 18. Home base only charging is denoted “H” and all-stop charging, “AS”. FCEVs can meet a greater percent of VMT for all range assumptions compared to BEVs for the three heavy duty vehicle categories. For the configurations examined, the 100-mi BEVs with home base charging have the lowest feasibility in terms of VMT electrified. As the BEV range increases, the percent of VMT captured increases both in absolute terms and as a percent compared to FCEVs. However, in order for BEV and FCEVs to support equivalent VMT levels, the BEVs need a 500-mile range and charge at least 200 kW.

Table 18. Comparison of Feasibility (% VMT) for FCEVs and BEVs at Maximum Charging Rate

	100 mi Range			200 mi Range			500 mi Range		
	FCEV	**BEV (H)**	**BEV (AS)**	**FCEV**	**BEV (H)**	**BEV (AS)**	**FCEV**	**BEV (H)**	**BEV (AS)**
Light-heavy (private)	92%	76%	92%	97%	87%	97%	100%	91%	100%
Light-heavy (commercial)	60%	40%	60%	72%	62%	72%	84%	72%	84%
Medium-heavy	59%	36%	59%	76%	61%	75%	94%	75%	93%
Heavy-heavy	27%	8%	27%	38%	23%	34%	68%	48%	58%

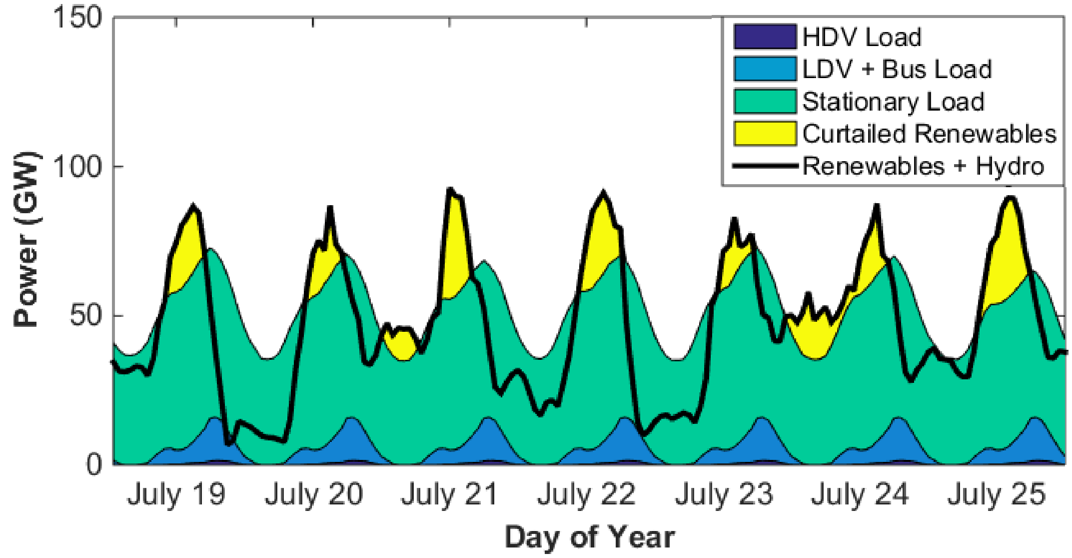
Quantifying the Impacts of V2G Services

This section presents the results of the electrification scenarios outlined in Table 13. These results suggest that the impact of vehicle electrification on the electric grid is dependent on the scale and timing of vehicle demand. If vehicle demand aligns with renewable availability, electrification can increase renewable utilization. Alternatively, if it does not align with renewable generation, it may negatively impact the grid's balancing requirements: increasing ramping rates, peak demand, and fossil fuel generation. The deployment of zero-emission HDVs with intelligent charging can help mitigate these impacts and potentially provide a net benefit in terms of grid performance and levelized cost of energy (LCOE).

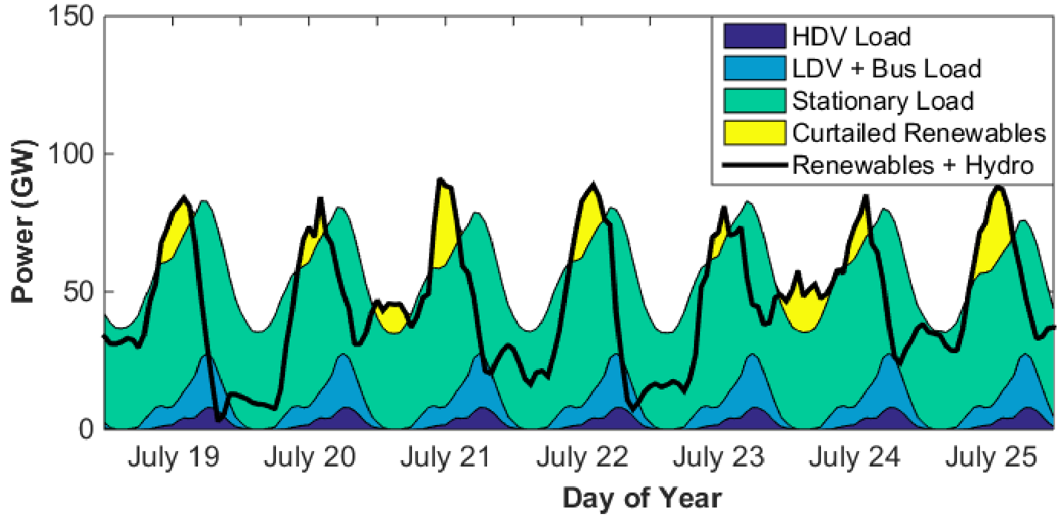
Comparing the results from the CPR base case with immediate charging and the 80% reduction in GHG emissions from the transportation grid, see Figure 52, increased BEV load demand tends to occur across the day and peak in the evening, when renewable generation is decreasing. While some of this new load can be met with previously excess renewables, a significant portion cannot.

The electric load demand that falls above the renewable availability (black line), often called the "net load," needs to be met with other dispatchable generation. In the case of California, this generation comes from natural gas simple cycle ("peaker") and combined cycle ("load-follower") plants. The proportion of peaker and load follower power plants required to meet the net load demand is dependent on the net load profile for each case. Rapid changes in electricity demand require peaker plants, which can ramp their power output up and down more quickly than load-followers, however, they are also more expensive and less efficient.

Figure 52. Timeseries of electric load demand versus renewable availability in 2050 for a) CPR base case with immediate charging and b) 80% reduction with immediate charging



a)

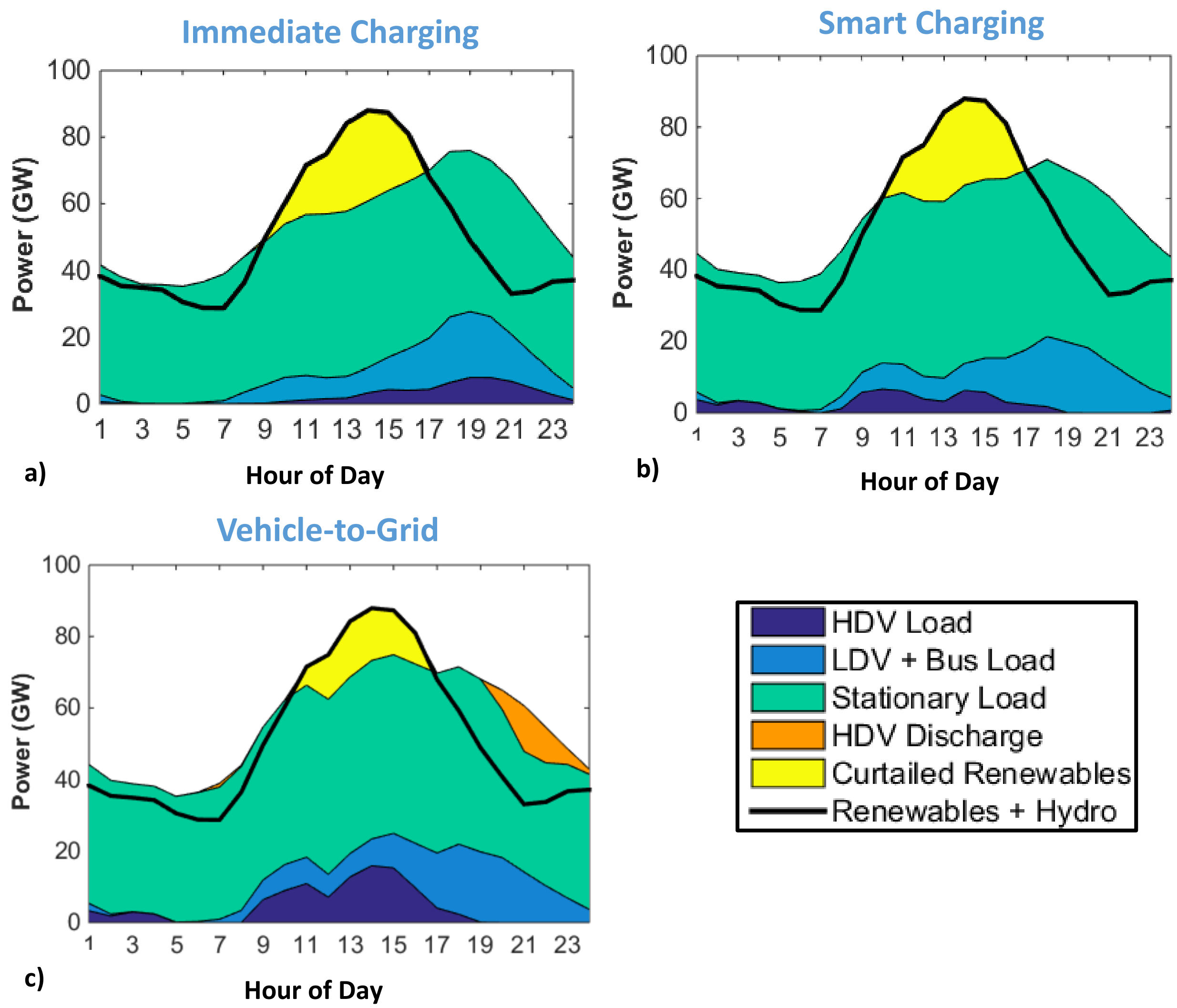


b)

Renewable Utilization and Balancing Fleet Operation

Increasing charging intelligence can allow the vehicle fleet to shift when charging occurs, so that electricity demand can better align with renewable availability, see Figure 53. In the scenarios presented, switching to smart charging almost eliminates charging during peak times, and instead, heavy duty BEVs charge in the early morning and during the day.

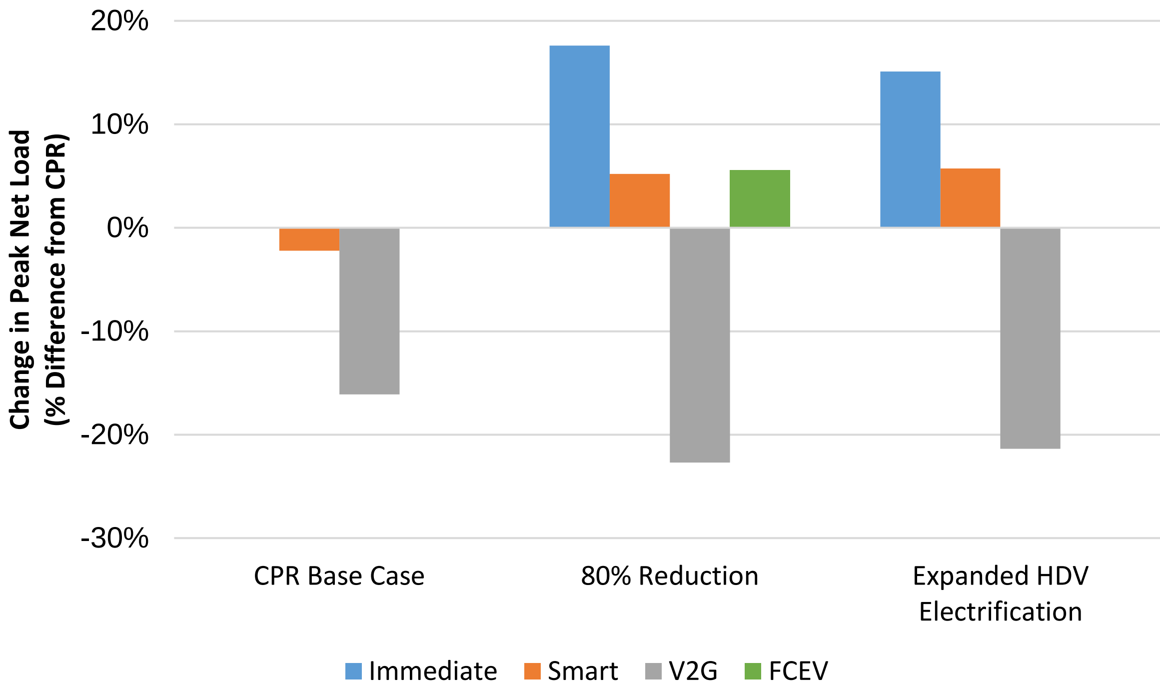
Figure 53. Sample days for the 80% reduction scenarios: a) immediate charging, b) smart charging, and c) Vehicle-to-Grid



Switching to V2G enables heavy duty BEVs to not only avoid charging during peak demand times, they are able to discharge during these periods, further reducing the demand for non-renewable generation. Because vehicles can discharge their batteries during the evening to support the electric grid, vehicles tend to start their days with a lower state-of-charge (SOC). A lower SOC means that the vehicles have a greater capacity to charge during the day (within charging infrastructure constraints), and therefore, capture more "otherwise curtailed" renewable generation, increasing overall renewable utilization.

Peak net load demand for all scenarios are presented in Figure 54 (80% GHG reduction from the grid) and Figure 55 (100% Clean Electric Grid-before energy storage ("ES") deployment).

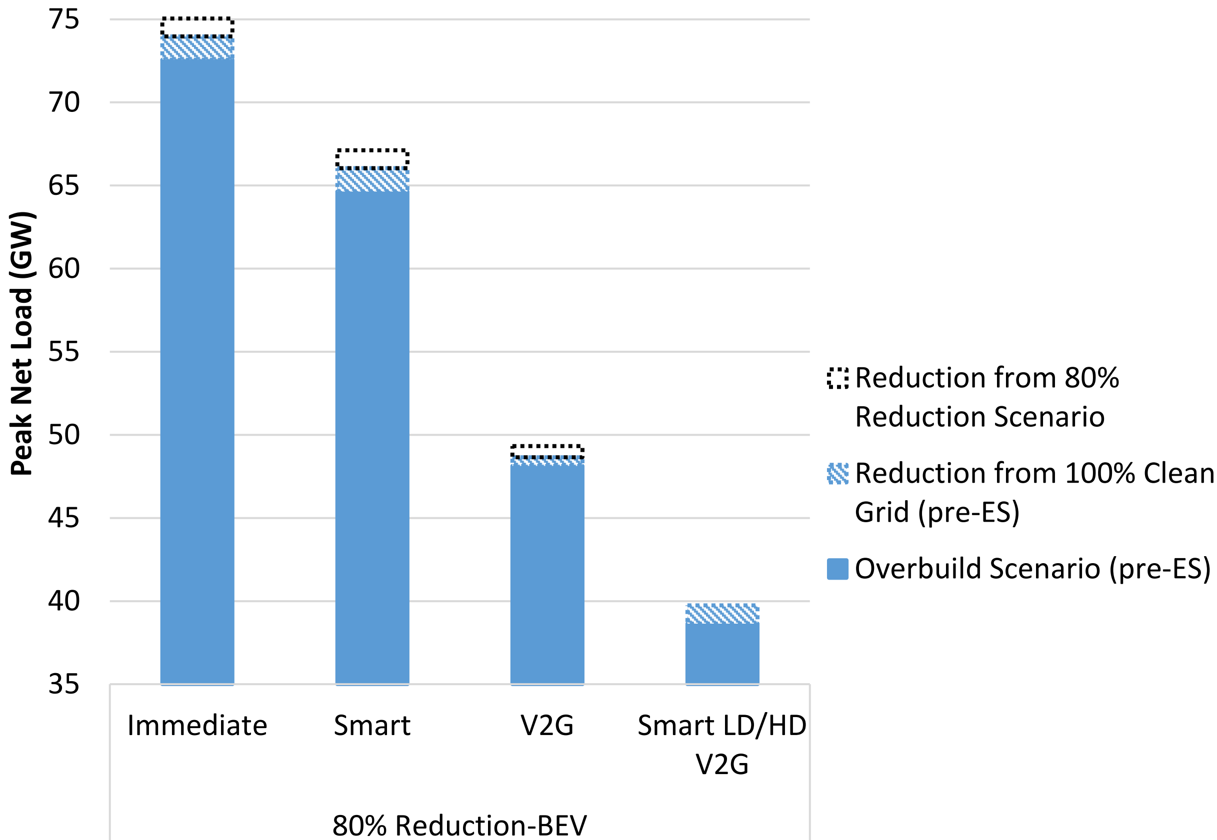
Figure 54. Change in peak net load demand for all 80% GHG reduction scenarios compared to CPR base case with immediate charging



The greatest net load peak is observed for the 80% Reduction scenario. Even though there are fewer vehicles being electrified in this scenario, they are using home base charging only, which can result in higher peak loads compared to all-stop charging (used in the expanded HDV electrification scenario). Shifting to smart charging still results in an increased in peak demand compared to the CPR base case, but the new peak values are reduced compared to the same vehicle scenarios with immediate charging. Switching to V2G results in a reduction in peak net load. This reduction is because vehicles discharge during peak net load times, offsetting the need for non-renewable generation. FCEV deployment with electrolytic hydrogen production also results in an increase in peak net load, indicating that, at times, hydrogen needs to be produced when there is insufficient renewable availability. The increase in peak net load is in line with smart charging of an equivalent population of BEVs.

Increasing the renewable capacity of the electric grid can also affect the peak net load, see Figure 55. Increasing the renewable capacity by 20% or even 50% can have marginal reductions in the peak net load. Nevertheless, vehicle charging intelligence has a greater impact on the peak, with smart light duty vehicles and V2G-enabled heavy duty vehicles having the potential to reduce peak net load by 47% for the scenarios presented.

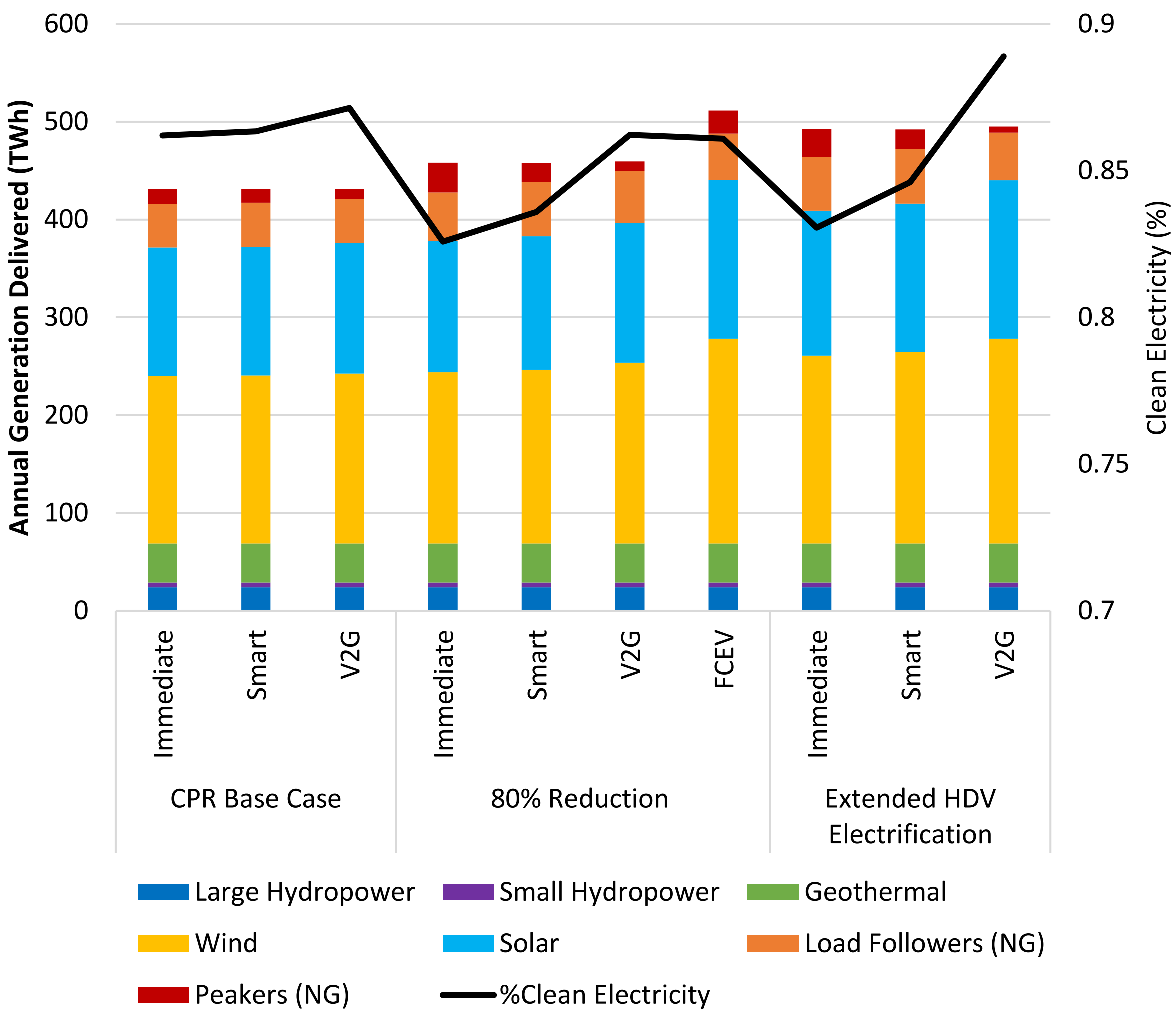
Figure 55. Change in peak net load (before energy storage) for increasing renewable capacity under the 80% reduction in GHG emissions from transportation scenarios



The electricity delivered by generation source for the 80% reduction in grid GHG emissions is presented in Figure 56. Increased charging intelligence for each expanded vehicle results in marginal increases in renewable penetration associated with an increase in the percentage of the BEV load met with renewable generation. Increased charging intelligence also decreases the reliance on peaker plants. Allowing vehicles to discharge back to the grid during peak demand times further reduces the number of periods when peaker plants would have otherwise provided power. In addition to reducing peaker plant generation, the V2G scenarios reduce load following generation.

The higher total load demands for the FCEV scenario comes from the lower efficiency of hydrogen production versus BEV charging, requiring increased load demand to supply the same amount of VMT. Electrolytic hydrogen production for FCEVs results in greater renewable utilization compared to the BEV scenarios. However, the V2G scenarios are more effective in reducing generation from natural gas power plants compared to the FCEV because vehicles discharge back to the grid and reduce the times when natural gas is needed.

Figure 56. Generation by resource for all 80% GHG reduction scenarios



GHG Emissions

The integration of renewable electricity is primarily driven by the goal of reducing GHG emissions. Therefore, assessing the impact of deploying heavy duty zero-emission vehicles on overall GHG emissions is critical. In order to determine the net impact of ZEV deployment, the changes in GHG emissions from both the grid and the transportation sector are assessed. The grid and transportation GHG emissions are calculated in tons of CO_2e using the following equation:

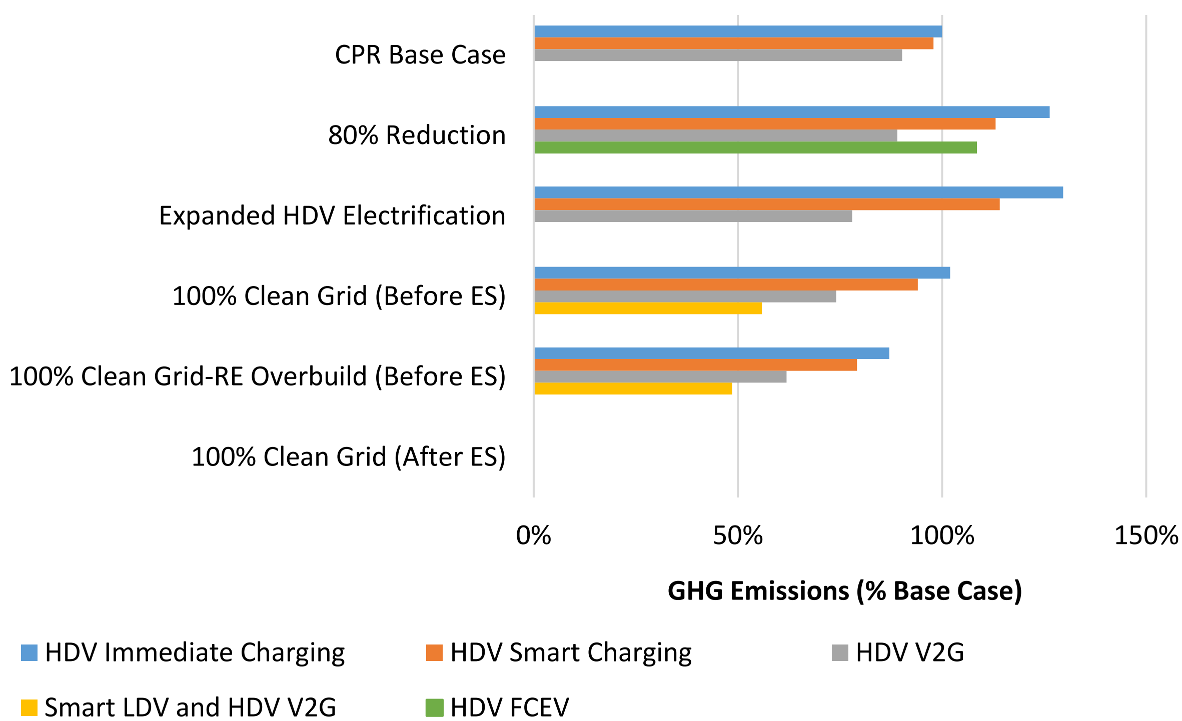
Equation 11. Carbon Dioxide Equivalency Based on 100-year GWP

$$CO_2e = 1CO_2 + 25CH_4 + 298\ N_2O$$

where, tons of carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O) are weighted by their 100-year global warming potential values relative to CO_2. Carbon dioxide is the predominant GHG produced by electricity production and transportation, with a weighted contribution of around 95% of the total tons of CO_2e.

Increases in the ZEV populations will decrease emissions from the transportation sector, but integrating them onto the electric grid, either directly through BEVs or indirectly through hydrogen production, may have positive or negative impacts on the electric grid's GHG emissions, depending on how they are integrated. The change in grid GHG emissions for each scenario is in Figure 57.

Figure 57. Change in Grid GHG Emissions for All 80% GHG Reduction Scenarios



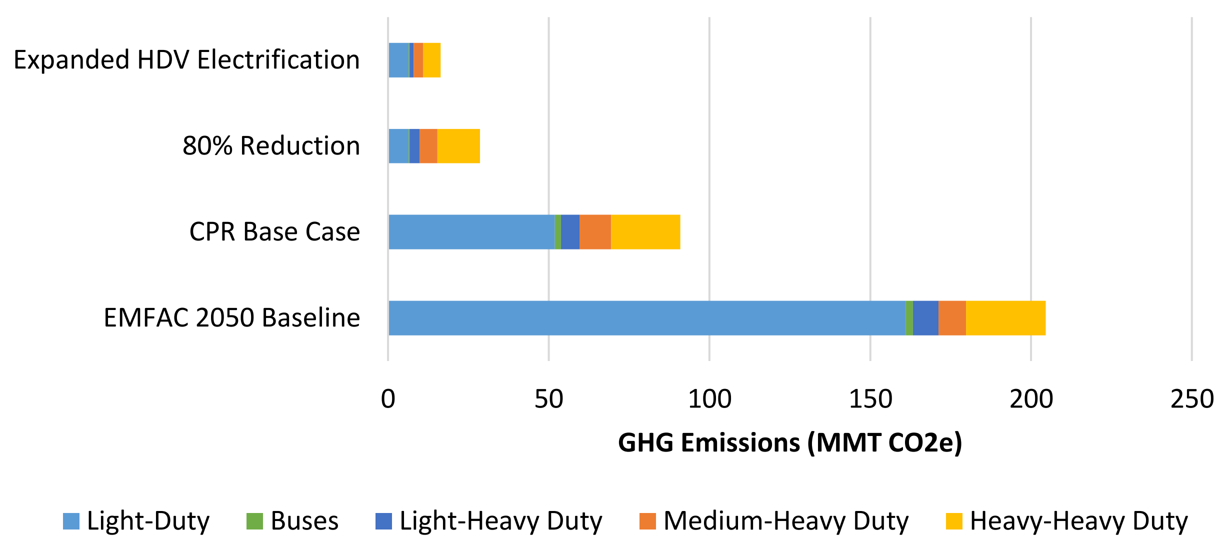
The CPR base case with immediate charging represents the approximate grid emissions reductions needed to support an economy-wide 80% in GHG reductions compared to 1990 levels. Emissions from the electric grid come from two sources: load-following natural gas combined cycle power plants and natural gas peaker power plants. The change in grid GHG emissions between the scenarios is a fraction of the remaining 20% of emissions still being emitted. In the highest GHG emission case-Expanded HDV Electrification with immediate charging, this translates to a 74% reduction in GHG emissions below 1990 levels. The greatest reduction is observed for the 100% clean electric grid and overbuild scenarios when energy storage is deployed to ensure a zero-emission grid.

Increasing heavy duty vehicle charging intelligence results in reduced grid GHG emissions. Switching to smart charging is more effective in reducing grid GHG emissions for scenarios with higher heavy duty BEV deployments (80% Reduction versus Expanded HDV electrification). Increasing charging intelligence to V2G further reduces emissions from the respective immediate charging scenarios. The 80% reduction scenario with V2G charging results in GHG emissions lower than the CPR base case.

When renewable capacity increases (80% Reduction compared to the 100% Clean Grid), vehicle electrification with immediate charging has a smaller negative impact on grid GHG emissions, and in the overbuild scenario, the higher renewable availability results in a net reduction in grid GHG emissions compared to the CPR base case.

Emissions reductions from the transportation sector are presented in Figure 58. Emissions for the EMFAC 2050 Baseline are taken from [133] and emissions factors are calculated from [129], [133], [232]. The EMFAC 2050 Baseline does not incorporate any policies mandating the adoption of ZEVs, the CPR base case incorporates current policies, and the 80% reduction and expanded HDV electrification scenarios include 80% GHG reduction targets for light-duty and bus categories (kept constant between the scenarios). The expanded HDV electrification scenario represent a greater than 80% reduction in GHG emissions from the HDV sector. Decreasing transportation vehicle emissions below an 80% reduction may offset increased emissions from the grid. Also, the higher reduction in emissions may have increased benefits in terms of air quality.

Figure 58. Change in Transportation GHG Emissions for All Scenarios



Emissions reductions from the transportation sector are driven by the number of vehicle miles that can be met with ZEVs. Switching between FCEVs and BEVs with immediate, smart, or V2G charging strategies for the same deployment level does not change the emissions reductions from the transportation sector.

Levelized Cost of Energy

The levelized cost of energy for the electric grid is the cost of energy delivered, levelized over the lifetime of the grid resources. It incorporates costs and resource operating parameters for each deployed technology, such as capital costs, operation and maintenance costs, fuel costs, the lifetime of each resource, and capacity factors [233]. The LCOE values for this analysis are calculated using the existing HiGRID Cost of Generation module, with updated costs for level 3 EVSE as well as transformer costs in order to account for the higher charging rates required for HDVs compared to LDVs. The costs for electrolyzers are taken from the optimistic and conservative projections presented earlier in this report. Values from Wang et al. (2019) are used for hydrogen storage and supply. Electrolyzer costs from the same analysis are used as a comparison to the calculated optimistic and conservative estimates [44].

Transformer upgrades will most likely be required for level 2 charging in residential areas and for level 3 charging in commercial areas [216]. The BEV and FCEV infrastructure costs used in this analysis are in Table 19, Table 20, and Table 21. This analysis assumes alkaline electrolyzers are deployed to produce renewable hydrogen for FCEVs. The costs for solid oxide and PEM electrolyzers are provided for comparison. The transformer upgrade cost and intelligent charging equipment are included as separate costs in the table but are added to the instant cost in the model. Costs for installing and operating level 3 chargers are based on existing projects, but due to the variability of location-specific costs as well as the relatively small-scale of level 3 EVSE that have been installed, these costs may evolve in the future. Additionally, smart and V2G charging strategies are still in development, so the intelligent charging costs may also evolve as the technologies mature.

Table 19. LCOE Parameters for BEV Infrastructure

	Level 2 **(19.2 kW)**	**Level 3** **(40 kW)**	**Level 3** **(120 kW)**	**Level 3** **(350 kW)**
Instant Cost ($/kW)*	157.70	1200	650	384.00
Fixed O&M ($/kW-yr)**	131.80	96.00	50.00	50.00
Variable O&M ($/MWh)**	0	0	0	0
Transformer Upgrade ($/kW) +	69.44	65.00	72.22	74.29
Intelligent Charging Equipment ($/kW) ++	221.35	106.25	35.42	12.14

* Values from [216], [234], ** Values from [44], +Transformer upgrades costs based on price for 225 kVA and 1000 kVA transformers and the number of chargers that can be supported per transformer [216], [235]–[237], ++Smart/V2G Charging hardware/software upgrade assumed to be $4250 per charger [216], [238]

Table 20. LCOE Parameters for Electrolyzers from Wang et al. (2019) [44]*

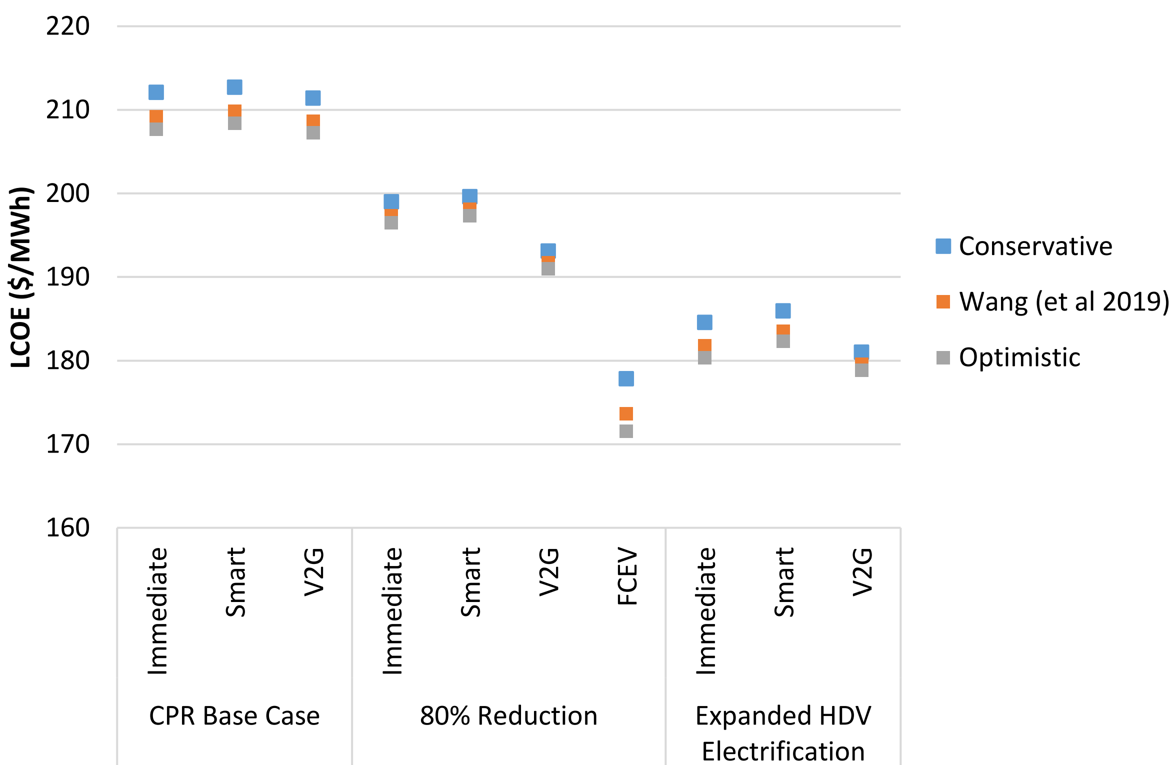
	Alkaline Electrolyzer, Onsite for Fueling Station	**Solid Oxide Electrolyzer, Onsite for Fueling Station**	**PEM Electrolyzer, Onsite for Fueling Station**
Instant Cost ($/kW)	289.62	466.60	398.30
Fixed O&M ($/kW-yr)	10.43	15.40	14.32
Variable O&M ($/MWh)	1.24	13.00	0.17

Table 21. Task 1 Conservative and Optimistic Costs for Electrolyzers

	Alkaline Electrolyzer	**Solid Oxide Electrolyzer**	**PEM Electrolyzer**
Conservative Instant Cost ($/kW)	603	899	906
Optimistic Instant Cost ($/kW)	132	191	199

The results of the LCOE analysis are presented in Figure 59. Despite the cost of installing BEV and FCEV infrastructure, the increase in the renewable electricity utilization by ZEVs results in a decrease in LCOE. This trend continues as more ZEVs are integrated (Expanded HDV Electrification scenario). Comparing the BEV and FCEV scenarios under the 80% reduction case, where there is an equal level ZEV deployment, the FCEV scenario results in a greater utilization of otherwise curtailed renewable electricity and therefore, despite FCEV infrastructure costs, they result in lower levelized cost per megawatt-hour.

Figure 59. Levelized Cost of Energy for 80% Grid GHG Reduction Scenarios



Comparing the conservative and optimistic costs for electrolyzers, the greatest difference occurs in the 80% reduction-FCEV scenario, where there is the greatest utilization of electrolytic hydrogen for FCEVs.

The difference between the conservative and optimistic case for this scenario is about $6/MWh (less than 1 cent/kWh). This scenario also has the greatest reduction in LCOE compared to the CPR base case (immediate charging), with a reduction of $34-36/MWh. The electrification level (% VMT electrified) and the vehicle choice (BEV versus FCEV) have a greater impact on LCOE than charging intelligence.

Discussion on Barriers to Heavy-Duty ZEV Deployment

This analysis focuses on the technical feasibility of heavy duty zero-emission vehicle adoption and utilization as grid resources through intelligent charging and V2G. Throughout this work, several barriers to the deployment of heavy duty ZEVs have been identified. The following is a discussion of these key barriers which will need to be addressed in order to achieve widespread deployment of heavy duty ZEVs.

Vehicles

Zero-emission heavy duty vehicles are an emerging market and as such, there are a limited number of vehicle models currently available. Of the vehicle categories and vocations that comprise the heavy duty sector, early ZEV models have focused on class 8 drayage, buses, and delivery trucks [231], [239]–[244]. If ZEVs are to expand across the heavy duty sector, more vehicle models will need to be released. As the heavy duty ZEV market grows, improvements in vehicle performance are projected, including increased vehicle range and decreased weight [125], [128]. Vehicle weight is particularly of concern for BEVs, as high battery weights can have negative impacts on fuel efficiency and maximum payload [245]. In addition to vehicle model expansion, cost is an important factor in determining whether fleet operators will purchase ZEV options. Cost considerations of switching to ZEVs can not only include cost of the vehicle but also fuel costs, O&M costs, and vehicle lifetime.

Infrastructure

The moderate to high levels of BEV and FCEV deployment modeled in this analysis assume that there is enough infrastructure to support charging and refueling requirements. Most of this infrastructure does not yet exist and will need to be constructed faster than or at the same rate as heavy duty ZEV adoption. BEV infrastructure expansion will require the construction of charging stations with the capability to support fleets of heavy duty vehicles charging at higher (level 3) rates. Decisions must be made on the location of these charging stations, who will have access to them, and who will incur the cost of building and operating them. Recently, Tesla has partnered with several companies, including PepsiCo, to construct fast charging stations at the companies' facilities. PepsiCo has said that it is open to sharing stations with other companies, citing the potential to distribute costs [246].

Upgrades to the electric grid transmission and distribution systems will depend on the location and scale of infrastructure required to support the future electric vehicle populations. Higher BEV charging rates will put greater constraints on local transformers and bidirectional charging/discharging will require both hardware and software upgrades. Like charging stations, these upgrades will need to be financed and costs recovered.

Most hydrogen refueling stations in California have relatively low hydrogen capacities (100-200 kg), suitable for serving a small population of light-duty vehicles. Currently, buses and trucks supported by these facilities tend to schedule refueling events during off-peak periods or have their own dedicated facilities that are not available to the public [247]. As heavy duty FCEVs become a more prominent, larger hydrogen refueling stations along truck routes will be needed to support the vehicles. For example, the CARB-funded project organized between the Port of Los Angeles, Toyota, Shell, and Kenworth is currently constructing two new hydrogen refueling stations to support the deployment of class 8 fuel cell trucks at the port [248]. Future hydrogen stations may need to be large enough to accommodate a mixture of vehicle types and higher overall demand as FCEV populations grow. Additionally, hydrogen delivery and storage methods will need to support higher throughput through hydrogen stations.

Grid Services and Battery Degradation

While higher charging rates and vehicle-to-grid discharging can increase BEV feasibility and improve grid services, both can also speed up battery degradation [249]. Factors affecting the rate of battery degradation include energy throughput, cycling patterns, (dis)charging rates, depth of discharge, and temperature. Battery degradation tends to increase with higher energy throughput, greater cycling, higher charging rates, greater depth of discharge, and higher temperatures [249]–[251].

Heavy-duty vehicles will require higher charging rates than most light-duty vehicles, which can, in turn, have negative impacts on battery life. In an experiment with four Nissan Leafs, Idaho National Laboratory compared level 2 and fast charging on battery degradation. It found that total distance traveled had a larger impact on battery degradation than charging rate, with all vehicles having a 22-25% reduction in energy capacity after traveling 40,000 miles. The increased degradation from fast charging amounted to about an additional 4% loss in energy capacity [252].

Wang et al. (2016) found that providing V2G services increased battery degradation, with the degree of degradation a function of which services were provided and how frequently. In their analysis, for the extreme case of providing services every day, battery life decreased from about 9 years in the base case to 5 years for net load shaping, 7.5 years for peak load shaving, and 8 years for frequency regulation [249]. Bishop et al. (2013) in their analysis calculated that battery replacement could occur as frequently as 1-3 years depending on depth of discharge when providing V2G services [250]. Most analyses examining battery degradation for grid services focus on light-duty PEVs [249]–[251]. Heavy-duty vehicles have different drive cycles and greater overall energy use, which warrant further research into the impact that providing grid services might have on battery-electric heavy duty vehicles. Furthermore, while this work has focused on V2G services from PEVs, there are no technical barriers to utilizing FCEVs for grid services and their use in a residential application has been demonstrated [253], [254].

In addition to technical considerations, utilities will need to establish formal market pathways for heavy duty zero-emission vehicles to participate in grid services in order for fleets to earn revenue from modifying their charging patterns. Potential revenue will be particularly important for fleets providing vehicle-to-grid services, as increasing the energy throughput of the vehicle battery may result in shorter battery life that translates to greater costs if fleets need to replace battery packs multiple times during the lifetime of the vehicle [255], [256].

1.5 Conclusions

- **The cost of electricity as an HDV fuel is greatly affected by infrastructure cost, which in turn is greatly affected by the assumed charging power, i.e., Level 1, Level 2, or Level 3. The infrastructure then directly impacts the feasibility of heavy duty BEVs.** The difference in cost of delivered electricity as a fuel for HDVs when using either level 2 or level 3 charging is approximately $8 per diesel gallon equivalent (DGE), due to the dramatic increase in electric charger cost for the higher power capacity. When applying LCFS credits, the cost for level 2-delivered electricity is very low, even slightly negative, while the cost for level 3-delivered electricity is the second-most expensive renewable fuel as modeled when assuming a conservative $100 per credit. The impact of altering the LCFS program to increase incentives for higher levels of electric charging would change the relative fuel cost between BEVs and FCEVs, and thus could have a substantial impact on resulting BEV and FCEV adoption. Furthermore, electric utilities have the ability to alter electricity prices through means such as time of use (TOU) rate structures, something that could be used to achieve a similar effect.
- **Renewable HDV fuel availability is limited by biomass availability but far less limited by electricity availability. An enhanced understanding of biomass allocation to various end-use sectors is needed to determine the actual biomass availability for the HDV sector (relative to other sectors including aviation, marine, off-road, etc.).** The availability of biomass is well-documented by the Billion Ton Report, but there is not agreement on how that biomass will be used in the different sectors of California. Such planning is needed and will have a direct effect on how much renewable HDV fuel can be made from these biomass resources. For electricity and electrolytic HDV fuel, limitations are much less stringent on electricity than biomass due to the ability to add renewable electricity generation at much larger scales than biomass farming for fuel production purposes.
- **Given the limited quantities of biogas and biomass feedstocks, as well as potential demands from competing sectors, electrolytic fuels will very likely be required in large scale transitions to hydrogen or RNG in the HDV sector.** Electricity is generally easier to install production capacity for than biomass, which requires farming, more land, and other logistical and environmental challenges. Having greater surplus feedstock can lead to more stable and lower electrolytic fuel costs in the long-term. Additionally, the dispatchable load characteristics of electrolytic fuel production can provide a significant benefit to the California electric grid and additional renewable generation is added.
- **RNG is best served by biomass feedstocks and the corresponding RNG production technologies from a cost perspective, unless a cheap source of carbon can be obtained for use in methanators to facilitate electrolytic pathways.** Carbon capture technologies post-combustion capture (PCC), direct air capture, and electrolytic cation exchange module (E-CEM) lead to much more costly RNG than the biomass-derived options. Methods of sourcing cheaper

carbon should be investigated and developed to make electrolytic production of RNG more cost-effective. Producing RNG from biomass costs \$3.40 to \$5.60 per diesel gallon equivalent (DGE), depending on the feedstock and production technology used. Producing RNG from electrolytic hydrogen and captured carbon costs \$86.50 to \$2500 per DGE, with most of that cost coming from the carbon capture technology used. Cheaper sources of carbon dioxide, such as integration with chemical processing plants or other industrial processes, are needed to make electrolytic production of RNG more cost-effective. This becomes increasingly valuable as the electric grid gets cleaner into the future.

- **LCFS and RFS can offer significant cost reduction to renewable diesel, particularly when using cellulosic biomass, as well as electricity fuel cost, both of which see reductions of roughly 30-60% depending on pathway. The cost of hydrogen and RNG fuel is not impacted as much, though reductions of up to 15% are realized for hydrogen and 19% for anaerobic digestion.** With an LCFS credit price of \$100 and an RFS D3 RIN price of \$1.5 yields a total incentive of \$7-8 per DGE. These incentives can make some renewable diesel production methods similar in cost to fossil diesel and the hydrotreated vegetable oil method often used for producing renewable diesel currently. This allows drop-in use of low or negative carbon intensity fuels in vehicles with conventional powertrains that are already on the road, a cost-effective method of meeting GHG legislation in the near-term.

- **Hydrogen costs are slightly above level 3-dispensed electricity. Electrolysis is a relatively efficient production method but requires the electric grid get cleaner over time to facilitate deep GHG reductions. Conversely, the gasification of biomass allows for the use of very low or negative carbon intensity biomass which can be a cost-effective method of producing low-carbon renewable hydrogen in the near- to mid-term.** Due to the relatively low installed base of electrolyzers, their cost can be dramatically reduced with support and increasing adoption. This would lead to reducing the cost of electrolytic hydrogen to the point that it becomes the cheapest method of producing hydrogen. As the electric grid reduces its emissions impact, this electrolytic hydrogen becomes a more cost-effective and clean fuel option.

- **RNG is most efficiently and cost-effectively produced by gasification of biomass feedstocks. Unless a more cost-effective source of CO_2 can be obtained for use in methanators to facilitate electrolytic pathways, electrolytic RNG is prohibitively expensive.** RNG produced from gasifiers is the most efficient pathway for RNG production studied, and it uses relatively low carbon intensity biomass as its feedstock. Furthermore, the dramatically high cost of carbon capture technology would need significant cost reduction before electrolytic RNG can be cost-competitive with biomass-derived RNG.

- **Electrolyzers, gasifiers, and anaerobic digesters are expected to have the greatest improvements in efficiency by 2050. At 2050, solid oxide electrolyzers (SOECs) are expected to be the most efficient method of producing hydrogen and both gasifiers and SOECs are expected to be the most efficient methods of producing RNG with similar efficiency.** SOECs are a relatively new electrolyzer technology that scientists and engineers are working hard to commercialize. This technology is already one of the most efficient electrolyzer technologies and it has more room to improve than most as well. Gasifiers are also a relatively new technology that have promisingly high efficiency, particularly for RNG production.

- **The future feasibility of battery electric vehicles for the heavy duty sector will depend on vehicle improvements.** Heavy-duty BEV models are still in development, with estimates on fuel efficiency and maximum battery capacity in flux. Most models currently have under 200 miles range. From this analysis, a 200-mile BEV charging along all-stops met up to 72-97% of VMT for classes 2B-7, 34% for class 8 vehicles. Converting some HDVs, especially for vocations with longer travel and more challenging drive cycles, will require increased battery capacity compared to current models. The increased weight of the battery may reduce the payload weight that can be added to the truck. Increased battery weight can also reduce the fuel efficiency of the vehicle as well as the achieved range. Reducing vehicle weight through vehicle redesigns and battery improvements can help counter these issues and increase ZEV utilization.

- **The ability of vehicles to support renewable integration is dependent on the scale of BEV deployment, charging intelligence, and charging location assumptions.** Vehicles charging only at home base may not capture solar generation, whereas, vehicles charging along their routes during the day have a greater ability to directly charge with solar generation. With immediate charging, home base charging peaks at 5 -9 pm, in line with peak stationary load. Alternatively, with charging at all stops, charging peaks between 12-2 pm, which aligns with peak solar. Vehicles with home base charging are able to utilize wind generation and can still provide valley-filling during evening decreases in demand when using intelligent charging strategies.

- **Enabling intelligent charging of BEVs is critical for reducing peak electricity demand.** Immediate charging of light-duty and heavy duty vehicles adds to peak demand periods, increasing the balancing generation capacity required. For a grid with natural gas power plants, increased peak demand and the associated ramping demand can increase the need for simple-cycle peaker plants and increase grid GHG and criteria pollutant emissions. For the 2050 scenarios investigated, switching from immediate charging to smart charging reduced peak demand by 2-12%, with greater reductions at larger vehicle populations. Switching from immediate to vehicle-to-grid reduces peak demand by 16-40%, again depending on vehicle population size.

- **The conversion of the heavy duty vehicle fleet to zero-emission vehicles to meet an 80% reduction in transportation GHG emissions may have positive or negative impacts on electric grid emissions depending on charging strategies.** Heavy-duty BEVs relying on immediate charging can increase peak load demand and exacerbate power plant ramping. Intelligent charging of heavy duty BEVs and renewable hydrogen production are both effective methods for utilizing otherwise curtailed renewable generation and reducing ramping requirements but may still increase grid GHG emissions if relying on natural gas power plants for grid balancing. Heavy-duty BEVs equipped with V2G capability can effectively reduce peak electricity demand and increase renewable penetration. At very high levels of heavy duty BEVs with V2G charging, grid GHG emissions can be halved compared to immediate charging.

- **Increased GHG emissions from the electric grid for the immediate and smart charging scenarios are more than offset by reductions in GHG emissions from the transportation sector.** While the grid emissions increase significantly under immediate and smart charging of a high penetration of heavy duty BEVs, the net impact is an overall reduction in system wide GHG emissions. In 2050, the greatest increase in grid GHG emissions is on the scale of 10 MMT CO_2e, whereas the decreases in the transportation sector range from 60 MMT CO_2e or more. The impact of the spatial shift in criteria pollutant emissions can be observed in the air quality results.

- **The integration of zero-emission vehicles onto the grid can reduce the LCOE due to the increased utilization of renewable generation.** The expanded heavy duty vehicle deployment scenarios resulted in a decrease in the LCOE. The High Hydrogen scenarios, which utilized the most otherwise curtailed renewable generation resulted in the greatest reduction in LCOE compared to the CPR base case (about 31% lower).

- **Heavy-duty ZEV deployment will require significant infrastructure expansion.** Expanding ZEV adoption will require investment in charging stations, grid upgrades, and hydrogen refueling stations to support ZEVs. Heavy-duty ZEVs require three or more times the energy per mile compared to light-duty ZEVs, and therefore, Level 3 charging will be required to support higher volumes of heavy duty BEVs and high capacity hydrogen refueling stations will be needed to meet the travel demands of FCEVs.

- **Reducing GHG emissions in the electric grid sector and/or transportation sector by more than 80% can provide greater flexibility to sectors that are not well-equipped to reduce their emissions.** In order to meet the 80% reduction in GHG emissions from 1990s levels, increases in grid or transportation emissions would need to be offset by another sector. Conversely, decreases in either grid emissions or transportation emissions beyond the 80% GHG emissions target may provide other sectors some flexibility in how much they reduce their emissions. A 100% clean electricity grid would provide further flexibility to other sectors. However, replacing equivalent reductions in GHG emissions in another sector may have varying impacts on air quality, due to differences in criteria air pollutant emissions between sectors.

1.6 Recommendations

- **Further work to determine a cost for logistics and labor of charging heavy duty PEVs is needed as this could significantly impact the overall cost of electricity as an HDV fuel.** Adopting a PEV can be cost effective for some fleets due to fuel costs. However, something not included in the present analysis is a quantitative cost associated with fleets working through the logistics of rearranging routes and the cost of labor for managing charging of the HDVs when adopting PEVs. The rearranging of routes is particularly a factor for BEVs due to their limited driving range.

- **Support for electrolytic fuels will likely be required across the full fuel pathway (production, distribution, and dispensing) including novel mechanisms (e.g. rate structures, raising hydrogen blending limits on the natural gas grid, etc.) for the provision of cost-effective electricity.** The cost of electricity is a critical determinant of electrolytic fuel pathways and requires consideration. For example, developing electric rate structures specific to transmission-connected renewable fuels facilities (e.g., electrolyzers and hydrogen liquefaction facilities) such as whole power market access and transmission charge would benefit both electrolytic hydrogen and RNG production.

- **Utility pricing structures and market participation rules may need to be updated in order to support heavy duty vehicle participation in grid services.** Increasing the charging intelligence of heavy duty BEVs resulted in increased charging peaks. The net impact is improved grid performance at the regional scale. However, in order to achieve load smoothing, it requires that vehicles are not penalized for increasing local peak demand. As previously discussed, commercial buildings are charged a "Demand Charge" based on their peak electricity use to disincentivize them from exceeding local transformer limits, which may result in transformer repair and upgrade costs. However, demand charges would be a disincentive to vehicles to provide certain grid services. Utilities must consider, as BEV adoption grows, which is more valuable: to have dynamic load support or to limit transformer upgrades.

2. Emissions Implications of Heavy Duty Connected and Automated Vehicles

2.1 Introduction and Background

The transportation sector is rapidly integrating robotics and communications technologies, creating connected and automated vehicles (CAV). "Connected" refers to technologies allowing the transfer of information between the vehicle and either a) other vehicles—vehicle-to-vehicle (V2V), b) infrastructure—vehicle-to-infrastructure (V2I), c) the internet or other cloud-based service—vehicle-to-cloud (V2C), or d) everything—vehicle-to-everything (V2X) [257], [258]. A more general term, machine-to-machine (M2M), has recently been formally introduced for CAV to refer to any configuration [259]. "Automated" refers to features that reduce driver input for vehicle operation. The main goals of CAV technologies are to improve vehicle performance, environmental impacts, safety, and/or mobility [260], [261].

CAV technologies as applied to light duty vehicles tend to make up the bulk of media interest, but significant advances are being made in the medium and heavy duty vehicle sectors as well. The integration of CAV technologies can reduce fuel consumption and improve system efficiency, resulting in overall lower commercial trucking costs, as fuel and driver wages account for two-thirds of trucking operational costs [262]. While such economic motivation could help guide trucking companies to adopt robotic systems, the environmental benefits of HD-CAV adoption could also help domestic policymakers reach environmental goals. On-road CAV testing is supported through government regulations and programs, such as the California DMV Autonomous Vehicle Tester Program and Autonomous Vehicle Driverless Tester program [263].

HD-CAVs have the potential to reduce fuel consumption and emissions, both criteria pollutants and greenhouse gases (GHG), but have a plethora of secondary, and yet unknown, impacts. This report explores and attempts to prioritize the major anticipated impacts of CAV technology on the HDV sector with specific regards to fuel efficiency and emissions, via 1) eco-driving, 2) platooning, and 3) other potential fuel economy and emissions impacts from HDV transportation shifts, such as changes to vehicle routes and fuel choices. It also identifies potential secondary impacts, such as safety and job displacement. The impact of HD-CAVs can be either positive or negative, potentially impacting vehicle energy consumption and emissions (both criteria pollutant and GHG) in many ways, through the change of vehicle operating profiles, travel demands, fuel choices, and vehicle designs.

This chapter seeks to compile information on barriers to use, potential GHG and criteria pollutant reductions, and costs, from the use of a broad range of connected and automated technologies (CAV) and efficiency upgrades, as well as anticipated changes to future demand on the heavy duty sector fleet mix and activity due to other market and technology trends. Potential unintended consequences that could be caused using CAV technologies in the heavy duty sector and how they could impact California's disadvantaged communities (DACs) are discussed.

2.2 Methods

This chapter consists of two main sections: a literature review to assess the potential applications of CAV technologies for the heavy duty sector and an estimation of the potential fuel savings from CAV technologies for the heavy duty sector at the state level by 2050. For the fuel analysis, scenarios were developed to determine the potential fuel savings if CAV technologies were widely adopted by the either the year 2025 or 2035. The baseline fuel usage, as well as the annual VMT and vehicle turnover were taken from CARB's Visions model. The fuel savings were calculated from the starting year (either 2025 or 2035) out to 2050. New vehicles starting with the start model year are assumed to have the identified CAV strategy enabled and therefore they realize the associated fuel savings. The range of potential fuel savings for each strategy was determined based on values reported in literature. The two CAV strategies examined are platooning and eco-driving. In addition to the state level analysis, DACs that are most likely to benefit from reduced HDV emissions under CAV strategies were identified using CalEnvironScreen 3.0.

2.3 Results and Discussion

2.3.1 CAV Technologies and Applications in the Heavy Duty Sector

CAV technologies encompass both hardware and software components that improve vehicle performance and safety. Components can be installed on the vehicles as well as on infrastructure, in the case of V2I or V2X configurations. Hardware additions include cameras, infrared and ultrasonic sensors, radar, light detection and ranging (LiDAR), global positioning system (GPS), internal navigation system (INS), dedicated short-range communication (DSRC), and a processing subsystem [260]. Software includes prebuilt maps and control algorithms (including artificial intelligence) that interpret collected data to direct vehicle movement [260], [264].

Vehicles equipped with CAV features are categorized based on their features and driver engagement requirements [265], see Table 22. For Automation levels 0-2, the driver remains in control of the vehicle during operation of the support features. Features include sensors to gauge conditions on the road in order to (1) provide feedback to the driver, such as collision warnings or lane departure warnings, or (2) take limited actions, such as cruise control or emergency braking. Automated safety features are generally referred to as advanced driver assistance systems (ADAS). For Levels 3-5, the vehicle operates without driver inputs when CAV features are enabled. Features focus on reducing or removing overall driver participation during vehicle operation. Automation levels 0-2 are already commercially available for the heavy duty sector, with higher levels of automation (levels 3-5) in development [266]. Recently, SAE established a standard (SAE J3216) for cooperative driving automation (CDA), which utilizes shared data (M2M) to operate the vehicle autonomous data [259].

CAV technologies for the heavy duty sector can provide several benefits at the vehicle level, such as improving fuel economy, decreasing the risk of collisions, and reducing emissions by either helping human drivers make better decisions or by replacing the human driver for certain tasks. Examples include optimal driving cycle and speed harmonization, optimal routing and dynamic eco-routing, reduced cold starts and idling, and trip smoothing [260]. CAV adoption can have impacts at the fleet or highway level, including reduced fleet fuel consumption, traffic mitigation, improved safety, and reduced operational costs [267]–[271].

Table 22. Levels of Vehicle Automation (SAE International)

Level	**Description**	**Technologies** [272]	**Availability**
0	Manual; may have warning signals	Collision warning, blind spot monitoring, lane departure warning, traffic sign recognition, pedestrian warning, left turn assist, adaptive headlights, automated wipers, etc.	Commercially Available
1	Driver assistance; Single function; independent functions	Adaptive cruise control, cooperative adaptive cruise control, lane keeping, electronic stability control, automatic emergency braking	Commercially Available
2	Partial automation; Combined functions	Traffic jam assist, high speed automation, automated assistance in roadwork and congestion	Commercially Available; Prototypes for some vocations [273]
3	Conditional automation; some self-driving functionality with driver still required to take over in some cases	Highway platooning, traffic harmonization [264], cooperative lane change [274]	In Development/ Testing; Limited Commercial Availability in LDVs
4	High automation; no driver engagement required; vehicle can drive under limited conditions	Self-driving in limited conditions	In Development/ Testing; Limited Deployment for Taxis
5	Full automation; no driver engagement required; vehicle can travel under all conditions	Self-driving	In Development/ Testing

Automation can occur under different driving environments: highways, urban and rural roadways, and off-road, which can affect potential CAV strategies and the resulting fuel consumption savings [275]–[278]. Fully automated on-road vehicles will be expected to navigate all normal driving situations including constant speed, braking, acceleration and deceleration events, lane changes, turning, merging, on and off ramps, and traffic intersections, as well as unexpected events, such as road debris [279], [280]. Depending on the vehicle vocation, more specialized vehicle functions also may be required.

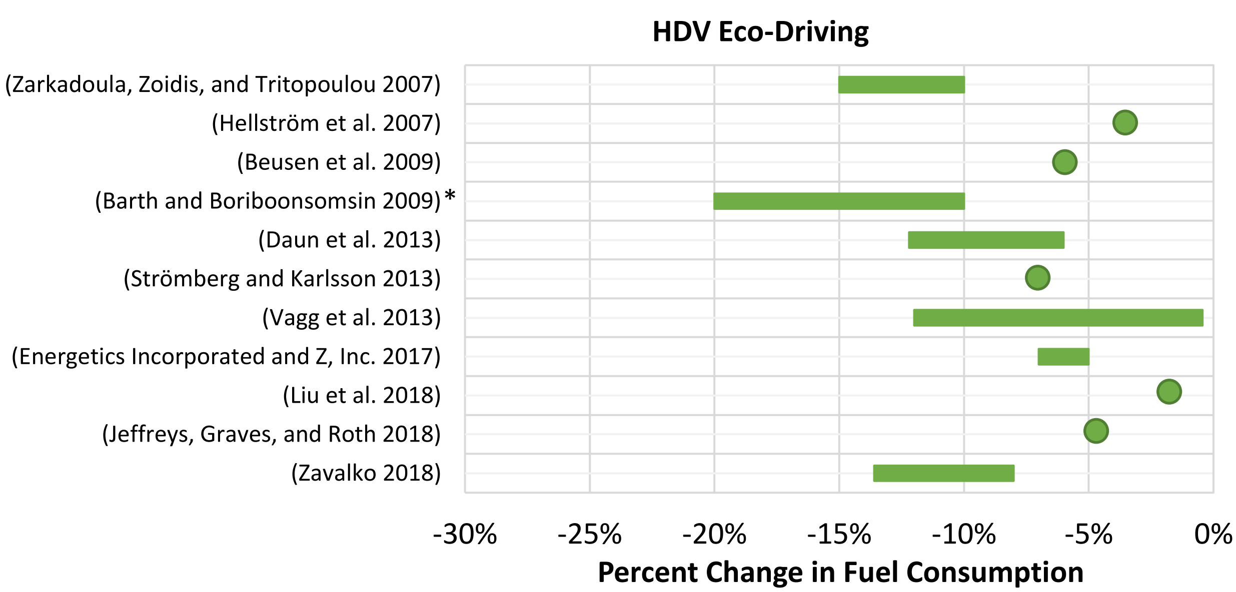
Similarly, connectivity can provide support under different driving conditions, with the focus on providing real-time feedback to an individual vehicle based on data collected by either another vehicle, infrastructure sensors, or cloud computing. Applications for heavy duty vehicles include improved vehicle speed decisions, vehicle routes, congestion mitigation and avoidance, and parking assistance. For example, V2I connectivity at intersections can inform vehicles of upcoming light changes, so that the vehicle can adjust its acceleration/deceleration events accordingly [279].

Eco-driving

Eco-driving encompasses many different strategies that decrease fuel consumption without altering vehicle design including minimizing braking-acceleration cycles, reduce idling, and maintaining engine operation at the most efficient operation points [281]. It is important to note that eco-driving modes focused on solely reducing fuel consumption can inadvertently increase pollutant emissions; instead, if pollutant emissions and fuel consumption are considered jointly, this impact can be mitigated [282]. The net impact of eco-driving on fuel consumption depends on the vehicle route, strategies employed, and whether it is automated or requires driver input.

In systems with little to no automation, eco-driving actions can be performed manually by drivers based on their observations of traffic flow or based on vehicle signals provided to the driver [283], [284]. Vehicle signals can include visual cues such as fuel consumption rates [284] or advice on acceleration and braking in response to changing traffic conditions [285], auditory cues such as beeping when speed exceeds the local limit [286], or physical cues such as haptic pedal feedback to communicate optimal acceleration rates [284]. With automation, eco-driving is accomplished with little to no driver input. Automated eco-driving can be more effective than manual eco-driving due to expanded features and improved accuracy [287]. In addition, removing manual inputs may reduce driver fatigue [272]. Furthermore, traffic conditions affect fuel savings. Barth and Boriboonsomsin (2009) found that eco-driving is more effective during high traffic congestion, while free-flow conditions yield little benefit [285]. The potential fuel savings for manual and automated eco-driving strategies for a range HDV applications are summarized in Figure 60 [285], [288]–[297].

Figure 60. Eco-Driving Impacts on HDV Fuel Consumption



* Highway driving only

Driver behavior is a major factor in determining the overall energy consumption and emissions for an individual vehicle. For example, the difference in fuel consumption could be up to 30% for the same HDV driven by different operators [298]. Therefore, manual eco-driving may have varying results depending on the driver. Education, monitoring, and feedback have been noted as important for influencing HDV operators towards more fuel efficient driving behavior [299]. Zarkadoula, Zoidis, and Tritopoulou (2007) found that when eco-driving benefits rely predominantly on driver training, the effectiveness declines overtime after the training session [288]. Fors, Kircher, and Ahlström (2015) found that vehicle signals that are straightforward and easy to understand are most effective in achieving the desired reduction in fuel consumption [300]. While fully automated CAV would avoid this issue, the use of CAV can still achieve benefits for HDVs under manual operation.

Platooning

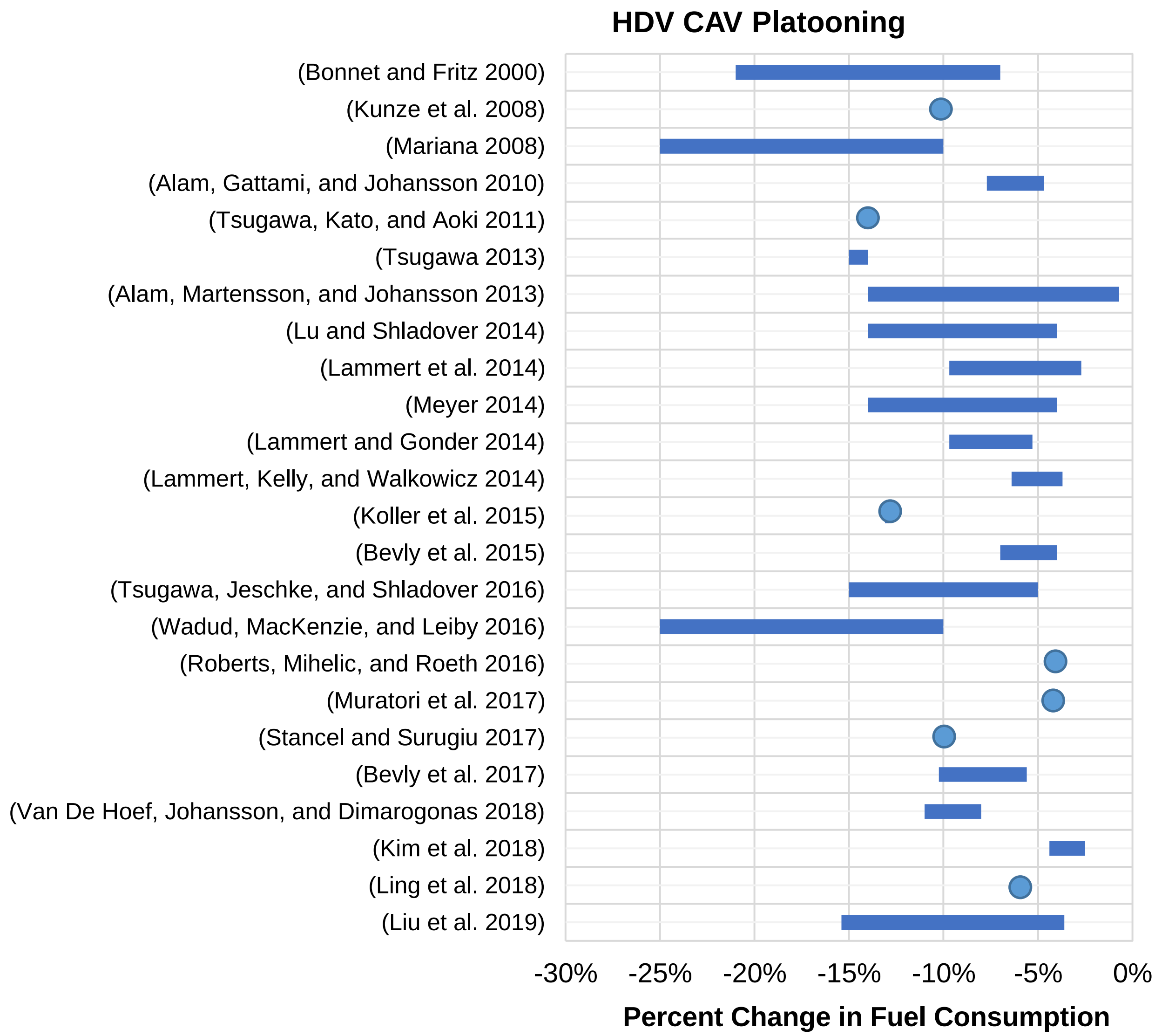
Platooning is the practice of grouping multiple vehicles closely together via cooperative control to reduce aerodynamic drag for all the vehicles, particularly those in the middle of the line. Reduced drag results in lower fuel consumption and emissions of the overall cooperative fleet. Platooning is considered a CAV strategy because the close distances between vehicles is unsafe without automation [301].

HDVs have greater opportunity to platoon compared to LDVs since HDVs will spend a greater percentage of travel on highways. The major freight corridors, which comprise approximately 60% of the interstate network, span 26,000 miles and may provide the most convenient opportunity for such platooning [302]. Muratori et al. (2017) estimate that this translates to 65-77% of freight miles that benefit from platooning [275].

Since most truck travel occurs on the highway, platooning can facilitate significant fuel and emissions decreases for the medium and heavy duty sector. A study by Mitra and Mazumdar (2007) suggests that the fuel-savings potential of platooning for HDVs may be greater than for LDVs. In their work, a wind-tunnel test conducted at 51 MPH was used to measure the drag coefficients of four vehicles in a platoon such that the vehicles were following at a close distance just 40% the total length of the vehicle. They found that the drag coefficient for the three following vehicles decreased by 14-32% for the LDVs versus 31-50% for the HDVs [303].

Pilot projects and experimental studies have quantified the fuel savings potential of platooning for HDVs. Various following distances and number of vehicles within the platoon were evaluated for fuel economy performance. In 2013, a real world demonstration project measured fuel consumption reduction in HDVs by 4%, 10% and 14% for a three truck platoon with 6 meter space between trucks, with the smallest fuel savings being the first truck and the greatest fuel savings to be the last truck in the platoon [304]. In 2016, a study on the energy impacts of HD-CAV platooning compared the several research works spanning simulated and real-world measurements, concluding that the energy impacts were consistent across studies at around 5% to 10% for the first truck, and about 10%-15% for following trucks [305]. Figure 61 presents the range of fuel saving results from a selection of HDV platooning studies [267], [268], [275], [305]–[324].

Figure 61. Platooning Impacts on HDV Fuel Consumption



In addition to these HD-CAV fuel savings, platooning can result in potential logistical improvements (e.g., speed of delivery from primary to retail availability) and reductions of logistical costs (e.g., avoidance of driver wages, loss of perishable food) could reduce the costs and losses of perishable foods in particular [271], [325]–[327].

Others

There are additional CAV navigation strategies that have the potential to reduce fuel consumption, such as eco-routing and congestion mitigation [268]. Improved vehicle routing via new positioning and communications systems can improve vehicle capacity utilization and reduced travel distances leading to GHG reductions of up to 20 to 40%, although in some cases and increased load negated emission benefits [328], [329]. Similarly, congestion mitigation has been shown to reduce energy consumption and emissions [330]. This could be particularly important in California due to the high levels of wasted energy attributed to congestion [331].

CAV Cost and Timeline

The deployment of CAV technologies for medium and heavy duty vehicles is expected to increase vehicle costs, due to the installation of new sensors and software controls [295], [332]. Current CAV technology costs are summarized in Table 23.

Table 23. CAV current and near-term costs

Source	Strategy/Technology	Cost ($/vehicle)	Timeline
Energetics and Z, Inc. (2017) [295]	Off-road guidance system	$1,500-$25,000	N/A
	Off-road autonomous retrofits	$200,000-$250,000	
	Predictive cruise control	$760-1,300	Current-2030
	LiDAR	$10-$250	Near Term
	LDV Adaptive Cruise Control & lane assist	$1,000-$5,050	Current
Janssen et al. (2015) [333]	Platooning, Level 3 (est.)	$11,900	2015
NACFE (2016) [313]	Platooning	$1,500-$2,000	2016
NREL (2016) [334]	LDV Partial Automation (Safety)	$400-$4,500	Current
	LDV Full Automation	$2,700-$10,000	Near Term
Ouster [335]	LiDAR	$3,500+	Current
Tesla [336]	LDV Conditional Autonomy	$3,000-$8,000	Current
U.S. DOT [337]	Forward Collision Warning	$500-$1,000	Near Term (from 2018)
	Automatic Emergency Braking	$2,000-$3,000+	
Velodyne [338]	LiDAR	$100-100,000 ($7,999 average)	Current
Roland Berger (2016) [332]	Platooning, Level 1	$1,800	
	Platooning, Level 2	$6,900	
	Delivery & Transit, Level 3	$13,100	
	Delivery & Transit, Level 4	$19,000	
	Delivery & Transit, Level 5	$23,400	

Costs associated with operating CAVs may also change—not only fuel costs, but also maintenance and insurance costs [339]. Improved performance and reduced accident risk may reduce maintenance and insurance cost, but increased complexity and new components may increase maintenance needs depending on reliability and lifetime [295], [334]. The higher initial costs of CAVs are expected to be partially, if not fully, offset over the lifetime of the vehicle due to improved performance and reduced fuel consumption [339], [340]. McKinsey and Company predict that full automation of HDVs platooning could reduce the total cost of ownership by 45% as soon as the year 2027 [341].

Some technologies can vary significantly based on the design and purpose. A prime example is LiDAR, where the cost can vary between $10-$10,000 depending on the device size and specificity (size and materials, number of lasers, range of vision, accuracy, and software). Future costs will depend on technology improvements and cost reductions due to increased economies of scale.

The timeline for widespread deployment of Level 3-5 automation in the heavy duty sector is dependent on a number of factors including demonstration results, implementation costs, consumer adoption rates, and regulatory hurdles. Projections estimate level 3-5 CAV commercialization between 5-10 years [295], [341].

2.3.2 Overarching Implications

The cumulative impacts of CAV technologies in the heavy duty sector are, as of yet, uncertain. While these technologies promise significant improvements in safety, fuel economy, and overall system efficiency, the widespread adoption may yield secondary, unintended impacts on the sector. For example, improved safety may enable higher travel speeds leading to higher energy consumption and emissions [271]. Second, lower costs may yield higher demand for services [342].

Just as there are potential impacts to energy consumption and transportation performance, there are potential impacts to the employment of those who support the transportation network as well. Approximately 10 million Americans rely on driving for employment, and there are about 3.5 million of those professional drivers who drive HDVs for a living. As with automation in other sectors, CAV technology could threaten the marketability of human drivers. Of the millions of domestic truck drivers, a recent study found that less than 10%, or just short of 300,000, of the minimally-specialized driving jobs would be actually threatened in the short term due to CAV technologies [343].

Even with automation, truck driving may not go away as a career but simply adapt. While driving is the most obvious role of truck drivers, it is not the only job duty. For example, truck drivers must constantly check the vehicle for issues such as low tire pressure or mechanical issues and address them prior to a failure, securing loads prior to driving and adjusting any shifting loads during driving (should a truck need to abruptly decelerate, the truck driver would need to inspect and possibly adjust cargo). Preventative measures taken to reduce downtime is essential to present profitability of the trucking operation, as the cost of a truck going out of commission during transport together with the associated service costs can exceed the profit of the trip.

Such are examples of non-driving tasks that would currently necessitate human interaction, though the number of humans required per truck may decrease. One can imagine a truck driver monitoring their own vehicle, and perhaps the performance of several fully autonomous vehicles following their vehicle in a platoon. While enough well-placed and calibrated sensors could ultimately displace the human required entirely, the non-driving tasks associated with HDV travel presently make the case that trucking jobs will remain though potentially shift.

Assessed impacts may differ depending on the perspective, such as from the perspective of heavy duty vehicle operators (Table 24) versus overall roadway impacts (Table 25). This section summarizes the identified potential impacts of CAV for the heavy duty sector from different perspectives and stakeholders, highlighting trade-offs and existing uncertainty.

Table 24. CAV impacts from a fleet perspective

Positive Impacts	Negative Impacts
Improved road safety	Improved safety may enable higher travel speeds leading to higher energy consumption and emissions
Greater fuel efficiency	Increased capital costs
Ease of driving	May need to share data and have connectivity with road and/or other vehicles (other companies), resulting in privacy/security concerns
Increased operation efficiency: real-time planning, reduced truck downtime	
Reduced fuel and labor costs	
Improved loading/unloading safety and efficiency	

Table 25. CAV impacts from a roadway perspective

Positive Impacts	Negative Impacts
Improved road safety	Construction due to installation of CAV infrastructure (e.g. for intersection connectivity): temporary increase in traffic and pollution
Reduced energy waste/emissions due to congestion mitigation, greater throughput	Low CAV percentages have minimal impact on traffic flow
Improved vehicle routing via new positioning and communications systems can improve vehicle capacity utilization and reduced travel distances	CAVs may make optimal decisions for individual vehicle/platoon, but may have unintended impacts on system

Statewide Implications for Future HDV Fuel Consumption

Quantifying CAV impacts on the heavy duty at the state-level is important in evaluating their potential role in meeting California's decarbonization goals. To that end, four CAV scenarios were developed to demonstrate the state-level potential fuel savings of adopting CAV technologies in the heavy duty vehicle sector: a) eco-driving becoming a standard feature for vehicle models starting in 2025, b) eco-driving becoming a standard feature for vehicle models starting in 2035, c) platooning becoming standard for vehicle models starting in 2025, and d) platooning becoming standard for vehicle models starting in 2035.

The CAV strategy and adoption timing affect the overall potential fuel savings as vehicle turnover rates will determine the percentage of vehicles that have CAV technologies over time. Eco-driving can be applied for all driving times, whereas platooning is a highway-specific CAV strategy and the fuel savings is, therefore, dependent on the percentage of vehicle miles that occurs on the highway. The highway range is assumed to be 65-77%, estimated by Muratori et al. (2017) [275]. The range of fuel consumption savings are informed from the literature review summarized in Figure 60 and Figure 61.

CARB's Vision 2.1 Heavy Duty Vehicle Expanded Zero Emission Scenario Tool is used to determine the baseline heavy duty vehicle fuel consumption for the years 2015-2050, encompassing Class 2B through Class 8 [228]. CAV fuel savings are applied for all categories represented. This analysis assumes that annual VMT does not change with the adoption technologies. The impact of CAV technologies on diesel, CNG, and gasoline consumption are presented.

Figure 62 presents the range of fuel consumption reductions assuming eco-driving strategies become standard for HDVs by the year 2025. Based on the literature review, fuel savings per vehicle can range from less than 1% up to around 15% (from Figure 60). The average fuel savings for studies identified is about 7.5%. Assuming an adoption year of 2025, fuel savings between the year 2025 and 2050 is about 5.8% compared to the baseline. The level of fuel savings is dependent on the year and the fleet turnover rate (which is pre-defined in Vision). The average annual fuel savings for the year 2035 is 3.5% and for 2050, it is 7.3%, indicating a nearly full vehicle turnover by 2050.

If a later adoption year of 2035 is assumed instead, the total fuel savings occurs between 2035 and 2050. Also, a smaller percentage of the population in 2050 has eco-driving capabilities, resulting in an average 2050 annual fuel savings of 6.3%, see Figure 63.

Figure 64 illustrates the potential range of fuel reduction assuming highway platooning becomes a standard HDV feature by the year 2025. While platooning has a higher fuel savings potential compared to eco-driving alone, the limited application of platooning on highways versus all roadways can limit the fuel reduction potential of this strategy. Future HDVs may in fact utilize platooning on highways and other connected or eco-driving strategies when on other roadways unsuited for close-proximity driving, resulting in greater fuel reductions compared to using only one strategy.

Figure 65 presents the impact of platooning if it is adopted later, in the year 2035. The later deployment results in lower overall fuel reduction and a lower percentage of vehicles in 2050 with platooning capabilities compared to the 2025 adoption scenario.

Figure 62. Fuel Reduction Range Associated with Adopting Eco-Driving by 2025

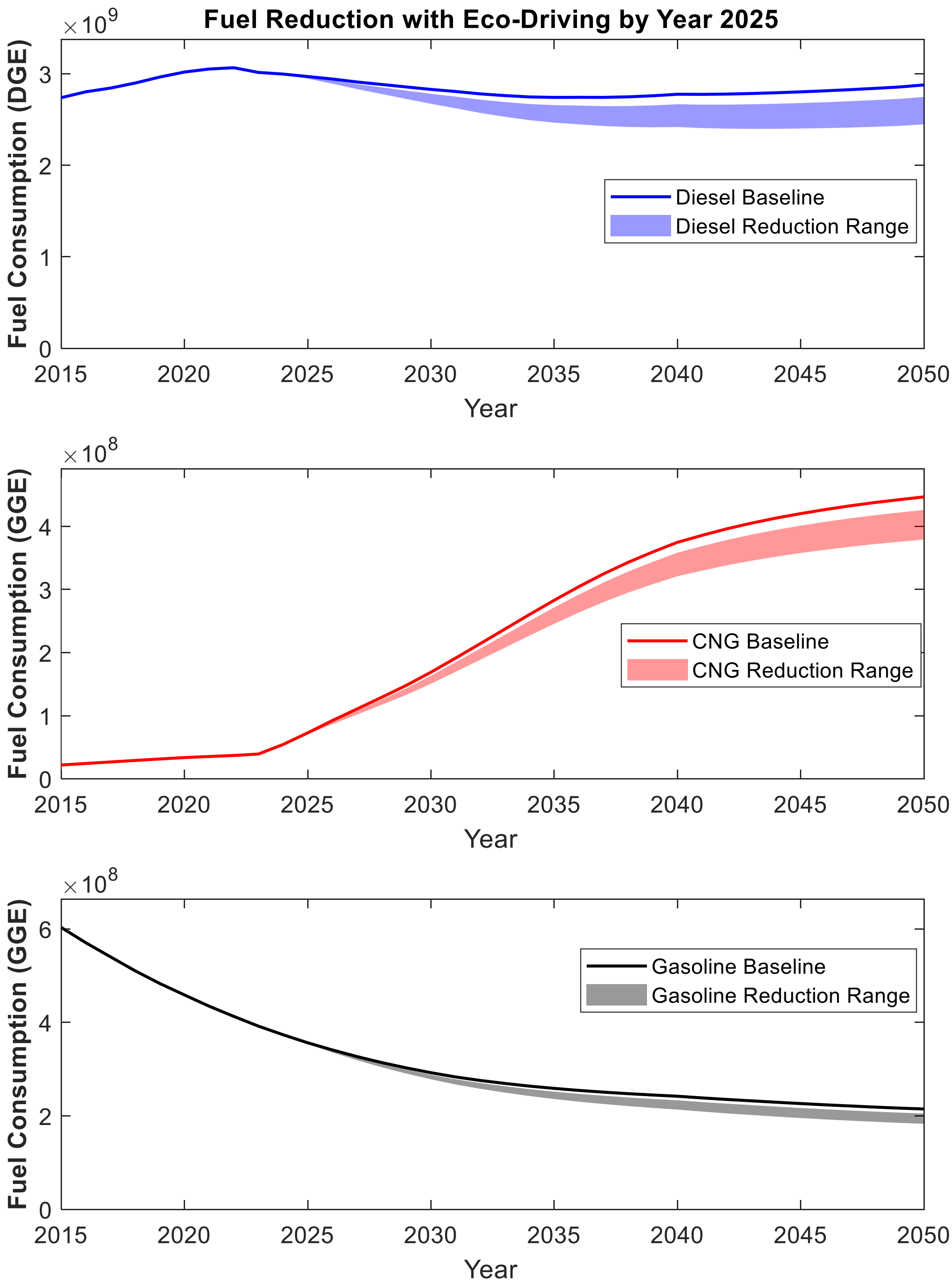


Figure 63. Fuel Reduction Range Associated with Adopting Eco-Driving by 2035

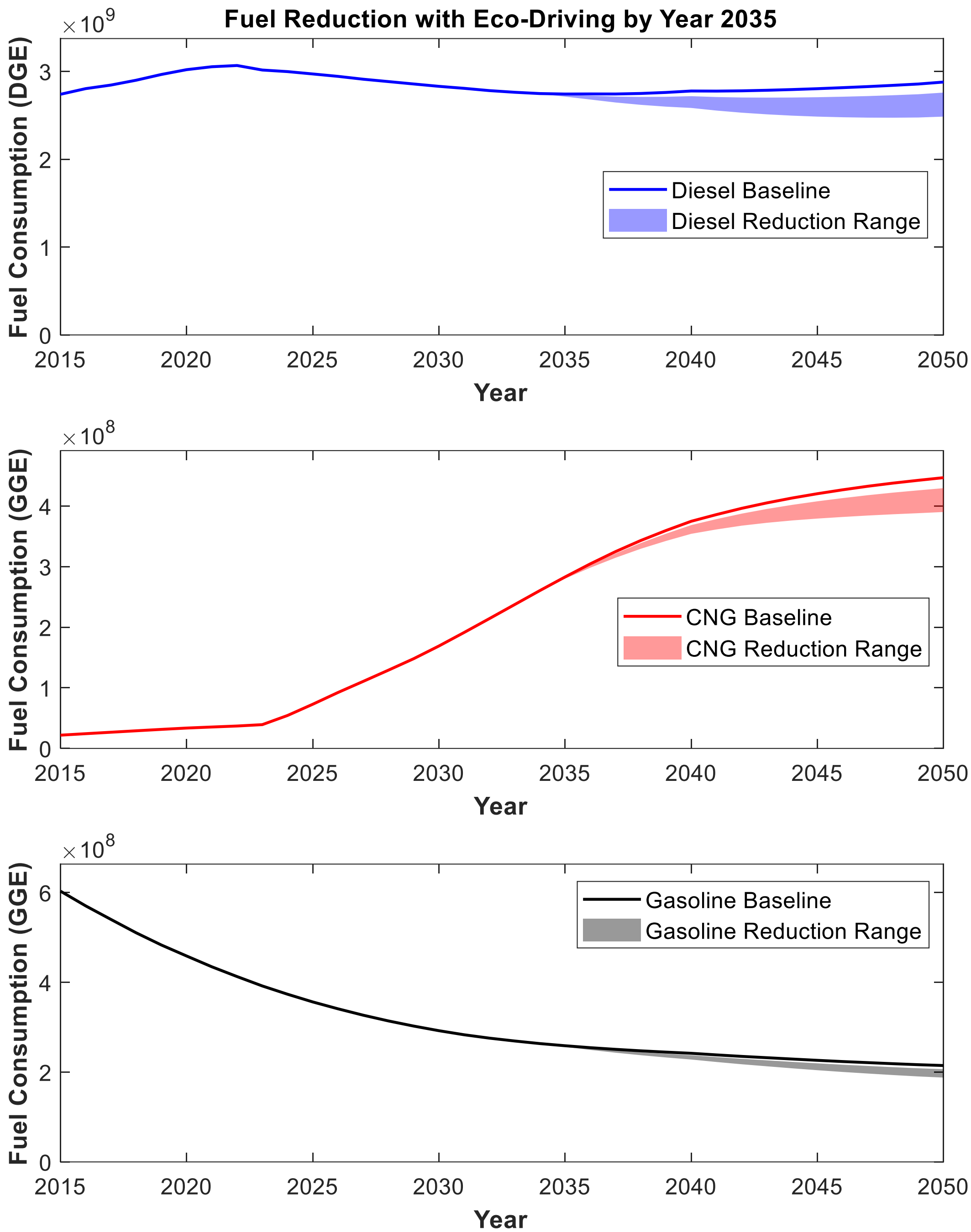


Figure 64. Fuel Reduction Range Associated with Adopting Highway Platooning by 2025

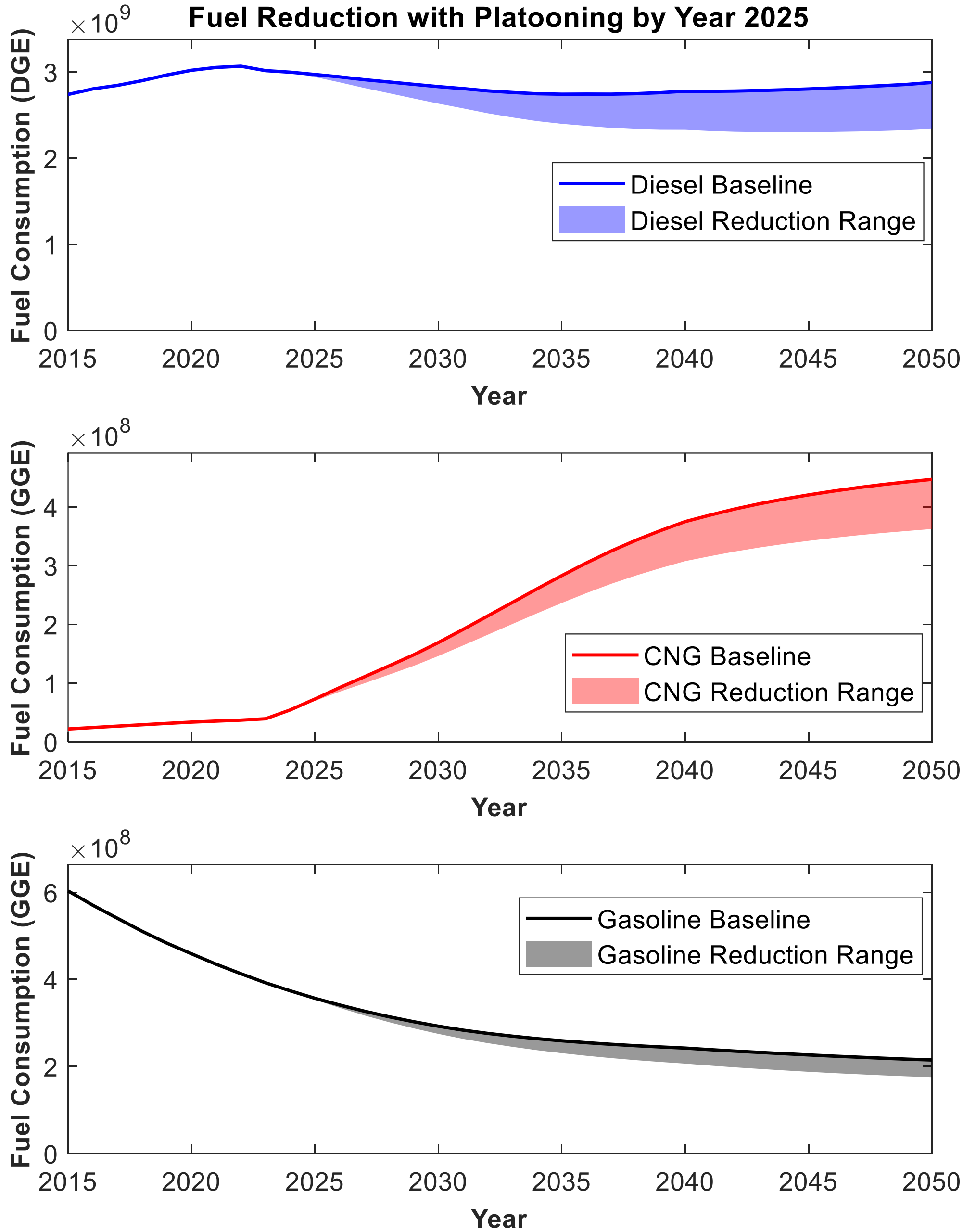
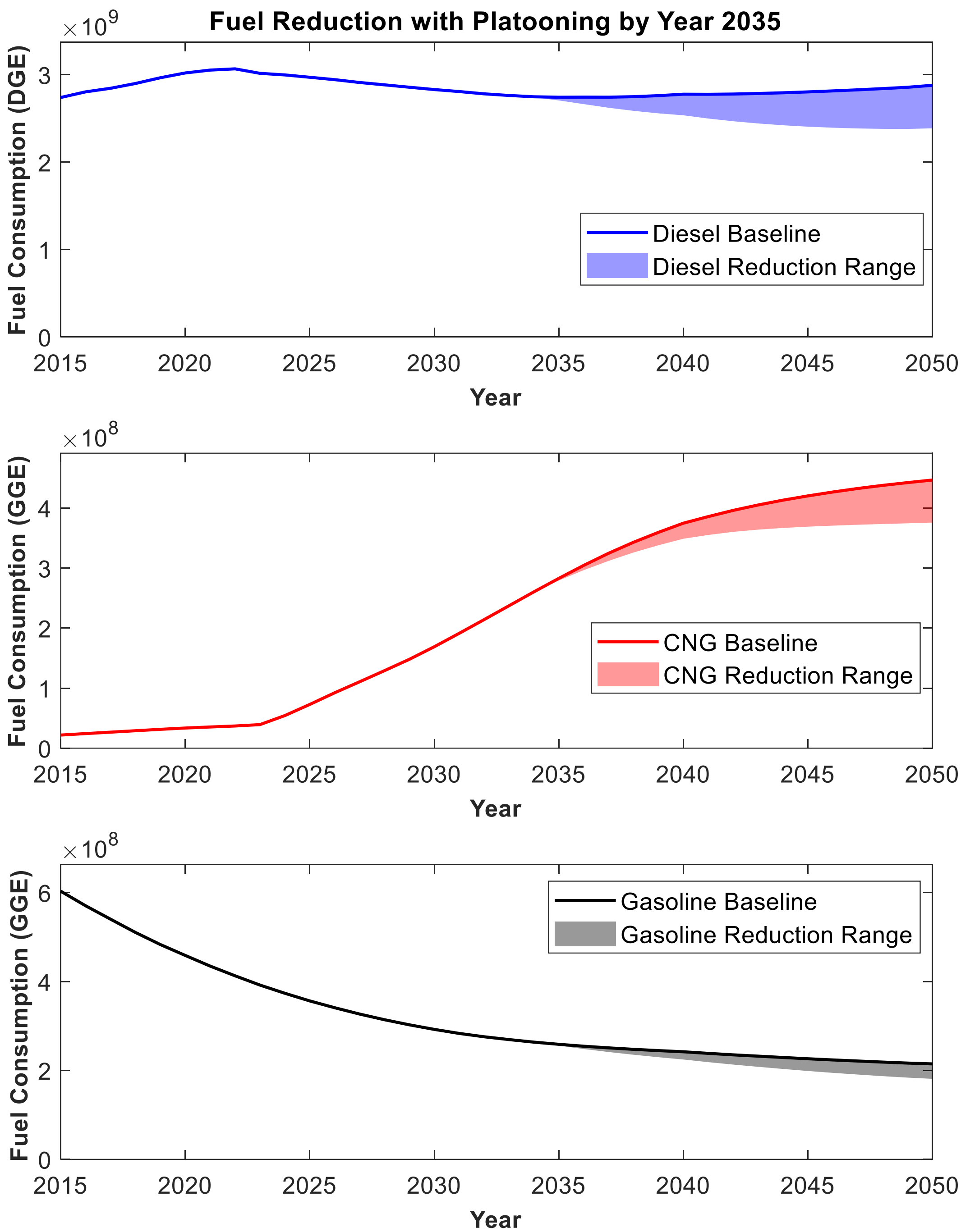


Figure 65. Fuel Reduction Range Associated with Adopting Highway Platooning by 2035



Supporting Alternative Fuels

In addition to impacts on energy demand and emissions through changes in vehicle performance, CAV may impact emissions by supporting transitions to alternative fuels, including electrification (hydrogen fuel cell and electric drive) and natural gas/renewable natural gas. A summary of potential impacts on ZEVs in presented in Table 26. Wadud, MacKenzie, and Leiby (2016) identify three mechanisms to support this point. First, use of CAV could bypass driver perceived cost and inconvenience associated with refueling including limited station availability and long fueling or charging periods. Second, current low-carbon fuels (including hydrogen, electricity, and natural gas/renewable natural gas) generally reduce operating range from current petroleum vehicles due to factors including volumetric energy density and costs for on-vehicle storage. CAV may improve the range from such technologies by improving management of refueling/recharging, automatically and while avoiding driver inconvenience. Third, present capital costs for alternative fuels and vehicles are high relative to current baseline vehicles. As CAV may be deployed in services including mobility-on-demand and car sharing, they may attain high-utilization rates and travel longer distances per year than current vehicles. For these conditions, vehicles with low operating costs, higher durability and efficiencies, and the use of lower cost fuel (e.g., electricity, natural gas) may be favored, despite higher capital costs [268].

Table 26. CAV impacts on zero emission vehicles

Positive Impacts	**Negative Impacts**
Further increase in fuel efficiency compared to BEV/FCEV improvements, increasing vehicle range	Increased brake PM due to greater vehicle weight
Automated refueling, recharging, and/or battery swapping schemes can be utilized	Construction impacts and high capital cost associated with building out charging/refueling infrastructure
Lower costs for some fuels	Higher vehicle costs
Improved routing to meet ZEV technical capabilities/infrastructure availability	Increase annual distance traveled to accelerate payback periods

Vocation-Specific Impacts

CAV benefits may vary based on the vehicle application. For example, several studies have examined the impact of CAVs on delivery, transit, and food distribution. CAV technology may enable vehicles to safely travel at higher speeds, allowing for faster and more optimized scheduling of deliveries. While enhancing the performance of a delivery network, such driving behavior could increase energy consumption and emissions for HDVs. This trade-off between efficiency improvements and increased energy consumption through higher travel speeds is uncertain [271].

Consideration of potential impacts on post-processing food distribution discussed in [271] provides an example of the potential trade-offs that must be considered for each vocation or industry. Potentially, CAV may displace grocery stores by delivering food directly to consumers due to convenience, which could have a number of system changes affecting emissions. First, the relative emissions outcome of last mile delivery optimization is unknown. Increased emissions could occur if a larger truck is displaced by multiple smaller vehicles. Additionally, consumers may order food in smaller quantities delivered separately which could increase transportation emissions, although food waste may be decreased for that scenario. Contrastingly, emissions may be avoided from consumer trips to physical grocery stores, as well as the emissions associated with grocery store retailing practices, e.g., operating refrigerated display cases, waste from over-stocking. Therefore, the use of CAV must be carefully monitored to ensure net emission increases do not occur in tandem with the benefits of improved food distribution.

Table 27. CAV Impacts on Food Distribution Logistics

Positive Impacts	**Negative Impacts**
Improve food distribution logistics by reducing costs and avoiding perishable food losses	Increased VMT from longer transport of perishable items facilitated by CAV efficiency gains
Avoid multiple consumer trips to supermarket	Delivery of food by multiple smaller trucks in place of one larger truck could increase emissions
Food waste decreased by consumers ordering smaller quantities more frequently	VMT may increase with frequency of consumer orders
Decrease in emissions from grocery retail practices including energy consumption for freezers, lighting, etc.	

Impacts on Disadvantaged Communities

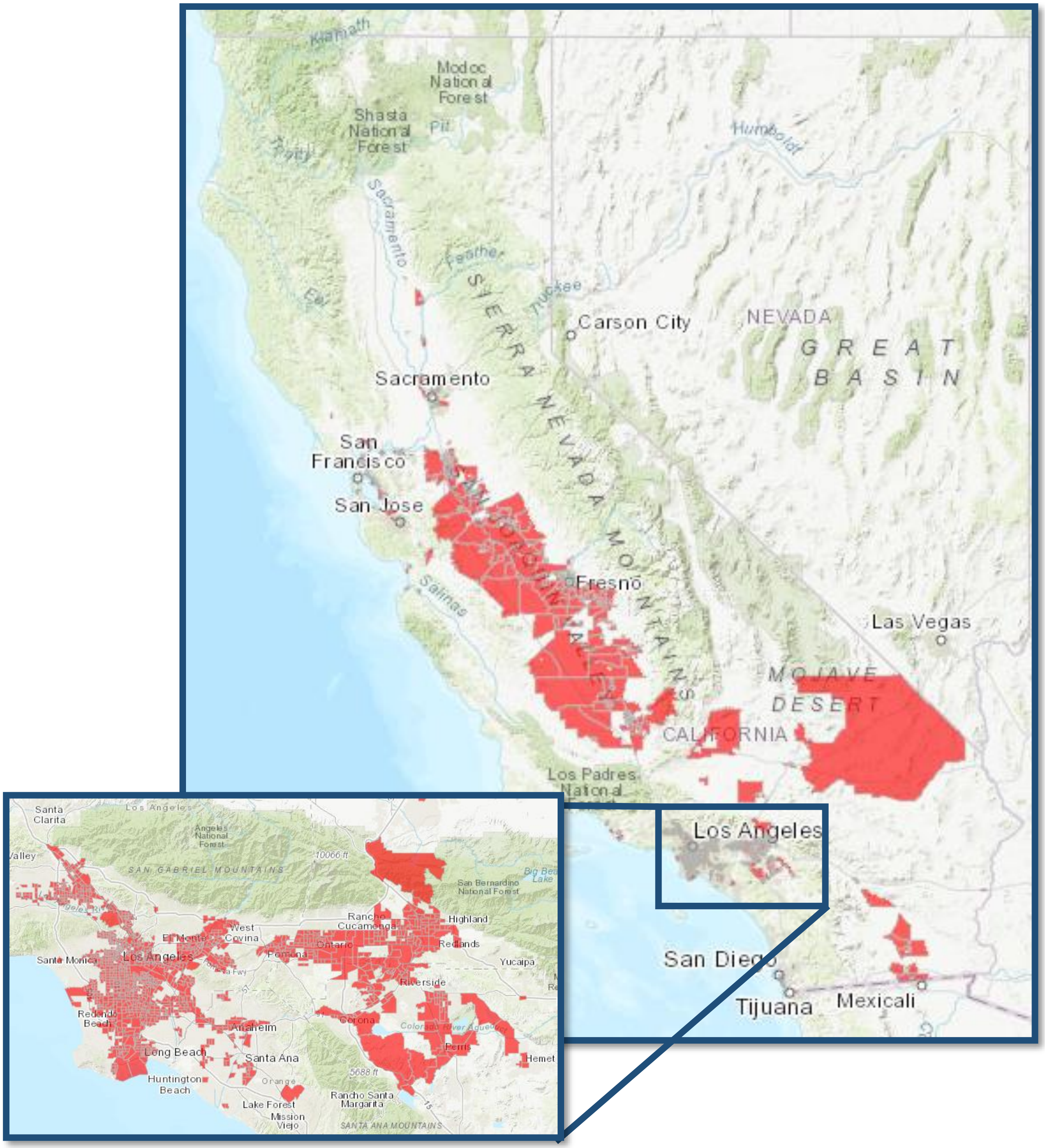
Reduced fuel consumption through CAV strategies as well as heavy duty ZEV adoption can significantly reduce pollution in DACs. DACs are disproportionately impacted by pollution from the heavy duty sector, driven by the location of freight corridors throughout the state, see Figure 66 and Figure 67. In fact, exposure to diesel PM (predominantly from HDVs) is one of the indicators used to classify DACs, see Figure 68.

There are limited studies examining the secondary, more complex impacts of heavy duty CAVs on disadvantaged communities. Most related research are in the context of changes to mass transit, rideshare access and affordability for vulnerable populations, and job prospects [272], [334]. A summary of potential CAV impacts on DACs is presented in Table 28. Most identified DAC benefits of CAVs are associated with reduced pollution and improved safety. Potential negative impacts include shifting travel demand, greater traveling speeds, and employment. Negative impacts, such as shifting truck routes, can be mitigated through new and intelligent strategies, e.g., smart eco-driving, which can take into account DACs when determining the optimal route. More research is required to understand the scope of potential impacts on DACs from CAV adoption.

Figure 66. National Highway Freight Network: California

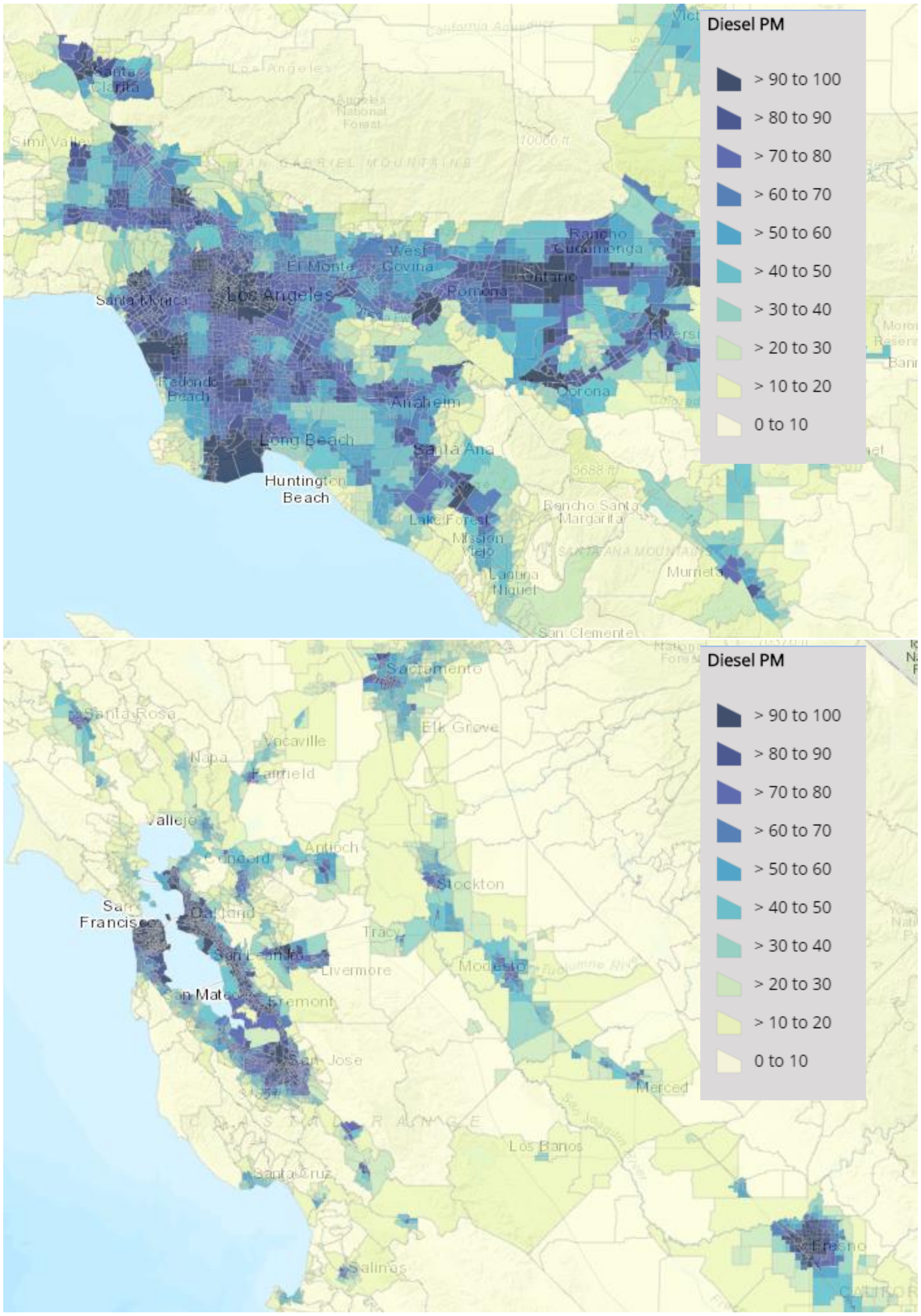
Source: U.S. Department of Transportation. Federal Highway Administration.
https://ops.fhwa.dot.gov/freight/infrastructure/ismt/state_maps/states/california.htm

Figure 67. CalEnviroScreen 3.0 Disadvantaged Communities under SB 535



Source: California Office of Environmental Health Hazard Assessment. SB 535 Disadvantaged Communities using CalEnviroScreen 3.0 results. https://oehha.ca.gov/calenviroscreen/maps-data

Figure 68. CalEnvironScreen 3.0 Diesel PM Indicator: a) South Coast Region and b) Bay Area Region



a)

b)

Source: California Office of Environmental Health Hazard Assessment. SB 535 Disadvantaged Communities using CalEnviroScreen 3.0 results (filtered to show Diesel PM). https://oehha.ca.gov/calenviroscreen/maps-data

Table 28. CAV impacts on disadvantaged communities

Positive Impacts	Negative Impacts
Reduced vehicle pollution (NOx, PM)	Shifting of truck routes can shift pollution burden
Reduced vehicle collisions	Eco-routing can shift truck routes into DACs
Reduced costs may increase transit and ride-share availability/affordability	Improved safety may enable higher travel speeds leading to higher energy consumption and emissions
	Fully autonomous vehicles can reduce available driving jobs
	Short-term increase in construction/traffic congestion associated with connectivity infrastructure build-out

2.4.3 Barriers to Use

Three main barriers to widespread CAV adoption in the heavy duty sector have been identified:

1. TECHNOLOGY PERFORMANCE AND RELIABILITY

   Advanced CAV technologies associated with Level 3-5 automation are still in development and as such there is uncertainty surrounding the technologies' future performance and reliability. Advancements are needed to improve the accuracy of interpreting and responding to external signals. Also, fuel consumption and associated emission reductions may vary across different vehicle applications. CAV technologies have been applied in a limited number of heavy duty use cases and so it is unclear whether these findings can be applied broadly across the sector. Overall, more work is required before widespread deployment of advanced CAV capabilities.

2. REGULATIONS AND STANDARDS

   There are currently a limited number of autonomous or semi-autonomous vehicles on the road, and rules vary across states and countries dictating how and where these vehicles can operate. Widespread adoption of these vehicles, especially for interstate travel, will require the development of comprehensive and consistent regulations across states and/or countries.

   Another related issue is that connected and autonomous features are being developed by many different companies and groups simultaneously, resulting in an array of different methods and operational parameters. Standardization and interoperability of technologies from different companies is key, particularly for V2V and V2I strategies which rely on the exchange of data between multiple sources. Furthermore, this communication exchange will need to be secure as data about commercial fleet locations is sensitive.

3. COST

CAV costs range significantly depending on the desired capabilities. Slowik and Sharpe (2018) did a review of CAV costs for long haul applications and found that costs for individual technologies available today range from a few hundred dollars (blind spot detection, V2V hardware) up to $75,000 (LiDAR) [273]. Higher capital costs and/or high retrofit costs can be a deterrent for adopting CAV technologies. This proposition is made more difficult in cases where CAV benefits are abstract and/or uncertain. In addition to vehicle features, connectivity can also involve the planning and construction of infrastructure in support connected vehicles, which can be an added cost-either for the company or the government if it decides to make connected infrastructure publicly available.

2.5 Conclusions

It is difficult at this time to predict the precise impacts of CAV in the heavy duty sector given the significant uncertainty in technical, behavioral, and regulatory aspects of commercialization. There is a range of potential outcomes of CAV adoption in the heavy duty sector, depending on the achieved performance of new features as well as secondary impacts such as changes in travel demand. Demonstrations of CAV technologies in the HDV sector have shown significant fuel savings associated with eco-driving and platooning strategies. However, there may be unintended consequences of some CAV strategies, such as shifting pollution burdens or increasing vehicle speeds. Overall, CAV adoption by HDV fleets will depend on performance benefits versus cost. High capital costs may be a barrier for adoption, especially as fleets are being directed to adopt zero-emission vehicle options.

2.6 Recommendations

- **Support the inclusion of proven and low-cost CAV technologies, specifically ADAS, in new HDVs.** While higher levels of automation are in development, lower levels of automation are still limited in the heavy duty sector. For example, while ADAS are standard in new LDVs, these features are less prevalent in HDVs. California and the U.S. more broadly could follow the European Union lead where ADAS for cars, vans, trucks, and buses are mandated by 2022 [344]. Alternatively, they could provide incentives or rebates to offset the higher cost of CAVs.

- **Early deployment must be monitored and evaluated carefully for environmental performance including insights into emissions outcomes of different configurations and optimizations of distribution fleets.**

- **Nimble policies will be required to navigate the evolving transportation landscape, adjusting rules and guidance as the understanding of CAV impacts matures.** There are numerous technologies and strategies that are being tested for CAV applications. At the moment it is unclear which will prevail and become standard. Even terminology can evolve, such as the recent introduction of the terms M2M and CDA to describe CAV capabilities [259]. Currently, policies should provide general guidance that supports advanced CAV testing, and when impacts are better understood, more direct and specific rules can be implemented.

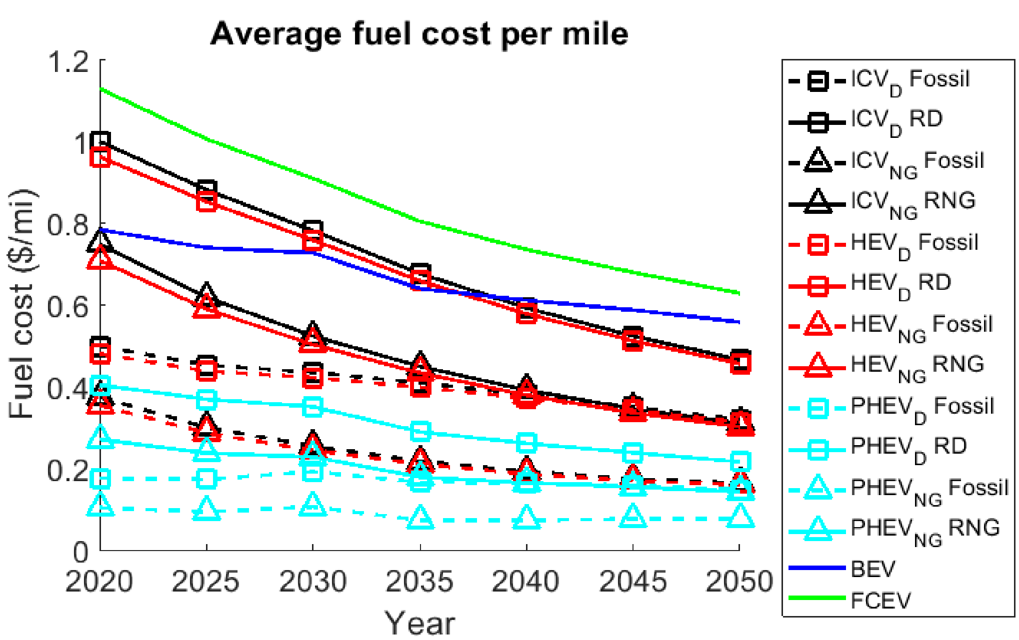
3. Optimal Pathways for Alternative Heavy-Duty Vehicle Fuels and Powertrains

3.1 Overview

The goal of Task 3 is to develop long-term scenarios for the evolution of the HDV sector in terms of fuels, infrastructure, and powertrains used that can achieve State energy and environmental goals. To do so, an optimization platform including techno-economic characterization of alternative HDV powertrains is developed to generate various fleet mix scenarios and assess them holistically for emissions, cost, and other relevant metrics. The results provide insight into the best evolutionary path forward for the HDV sector in California.

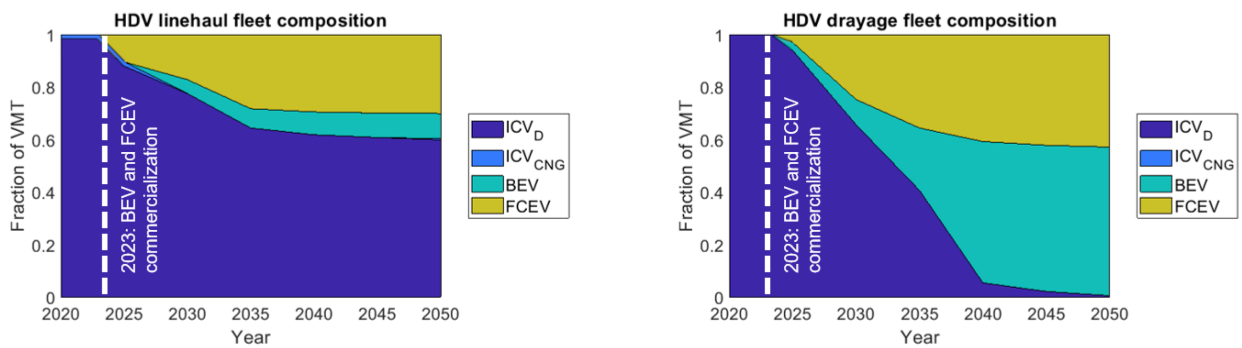
The approach starts with a techno-economic characterization of the various HDV powertrains under consideration with similarity to what was accomplished for fuels in Task 1, presented in Chapter 1. Major powertrain components are characterized including size and cost. Cost projections are made using Wright's Law on a component basis. Additionally, vehicle efficiency is characterized. Combining the fuel costs developed in Task 1 with the efficiency projections developed in Task 3, Figure 69Figure 76 shows the average fuel cost per mile of the various HDV pathways considered. Next, the techno-economic results are used as an input into a novel optimization model named Transportation Rollout Affecting Cost and Emissions (TRACE.) Beyond the techno-economic data, also included are environmental legislation and goals. Examples include AB 32, SB 32, and CA Executive Order #S-03-05 which all constrain greenhouse gas (GHG) emissions from 2020 to 2050 [18]–[20]. Additional constraints include fuel feedstock availability, vehicle powertrain availability, vehicle miles traveled (VMT) demand of modeled HDV vocations, and others to better reflect real-world deployment.

Figure 69. Heavy-duty vehicle fuel cost per mile projections



Using TRACE, two fleet mix scenarios are developed and holistically assessed for fuel pathway rollout, vehicle rollout, cost, and emissions. The first, referred to as "GHG Scenario", includes GHG constraints culminating in an 80% reduction compared to 1990 levels by 2050. The cost-optimal method of reaching this goal is heavy reliance upon negative carbon intensity biomass, including manure and food waste, to produce renewable diesel which is used in internal combustion vehicles (ICVs). The linehaul fleet builds up to 40% of vehicle miles traveled (VMT) met by ZEVs, with a roughly three-to-one split of FCEVs and BEVs. The drayage fleet has relatively quick adoption of ZEVs, starting with a greater portion of FCEVs and evolving to a slightly greater portion of BEVs by 2050. The refuse fleet has significant use of renewable natural gas, with increasing ZEV adoption as time goes on. Lastly, the construction fleet is met partly by renewable natural gas in the mid-term, and increasingly by FCEVs into the future. Fuel production in this scenario is predominantly as follows: gasification for hydrogen, anaerobic digestion for renewable natural gas, and liquefaction for renewable diesel. To summarize key results of the GHG Scenario, the projected HDV linehaul and drayage fleet composition is depicted in Figure 70, and the various projected fuel, fuel feedstock, and fuel production equipment are depicted in Figure 71.

Figure 70. GHG scenario: HDV linehaul and drayage fleet composition



Next, the High ZEV Scenario is developed to assess the aggressive adoption that may be required to meet future environmental quality and energy goals in California (e.g., improving degraded air quality in disadvantaged communities). The scenario includes an increasingly stringent ZEV mandate starting from 0% in 2020 up to nearly 100% of VMT by 2050. This scenario leads to a significantly higher percentage of electricity being used as a fuel feedstock, with biomass being relied upon less heavily. Furthermore, this scenario necessarily reduces the amount of ICVs projected, particularly in later years. The linehaul fleet is served by natural gas ICVs in the mid-term and increasing ZEVs, with a modest and consistent share of BEVs and a dominant and increasing share of FCEVs. The drayage fleet has faster ZEV growth, with a relatively even split between BEVs and FCEVs though ending with a slightly larger share of BEVs by 2050. The refuse fleet has significant natural gas ICV use, while BEV adoption increases nearly linearly to 2050. Lastly, the construction fleet uses some natural gas ICVs in the mid-term, and ZEVs are primarily BEVs until 2050, at which point FCEVs are significantly adopted due to driving range limitations of BEVs. Compared to the GHG Scenario, the High ZEV Scenario has significantly higher hydrogen use, which is made both with biomass gasification and electrolytically, and a declining use of both fossil diesel and natural gas rather than significant use of renewable diesel and small amounts of renewable natural gas.

Figure 71. GHG scenario: fuel characteristics

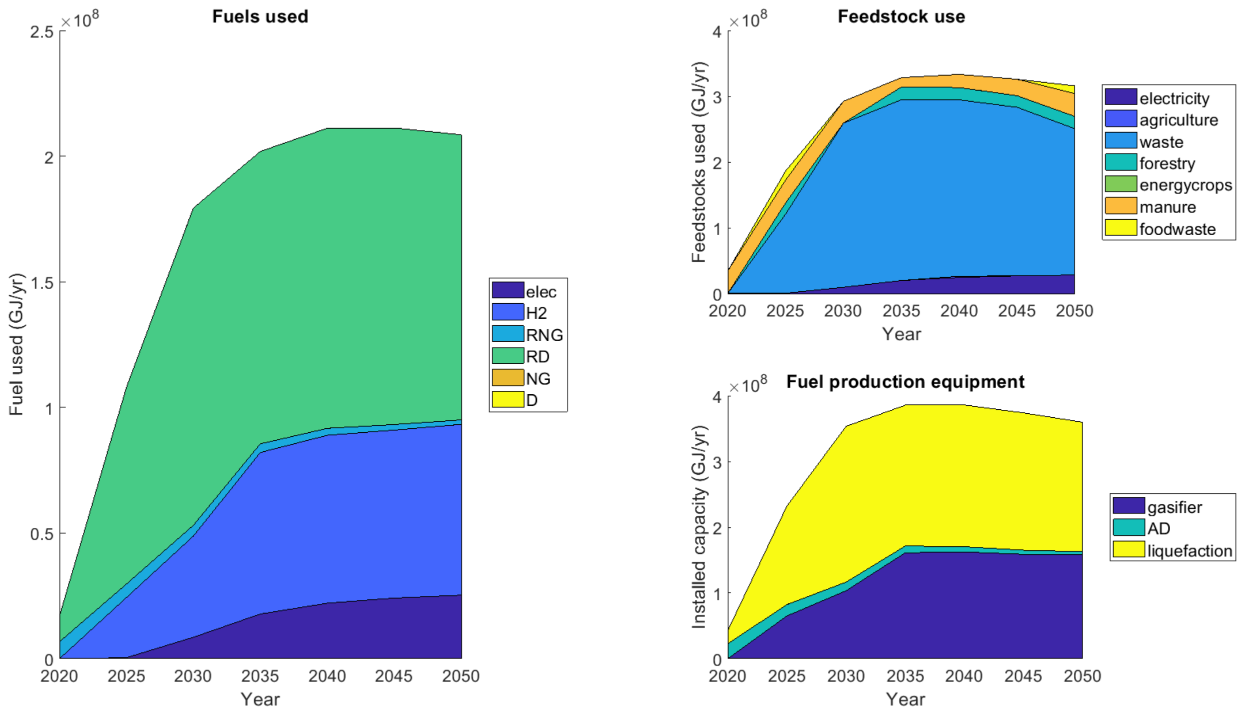
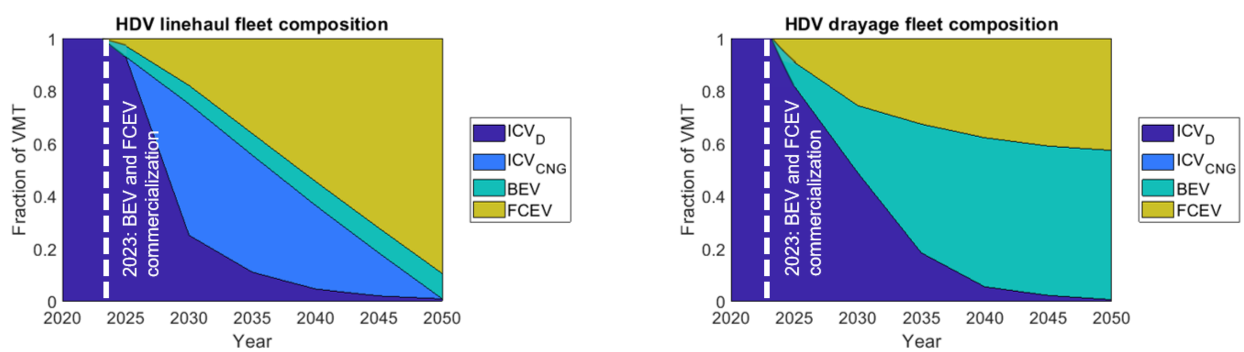


Figure 72. High ZEV scenario: HDV linehaul and drayage fleet composition



Major conclusions of Task 3 are as follows:

- **Clarity is required on the manner by which California GHG laws and goals will be implemented on a sector-by-sector basis in order to determine the emissions reductions for each sector.** The present work assumes the percentage reduction in GHGs will be applied equally across all sectors including HDVs. Therefore, an 80% reduction in HDV GHGs is imposed, even though the Executive Order inspiring that limit only places the goal on California in general. Proportioning the GHG reductions differently amongst the various sectors could have a significant impact on how the HDV sector should evolve, either with more or less aggressive alternative technology adoption depending on how GHG limits are imposed.

- **Planning for the allocation of California's biomass resources should be a high priority as availability for HDV fuel production affects fuel pathway and vehicle powertrain projections and can pose challenges in meeting GHG goals.** The U.S. DOE's Billion Ton Report data are used in this work to set limits on the availability of biomass for HDV renewable fuel production. This work's GHG Scenario is to meet 1990 levels of HDV emissions in 2020, a 40% GHG reduction by 2030, and an 80% GHG reduction by 2050. The resulting fleet mix heavily relies on biomass for HDV fuel production, and in particular negative CI biomass feedstocks. Should the availability of these feedstocks be reduced due to use in other sectors of the economy, misjudgment of availability, or any other reason, resulting fuel pathway and vehicle powertrain projections would be altered and challenges will arise in meeting GHG targets.
- **A heavy reliance on negative carbon intensity (CI) biomass to meet California's HDV GHG goals reduces the adoption rate of ZEVs.** The GHG goals that California has in place could be met, in part, using negative CI biomass to produce fuel for HDVs. ZEVs are projected to play a significant role in reducing emissions, and modeled constraints such as CARB's Advanced Clean Trucks proposed regulations do enhance adoption of ZEVs. However, the use of biomass with negative CI (e.g. manure and food waste) could result in renewable diesel playing a prominent role in attaining necessary GHG reductions at the expense of ZEV adoption. This could yield a cost-effective method of reducing GHGs from the HDV sector. However, the adoption of ZEV in the near- to mid-term results in cost reductions that improve the techno-economics of ZEV pathways in the long-term. Such tradeoffs should be considered in planning decisions.
- **The cumulative cost of aggressive adoption of ZEV is comparable to mixes of renewable diesel and renewable natural gas ICVs, demonstrating the cost reductions that can be realized from pursuing ZEVs in the near- to mid-term.** The cost of the High ZEV Scenario is 0.53% higher than the GHG Scenario.
- **HDV GHG emissions can be reduced below the 2050 target at nearly the same cumulative cost of meeting the target by the imposition of an increasing ZEV mandate.** By imposing an increasingly strict ZEV mandate, starting from 0% in 2020 up to 100% in 2050, the 2050 GHG emissions are 77% lower than the 80% reduction from 1990 levels. However, this High ZEV Scenario leads to higher levels of GHG emissions than required by AB 32 in 2020 and SB 32 in 2030, with later emissions reductions benefited by the 2045 requirement of zero carbon electricity in California.
- **The use of High ZEVs in HDV can support GHG reductions in other difficult to electrify end-use sectors.** In the High ZEV Scenario, low use of biomass for HDV fuels in the near-term frees the biomass for use in other sectors. Priority for biomass in these years can be given to sectors that have greater challenge in electrifying or using electrolytic fuels (e.g. marine, aviation, and freight) and provide the opportunity to advance technologies in the mid-term. With those other sectors given the opportunity to electrify or use electrolytic fuels more successfully, a higher percentage of biomass could be apportioned to HDV fuel production.

- **Hybrid and plug-in hybrid internal combustion powertrains are not prioritized due to the relatively modest efficiency improvement compared to the additional cost of the vehicle.**

- **If aggressive adoption of ZEVs is pursued (e.g. in line-haul), FCEVs play an important role in meeting portions of HDV travel that are less feasible for BEV.** Heavy-duty FCEVs do not have the low range and long fueling time restrictions that BEVs have. This not only increases the extent to which FCEVs and by extension ZEVs can serve the HDV sector, but it can also ease logistical integration of ZEVs into HDV fleets.

- **BEVs generally represent the most cost-effective option for zero emission HDVs, but practically are constrained by range and recharging time limitations, as well as resulting logistical challenges including fleet routes and additional labor required for managing fleet charging.** These constraints limit the extent to which BEVs can be adopted by the various HDV vocations. Should future technology advances significantly extend range and reduce charging time of heavy-duty BEVs, it can be expected that BEVs will increase their prevalence in the heavy-duty sector, though FCEVs will continue to play an important role and provide additional benefits through their connection to the hydrogen grid and associated energy storage aspects.

- **CNG HDVs are attractive as an intermediate solution capable of using renewable natural gas made from low and negative carbon intensity biomass sources combusted in a low-NO_x engine.** However, as emissions constraints get tighter and the limited supply of negative carbon intensity biomass sources are set to lose their environmental credit advantage in the mid-term, these CNG HDVs are not expected to be a significant portion of the long-term heavy-duty fleet in California.

- **Renewable diesel is a cost-effective drop-in fuel that can use low and negative carbon intensity biomass while taking advantage of the expansive diesel infrastructure and the overwhelming majority of HDVs that can use the fuel with no modifications. However, given that that the State may decide to prioritize the limited supply of biomass for other sectors, it is unclear the extent to which renewable diesel will be available for use in HDVs, especially in the absence of a low-NOx diesel engine.**

3.2 Introduction and Background

3.2.1 Motivation

Given the wide range of potential evolutionary pathways for the heavy duty vehicle (HDV) sector in California, clarity is needed regarding the optimal mix of technologies, fuels, and fuel production pathways that can best meet California policy goals while minimizing costs. Issues including fleet turnover periods, barriers, costs, and technological maturity must be considered amongst many other factors. For example, the pace and timing of advances in technology must be appropriately considered to ensure maximization of environmental and community benefits, economic and job growth potential, and system efficiency gains.

After introducing and analyzing the vast number of options for alternative fuel production, infrastructure, and powertrain options for HDVs in Task 1, it is apparent that a comprehensive, objective methodology is needed to account for techno-economic data as well as fuel infrastructure and vehicle use characteristics. The fuel production pathways of Task 1 and vehicle powertrain options detailed in this chapter will serve as the map from which such a methodology will follow, adding to it the necessary data and projections needed to comply with environmental legislation.

3.2.2 Objective

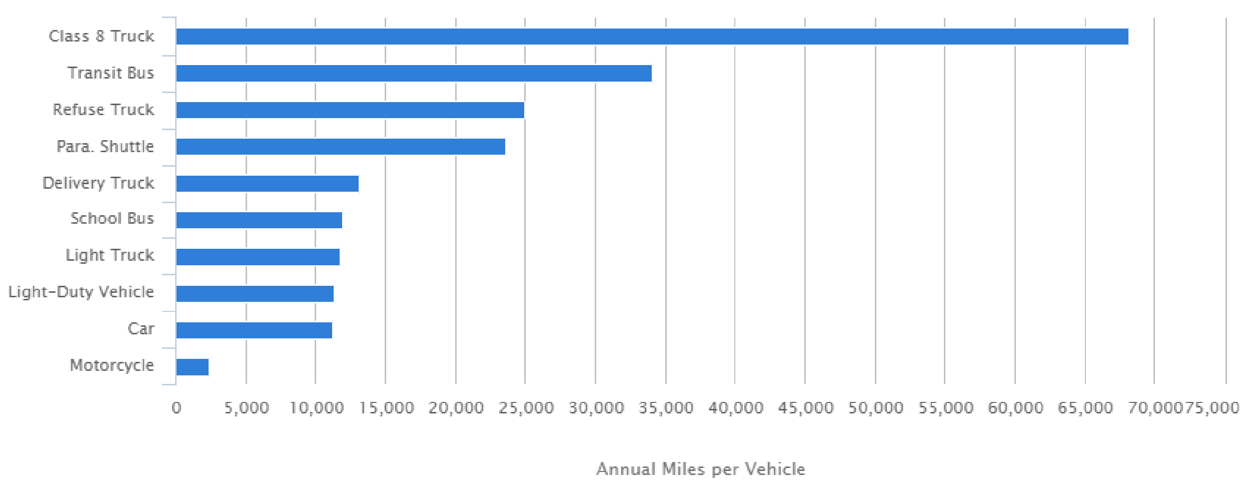
The goal of Task 3 is to develop long-term scenarios for the evolution of the HDV sector in terms of fuels, infrastructure, and powertrains used that can achieve State energy and environmental goals. To do so, an optimization platform including techno-economic characterization of alternative HDV powertrains is developed to generate various fleet mix scenarios and assess them holistically for emissions, cost, and other relevant metrics. The results provide insight into the best evolutionary path forward for the HDV sector in California.

3.2.3 Background

Heavy-Duty Vehicle Powertrains

HDVs are classified by their weight. In fact, all such large vehicles are classified into a scheme from Class 1 through Class 8 based on their gross vehicle weight rating (GVWR), which is the total weight of the loaded vehicle including cargo. Given the very wide range of vehicles it is not feasible to model all GVWR classes. The present work focuses on only Class 8 HDVs, which are 33,001 pounds and greater. These Class 8 HDVs are responsible for the most vehicle miles traveled (VMT) of any vehicle category [345], as shown in Figure 73. Class 8 HDVs are also responsible for a large portion of GHG and CAP emissions in the transportation sector [346][1].

Figure 73. Annual VMT by vehicle category, from U.S. Department of Energy [345]



Six powertrain configurations can be found in the literature for being potential contenders in both the current and future market for HDVs: ICVs, hybrid electric vehicles (HEVs), PHEVs, BEVs, FCEVs, and PFCEVs [347]–[351]. For vehicle types with a combustion engine (ICVs, HEVs, and PHEVs), the specific fuel used is a further consideration. For HDVs in the U.S., both diesel and natural gas are prevalent depending on the vocation (i.e. type of work, including long haul, refuse collection, etc.); therefore, both of these fuels are considered for the combustion engine of HDVs in this work.

The transition of HDVs is not as rapid or as ripe with options as that of passenger vehicles. Currently, about 98% of Class 8 HDVs are diesel-fueled ICVs [1]. However, there is strong encouragement to increase the rate of alternative fuel powertrain adoption for HDVs. The California Energy Commission (CEC) awarded an $8 million grant for a hydrogen refueling station dispensing hydrogen sourced exclusively from biogas at the Port of Long Beach using a technology known as tri-generation to produce electricity, heat, and hydrogen fuel to support the use of FCEV Class 8 drayage trucks [140][352]. Grants like this along with the various laws, regulations, and goals of California show the focus on transitioning HDVs to cleaner technologies.

Important to note are different vocations for HDVs. HDVs are specialized in a task or set of tasks. These tasks vary from transporting goods from ports to distribution centers, hauling goods long distances, collecting trash from communities and delivering it to landfills, and many others. For this work, four vocations are selected based on total number of miles traveled in California and the relative impact they have on air quality through CAP emissions. The four vocations considered are as follows: (1) linehaul, which transport goods long distances, (2) drayage, which transport goods from ports to distribution centers, (3) refuse, which collect waste from various locations and transport it to processing centers or landfills, and (4) construction, which move construction material or assist in construction of buildings and other built structures. The inclusion of these four vocations provides a good representation of the HDV sector, including the range of technical and economic features that may result in one alternative technology being more attractive for a given vocation.

Vehicle emissions are composed of the emissions from the vehicles tailpipe and also include other emissions such as tire and brake emissions. While tire and brake emissions do depend on vehicle mass (which varies from one vehicle powertrain to another), this factor is not considered in this work as data on the emission differences between vehicles is not currently available. Neither is potential reduced braking of electric powertrains. Therefore, all vehicle powertrains are assumed to have the same tire and brake emissions. Due to this assumption, there is no comparative advantage between powertrain configurations in this modeling, so these tire and brake emissions are neglected in this work. Future work should consider this issue as appropriate data becomes available.

The BEV, FCEV, and PFCEV are all zero-emission vehicles (ZEVs), meaning there are no tailpipe emissions from these vehicles. All other powertrain configurations have tailpipe emissions that must be analyzed.

There has been recent advancement in ICV engines which are referred to as low-nitrogen oxides (low-NO_x) engines. Both diesel and CNG engines have low-NOx variations that are either available now (for CNG) or expected to be on the market soon (for diesel) [353]. These standards set limits of 0.02 grams of NOx emission for each brake horsepower-hour of operation [354], [355]. It is assumed that any HDVs that are fueled by either RNG or renewable diesel in this modeling effort will be low-NO_x engines once the technology has become available. More information on the availability of low-NO_x diesel engines will be detailed later.

Internal Combustion Vehicle

ICVs have been the primary vehicle type in recent history. ICVs use a fuel (typically the hydrocarbons diesel or natural for HDVs). This fuel is combusted in the engine which, through mechanical linking of the powertrain, leads to the spinning of the vehicle's wheels. The combustion process leads to tailpipe GHG and CAP emissions from these vehicles.

Diesel is a liquid fuel, so it is stored in a typical liquid fuel tank. RNG is a gaseous fuel, so to store any reasonable quantity of fuel on the vehicle, RNG must be stored either at pressure or a liquid after being liquefied. Storing as a gas is more prevalent in vehicles and more efficient as it does not require the energy intensive and costly step of liquefying. Either option requires a robust tank that can withstand significant pressure.

Hybrid Electric Vehicle

HEVs add a traction battery and electric motor to the ICV powertrain to gain efficiency in moving the vehicle. The addition of the battery and electric motor offer two main benefits over the ICV. First, the HEV can recharge its battery when braking by running the electric motor in reverse, as a generator. This is known as regenerative braking and is done instead of or in addition to using the brakes of the vehicle, which has the additional benefit of extending brake pad life. Regenerative braking reduces the amount of fuel needed because the battery helps accelerate and drive the vehicle in addition to using fuel in the combustion engine. HEVs also allow the engine to run at more efficient operating conditions while the battery works on the dynamic portions of the power demand.

Plug-in Hybrid Electric Vehicle

The evolution of the HEV is the PHEV. Quite similar to HEVs, PHEVs have two major benefits stemming from the inclusion of a larger traction battery than the HEV: (1) a modest battery electric range (BER) and (2) recharging of the traction battery from an external electricity supply, which classifies the PHEV as a PEV. This allows for efficient and tailpipe emissions-free driving for a limited range but does not limit drivers to only go short distances as a combustion engine works as a range extender.

Due to the design characteristics of PHEVs, which are catered toward shorter distances and stop-and-go duty cycles, the present work assumes they will not be used in long distance linehaul HDV applications.

Battery Electric Vehicle

BEVs are powered by a traction battery, typically significantly larger than that of PHEVs. This increased size is needed as the battery is the sole source of power to move the vehicle. Refueling the BEV is done by connecting the vehicle to some electricity source. Typically, this electricity source is the electric grid, but with the right equipment, it would be possible to recharge the BEV (or any other PEV) from off-grid renewable electricity.

Because there is no combustion engine in a BEV, there are no tailpipe emissions. In fact, there is no tailpipe at all. BEVs also have very high efficiency compared to most other vehicle types. However, they typically cannot drive as far or refuel as fast as other vehicle types.

While BEVs do not have tailpipe emissions, they can indirectly create emissions depending on the source of the electricity charging them. If a BEV is charged using only renewable sources, it is effectively emission-free (aside from other life-cycle emissions such as manufacturing that is beyond the scope of this work). However, if the BEV is charged from the California electric grid, it has emissions associated with the natural gas power plants that, along with the emissions-free renewables, are part of the electric grid. There is a trend of increasing emission-free electricity, particularly in California, so the emissions of BEVs (and all PEVs) are decreasing accordingly [356].

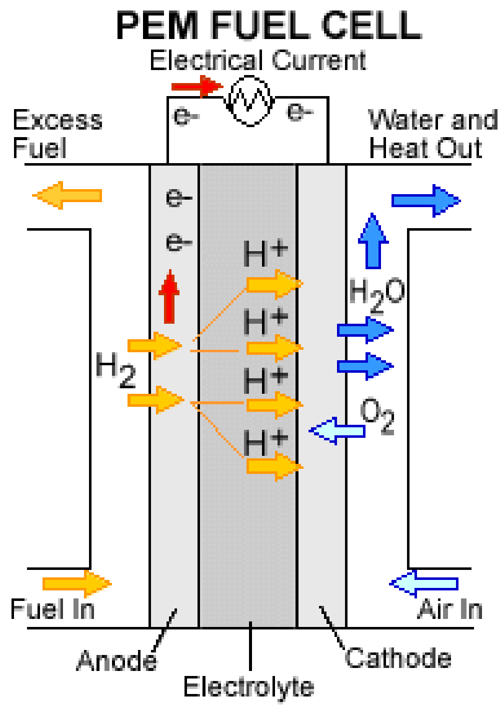
For HDVs, long charging time and short driving range can severely limit the types of work these vehicles are able to do. Therefore, careful consideration must be given for BEV adoption in the HDV sector. While improving battery and charging technology may increase the aptitude of heavy duty BEVs, current thinking is that BEVs will have a limited role in the heavy duty sector, particularly regarding range.

Note that catenary HDVs, which use external electrified lines to charge the battery of a vehicle (whether BEV or any PEV), are not considered in this work due to the necessity of spatial resolution. Catenary technology is best suited for particular sections of a highway that may cause trouble for a HDV relying on batteries, for example, an extended incline, and that spatial resolution is not within the scope of this work [357]. This does not mean, however, that catenary HDVs will not play a role in helping to electrify some HDV areas. This work assumes that application of catenary HDVs will be done on a case-by-case basis in a limited number of locations.

Fuel Cell Electric Vehicle

FCEVs are powered by a fuel cell. A fuel cell is an electrochemical device, similar to a battery. The main difference is a battery stores its fuel and oxidant within the housing of the battery itself. A fuel cell stores these two outside, with the fuel in a tank and oxidant often being ambient air. This key difference allows for the power and energy to be scaled independently for fuel cells, unlike batteries. FCEVs use proton exchange membrane fuel cells (PEMFCs) as they are relatively low temperature (below 100 °C) and handle dynamic operation better than other fuel cell varieties. PEMFCs operate on hydrogen fuel. Because hydrogen is a gas with relatively low volumetric energy density, it must be compressed to very high pressures (typically 35 MPa for most HDVs) for vehicular use. A schematic diagram of a PEMFC is shown in Figure 74. One important note is that, despite not being in the name, FCEVs are typically hybrids with a traction battery installed to allow for regenerative braking and efficient fuel cell operation. FCEVs in this work are assumed to be hybrids.

Figure 74. Schematic of PEM Fuel Cell, from U.S. Department of Energy [358]



FCEVs are nearing entrance to the commercial market in the HDV sector, though their light-duty counterparts have been available for several years. Their overall emissions are dependent on the method of fuel production (of which there are many options, as has been detailed). Nearly all of the current production of hydrogen in the U.S. is from natural gas by SMR [58]. This will likely change in future as, already, California requires at least one third of the hydrogen sold at fueling stations has to have a renewable feedstock if that station receives State funds [30]. This requirement will necessarily increase the use of biomass and renewable electricity in hydrogen production.

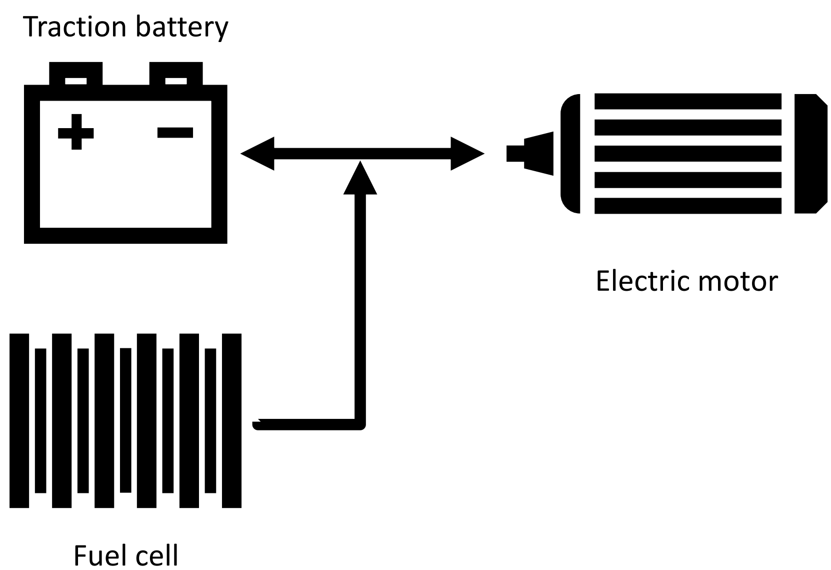
In practice, FCEVs share similarities to both BEVs and ICVs. Like BEVs, FCEVs have no tailpipe emissions, other than the small amount of water produced by the fuel cell, and relatively high efficiency, though not as high as that of BEVs. Like ICVs, refueling FCEVs is fast, nearly as fast as refueling a diesel vehicle. Additionally, driving range is also comparable to ICVs due to the independent sizing of power and energy, so an adequately sized hydrogen tank can be incorporated. The former qualities make an environmentally friendly vehicle. The latter qualities make a vehicle convenient for drivers and fleet managers.

While the above is true in theory, the current lack of hydrogen fueling infrastructure means fueling is not yet very convenient. This becomes less of an issue with time as the fueling infrastructure develops and optimism in the market increases. The LDV hydrogen fueling network has grown significantly in recent years and is now comprised of 44 stations throughout California with 18 stations planned [359]. This demonstrates that ability of California to successfully scale up hydrogen refueling networks and, while challenging, it is clearly feasible for the same to be accomplished for HDV. Indeed, steps are already being taken towards this eventuality, e.g., the California Energy Commission has awarded an $8 million grant for a hydrogen station at the Port of Long Beach which will use 100% biogas [117].

Plug-in Fuel Cell Electric Vehicle

The PFCEV shares similarities with the FCEV and PHEV. From a systems level, the PFCEV operates the same as a PHEV; however, instead of a combustion engine, the PFCEV has a fuel cell and it is fueled by hydrogen. A schematic of a PFCEV powertrain can be seen in Figure 75. Note that all of the powertrain components are electric. This increases the efficiency compared to the PHEV as it removes the efficiency loss of converting from mechanical energy of a combustion engine to electrical energy through an electric generator. Similar to PHEVs, PFCEVs allow for limited driving on the very efficient and potentially clean battery electricity, but a more important benefit of the heavy duty PFCEV would be in using the battery power in conjunction with the fuel cell, allowing for a downsized fuel cell and hydrogen tank when compared to the FCEV.

Figure 75. Simplified powertrain schematic of PFCEV



PFCEVs are not yet commercially available in the heavy duty sector. Technological progress is further developed in the light-duty sector, where a recent Mercedes-Benz pilot program of leased PFCEVs has given early adopters the chance to use and test this powertrain technology [360], [361]. The literature has many studies analyzing this vehicle powertrain configuration, though most is focused on the light-duty sector [347], [348], [350], [362]–[367]. While the PFCEV powertrain may have value in the HDV sector in the future, the justification for further analysis in this work is not present at the moment.

Heavy-Duty Vehicle Components

Having described each of the vehicle powertrains considered in this work, it is helpful to now summarize the various components of these vehicles that will be combined to determine an overall vehicle cost in this work. These components are listed in Table 29.

Table 29. HDV components used in modeling

Component	Component description
Glider	The HDV glider includes all of the vehicle components that are not part of the powertrain. This includes parts such as the chassis, wheels, windows, etc.
IC engine, diesel	For HDVs, the diesel IC engine is one option for the power plant of ICVs, as well as a co-power plant (along with a battery) of HEVs and PHEVs
IC engine, CNG	For HDVs, the CNG IC engine is one option for the power plant of ICVs, as well as a co-power plant (along with a battery) of HEVs and PHEVs
Fuel cell	The fuel cell is the sole power plant of FCEVs and co-power plant of PFCEVs
Traction battery	The traction battery is the sole power plant of BEVs, and co-power plant of HEVs, PHEVs, FCEVs, and PFCEVs
Electric motor / generator	The electric motor is used in all electric powertrains (HEV, PHEV, BEV, FCEV, and PFCEV) to convert electrical energy to motion of the wheels, and it can be run in reverse as a generator to convert wheel motion into electric energy
Diesel fuel tank	The diesel fuel tank holds diesel for ICVs fueled by that liquid fuel
CNG FUEL tank	The CNG fuel tank is a stronger, more robust tank that holds pressurized CNG (typically around 25 MPa [368]) for HDVs fueled by CNG, which is typically stored as a gaseous fuel
Hydrogen fuel tank	The hydrogen fuel tank is an even stronger and more robust tank that holds pressurized hydrogen (typically gaseous at around 35MPa) for vehicles fueled by hydrogen
Hybrid adder	The HDV hybrid adder accounts for various equipment beyond the traction battery and electric motor (i.e. controls, wiring, etc.) needed to convert an HDV powertrain into its equivalent hybrid one
Plug-in hybrid adder	The HDV plug-in hybrid adder accounts for various equipment beyond the traction battery and electric motor (i.e. controls, wiring, etc.) needed to convert an HDV powertrain into its equivalent plug-in hybrid one

Optimization and Linear Programming

So far, many vehicle fuel production pathways have been introduced. Furthermore, several vehicle types that can use those fuels have been introduced. Together, there is a wide range of potential options that can be pursued for the transportation sector. In a problem as complex as this, it is important to have a systematic and objective approach.

Optimization is a mathematical methodology which selects the "optimal" option from a given set of possibilities. Here, "optimal" is defined using what is known in the optimization discipline as the cost (or objective) function. Each possible solution has an associated cost which is defined by this cost function, and the optimal solution is typically the one with the lowest cost.

In addition to the cost function, optimization often includes constraints. These are mathematical representations that prevent certain solutions from being chosen for any desired reason, such as physical impossibility or respecting an existing regulation.

Linear programming (LP) is a subset of optimization in which the cost function(s) and each of the constraints is linear. This means that of every term in the cost function(s) and constraints, there is at least one term that is of mathematical order one, and there are no terms of higher order. Linear programming is less computationally intensive than non-linear programming, leading to solutions that converge much faster and consistently. In general, it is advisable to attempt to linearize a non-linear problem using approximations to make solving the programming problems faster and better-behaved (better convergence). Linear programming is used in this work for the above reasons.

3.3 Methods

First, a similar techno-economic characterization approach like that of Task 1 work is applied to HDVs, focusing primarily on the various powertrains. Major powertrain components are characterized including size and cost. Cost projections are made using Wright's Law on a component basis. Additionally, vehicle efficiency is characterized.

Following Task 1 results which included determining viable fuels and powertrain configurations for HDVs, this work of Task 3 takes the techno-economic results and inputs them into an optimization model. This optimization model is named Transportation Rollout Affecting Cost and Emissions, or TRACE.

Beyond the techno-economic data, also included are environmental legislation and goals. Examples include AB 32, SB 32, and CA Executive Order #S-03-05 which all constrain greenhouse gas (GHG) emissions from 2020 to 2050 [18]–[20]. Other constraints are added as well, such as fuel feedstock availability, vehicle powertrain availability, vehicle miles traveled (VMT) demand of modeled HDV vocations, and several others to better reflect how the technologies could deploy in the real world.

3.3.1 Heavy-Duty Vehicle Powertrain Configurations

Four main HDV class 8 categories are modeled in this work: linehaul, drayage, refuse, and construction. These categories were selected based on the number of miles traveled and the amount of GHG and CAP emissions from them. These four vocations were selected to have a balance between adequately representing the wide range of HDVs (each with their own technical requirements, duty cycles, powertrain specifications, etc.) without going beyond the scope of this work and getting lost in the vast amount of work that must be done to characterize every single HDV category.

Vehicle Efficiencies

Shown in Table 30 are the efficiencies of each of the HDV powertrains introduced above for each of the four vocations modeled in the simulation year 2020. Efficiency projections into the future will be detailed shortly. The "vehicle efficiency" number is the typical miles per diesel gallon equivalent

(MPDGE) that one typically sees for HDVs. For vehicles that have both battery and a range extender, this efficiency is known as the charge sustaining (CS) efficiency as it is the efficiency of the vehicle when not using the battery. The “charge depleting (CD) efficiency” is applicable only for PEVs, and it is the efficiency of the vehicle when driven on the battery alone, depleting its charge. In comparison, for PEVs, the former “vehicle efficiency” could be considered the charge sustaining (CS) efficiency, meaning the electric charge of the vehicle is held constant and only the range extender is used, if one is available. The CD efficiency is shown in miles per kilowatt-hour. Note that the BEV efficiency is not shown as the CD efficiency as the battery is the only source of power for BEVs and efficiency is easier to compare using the MPDGE value. Determining these efficiencies for HDVs takes some extrapolation because not all of the powertrains are available for purchase or have much public information at the time of this work.

First is a focus on linehaul HDVs. The efficiencies for the ICV, HEV, PHEV, BEV, and FCEV linehaul vehicles are from Zhao et al. [369]. The CS efficiency for the HDV PHEV is determined by taking the ratio of the LDV PHEV CS efficiency compared to the LDV HEV efficiency and multiplying that ratio to the efficiency of the corresponding HDV HEV. The methodology is captured in Equation 12.

Equation 12. CS efficiency of HDV PHEV

$$\eta_{CS,HDV\ PHEV} = \frac{\eta_{CS,LDV\ PHEV}}{\eta_{LDV\ HEV}} * \eta_{HDV\ HEV}$$

The CD efficiency of the HDV PHEV is obtained by multiplying the above CS efficiency for the vehicle by the ratio of CD efficiency to CS efficiency of the LDV PHEV. The methodology is captured in Equation 13.

Equation 13. CD efficiency of HDV PHEV

$$\eta_{CD,HDV\ PHEV} = \frac{\eta_{CD,LDV\ PHEV}}{\eta_{CS,LDV\ PHEV}} * \eta_{CS,HDV\ PHEV}$$

Next is to determine the efficiencies of the other vocations for the HDVs. Work by Kast et al. [227] is used to extrapolate the linehaul efficiencies to the three other HDV vocations of the present work. Kast et al. details the differences in efficiency for FCEVs by vocation using an appropriate duty cycle for the simulation of the vehicles. While the work only details the efficiencies for FCEVs, the present work assumes those efficiency differences will carry across all powertrain types. The efficiencies for HDV vocations have now been determined and are presented in Table 30.

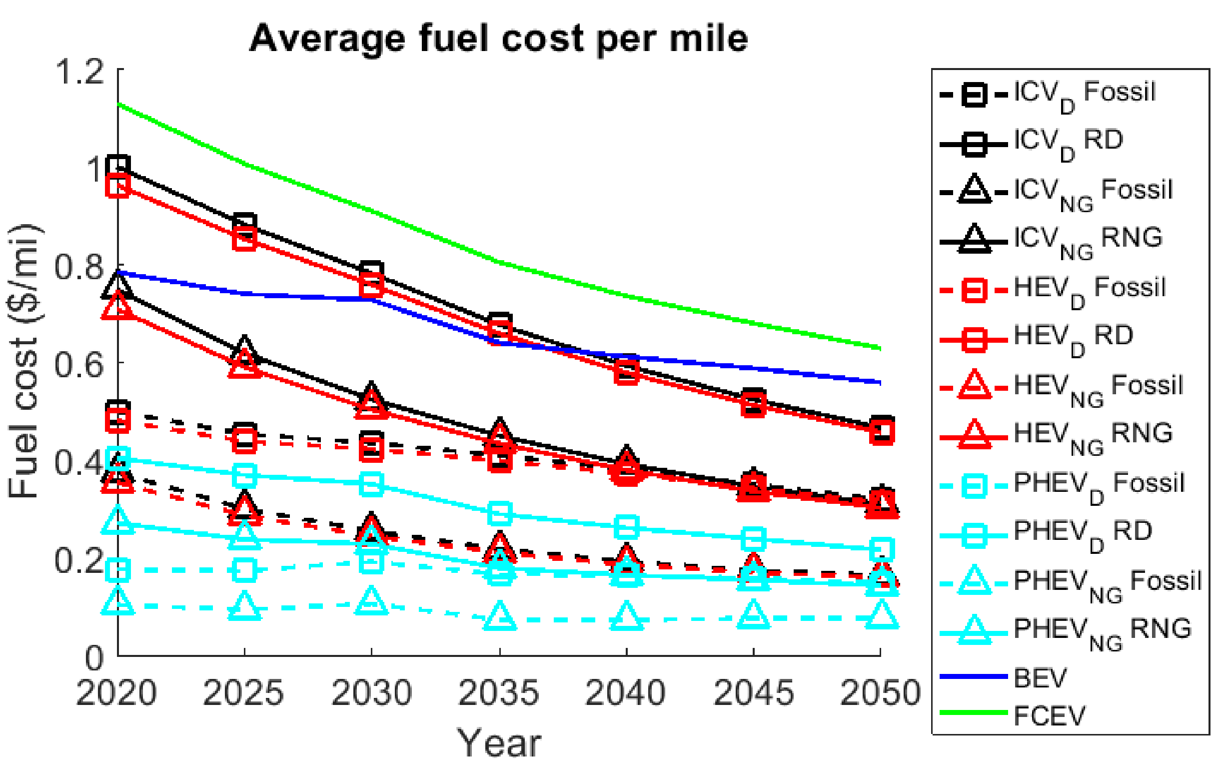
Vehicle efficiency projections into the future are based on historical vehicle efficiency improvements. Sival and Schoettle show HDVs have improved in efficiency by about 1.15 MPG every 5 years from 1982 until 2015 [370]. While it is possible that the advanced alternative vehicles, such as FCEVs or BEVs, may have different efficiency improvements over time compared to the historical powertrains included in the referenced work, these vehicles have not been on the market long enough to determine if there will be any significant difference in efficiency evolution. Therefore, the assumption of using the same projection is used due to the lack of more-detailed information.

Table 30. HDV efficiencies for the year 2020

Powertrain		Vehicle efficiency (MPDGE)				CD efficiency (mi/kWh)			
		Linehaul	Drayage	Refuse	Const-ruction	Linehaul	Drayage	Refuse	Const-ruction
ICV	Diesel	5.59	6.30	6.50	9.35	-	-	-	-
	CNG	4.37	4.93	5.09	7.31	-	-	-	-
HEV	Diesel	5.81	6.55	6.76	9.72	-	-	-	-
	CNG	4.62	5.21	5.38	7.73	-	-	-	-
PHEV	Diesel	-	6.80	7.02	10.09	-	0.32	0.31	0.21
	CNG	-	5.41	5.58	8.03	-	0.25	0.24	0.17
BEV		12.23	10.85	10.51	7.31	-	-	-	-
FCEV		7.15	8.06	8.32	11.96	-	-	-	-

Combining the fuel costs presented previously with the efficiency projections above, Figure 76 shows the average fuel cost per mile of the various vehicles.

Figure 76. Heavy-duty vehicle fuel cost per mile projections



Vehicle Costs

The approach for determining vehicle costs is to categorize vehicle cost by their components as introduced previously. The reason for this is that each vehicle component will have different learning rates (LRs) associated with them. For example, the vehicle glider, which is a very mature technology, will have a lower LR compared to a fuel cell, which is a much less mature technology. Note that the default LRs used are reminiscent of those for some of the fuel production technologies. A LR of 0.1 is used for more mature technologies, and a LR of 0.14 is used for less mature technologies. Both the costs and LRs for each of the major vehicle components is listed in Table 31. Note the hybrid and plug-in hybrid cost adders. These adders consider the additional cost beyond just the battery addition of a hybrid, such as control equipment, wiring, and additional engineering work that go into creating these vehicle types. The cost values in Table 31 are sourced primarily from Zhao, Burke, et al. [369] and Zhao, Wang, et al. [371], with some changes to better match expected values.

Table 31. Vehicle Component Starting Costs and Learning Rates

Component	Cost	Units	Component LR
Glider, HDV	95,539.00	$	0.1
ICE, gasoline	27.78	$/kW	0.1
ICE, diesel	27.78	$/kW	0.1
ICE, CNG	30.86	$/kW	0.1
Fuel cell	300.00	$/kW	0.14
Traction battery	300.00	$/kWh	0.14
Electric motor and inverter	50.00	$/kW	0.1
Diesel fuel tank	79.31	$/GJ	0.1
CNG fuel tank	2,207.23	$/GJ	0.1
Hydrogen fuel tank	4,166.67	$/GJ	0.14
Hybrid cost, HDV	15,000.00	$	0.1
Plug-in hybrid cost, HDV	25,000.00	$	0.1

In addition to the component costs, the component specifications for each vehicle are also needed to determine the total vehicle cost. These vehicle specifications are shown Appendix C. Note that the values listed there are from a variety of sources [227], [347], [369], [371], [372]. Some modifications are made to some of the HDVs to ensure that vehicle powers and driving ranges are adequate to meet the needs of different vocations, particularly with power requirements of drayage trucks (400 horsepower) [36], [373] and range requirements of linehaul and drayage trucks [373]. BEVs are expected to have difficulty in meeting range requirements of some HDV vocations, so lower ranges are modeled with the tradeoff that use will be limited; those issues will be addressed in more detail later in the model constraints.

Total costs for the various vehicle powertrain configurations can be seen in Table 32 for HDVs. Note that these costs are the starting costs, used initially at year 2020 in the model runs. The costs of these vehicles will come down as more are selected to be produced by the modeling, according to the cost and LR of the individual powertrain components listed in Table 31 as part of Wright's Law.

Table 32. HDV starting costs by powertrain configuration and vocation

Powertrain		Starting cost ($)			
		Linehaul	**Drayage**	**Refuse**	**Construction**
ICV	**Diesel**	105,539.02	102,874.55	102,426.44	100,732.75
	RNG	140,539.32	133,801.51	112,874.33	114,769.74
HEV	**Diesel**	128,516.30	129,461.18	128,977.10	123,043.41
	RNG	163,236.29	160,187.34	139,219.39	136,931.01
PHEV	**Diesel**	-	179,784.33	164,619.80	153,218.30
	RNG	-	207,613.50	173,688.97	164,701.03
BEV		265,539.00	242,844.37	238,780.92	195,958.66
FCEV		285,572.67	240,731.64	219,544.14	179,068.41

Vehicle Tailpipe Emission Factors

Emission factors for BEVs and FCEVs are quite simple as they are all ZEVs, so they all have emission factors of zero for the vehicles themselves. It is important to remember, however, that this does not mean there are no emissions associated with using these vehicles. There are still potentially emissions associated with the fuel production, depending on which fuel feedstock is used. The ICVs, HEVs, and PHEVs have tailpipe emissions and therefore it is necessary to characterize these vehicles' emission factors.

The total effective GHG emissions can be calculated from the three main GHG emissions using what is known as global warming potential (GWP) of the individual emissions. The GWP relates the strength of a GHG to carbon dioxide. For example, a GHG that has ten times the heating effect per quantity of emission compared to carbon dioxide has a GWP of 10. The sum of GHG emissions is often given in the units of some mass of carbon dioxide equivalent (CO_{2e}). Equation 14 shows the total GHG emissions given the three primary GHG emissions, which are carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O).

Equation 14. GHG emissions from individual components

$$\text{mass of GHG, CO}_{2\text{e}} = 1 * (mass\ of\ CO_2) + 25 * (mass\ of\ CH_4) + 298 * (mass\ of\ N_2O)$$

GHG tailpipe emission factors for HDVs are calculated using GREET 2018 Well-to-Wheel Calculator. The GHG emission factor for diesel-fueled vehicles is 12,444 $gCO2_e$/DGE and for CNG-fueled vehicles it is 9963 $gCO2_e$/DGE [42]. Values for the VOC, CO, NO_x, and PM are California Air Resources Board levels for the federal test procedure. The CNG engine is based on a Cummins 11.9 L CNG engine from 2019 [374], which is a low-NOx engine as it meets the standard of 0.02 grams of NOx emission for each brake horsepower-hour of operation (g/bhp-h) [354], [355]. The diesel engine is based on a Cummins 11.8 L diesel engine from 2019, with the NO_x emissions artificially lowered to the low-NOx standard [375]. This assumption for low-NO_x diesel engines is made to the lack of test data for these vehicles. Values for HDV tailpipe emission factors are shown in Table 33. Units have been converted to g/DGE to allow for easier comparison, despite being somewhat inappropriate for HDVs (as HDVs do not typically take gasoline as a fuel).

Table 33. Low-NOx HDV tailpipe emission factors

Powertrain	**Emission factor (g/DGE)**				
	GHG (CO_{2e})	**VOC**	**CO**	**NO_x**	**PM_{10}**
Low-NO_x CNG – ICV, HEV, and PHEV	9963	0.23	84	0.56	0.56
Low-NO_x diesel – ICV, HEV, and PHEV	12,444	0.56	23	1.1	0.23
BEV and FCEV	0	0	0	0	0

Combining the above emission factors with the efficiencies of each of the powertrain configurations yields the emissions in terms of grams per mile. This along with the VMT yields the total emissions of these vehicles. Vehicle emission factors are assumed to be constant through time, but the efficiency improvements yield lower emissions per mile traveled as time progresses.

3.4.2 Establishing the Optimization Problem

The various components of the chain from fuel production to vehicles have been analyzed for efficiency, emissions, and cost; and Wright's Law has been identified as the methodology of projecting these costs into the future. With these data, it is now possible to calculate the total cost of each potential pathway. Additionally, the various constraints of the problem have been detailed. This section is devoted to describing how these costs and constraints are implemented into a formal optimization problem for the timeframe of 2020 (the near future) into 2050.

The modeling tool developed to project the rollout of fuel and vehicle technologies is named Transportation Affecting Cost and Emissions (TRACE). The model, including projections and optimization, will hereafter be referred to as TRACE.

Optimization Method

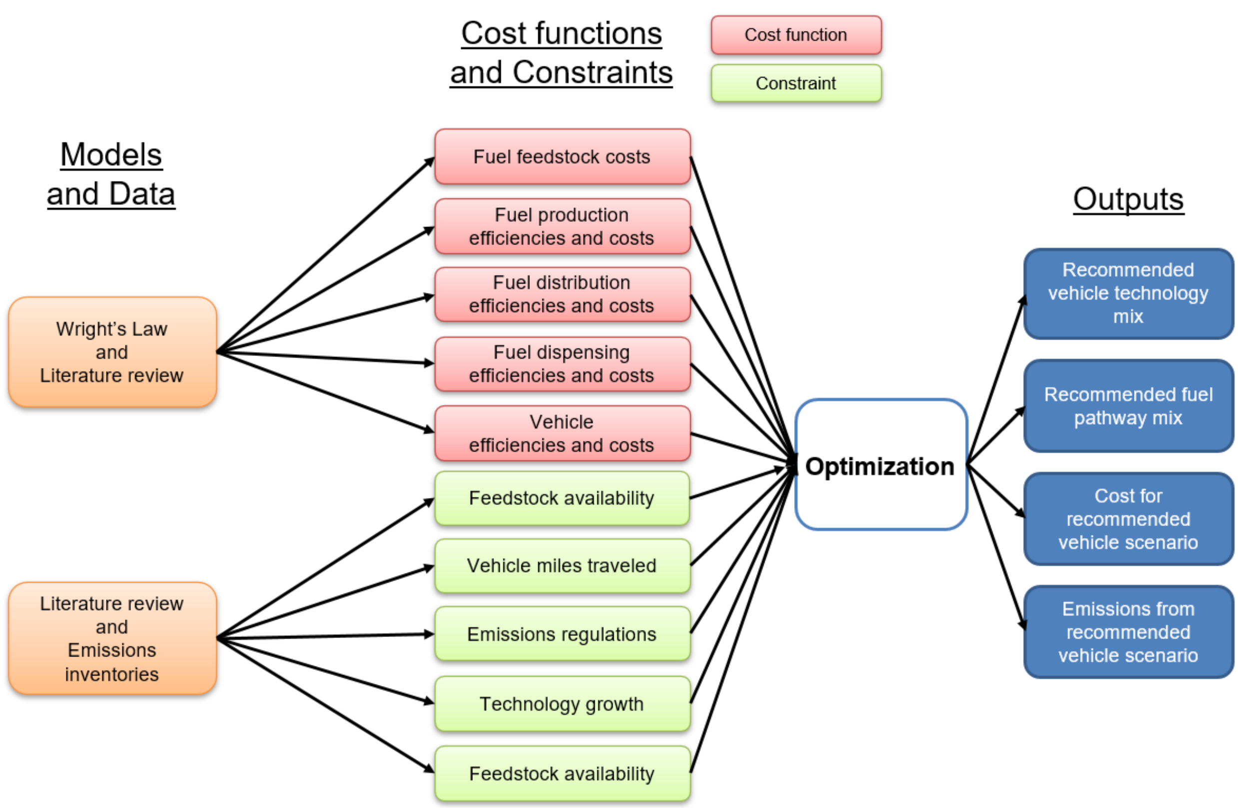
Given the techno-economic data and constraints, linear programming is an appropriate optimization framework for TRACE. As there is no explicit spatial consideration in this work, individual fueling stations are not considered, but instead analyzed as a continuous quantity of fuel being distributed and dispensed with costs varying continuously as well.

IBM's CPLEX software integrates well with MATLAB, so it is the software of choice. Additionally, the MATLAB toolbox YALMIP is used to set up the constraints of the optimization problem [376].

The variables that describe this problem are the fuel pathways and the miles traveled by vehicles. Fuel pathways are differentiated by feedstock (and, when appropriate, feedstock separated by distinct selling price) and fuel production technology. Vehicles are differentiated by each of the HDV vocations for all appropriate vehicle powertrain configurations.

TRACE operates in five-year increments from 2020 to 2050, where each five-year segment is assumed homogenous for total cost purposes, while results displayed in 3.4 Results and Discussion include interpolation between those segments. A flowchart of the structure of TRACE is presented in Figure 77.

Figure 77. TRACE model diagram



Cost Function

The cost function of TRACE is determined by the techno-economic data gathered and projection methods described in Chapter 1 and the preceding portion of Chapter 3. Each fuel pathway and corresponding vehicle powertrain configuration will have an associated cost per amount of energy of fuel and correspondingly number of vehicles. A 2% rate of inflation is assumed [142] and a capital recovery factor (CRF) of 0.12 is used to annualize the capital costs of fuel production equipment and vehicle cost [143].

The cost function is generally split into two categories: (1) fuel feedstock, production, distribution, and dispensing; and (2) vehicles. One exception to the above is for PEVs. For PEVs, the electricity feedstock cost is calculated separately and both electricity distribution and dispensing costs are lumped with the PEV cost (recall that electricity production costs are incorporated into the feedstock cost). This is because electricity distribution and dispensing costs are dependent upon the level of charging power required by the PEV. Due to these infrastructure cost differences; the distribution and dispensing costs are grouped with the vehicle cost so the appropriate numbers are used.

The TRACE cost function is presented in Equation 15. This cost function is minimized for each timestep (i.e. 2020 to 2050 in five-year increments). After each timestep, costs and efficiencies are updated as noted previously.

Equation 15. TRACE cost function

$$\min\left(\sum_{i,j,k,m,t}\left(\frac{feedstock_{i,t}+\dfrac{\left(\dfrac{\left(production_{j,t}*CRF\right)+FOM_j}{CF_i*8760\,\frac{h}{yr}}+VOM_j\right)}{0.0036\,\frac{GJ}{kWh}}}{\eta_{production,j,t}*\eta_{distribution,k}*\eta_{dispensing,m}}+\frac{distribution_k}{\eta_{dispensing,m}}+dispensing_m\right)*x_{n,t}+\sum_{p,q,t}\left(\frac{vehicle_{p,t}*CRF}{aaVMT_q}\right)*y_{p,t}\right)$$

The sets, variables, and parameters used in Equation 15 are described in Table 34.

Table 34. Description of optimization problem sets, variables, and parameters for TRACE cost function

Sets	**Description**	**Units**
$i \in I$	Set of fuel feedstocks at each selling price	-
$j \in J$	Set of fuel production equipment technologies	-
$k \in K$	Set of fuel distribution methods	-
$m \in M$	Set of fuel dispensing methods	-
$n \in N$	Set of appropriate combinations for the fuel feedstocks, production technologies, distribution methods, and dispensing methods for fuel pathways	-
$p \in P$	Set of vehicle types including HDV vocation and powertrain configuration	-
$q \in Q$	Set of HDV vocations	-
$t \in T$	Set of timesteps modeled	-
Variables	**Description**	**Units**
$x_{n,t}$	Fuel decision variable	GJ/yr
$y_{p,q,t}$	Vehicle decision variable	mi/yr
Parameters	**Description**	**Units**
$feedstock_{i,t}$	Cost of fuel feedstock i at timestep t	$/GJ
$production_{j,t}$	Cost of fuel production equipment j at timestep t	$/kW
CRF	Economic term to convert capital cost into annual payments	-
FOM_j	Cost of FOM for fuel production equipment j	$/kW-yr
VOM_j	Cost of VOM for fuel production equipment j	$/kWh
CF_i	Fraction of nameplate capacity a fuel production facility uses on average	-
$distribution_k$	Cost of fuel distribution method k	$/GJ
$dispensing_m$	Cost of fuel dispensing method m	$/GJ
$\eta_{production,j,t}$	Efficiency of fuel production equipment j at timestep t	-
$\eta_{distribution,k}$	Efficiency of fuel distribution method k	-
$\eta_{dispensing,m}$	Efficiency of fuel dispensing method m	-
$vehicle_{p,t}$	Cost of vehicle type p at timestep t	$
$aaVMT_q$	Average annual vehicle miles traveled by HDV vocation q	mi/yr

Note that for PEVs, as mentioned previously, the fuel distribution and dispensing costs of the electricity are grouped with the vehicle costs instead of with the fuel feedstock and production to accommodate different distribution and dispensing costs for the different levels of electric chargers appropriate for the different PEVs. These distribution and dispensing costs are divided by the PEV's CD efficiency to convert from cost on a per mile energy basis to a per mile basis for consistency with the vehicle cost.

Both electrolytic fuels and biomass fuels can have different capacity factors, which could affect the cost of the associated fuel. For electrolytic fuels is a high capacity factor of 0.8, which depicts a scenario in which P2G is run nearly continually to maximize the usage and fuel output. This is most appropriate for use with the distribution electricity grid with a mix of both renewable and non-renewable resources, which fits the data from E3 [41]. Using the high capacity factor decreases capital cost of fuel production equipment compared to fuel output. For biomass feedstocks, a 0.8 capacity factor is also used, assuming a relatively high biomass throughput to capitalize on the biofuel production plants purchased but also allowing for downtime of repairs and other necessary upkeep. Biomass cost is not as dependent on capacity factor as electricity cost is.

Constraints

To better model the world that these fuel pathways and vehicles will exist in, constraints are added. These constraints take the following five categories: (1) general, (2) vehicle miles traveled (VMT), (3) emissions, (4) technology availability, and (5) feedstock availability.

Table 35. Description of additional optimization parameters for TRACE constraints

Parameters	**Description**	**Units**
$VMT_{q,t}$	VMT requirement for vehicles of vocation q at timestep t	mi/yr
$feedstockCapacity_{i,t}$	Capacity of feedstock i at timestep t	GJ/yr
$productionCapacity_{j,t}$	Capacity of production technology j at timestep t	GJ/yr
$\eta_{vehicle,p,q,t}$	Vehicle efficiency of vehicle type p and vocation q at timestep t	mi/GJ
$EF_{r,n,t}$	Emission factor of chemical r for fuel production pathway n at timestep t	g/GJ
$EF_{r,p,q,t}$	Emission factor of chemical r for vehicle type p and vocation q at timestep t	g/GJ
$legacyEmissions_{r,t}$	Emissions of chemical r from on-road vehicles made prior to 2020 at timestep t	g/yr
$limitsEmissions_{r,t}$	Limits on emissions of chemical r at timestep t	g/yr
$limitsNOxDrayage_t$	NO_x emission limits extrapolated from ARB's Mobile Source Strategy to cover all drayage HDVs	g/yr
$limitsPM10Drayage_t$	NO_x emission limits extrapolated from ARB's Mobile Source Strategy to cover all drayage HDVs	g/yr
$limitsFossilFuel_t$	Limit on the fraction of total fuel energy that can come from fossil fuels (either natural gas or diesel)	-
$limitsBEV_{q,t}$	Limit on the fraction of total VMT that can be met by BEVs for vocation q	-

General

These general constraints model things such as ensuring the fuels are used in the proper vehicles fuel production plants are used once they are built.

Equation 16 links fuel production to VMT to ensure there is no excess fuel production that is not used in a vehicle, or any vehicle that is produced that does not have fuel to power it.

Equation 16. Constraint: Fuel and vehicle pairing

$$\sum_{n,t} x_{n,t} = \frac{y_{p,q,t}}{\eta_{vehicle,p,q,t}} \; for\ every\ corresponsing\ fuel\ that\ can\ be\ used\ in\ each\ vehicle\ type$$

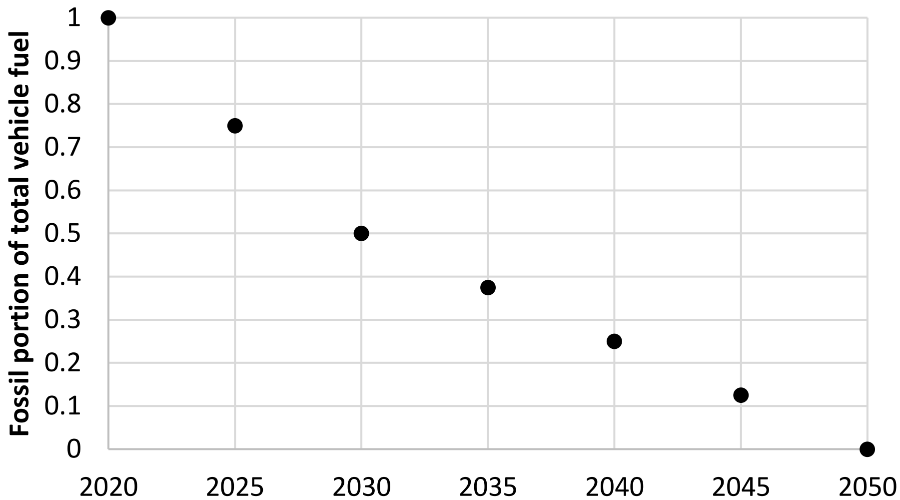
The use of CRFs to turn capital costs into annual payments requires that TRACE continues to use fuel production equipment if it is adopted. Otherwise, it is conceivable that TRACE might select a fuel production technology for one timestep but stop using it in the next timestep. This is akin to signing up for a three-year car lease, making one month's payment for using it, and then returning the car and neglecting the rest of the lease contract. This would not be acceptable, so *Equation 17* is implemented to ensure the large capital investments of fuel production plants are used for their lifetime. The lifetime of the equipment used is expected to be long enough to last the timeframe of this problem (at most 30 years if adopted in 2020), which for some technologies is aided by regular upkeep costs as part of the FOM and VOM costs [160], [201], [202], [377]. To add some flexibility to the market, a 20% relaxation is added to this constraint, which allows for transitions away from one fuel production technology toward another as emissions constraints become more stringent with time.

Equation 17. Constraint: Continued fuel production plant use

$$x_{i,t} \geq 0.8 * x_{i,t-1} \; for\ each\ individual\ production\ technology\ type$$

In progressing California's move toward renewable fuels away from fossil fuels, an additional constraint is imposed to reduce fossil fuel for vehicles. Specifically, this limits the use of fossil natural gas and diesel. These limits are not imposed on any portion of electricity that may be produced by fossil fuel generators. Major milestones are limiting all fuel energy to be at most half fossil fuel by 2030, inspired by the CARB's 2016 Mobile Source Strategy [378], and no fossil fuel is used by 2050. Intermediate limits are linear interpolations to meet those goals, as shown in Figure 78.

Figure 78. Fraction of total vehicle fuel energy met by fossil fuels



Equation 18 sets a limit to the amount of fossil fuel (natural gas and diesel) that can be used per the limits ("$limitsFossilFuel_t$") depicted in Figure 78.

Equation 18. Constraint: Fossil fuel use limits

$$x_{n=fossil\ fuel,t} \leq limitsFossilFuel_t * x_{n=total,t}$$

VMT

Vehicle miles traveled (VMT) constraints are essential to model as they are what determine how much fuel should be produced at each time step. Additionally, VMT can be used along with average number of miles traveled by a given type of vehicle to determine how many of those vehicles are on the road and projected to be on the road.

Vehicle fleet turnover rates show the amount of time that vehicles spend on the road. It is not realistic to expect all vehicles on the road to immediately be recycled and replaced with ZEVs. Additionally, considering the emissions associated with manufacturing and recycling the vehicles, that approach may not even be the best on an environmental basis even if it were possible. Therefore, it is necessary to impose some sort of constraint on how quickly the current vehicles on the road will be replaced by new vehicles suggested by the present modeling.

Fleet turnover rates are determined by EMFAC projections of vehicle use [1]. These EMFAC data project VMT by vehicle year for each of the vehicle classes included in the present work. Gathering data every five years from 2020 to 2050 shows how the VMT from vehicles of prior years' decreases as time goes on. Germane to the present work are the VMT from vehicles made prior to 2020, as vehicles made in 2020 and beyond to 2050 will be dictated by the optimization.

Figure 79 through Figure 82 show the EMFAC projections for total VMT, VMT met by vehicles manufactured prior to 2020, and VMT met by vehicles manufactured in 2020 and beyond. The reason for the split in vehicle manufacture year is to account for the modeling of the present work. Any vehicles made prior to 2020 will be considered in the analysis as legacy vehicles, whose powertrain configuration and corresponding fuel and tailpipe emissions have been set. However, any vehicle made starting in 2020 will have its powertrain and associated emissions determined by the modeling of the present work.

The vocations listed are a composite of various EMFAC vehicle classifications. The linehaul category includes EMFAC's 2011 vehicle classification of T7 Tractor, T7 NOOS, T7 NNOOS, and T7 CAIRP (meaning out-of-state and international trucks are included). Drayage includes T7 Other Port, T7 POAK, and T7 POLA. Refuse includes T7 SWCV and T7 SWCV-NG, which distinguishes between diesel- and natural gas-powered vehicles. Construction includes T7 CAIRP Construction, T7 Single Construction, and T7 Tractor Construction.

Figure 79. Linehaul HDV fleet turnover by VMT, data from [1]

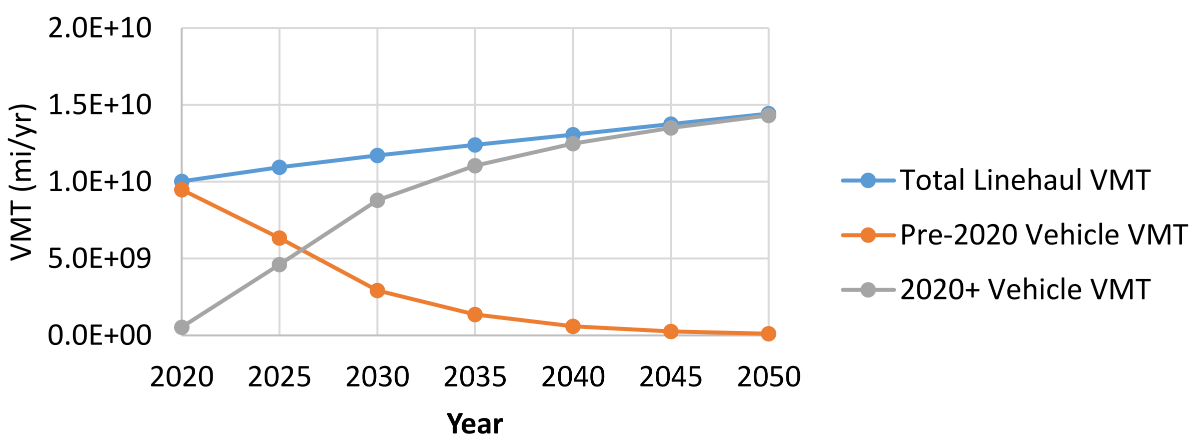


Figure 80. Drayage HDV fleet turnover by VMT, data from [1]

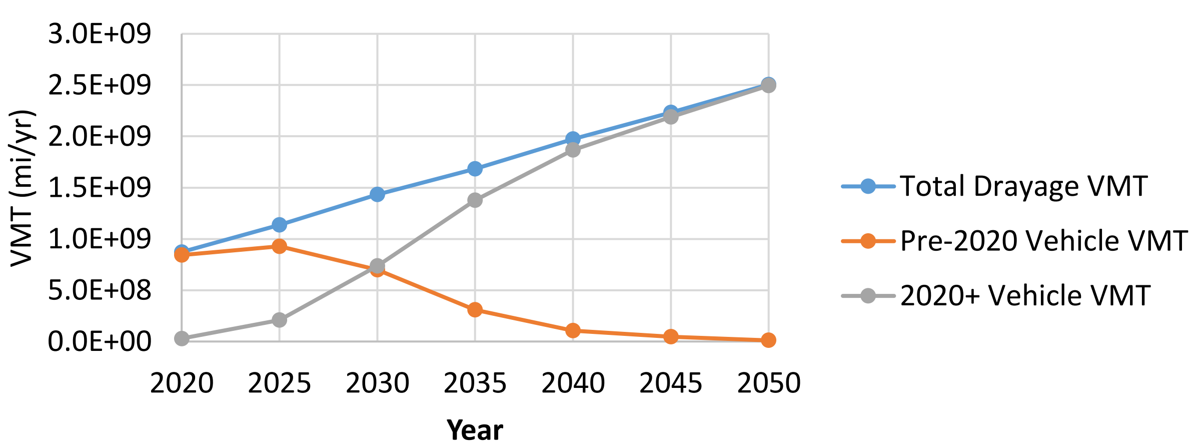


Figure 81. Refuse HDV fleet turnover by VMT, data from [1]

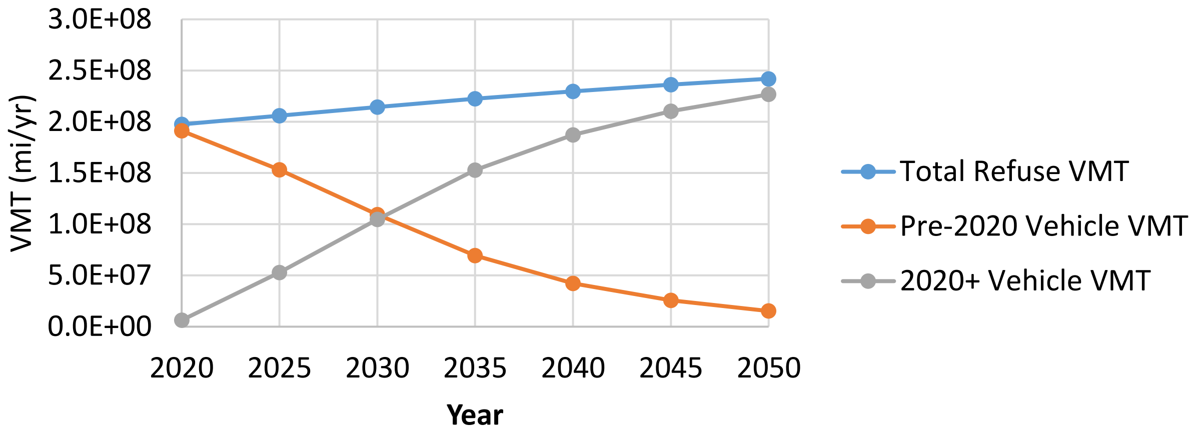
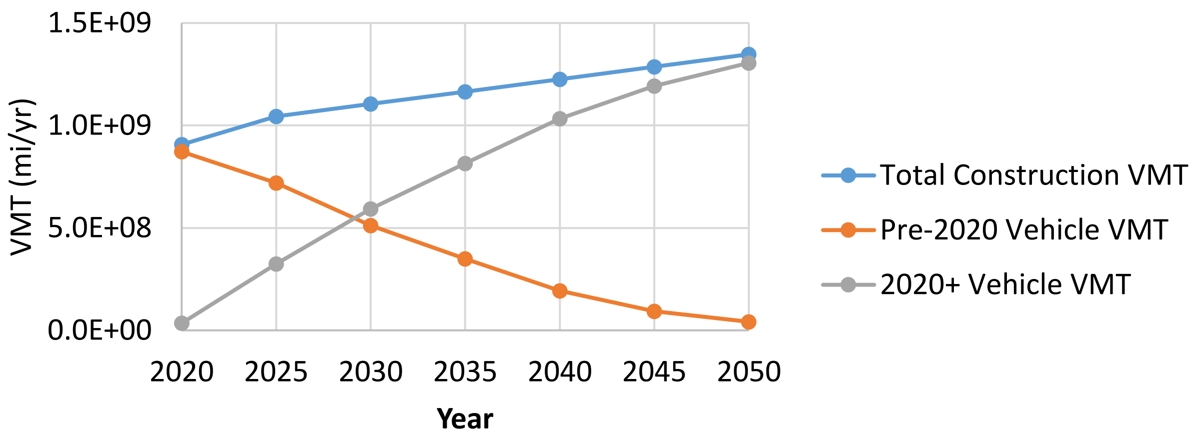


Figure 82. Construction HDV fleet turnover by VMT, data from [1]



For HDVs of the various vocations, an average annual VMT is used to convert from the number of miles that must be traveled to the number of vehicles that must be purchased at each timestep to meet that travel demand. Linehaul trucks average 72,000 miles per year, drayage trucks average 44,100 miles per year, refuse trucks average 14,900 miles per year, and construction trucks average 44,300 miles per year [1]. Implicit in this is an assumption that the average number of miles traveled by each vehicle in each vehicle category will stay constant with time. If perhaps average VMT per vehicle increased, the number of vehicles purchased would decrease proportionally, decreasing the money spent on vehicles but keeping money spent on fuel constant. If VMT per vehicle decreased, the number of vehicles purchased would increase and money spent on vehicles would increase while money spent on fuel would be constant.

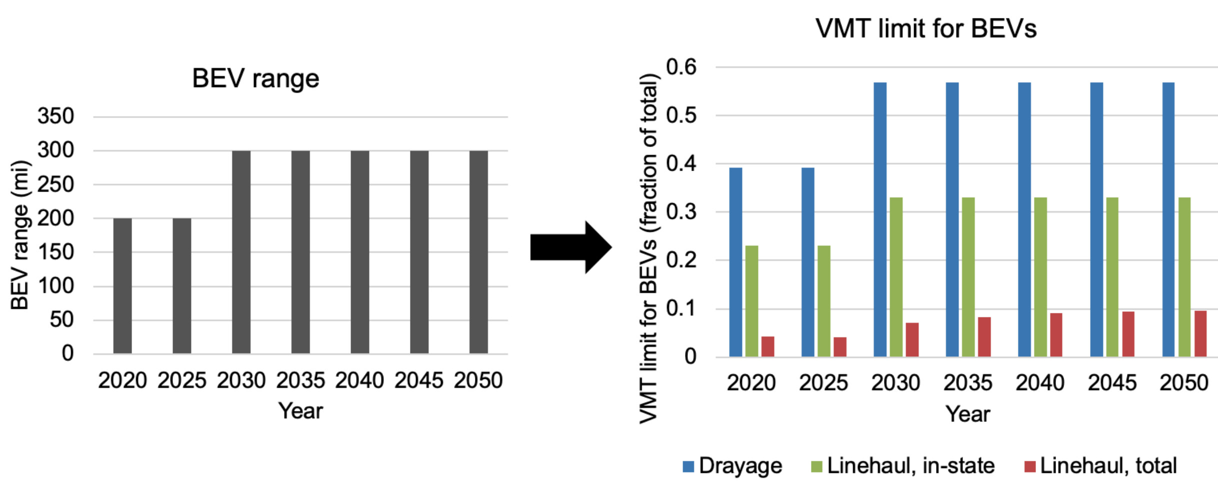
Using the above, *Equation 19* ensures VMT for each HDV vocation are met.

Equation 19. Constraint: VMT requirement

$$\sum_{p,q,t} y_{p,q,t} = VMT_{q,t}$$

BEVs have relatively limited driving ranges compared to conventional and other powertrain configurations. Modeled BEV ranges for linehaul and drayage are shown in Figure 83. Due to the limited range of the BEVs, the amount of VMT that could be met by BEVs of the various vocations is limited as well, particularly for the linehaul and drayage vocations. Figure 83 also shows how these range limits translate to VMT limits. For linehaul, care is taken to distinguish between in-state and out-of-state vehicles. Trucks from out-of-state are assumed not to be feasible with BEVs due to the range limitations. Limits for the linehaul vehicles are from Forrest et al. [2]. Limits for drayage vehicles are from Di Filippo et al. [379], with additional work to convert from vehicle to driving range. For the refuse vocation, it is assumed that all VMT can be met by BEVs due to that vocation's relatively low daily VMT. For construction vehicles, it is assumed that 80% of VMT can be met by BEVs for similar reasons.

Figure 83. Linehaul and drayage BEV driving range and VMT limits



Equation 20. BEV VMT limits

$$\sum_{p,q,t} y_{p=BEV,q=\,linehaul\ and\ drayage,t} \leq limitsBEV_{q,t} * VMT_{q,t}$$

The utility factor (UF) of a vehicle specifies how many of the miles that vehicle travels using the battery as the power source compared to the total number of miles traveled. An ICV has a UF of 0 because it has no battery to supply driving power, a BEV has a UF of 1 because it has only a battery to supply driving power, and a PHEV can have a UF anywhere from 0 to 1, depending on how the vehicle is driven and fueled. For example, a PHEV that travels 30 miles on its battery charge and 70 miles using liquid fuel in a combustion engine has a UF of 0.3 for that trip. UFs vary greatly by vehicle specification (BER, CD efficiency, CS efficiency), trip composition (length, grade, etc.), fueling habits (whether one charges the vehicle at home or not), driving personalities (speed, acceleration, etc.), and other factors. Therefore, it is most practical to use an average UF that represents the spectrum of possibilities.

The Society of Automotive Engineers (SAE) International defines a particular UF as a fleet UF (FUF). SAE International suggests using the FUF to determine the electricity and other fuel use for a fleet of vehicles, which is the intended use in the present work. The FUF is calculated using a distribution of vehicle trips and dividing the miles of CD travel by the total number of trip miles [380].

Using the SAE International J2841 specification along with BER specifications with a vehicle yields the FUF. The FUF for each vocation of HDVs are shown in Table 36, using the BER and FUF correlation from SAE International J2841 [380]. The BER for the various HDV vocations are calculated using the battery capacity and CD efficiency of each of the plug-in hybrid options (diesel and RNG PHEV) and then taking the average of those results to get a representative vocation-wide BER. The linehaul vocation is not present as the PHEV powertrain is not appropriate for the typical linehaul duty cycle. It should be noted that the FUFs listed in Table 36 are from a methodology that uses National Household Travel Survey data to determine trip length distribution. There has been no work detailing the FUF of HDVs by vocation or in general as heavy duty PHEVs are a new technology.

Table 36. FUF for analyzed vehicle types and vocations

	HDV		
	Drayage	Refuse	Construction
BER (mi)	47	36	37
FUF	0.669	0.583	0.592

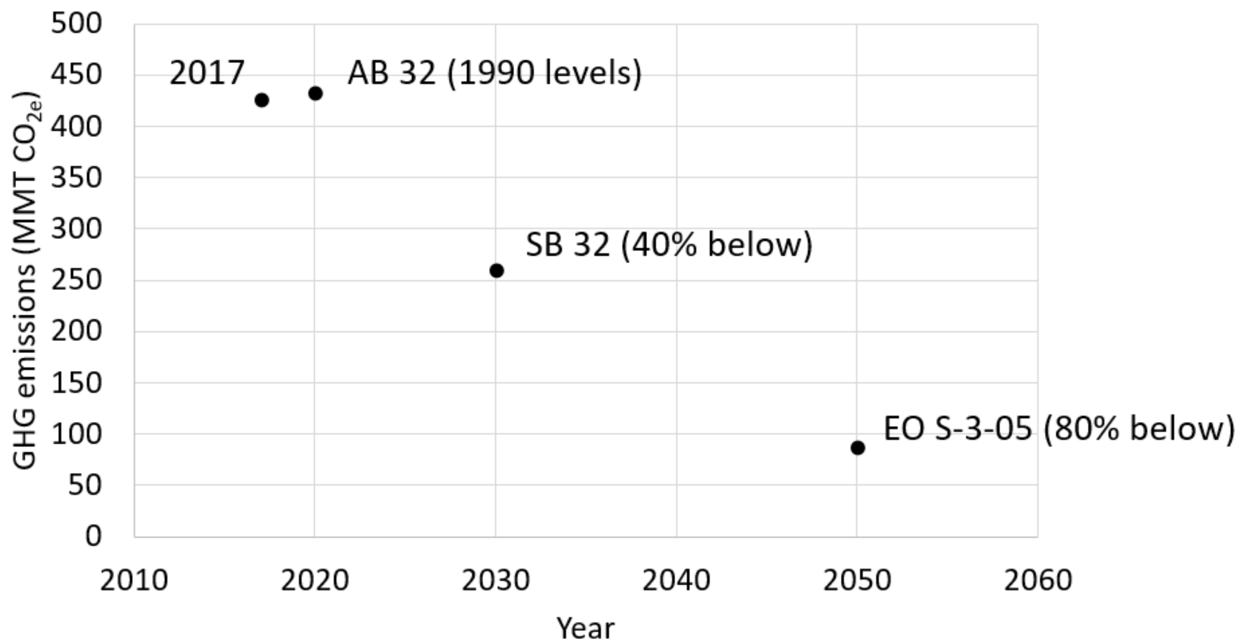
Emissions

California laws and an Executive Order set limits on GHG emissions from the State. AB 32 requires GHG emissions in 2020 to be reduced to 1990 levels [18]. SB 32 requires GHG emissions in 2030 to be 40% below 1990 levels [19]. Lastly, California Executive Order S-3-05 requires GHG emissions in 2050 to be 80% below 1990 levels [20]. Note that only AB 32 and SB 32 have been signed into law. The Executive Order is, at this point, only a goal. However, the State has been acting and planning to achieve this goal, so it is considered a constraint of this work.

In 1990, the basis for the above limits, 32% of CA GHG emissions were from on-road transportation [381] and (in 2018) 11% of those emissions are from HDVs modeled in this work. Accounting for upstream fuel emissions yields 7.0% of all CA GHG emissions [382]. Therefore, the GHG emissions constraints are taken to be 7.0% of the levels specified in the legislation and Executive Order of Figure

84. Note also that linear interpolation is used to provide constraints for the years with no explicit limitation (2025, 2035, 2040, and 2045).

Figure 84. GHG emissions legislation and Executive Order



Like for the VMT constraints, data from EMFAC include emissions from the HDVs from different years [1]. Emissions from vehicles made prior to 2020 are gathered and taken to be baseline emissions that will occur regardless of what the optimization suggests for new vehicle purchases. Fuel emissions are added to this using the historic ratio of total emissions according the CARB emissions inventory to tailpipe emissions from EMFAC and applying this to each vehicle type [382].

Equation 21. Constraint: GHG emissions limits

$$\sum_{j,k,m,n,r,t} \frac{x_{n,t}}{\eta_{production,j,t} * \eta_{distribution,k} * \eta_{dispensing,m}} * EF_{r=GHG,n,t} + \sum_{p,q,r,t} \frac{y_{p,q,t}}{\eta_{vehicle,p,q,t}} * EF_{r=GHG,p,q,t} + legacyEmissions_{r=GHG,t} \leq limitsEmissions_{r=GHG,t}$$

Further emissions constraints are found in the 2016 Mobile Source Strategy from the CARB. The Mobile Source Strategy sets goals to reduce nitrogen oxide (NOx) tailpipe emissions by 80% and diesel particulate matter (PM) tailpipe emissions by 45% by 2031 in the South Coast Air Basin (SoCAB) [378]. For the year 2035, 81% of drayage NOx emissions and 82% of drayage PM10 emissions (these are the PM emissions 10 micrometers in diameter or smaller) in California are projected to be from ports in the SoCAB (Port of Los Angeles and Port of Long Beach) according to the CARB Standard Emission Tool [383].

Therefore, due to the high emissions impact of SoCAB drayage trucks on California drayage in general, the additional constraints of 65% NOx tailpipe reductions and 37% PM10 tailpipe emissions by 2030, the modeled year closest to 2031 of the goal, are applied to all drayage trucks.

To get the baseline for these emissions for 2020, the default NOx and PM10 emissions from EMFAC are determined to be 6,590 metric tons per year of NOx and 40.7 metric tons per year of PM10. NOx emissions are assumed to decrease linearly to the 65% reduction goal in 2030, then are held constant afterward. PM10 emissions are assumed to decrease linearly to the 37% reduction goal in 2030, then are held constant afterward. These constraints are summarized in Equation 22.

Equation 22. Constraint: Drayage tailpipe CAP limits

$$\sum_{r=NOx,p,q=drayage,t} y_{q=drayage,t} * EF_{r=NOx,p,q,t} \leq limitsNOxDrayage_t$$

$$\sum_{r=PM10,p,q=drayage,t} y_{q=drayage,t} * EF_{r=PM10,p,q,t} \leq limitsPM10Drayage_t$$

As a broader NO_x emission reduction constraint, the following constraint of Equation 23 is introduced. While there is no legislation mandating these NO_x emissions reductions, it is generally accepted that NO_x must be reduced for air quality. Therefore, the same percentage of emissions reductions for the GHG emissions are imposed here, culminating with an 80% reduction of NO_x by 2050.

Equation 23. Constraint: NO_x emissions limits

$$\sum_{j,k,m,n,r,t} \frac{x_{n,t}}{\eta_{production,j,t} * \eta_{distribution,k} * \eta_{dispensing,m}} * EF_{r=NOx,n,t} + \sum_{p,q,r,t} \frac{y_{p,q,t}}{\eta_{vehicle,p,q,t}} * EF_{r=NOx,p,q,t} + legacyEmissions_{r=NOx,t} \leq limitsEmissions_{r=NOx,t}$$

The CARB has proposed Advanced Clean Trucks (ACT) regulations to mandate a minimum of ZEVs used in the heavy duty sector [220]. These are imposed on both tractor and box trucks. Tractor trucks include linehaul, drayage, and some construction trucks (roughly 55% of VMT). Box trucks include refuse and some construction (roughly 45% of VMT). The percentages shown in Table 37 are the lower limit of ZEVs required by the ACT regulations. Within TRACE, these are the lower limits of VMT that must be met by ZEVs for the respective vocations. These constraints are applied to both in-state and out-of-state vehicles.

Table 37. CARB Advanced Clean Trucks proposed regulation, from [220]

Model Year	Box Trucks	Tractor Trucks
2020	0%	0%
2025	11%	7%
2030	50%	30%
2035+	75%	40%

The Port of Los Angeles and the Port of Long Beach, the two primary ports in California, have the goal of reaching all ZEVs by 2035 [379]. This constraint, along with a linear interpolation from the current 0% to the goal of 100% by 2035, are imposed in TRACE.

There is interest in making refuse trucks clean (either ZEVs or low-NO_x natural gas engines). This is due to the nature of the trucks traveling in residential areas for a large portion of their miles, thereby exposing many individuals to any exhaust emissions. To model this goal, it is imposed that by 2050 all refuse vehicles will be either ZEVs or use natural gas engines. The EMFAC data show 47% of refuse VMT is expected to be from vehicles that meet these standards (with natural gas trucks) in 2020, and this combined with a linear interpolation to 100% in 2050 creates the constraints for TRACE.

Technology Availability

Realistic technology deployment rates are needed to ensure results are meaningful. One could imagine a scenario in which a single technology happens to be the cheapest and most efficient at producing fuel, but perhaps it would not be feasible to produce fuel using only that equipment because production takes time. Therefore, these technology deployment constraints are conceived to protect against unreasonable adoption of any given technology.

There are three categories of technologies detailed in the following sections regarding the rate at which the technologies can be adopted. The first is electrolyzer production limits, which constrains the three distinct electrolyzer technologies for fuel production. The second is a limit on biomass fuel production, which includes equipment such as gasifiers and liquefaction. The third category are future vehicle powertrain availabilities, which estimate when currently unavailable powertrains might come to the market. There are no constraints placed on vehicle technology deployment rates. Instead, the constraints on the fuel production methods secondarily limit the deployment of the corresponding vehicles that use those fuels.

Growth scenarios for technologies are bounded by current capacity and market size. Current capacity for electrolyzers is sourced from Schoots et al. [384], with a split of 60% AEC technology and 40% PEMEC technology, based on the fact that AEC technology is more mature and deployed than PEMEC technology. Future projections for electrolyzer production scale are by IEA and DOE projections for hydrogen usage and then back-calculating the required installed capacity of electrolyzers [385], [386]. Growth for electrolytic RNG technologies is bounded by natural gas utilization in the U.S. and worldwide, which are 1 TW and 4 TW, respectively. This is due to the market size cap of RNG being the amount of natural gas used, and this is a reasonable limit to the amount of RNG produced by 2050. These natural gas usage data are sourced from the U.S. Energy Information Administration (EIA) [387]. Two scenarios, one with a more conservative, lower electrolyzer capacity in Figure 85 and one with a more optimistic, higher electrolyzer capacity in Figure 86.

Figure 85. Future electrolyzer market size projections in 2030, 2035, and 2050 (based on assumed efficiency of 50kWh/kg and capacity factor of 90%)

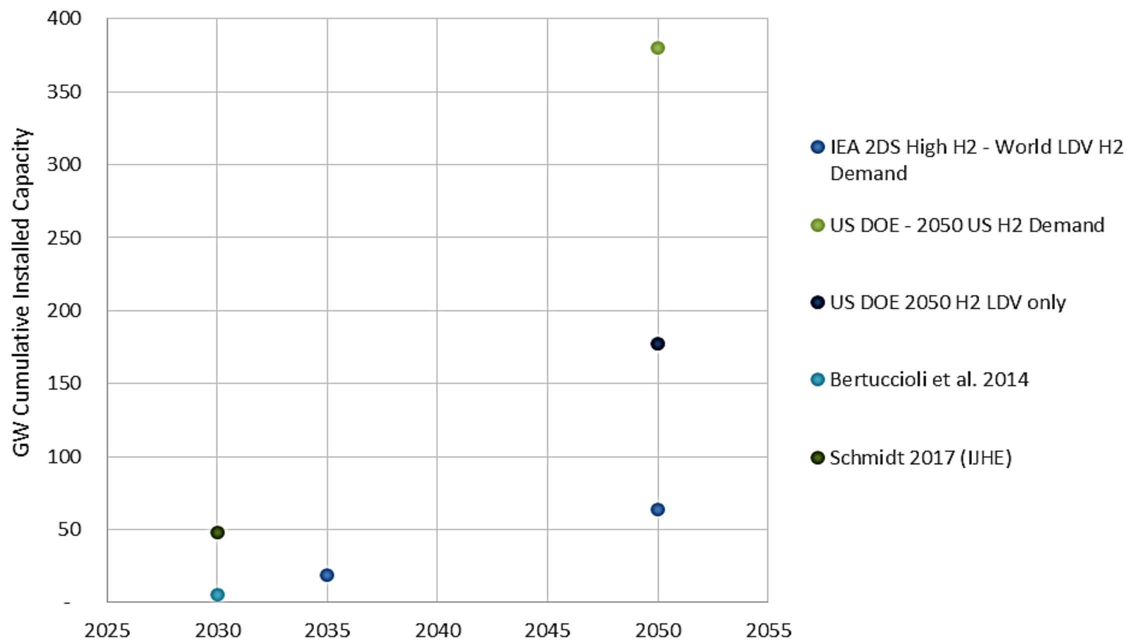
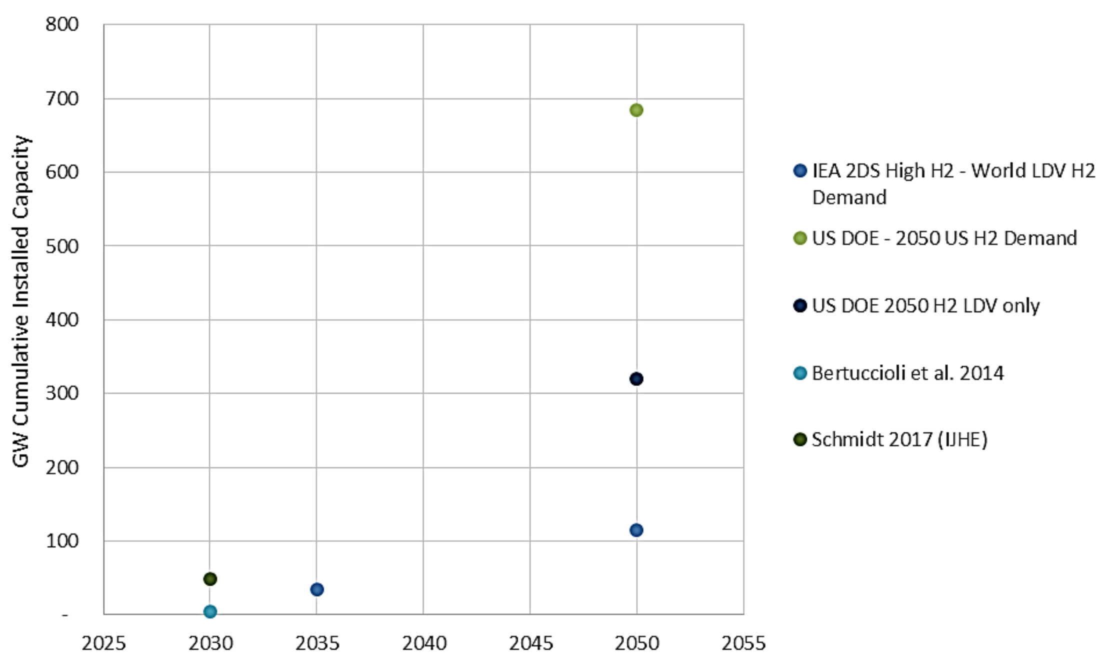


Figure 86. Future electrolyzer market size projections in 2030, 2035, and 2050 (based on assumed efficiency of 50kWh/kg and capacity factor of 50%)



Given the previous notes and plots using data from the literature, conservative and optimistic scenarios for electrolyzer production can be developed from the corresponding high and low capacity factors of the previous projections, respectively. Plots for the cumulative production limits of the three electrolyzer technologies for the conservative scenario and the optimistic scenario are found below in Figure 87 and

Figure 88. Note that these electrolyzer production limits are the only limits applied to RNG production; limits for the methanator equipment and the various carbon capture equipment are assumed not to be more stringent than these electrolyzer limits as the methanator technology is much simpler.

Figure 87. Conservative estimate on electrolyzer cumulative production limits

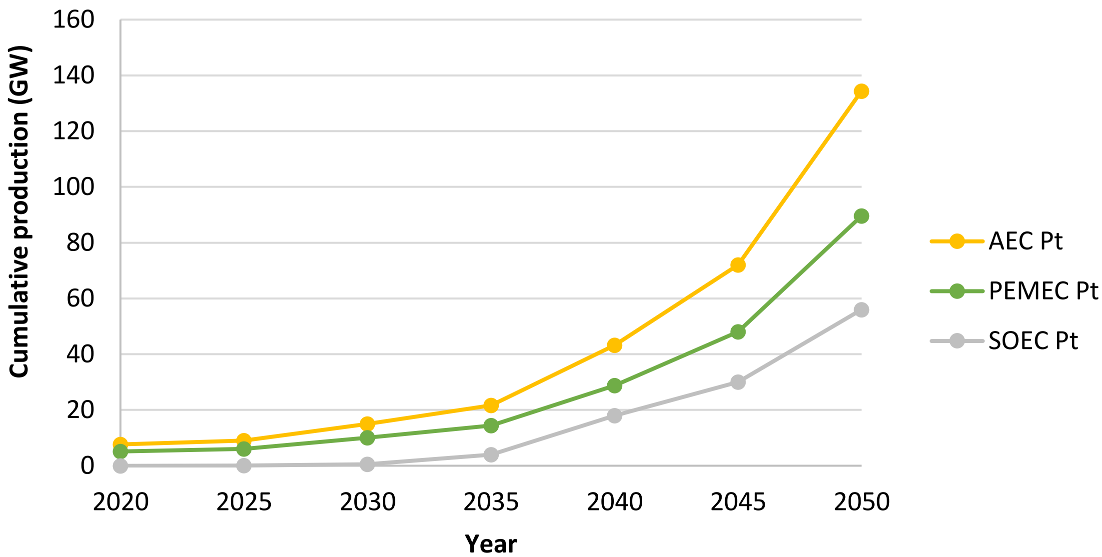
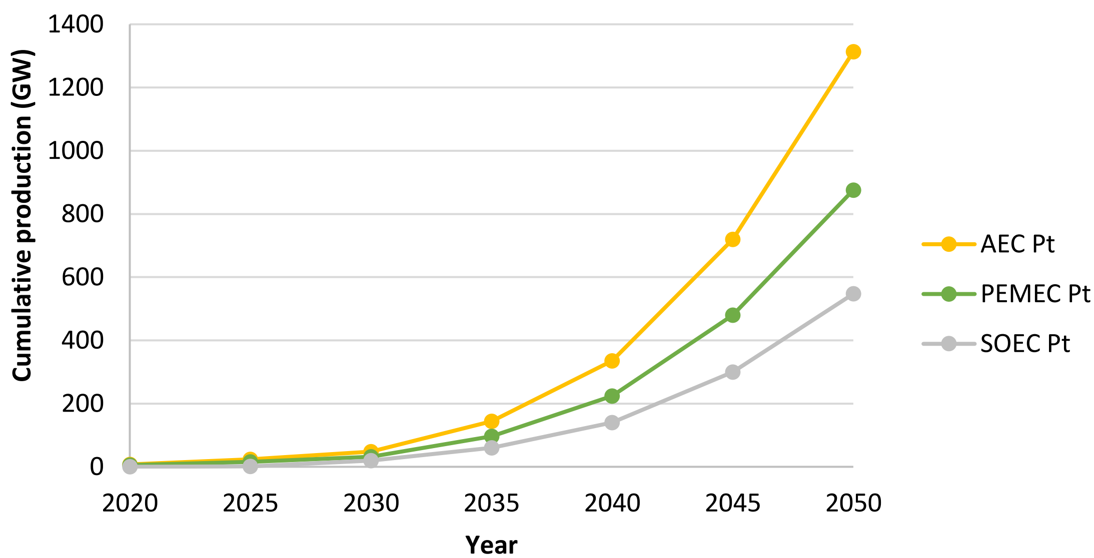


Figure 88. Optimistic estimate on electrolyzer cumulative production limits

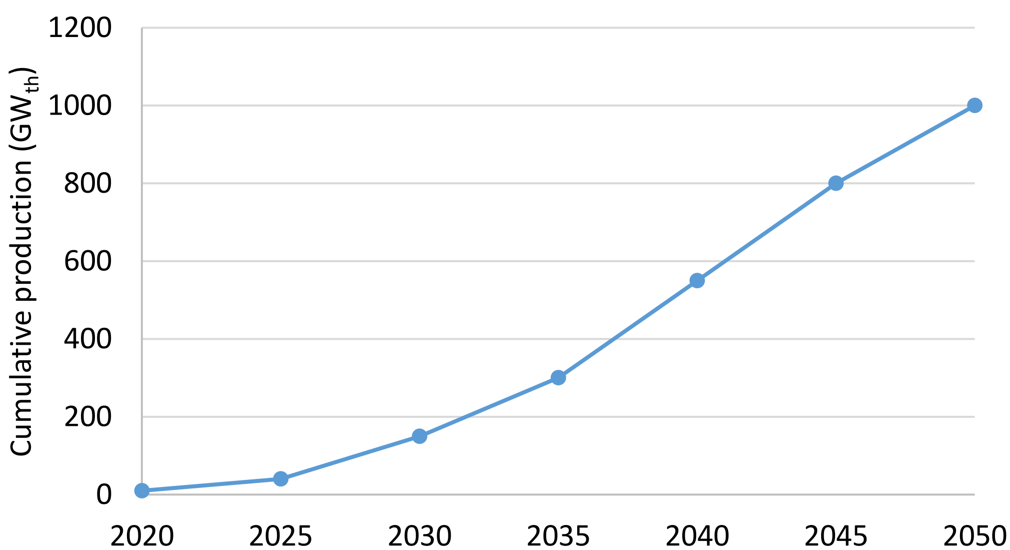


The present work uses the conservative estimates of Figure 87 as constraints for the scenarios presented at the end of this chapter.

Biomass Feedstock Fuel Production Equipment Cumulative Production Limits

The International Energy Agency projects a 1.7 times increase of bioenergy compared to current use by 2040, and a 4 times increase by 2050, which gives a reference to determine feasibility of biomass technology installed capacities [388], [389]. Gasification current installed technology is from the Global Syngas Technologies Council [390]. Similar to the electrolyzers, the upper limits are sourced from the U.S. Energy Information Administration (EIA) [387]. Plots for the cumulative production limits of gasifiers, AD, gasifier-FT, hydrolysis, pyrolysis, and liquefaction are shown in Figure 89. Note that unlike the electrolyzers, which are more technically advanced and complicated than the biomass conversion processes as well as having less data in the literature, there are no conservative and optimistic projections; there is simply one projection.

Figure 89. Biomass feedstock fuel production equipment cumulative production limits



Equation 24 constrains fuel production equipment adoption to limits established above.

Equation 24. Constraint: Fuel production equipment technology capacity

$$\sum_{i,j,k,m,n,t} \frac{x_{n,t}}{CF_i * \eta_{production,j,t} * \eta_{distribution,k} * \eta_{dispensing,m}} \leq productionCapacity_{j,t} \; for \; each \; x_{n,t} that \; uses \; production \; technology \; j$$

As for the fuel production technologies, some constraints must be imposed on the availability of various HDV powertrains. Because not all powertrains are commercially available as of the time of this work, the following constraints of Equation 25 are introduced to ensure powertrain availability is followed. Recent feasibility studies have shown manufacturers expect BEVs to be commercially available in non-trivial quantities in 2020 or shortly thereafter and FCEVs to come to the market after either in 2021 or shortly after [36][379]. For all vocations, FCEVs are modeled to be available in 2025.

Equation 25. Constraint: HDV future powertrain availability

$$y_{p=HDV\ FCEV,t=2020} = 0$$

Regarding low-NOx engine technologies, low-NOx CNG engines are already available for purchase [374]. However, low-NOx diesel engines are not. The assumption is made that these engines will be available shortly, in the year 2020.

Feedstock Availability

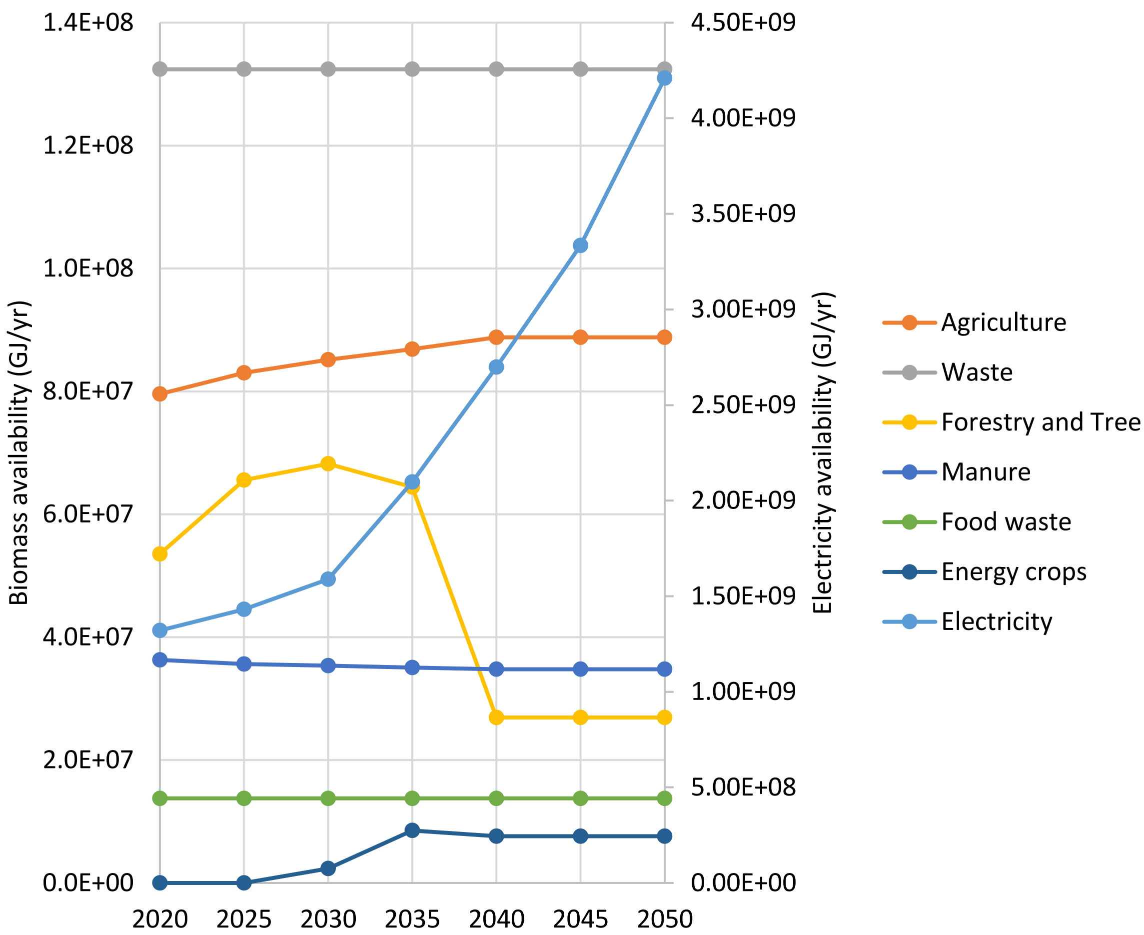
The last set of constraints is for fuel feedstock availability. For the non-fossil fuels, these take two forms: (1) for electricity, the electric grid can only feasibly grow a limited amount from year to year and (2) for biomass, there is only so much biomass available to be harvested.

Electricity availability is constrained more by the infrastructure that distributes it than by the availability of its feedstocks (natural gas, solar, wind, nuclear, etc.). An in-depth assessment of the logistics of an electricity infrastructure upgrade is beyond the scope of this work, but a reasonable cap on growth is applied. Electricity for vehicle use is assumed to be up to about 20% of total electricity production by E3's work using their PATHWAYS model [41], [391]. Electricity limits for this present work are taken to be that 20% of the projected electricity capacity from E3's PATHWAYS work of the "straight line base" scenario [41], with an additional buffer of 20% on top of the total electricity production. To summarize, this present work assumes a quantity of electricity equal to 40% of the electricity production projected by E3 could be available for transportation fuel. These projections account for increased PEV adoption, and the additional 20% buffer applied is to account for a potentially high PEV adoption. However, it would be impractical to assume that every vehicle could become a PEV very rapidly due to the amount of time required to make the electric grid more robust. Similarly, electrolytic fuels that use electricity as a feedstock must be constrained as well. Therefore, the additional production limit prevents too drastic an increase in electricity throughput for either vehicle fuel or fuel feedstock. The electricity feedstock availability, along with biomass feedstock availability, is shown in Figure 90.

Biomass feedstock limits are taken as previously shown in Figure 17 from the Billion Ton Report [40]. As a reminder, the availability is a function of both year as well as selling price. A higher selling price of some biomass feedstocks leads to a higher quantity available. Some simplifications are made to aid in implementation, specifically in areas in which increasing selling price of biomass only slightly increases availability. In these cases, the slight increase in availability is neglected for the higher selling price. The maximum biomass feedstock availabilities used in the modeling, regardless of price, are shown in Figure

90, along with the electricity feedstock availability. Note that both forestry and tree biomass are interchangeable for the purpose of this work, so the combined availability is shown. Also, note that the biomass availabilities are displayed on the left y-axis and the electricity availability is displayed on the right y-axis, due to a difference in availability by nearly an order of magnitude.

Figure 90. Electricity and biomass fuel feedstock availability, data from [41] *and* [40]

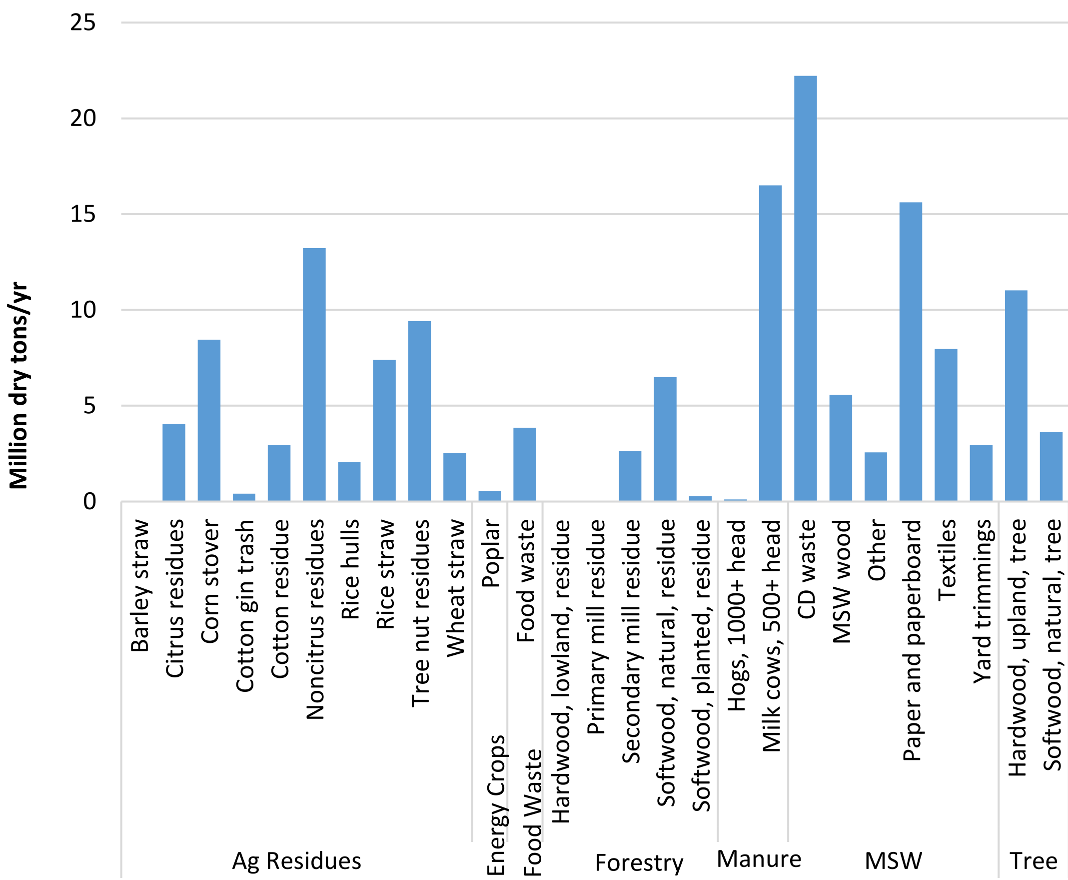


Equation 26 constrains fuel production to respect the amount of feedstock that is available at each timestep as detailed above.

Equation 26. Constraint: Feedstock capacity

$$\sum_{i,j,k,m,n,t} \frac{x_{n,t}}{\eta_{production,j,t} * \eta_{distribution,k} * \eta_{dispensing,m}} \leq feedstockCapacity_{i,t} \;\; for\ each\ x_{n,t} that\ uses\ feedstock\ i$$

Figure 91. Biomass feedstock availability by individual feedstock, data from [40]



Cost and Efficiency Updates

After each timestep of optimization in TRACE, fuel production technology and vehicle component costs are updated based on Wright's Law (Equation 3). The cumulative installed capacity of every piece of technology is increased by the quantity of each that TRACE determines is the lowest cost option of meeting the constraints. Recall that vehicle costs are split into major powertrain components and the glider that remains to account for different learning rates of the various equipment within the vehicle.

Additionally, efficiencies of each vehicle technology are increased after each timestep. The efficiency projections for each fuel production technology are detailed in Task 1. The efficiency improvements of each vehicle technology are as previously detailed, namely 1.0 MPPGE improvement every five years for all HDV vocations [370].

3.4 Results and Discussion

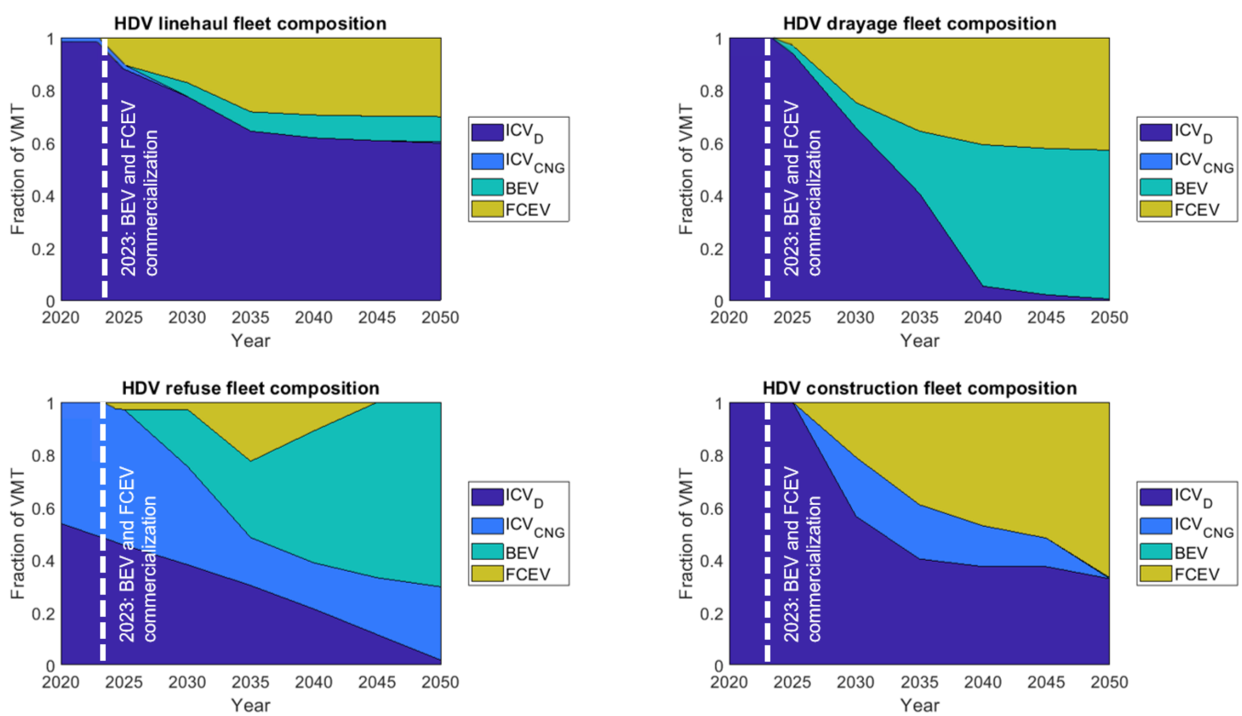
The following section presents the resulting HDV fuel and powertrain adoption curves from the TRACE model. TRACE operates in five-year increments from 2020 to 2050, where each five-year segment is assumed homogenous for total cost purposes, while resulting plots in this section include interpolation between those segments.

3.4.1 GHG Scenario

The first scenario, the GHG Scenario, includes all the previously introduced constraints to represent a realistic scenario for California to reach its environmental goals and is constrained to meet 1990 level HDV emissions by 2020, 40% reduction by 2030, and 80% reduction by 2050.

Figure 92 shows fleet projections for the four HDV vocations modeled for this GHG Scenario. This scenario leaves significant portions of the HDV fleet using internal combustion engines (ICEs) with renewable liquid and gaseous fuels. CNG engines are projected to be used in the refuse fleet throughout the analysis while the construction fleet uses them as a transitional technology. One notable exception to this general ICE trend is in the drayage fleet, which reaches nearly all ZEV use by 2040. Both BEV and FCEV technologies are used to a large degree, except for the construction fleet which does not adopt BEVs. Note that while optimization modeling is done in five-year increments, the initial five-year segment from 2020 to 2025 is post-processed to address the critical timeframe during which heavy duty ZEV technologies will be commercially available. Both BEVs and FCEVs are expected to be commercially available by 2023, based on previously referenced literature. This introduction is noted in Figure 92.

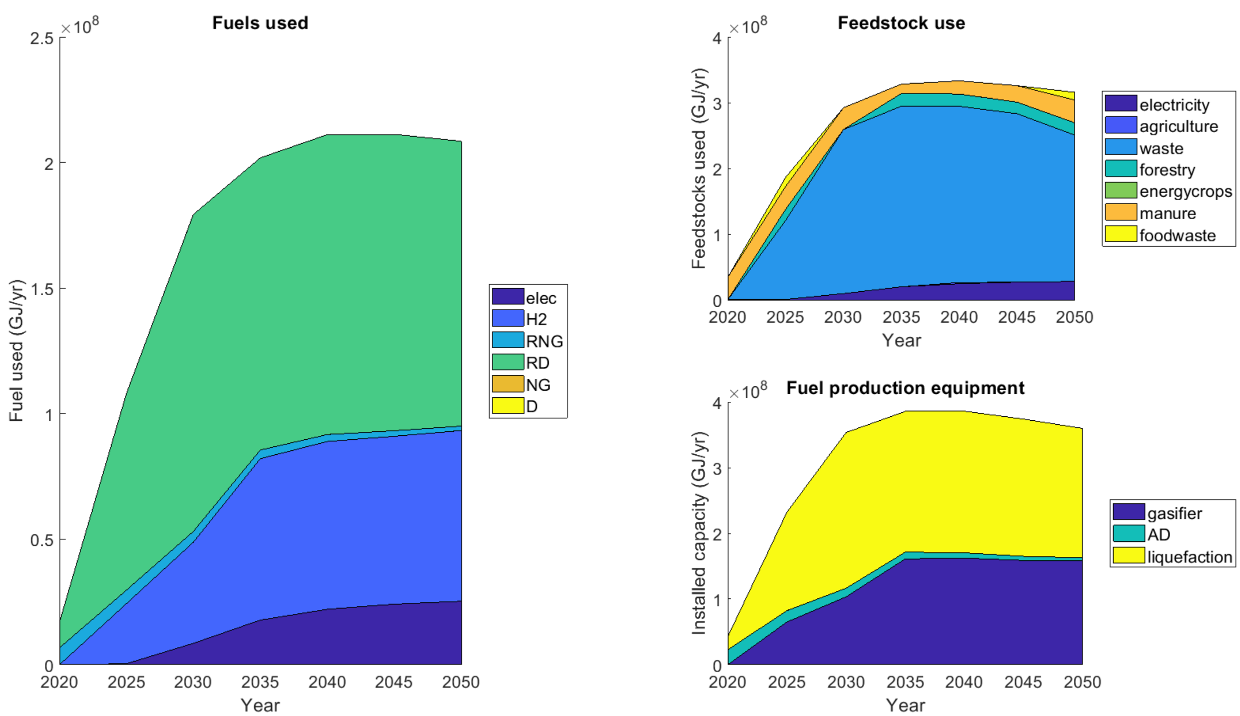
Figure 92. GHG Scenario: HDV fleet composition



One peculiar result of interest is the introduction and phasing out of FCEVs in the refuse fleet. Due to the relatively low daily VMT of refuse vehicles, no constraints are placed on the upper limit of BEV adoption to account for lower vehicle range compared to other vehicle powertrains. As both electric grid emissions and battery costs decline, the BEV with its high pathway efficiency is able to meet the demands of the refuse fleet while satisfying constraints.

Renewable diesel, renewable hydrogen, and electricity are the major fuels projected to be used in this scenario, with renewable natural gas contributing in a minor fashion. A variety of biomass feedstocks are utilized, with waste being the most heavily used category. Note that while hydrotreatment of vegetable oils (HVO) is a significant source of competitively priced renewable diesel presently, liquefaction of biomass is modeled to produce similarly priced renewable diesel as shown in Chapter 1. Additionally, further work needs to be done to characterize the availability of waste and vegetable oil availability for HVO use, while biomass availability for liquefaction is characterized in greater detail. The present work suggests that HVO production of renewable diesel could be a transitional production method until liquefaction of biomass can increase installed capacity.

Figure 93. GHG Scenario: Fuel characteristics



GHG emissions legislation and goals are achieved with the emissions benefits of negative carbon intensity biomass, in particular manure and food waste. The benefit of these negative carbon intensity biomass feedstocks is reduced by 2040 as SB 1383 is fully implemented, and this can cause difficulty in meeting the final 2050 goal of an 80% reduction compared to 1990 levels due to the relatively heavy use of non-ZEV technologies in the linehaul fleet, which may be more difficult to regulate due to the use of out-of-state HDVs. Note that the recent California goal to reach carbon neutrality by 2045 is not implemented in this or the following scenario as the goal was introduced at the end of this study.

While California as a whole is on track to meet AB 32's requirement of reaching 1990 levels of GHG emissions by the end of 2020, it is interesting to see that the HDV sector is not on track to meet its own sector's 1990 levels of GHG emissions by the end of 2020 without significant use of negative carbon intensity biomass. That is to say the HDV sector has become a larger fraction of California's GHG emissions in 2020 than it was in 1990. This speaks to the need for assessing individual sectors of California and what role each will play in meeting total GHG emissions legislation and goals, especially as those constraints get tighter with time.

Figure 94. GHG Scenario: GHG and CAP emissions

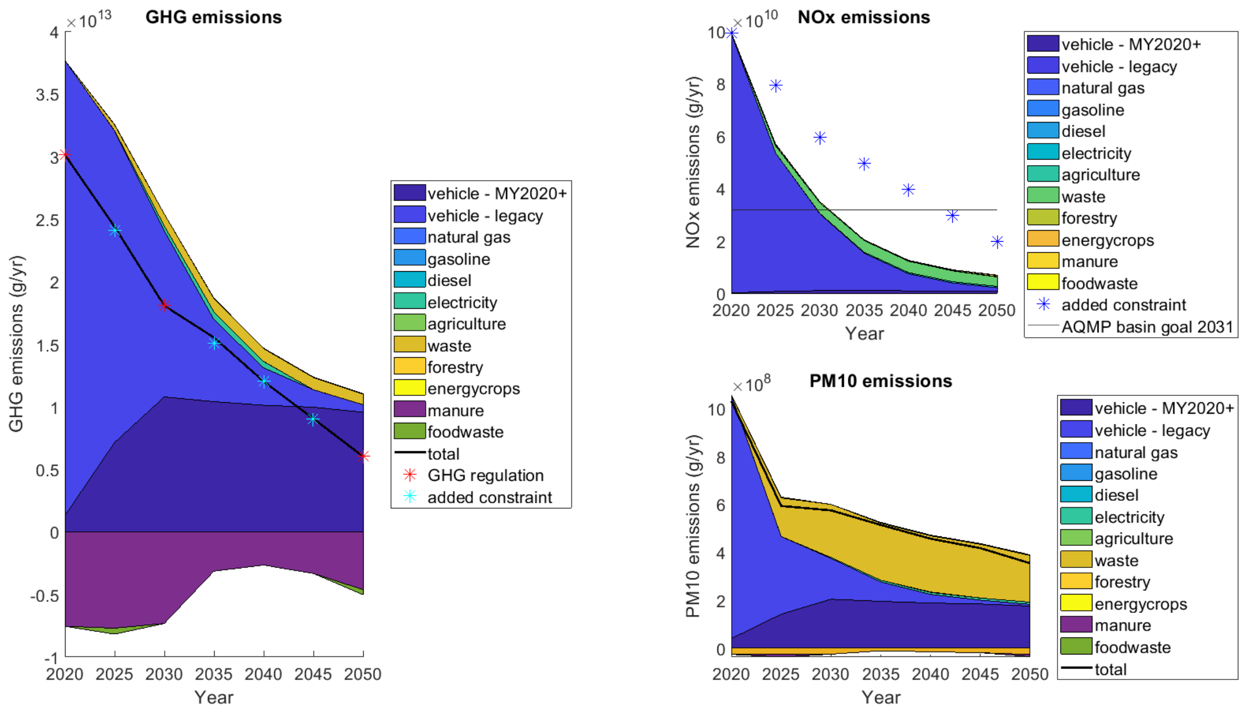


Table 38 shows both the annual cost for each of the years modeled as well as cumulative cost by the end of that year since 2020 for all vehicles of model year 2020 through 2050 and the fuel those vehicles use. The cumulative cost assumes the cost of each modeled year is carried through the rest of the proceeding four years up to the next modeled year.

Table 38. GHG Scenario: Cumulative cost

Year	2020	2025	2030	2035	2040	2045	2050
Annual Cost (billions of $)	0.747	4.75	7.93	9.56	10.6	10.9	11.3
Cumulative cost (billions of $)	0.747	8.49	35.4	76.7	126	179	234

3.4.2 High ZEV Scenario

While meeting GHG emissions goals is a major focus for the HDV sector going forward, it is not the only method for reducing emissions. Another approach is to impose ZEV constraints, such as those of the CARB Advanced Clean Trucks (ACT) proposed regulations. The present High ZEV Scenario is constrained by portion of vehicles that must be ZEVs rather than by the total GHG emissions.

Constraints imposed in this scenario include some of those previously introduced, all of which are applied in the preceding GHG Scenario, as well as additional constraints to induce the adoption of ZEV technologies,

The following constraints are included in the High ZEV Scenario: fuel and vehicle paring, continued adopted fuel production technologies, VMT, BEV HDV limitations, fuel production equipment technology capacity, HDV future powertrain availability, and feedstock.

The added constraint for increased ZEV technologies is shown in Equation 27. Note that the coefficient linearly increases from 0 at 2020 to 1 at 2050, This means none of the new vehicles are required to be ZEVs in 2020 and nearly all vehicles are ZEVs in 2050, save for the small ICV legacy fleet that EMFAC projects still be on the road in 2050.

Equation 27. Constraint: High ZEV adoption

$$y_{p=ZEV,q,t} \geq minimumZEV_t * y_{p,q,t}$$

The following are the results of the High ZEV Scenario. Figure 95 shows the HDV fleet projections of the four vocations by powertrain technology. Note the heavy use of FCEVs in the linehaul and drayage vocations, and heavy use of BEVs in the drayage, refuse, and construction vocations. Additionally, construction has significant FCEV adoption at the last timestep as non-ZEV technologies are nearly completely phased out. As in the GHG Scenario, though to a larger degree here, CNG vehicles are used as a transitional technology with significant adoption in the mid-term.

One difference to note when comparing to the GHG Scenario is the dominant adoption of BEVs in the construction fleet rather than FCEVs. With biomass being limited and costs depending on quantity used, this scenario prioritizes biomass for other vocations and instead uses primarily electricity in BEVs to meet constraints with a lower cost. Due to the limited range of BEVs, however, some FCEVs are needed by 2050 to enable nearly 100% ZEVs.

As in the GHG Scenario, the initial five-year segment from 2020 to 2025 is post-processed to address the critical timeframe during which heavy duty ZEV technologies will be commercially available. While there is no explicit constraint to reduce fossil fuel use in the High ZEV Scenario, it is clear from Figure 96 that imposing ZEV requirements necessarily reduces the use of fossil diesel and natural gas over time.

Figure 95. High ZEV Scenario: HDV fleet composition

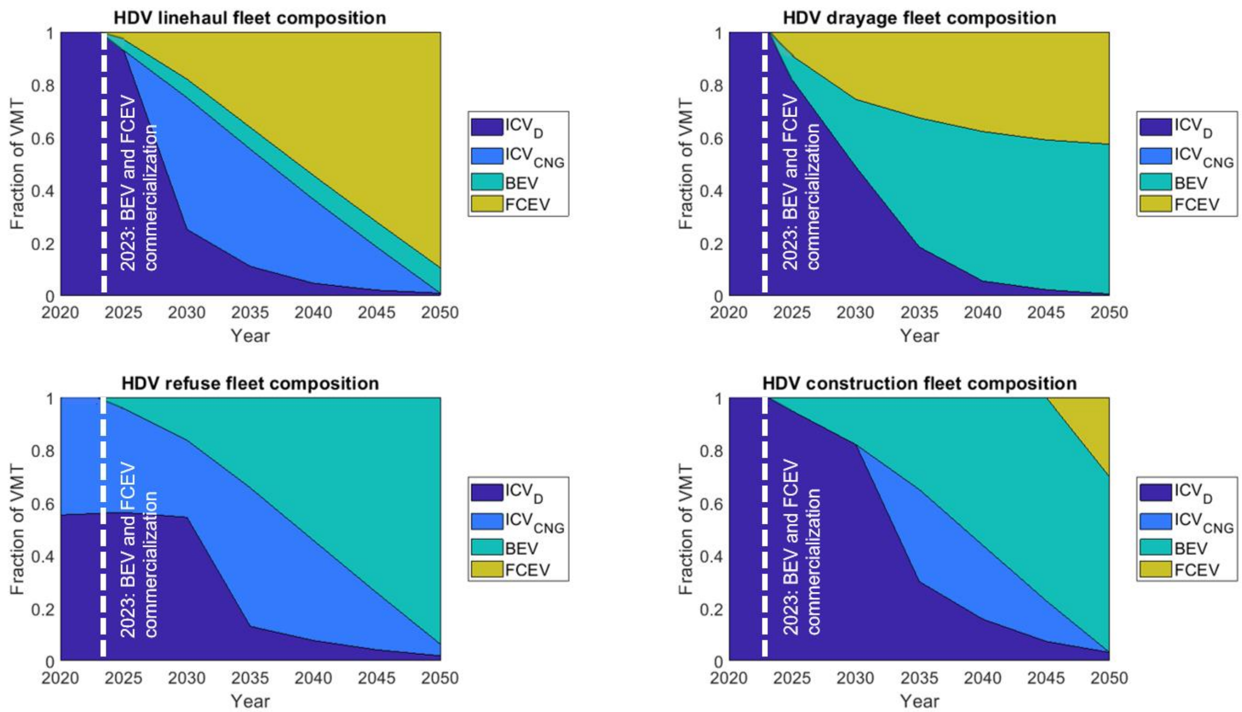
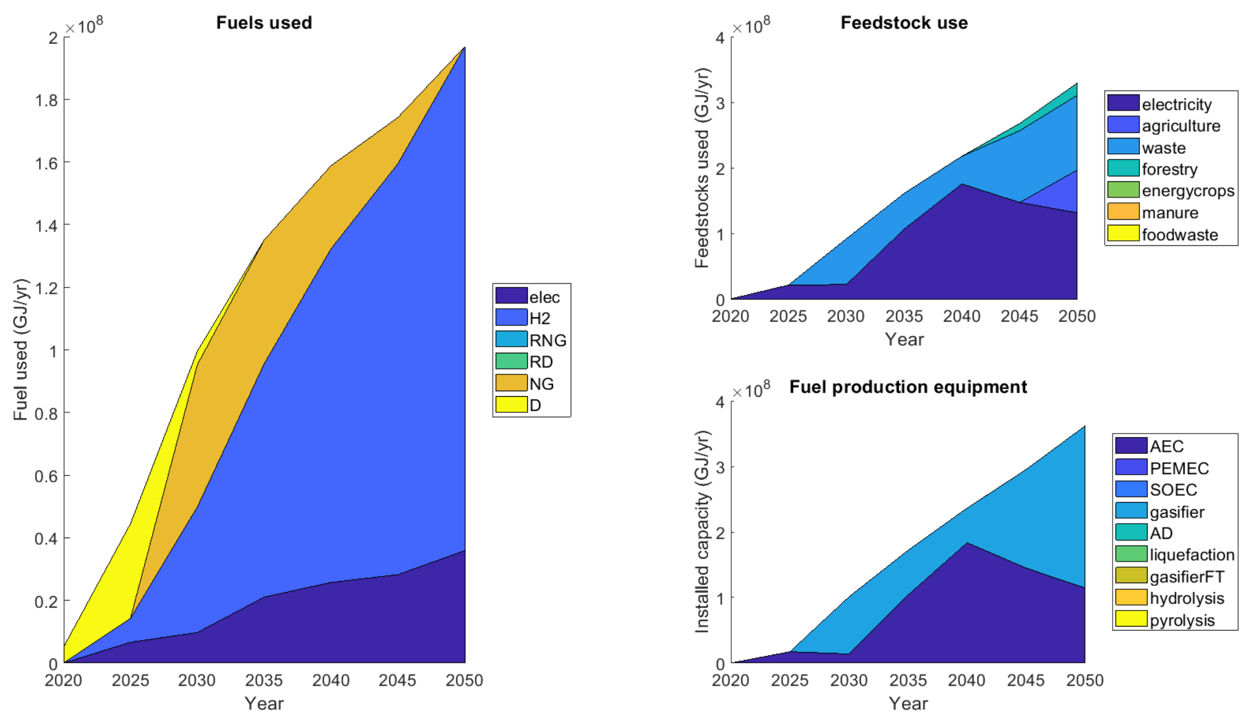


Figure 96. High ZEV Scenario: Fuel characteristics



One major change in fuel feedstock use for the High ZEV Scenario compared with the GHG Scenario constrained by GHG emissions is the amount of negative carbon intensity biomass recommended. The

GHG Scenario projects significant use of manure and some food waste, both of which assume a negative carbon intensity. However, due to the lack of GHG constraints in the present High ZEV Scenario, these feedstocks are not highly prioritized. In fact, neither of these negative carbon intensity biomass feedstocks are projected. This is due to their relatively higher cost per unit energy.

Figure 97 shows the resulting GHG and CAP emissions of the High ZEV Scenario. Recall that this High ZEV Scenario does not include any constraints on GHG emissions. Rather, emission improvements are a result of transitioning to ZEV technologies. Note that the removal of GHG constraints leads to the not meeting legislation requiring 1990 levels of GHG emissions by 2020 and 40% below by 2030. However, it is similarly important to note that the goals plotted (again, not active constraints for this scenario) are using 1990 levels of transportation GHG emissions, and a fraction thereof based on 2020 EMFAC projections of the four vocations modeled in this work.

As noted for the GHG Scenario, the HDV sector has become a larger fraction of California's GHG emissions in 2020 than it was in 1990 so even though California is on track to meet AB 32's GHG requirements by the end of 2020, the HDV sector in particular may not reach 1990 levels. The GHG emissions reductions imposed by AB 32, SB 32, and Executive Order #S-03-05 are for California as a whole, not explicitly for each and every sector individually. Therefore, it is reasonable to expect that some sectors which may prove harder to clean will have less reduction while sectors that are easier to clean may achieve more than the prescribed reductions.

Figure 97. High ZEV Scenario: GHG and CAP emissions

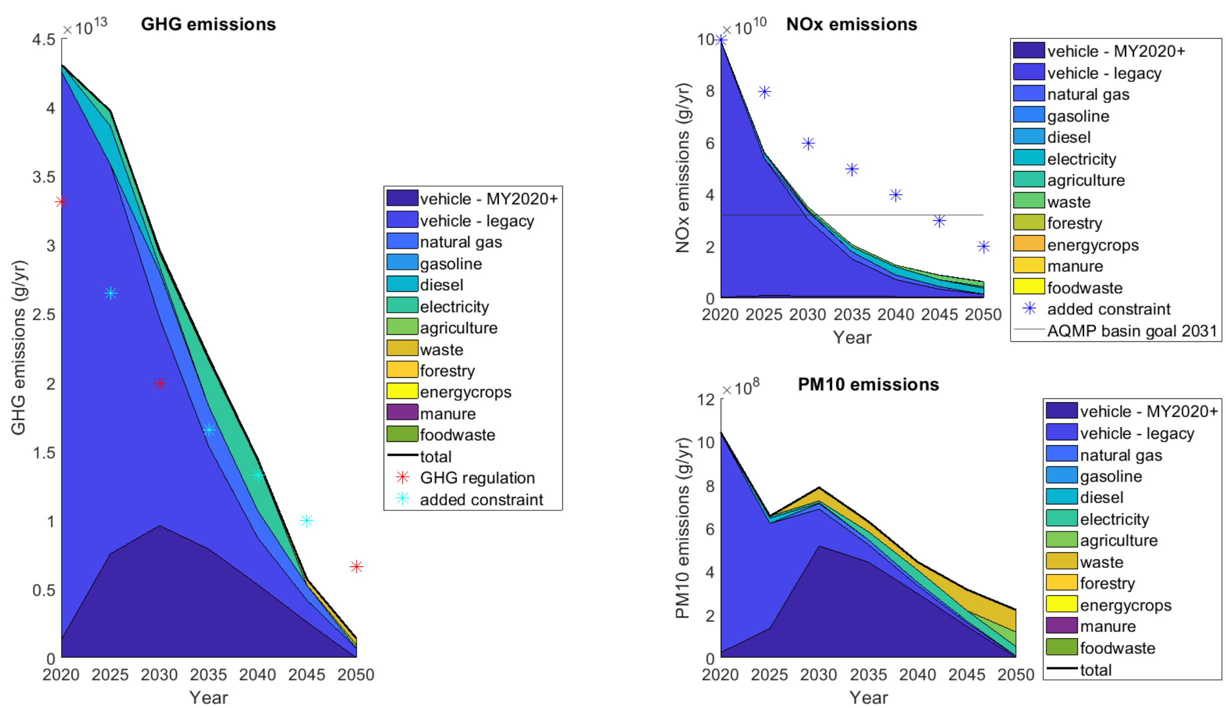


Table 39 shows both the annual cost for each of the years modeled as well as cumulative cost by the end of that year since 2020 for all vehicles of model year 2020 through 2050 and the fuel those vehicles use. The cumulative cost assumes the cost of each modeled year is carried through the rest of the proceeding four years up to the next modeled year.

Table 39. High ZEV Scenario: Cumulative cost

Year	2020	2025	2030	2035	2040	2045	2050
Annual cost (billions of $)	0.234	2.86	6.41	9.26	11.7	13.4	15.8
Cumulative cost (billions of $)	0.234	4.03	21.9	56.8	105	166	235

3.5 Conclusions

- **A heavy reliance on negative carbon intensity (CI) biomass to meet California's HDV GHG goals reduces the adoption rate of ZEVs.** The GHG goals that California has in place could be met, in part, using negative CI biomass to produce fuel for HDVs. ZEVs are projected to play a significant role in reducing emissions, and modeled constraints such as CARB's Advanced Clean Trucks proposed regulations do enhance adoption of ZEVs. However, the use of biomass with negative CI (e.g. manure and food waste) could result in renewable diesel playing a prominent role in attaining necessary GHG reductions at the expense of ZEV adoption. This could yield a cost-effective method of reducing GHGs from the HDV sector. However, the adoption of ZEV in the near- to mid-term results in cost reductions that improve the techno-economics of ZEV pathways in the long-term. Such tradeoffs should be considered in planning decisions.
- **The cumulative cost of aggressive adoption of ZEV is comparable to mixes of renewable diesel and renewable natural gas ICVs, demonstrating the important cost reductions that can be obtained from pursuing ZEVs in the near- to mid-term.** The cost of the High ZEV Scenario is 0.53% higher than the GHG Scenario.
- **HDV GHG emissions can be reduced beyond the 2050 target at nearly the same cumulative cost of meeting the target if an increasing ZEV mandate is imposed.** By imposing an increasingly strict ZEV mandate, starting from 0% in 2020 up to 100% in 2050, the 2050 GHG emissions are 77% lower than the 80% reduction from 1990 levels. However, this High ZEV Scenario leads to higher levels of GHG emissions than required by AB 32 in 2020 and SB 32 in 2030, with later emissions reductions benefited by the 2045 requirement of zero carbon electricity in California.
- **The use of High ZEVs in HDV can support GHG reductions in other difficult to electrify end-use sectors.** In the High ZEV Scenario, low use of biomass for HDV fuels in the near-term frees the biomass for use in other sectors. Priority for biomass in these years can be given to sectors that have greater challenge in electrifying or using electrolytic fuels (e.g. marine, aviation, and freight) and provide the opportunity to advance technologies in the mid-term. With those other

sectors given the opportunity to electrify or use electrolytic fuels more successfully, a higher percentage of biomass could be apportioned to HDV fuel production.

- **Hybrid and plug-in hybrid internal combustion powertrains are not prioritized due to the relatively modest efficiency improvement compared to the additional cost of the vehicle.**
- **Overall, the results demonstrate an important role for FCEVs in meeting portions of HDV travel that are less feasible for BEV if aggressive adoption of ZEVs is pursued, e.g. in linehaul.** Heavy-duty FCEVs do not have the low range and long fueling time restrictions that BEVs have. This not only increases the extent to which FCEVs and by extension ZEVs can serve the HDV sector, but it can also ease logistical integration of ZEVs into HDV fleets.
- **BEVs generally represent the most cost-effective option for zero emission HDVs, but practically are constrained by range and recharging time limitations, as well as resulting logistical challenges such as how a fleet's routes are planned and additional labor required for managing fleet charging.** These constraints limit the extent to which BEVs can be adopted by the various HDV vocations. Should future technology advances significantly extend range and reduce charging time of heavy duty BEVs, it can be expected that BEVs will increase their prevalence in the heavy duty sector, though FCEVs will continue to play an important role and provide additional benefits through their connection to the hydrogen grid and associated energy storage aspects.
- **CNG HDVs are attractive as an intermediate solution capable of using renewable natural gas made from low and negative carbon intensity biomass sources combusted in a low-NO_x engine.** However, as emissions constraints get tighter and the limited supply of negative carbon intensity biomass sources are set to lose their environmental credit advantage in the mid-term, these CNG HDVs are not expected to be a significant portion of the long-term heavy duty fleet in California.
- **Renewable diesel is a cost-effective drop-in fuel that can use low and negative carbon intensity biomass and take advantage of the expansive diesel infrastructure and the overwhelming majority of HDVs that can use the fuel with no modifications. However, with a limited supply of biomass that the State may decide to prioritize for other sectors, it is unclear the extent to which renewable diesel will be used in HDVs, especially if a low-NOx diesel engine does not become commercially available.**

3.6 Recommendations

- **More clarity on how California's GHG laws and goals will be implemented on a sector-by-sector basis is needed to determine what emissions reductions should be targeted by each sector.** The present work assumes the percentage reduction in GHGs will be applied equally across all sectors including HDVs. Therefore, an 80% reduction in HDV GHGs is imposed, even though the Executive Order inspiring that limit only places the goal on California in general. Proportioning the GHG reductions differently amongst the various sectors could have a significant impact on how the HDV sector should evolve, either with more or less aggressive alternative technology adoption depending on how GHG limits are imposed.

- **Planning for the allocation of California's biomass resources should be a high priority as availability for HDV fuel production affects fuel pathway and vehicle powertrain projections and can pose challenges in meeting GHG goals.** The U.S. DOE's Billion Ton Report data are used in this work to set limits on the availability of biomass for HDV renewable fuel production. This work's GHG Scenario is to meet 1990 levels of HDV emissions in 2020, a 40% GHG reduction by 2030, and an 80% GHG reduction by 2050. The resulting fleet mix heavily relies on biomass for HDV fuel production, and in particular negative CI biomass feedstocks. Should the availability of these feedstocks be reduced due to use in other sectors of the economy, misjudgment of availability, or any other reason, resulting fuel pathway and vehicle powertrain projections would be altered and challenges will arise in meeting GHG targets.

4. Development of a Guidance Document for Fleets Transitioning to Alternative Fuel

4.1 Introduction and Background

4.2.1 Motivation

Over the past several decades, the public's interest in mitigating the negative externalities of conventionally fueled fleets has led to a complicated environment of regulatory mandates and government incentives targeted at fleet operators. This is particularly true in the State of California, which has acted as a national leader on regulating air quality for nearly half a century. Heavy duty fleets must navigate this more complex environment by balancing the trade-offs between these mandates and incentives with their own motives for cost reductions and overall fleet efficiency.

Since this is not a recent problem, there is a significant academic and technical literature on this topic, including a number of fleet guidance documents available from government and industry trade groups. However, the recently accelerated pace of changes to the regulatory environment along with the development of potentially game-changing shifts deriving from CAV technologies means that fleet managers have increasingly challenging decisions to make regarding investments in alternative technologies and fuels.

4.2.2 Objective

The goal of Task 4 is to address the general problem that fleet managers need assistance in making these investment decisions for short-, medium-, and long-term planning horizons. To address this problem, these more fundamental questions must be answered and communicated to decision makers across the heavy duty vehicle sector:

- What are the challenges, costs, barriers, and tradeoffs, and potential solutions to overcome barriers, associated with investing in low carbon fuels and advanced technology?
- How can fleets best transition to alternative vehicles and/or fuels?

As we've seen in the work described for Tasks 1-3, contract 16RD011 focuses on the central questions related to identifying the most promising fuel pathways for the heavy duty sector. These are largely supply-side concerns related to the potential for specific technologies to meet the legislative and executive policy targets that continue to evolve, including the July 2020 passage of the Advanced Clean Trucks regulation[1] and the proposed Advanced Clean Fleets regulation[2]. Furthermore, has begun exploring demand-side questions in a pair of ongoing projects, including:

- 19RD010: Determinants of Medium and Heavy Duty Truck Fleet Turnover
- 19RD026: Low-Carbon Transportation Incentive Strategies Using Performance Evaluation Tools for Heavy-Duty Trucks and Off-Road Equipment

[1] https://ww2.arb.ca.gov/our-work/programs/advanced-clean-trucks
[2] https://ww2.arb.ca.gov/our-work/programs/advanced-clean-fleets

The results of these demand-related projects will offer significant additional support for augmenting this product with demand-side insights. In this context, the focus recommended for the fleet guidance arising from this project is on interpreting the implications of Tasks 1-3 in a way that relevant fleets, as determined by the vocation-specific findings from these Tasks, can use in the near- to medium-term planning.   With this in mind

4.2.3 Background and Literature Review

The development of concrete guidance for fleets looking to transition their heavy duty operations to alternative fueled vehicles really began with a collection of programs coordinated through the DOE's Vehicle Technology Office (VTO), dating back to the Alternative Motor Fuels Act of 1988 and the Clean Air Act Amendments of 1990, which led to the creation of the Alternative Fuels Data Center (AFDC) to "to collect, analyze, and distribute data used to evaluate alternative fuels and vehicles". The Energy Policy Act of 1992 (EPAct) created mandates for certain fleets to acquire AFVs, which led the DOE to create its Clean Cities Program to "foster the nation's economic, environmental, and energy security by working locally to advance affordable, domestic transportation fuels, energy efficient mobility systems, and other fuel-saving technologies and practices" [392]. Though not strictly limited to heavy duty vehicles, both the AFDC and Clean Cities program offer a range of resources to assist fleets in transitioning to AFVs.

Even though it is nearly a decade old, the 2013 USDOE Clean Cities Program Clean Cities *Guide to Alternative Fuel and Advanced Medium- and Heavy-Duty Vehicles* [393] offers the following a comprehensive assessment of the process of constructing medium and heavy duty vehicles AFV, including broad assessments of various vehicle applications, associated emissions standards, multi-stage construction of vehicles, a variety of alternative fuel drivetrains (including conversions), and specific vehicle options by application, which remains a useful primer today even if the evolution of the market means that some of its technology-related content needs updating.

The International Council on Clean Transportation's 2017 white paper *Transitioning to zero-emission heavy duty freight vehicles* [394] discusses BEV, FCEV, and overhead catenary solutions, including summaries of demonstrations, cost estimates, and fleet perspectives from China, Europe, and the United States. Though this is not strictly a fleet guidance document, their overall conclusion that *"different electric-drive technologies are suitable for different heavy duty vehicle segments, but massive infrastructure investments would be needed"* is still applicable.

The Fleets for the Future (F4F) program funded by the US DOE was designed to reduce the barriers for public fleets to procure clean vehicles for their fleets [395]. The broad goals of the program included creation of a set of procurement best practices coupled with an education and outreach campaign. Though not limited to HDVs and though its focus was on public fleet AFV procurement, the F4F's collection of guides offer valuable information that is useful for public and private fleets of any size. Specific recommendations for cooperative procurement that are more narrowly targeted at public fleets include (1) the importance of drawing on others' experience, (2) ensuring procurement options offer variety and flexibility, (3) the importance of education.

F4F's guidance documents offer topic-specific support for overall planning, specific fuel types, as well as financing processes.

- *Fleet Transition Planning for Alternative Fueled Vehicles* [396]
- *Electric Vehicle Procurement Best Practices Guide* [397]
- *Gaseous Fuel Vehicle Procurement Best Practices Guide* [398]
- *Guide to Financing Alternative Fuel Vehicle Procurement* [399]

The North American Council for Freight Efficiency (NACFE) has recently published a collection of guidance reports[3] including most notably:

- *Guidance Report: Viable Class 7/8 Electric, Hybrid and Alternative Fuel Tractors* [400], which offers reviews of
    - The class 7/8 regional and long haul market
    - The stakeholders interested in tractors
    - Comparison of alternative fuel similarities and differences:
    - Branding and influence concerns
    - Findings, recommendations, and conclusions
    - Fuel type appendices, including tractor and infrastructure details.
- Guidance Report: Electric Trucks—Where They Make Sense [401]. This report "assesses the viability for North American Class 3 to 8 commercial battery electric vehicles (CBEVs) to help the industry understand the many arguments for and against them."
- Amping Up: Charging Infrastructure for Electric Trucks Guidance Report [402] focuses on charging infrastructure decision factors for North American CBEVs, with a particular focus on medium-duty urban delivery. Specific findings are based on the assertion that CBEV operations will rely on depot-based charging. The report is comprehensive in its detail regarding the multiple fleets should consider in planning for charging infrastructure, emphasizing the importance of planning, engaging with stakeholders---utilities in particular.
- Medium-Duty Electric Trucks—Cost of Ownership: This report focuses on total cost of ownership (TCO) decision factors for North American medium-duty commercial battery electric vehicles (MD CBEV).

NACFE reports are particularly effective because they are specifically designed to offer guidance from a fleet perspective. Of particular note is how NACFE characterizes development of alternative-fuel technologies for HDV today (in 2020) as consisting of immature technology that has "many unknowns and challenges." This characterization is generally consistent with the outreach findings detailed previously, with the possible exception that fleets operating CNG vehicles tend to have favorable feelings about the technology and don't express a significant number of challenges beyond cost concerns. In the same characterization, NACFE projects the next two decades to be a "bridging period" that will involve a growing number of fuels and supporting infrastructure producing optimized solutions that allow for maturation of the technology over this time frame, leading to better understanding of costs and performance, before maturing in the 2040 time frame with FCEV and CBEV technology. These projections are generally consistent with the findings of the technology research conducted as part of this project.

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[3] https://nacfe.org/emerging-technology/

Beyond these specific guidance documents, various local or regional documents are available (e.g., [403] [404]), most of which are structured toward specific government-sponsored programs in their jurisdictions. These documents tend to focus on providing general facts about various AFV technologies, vocational applications, and point the reader to sources of additional information---the various resources provided by the AFDC [405] being the most common sources.

Among the various fleet guidance documents reviewed, several common themes are addressed, including:

- Fuel type summary, including characteristics, performance, and suitability for specific applications.
- Specific vehicle options
- Infrastructure
- Total Cost of Ownership
- Education and training
- Maintenance
- Procurement best practices
- Financing and procurement
- Vehicle disposal
- Applicable laws and available incentive programs

We view these themes as a starting point for the development of fleet guidance under this project, but sought to enhance the development of guidance by considering the literature for AFV fleet adoption behavior. We note that there is scant research focusing on heavy duty AFV adoption behavior especially from fleet purchase decision maker points of view [406], and those that do exist are generally limited to hypothetical or stated preference designs. The lack of empirical studies of revealed behavior is driven by the immaturity of the AFV market in the heavy duty sector, particularly as it relates to the emerging technologies described in earlier chapters, which limits the availability of representative revealed preference data. This is one motivation for adopting a qualitative approach in this research to obtain additional information regarding the decision-making processes of fleets across a range of vocations and organizational structures. Of the several studies identified [407]–[412] that have explored heavy duty AFV adoption behavior, most have focused on the European HDV sectors and the findings from European countries [407]–[410] may not be necessarily translated to other regions given that culture, policy context, and market conditions vary across different regions. Furthermore, research focusing on a single specific vocation [408], [411], [412] may not be sufficient for the purpose of obtaining comprehensive insights into heavy duty AFV adoption decisions because of diverse HDV applications. While there has typically been limited accessibility to HDV fleet operators – those who actively considered purchasing AFVs and made a decision – there is greater opportunity in California to examine heavy duty AFV adoption behavior since the state is recognized as a national leader in zero emission vehicles in the U.S. with the highest percentage (29%) of the U.S. total of AFV refueling stations followed by Texas (5.6%) [413]. Therefore, this study aims to fill a key gap in the AFV adoption research area by investigating the factors that have influenced alternative fuel adoption and non-adoption decisions made by California HDV fleet operators.

Generally, there is very limited understanding of heavy duty AFV adoption behavior. The literature is more robust with findings about alternative fuel adoption in households (e.g., [414], [415]), or light-duty vehicle (LDV) fleets, but these cannot be directly transferred to HDV fleets [416]. The major structural distinction between passenger car and fleet vehicle markets (e.g., business-to-consumer features for the former vs., business-to-business characteristics for the latter) [407] may restrict the interchangeability of the findings from those two sectors. As previously addressed, numerous inherent traits were found that could be applied only to AFV fleet adoption behavior in organizations [406], including TCO (e.g., [407], [417]–[421]), operating vehicles on fixed routes (e.g., [420]), first mover advantage (e.g., [418], [420]), and Corporate Social Responsibility (CSR) (e.g., [407], [422]). At the same time, research findings focusing on LDV fleets may also not be simply translated into HDV fleets since diverse application areas of fleet vehicles are differentially applied to LDVs (e.g., taxi, vans, and delivery trucks) and HDVs (e.g., long- or short-haul trucks, transit buses, refuse trucks, sweepers, and vocational trucks) under market circumstances, fleet operational aspects, and governmental policy contexts that are unique to each [406].

Only recently have academic researchers started to address alternative fuel adoption behavior in fleets. In our review, we identified 29 articles related to this question. Table 40 shows a summary of the literature identified, including fleet characteristics, fuel type(s), and methodologies used. The literature on organizational adoptions of AFV fleet vehicles was very limited especially before 2010. Since the early 2010s, those studies have increased in number: 23 articles (79% of the reviewed studies) were published after 2010. The majority of these studies (62%) focus on electric vehicles (EVs), followed by natural gas or biogas vehicles (24%). Other fuels, such as liquid petroleum gas, methanol, or flex-fuel had gained attention particularly before 2010. In accordance with recent technological advancements, two studies ([408], [423]), which dealt with hydrogen-powered vehicle fleet adoptions, were published in the early 2010s. As for the scope of vehicle classes, only three articles solely concentrate on heavy duty vehicle fleets (Pfoser et al., 2018; Seitz et al., 2015; Walter et al., 2012) while most of other articles focus on LDV fleets. For methodologies used, out of the 29 reviewed articles, 10 articles applied qualitative approaches such as focus groups and interviews, 18 employed quantitative approaches by conducting online or mail surveys, and 1 was based on a review of demonstration projects. As for the study participants, 20 articles (71%) targeted fleet purchase decision-makers such as fleet managers and organization representatives, while 6 studies targeted fleet vehicle drivers with an emphasis on the acceptance of drivers for successful implementation of AFVs (Johns et al., 2009; Wikström et al., 2015, 2016). Two studies targeted both fleet purchase decision-makers and vehicle drivers. Finally, the study areas of most literature (20 articles, 69%) were in Europe while the U.S. is represented with 6 articles (21%). Two articles involve both Europe and the U.S., and one other article was carried out in Asia.

Walter et al. [408] conducted a choice experiment in Switzerland and Germany to assess fleet operator preferences for hydrogen-powered sweepers, finding two monetary attributes – vehicle purchase price and running costs – to have the most profound influence on the purchasing decision. Another study in Germany by Seitz et al. [407] was based on the Technology–Organization–Environment framework [424] which identifies three contextual aspects– technological, organizational, and external task environmental contexts – that influence the innovation adoption process of an organization. The researchers used a multiple linear regression analysis with their quantitative survey results, finding the CSR with environmental attitudes to be the most prevalent factors for heavy duty AFV adoption [407]. Pfoser et al. [409] developed a structural equation model based on their online survey results in European Rhine-Main-Danube axis areas, estimating that accessibility/availability of technology and refueling infrastructure, attitude towards AFVs, expected usability, and expected usefulness significantly determined an acceptance of liquefied natural gas for heavy duty long distance transport operators.

Mohamed et al. [412] conducted 11 in-depth interviews with transit service providers in Canada to identify the factors that hinder the implementation of electric buses, highlighting risk mitigation, operational capabilities, and cost reductions as the potential measures for electric buses to penetrate the marketplace. Another recent study by Blynn and Attanucci [20] also investigated the factors that affect electrification of transit bus fleets in California, Kentucky, and Massachusetts, finding environmental benefits as the top motivation factor, and high first cost and charging infrastructure costs as the most cited substantial obstacles by all 12 agencies interviewed. Anderhofstadt and Spinler [410] employed the Delphi method to examine the factors affecting adoption of heavy duty AFVs in Germany, finding the key factors to be truck reliability, available fueling infrastructure, the possibility to enter low-emission zones, and current and future fuel costs. Though informative, these previous studies present results centering on different regions or a specific single vocation and therefore may not fully explain heavy duty AFV adoption behavior in California, which justifies the need for stand-alone research probing alternative fuel adoption decisions made by HDV fleet operators from various vocational sectors in California.

Nevertheless, some insights from light-duty AFV fleet adoption studies can inform the design of this research. For example, Bae et al. [416] noted significant heterogeneities in the adoption behavior depending on various dimensions such as organizational sector [425], organization's size [420], vehicle vocation [426], and adoption status (e.g., 'innovators' or 'early adopters' vs. 'late majority' or 'laggards' [427]). In addition, there has been a lack of studies about revealed non-adoption cases [406] where potential adopters considered purchasing an AFV but decided not to buy it, which can provide a clearer understanding of critically perceived weaknesses of and barriers to heavy duty AFV fleet adoption. Those two insights were considered in this work, such as for the sampling strategies of the qualitative interviews described in the next section.

Table 40. Alternative fuel vehicle fleet adoption behavior literature summary

No.	Author(s), Year	Type	Fuel Type[1]	Vehicle Class (Vehicle Type)	Methodology	Statistical Model[2]	Location	Number of Respondents
[428]	(Morganti & Browne, 2018)	PRJ[4]	ELEC	LDV (passenger cars)	Survey	CV / structural equation model	Germany	575 (drivers) [3]
[429]	(Morrison et al., 2018)	PRJ	ELEC	LDV (light commercial vehicles ≤ 7000 lbs)	Interview	.	France, UK	23
[421]	(Pfoser et al., 2018)	Conf	BD, CNG, RNG, LNG, LPG, HD, ELEC	L-HDVs (shuttles; emergency response and security vehicles; facilities and maintenance vehicles)	Online survey / Interview	.	USA	33 for survey / 16 for interview
[409]	(Altenburg et al., 2017)	PRJ	LNG	HDV (heavy duty and long distance transport)	Online Survey	CV / structural equation model	European Rhine-Main-Danube axis areas	157
[418]	(Globisch et al., 2017)	Conf	ELEC	L-HDV (van or freight trucks)	Interview		The Netherlands	14
[430]	(Saukkonen et al., 2017)	PRJ	ELEC	LDV	Online survey	CV / ordinary least square	Germany	229
[419]	(Boutueil, 2016)	PRJ	NG, BG	L-HDVs (taxi, delivery, waste management, etc.)	Interview	.	Finland	7
[431]	(Kaplan et al., 2016)	PRJ	ELEC	LDV	Interview	.	Paris, France	44
[432]	(Klauenberg et al., 2016)	PRJ	ELEC	L-HDV (commercial vehicles)	Online survey	CV/ structural equation model	Austria, Denmark, and Germany	1,443
[433]	(Quak et al., 2016)	PRJ	ELEC	LDV	Online Survey	.	Austria and Germany	752
[434]	(Wikström et al., 2016)	PRJ	ELEC	Not found (freight vehicles for daily city logistics)	Reviews of projects and demonstrations	.	Europe	n/a

[435]	(Bennett, 2015)	PRJ	ELEC	LDV (passenger cars and vans)	Focus group	.	Sweden	40
[422]	(Seitz et al., 2015)	PRJ	ELEC	LDV	Online survey	CV / partial least squares	UK	364
[407]	(Wikström et al., 2015)	PRJ	AF	HDV (≥12,000 lbs)	Interview / Online survey	CV / multiple linear regression	Germany	177
[436]	(Kirk et al., 2014)	PRJ	ELEC	LDV (transport and passenger vehicles)	Survey / Focus Group / Interview / Logbooks	.	Sweden	550 (drivers)
[437]	(Koetse & Hoen, 2014)	PRJ	CNG	LDV (vans)	Interview / Focus group	.	UK	15
[438]	(Nesbitt & Davies, 2014)	PRJ	ELEC, HD, E85	LDV	Online Survey	CM /multinomial logit model	The Netherlands	940 (drivers)
[417]	(Rolim et al., 2014)	Conf	ELEC	LDV (pickup trucks)	Interview / Online survey	.	California, USA	53 (drivers)
[439]	(Sierzchula, 2014)	Conf	ELEC	LDV	Interview	.	Portugal	25 (drivers)
[420]	(Wikström et al., 2014)	PRJ	ELEC	LDV	Interview	.	USA and the Netherlands	11
[440]	(van Rijnsoever et al., 2013)	PRJ	ELEC	LDV	Online Survey / Interview / Logbooks	.	Sweden	42 / 57 / 44 / 30 (5) (drivers)
[423]	(Walter et al., 2012)	PRJ	ELEC, BG, HD	Not found (local government fleets)	Expert Interview / Online survey	CM /ordinal logit model	The Netherlands	50
[408]	(Johns et al., 2009)	PRJ	HD, CNG/BG	HDV (sweepers)	Expert Interview / Online survey	CM/hierarchical Bayesian analysis	Germany and Switzerland	274
[441]	(Rahm & Coggburn, 2007)	PRJ	bi-fuel E85, bi-fuel CNG, bi-fuel LPG	Not found (local government fleets)	Mail Survey	CV /censored normal regression	Illinois, USA	41 (drivers)
[442]	(Loo et al., 2006)	PRJ	BD, E85, ELEC, LPG,	L-HDV	Online Survey	.	USA	30

			CNG, LNG, MTH, HD					
[426]	(Nesbitt & Sperling, 2001)	PRJ	LPG	LDV (public light buses)	Survey	CM /multinomial logit model	Hong Kong	483
[443]	(Nesbitt & Sperling, 1998)	PRJ	AF	LDV	Focus group / Interview / Mail survey	.	California, USA	59 / 39 / 2131(6)
[444]	(Golob et al., 1997)	PRJ	AF	LDV	Focus group / Interview / Mail survey	.	California, USA	59 / 39 / 2131(6)
[425]	(Morganti & Browne, 2018)	PRJ	ELEC, CNG, MTH	LDV and medium duty trucks (≤14,000 lbs)	Mail Survey	CM /multinomial conditional logit model	California, USA	2,023

*Note: (1) AF: alternative fuels in general, BD: biodiesel, BG: biogas, CNG: compressed natural gas, ELEC: electricity, E85: flex fuel, HD: hydrogen, LNG: liquefied natural gas, LPG: liquid petroleum gas, MTH: methanol, NG: natural gas. (2) CM: choice modeling method, CV: contingent valuation method. (3) Respondents consist of (or include) fleet vehicle drivers. Otherwise unmentioned, study participants include fleet operators, organization representatives, or other members involved in their fleet purchase decision making. (4) Conference papers or proceedings. Otherwise unmentioned, articles are peer-reviewed journal papers. (5) 42, 57, and 44 for the 1st, 2nd, and 3rd surveys, respectively; 30 for interviews. (6) 59 for focus groups; 39 for one-on-one interviews; 2131 for surveys.

4.3 Methods

This task was broken into three main steps, beginning with a detailed literature review, focusing on fleet decision-making processes, then following that with outreach to fleet managers and other stakeholders, and finally distilling the resulting findings into a fleet guidance document that can support fleet decision makers as they consider transitioning to alternative fuel vehicles for their heavy duty operations.

4.3.1 Outreach

Building on the initial literature review, the team turned to obtaining information from fleet managers about their experiences related to the decision to purchase alternative fueled heavy duty vehicles. Since this is an immature market, we chose to focus on early adoptors who could provide insight into the issues they had to consider and navigate in order to successfully deploy specific alternative fuel technologies. The market's immaturity also led to the use of a qualitative research approach as an inductive strategy for generating a theory informed by data [445], since its main strengths lie in revealing a complex phenomenon, a better chance of being relevant [446], and a more in-depth analysis, than quantitative methods [447]. Furthermore, in this case, we are focused on identifying the factors that may be relevant to fleets regarding vehicle purchases for hypothetical or emerging technologies. The lack of revealed behavior in these scenarios, or in sufficiently analogous situations, justifies a qualitative approach that can explore both revealed and hypothetical situations with fleet decision makers. It is worth noting that interpretation of such survey findings must be made with caution, but they can still be informative in the context of providing guidance to fleets who may be considering AFV adoption.

Since the Institute of Transportation Studies at the University of California, Irvine has been administering the CEC's Natural Gas Vehicle Incentive Project (NGVIP), the research team used the connections developed during that effort to recruit recent heavy duty NGV fleet adopters and non-adopters sampled from NGVIP applicants. According to Rogers' theory of diffusion of innovations [427], non-adopters can be categorized into two groups: 1) an active rejection case which occurs when an organization considers adopting an innovation, but later decides not to adopt it; and 2) a passive rejection case which happens when an organization does not think about adopting the innovation at all. The analysis here focused on the former since those active rejection cases can provide more specific reasons for non-adoptions – beyond being unaware of alternative fuel technologies. Those "active" non-adopters are accessible from the organizations that applied for NGVIP incentives but cancelled their applications later.

To build up a sampling strategy, the analysis of NGVIP applicants began by identifying the basic characteristics of the fleets (e.g., locations, business sectors, numbers of NGVs purchased, and relevant air quality management district (AQMD constraints). Based upon earlier research [406], an initial hypothesis was formed that the structure of influencing factors would vary depending on diverse parameters: 1) public vs. private status; 2) business types (e.g., organizations that are likely to pursue an environmentally friendly image, such as waste management or educational services vs. others); 3) the number of AFVs; and 4) whether or not the organization is subject to any regulations requiring AFV purchases (e.g., the Fleet Rules of South Coast AQMD [448] in Southern California). Under these hypotheses, purposeful sampling was employed, as it is the most common sampling technique for qualitative research [449]. Although no attempt was made to obtain a statistically representative sample of California HDV fleets given a small sample size for in-depth interviews, a wide diversity of HDV fleets were recruited so as to capture major variances across different segments. Also, though a majority of the interviewees were heavy duty NGV operators, further efforts were made to capture other AFV purchasing behavior by asking the interviewees about their decisions of adoption and non-adoption of other alternative fuel technologies. Consequently, a total of 25 adoption and 41 non-adoption cases were investigated across various alternative fuel options using the responses from 18 fleets. In this context, a “case” is a situation in which a given fuel was considered for the purchase of one or more vehicles by a given fleet. A single fleet could have multiple adoption cases (a fuel was considered and a vehicle purchased) and non-adoption cases (a fuel was considered and a vehicle NOT purchased).

Across these interviews, a total of 25 adoption and 41 non-adoption cases across various alternative fuel options were identified as summarized in Table 41. The participants included an even balance between public and private fleets and skewed toward larger fleets (>100 vehicles). Most participating fleets had at least 3 years of experience since their first deployed HD AFVs.

Table 41. Participating HDV fleet characteristics

Classification	**Number of organizations (n = 18)**
Public vs. private	
Public	9 (50.0%)
Private	9 (50.0%)
HDV fleet size	
> 100	11 (61.1%)
20 to 100	5 (27.8%)
≤ 20	2 (11.1%)
Year of the 1st heavy-duty AFV purchased	
after 2015	3 (16.7%)
before 2015	14 (77.8%)
Fleet vocation	
Various	7 (38.9%)
Refuse trucks	5 (27.8%)
School buses	2 (11.1%)
Local delivery	2 (11.1%)
Freight trucking	1 (5.6%)
Paving work	1 (5.6%)
Subject to SCAQMD fleet rules [c]	
Yes	11 (61.1%)
No	7 (38.9%)

Classification	**Number of organizations (n = 18)**
Heavy-duty AFV adoption status [a]	
CNG	17 (94.4%)
LNG	3 (16.7%)
LPG	4 (22.2%)
Electricity	1 (5.6%)
Heavy-duty AFV non-adoption status [b]	
CNG	1 (5.6%)
LNG	9 (50.0%)
LPG	5 (27.8%)
Electricity	11 (61.1%)
Hydrogen	6 (33.3%)
Biodiesel	8 (44.4%)
E85	2 (11.1%)

4.3.2 Content Analysis and Interview Data

A total of 18 one-on-one interviews were conducted with key individuals who participate in the fleet purchase decision-making process. The participants were fleet managers in most cases, but also included company presidents, project engineers, and energy analysts. Each interview consisted of a set of thirteen standard interview questions regarding 1) basic fleet information such as fleet size, vocation, and fuel diversity, 2) the types of alternative fuels that were considered the adoption, 3) the factors that influenced their heavy duty AFV fleet adoption or non-adoption decisions, and 4) whether any laws or regulations affected their purchasing decision. Each interview was conducted via a phone or in person, and lasted 1 hour 12 minutes on average. Prior to each interview, a detailed information package including consent forms and a study information sheet was sent to the participants. All study materials and interview protocols were approved by the University of California, Irvine Institutional Review Board. Out of the 18 completed interviews, 16 interviews were recorded and professionally transcribed. The other two sets of interview data were collected via an electronic document since the interviewees did not want to communicate verbally or did not allow recording. To increase consistency of the interview procedure across all participants, multiple follow-up questions were asked for those non-recording cases.

The interview transcriptions and written documents were analyzed using content analysis [450]. Content analysis involves a systematic coding process, extracting categories, and identifying themes from these categories so as to answer the research questions [451] and to make replicable and valid inferences from texts [450]. For this, the interview data were initially coded using ATLAS.ti, a qualitative analysis tool that assists in managing numerous codes (i.e., discrete units of meaning) and their associated quotations. Among a long list of codes, those with related meanings were combined into discrete textual categories, by which an interview data abstraction sheet was created. Then, two researchers (called coders) independently filled in the data abstraction sheet using their own notes and the interview data. When filling in this data sheet, each coder identified the existence of each category, and wrote down its sign (i.e., "+" being positively stated as motivators or facilitators, and "–" being negatively stated as barriers) along with its strength (i.e., "1" being implied or indirectly affected, "2" explicitly mentioned, and "3" emphasized as overarching factors, following [420], [452]), and collected the relevant quotations. In case an opinion for a textual category was neutrally stated, the rating "n" was given. The list of categories for the interview data abstraction sheet was almost finalized using a preliminary analysis with seven interviews (39% of the data). To ensure inter-coder reliability of the findings, Krippendorff's α [450] was computed as the most general agreement measure in content analysis. The Krippendorff's α is generally defined by Equation 28.

Equation 28. Krippendorff's α equation

$$\alpha = 1 - D_0/D_0$$

where D_0 is a measure of the observed disagreement and D_e is a measure of the disagreement that can be expected when chance prevails. The Krippendorff's α has a value between 0 and 1: a value of 1 indicates perfect agreement and 0 indicates perfect disagreement. A more detailed description of the computation of the Krippendorff's α can be found in the literature ([450], [453]). After extracting categories from interview data by each of the two coders, data is considered reliable if Krippendorff's α is above 0.9 [454]. Any disagreement between the two coders is settled by a third coder. Using agreed categories between coders along with relevant quotations from interviews, themes along with hypotheses will be identified to address the research questions.

The outcomes from the two coders' work resulted in a Krippendorff's α of 0.950, which confirmed the reliability. The remaining discrepancies between the two coders were resolved by a third coder who participated in this study. Through a series of discussions between the coders with agreed categories and relevant quotes, themes and hypotheses were identified to address the research questions. Consequently, both quantitative and qualitative analyses were agreed and verified by the researchers participating in this study.

4.4 Results and Discussion

Our analysis of the interviews focused on 5 main topic areas:

1. Fleet characteristics and organizational structure
2. Factors influencing AFV adoption decisions
3. Refueling behavior
4. Other facilitators to AFV purchase
5. Opinions on viable alt-fuel options for HDVs in the 2030s.

These are each addressed in the following sections.

4.4.1 Fleet characteristics and organizational structure

Basic fleet information about each fleet is summarized in Table 44, with their fleet sizes, public/private status, fleet vocations, numbers of heavy duty AFVs, year of the 1st heavy duty AFV purchased, and refueling facilities currently being used. Figure 98 shows a visual summary of alternative fuel adoption status of each participating HDV fleet. Along with heavy duty CNG vehicles being operated, three organizations adopted LNG vehicles, one adopted electric refuse trucks, and four adopted LPG vehicles. Only one organization considered but then rejected the adoption of a CNG vehicle (Org. 18), whereas the other organizations (Org. 1-17) evaluated multiple alternative fuel options and then rejected most of them except CNG.

Following our findings from the literature review that organizational structure and associated decision-making steps are critical factors to consider in designing generalized guidance for fleets, we categorized the fleets into four topological decision-making categories following [417], [443] as shown in Table 42. Each category of decision-making structure is differentiated from the others in terms of personnel involved in their decision, the time consumed for making their decision, and factors considered important and/or sensitive. Specifically:

- Hierarchic fleets (central and formal): "Reasoned choices with life-cycle cost analysis and strategic interests," "likely to be most deliberately resistant to government mandates when those

- Autocratic fleets (centralized and less formal): “decision making based on purchase prices (rather than life-cycle costs analysis),” “less inclining to public relations benefits,” and “susceptible to hearsay and rumor.”
- Bureaucratic fleets (formal and less centralized): “slow and veto-prone decision process,” “firm and clear government rules,” and “likely to be responsive to mandates in case of government-operating fleets.”
- Democratic fleets (less centralized and less formal): “influenced by lower-level members,” “better informed and more broadly analytical decision process,” and “slow to act.”

Table 42. Fleet decision-making categories

Topology categories of decision-making behavior	Characteristics (Nesbitt & Sperling, 2001)	Number of participating organizations	(%)	Examples	Note (e.g., fleet size / public vs. private)
Hierarchic	Central & Formal	4	(22%)	Org.4	Various fleet sizes / 2 public, 2 private entities
Autocratic	Central & Less Formal	3	(17%)	Org.11,18	small or medium fleets / all private entities
Bureaucratic	Less central & Formal	8	(44%)	Org.15	all large size fleets / 5 public, 3 private
Democratic	Less central & Less formal	3	(17%)	Org.2,14	medium or large fleets / 2 public, 1 private
Sum		18	(100%)		

Table 43. Variations in AFV purchase planning stages by organization topology

Stages (based on literature)	Stages (based on the interviews)	Steps	Hierarchic	Autocratic	Bureaucratic	Democratic
1. Awareness	**Fleet-level Plan**	• Replacement/ expansion plans	V	V	V	V
		• Regulation check	V	V	V	V
		• Refueling plans	V	V	V	V
	Vehicle-level Decision	• Availability check	V		V	V
2. Consideration		• Discussion with internal customers			V	V
		• Suitability check	V	V	V	V
		• Specification	V		V	V
		• Getting feedback from adopters	V			
		• Cost analysis	V		V	
		• Bidding	V		V	V
		• Applying for incentives	V	V	V	V
3. Adoption Decision		• Final approval (by C-suite or board)	V		V	
		• Placing an order	V	V	V	V
4. Implementation	**Implementation**	• Trying vehicles and getting feedback	V	V	V	V
5. Confirmation	**Confirmation**	• Purchasing multiple more vehicles	V	V	V	V

The impact of organizational structure related to the variations in decision-making stages as shown in Table 43, which relates the 5 stages of organizational decision-making obtained from the literature search: 1) Awareness, 2) Consideration, 3) Adoption Decision, 4) Implementation, and 5) Confirmation [417] to a slightly less rigid hierarchy of decision-making obtained from the interviews that involve: 1) fleet-level planning, 2) vehicle-level decisions, 3) implementation, and 4) confirmation. We identified 15 distinct steps that were mentioned by at least one respondent and mapped them onto these stages. The last four columns show which steps were carried out by each organizational structure. Perhaps unsurprisingly, the more formal organizations (Hierarchic and Bureaucratic) tended to perform most of the distinct steps that were identified, while Autocratic organizations performed significantly fewer.

Additional general insights from the analysis included the following:

Insight 1. *Key decision-makers (e.g., fleet managers)' leadership is critical throughout the entire decision-making stages.*

Insight 2. For bureaucratic, democratic, and hierarchic decision-making behavior, the processes can be inherently complex because of multiple people involved from different positions and/or many steps need to be passed.

Insight 3. For some autocratic fleets**,** inertia to follow previous purchases of a specific fuel option without any cost analysis can be an internal barrier to adoption of other heavy duty AFV option.

Insight 4. Although vehicle drivers are typically not key-decision makers, their input and feedback can be often used in adoption decision and/or confirmation stages, and this role may depend on the decision-making structure of the organization.

Insight 5. For potential new adopters who have never tried heavy duty AFVs, practical information shared by other adopters and supporting efforts from technology suppliers (e.g., testing AFVs) may facilitate their decision-making processes.

Though broad conclusions from these findings are not possible due to the limited sample size, a reasonable takeaway from these insights is that guidance for diverse fleets should consider the differences in organizational structure when structuring advice, recognizing that decision-making may involve people with diverse backgrounds and expertise, which broadens the potential audience for the guidance, and that some steps of the process may not exist for some organizations. Though outside the scope of 16RD011, additional empirical work to understand the role of organizational structure in AFV purchase decision-making in the heavy-duty sector is warranted and underway by the authors in a separate project.

4.4.2 Factors influencing AFV adoption decisions

Figure 99 through Figure 101 present the results of the content analysis showing the sign and strength of the factors that influenced the organizations' heavy duty AFV adoption decisions. With regard to CNG adoption decisions (see Figure 99), the most recurring factors addressed by more than a half of the participating organizations are: functional suitability (in terms of power, payload, and/or range), environmental consciousness regarding vehicle emission (or CSR), availability of vehicles, and regulations by the SCAQMD fleet rules. Other important but less common factors mentioned by more than a third of the participants include: overall costs (or TCO), vehicle purchase price, fuel price, fuel infrastructures, vehicle reliability/safety, contract with municipalities, regulations by CARB, and financial incentives. Among those common factors, the most frequently emphasized factors (i.e., with "±3" symbols) are: regulations by the SCAQMD, financial incentives, environmental consciousness/CSR, vehicle availability, and fuel price. As to the other alternative fuels than CNG (see Figure 100 and Figure 101), not only similar criteria to the CNG adoption decisions, but fuel-specific issues along with firm-specific matters were addressed as motivators or barriers to the adoption. While a number of insights with these key themes stem from a combination of qualitative and quantitative analysis, we summarize seven major hypotheses below. While each of these requires further empirical study, they serve as initial findings for the development of fleet guidance.

Hypothesis 1. *Regulations requiring AFV purchases combined with a limited technology availability have created a constrained fuel choice toward CNG for some HDV fleet operators.*

The regulations implemented by South Coast AQMD together with a limited availability of AFV options were most commonly addressed as overarching reasons for CNG adoption. The SCAQMD fleet rules [448] require government fleets and private contractors under contract with public entities (e.g., school bus, refuse hauler) to purchase alternative fuel vehicles (e.g., CNG, LNG, LPG, methanol, electricity, or fuel cells). At the same time, CNG has been perceived as the most viable and commercially available alternative fuel option in the heavy duty sector in California. One organization stated, “The decisions about the alternative fuel are forgone. We are affected by AQMD rules 1196, what’s called fleet rules. We’re mandated. (…) The only alternative in 2009 was compressed natural gas vehicle” (Org. 2).

While more than half the organizations interviewed made such decisions constrained toward CNG, the actual effect of regulations seemed to vary depending on organization-specific characteristics such as fleet size and CNG fueling facilities being used. For example, one organization with a medium fleet size and using off-site fueling stations noted, if there were no such rules, they would “buy diesel due to the incremental costs” (Org. 2). Another organization with a medium fleet size but equipped with on-site fueling facilities stated, “I would actually diversify a little bit more” (Org. 1) as operating both alternative and conventional fuels “would be for the safety (of the fleet operations) during emergency”. In contrast, several organizations with a large fleet size (100+ vehicles) and their own on-site refueling facilities (e.g., Org. 7, 15, and 17) expressed a consistent commitment to using CNG even without regulations.

The implications of regulatory constraints on allowable technology revealed by the respondents are an important consideration in the development of policy such as the proposed Advanced Clean Fleets regulation. In some cases explored here, CNG was often the only viable fuel due to both vehicle and infrastructure considerations, and the constrained choice set led to fleet investment in these technologies. However, the anticipated role of natural gas as a transportation fuel to help California meet its policy targets---including the findings outlined in earlier chapters---is far from certain. Fleets who have followed these mandates may have therefore made investments in technologies that have a constrained future. Long-term viability of specific fuel pathways should therefore be a consideration in regulatory actions.

Table 44. Summary of participating fleets

Organi-zation	HDV fleet size	Public vs. private	Vehicle vocation	Number of heavy duty AFVs [b]	Number of HD AFVs to be expanded	Year of the 1st HD AFV purchased [c]	AFV refueling facilities [d]
Org. 01	51	public	school buses	19 CNGVs	15 CNGVs	2002	On-site (slow-fill/fast-fill)
Org. 02	27-29	public	tractor, sewer trucks, crew trucks	9 CNGVs	11 CNGVs	2009	Off-site *(On-site will be built)*
Org. 03	650	public	various (street maint., water trucks, truck tractors, etc.)	80 CNGVs	9 CNGVs	≈ 1997	On-site (fast-fill) and Off-site
Org. 04	70	private	local delivery	2 CNGVs	9 CNGVs	2017	Off-site (*On-site facilities will be built)*
Org. 05	22	private	Delivery	32 CNGVs	Will expand CNGVs if business grows	1973	On-site (slow-fill)
Org. 06	105	private	solid waste collection	≈ 100 CNGVs	2 CNGVS	≈ 2013	On-site (slow-fill/fast-fill)
Org. 07	900+ (all classes) [a]	private	waste collection, recycling material collection	400 CNGVs, 8 LPGVs	50+ CNGVs	2004 (CNG), 2004 or 2007 (LPG)	On-site (slow-fill/fast-fill) / LPG wet-hosing [e]
Org. 08	16	private	hauling (biosolids, diatomaceous earth, wine grapes, compost gypsum, gravel, etc.)	2 CNGVs	4 CNGVs	2016	Off-site *(On-site facilities will be built)*
Org. 09	129	public	various (construction, refuse collection, sewer and drain cleaning vehicles, and firefighting)	41 CNGVs	25 CNGVs, ≈ 124 HDVs will eventually be AFVs	2016	On-site (slow-fill)
Org. 10	2400 (all classes)	public	various (public works activities, park maintenance, law enforcement, sheriff, social services, and refuse trucks)	15 CNGVs, LNGVs (being migrated to CNGVs), 20-30 LPGVs, RD*	50 CNGVs, 2 EVs	2000 (LNG), 2014 (CNG)	On-site (slow/fast-fill)/ Off-site LPG stations (a contract through the propane provider) /

							On-site EV stations planned
Org. 11	38	private	waste collection	36 CNGVs	none	2000	Off-site *(On-site facilities will be built)*
Org. 12	35000 (in the U.S.)	private	school buses	22 CNGVs, ≈ 2000 LPGVs	Will expand CNGVs and LPGVs	2017 (CNG), ≈ 2015 (LPG)	(not specified for CNG)/ On- and off-site LPG stations and wet-hosing
Org. 13	615 (all classes)	public	various (sewer jetter trucks, street maint., refuse trucks, pickup trucks, etc.)	256 CNGVs	Will expand CNGVs	1998	On-site (slow-fill/fast-fill)
Org. 14	900 +	private	waste collection	≈ 400 CNGVs, 10 LPGVs	≈ 500 CNGVs	2002	On-site (slow/fast-fill)/ LPG wet-hosing
Org. 15	800	public	various (refuse, street sweeping, fire dept., police, public works, parks, beach maint., gas department, etc.)	60 CNGVs, 75 LNGVs, RD*	80 CNGVs	2015 (CNG), 2005 (LNG)	On-site (slow-fill); Off-site (fast-fill)
Org. 16	179	public	various (mobile service, trucks, utility, tractors, lowboy, etc.; CNG vehicles' applications: pick-up and delivery)	3 CNGVs	Will expand CNGVs	≈ 2012	Off-site (fast-fill)
Org. 17	721	public	solid waste collection	310 CNGVs, 282 LNGVs (being migrated to CNGVs)	Will expand CNGVs	1994 (duel fuel LNG)	On-site (slow-fill/fast-fill)
Org. 18	10 +	private	dump trucks, tankers, tow trucks (paving company)	0 (i.e. non-adopter)	none	n/a	n/a

[Note] (a) In the case that the interviewee did not have the record of the number of HDVs, the whole fleet size (including light-duty vehicles) was collected. (b) CNGVs: Compressed Natural Gas Vehicles, LNGVs: Liquefied Natural Gas Vehicles, LPGVs: Propane Vehicles, and RD*: Renewable diesel is being used for all diesel vehicles. (c) The year when the first heavy duty AFV was purchased since the interviewee had started working at the organization unless the interviewee had their previous record. (d) On-site: the organization is using their own CNG (and LNG) refueling station at their fleet site. Off-site: the organization is using off-site CNG (and LNG) station(s) which is close to their site or en route for their daily route. (e) The organization has an arrangement with a propane vendor to come and bring a propane tank and fill up the LPGVs on site.

Figure 98. Alternative fuel adoption status of participating fleets

Organizations (vocations)	01 (school bus)	02 (various)	03 (various)	04 (delivery)	05 (delivery)	06 (refuse)	07 (refuse)	08 (hauling)	09 (various)	10 (various)	11 (refuse)	12 (school bus)	13 (various)	14 (refuse)	15 (various)	16 (various)	17 (refuse)	18 (paving)
Fleet Characteristics (a) / Alternative Fuels	Pb M On-site	Pb M (On-site)	Pb L On-site	M (On-site) <15 NGV New	M On-site	L On-site	L On-site other AFV	S (On-site) <15 NGV New	Pb L On-site other AFV	Pb L On-site ELEC On-site other AFV	M (On-site)	L n/a other AFV New	Pb L On-site	L On-site other AFV	Pb L On-site other AFV	Pb L <15 NGV	Pb L On-site	S
CNG	A(b)	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	N
LNG	N		N					N	A→N		N		N		A→N	N	A	
Electricity	N		N	N		N	N	N	N	A			N	N	N	N		
Hydrogen	N		N					N				N			N	N		
Propane (LPG)	N	N	N				A	N		A		A		A		N		
Ethanol							N									N		
Biodiesel							N	N	N	N		N	N		N	N		
Renewable diesel(c)			A							A			A		A			
Any other AFV than CNG**	N	N		N	N		N		N		N		N					

[Note] (a): Each symbol represent a specific fleet characteristic: "Pb": public entities (c.f., private entities, otherwise unmentioned), "L": large fleet size (>100 vehicles), "M": medium fleet size (20-100), "S": small fleet size (≤ 20), "On-site": Has their own on-site CNG station(s) (c.f., use off-site CNG stations, otherwise unmentioned), "(On-site)": Will build their own on-site CNG stations, although they currently rely only on off-site station(s), "n/a": information about CNG fueling stations unavailable, "ELEC On-site": planning to build their own on-site electric heavy duty charging stations, "<15 NGVs": the total number of NGVs, including both those are being currently operated and those to be expanded in the near future, will less than 15 NGVs, "New": the year of the first heavy duty AFV purchased was after 2015, and "Other AFVs": operating other type(s) of heavy duty AFVs along with CNG vehicles. (b) 'A': adopted an alternative fuel for their heavy duty vehicle operations, 'N': did not adopt it (active rejection cases), 'A→N': an alternative fuel adopted before is being migrated to another fuel option. (c) 'A's with 'Renewable diesel' represent the organizations those who are using renewable diesel for their conventional diesel heavy duty vehicle operations.

Hypothesis 2. *Perceived technology characteristics, mainly in terms of functional suitability, monetary costs, fuel infrastructures, and vehicle reliability/safety, are evaluated in a comprehensive approach for CNG adoption decisions.*

Various technological characteristics tended to be simultaneously considered during the organization's CNG adoption decisions. Those traits are in line with a range of attributes of previously defined by Rogers [455], namely perceived relative advantage (e.g., a lower TCO), compatibility (e.g., functional suitability), complexity (e.g., issues associated with inadequate fueling infrastructures) , and uncertainty (e.g., safety and reliability). Of those, the most frequently identified factor by two thirds of participating organizations was functional suitability in terms of vehicle power, payload, and/or driving range. In other words, the vehicles need to "meet our operational requirements" (Org. 17) and "fit and work in the areas that we need it" (Org. 7). In addition to suitability, vehicles' safety/reliability was also frequently cited as another main factor, meaning that the vehicle should "be operated safely for the life cycle of the vehicle." (Org. 10). Such functional suitability and safely/reliability of one technology can be evaluated differently between different fleet vocations. For example, some refuse or local delivery truck operators favorably perceived suitability and safety of heavy duty CNG vehicles (e.g., Org. 4 and 6) while a paving company (Org. 18) rejected adopting CNG because of its unfulfilled functionality and safety concern. The organization explained, “we are skeptical on their (CNG vehicles) towing capacity and their load limits of materials that we currently haul in our trucks. (…) When we did look into them, the way they were configured was not - to us, didn’t seem safe for our work. Because we pick up asphalt that is 350 (Fahrenheit) degrees. (…)” (Org. 18). It is worth noting the frequency of a particular response shouldn’t be interpreted as necessary or sufficient for defining relative importance of a topic. Similarly, just because some fleets didn’t mention a factor, it doesn’t necessarily mean that it wasn’t important to them, but rather it may have not occurred to them to mention in an open-ended interview. However, in the qualitative approach adopted here, we do interpret frequently mentioned items as factors that warrant discussion in any guidance document since those themes were commonly observed. Further, they do suggest avenues for follow-on quantitative research that can effectively assess their relevant importance.

Monetary costs and fuel infrastructures were also commonly addressed by more than a third of the organizations. For some fleets, financial costs were assessed on a basis of total cost of ownership (TCO) considering both capital expenses (CAPEX) and operating expenses (OPEX) (e.g., “CAPEX and OPEX - how much does it cost and what it cost to run” (Org. 14)). Such overall costs can be estimated differently depending on fleet characteristics (e.g., fleet size, annual vehicle mileage, etc.), which may lead to contrasting evaluations. On the other hand, some organizations highlighted separate components of the financial costs including vehicle purchase price and fuel price as being critical to the decision without noting TCO considerations. . At the same time, more than a half of CNG adopters cited refueling infrastructure as one of the primary factors influencing their decisions. Such perceived complexity of CNG adoption associated with the refueling facilities can differ based on fleet site locations and fueling facilities being currently used.

Hypothesis 3. *The availability of governmental financial incentives for offsetting initial capital costs were a driver to adoption.*

A higher purchase price of heavy duty CNG vehicle was identified as one of the main barriers to its adoption for many organizations (6 out of 17 CNG adopters) with all across small, medium, and large fleet size. One fleet manager noted, “The (CNG) vehicles that we’re purchasing are about $225,000 apiece. Our standard conventional diesel trucks are about $115,000 to $125,000. So, it’s almost two to one.” (Org. 8). Of all 17 CNG adopters who utilized financial incentives to offset the incremental costs, 7 organizations addressed the incentives as one of the motivating or facilitating factors and 4 of those emphasized the incentives with its overarching effect on their decisions. One organization stated, “because of the grants that were available here locally through our air district, that enabled [our organization] to do a lot of migration [to NGVs]...” (Org. 10). Moreover, four organizations mentioned that the unavailability of financial incentives would make it difficult to continue with CNG or at least slow down the replacement of diesel, which would imply a higher effect of the incentives on the decisions of some portion of HDV fleet operators. “Certainly that (NGVIP incentives) influenced the decision (…). I don’t think that we would have otherwise purchased those (CNG) buses had we not had the financial incentive that was offered” (Org. 12). The importance and effectiveness of incentives on both the magnitude and timing of HDV AFV adoption is a critical open question that is being addressed by CARB 19RD026.

Hypothesis 4. *Insufficient refueling infrastructures are another major barrier to heavy duty CNG adoption: most of the organizations interviewed do not want to solely rely on off-site stations.*

Though only a few organizations described discouraging perceptions about fueling infrastructures, it should be noted that a majority of the CNG adopters interviewed (11 out of 17) have already built their own on-site CNG fueling stations. Furthermore, among the five organizations that are currently using only off-site stations, four fleets – even with their small or medium fleet size – are planning to build their own on-site CNG fueling facilities. Overall, these propensities imply that most of the organizations interviewed do not have a desire to solely rely on off-site stations. One stated, “The main issue that I’ve run into is lack of infrastructure. That’s a huge issue” (Org. 8). Also, a limited accessibility to the fueling stations will increase the complexity regarding their fleet operations and require additional operational disparities. One described, “We have to make sure our tanks are full, especially if we have some longer routes. (...) The availability of gasoline or diesel is still, even in a state like California, so much more available than what it would be for propane or CNG” (Org. 12). Additional reasons for planning to build their own on-site fueling facilities included “getting a cheaper fuel price than offered by off-site stations” and “saving labor costs getting back and forwards the off-site stations” (Org. 2).

Hypothesis 5. *Organizational intrinsic values, “corporate social responsibility or environmental consciousness regarding vehicle emissions,” and business strategic motives, “contracts with municipalities,” can be strong motivators to overcome the major barriers to AFV adoption.*

Environmental consciousness regarding HDVs’ harmful emissions was often identified, by more than half the organizations across various public and private sectors, as one of the primary motivators to adopt AFV. One fleet manager stated, “If I prioritize them (the influencing factors), number one would be the environmental impact that they have. (...) They (CNG vehicles) would be better than (diesel vehicles). (…) It’s about 90 percent reduction [in NOx]” (Org. 4). Another described, “Everybody’s concerned about global warming and pollution and environment, so, you know, just doing the right thing is probably the biggest driver” (Org. 14). Despite the fact that many of them acknowledged the adoption barriers, as addressed in Hypothesis 3 or 4, they presented a commitment to using CNG even with an intent to expand their CNG vehicle fleet. These statements should be evaluated carefully, however, as it is difficulty to definitely interpret them as “intrinsic values” versus an expression of a desired corporate image deriving from a profit-maximizing corporate strategy. For instance, some respondants who reported pursuing contracts with municipalities (6 adopters out of 17) noted that CNG adoption was perceived as advantageous based on their business strategic motives. One fleet manager explained, “My customers, mainly the municipalities (…) They are more receptive to people that are running green vehicles (…) It (CNG vehicle) helps us out in our contracts. So, it gives you just a step up above your competitors if you're running natural gas (…)” (Org. 8).

Hypothesis 6. *Some other alternative fuels (e.g., LPG) were adopted based on parallel criteria to CNG adoption decisions while some others (e.g., electricity) were adopted due to organizational-specific reasons.*

Six organizations adopted LPG, LNG, electricity, and/or renewable diesel along with CNG. Four LPG adopters identified similar motivations to their CNG adoption. For example, one fleet manager noted that "natural gas sweepers were not very prevalent at that time" (Org. 7) when the SCAQMD fleet rules were implemented, which led to their LPG sweepers adoption instead of CNG. In addition, contracts with municipalities (e.g., school districts) "have required us (the organization) to buy the propane as well" (Org. 12). In two cases, LPG was evaluated functionally suitable "for specific bus applications (such as) shuttle buses" (Org. 10) and as a less complex option in terms of its fuel availability (Org. 10) and easier maintenance (Org. 12). Consideration of environmental impacts from HDVs also affected their LPG adoption (Org. 12 and 14). Similarly, three organizations among those who are using renewable diesel identified complying with the state's direction (Org 13), and less complexity due to its "pretty straight transition" (Org. 3) and no needs to "have the fueling infrastructure investments that we've made with our CNG" (Org. 10), as their major motivations to use renewable diesel than the conventional one.

On the other hand, electric refuse trucks have been adopted by one public organization that possesses an inclination toward green innovative technologies. "Because we have a reputation as a very progressive and green public fleet, (…) and kind of been on the leading edge of a lot of fleet sustainability efforts, so they (manufacturers) really wanted us to demonstrate the technology" (Org. 10). As to LNG adoption decisions, a noticeable trend was observed that most of the organizations who considered LNG decided not to adopt or to discontinue using it. However, one presented a continuing commitment because of their LNG fueling infrastructures "already invested" along with a desire "to diversify the fuel options" in preparation for any emergency cases (Org. 17). Such inertia recalls the cautionary recommendation from Hypothesis 1 that fleet rule making should carefully consider the longevity of a fuel pathways in regulations that constrain fleet choices.

The relatively limited diversity in the fuels adopted by the fleets interviewed makes this hypothesis somewhat tentative. The reasons for this lack of diversity include a self-selection bias in the sample because it was drawn from participants in the NGVIP, but also likely reflect limited technology options for AFV in heavy duty fleets. The sole fleet that adopted an electric vehicle did so for non-operational reasons and appears to have been a pilot. For the purposes of fleet guidance, cost and operations-driven criteria observed in most cases would apply across fuels in the broader market, though some discussion of pilot and early market deployment opportunities is also warranted.

Hypothesis 7. *Technical capabilities, including unsuitable functionality and reliability/safety issues, were a deciding factor resulting in non-adoption decisions.*

Almost all participating organizations evaluated multiple alternative fuel options along with CNG and then rejected most of them (See Figures 3-4). The most common reason for their non-adoption decisions was the fact (or the perception) of commercial unavailability of an alternative fuel technology for their specific heavy duty fleet application. "we're familiar with the electric trash trucks they're experimenting with, but nobody is running, (…) That's just an experiment right now" (Org. 14).

Even if an alternative fuel option other than CNG was perceived commercially available, the fleet operators tended to use a parallel list of their decision criteria to CNG adoption. In case any of those conditions was unfulfilled, they decided not to adopt it. For example, electric vehicles were often "ruled out" particularly due to their unsuitable functionality for a specific heavy duty vocation. Fleet managers stated, "they (electric vehicle) don't have range" needed for a school bus (Org. 1), "they are so heavy" with a limited payload (Org. 8), and "the capacity it can haul is insufficient" for refuse trucks (Org. 15). In addition, reliability and safety issues – which sometime impose extra maintenance requirements – were identified as main reasons why some fleet operators rejected an alternative fuel option, specifically, LNG or biodiesel. One fleet operator described, "we have difficulties working with those (LNG duel-fuel) vehicles because the fuel has to be basically cryogenically kept (…) That created issues for maintenance. (...) The fuel tanks would vent if the temperature wasn't fuel locked" (Org. 9). Biodiesel was cited as problematic by several organizations, saying "it's just completely destroying those engines" (Org. 8), and accordingly, two organizations (Org. 10 and 13) use renewable diesel instead while they "stay away from" biodiesel.

Another major reason of rejection of an alternative fuel option was due to unacceptable monetary costs from a business standpoint. If an expensive vehicle price (e.g., electric or hydrogen vehicle) or highly increased operational costs (e.g., due to a lot of maintenance issues for LNG vehicles) does not financially make sense to an organization, they regarded that fuel option as a "non-starter" when they began with their decision-making process (Org. 9), and even decided to "retire the (LNG) vehicles" once it turned out "not to be cost effective to continue to operate" (Org. 15). Other barriers to adopt an alternative fuel included insufficient fueling/charging infrastructures (e.g., LNG non-adoption by Org. 16 and electricity non-adoption by Org. 8), uncertain environmental benefits and unpredictable fuel price (e.g., E85 non-adoption by Org. 7), and a huge investment already made to CNG (e.g., non-adoption of any other alternative fuels by Org. 1).

It is important to note that technical suitability is a fleet-level assessment that is tied to general requirements of the vocational application, but also to the specifics of a given fleet's operations. Additional research is needed to understand how these differences might be characterized for the purposes of quantitative assessment and the development of models that can predict the impact of these variations on fleet choice behavior. For near term guidance, fleets should be encouraged to consider their operational requirements carefully in order to assess the technical suitability of particular fuel options.

4.4.3 Refueling Behavior

Questions related refueling behavior resulted in the following set of insights, which are generally well-known in the literature.

Insight 1. Most organizations with on-site refueling stations are satisfied with their facilities while those using off-site stations tend to be less satisfied or dissatisfied with the facilities.

Insight 2. Major advantages of having on-site refueling stations are 1) saving time – and associated financial expenses – required to drive to any off-site stations, 2) lower fuel prices, and 3) reduced uncertainty in refueling fleets attributed to 'fueling convenience', 'fuel consistency', 'facilities reliability', and 'easiness of facilities maintenance'

Insight 3. Disadvantageous aspects of having on-site fueling stations include costs and complexities associated with building the facilities, and maintenance issues for old equipment.

Insight 4. Although a few of fleets using off-site stations were satisfied with specific traits of the refueling facilities, all of them reported one to multiple unsatisfactory aspects including 'longer time taken to drive to off-site refueling stations', 'waiting time', 'not inexpensive fuel prices', and 'complexity increased with fleet routing'.

Insight 5. Fuel security and fuel availability were addressed as common concerns by both fleets with and without on-site fueling facilities.

Though these findings are slanted toward the particulars of gaseous fuels (CNG in particular), the importance of available refueling infrastructure is a recurrent and well known theme that applies to battery-electric vehicles as well, where a lack of infrastructure coupled with sometimes lesser performance characteristics of alternative fuels leads to higher risk assessments from the fleet perspective as it relates to confidence that a particular technology can meet business needs. Guidance provided to fleets should focus on highlighting the relative tradeoffs of different refueling options. Since the infrastructure for emerging technologies in the heavy-duty sector, such as BEV hydrogen FCEV, is heavily dependent on state and regional regulatory action and investment, it is important that fleets are provided with a clear roadmap for navigating this complex and evolving landscape since lack of clarity regarding infrastructure investments will likely increase perceived risk and degrade adoption. Further, regulatory action to mandate adoption of particular fuels should consider the suitability of infrastructure to satisfy the resulting demands in a cost-reasonable manner.

Figure 99. Factors influencing Heavy-Duty AFV CNG Vehicle Adoption Decision

Organizations (vocations)	01 (school bus)	02 (various)	03 (various)	04 (delivery)	05 (delivery)	06 (refuse)	07 (refuse)	08 (hauling)	09 (various)	10 (various)	11 (refuse)	12 (school bus)	13 (various)	14 (refuse)	15 (various)	16 (various)	17 (refuse)	18 (paving)
Fleet characteristics	Pb M On-site	Pb M (On-site)	Pb L On-site	M (On-site) <15 NGV New	M On-site	L On-site	L On-site other AFV	S (On-site) <15 NGV New	Pb L On-site other AFV	Pb L On-site ELEC On-site other AFV	M (On-site)	L n/a other AFV New	Pb L On-site	L On-site other AFV	Pb L On-site other AFV	Pb L <15 NGV	Pb L On-site	S
CNG adoption status / Categories	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	N
• Functional suitability (e.g., in terms of max power, payload, and range)			n	+2		+2	+2	+2	+2	+2		+,-2			+3	+2	+2	-3
• Overall costs (capital + operational expenses)			n					+3	+3	+2			n	n	+2	n		-2
• Vehicle purchase price	-2	-2		-2				-2		-2		-2		n				
• Fuel price	+1			+2	+2		+3	+3	+3	+2				+1			+2	
• Maintenance issues	+2							2				-2			+2	-2		
• Resale value				n														
• Other costs								+2										
• Fuel economy	-2																+1	
• Noise level								+2										
• Fuel infrastructures			+2	+2	+2			-3	+2		+2	-2			+1	+,-2		
• Fuel security		-2																
• Stable fuel price					+1													
• Vehicle reliability and safety				+2		+2			+1	+3			n		+2	-2		
• Engine reliability			n	-2		+1												
• Environmental consciousness/CSR	+2			+3				+2	+1	+2		+3	+2	+3	+2		+3	
• Demonstration of technologies			+2															
• Contract w municipalities						+2	+2	+2			+3	+2		+2				
• Promoting environmental sensitivity	+1													+1		+2	+1	
• Sustainability plans within the org.													+3				+2	
• Attitude of DMU members				+2				+2							+1	+1		
• Acceptance of users (drivers)										+2						n		
• Regulations by AQMDs	+3	+3	+2				+2				+3			+3	+3	+2	+2	
• Regulations by CARB				n		+2	+2	n		n		n	-2				+2	
• Other regulations/policies			+2									n						
• Financial incentives	+3			+3	+2			+2		+3		+3					+2	
• The only available/viable option	+3	+3		+2		+2	+2	+3			+3		+2		+2	+1	+2	
• Opportunity to test a vehicle								+2							+1		+1	
• Warranty/maintenance provided by a manufacturer				n			n			+2								
• Technologies proven in the industry									+2									

[Note] (a) "+": factors positively stated as motivators or facilitators, "-": factors negatively stated as barriers or drawbacks, "+,-": factors which can be either motivators or barriers depending on certain conditions (e.g., vocations and locations where to vehicles are dispatched). (b) "1": factors implied or indirectly affected the decisions, "2": factors explicitly mentioned, and "3": factors emphasized as overarching reasons. (c) "n": factors neutrally stated due to two different possibilities, (i) unidentified whether it was considered a motivator or a barrier during the interview (ii) relatively minimal impacts on the purchasing decisions

Figure 100. Factors influencing heavy duty AFV adoption decisions: LNG, LPG, and bio/renewable diesel cases

Organizations (vocations)	01 (school bus)	02 (various)	03 (various)	04 (delivery)	05 (delivery)	06 (refuse)	07 (refuse)	08 (hauling)	09 (various)	10 (various)	11 (refuse)	12 (school bus)	13 (various)	14 (refuse)	15 (various)	16 (various)	17 (refuse)	18 (paving)
Fleet characteristics	Pb M On-site	Pb M (On-site)	Pb L On-site	M (On-site) <15 NGV New	M On-site	L On-site	L On-site other AFV	S (On-site) <15 NGV New	Pb L On-site other AFV	Pb L On-site ELEC On-site other AFV	M (On-site)	L n/a other AFV New	Pb L On-site	L On-site other AFV	Pb L On-site other AFV	Pb L <15 NGV	Pb L On-site	S
LNG / **Categories**	N		N					N	A→N		N		N		A→N	N	A	
• Functional suitability (e.g., in term of vehicle power, payload, and range)									-2							-2		
• Overall costs (including capital and operational expenses)			-3												-2			
• Maintenance issues			-3						-2							-1		
• Fuel infrastructures								-2					-1			-2	+1	
• Fuel system conversion of vehicles	-1																	
• Vehicle reliability and safety								-2			-2							
• Commitment already made to specific fuel option(s)	-2																+2	
• Diversification of fuel options																	+2	
• Availability of vehicles															-3			
Propane / **Categories**	N	N	N				A	N		A		A		A		N		
• Functional suitability (e.g., in term of vehicle power, payload, and range)	-2									+2								
• Maintenance issues												+2						
• Noise level														+2				
• Fuel infrastructures										+2								
• Environmental consciousness regarding vehicle emissions/CSR)												+2		+2				
• Contract w municipalities							+2					+3						
• Regulations by AQMDs							+2							+1				
• Financial incentives												+2						
• Availability of vehicles	-2	-2	-2					-2								-2		
• The only available option due to a region-specific context														+2				
Biodiesel / **Categories**							N	N	N	N		N	N		N	N		
• Vehicle reliability and safety																-2		
• Engine reliability								-3										
• Other unspecified reasons										-2		-1	-2		-2			
• Regulations by AQMDs							-2											
• Availability of vehicles									-1			-2						
Renewable diesel / **Categories**			A							A			A		A			
• Fuel price										+1								
• Fuel infrastructures										+2								
• Fuel system conversion of vehicles			+2															
• Engine reliability															-2			
• Sustainability plans implemented within the organization			+2															
• California State's direction													+2					

[Note] (a) "+": positively stated as motivators or facilitators, "-": negatively stated as barriers or drawbacks. (b) "1": implied or indirectly affected the decisions, "2": explicitly mentioned, "3": emphasized as overarching reasons.

Figure 101. Factors influencing heavy duty AFV adoption decisions: electricity, hydrogen, and E85 cases

Organizations (vocations)	01 (school bus)	02 (various)	03 (various)	04 (delivery)	05 (delivery)	06 (refuse)	07 (refuse)	08 (hauling)	09 (various)	10 (various)	11 (refuse)	12 (school bus)	13 (various)	14 (refuse)	15 (various)	16 (various)	17 (refuse)	18 (paving)
Fleet characteristics	Pb M On-site	Pb M (On-site)	Pb L On-site	M (On-site) <15 NGV New	M On-site	L On-site	L On-site other AFV	S (On-site) <15 NGV New	Pb L On-site other AFV	Pb L On-site ELEC On-site other AFV	M (On-site)	L n/a other AFV New	Pb L On-site	L On-site other AFV	Pb L On-site other AFV	Pb L <15 NGV	Pb L On-site	S
Categories \ Electricity	N		N	N		N	N	N	N	A			N	N	N	N		
• Functional suitability	-3			-2		-2	-2	-2							-2			
• Vehicle purchase price									-3									
• Other costs																		
• Additional costs related to fuel infra	-3							-2										
• Life cycle-based environmental impacts	-2																	
• Fuel infrastructures									-1									
• Charging time when power blackout occurs	-2																	
• Battery issues (e.g., degradation issues)	-2																	
• Demonstration of technologies (w/ progressive effort)										+3								
• Commitment already made to specific fuel option(s)	-3																	
• Regulations by AQMDs																-2		
• Availability of vehicles			-1	-2			-2	-2	-1				-2	-2		-2		
Categories \ Hydrogen	N		N					N				N			N	N		
• Vehicle purchase price																-3		
• Availability of vehicles	-3		-2					-3				-2			-2			
Categories \ E85							N									N		
• Fuel price							-2											
• Uncertain environmental benefits							-2											
• Unstable fuel price							-2											
• Availability of vehicles																-2		
Categories \ Any alternative fuels other than CNG	N	N		N	N		N		N		N		N					
• Functional suitability				-2														
• Fuel infrastructures				-2					-3									
• Commitment already made to specific fuel(s)	-3				-1		-2											
• Availability of vehicles		-3									-3		-2					

[Note] (a) "+": positively stated as motivators or facilitators, "-": negatively stated as barriers or drawbacks. (b) "1": implied or indirectly affected the decisions, "2": explicitly mentioned, and "3": emphasized as overarching reasons.

4.4.4 Other facilitators to AFV purchase

Additional facilitators were identified from the interview results that highlighted the relative importance of information gathering during AFV HDV vehicle purchase. Specific insights of interest included:

Insight 1. Opportunities to test a heavy duty AFV and warranty/maintenance services provided by vehicle and engine manufacturers would positively affect the process of decision-making, particularly the Consideration and Adoption Decision stages

Insight 2. Educational training programs provided by vehicle/engine manufacturers, fuel providers or other institutes have essentially helped the Implementation stage right after heavy duty AFV adoptions

Insight 3. Though driver trainings tended to be provided in a less extensive way than technicians/mechanics trainings, drivers would become not only better aware of how to use the vehicles but more acceptable toward the vehicle adoption, with the support of the trainings

Insight 4. Social networks can affect heavy duty AFV purchase decisions in a way of obtaining feedback from other fleet operators who already have experiences in operating the vehicles and/or of following a social norm prevalent in the industry

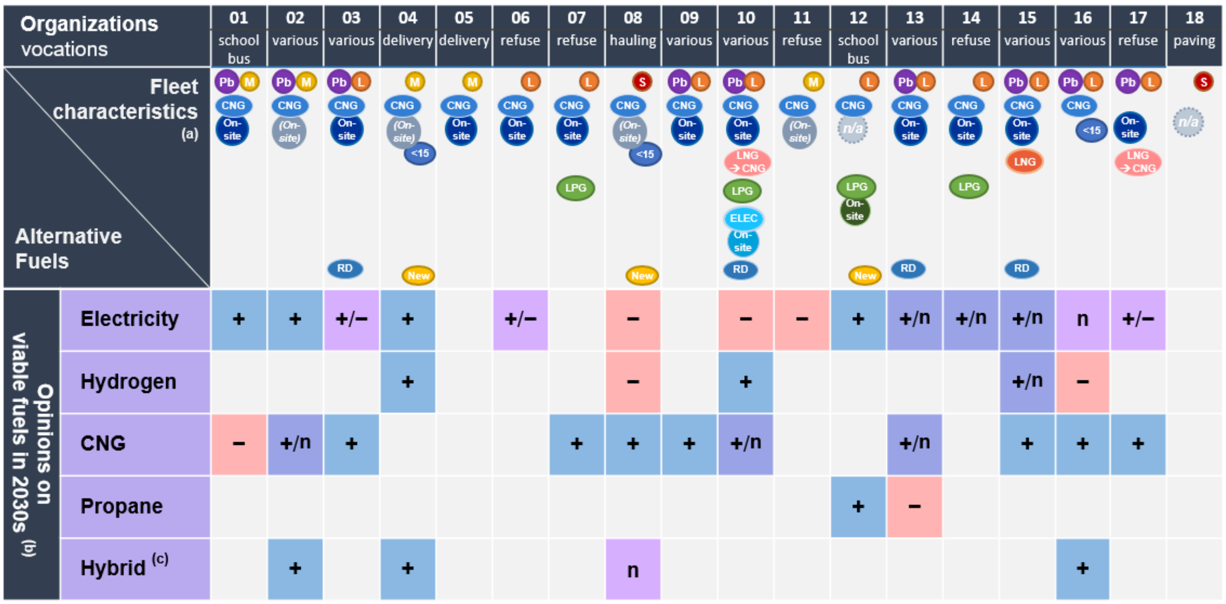
Insight 5. Some fleet operators, particularly in an industry, would be intentionally inactive in sharing information with other fleet operators – potential competitors – regarding heavy duty AFVs

The most notable feature of these insights is probably that there wasn't an explicit mention of any particular source of information as central to their decision-making process. On the other hand, manufacturer support, in the form of education or testing opportunities were positively noted as an influencing factor. The implication of these findings are difficult to generalize, but should be noted in any guidance to fleets, as well as suggest that OEMs would benefit their AFV offerings by providing better customer support.

4.4.5 Perspectives on Viable Alternative Fuels for Heavy-duty Vehicles in 2030s

To understand fleet perspectives fleets participating in the interviews were asked: "If you look 10 to 20 years down the road, what do you think about viable options of alternative fuels for your heavy duty vehicles?" Figure 102 presents a visual overview of the opinions obtained from the participants along with their fleet characteristics, including public/private status, fleet vocation, fleet size, alternative fuel adoption status, and type of refueling facilities used for their heavy duty AFVs. Of 18 participating fleets, 17 are CNG adopters while one organization stated that they considered but rejected the adoption of a CNG vehicle. Along with heavy duty CNG vehicles, three organizations adopted LNG, although two of them are replacing their LNG vehicles with CNG vehicles (Org. 10 and 17). Some participating organizations adopted propane for their heavy duty buses or refuse trucks (Org. 7, 10, 12, and 14). Several fleets are using renewable diesel instead of conventional diesel (Org. 3, 10, 13, and 15). One organization adopted electric refuse trucks (Org. 10).

Figure 102. A Summary of Opinions on Viable Alternative Fuel Options for HDVs



Opinions on viable fuels in 2030s (b)	01	02	03	04	05	06	07	08	09	10	11	12	13	14	15	16	17	18
Electricity	+	+	+/−	+		+/−		−		−	−	+	+/n	+/n	+/n	n	+/−	
Hydrogen				+				−		+					+/n	−		
CNG	−	+/n	+				+	+	+	+/n			+/n		+	+	+	
Propane												+	−					
Hybrid (c)		+		+				n								+		

[Note] (a): Each symbol represent a specific fleet characteristic: "Pb": public entities (c.f., private entities, otherwise unmentioned), "L": large fleet size (>100 vehicles), "M": medium fleet size (20-100), "S": small fleet size (≤ 20), "CNG": currently operating heavy duty CNG vehicles, "On-site" (right below "CNG"): has their own on-site CNG station(s) (c.f., use off-site CNG stations, otherwise unmentioned), "(On-site)": will build their own on-site CNG stations, although they currently rely only on off-site station(s), "n/a": information about CNG fueling stations unavailable, "<15 NGVs": the total number of NGVs, including both those are being currently operated and those to be expanded in the near future, will less than 15 NGVs, "LNG⍰CNG": heavy duty LNG vehicles adopted before are being migrated to CNG vehicles, "LPG": operating heavy duty LPG vehicles, "On-site" (right below "LPG"): has their own on-site LPG station(s) (c.f., use off-site LPG stations or LPG wet-hosing, otherwise unmentioned), "ELEC": operating Electric HDVs, "On-site" (right below "ELEC"): planning to build their own on-site electric heavy duty charging stations, "RD": using renewable diesel for their conventional diesel HDVs, and "New": the year of the first heavy duty AFV purchased was after 2015. (b) "+": positive aspects were addressed as a viable fuel option for HDVs in 2030s, "–" negative aspects were described, "n": remarks were neutrally stated, "+/–": both positive and negative aspects were explained, "+/n": both positive and neutral opinions were stated. (c) A vehicle that uses two or more types of power (e.g., a hybrid electric vehicle). Aside from electric, hydrogen, CNG, LPG, and hybrid HDVs, no participants addressed other alternative fuels such as LNG, biodiesel, and ethanol.

Interestingly, the participants' perspectives on viable alternative fuel options in 2030s seem inconsistent with their current adoption status of alternative fuels. For example, though most of the organizations interviewed have rejected the adoption of an electric HDV, a majority of the participants (14 out of 18) expressed their opinions on electric HDVs: fully positive remarks from four fleets, positive or neutral comments from four, mixed viewpoints from three, and purely negative opinions only from three organizations. While nearly all the participating fleets were CNG adopters (17 out of 18), less than two thirds of those explicitly regarded CNG as promising in 2030s. Despite none of the participants being hydrogen HDV adopters, five organizations addressed hydrogen HDVs, including three fleets which expressed positive aspects and two with negative remarks. Hybrid options and propane HDVs were also discussed by several organizations either positively or negatively. Aside from those fuels listed above, no participating fleets expressed their opinions on other alternative fuels (e.g., biodiesel, ethanol, and LNG) as future viable fuel options.

As a part of the qualitative analysis results, Figure 103 and Figure 104 present the positive (i.e., with "+" symbols), negative ("–"), or neutral opinions ("n") on each fuel technology in 2030s from the participating fleets' perspectives. Based on these results along with the relevant quotations, main motivators or facilitators for, and barriers to the future adoption of electric, hydrogen, CNG, propane and hybrid HDVs are discussed. These results represent a set of perspectives obtained from the fleets interviewed and should not be seen as generalizable findings that endorse or condemn any particular technology. In general, these findings offer additional context for identifying how fleets view emerging technology. The factors identified are drawn via content analysis of fleet responses to a general prompt about alternative fuels in the 2030s. Though again not definitely generalizable to the broader market, they do offer a useful roadmap of topics to discuss in guidance to fleets that is likely to be relevant to decision-makers.

Electric HDVs in 2030s

Electric HDVs can draw electricity from the grid or other external sources by plugging the vehicle into the source. The vehicles are thus also called plug-in electric vehicles (c.f., hybrid electric HDVs are fueled with diesel but use batteries to recapture energy during regenerative braking, which is discussed in a later section). Electric HDVs can store electricity in batteries to power the electric motor [405]. Around 20 manufacturers (e.g., BYD, Ford) are offering electric HDVs in the U.S. across various fleet vocations including transit/school buses, tractor trucks, sweepers and refuse trucks (see Table 4). Of the organizations interviewed, 78% paid attention to electric HDVs. As outlined in Figure 2, the majority of the participating fleets regarded electric HDVs as promising because the technologies are advancing, produce zero tailpipe emissions, and are in line with the state's direction. Nonetheless, various concerns and uncertainties were reported, which is related to the vehicle's functional suitability, charging infrastructures, vehicle availability, total life cycle emissions, and total cost ownership.

(+) Emerging and advancing technologies – The most common positive opinion across diverse vocational areas is that the electric HDV technologies are "advancing very fast", which makes the fleet operators "keep an eye on electric" (Org. 3). As related quotations, one refuse truck operator stated, "I think it (an electric HDV) is going to have adequate power to operate all the functions necessary to operate a collection vehicle where it packs its load as it goes, et cetera. I think everything will be battery-operated 20 years from now" (Org. 6). One school bus operator also addressed, "We do not currently have any all-electric-powered vehicles, but that's going to be changing here fairly soon (…). We will certainly be considering an electric-powered bus within the next year (…)" (Org. 12).

(+) The state's and industry's direction – Some public organizations underlined that there is "the big push right now towards electric vehicles" (Org. 13). One city fleet operator described, "Maybe, in five to ten years, the industry (refuse trucks and street sweepers) will be going electric" (Org. 13). One school bus operator stated, "I know it's just the matter of the time, before we get some electric buses, the state wants all electric by 2030 or (…)" (Org. 1).

(+) ZEVs for our environment – A crucial need of zero emission vehicles (ZEVs) for the future was emphasized by both public and private fleet operators: "My priority would be eventually get that zero emissions, whether it's electric or some other, hydrogen, (...) I'm aware of the change over the years and the bottom line for companies now threefold. It used to be all profit, and then it became profit and people, and now it's profit, people, and planet. I'd say that following that line, even as an organization, all electric (…)" (Org. 4).

(–) Functional/operational unsuitability – However, many fleet operators perceived functional suitability of electric HDVs as still unresolved. Several organizations addressed that "heavy batteries" caused "range issues" and "a need for learning." For example, one described, "There's a lot of added weight to get the range that you need. There still needs to be some improvements on the weights of batteries (...) I think electric is coming a long way just once again with batteries" (Org. 3). Another stated, "These battery vehicles seem to be pretty heavy. So, there's a lot yet to be learned in that alternative style of power" (Org. 11). In addition, uncertain functionality in payload capacity or power of the vehicle was addressed by refuse and hauling truck operators: "We still think it's some years down the road before they can perfect it. These vehicles (electric HDVs) are certainly are in a need of capacity to haul payloads of waste" (Org. 11); "They (electric HDVs) would work great for drayage at ports or local delivery, but they wouldn't work in an application like what I'm doing (hauling)" (Org. 8).

(–) Feasibility issues with charging infrastructures for electric HDVs – Though only one participating organization adopted electric HDVs, they highlighted an adverse aspect when deploying the vehicles "in the near term", due to a lot of feasibility problems associated with unready charging infrastructures: "From a practicality standpoint, heavy duty electrification, it's going to be a hard sell any time soon, because of the charging infrastructure and demand charges potentially from our electric utilities (…)" (Org. 10).

(–) Perceived unavailability of electric HDVs – A limited number of available vehicle models for certain vocations (e.g., only two models for refuse trucks (Table 4)) made some fleet operators perceive electric HDVs still commercially unavailable: "Right now, in the horizon, we see the emerging technology including electrification. But, as far as heavy duty vehicle application, we have not seen widespread application of that yet. We saw a few demonstration projects here and there, but none to commercialization as we are aware of" (Org. 17).

(n) Depending on evaluations based on business standpoint – The willingness to pay (WTP) for electric HDVs would depend on "whether it's cheaper and pays for itself, that makes good business sense" (Org. 14) and "what the ROI [return on investment] is" (Org. 15) from a business standpoint.

(n) Depending on total life cycle emissions – Moreover, the WTP would also be based on the evaluation of life cycle analysis of carbon intensity. One explained, "I want to say they [sustainability group] look at the total fuel cycle analysis (...) where they consider the carbon intensity of the entire process" (Org. 13).

Hydrogen HDVs in 2030s

Hydrogen HDVs (a.k.a., fuel cell electric HDVs) use hydrogen in a fuel cell to generate electricity to power the electric motor [456]. Only few manufacturers provide hydrogen HDVs in the U.S (Table 4). Such limited vehicle models include H2 drayage truck produced by US Hybrid, and AXESS transit bus by ElDorado National-California. Given that hydrogen HDVs are in the early stages of implementation, the hydrogen option received relatively less attention than electric HDVs from the organizations interviewed. Several organizations (5 out of 18) addressed its positive or negative aspects as a future fuel option, which was overall similar to those of electric HDVs (e.g., the technologies being advanced, a need of ZEVs for the future, uncertain functional suitability for HDV applications). Interestingly, one fleet operator emphasized a distinct positive remark that hydrogen can be a practical and economical fuel option especially when producing from renewable sources.

(+) ZEVs for our environment – As hydrogen HDVs emit only water vapor and warm air, they thus produce to tailpipe emissions. Moreover, when producing from renewable energy sources (e.g., biomass, wind, and solar), hydrogen HDVs can avoid the emissions associated with energy production [456]. Some public and private fleet operators (e.g., Org 4 and Org .10) emphasized the essential environmental benefits from the ZEVs: “Certainly a lot of emissions benefits from a well-to-wheels perspective (…) Hydrogen is the true zero emissions if you’re getting it from renewable sources” (Org. 10).

(+) Emerging and advancing technologies – One organization recognized that hydrogen HDVs technologies will be more advanced, along with the electric option: “Electric and hydrogen HDVs remains to be seen (10-20 years down the road)” (Org. 15).

(+) Practical and economical fuel production from renewable sources – An additional promising remark was emphasized by the most progressive adopters of alternative fuels among those interviewed (Org. 10). They highlighted hydrogen as a “practical” and “economical” fuel option: “10 or 20 years down the road, I think we’re going to have hydrogen. Because it’s a practical fuel, it’s already coming to market. We just have to have more of it produced from renewable sources regionally, not just trucked in like it is now (...) It can be produced economically. We believe that there’s a lot of opportunity there related to hydrogen in trucks. (...)” (Org. 10).

(–) Perceived unavailability of hydrogen HDVs – Due to only few vehicle models available in the market, fleet operators could perceive the hydrogen option commercially inaccessible. Furthermore, several heavy duty vocations (e.g., refuse trucks and street sweepers) still do not provide the hydrogen option in the U.S. One fleet operator explained, “I mean, they’re just scratching the surface on the hydrogen. (...) The concept vehicles out, (...) but they wouldn’t work in an application like what I’m doing” (Org. 8).

(–) High upfront costs of the vehicles – Another major barrier is the “huge purchase cost” of the vehicle (Org. 16). For example, a hydrogen transit bus costs around $1.2 million, compared to $750,000 for an electric bus, and $500,000 for a diesel bus [413], [457].

(–) Inaccessibility to hydrogen fueling infrastructure – Despite the increased number of hydrogen fueling stations in California (e.g., 41 stations in 2020 compared to 25 in 2016) [458], fleet operators could regard the accessibility to infrastructures as still extremely restricted. One organization mentioned, there is “no infrastructure” for hydrogen vehicles (Org. 16).

CNG HDVs in 2030s

CNG HDVs use compressed natural gas which is stored onboard a vehicle in a compressed gaseous state [456]. CNG vehicles are commercially mature technologies which are used in diverse heavy duty applications including transit/school buses, tractor trucks, and refuse trucks (Table 4). As of 2020 January, around 100 CNG HDV models are available from over 30 manufactures in the U.S. (e.g., Peterbilt, Autocar, Gilling, etc.). Many participating fleets (10 out of 18), particularly those already adopted CNG, regarded the fuel as foreseeable in 2030s, mainly due to the fact that they previously invested in the vehicles and fueling facilities. However, some of them also presented a partially neutral remark that CNG would a transitional fuel, ultimately towards electricity. Moreover, one pointed out that CNG is not in line with the state's direction.

(+) Continued use of CNG due to the investments already made – Both in small and large fleets across various sectors, particularly those organizations who already built on-site CNG fueling facilities, stated that CNG will still be in their plan "for the next 10, 15, maybe even 20 years" (Org. 3), because of the investment made in CNG vehicle and infrastructures. For example, one fleet operator explained, "In refuse collection services, I'm under the assumption that we would only be heavily using CNG vehicles only because we have invested in the infrastructure, and we've invested in the conversion. I can't see in the next 10 to 20 years switching to a different type of alternative fuel (…)" (Org. 9).

(+) Foreseeable fuel option (though transitional) – Even in the case of no investments made in on-site fueling facilities, one organization predicted the "increased use of CNG in HDVs" (Org. 16). Another fleet operator further described promising aspects of CNG such as "relatively inexpensive and pretty clean with the near zero engines" (Org. 15) while forecasting an optimistic trend of the use of CNG. However, there was a rather neural opinion: CNG is a transitional option towards electric solutions. One organization stated, "I think that the natural gas is a real transitional fuel. I think it's gonna get us from really dirty diesel to cleaner electric, hybrid types solutions" (Org. 2). Another also addressed, "If there is no electric available then it would be CNG. If electric would be available, then probably electric" (Org. 13).

(–) Not in line with the State's direction – One fleet operator indicated that they perceived CNG as disaccord with the state's plans: "(regarding) what future funding is, right now, (...) CNG vehicles and CNG Infrastructure are not under radar" (Org. 1). For instance, the Clean Transportation Program by California Energy Commission [459], which had allocated around $14 million on annual average for natural gas vehicle incentives or infrastructure projects until 2018, has not provided the funding since the program began to prioritize ZEVs. Nevertheless, one organization underscored the need of CNG until resolving feasibility problems with the electrification: "If our state doesn't put all of their eggs in one basket with electric trucks, we're going to continue to buy CNG. (...) I mean, there's just a lot of feasibility problems with thinking that we're going to get there (electrification) in the near term, and we've got to do something in the meantime (…)" (Org. 10).

Propane HDVs in 2030s

Propane (a.k.a., liquefied petroleum gas) is produced as a by-product of natural gas processing and crude oil refining. In a propane HDV, propane is stored onboard in a pressurized tank which makes it liquid [34]. As a vehicle fuel, propane has been used for decades [34]. There are over 30 propane HDV models available from about 14 manufacturers (e.g., Thomas Built, Turtle Top, Ford, etc.) for several fleet applications such as school buses, shuttle buses, and vocational trucks. Compared to electricity, hydrogen, or CNG, propane HDVs received limited attention from the participating fleets.

Figure 103. Opinions on Viable Alternative Fuels for HDVs in 2030s: Electricity, Hydrogen, and CNG

Organizations vocations			01 school bus	02 various	03 various	04 delivery	05 delivery	06 refuse	07 refuse	08 hauling	09 various	10 various	11 refuse	12 school bus	13 various	14 refuse	15 various	16 various	17 refuse	18 paving
Fleet characteristics			Pb M CNG On-site	Pb M CNG (On-site)	Pb L CNG On-site RD	M CNG (On-site) <15 New	M CNG On-site	L CNG On-site	L CNG On-site LPG	S CNG (On-site) <15 New	Pb L CNG On-site	Pb L CNG On-site LNG→CNG LPG ELEC On-site RD	M CNG (On-site)	L CNG n/a LPG On-site New	Pb L CNG On-site RD	L CNG On-site LPG	Pb L CNG On-site LNG RD	Pb L CNG <15	Pb L On-site LNG→CNG	S n/a
Electric HDVs	+	State's direction / Industry's trend	X												X					
	+	Technologies are emerging and advancing			X			X						X		X	X		X	
	+	ZEVs are needed for the future when considering our environment		X		X														
	-	Functional/operational suitability issues (e.g., battery weight, power, ranges, charging time)			X			X		X			X		X			X		
	-	Feasibility issues with charging infrastructures										X								
	-	Vehicle unavailability for HDV applications (as of now)																	X	
	n	WTP(a) depends on evaluations based on total life cycle emissions													X					
	n	WTP depends on evaluations based on business standpoint														X	X			
Hydrogen HDVs	+	ZEVs are needed for the future when considering our environment				X						X								
	+	Practical/economical fuel production from renewable sources										X								
	+	Technologies are emerging and advancing															X			
	-	Vehicle unavailability for HDV applications (as of now)								X										
	-	Huge upfront costs																X		
	-	Issues with charging infrastructures																X		
	n	WTP depends on evaluations based on business standpoint															X			
CNG HDVs	+	We'll continue to use the fuel as investments have already been made			X				X	X	X									
	+	Foreseeable fuel option (*It would be transitional, though) (b)		X*								X*			X*		X	X	X	
	-	Not the state's direction	X																	

[Note] (a) WTP: willingness-to-pay. (b) X* represent the case where the participants added the neutral remark (i.e., CNG would be a transitional fuel option, though foreseeable).

Figure 104. Opinions on viable alternative fuels for HDVs in 2030s: LPG, hybrid, and others

Organizations vocations		01 school bus	02 various	03 various	04 delivery	05 delivery	06 refuse	07 refuse	08 hauling	09 various	10 various	11 refuse	12 school bus	13 various	14 refuse	15 various	16 various	17 refuse	18 paving
Fleet characteristics		Pb M CNG On-site	Pb M CNG (On-site)	Pb L CNG On-site RD	M CNG (On-site) <15 New	M CNG On-site	L CNG On-site	L CNG On-site LPG	S CNG (On-site) <15 New	Pb L CNG On-site	Pb L CNG On-site LNG→CNG LPG ELEC On-site RD	M CNG (On-site)	L CNG n/a LPG On-site New	Pb L CNG On-site RD	L CNG On-site LPG	Pb L CNG On-site LNG RD	Pb L CNG <15	Pb L On-site LNG→CNG	S n/a
Propane HDVs	+ We'll continue to use the fuel as investments have already been made												X						
	- Less viable option compared to CNG and electric HDVs													X					
Hybrid HDVs	+ Economic saving		X														X		
	+ Drivers' good acceptance																X		
	+ Low emissions				X														
	n WTP[a] depends on the functional suitability (e.g., vehicle weight)								X										
Other remarks	n Any type of fossil fuel vehicles will be closing up				X				X										
	n Alternative fueled HDV market won't be changed much							X											
	n It depends on whether any safety issues are resolved																		X
	n I have no opinions					X													

[Note] (a) WTP: willingness-to-pay.

(+) Continued use of propane due to the investments already made – One organization, who already built on-site propane stations for more than 2,000 propane buses being operated in the U.S., expressed the commitment to continued use of propane buses: "Right now about a little bit more than 90 percent of our fleet is diesel-powered buses. I would hope to think that 20 years from now that would be reversed. That 90 percent of our fleet would either be propane or electric. And I'm fairly confident that that will occur" (Org. 12). In contrast, the other three LPG adopters (e.g., Org. 7, 10, and 14) – who were relying on off-site LPG stations or LPG wet-hosing (i.e., an arrangement with a propane vendor to come and bring a propane tank and fill up the vehicles on site) – did not mention LPG as a future fuel option, presumably due to lack of interest or perceived unviability.

(–) Less viable option compared to CNG and electric HDVs – One organization explicitly commented that "propane would be our least viable option" (Org. 13). Though the organization has experiences in operating light-duty propane vehicles, they "were actually trying to get away from propane" as they favored electricity and CNG options.

Hybrid HDVs in 2030s

Hybrid HDVs use two or more types of power [458]. For example, hybrid electric HDVs are powered by a diesel internal combustion engine together with an electric motor that uses energy stored in a battery. Hybrid electric vehicles do not plug in to charge since the battery is charged through regenerative braking [405]. As of 2020 January, only few hybrid HDVs are available in the U.S [460]. For instance, Ford is the only manufacture which offers hybrid electric HDVs with around a dozen of models (e.g., E450 Cutaway and F-59 Stripped Chassis [460]). Just few participating fleets addressed hybridization as a viable fuel option while reporting some unique advantages such as vehicle drivers' good acceptance and potential economic savings.

(+) Economic saving – Alternative fuel prices are not always lower than those of conventional fuels even though they are generally less expensive (e.g., average retail fuel prices for CNG was $2.30/diesel gallon equivalent vs. $1.90/gallon for diesel in 2016 April [461]). Moreover, as reported from Org. 2 and 4, an additional markup is sometimes applied at some alternative fuel stations. Furthermore, alternative fuel stations are not as abundant as gas stations, which causes a travelling need and increased complexity of fleet routing plans. Taken together, these aspects can lead to uncompetitive costs in using alternative fuels. Hybrid option could resolve these drawbacks to some extent as the vehicle can run on either alternative fuel or diesel: "Hybridization will result in real economic savings. (…) Look, I have hybrid (light-duty) vehicles of my fleet. We're maximizing those hybrids (…) we never really realized the cost savings on our CNG trucks, another point" (Org. 2).

(+) Drivers' good acceptance – Another potential advantage of using hybrid vehicles can be favorable acceptance from vehicle drivers, mainly owing to lowered range anxiety. One organization who have hybrid electric sedans addressed, "(hybrid vehicles have) good user' acceptance and, no operational/maintenance issue" (Org. 16).

(+) Low emissions – Hybrid vehicles can bring environmental benefits with reduced tailpipe emissions particularly when running on alternative fuels (Org. 4).

(n) Depending on the vehicles' functional suitability and overall costs – At the same time, the WPT for a hybrid HDV would depend on whether it satisfies the functional suitability required for a certain application, and the resulting overall costs. One hauling truck operator explained, "It's going to depend on the weight of the vehicle. Because those (hybrid) electric vehicles are so heavy (...) you start cutting into your bottom line. We're saving money over here, but we're not making as much on the payloads" (Org. 8).

Other Remarks

For the other alternative fuels such as LNG, biodiesel, and ethanol, none of the participating fleets stated their opinions. Some of them explained their non-adoption decisions of those fuels by citing several reasons, including numerous maintenance problems (e.g., LNG non-adoption by Org. 9), engine reliability issues (e.g., biodiesel non-adoption by Org. 8), uncertain environmental benefits, and unpredictable fuel prices (e.g., E85 non-adoption by Org. 7). Such adverse experiences would cause disinterest in those fuels as a future option.

In the meantime, one fleet operator in a paving company addressed that viability of any fuel options will depend on whether the fuel and vehicle technologies can "assure no safety concerns" (Org. 18). They explained their CNG rejection decision because of its safety concern along with unfulfilled functionality. On the other hand, some organizations stated that the use of "any type of fossil fuel vehicles (will be) sort of closing up in time" (Org. 4) and "there's no reason for me to go back to diesel as long as the alternative fuels keep progressing" (Org. 8).

Nevertheless, there was an opinion that the alternative fueled HDV market in the U.S. will not be changed much from now – without other states' participation and more effective market actions which can attract fleet operators to purchase AFVs: "If you look at how, where we've come in the last ten years – it's all market driven. (…) You know, engine and truck manufacturers will bend to the will of what the purchasers are wanting. And I tell you, I just don't see a huge demand anywhere else other than California. (...) So, in the next 20 years if nothing changes? I see things very much the same. You know, maybe, they'll be a few improvements. (…) But I don't see the landscape changing significantly unless other states are purchasing a lot more trucks and the market opens up and other people jump in" (Org. 7).

Table 45. Available AFV Models and Makes (As of 2020 January) [460]

Fuels and Vocations	Number of Models	Number of Manufacturers	Manufacturers
CNG	**100**	**37**	
Refuse truck	10	4	Heil Environmental, McNeilus, Mack, Autocar
Street Sweeper	11	6	TYMCO, Elgin, Global, Schwarze Industries, Autocar, Nitehawk
School Bus	5	2	Thomas Built, Blue Bird
Shuttle Bus	13	5	Turtle Top, Thomas Built, Blue Bird, Hometown Trolley, Champion Bus
Transit Bus	17	8	COBUS Industries LP, Gillig, New Flyer, ENC, MCI, Nova Bus, Cummins Westport, ENC
Tractor	12	9	Kenworth, Capacity, Freightliner, Autocar, Mack, Kalmar, Peterbilt, TICO, Volvo
Vocational/ Cab Chassis	32	13	Ford, Crane Carrier, Freightliner, Peterbilt, Autocar, Chevrolet, Kenworth, Greenkraft, GMC, Isuzu, Mack, McNeilus, Ford
LNG	**32**	**14**	
Refuse truck	6	3	McNeilus, Mack, Autocar
Street Sweeper	1	1	Autocar
Transit Bus	3	2	ENC, ENC

Tractor	11	8	Kenworth, Capacity, Autocar, Freightliner, Mack, Kalmar, Peterbilt, Volvo
Vocational/ Cab Chassis	11	7	Autocar, Kenworth, Peterbilt, Mack, McNeilus, Freightliner, Freightliner
EV/HEV/PHEV[(a)]	**68**	**21**	
Step Van	5	4	US Hybrid, BYD, Zenith Motors, Workhorse
Refuse truck	2	1	BYD
Street Sweeper	2	1	Global
School Bus	7	4	Blue Bird, Lion Electric, Thomas Built, GreenPower Bus
Shuttle Bus	7	5	GreenPower Bus, Lion Electric, Zenith Motors, Ford, US Hybrid
Transit Bus	27	8	BYD, COBUS Industries LP, GreenPower Bus, Proterra, New Flyer, Nova Bus, eBus, Gillig
Tractor	4	3	BYD, Orange EV, US Hybrid
Vocational/ Cab Chassis	14	5	Ford, Zenith Motors, BYD, ZeroTruck, Ford
Hydrogen	**5**	**2**	
Step Van	1	1	US Hybrid
Shuttle Bus	2	1	US Hybrid
Transit Bus	1	1	ENC
Tractor	1	1	US Hybrid
Propane	**35**	**14**	
Street Sweeper	2	1	Nitehawk
School Bus	5	3	Blue Bird, Thomas Built, IC Bus
Shuttle Bus	12	5	Turtle Top, Blue Bird, Hometown Trolley, Thomas Built, IC Bus
Tractor	1	1	TICO
Vocational/ Cab Chassis	15	6	Ford, Freightliner Custom Chassis, Chevrolet, Greenkraft, Ford, GMC
E85	**6**	**3**	
Vocational/ Cab Chassis	6	3	Ford, GMC, Chevrolet
Biodiesel	**15**	**7**	
Shuttle Bus	1	1	Hometown Trolley
Vocational/ Cab Chassis	14	6	Hino, Ford, Chevrolet, Isuzu, GMC, RAM

4.5 Conclusions and Recommendations for Developing a Fleet Guidance Document

Despite the aggressive policy goals to reduce harmful emissions, demand-side understanding regarding alternative fuel adoptions in HDV fleets is still limited. This work investigated HDV fleet operators' perspectives on future viable alternative fuel options in California, based on the in-depth qualitative interviews. Electric, hydrogen, and CNG along with hybrid options were commonly perceived as viable and worthy of consideration for at least some vocational applications by the participating fleets. Many positive motivators were addressed, including advancing electric/hydrogen HDVs technologies, environmental benefits from those ZEVs, continued commitments to CNG due to the investments already made, and drivers' good acceptance towards hybrid options. However, various concerns and uncertainties were also reported, such as functional unsuitability (electric), feasibility problems in charging infrastructure (electric), upfront and total ownership costs (electric/hydrogen), perceived unavailability (electric/hydrogen), and unpromising support from the state (CNG). The results of the outreach efforts offer improved understanding of HDV fleet operators' perception on alternative fuels in 2030s and provide the backbone for a necessary way to develop effective demand-side strategies to aid the success of AFV diffusion throughout the HDV market.

What is clear is that the heavy-duty sector, including its range of vehicle applications, their associated duty-cycles and refueling requirements, and the heterogenous nature of fleet decision-making organizations make developing a one-size fits all guidance document a significant challenge. As such, we recommend the companion guidance document focus on navigating the "bridging period" from today's tentative and exploratory AFV applications in the heavy-duty sector according to the strategies selected by CARB from both the analyses in prior chapters and from CARB's annual heavy duty investment strategy[4].

Among the greatest challenges for providing a guidance document in a technology and regulatory landscape evolving as rapidly as California's heavy-duty alternative vehicle sector is that these documents represent a snapshot in time such that technological details have the potential to become quickly outdated. As such, we recommend the guidance document focus on the interpreting the specific findings and recommendations identified in all tasks of this project (chapters 1-3 and 5) through the lens of the findings outlined above regarding specific experiences of early adopters of alternative heavy duty vehicles. Recalling the common features of guidance documents identified in the literature review, we suggest a focus on the following:

- **Fuel type summary, including characteristics, performance, and suitability for specific applications**: Provide an overview for the four vocational applications modeled in chapter 3: line haul, drayage, refuse, and construction, using the TRACE results and CARB Heavy-Duty Investment strategy to highlight fuels and their suitability for these specific applications.
- **Infrastructure:** Highlight the findings from chapters 1 and 5 regarding the importance of infrastructure development for AFV deployment success as well fuel-specific concerns, such as the importance of engaging with utilities for pricing structures with respect to heavy-duty BEV charging. Discuss the anecdotal experience of interviewed fleets (chapter 4) regarding coordinating on- and off-site refueling.
- **Specific vehicle options**: Provide an expanded verson of the available vehicles summary in Table 45 and links to additional resources for identifying new products as they come onto the market, such as the DOE's Alternative Fuels Data Center[5].
- **Total Cost of Ownership**: Emphasize the importance of considering both capital and operating expenses in the fleet purchase decision-making process, itemizing factors of specific concern by fuel type and vocation.

[4] https://ww2.arb.ca.gov/sites/default/files/2020-11/appd_hd_invest_strat.pdf
[5] https://afdc.energy.gov/vehicles/search/

- **Education and training**: Provide an overview training resources by type (planning, procurement, operations, etc.) and source (government, OEMs, NGOs, consultant reports, etc.). Highlight the importance of online resources for obtaining the most recent information available.
- **Applicable laws and available incentive programs:** Summarize the findings of Chapter 5 to provide assessment of California's regulatory landscape and incentive programs, including regulations under development.

Certain common guidance document features noted in the literature review are out of scope for the document generated from this research and we recommend they be mentioned, but not detailed, with appropriate references for obtaining more information provided. These include the following:

- Vehicle disposal
- Maintenance
- Procurement best practices
- Financing and procurement

5. Policy Analysis for Alternative Fuels for Heavy-Duty Vehicles

5.1 Overview

The exact number of programs impacting heavy duty vehicles specifically and transportation more generally in California probably cannot be precisely calculated, but it likely would be in the hundreds. This fact alone is enough to deter those fleet operators who are not large enough, profitable enough, or expert enough to make their way through the morass to properly identify those programs that would be most applicable to their specific situation. Different programs apply differentially depending on fleet size, fuel used, and a variety of other factors, again making the proper identification of applicable programs cumbersome and time-consuming.

Appendix D provides an incomplete listing of 110 programs, regulations, standards, assessments, plans, and reports initially identified as potentially applicable to HDVs in California. The relevant agency (or agencies) is (are) also identified to enable the reader to do his or her own further research. Although care has been taken in compiling this incomplete listing to ensure accuracy of those programs that are included, programs evolve over time with respect to funding sources and relevant agencies, and there are certainly errors and oversights. The purpose of providing this listing is twofold. The first purpose is to inform fleet owners about potential programs that may benefit their fleet operations. The second purpose is to illustrate the complexity entailed in what started out as a seemingly simple task of identifying the programs in California relevant to HDVs.

The overarching recommendation is to simplify the process at all relevant stages. The large number of programs stems from well-intentioned regulators and legislators who want to correct a perceived shortcoming or provide an incentive to encourage fleet owners to do their part to move forward California's environmental and energy goals. Despite these good intentions, the result is an overly complex tangle of competing programs and regulations overseen by numerous different agencies, offices, administrations, districts, and boards that thwarts many of the good intentions. A comprehensive statewide review and simplification of these programs (and others inadvertently not identified) should be undertaken to ensure that a more streamlined process is available to ensure the most efficient movement toward fulfilling the intent of California's regulators and legislators.

5.1.1 Transportation Programs Assessed

Time and budget constraints limited the number of transportation-related programs that could be assessed in detail in the following chapters of this report. Programs for more-detailed assessment were prioritized based on the amount of funding provided, with those programs providing more funding receiving the highest priority. The five programs selected for more-detailed assessment include the following, all of which are California-specific programs except for the first, which is a nationwide federal program:

- Federal Renewable Fuel Standard,
- Low Carbon Fuel Standard,
- Hybrid and Zero-Emission Truck and Bus Voucher Incentive Program,
- Carl Moyer Memorial Air Quality Standards Attainment Program, and
- Volkswagen Diesel Emissions Environmental Mitigation Trust.

Details of each of these programs is provided in the remaining sections of this chapter. A summary of the recommendations associated with each program is provided at the end of each section.

5.1.2 Overall Recommendations

The main recommendation to come out of this analysis is to simplify and streamline programs and their implementation to the greatest extent possible. More certainty as to process and program longevity encourages participation and investment. The sheer number of possible incentive programs and the complexity of each program can act as deterrents for participation, particularly by smaller fleets that are typically more constrained with respect to budgets and people.

Providing an easy to use, comprehensive tool to identify applicable programs is the first step towards streamlining the implementation process. CALSTART's Funding Finder Tool is a great start towards creating a single location where fleets can browse funding options. There are currently 24 programs covered under the tool. Eligible programs can be filtered based on location, technology type, fleet type, and vehicle and/or infrastructure type. The Funding Finder Tool has the potential to serve as a long term, effective tool, if the site gains improved visibility, expands functionality, and remains up to date on available programs.

The use of vouchers issued by vehicle dealerships is the best model for success for vehicle-related incentive programs for several important reasons:

- Relative ease of accessibility (from the point of view of the fleet owner)
- Clear definition of those vehicles that meet the issuing agency's desired policy goals (from the point of view of vehicle dealerships)
- Alignment of goals of fleet owners, vehicle dealerships, and issuing agency
    - Fleet owners value incentives that are easy to access and that make fleet turnover more affordable compared to business-as-usual
    - Vehicle dealerships value incentives that encourage increased vehicle sales
    - Issuing agencies value incentives that are designed to result in desired policy goals.

The availability of a voucher with clearly defined parameters is perceived as more accessible and less intimidating to fleet owners than is a bilateral contract option because the need for one-on-one contract negotiations is avoided. The enabling role of voucher programs is akin to the role that realtors and the multiple listing service in the real estate market: Realtor fees can be avoided if homeowners sell their homes without a realtor, but many potential buyers are scared away by the idea of having to negotiate a deal one-on-one in a bilateral contract negotiation.

Available "one-stop shopping" for any given program encourages program uptake, particularly for smaller fleet operators who lack the administrative staff of larger fleet operators. The resources needed to comply with almost any program can be a huge impediment despite policy makers' best intentions. In addition to the cost and technical issues associated with new vehicle technologies, the "softer" human issues must be addressed to enhance driver willingness to make the desired vehicle changeover. Alternate-fueled vehicles may require drivers to make changes to deeply ingrained driving habits, to adapt to different vehicle handling and route optimization, and to adjust to different refueling times and vehicle range. Sometimes the softer issues are more difficult to solve than are the more straight-forward cost and technical issues.

Review of the five identified programs found that incentives for low carbon fuels as well as heavy duty vehicles and related infrastructure are in-demand and have the potential to significantly accelerate the adoption of zero/low emission heavy duty vehicles if shortcomings are addressed. For example, RFS and LCFS programs are popular and provide significant revenue to offset the higher cost of low carbon fuels, however, navigating the programs for initial certification and for submitting reports can be confusing and time consuming. The HVIP is another popular program, due in part to its voucher structure, however, it is over-subscribed, and its application procedure may limit small fleet participation. The Carl Moyer Program and VW Mitigation Trust Fund may be similarly challenging to navigate—the former, due to a lengthy set of procedures that govern the program, and the latter, due to varying implementation policies depending on the air quality district a fleet is operating in. Overall, the recommendation is to streamline application processes and ensure fleet engagement to maximize use by eligible parties.

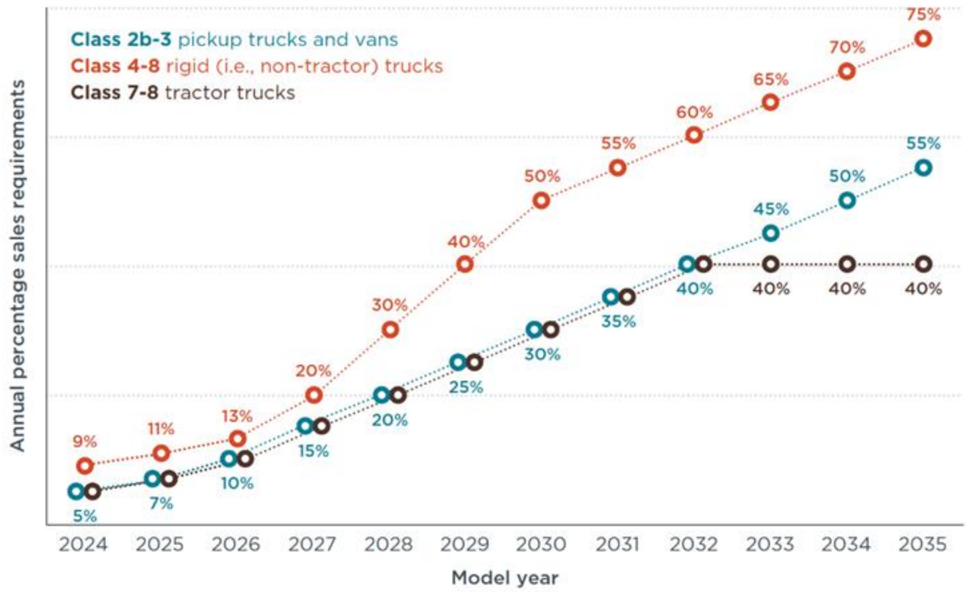
5.2 Introduction and Background

The deployment of zero and near-zero emission pathways represents heavy duty strategies that can best assist California in improving the environmental and human health impact of the HDV sector. However, potential technical, economic, regulatory, and societal barriers exist to achieving market success, some of which require policy and economic incentives to overcome. The purpose of this chapter is to: (i) Identify the potential policy barriers to the deployment and use of zero and near-zero HDV sector pathways, and (ii) recommend policy and economic mechanisms to best overcome the identified barriers to maximize benefits in the HDV sector.

In 2020, the California Air Resources Board passed the Advanced Clean Trucks regulation [462]. The regulation establishes zero-emission heavy duty vehicle sales mandates between 2024 and 2035, see Figure 105 [463]. The analysis conducted in this chapter provides insight into how policies can advance these targets.

This chapter identifies how California policies (e.g., incentives and pricing) can support the use of zero and near-zero emission HDVs and associated fuels, as well as promote the responsible use of CAV technologies to achieve the State of California's long-term climate and air quality goals, as well as the broader sustainability goals for California's freight transport system.

Figure 105. Zero-Emissions Sales Schedule by Vehicle Category



Source: International Council on Clean Transportation 2020 [463]

5.3 Methods

This chapter is a review of current and proposed policies in California, which is conducted primarily through a literature review. Information from government and third-party reports, current program websites, and guidance documents are also included.

5.4 Results and Discussion

5.4.1 Federal Renewable Fuel Standard and California Low Carbon Fuel Standard

There are two major programs affecting California that encourage the de-carbonization of transportation fuels through the displacement of fossil fuels by renewable-based fuels having lower carbon intensity.

The first program, the Renewable Fuel Standard ("RFS") program, is a federal program administered by the U.S. Environmental Protection Agency ("EPA") that was created under the Energy Policy Act of 2005, which amended the federal Clean Air Act ("CAA"). The motivating force behind the RFS program was to reduce the dependence of the United States on imported oil by creating a system of tradeable credits that could be generated based on setting annual mandated volumes of renewable transportation fuels required to be blended into traditional fossil fuel-based transportation fuels. The Energy Independence and Security Act of 2007 ("EISA") further amended the CAA by expanding the RFS program, with such expansion sometimes referred to as RFS II program.

The second program, the Low Carbon Fuel Standard ("LCFS") program, is a California-specific program established in response to a provision in the Global Warming Solutions Act of 2006[6] that tasked the California Air Resources Board ("ARB") with the responsibility of reducing the Carbon Intensity of transportation fuel by at least 20 percent by 2030. The ARB developed the LCFS program in 2010 as a tradeable credits program, the primary purpose of which is to reduce GHG emissions.

The federal RFS program applies across the United States whereas the LCFS program is specific to California. Both programs require that the program-eligible fuels be used in a transportation application. The tradeable credits produced after opting into either the RFS or LCFS program can be sold for compliance purposes to the obligated parties under each program. It is possible to opt in to both the LCFS program and the RFS program if the generated fuel is eligible under both programs and is demonstrably used in California for transportation.

A more-detailed discussion of each of these programs follows.

U.S. EPA Renewable Fuel Standard Program

The RFS program's initial goal was to reduce the amount of foreign oil imported into the United States by requiring certain volumes of specific alternate fuels to be blended into gasoline. The RFP II program expanded the program to include renewable diesel fuels, renewable natural gas, and even renewable electricity as long as these end products are used to displace traditional fossil-based transportation fuels.

The RFS program created a system of credits that assign a unique Renewable Identification Number ("RIN") to each gallon of renewable-based fuel. Each RIN is used to track the disposition of its associated gallon of renewable-based fuel from creation through to retirement. The number of RINs generated per gallon of renewable-based fuel depends on its energy content compared to the energy content of a gallon of ethanol.

The RFS program identifies different categories of RINs by assigning various renewable-based fuel pathways to one of five different "D codes," described in very general terms as follows:

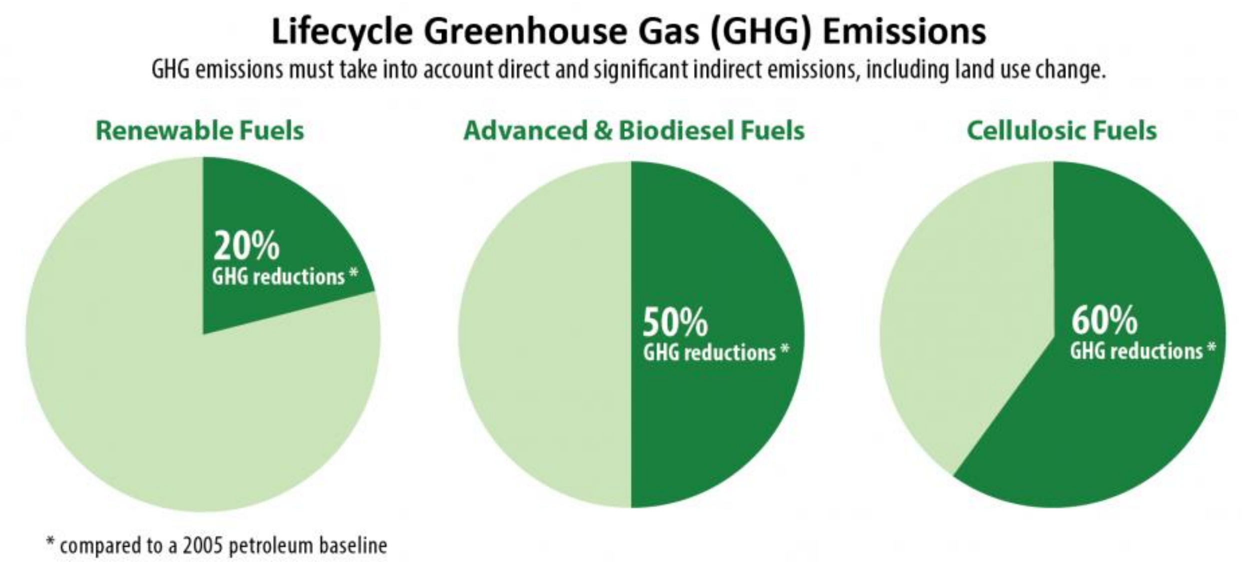
- D3: Cellulosic biofuels ("CB")
    - Minimum 75 percent cellulosic feedstock
- D4: Biomass-based diesel ("BBD")
- D5: Advanced fuels ("AF")
    - Less than 75 percent cellulosic feedstock, which allows for co-processing (e.g., adding food waste)
- D6: Renewable fuels ("RF")
- D7: Cellulosic biofuel or biomass-based diesel

[6] The Global Warming Solutions Act of 2006 is commonly referred to as "AB 32" for the California legislative Assembly Bill that created it.

Appendix D provides a detailed description of the fuel types, feed stocks, and production processes associated with each D code. The RFS program does not have any approved pathways for hydrogen fuel produced using renewable energy sources.

The RINs for each D code have an associated level of the (approximate) greenhouse gas ("GHG") emissions reduction provided by the renewable-based fuel pathways eligible for that D code compared to a petroleum-based baseline, as noted in Figure 106 below.

Figure 106. GHG emissions reductions associated with RFS program D codes



Source: https://www.epa.gov/renewable-fuel-standard-program/overview-renewable-fuel-standard; Water Environment Federation, 4/29/2018, "How to Win with RINs" Webinar.

Gasoline and diesel refiners and importers became Obligated Parties under the RFS program. They, along with exporters of renewable fuel, are required to generate (or purchase) a specific number of RINs for blending each year to comply with their specific annual Renewable Volume Obligation ("RVO") for D3, D4, D5, and/or D6 RINs (each of which has its own RVO). Cellulosic diesel associated with D7 RINs does not have an annual RVO.

- The RVO for gasoline and diesel refiners is calculated based on multiplying the Obligated Party's produced or imported volume of non-renewable gasoline and diesel times the annual RFS percentage set by EPA (which percentage increases each year); any prior year deficit is added to the current-year RVO [464].
    - From 2018 to 2020 the annual RFS percentages increased from 0.159 to 0.29 percent for cellulosic biofuel; from 1.74 to 1.99 percent for biomass-based diesel; from 2.37 to 2.75 percent for advanced biofuel; and, from 10.67 to 10.92 percent for renewable fuel [464], [465].

    - Determination of the annual RFS percentage by EPA is a significant undertaking, particularly if shortfalls in alternate fuel production require EPA to reset the annual RVO [466].
- The Equivalence Value ("EV") for any given fuel determines how many gallons of RINs ("V_{RIN}") are generated for each physical gallon of renewable fuel ("V_s"), using Equation 29.

Equation 29. Gallons of RIN generated

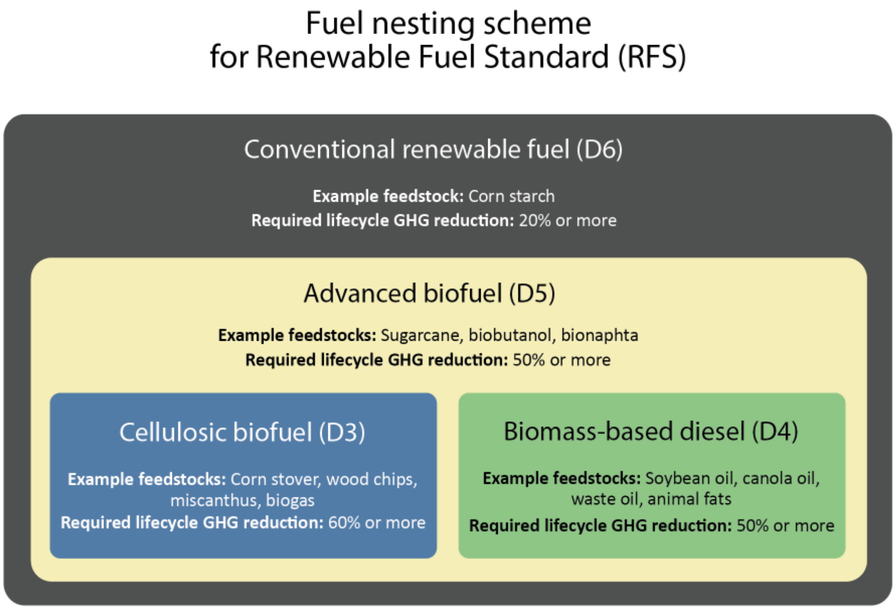
$$V_{RIN} = EV \times V_s$$

- The standard EV for various renewable fuels is as follows [464]:
    - Denatured alcohol: EV = 1.0
    - Biodiesel (mono-alkyl ester): EV = 1.5
    - Butanol: EV = 1.3
    - Non-ester renewable diesel (LHV >= 123,500 Btu/gal): EV = 1.7
    - 77,000 Btu (LHV) compressed natural gas (CNG) or liquefied natural gas (LNG): EV = 1.0
    - 22.6 kWh of electricity = EV = 1.0

RINs generated by an Obligated Party beyond its annual RVO can be sold to other Obligated Parties who generate too few RINs to meet their own annual RVO obligations. Current-year RINs generated may be used for RFS compliance in the current year or banked for compliance in the immediately-following year; in theory, banked RINs can account for up to 20 percent of current-year compliance, though shortages in RINs generation have significantly reduced the number of available banked RINs [3]. An Annual Compliance Report must be filed with the EPA each calendar year by each Obligated Party, as well as quarterly activity and transaction reports [464].

In general, the greater a D code's GHG emissions reduction potential, the higher the value of the associated RINs. This relationship is formalized in the RFS program's fuel "nesting" scheme, which allows RINs with higher GHG emissions reduction potential to be substituted for RINs with lower GHG emissions reduction potential for purposes of RFS program compliance. This relationship is illustrated in Figure 107, which shows that D3 and D4 RINs can be substituted for D5 RIN compliance, and D3, D4, and D5 RINs can be substituted for D6 RIN compliance [467].

Figure 107. Fuel Nesting Scheme for Federal RFS Program D Code



Source: https://www.epa.gov/renewable-fuel-standard-program/renewable-fuel-annual-standards U.S. EPA. Renewable Fuel Standard Program.

It is possible that the EPA is required to adjust the RVOs downward due to insufficient generation of program-eligible fuels in any given year. When this occurs, the EPA must offer a Cellulosic Waiver Credit ("CWC") to cover the insufficient generation, at a price that is tied directly to wholesale gasoline prices. The CWC price is the greater of $0.25/gallon or $3.00/gallon minus the twelve-month average wholesale price of gasoline as of September 30 each year, where both the $0.25 and $3.00 are adjusted for inflation. The annual CWC would therefore be calculated as shown in Equation 30:

Equation 30. Cellulosic waiver credit equation

$$\text{CWC} = \$3.00/\text{gallon (inflation adjusted)} - \text{Wholesale Gasoline Price}$$

Thus, the CWC applicable in any given year is highest when wholesale gasoline prices are lowest. The CWC price has ranged from a low of $0.42/gallon in 2013 to a high of $2.00/gallon in 2017. The CWC for calendar years 2018 and 2019 was $1.96/gallon and $1.77/gallon, respectively [468], [469]. A CWC may only be used to comply with a cellulosic biofuel RVO incurred in the compliance year; they may not be traded or used to satisfy a prior-year deficit [470]. The existence of a known CWC value sets up a fairly predictable relationship between the prices of D3 and D5 RINs, given that D3 RINs have a minimum 75 percent cellulosic feedstock threshold [223]; this relationship is shown in Equation 31.

Equation 31. D3 RINs Price

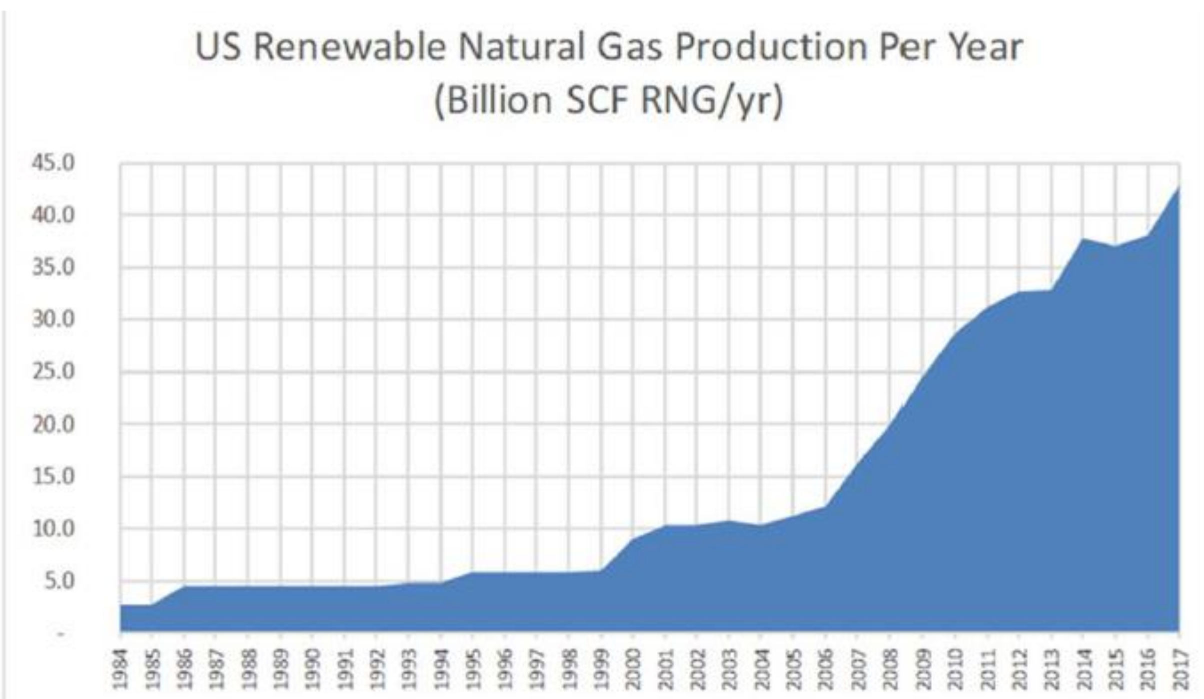
$$\text{D3 RINs Price} = \text{D5 RINs Price} + \text{CWC}$$

There is a trade-off between the use of cellulosic and non-cellulosic feedstock because meeting the 75 percent cellulosic feedstock threshold generates higher-priced RINs but a lower volume of fuel. This makes the optimal mix of cellulosic and non-cellulosic feedstock a moving target since RINs prices and fuel prices are both volatile and ever changing [223].

RINs can be separated and sold separately from the fuel that generated them. Thus, the value of the RINs is in addition to the value of the fuel. The importance of this additive process can be seen in the case of renewable natural gas ("RNG"), also known as bio-methane. RNG is any biogas that been upgraded to meet the pipeline quality specifications for natural gas. RNG can therefore be used interchangeably with natural gas and injected directly into the natural gas pipeline system. However, RINs are currently generated only for RNG used as transportation fuel under the RFS program, not for RNG used to generate electricity (for example).

The current production costs of RNG (including debt service and operations and maintenance costs) is higher than the market price of natural gas, emphasizing the importance of generating RINs to offset the cost differential. However, this also makes RNG producers completely reliant on the existence of the RINs. Figure 108 shows the significant increase in RNG production since the 2006 inception of the federal RFS program [223].

Figure 108. U.S. Renewable Natural Gas Production per Year



Source: Water Environment Federation, 4/19/18, *How to Win with RINs* Webinar.

The ARB's Low Carbon Fuel Standard Program

The purpose of the LCFS program is to reduce the Carbon Intensity ("CI") value of transportation fuels used in California by at least 20 percent by 2030 by providing monetary incentives for lower-carbon transportation fuels to displace higher-carbon fuels. In addition to reducing greenhouse gas emissions, the LCFS will transform and diversify the fuel pool in California to reduce petroleum dependency and achieve air quality benefits.

The CI value is expressed in grams of CO_2-equivalent per Mega Joule of energy ("g $CO_{2\text{-eq}}$/MJ") and is calculated based on the amount of carbon emitted over the complete life cycle of the fuel, including its production, transportation, and consumption [471]. The ARB sets an annual CI standard value ("CI_{std}") that declines over time.

Tradeable LCFS credits for any given fuel are generated based on a comparison of the CI value of the fuel pathway ("CI_{fuel}") against the CI standard value, adjusted for the energy density of the fuel and its Energy Economy Ratio ("EER_{fuel}") compared to a reference fuel [472]. (EER reflects the efficiency of the fuel when used in a specific powertrain.) Equation 32 shows a standardized formula for calculating the number of LCFS credits generated for any given fuel volume.

Equation 32. LCFS Credits

$$\text{LCFS Credits} = (CI_{std} - CI_{fuel}/EER) \times EER \times \text{Energy Density} \times \text{Fuel Volume} \qquad (4)$$

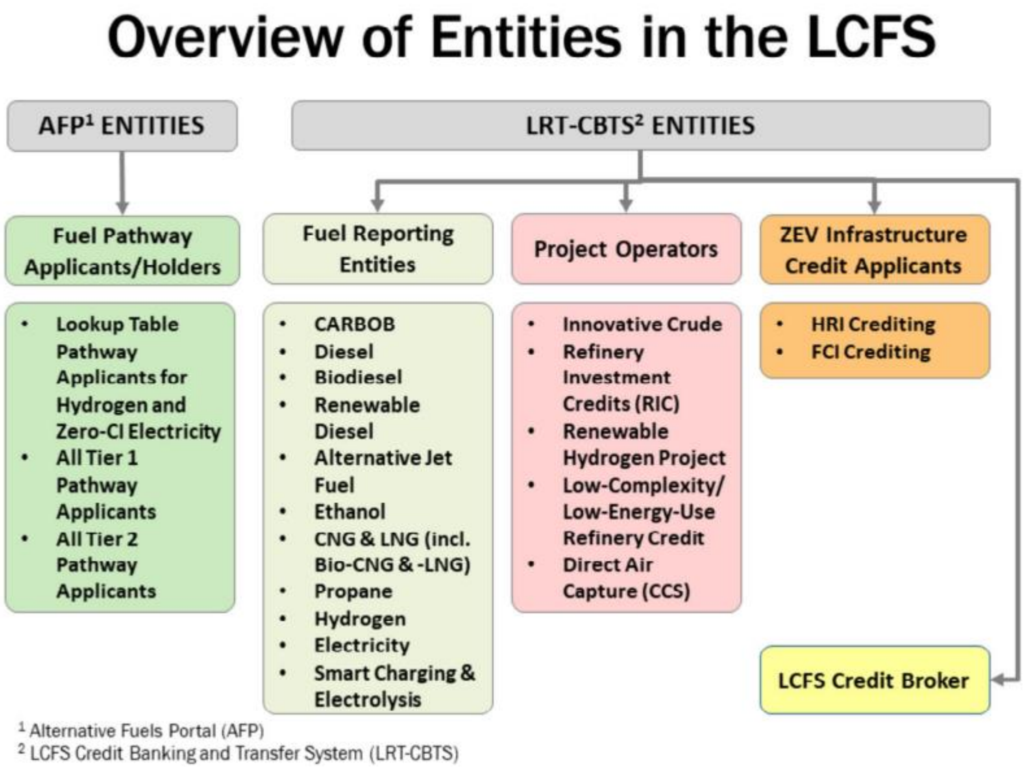
Fuels having a CI value greater than the annual reference CI value accrue an LCFS deficit and fuels having a CI value below the annual reference CI value generate LCFS credits; the lower the CI value of the fuel pathway, the greater the number of LCFS credits generated [25]. The

The LCFS program provides specific default CI values for the following five predominantly fossil fuel-based transportation fuels:

- California Reformulated Gasoline Blendstock for Oxygenate Blending ("CARBOB")
- California Ultra-low Sulfur Diesel ("ULSD")
- Compressed Natural Gas ("CNG")
- Propane
- California Grid-average Electricity.

An overview of entities included in the LCFS program are listed in Figure 109 [471].

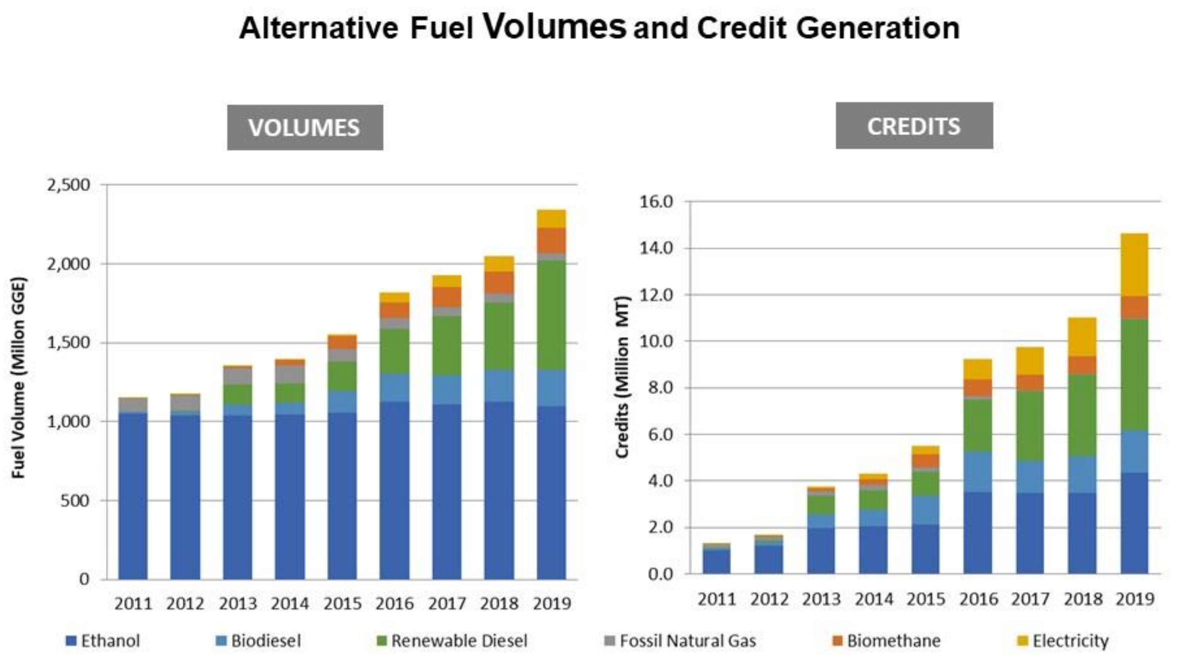
Figure 109. Overview of Entities in the LCFS



Source: California Air Resources Board. LCFS Basics.

Appendix D provides a detailed description of the fuel types, feed stocks, and production processes associated with each of the LCFS program fuel pathway classifications, incorporating all amendments approved in January 2019 [473]. The LCFS amendments proposed in 2019 had not been approved as of March 1, 2020, but none of these pending amendments changes the LCFS program fuel pathway classifications illustrated in Appendix D [474]. Figure 110 summarizes the fuel volumes and associated LCFS credits generated by fuel though 2018 [475].

Figure 110. LCFS Fuel Volumes and Credits Generated: Total by Fuel Through 2019



Last Updated 05/31/2020

The LCFS recognizes that the use of certain fuels results in greater greenhouse gas reductions than others; comparing volumes of each fuel and the total credits generated by that fuel reveals trends both in supply changes as well as the shifts in a fuel's source or innovation in its production. For instance, while ethanol makes up the largest amount of alternative fuel on a volume and energy basis, in 2019 about seventy percent of the LCFS credits were generated by non-ethanol fuels with lower carbon intensities. All other fuel types reported to the LRT-CBTS make up less than 1% of the total volume and credits and are not visually represented.

Source: California Air Resources Board

As was the case for RINs under the federal RFS program, LCFS credits can be separated and sold separately from the fuel that generated them. This allows out-of-state entities to participate in the LCFS program if those entities can demonstrate that the fuel is ultimately being dispensed as a transportation fuel in California. The vast majority of RNG used in vehicles is destined for use in California, a fact encouraged by the simultaneous ability for RNG producers to generate RINs under the RFS program and LCFS credits if the RNG is demonstrably sold into the California transportation fuel market [475].

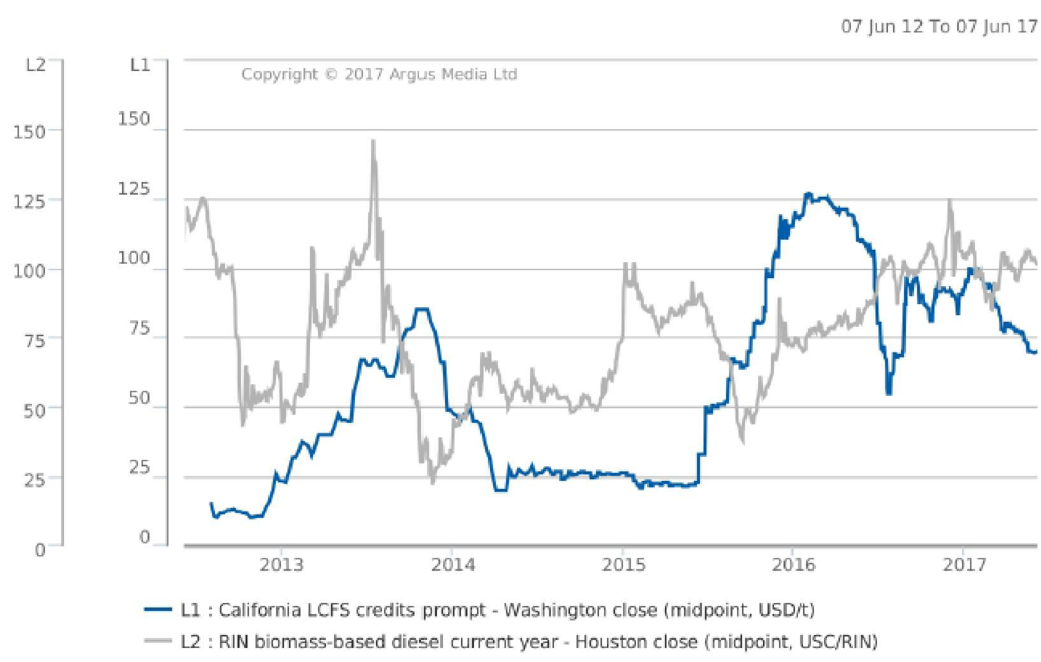
Both fossil fuel-based hydrogen and renewable hydrogen fuel pathways can be used to generate LCFS credits based on their respective CI values. The LCFS credits generated by the hydrogen fuel pathways can be sold or traded to help offset the hydrogen production costs. In contrast, there are no hydrogen pathways eligible to generate RINs under the federal RFS program. This disadvantages renewable hydrogen producers who compete with RNG producers for the same biogas feedstock, since RNG producers can generate RINs and LCFS credits whereas renewable hydrogen producers can only generated LCFS credits [476]. Though the value of LCFS credits improve project economics, they are different from and do not replace the need for the Renewable Energy Credits ("RECs") that most of California's hydrogen producers currently require to achieve the 33 percent renewable hydrogen threshold mandated under Senate Bill 1505 [476], [477]. The purchase of RECs can be used to meet a project's 33 percent renewable hydrogen mandate [476].

Other amendments to the LCFS program added incentives for smart charging of electric vehicles and smart generation of hydrogen produced through electrolysis. Smart strategies allow for the inclusion of otherwise-curtailed renewable energy and having 100 percent renewable electricity. This in turn encourages the co-location of fuel production facilities with large-scale renewable energy projects and substantially reduce the curtailment of intermittent renewable generation. Reducing curtailment of intermittent renewable generation will become increasingly important as additional renewable generation capacity is added to the grid to meet the higher Renewable Portfolio Standards being put in place by California, among other states. LCFS has also added off-road categories and updated the heavy-duty EER [478], [479]. Another update is the addition of third-party audits and verification of LCFS credits claimed [473]. Third-party verification is not required for all LCFS credits but are subject to CARB internal audits.

Price Volatility of RFS RINs and LCFS Credits

Both the RFS and LCFS programs have experienced significant price volatility in the value of their respective compliance credits, as shown by the value comparison of D4 RINs and LCFS credits in Figure 111 [480]. If a credit shortfall occurs in the LCFS market in any given year, a Credit Clearance Market ("CCM") is initiated that sets an LCFS credit price cap of $200 (adjusted for inflation) and provides a route for compliance through pro rata sharing of available credits at the capped price. The CCM was last initiated in 2016 [481].

Figure 111. Value of LCFS Credits vs. Biomass-Based Diesel D4 RINs



Source: Cynthia Obadia Consulting, 2017, Renewable Fuels: Overview of Market Developments in the U.S. and a Focus on California.

The value of LCFS credits has a major impact on D4 RINs prices and blending incentives, given that fuel producers selling biomass-based diesel (the basis of D4 RINs) into California gain the added value of the

LCFS credits (on top of the D4 RINs). An additional wild card affecting the production of D4 RINs has been the biodiesel Blender's Tax Credit ("BTC"), a $1.00/gallon federal tax credit for biodiesel blenders only that as often as not has been allowed to expire before being renewed retroactively. The on-again, off-again nature of the BTC increases volatility in the RINs market, the most recent example of which was the BTC retroactive renewal to January 1, 2018, that was enacted by Congress nearly two years later, on December 19, 2019, and extended through December 31, 2022 [482]. Although the BTC does not apply directly to biodiesel producers, the BTC increases the demand for biodiesel blending, which indirectly increases the demand for biodiesel production.

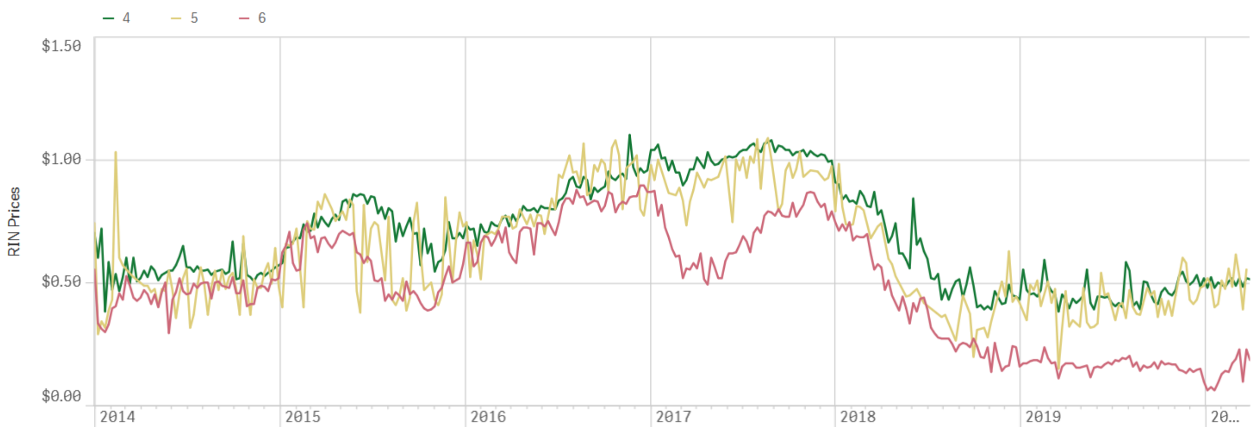
The following real-world example from OPIS demonstrates the importance and mechanics of the BTC to biodiesel blenders [483]:

> "In the simplest terms, the BTC makes the biofuel more price competitive with conventional diesel.
>
> Biomass-based diesel is priced higher than conventional diesel and that difference is particularly pronounced when crude prices are at or near the $50/bbl. mark, where they spent much of 2019.
>
> Renewable Identification Number (RIN) credits under the Renewable Fuel Standard (RFS) can help narrow that premium, but prices for D4 biomass-based RINs spent much of last year in the 40cts/credit range, meaning that biodiesel blenders could narrow the gap with conventional diesel by no more than 60cts to 70cts/gal [given that biodiesel has an EV=1.5].
>
> The BTC's return, however, changes that calculation.
>
> Consider where the market stood in the week ended Jan. 2, 2020. According to OPIS's *Ethanol and Biodiesel Information Service* newsletter, biodiesel at U.S. racks that week averaged $3.706/gal, $1.67 above the average on-road petroleum diesel price of $2.036/gal.
>
> Current-year D4 RIN prices that week averaged about 40cts/credit, a number that would give biodiesel 60cts/gal in added value per gallon. That, however, would still leave the biofuel about $1.07/gal more expensive that conventional diesel.
>
> But add the $1/gal provided by the tax credit and the premium narrows to a much more manageable 7cts/gal. Compare that with where the market was a month ago, before the BTC was reinstated – biodiesel held an 81.55ct/gal premium over conventional diesel, despite RIN credit prices that in early December were 31% higher."

The value of D6 RINs (dominated by corn ethanol) was unusually low relative to D4 and D5 RINs prices in 2017, as shown in Figure 112 [222]. Some of this disparity might have been related to policy uncertainties after the 2016 U.S. Presidential election. The 2017 RFS volume mandates were significantly higher than in 2016, but 2017 saw little growth in RINs generation. A significant RINs bank had been built in 2016, but imports of D6 RINs from Argentina and Indonesia fell significantly due to tariffs. Flat gasoline growth limits the amount of ethanol that can be blended into the gasoline pool, which in turn limits the value of D6 RINs. Based on existing cellulosic ethanol production facilities, there is an assumed annual production limit on "inexpensive" D6 RINs of 15 billion gallons [466]. The decline in the value of D6 RINs starting at the end of 2017 is largely attributed to the reduced demand for D6 RINs after small refineries were exempted from the blending requirement. This increased the relative supply in D6 RINs and resulted in their declining value [484].

D4 RINs are considered the price-making RINs category for the RFS program because their underlying fuel (predominantly biomass-based diesel) is considered the incremental supply and because they can be used for D6 RINs compliance under the RFS program's nesting scheme. In addition, the economic incentives provided by California's LCFS program for alternate fuels with a lower CI value is expected to enable more expensive advanced fuels that generate D5 RINs over currently dominant corn ethanol fuel (D6 RINs) [466]. Uncertainty and volatility in credit values translates to uncertainty in fuel pathway investments.

Figure 112. RFS RINs Prices, 2014-2020 (In U.S. dollars/RIN)



Source: U.S. Environmental Protection Agency, 2020, RIN Trades and Price Information.

Recommendations

1. EXTEND THE TERM OF THE RFS PROGRAM

Investment in alternate fuel production projects is a long-term proposition. Risk-averse investors in such projects desire as much certainty as possible in their project economics. The 2019 extension of California's LCFS program provided investors with added confidence about the program's longevity and helped mitigate some of the ever-present risk of changes being made to the federal RFS program. The latter risk is mitigated by the fact that the RFS program has provided significant wealth for agricultural communities in the rural United States and that there are 52 senators from agricultural states [223], [466].

2. REDUCE COMPLEXITY TO ENHANCE PROGRAM PARTICIPATION

The above descriptions of the RFS and LCFS programs are purposefully as simple as possible while still providing the fundamentals of each program. The regulations underlying each program run to hundreds of pages and involve an incredible level of detail that really requires dedicated people resources to gain a working knowledge of the programs. The dedication of such resources might exceed the capabilities of many smaller fleets to participate. The simpler each program is to understand, the greater and more efficient will be the program participation.

Previously, the complexity of the LCFS opt-in rules made it difficult for smaller fleets to opt into the program. Independent contractors would have to be incorporated or have a federal employer identification number ("EIN"), adding another administrative layer to their workload. They would also have to reliably track electricity use for any EVs generating LCFS credits, submit to potential audits, and figure out how to sell their LCFS credits into the marketplace [483]. In 2018, amendments to the program made it simpler for smaller fleets to participate by allowing an aggregator to act as administer. This revision is an example of ways that the ARB can continue to solicit feedback from fleets and update and simplify procedures as technical and/or policy issues are identified.

3. EXPAND ELIGIBLE FUEL PATHWAYS

Increasing the number of fuel pathways that are eligible to participate in both the RFS and the LCFS program should increase the potential alternate fuels produced. Each eligible fuel pathway must contribute to the goals of its respective program.

4. INCREASE COMPATIBILITY OF THE RFS AND LCFS PROGRAMS

The federal RFS program would likely benefit by adding hydrogen pathways that are consistent with the hydrogen pathways eligible under California's LCFS program. The lack of hydrogen pathways in the RFS program became more glaring with the recent addition of smart electrolytic production of hydrogen as an eligible pathway in the California LCFS program.

5. INCREASE DEMAND FOR ALTERNATE FUELS THROUGH CUSTOMER INCENTIVES

Demand-side incentives would increase interest in the alternate fuels whose production is encouraged by the RFS and LCFS programs. Incentives for customers to buy alternate-fuel vehicles have been inconsistent and short-lived. To encourage a more rapid turnover of the vehicle fleet, longer-term customer incentives to purchase alternate-fuel vehicles should be put in place, either at the federal level or as part of a collaborative effort between the federal and state governments. Vehicle manufacturers should also be part of the collaboration since more alternate-fuel vehicle purchases would facilitate design innovation and contribute to achieving federal fleet mileage standards.

6. PROVIDE INCENTIVES TO ENCOURAGE ALTERNATE FUEL PRODUCTION

California imports the majority of its RNG due to the high cost and difficulties of building in-state RNG production facilities [475]. California has made significant strides toward encouraging in-state RNG production, enacting several key pieces of legislation to help reduce the costs of producing in-state RNG, including:

- Senate Bill 1383 – Requires statewide methane emissions to be reduced by 40 percent from 2013 levels by 2030, which should encourage digester projects at dairies and additional use of RNG in transportation and electricity generation [10].
- Assembly Bill 2313 – Provides incentives of up to $3 million to offset interconnection costs with natural gas pipelines for RNG projects and up to $5 million for clusters of dairy digester projects [485].
- Senate Bill 1440 – Establishes a statewide RNG procurement program to benefit rate payers, be cost effective, and advance California's environment and energy policies; signed into law in September 2018 [486].
- Assembly Bill 3187 – Also signed into law in September 2018, requires the California Public Utilities Commission to open a proceeding to consider options to promote the in-state production and distribution of biomethane, including recovery in rates of the costs of interconnection infrastructure investments [487].

California Governor Newsom in November 2019 vetoed Assembly Bill 1195 that would have allowed the use of RNG in the production of traditional transportation fuels. The Governor alleged that the bill would misapply the state's LCFS regulation by allowing RNG deliveries by common carrier pipelines [488].

7. ESTABLISH COMPATIBILITY IN NATURAL GAS PIPELINE SPECIFICATIONS

California has some of the strictest natural gas pipeline specifications in the country with respect to minimum heat content and maximum siloxane limits. Research is being done by the California Council on Science and Technology to analyze the impact of loosening these specifications to encourage the development of in-state RNG production facilities [475]. This is likely a necessary first step to ensure the successful implementation of the last two pieces of legislation mentioned above.

8. CONSIDER ALTERNATIVES TO GASOLINE AND DIESEL TAXES

As alternate fuels displace gasoline and diesel, it will be necessary for federal and state governments to consider new means to funding roads in lieu of standard gasoline and diesel taxes. This is particularly true as the penetration of electric and fuel cell vehicles increases.

5.4.2 Hybrid and Zero-Emission Truck and Bus Voucher Incentive Program and Low NOx Engine Incentive Program

The Hybrid and Zero-Emission Truck and Bus Voucher Incentive Program (HVIP) and Low NO_x Engine Incentive Program incentives benefit the citizens of California by providing immediate air pollution emission reductions while stimulating development and deployment of the next generation of zero-emission, hybrid, and low NO_x commercial vehicles (Classes 2-8). The HVIP and Low NO_x Engine Incentives have been implemented through a partnership between the California Air Resources Board (CARB) and a Grantee and selected via a competitive CARB grant solicitation [489]. The Fiscal Year 2019-20 funding level for the HVIP and Low NO_x Engine Incentives is $142 million [490], up from $125 million in the previous fiscal year [489]. The HVIP has experienced a significant increase in voucher demand and started a waitlist on July 23, 2019, with a funding backlog estimated at over $100 million [490].

HVIP and Low NO_x Engine Incentives support the statutory goals of California SB 1204 by prioritizing funds for early commercial clean heavy duty vehicles and engines. The HVIP and Low NOx Engine Incentive funding levels are meant to ensure that at least 20 percent of Low Carbon Transportation truck funding supports early commercial deployment of existing zero- and near zero-emission heavy duty truck technology [489].

HVIP vouchers are intended to reduce the incremental costs of purchasing hybrid and zero-emission medium-duty and heavy duty trucks and buses by about half. The HVIP provides vouchers on a first-come, first-served, statewide basis to public and private fleets of all sizes that operate in California and each vehicle that receives an incentive must stay in California for at least three years. Priority is given to projects that benefit disadvantaged communities.

The HVIP and Low NO_x Engine Incentives provide a point-of-sale voucher for the incentive amount for eligible vehicles. The HVIP provides up to $15,000 in increased incentives for fleets located in or serving disadvantaged communities. The voucher is redeemed at the time the truck or bus is purchased or leased from a registered dealer; the registered dealer works with the buyer to complete the voucher request form when the vehicle is ordered [489]. There is only one voucher assigned to each vehicle and each fleet is limited to a total of 200 vouchers under the program [491]. There were 76 HVIP registered dealers on the HVIP Approved Vendor List as of March 2020 [492].

The HVIP has been so successful since its inception in 2009 that hybrid trucks and buses and low NOx engines were "graduated" out of the program on October 25, 2019 and are no longer eligible to receive new HVIP incentives. Low NO_x Engine Incentives implemented through the HVIP were applicable for both new and repowered natural gas vehicles and engines, with a renewable natural gas contract required for a minimum of three years [493]. Incentives for Low NO_x Engines could be used in conjunction with other vehicle incentives (e.g., the California Energy Commission's Vehicle Incentive Program, programs manages by regional air quality districts) as long as funding for the incremental cost of the low NO_x portion of the cost relative to a diesel engine was not duplicated [494].

Eligible Vehicle Types, Voucher Limits, and Funding Structures

Once hybrid vehicles and low NOx engines were "graduated" out of the HVIP program in October 2019, only two categories of eligible vehicles remain, each with its own HVIP funding structure, as follows:

- Zero Emission – Any vehicle that produces no emissions when stationary or operating. Hydrogen fuel cell trucks have a tiered incentive allocation based on the Gross Vehicle Weight Rating (GVWR), whereas the incentives for hydrogen fuel cell buses depend on length [489].
- ePTO (Electric Power Take-Off) – A device that takes power from an on-vehicle source (e.g., a battery) that produces no emissions and that is used to power an aerial boom [493]. ePTO incentives are limited to half of their incremental cost and are based on battery system size and work site performance, the latter to ensure that ePTO systems optimize engine-off time to maximize emissions reductions [489].

Table 46 presents a summary of the number of eligible vehicles by type and original equipment manufacturer (OEM) as of March 2020, with the associated range of HVIP incentives listed for vehicles not based in disadvantaged communities.

The rapid increase in the number of ZEVs in the past several years has resulted in the total number of eligible vehicles for HVIP incentives remaining virtually the same from Fiscal Year 2019-20 to Fiscal Year 2018-2019 despite the removal of hybrid vehicles and low NO_x engines from the program. As noted above, certain zero-emission truck and bus vehicles qualify for up to $15,000 in added HVIP incentives if the vehicle is based in a disadvantaged community. All eligible terminal and yard truck vehicles will be transferred to the Off-Road Zero-Emission Freight Voucher Program when that program is operational [489].

A detailed downloadable list of each eligible vehicle and its eligible voucher amount is published on the HVIP and Low NOx Engine Incentives website [492]. Information is also available by calling 1-888-457-HVIP.

Table 46. HVIP Eligible Vehicles, By Type, OEM, Number, and Range of Incentives

ELIGIBLE VEHICLES BY TYPE & OEM		ELIGIBLE MODELS	RANGE OF INCENTIVES/VEHICLE
I.	**Zero Emission Vehicles**	**103**	**$50,000 - $300,000**
1.	Blue Bird	7	$120,000 - $220,000
2.	BYD Motors	15	$80,000 - $175,000
3.	Chanje	1	$80,000
4.	Complete Coach Works	1	$71,250
5.	Eldorado National (ENC)	2	$120,000 - $300,000
6.	Envirotech (EVT)	1	$80,000
7.	Gillig	3	$90,000 - $150,000
8.	GreenPower	8	$80,000 - $220,000
9.	Kalmar Ottawa	1	$150,000
10.	Lightning Systems	7	$50,000 - $90,000
11.	Lion Electric	5	$150,000 - $220,000
12.	Micro Bird	2	$80,000 - $90,000
13.	Motiv Power Systems	6	$80,000 - $150,000
14.	New Flyer	5	$120,000 - $300,000
15.	Orange EV	4	$71,250 - $150,000
16.	Phoenix Motor Cars	5	$80,000 - $90,000
17.	Proterra	12	$120,000 - $150,000
18.	SEA Electric	16	$80,000 - $150,000
19.	Thomas Built	1	$220,000
20.	Xos	1	$90,000
II.	**ePTOs**	**6**	**$17,000 - $40,000**
1.	Altec	4	$17,000 - $32,000
2.	Odyne Systems	1	$40,000
3.	Utility Crane & Equipment	1	$30,000

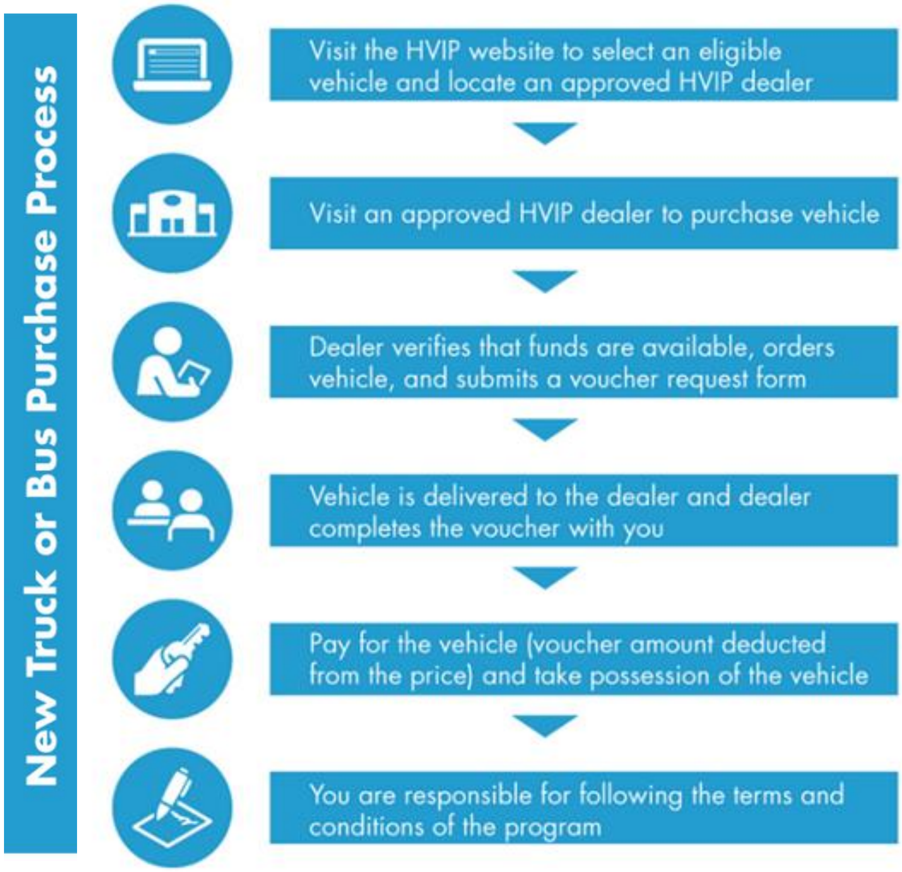
Required Warranty Offerings for HVIP-Eligible Vehicles

Manufacturers of HVIP-eligible vehicles have the option of offering either a 3-year/50,000-mile vehicle warranty or a 2-year/100,000-mile warranty. Extended warranty coverage may be offered if requested as follows: $2,000 for warranty coverage of 6 years or 300,000 miles; $4,000 for 7 years or 350,000 miles; or $6,000 for 8 years or 400,000 miles [489].

Step-By-Step Outline of HVIP New Vehicle Purchase Process

Figure 113 provides a step-by-step outline of the HVIP new truck or bus purchase process [491].

Figure 113. HVIP New Truck or Bus Purchase Process



Source: California HVIP

Recommendations

1. RECOGNIZE THE UNCERTAINTY ASSOCIATED WITH NEW TECHNOLOGIES

As fleet owners transition to zero-emission trucks and buses, they are faced with numerous operational and cost uncertainties, including [379]:

a. An unfamiliar technology (*e.g.*, electric or fuel cell)
b. Limited number of vendors [495]
c. Limited vehicle range that may require redefining optimal vehicle routes or risk limiting vehicle revenue opportunities for longer trips or back-to-back shorter trips that would exceed vehicle range. For drayage trucks, this issue could be resolved by sub-fleeting, where vehicle routes are assigned based on vehicle range and zero-emission trucks are given priority to short-range trips (or combinations of short-range trips).
d. Space and time constraints for vehicle charging (longer charging time increases space required)
e. Lack of available charging or fueling stations for long-haul trucks [495]
f. Lack of standards for charging and fueling equipment and need for electrical upgrades [495]
g. High up-front capital costs for vehicles and charging infrastructure

h. Lack of parts and maintenance expertise [495]
i. Insufficient credit rating or business history that increase the size of required down payments for commercial truck loans. This may be particularly acute for independent contractors, at times making it necessary for licensed motor carriers to step in and acquire trucks to lease to their drivers.

In addition, the batteries in battery-electric trucks are so heavy that the combined tractor weight plus cargo payload may be higher than the 80,000 pound overall gross weight allowed on California's streets and highways. The additional weight of the batteries must therefore come out of the payload being hauled. Fuel cells have a much higher energy density than batteries, making fuel cell trucks lighter than battery-electric trucks [495].

2. AVOID MAKING INCENTIVES MORE GENEROUS THAN NECESSARY

The fact that the HVIP has been over-subscribed for the past two years may indicate that the program is overly generous (in addition to being easier to use than some of the competing programs). If the incentives are too generous, the number of new vehicles able to take advantage of the incentives will be too low. As more eligible vehicles enter the market, incentive levels will have to be continually reviewed and potentially reduced as initial purchase costs decline. Incentives should consider the Total Cost of Ownership ("TCO") to ensure that the incentives provided are not overly generous compared to alternative trucks and buses [379].

3. EMULATE THE HVIP VOUCHER PROGRAM FOR OTHER INCENTIVE PROGRAMS

The HVIP and Low NO_x Engine Incentives are available to fleet owners through a relatively straight-forward voucher program that clearly identifies which vehicles are eligible for the incentives and that is administered through a network of registered dealers who work with fleet owners to complete the voucher request forms.

a. The relatively straight-forward nature of the voucher program is reflected in the fact that the implementation manual is only 70 pages long [493].
b. The relative simplicity of the HVIP and Low NO_x Engine Incentives programs encourages fleet owners of any size fleet to pursue incentives for vehicle replacement that move the State of California towards its desired regulatory goals.
c. These types of voucher programs should therefore be emulated for their clarity, ease of use, and alignment of incentives between fleet owners, registered dealers, and regulatory agencies.

4. COORDINATE WITH AFFECTED STAKEHOLDERS TO ENHANCE PROGRAM EFFECTIVENESS

A combined "carrot and stick" approach to reducing emissions from trucks and buses is likely to be more effective than a single "carrot" or "stick" policy. The HVIP and Low NO_x Engine Incentives provide "carrots" to encourage the uptake of zero-emission trucks and buses. Aligned "stick" policies, such as differentiated impact fees for port drayage trucks based on compliance with clearly stated emissions standards, would encourage more aggressive purchasing of compliant trucks, while also raising additional revenue for the ports [33, p. 40]. The revenues could also be used to reward zero-emission vehicles with a rebate for moving cargo to or from the ports, though such a program could prove to be administratively complex and possibly require more staff; it may be necessary to limit lifetime rebate value or the number of trucks participating to avoid funding risk [33, p. 41].

5. PROVIDE "ONE-STOP SHOPPING" FOR EDUCATION AND OUTREACH

Potential program participants should be able to identify where they can get technical assistance and help with understanding program compliance requirements.

6. ENHANCE USE OF PRIORITY LANES FOR ZERO-EMISSION VEHICLES

As in most businesses, time is money in the trucking business. Providing priority lanes for zero-emission trucks and buses would encourage increased uptake of such vehicles, particularly if the effective hours for the priority lanes were well-chosen to optimize limited road space (*e.g.*, by avoiding competition for lanes during light-duty vehicle rush hours).

7. ENSURE THAT DYNAMIC ONLINE INFORMATION REFLECTS CURRENT PROGRAM STATUS

Online resources should be coordinated to ensure that they are all updated at the same time to reflect the current status of each program. This is particularly important because fleet owners researching program information online are likely to assume that whichever information they access first is current; they are unlikely to realize or suspect that there are different versions of (apparently) the same information available on the same web page.

a. A prime example of such a case of conflicting program information is the web page where both a dynamic listing of the Eligible HVIP Vehicle Catalog is provided [492] as well as (immediately beneath it) a downloadable file of "the catalog of eligible [HVIP] vehicles" [496]. Several separate updates to the downloadable catalog are included to reflect eligible vehicle exclusions due to "dealer unavailability" [497], [498].
b. A fleet owner would reasonably expect that the dynamic listing would reflect the most recent information about eligible vehicles. However, the dynamic listing still includes vehicles that are no longer eligible for HVIP incentives, an unnecessary source of confusion.

8. RECOGNIZE LIMITED RESOURCES OF HVIP PARTICIPANTS, PARTICULARLY SMALLER FLEET OWNERS

In addition to the standard, well-defined program provisions, the HVIP and Low NOx Engine Incentives program allows for case-by-case consideration of exceptions to certain specified program provisions. While these case-by-case considerations potentially extend program applicability, they require additional effort and introduce increased uncertainty on the part of fleet owners. Larger fleet owners may have the wherewithal to pursue such one-off eligibility efforts, but smaller fleet owners are less likely to be able to pursue these program enhancements, likely lacking even the personnel and wherewithal to pursue the standard program provisions.

9. ACKNOWLEDGE AND CREATE SOLUTIONS FOR REQUIRED BEHAVIORAL CHANGES

Different truck duty cycles will present different challenges when transitioning to a zero-emissions truck fleet. Truck drivers typically want a truck that is not limited to one duty cycle since duty cycles differ based on loads that change by day, by season, or by contract [495].

The length of electric vehicle charging times will require changes to be made to driver schedules, given mandatory trucker driving limits and rest requirements. Unless drivers can sleep while the vehicle is charging or time the charging to coincide with their mandatory ten consecutive off-duty hours, charging time will come out of drivers' hours-of-service driving window and thus, truck drivers will want to have access to a charging station at the end of their shift [495].

5.4.3 Carl Moyer Memorial Air Quality Standards Attainment Program

The primary objective of the Carl Moyer Memorial Air Quality Standards Attainment Program (Carl Moyer Program) is to obtain cost-effective and surplus emission reductions to be credited toward California's legally-enforceable obligations in the State Implementation Plan (SIP) – California's road map for attaining health-based national ambient air quality standards. Emission reductions funded through the Carl Moyer Program must be permanent, surplus, quantifiable, and enforceable in order to meet the underlying statutory provisions and be SIP-creditable [499]. Eligible projects must be "early or extra," meaning the emissions reductions resulting from the incentives cannot be required by any existing regulation, memorandum of understanding, or other legal mandate. The Carl Moyer Program, started in 1998, will be largely displaced by new regulations being put into place by 1 January 2023.

The Carl Moyer Program is a voluntary grant program for cleaner-than-required engines and equipment, funded through the California Air Resources Board (ARB) in partnership with California's 35 local air districts, who administer the grants and select which eligible projects to fund. The ARB works collaboratively with the local air districts and other stakeholders to set guidelines to ensure that the Carl Moyer Program reduces pollution earlier and/or beyond what is required by existing regulations [500]. Figure 114 identifies each of California's counties and 35 local air districts [501].

The Carl Moyer Program (as most-recently modified in 2019) provides incentives to replace, repower, or convert older, more-polluting vehicles and engines. Replacement requires scrappage of the old vehicle. A repower involves the replacement of an older, dirtier engine with a newer, cleaner one. A conversion involves the replacement or modification of the original engine or vehicle to include either a cleaner engine or other system that provides motive power and changes the fuel type used. For repower and replacement projects, the replacement engine must achieve an annual NO_x emissions benefit of at least 15 percent to receive any funding for NO_x reductions [499].

Public and private entities are eligible for funding under the Carl Moyer Program, and Carl Moyer Program funds may be combined with funding from other programs so long (i) as total project costs are not exceeded and (ii) private-sector projects include a 15 percent cost share [499]. Small businesses with vehicles or equipment that are exempt from or not yet subject to air quality regulations are particularly encouraged to participate [500]. The Carl Moyer Program pays up to 85 percent of the cost to repower engines and up to 100 percent to purchase an ARB-verified retrofit device.

Figure 114. California Counties and Local Air Districts

Source: California Environmental Protection Agency

Carl Moyer Program Cost-Effectiveness Limits

Emissions factors and deterioration rates are provided by the ARB based on engine model year and applicable emission standards for both the baseline engine and the reduced emission engine to ensure that funding is provided only for vehicles that meet the reduce emission targets [38, pp. 4-8]. Conventional diesel clean-up projects must meet a cost-effectiveness limit of $30,000 per weighted ton of emissions reductions, whereas the limit for emerging technologies is up to $100,000 including advanced projects that are zero-emission or that meet the cleanest certified optional standard applicable [38, pp. i-ii]. School buses have an even higher cost-effectiveness limit of $276,230, which allows the Carl Moyer Program to fund at levels equivalent to the Lower-Emission School Bus Program [38, pp. 1-7].

Carl Moyer Program Source Categories

There are several so-called "source categories" for the Carl Moyer Program incentives, the major ones of which are outlined below; for clarity, categories listed below each source category are referred to here as sub-source categories. Incentives may be procured for replacements, repowers or conversions in two different manners: (i) By contract for vehicles in any of the On-Road Heavy-Duty Vehicles sub-source categories, or (ii) through a Voucher Incentive Program for the On-Road Heavy Duty Trucks and Buses and Drayage Trucks sub-source categories—emergency vehicles are only eligible for repower/conversion funding on a case-by-case basis, and only up to $20,000 per vehicle [499].

1. On-Road Heavy Duty Vehicles
    a. On-Road Heavy Duty Trucks and Buses
    b. School Buses
    c. Transit Fleet Vehicles
    d. Drayage Trucks
    e. Solid Waste Vehicles
    f. Public Agency/Utility Vehicles
    g. Emergency Vehicles (Fire Apparatus, Pumpers, Ladder Trucks, Water Tenders, and Prisoner Transport Buses) [499]
2. Off-Road Equipment
    a. Forklifts, Construction, Agricultural, Airport Ground Support, and Industrial Equipment
3. Locomotives
4. Marine Vessels
5. Light-Duty Vehicles
6. Lawn and Garden Equipment Replacement
7. Infrastructure
    a. Commercial Battery Charging
    b. Alternative Fueling Stations (On- and Off-Road Vehicles and Equipment)
    c. Marine Shore Power Electrification
    d. Stationary Agricultural Projects.

Although infrastructure does not directly deliver emission reductions, it enables the advanced clean vehicles and equipment that do. Infrastructure projects are not required to meet a cost-effectiveness limit. Infrastructure projects are funded up to 50 percent of their total cost, with the possibility of adding one of the following: (i) An additional 10 percent if fueling stations are open to the public; (ii) an additional 15 percent if the project includes onsite wind or solar; or (iii) up to 100 percent for alternative fueling stations or electric charging stations for school buses [499].

All funded projects under the Carl Moyer Program must provide annual reports to the local air district throughout the life of the project [499]. High-level details are summarized below for a number of the sub-source categories related to On-Road Heavy-Duty Vehicles. Additional details can be found in the Carl Moyer Program Guidelines, which run to over 400 pages in two volumes [499], [502].

Carl Moyer Program On-Road Heavy-Duty Vehicles Source Category

The Carl Moyer Program On-Road Heavy-Duty Vehicles source category provides incentives to replace older high-polluting heavy duty vehicles and buses to provide real emissions benefits earlier than would have been expected through normal attrition. The existing old vehicle must be model year 2010 or older, though existing school buses and log trucks may be any model year [499]. Eligible log truck applicants must be registered for the Truck and Bus Regulation Log Truck Phase I option or for the NOx Exempt Area extension; eligible log trucks under the Log Truck Phase I option must have log bunks permanently attached to the vehicle [38, pp. 4-14]. New or used replacement vehicles must have a model year 2013 or newer engine and be certified to a PM emission standard of 0.01 g/bhp-hr. and a NOx family emission limit or NOx standard level of 0.20 g/bhp-hr. and the old vehicle must be scrapped [38, pp. 4-24]. For fleets with ten or fewer vehicles, the total State funding amount cannot exceed 80 percent of the vehicle cost (excluding taxes and fees); for larger fleets, the funding limit is 50 percent. The funding limit (if any) for emergency vehicles is unclear, variously cited as 80 percent and up to 100 percent, regardless of fleet size [38, pp. 4-5]. Maximum funding amounts are as shown in Table 47, though funding amounts may be adjusted downward based on cost-effectiveness [499].

Table 47. Carl Moyer Program Conventional Diesel or Alternate Fuel or Hybrid Replacements: Maximum Funding Amounts

NOx Certification Level (2013+ Engine Model Year)	Per Heavy Heavy-Duty (HHD) Vehicle; GVWR >33,000 lbs.	Per Medium Heavy-Duty (MHD) Vehicle; GVWR 19,501-33,000 lbs.	Per Light Heavy-Duty (LHD) Vehicle; GVWR 14,001-19,500 lbs.	Per Emergency Vehicle; GVWR > 14,000 lbs.
0.20 g/bhp-hr. or cleaner	$60,000	$40,000	$30,000	80% of Cost

There are separate state funding caps for Optional Low NOx Replacements, ZEV replacements or repowers, and hybrid conversions, as shown in Table 48. The funding caps in Table 48 are subject to the additional constraint that the funding provided is no more than 80 percent of the vehicle cost for fleets with ten or less vehicles and no more than 50 percent for larger fleets (except for emergency vehicles). Optional Low NOx Repower funding caps are limited to $20,000 per vehicle for Transit Buses and $40,000 per vehicle for other trucks and buses, regardless of fleet size [38, pp. 4-7]. Applicants may combine the impact of two baseline vehicles for to obtain funding for an eligible replacement vehicle [38, pp. 4-8]. Replacement vehicles must typically be in the same weight class as the baseline vehicle, though an MHD can replace an HHD vehicle if they have the same axle configuration, though the funding will be limited by at MHD vehicle [38, pp. 4-10].

Table 48. Carl Moyer Program Optional Low NOx Replacements and ZEV Replacements or Conversions: Maximum Funding Amounts

Optional Low NOx Standard	Per HHD Vehicle	Per MHD Vehicle	Per LHD Vehicle	Per Transit Bus
0.10 g/bhp-hr	\$70,000	\$50,000	\$40,000	\$25,000
0.05 g/bhp-hr	\$80,000	\$60,000	\$50,000	
0.02 g/bhp-hr	\$100,000	\$80,000	\$70,000	
ZEV (Truck or Bus)	\$200,000	\$150,000	\$80,000	\$80,000
Hybrid Conversion	\$15,000	\$10,000	\$7,500	N/A

School buses under the Carl Moyer On-Road Heavy Duty Vehicles source category have their own funding caps, as shown in Table 49, though all Carl Moyer Program funding caps may be adjusted downward based on cost-effectiveness measures [499].

Table 49. Carl Moyer Program School Bus Projects: Maximum Funding Amounts

Project Type	Per School Bus
New Vehicle Purchase	\$400,000 (ZEV Only)
Diesel or Alternative Fuel Replacement	\$165,000
Low-NOx or Hybrid Replacement	\$220,000
Repower Existing Vehicle	\$70,000
Electric Conversion	\$400,000

The minimum project life for all projects is one year. The maximum eligible project life by project type is summarized in Table 50. A longer project life may be approved on a case-by-case basis if applicants provide justifying documentation [499].

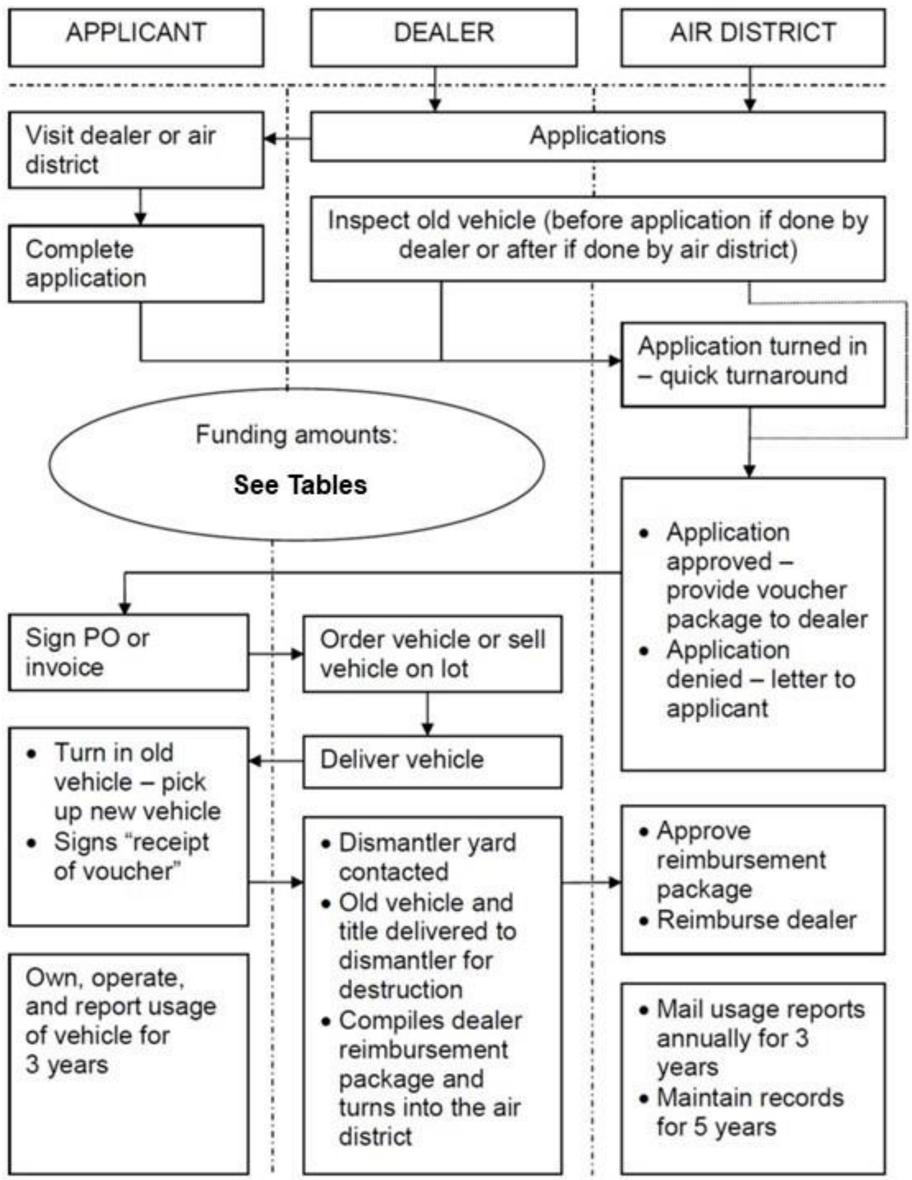
Table 50. Carl Moyer Program Maximum Project Life for On-Road Vehicles

Project Type	Maximum Project Life (Years)
Emergency Vehicles	14
Transit Bus Replacements	12
School Bus Replacements	10
Other Replacements	7
Repowers	7
Electric Conversions	5
Other On-Road Projects	3

Carl Moyer Program On-Road Voucher Incentive Program

The Carl Moyer Program On-Road Voucher Incentive Program (VIP) provides incentives through vouchers rather than by contract and is funded with about \$60 million per year to help scrap and replace older on-road, heavy duty trucks earlier than otherwise would have been expected through normal attrition or by regulation. Eligible heavy duty trucks must have a gross vehicle weight rating (GVWR) greater than 14,000 pounds. The VIP is implemented at the discretion of the local air districts through participating vehicle dealerships. The flow chart provided in Figure 115 illustrates the entire truck replacement process under the VIP and emphasizes the need to reference the additional details in the Carl Moyer Program Guidelines [499], [502] before seeking funding [502].

Figure 115. Carl Moyer Program VIP Truck Replacement Process Flow Chart



Source: California Air Resources Board

The buyer initiates the process for participating in the VIP by submitting a voucher application at a participating dealership. The dealership forwards the application to the local air quality district for evaluation and approval within 15 days. Eligible fleets must have ten or fewer 2009 or older model year diesel or alternative fuel vehicles and be currently compliant with all applicable federal, state, and local air quality rules and regulations. If the existing vehicle is a drayage truck, the existing engine model year may only be 2007 through 2009. Trucks must be owned and operated in California, with at least 75 percent of the miles traveled or fuel consumed over the past two years in California. Voucher amounts range from \$10,000 to \$60,000 per vehicle, depending on the GVWR of the vehicle being replaced, its miles traveled per year, the emission standard of the replacement vehicle, and whether the replacement vehicle is new or used. In general, the older the engine model year and the higher the yearly mileage of the vehicle being replace, the larger the Carl Moyer Program funding award. The old vehicle must be destroyed according to specific dismantling procedures, pp. 24-25 of [502]. Funding also depends on the future compliance date to replace or retrofit the vehicle. Eligible replacement vehicles include new or used 2013 or newer engine model year trucks with a California-certified engine (0.20 g/bhp-hr. NO_x and 0.01 g/bhp-hr. PM or cleaner) [502].

Community Air Protection Incentives

New funds have been available since 2017 to reduce emissions in the communities most affected by air pollution. Grants under Assembly Bill (AB) 617, known as Community Air Protection incentives and implemented by air districts through the Carl Moyer Program, are designed to put help owners of older, high-polluting vehicles and equipment replace them with newer models that have much lower, or zero, emissions. Community Air Protection incentives may also be used: (i) For changes at local industrial facilities to reduce emissions of toxic or smog-forming pollutants, (ii) to build zero-emission charging stations or natural gas fueling infrastructure, or (iii) to support local measures identified by air districts and communities through Community Emissions Reduction Programs. Local measures must go beyond the existing benefits of air district rules and regulations. A supplement to the existing Carl Moyer Program Guidelines was adopted in 2018 to implement the CAP incentives under AB 617 and was revised in 2020 [503].

Recommendations

1. Ensure consistency of online resources to avoid unnecessary confusion. The Carl Moyer Program Guidelines have been updated several times since the inception of the Carl Moyer Program, with a major revision in 2017 and less significant changes made in 2018 and 2020. It is unclear that all necessary revisions have been made when reviewing online documents having many different dates.

2. Ensure consistency of usage throughout all program documentation to avoid confusion. For instance, the vehicle (or engine) being replaced/repowered/converted is variously referred to as the existing vehicle or the baseline vehicle in the Carl Moyer Program Guidelines.

3. SIMPLIFY. The time and effort required to identify the applicable portions of the 400+ pages of Carl Moyer Program Guidelines would almost certainly be a deterrent to program participation, particularly for smaller fleet owners.

4. AVOID MAKING INCENTIVES MORE GENEROUS THAN NECESSARY. Incentives must consider the Total Cost of Ownership (“TCO”) to ensure that the incentives provided are not overly generous [379]. If the incentives are too generous, the number of new vehicles able to take advantage of the incentives will be too low. As more eligible vehicles enter the market, incentive levels will have to be continually reviewed and potentially reduced as initial purchase costs decline.

5. Requiring scrappage of old vehicles means owner must give up the potential resale value of the old truck, making the decision to participate in the Carl Moyer Program more difficult. More drivers might be willing to replace their trucks earlier if they could realize the resale value of their old truck rather than scrapping it. Assuming their old truck replaces an even older truck, allowing resale of the old truck might still result in a win-win situation [495].

5.4.4 Volkswagen Environmental Mitigation Trust Funding

In January 2016, the United States sued Volkswagen for installing defective emission devices in certain model years 2009-2016 vehicles in the Volkswagen “Clean Diesel” Marketing, Sales Practices, and Products Liability Litigation. The parties reached a settlement agreement, under which Volkswagen agreed under the Environmental Mitigation Trust Agreement for State Beneficiaries (State Mitigation Trust) to establish a $2.6 billion trust fund to fulfill Volkswagen's environmental mitigation obligations under the settlement. The State Mitigation Trust was approved by court order on September 19, 2017; the final fully executed version was filed on October 2, 2017, which became the effective date for the State Mitigation Trust. The State Mitigation Trust included an allocation of the $2.6 billion of total trust funds to each of the 50 United States and the District of Columbia [504].

California’s allocated share of the State Mitigation Trust (hereafter referred to as the Volkswagen (VW) Environmental Mitigation Trust) was $423 million, to be used to mitigate the excess nitrogen oxide (NO_x) emissions caused by VW’s use of illegal defeat devices in certain diesel vehicles. In California, the excess amount of NO_x emissions is estimated to be 10,000 tons. The VW Environmental Mitigation Trust funding opportunities are focused on reducing NO_x emissions by the 10,000 tons mostly through scrap-and-replace projects of the heavy duty sector, including on-road freight trucks, transit and shuttle buses, school buses, forklifts and port cargo handling equipment, commercial marine vehicles, and freight switcher locomotives [505].

California’s Beneficiary Mitigation Plan

California filed its Beneficiary Mitigation Plan with the fund administrator of the State Mitigation Trust in June 2018 and the initial tranche of funding of $31.85 million was issued to CARB in 2019. Seventy-two percent of the initial funding was applied to equipment and the balance was applied to administrative expenses [506].

Under California’s proposed plan, grants will be available to eligible recipients to replace or repower vehicles with new diesel, alternative fuel, or all-electric vehicles or engines. Most of the funding ($220 million) will go toward zero-emission buses and large and medium trucks, with $130 million for transit, school, and shuttle buses and $90 million for Class 8 and port drayage trucks. Another $130 million will be distributed between locomotives, ferries, tugs, ocean going vessel shore power, airport ground supply equipment, and forklift and port cargo handling equipment. The remaining funding is allocated to light-duty vehicle infrastructure ($10 million) and reserves ($63 million). The funding provisions of California's VW Environmental Mitigation Trust are summarized in Table 51, Table 52, and Table 53 [507].

As seen in Table 51, the purpose of each funding category differs slightly from the other funding categories, with purposes ranging from vehicle replacement with zero-emission vehicles (ZEVs) to market expansion, to maximizing NOx reductions, to installation of shore power at ports. The maximum funding levels differ by category and by vehicle type within categories, and some categories are funded on a first-come, first-served basis, while others are funded by competitive solicitation. It is important for potential applicants to understand very clearly the funding provisions applicable to their specific need.

Other significant differences in funding provisions of California's VW Environmental Mitigation Trust are that government-owned vehicles are eligible to have 100 percent of costs covered in all funding categories whereas non-government-owned vehicles are eligible to have a maximum of 75 percent of costs with as little as 25 percent of costs covered for switcher locomotive replacement and for some low NO_x truck replacements.

In all categories, at least 50 percent of the eligible VW Environmental Mitigation Trust funds must be used to benefit disadvantages or low-income communities; this rises to 75 percent in the case of freight and marine projects. Scrappage is almost always required, except for oceangoing vessel shore power projects and zero-emission ferry, tugboat, and towboat repower projects.

The VW Environmental Mitigation Trust funding allows for stacking of funds with several other transportation-related programs for many, but not all, funding categories. For instance, stacking of funds under the Hybrid and Zero-Emission Truck and Bus Voucher Incentive Program (HVIP) and Low NOx Engine Incentives program discussed in Chapter III is allowed for low NO_x Class 7-8 freight trucks and zero-emission Class 8 freight trucks and port drayage trucks but not for transit, school, and shuttle buses. Stacking of funds under the Carl Moyer Program discussed in Chapter IV is allowed under similar terms and extends to switcher locomotives and certain ferry, tugboat, and towboat repower projects.

Implementation guidelines for disbursement of California's VW Environmental Mitigation Trust funding have been developed by individual air quality control districts. The San Joaquin Valley Air Pollution Control District opened the initial first-come/first-served application period for the Zero Emissions Transit, School, and Shuttle Buses program, which was almost immediately oversubscribed for school buses. The South Coast Air Quality Management District is working with the ARB on programs for Zero-Emission Class 8 Freight and Port Drayage Trucks and for Combustion Freight and Marine Projects; the Bay Area Air Quality Management District is working with the ARB on programs for Zero-Emission Freight and Marine Projects and for Light-Duty Zero-Emission Vehicle Infrastructure. All programs are expected to terminate by May 2028 [506].

Table 51. VW Environmental Mitigation Trust – California Funding Provisions

Funding Category and Goal	Total Allocation (MM$)	Purpose	Eligible Vehicles or Equipment
Zero-Emission Transit, School, and Shuttle Buses	**$130**	Replacement with zero-emission technologies.	Class 4-5 ICE, compliant with current regulations; Model Year 2009 or older for transit & shuttle buses.
Zero-Emission Class 8 Freight & Port Drayage Trucks	**$90**	Replacement with ZEVs; 70% of funds to expand market.	Class 8 freight & port drayage ICE trucks + waste haulers, dump trucks, & concrete mixers; compliant with current regulations; Model Year 1992-2012.
Zero-Emission Freight & Marine Projects	**$70**	Replacement with ZEVs; install shore power at ports; maximize NOx reductions.	
Forklifts & Port Cargo Handling Equipment & Supporting Infrastructure			Forklifts: Stackers, side loader, top loaders with >8,000 lb. lift capacity; Port Cargo Handling Equipment: Rubber-tired gantry cranes, straddle & shuttle carriers, terminal tractors, and yard hostlers & tractors.
Airport Ground Support Equipment			Pre-Tier 3 diesel or ≥3 g/bhp-hr. NOx + HC spark-ignition engines.
Oceangoing Vessel Shore Power			Berths that service vessels not required by regulation to reduce their onboard power generation. Eligible components: Cables, cable management systems; shore power coupler systems, distribution control systems, power distribution from local utility grid.
Zero-Emission Ferry, Tugboat, & Towboat Repowers			All-electric engine repower, including fuel cells.
Combustion Freight & Marine Projects	**$60**	Maximize NOx reductions— replace vehicle/ engine with most cost-effective, lowest-emission engine projects.	
Low NOx Class 7-8 Freight Trucks			Model Year 1992-2012, including waste haulers, dump trucks, and concrete mixers.
Tier 4 Freight Switcher Locomotives (or Engines)			Pre-Tier 1 locomotives or engines.
Tier 4 or Hybrid Ferry, Tugboat, & Towboat Repowers			Pre-Tier 3 engines.
Light-Duty ZEV Infrastructure	**$10**	******* NOT APPLICABLE TO HEAVY DUTY VEHICLES *******	
Reserve (Including admin. costs)	**$63**	******* NOT YET ALLOCATED TO ANY FUNDING CATEGORY *******	
Total	**$423**		

Table 52. VW Environmental Mitigation Trust – Funding by Vehicle or Equipment Type and Other Provisions

			Total Cost Limit (%)		Other Provisions	
Funding Category and Goal	**Maximum Incentive Funding, Per Vehicle or Equipment**	**Funding Method**	**Govern-ment Owned Vehicles**	**Non-Government Owned Vehicles**	**Scrappage Required?**	**% of Funds to Benefit DAC or Low-Income Communities**
Zero-Emission Transit, School, and Shuttle Buses **(No more than 50% of total funds to a single category)**	ARB suggests 5% in school district matching funds.	First-Come, First-Served	100%	75%	Yes	50%
Battery-Electric School Bus & Supporting Infrastructure	$400,000		100%	75%	Yes	50%
Battery-Electric Transit Bus & Supporting Infrastructure	$180,000		100%	75%	Yes	50%
Fuel Cell-Electric Transit Bus & Supporting Infrastructure	$400,000		100%	75%	Yes	50%
Battery-Electric Shuttle Bus & Supporting Infrastructure	$160,000		100%	75%	Yes	50%
Zero-Emission Class 8 Freight & Port Drayage Trucks	$200,000	First-Come, First-Served	100%	75%	Yes	50%
Zero-Emission Freight & Marine Projects		Competitive Solicitation	100%	75%	Varies (See Below)	75%
Forklifts & Port Cargo Handling Equipment & Supporting Infrastructure	$175,000		100%	75%	Yes	75%
Airport Ground Support Equipment	Full Increment. Cost		100%	75%	Yes	75%
Oceangoing Vessel Shore Power	$2,500,000		100%	75%	No	75%
Zero-Emission Ferry, Tugboat, & Towboat Repowers	$2,500,000		100%	75%	No	75%
Combustion Freight & Marine Projects		Competitive Solicitation	100%	Varies by Project Type (See Below)	Yes	50%
Low NOx Class 7-8 Freight Trucks	$85,000 (certified 0.02 g/bhp-hr low NOx engine truck); $35,000 (non-government owned)/ $50,000 (government owned) low-NOx repower.		100%	Replacement: 25% (50% for Class 8 port drayage truck); Repower: 40%.	Yes	50%
Tier 4 Freight Switcher Locomotives (or Engines)	$1,350,000		100%	Replacement:25% Repower: 40%.	Yes	50%
Tier 4 or Hybrid Ferry, Tugboat, & Towboat Repowers	$1,000,000		100%	40%	Yes	50%

Table 53. VW Environmental Mitigation Trust – Stack Funding Rules

	Stacking Funds Allowed?					
Funding Category and Goal	**AB 617 Community Air Protection Program**	**Carl Moyer Program**	**Federal Transit Admin. Funds**	**Goods Movement Emission Reduction Program (Prop 1B)**	**HVIP (Hybrid & Zero-Emission Voucher Incentive Program)**	**Low NOx Engine Incentives**
Zero-Emission Transit, School, and Shuttle Buses			Yes		No	
Zero-Emission Class 8 Freight & Port Drayage Trucks	Yes	Yes		Yes	Yes	
Zero-Emission Freight & Marine Projects						
Combustion Freight & Marine Projects		Yes		Yes	Yes	Yes
Low NOx Class 7-8 Freight Trucks		Yes, subject to local air district funding discretion		Yes, ($100,000/Class 8 replacement vehicle; no refuse trucks; local air district funding discretion)	Yes, (Scrappage not required)	Yes, (Scrappage not required)
Tier 4 Freight Switcher Locomotives (or Engines)		Yes, up to 85% of replacement cost, subject to local air district funding discretion				
Tier 4 or Hybrid Ferry, Tugboat, & Towboat Repowers		Yes				

Recommendations

California's Beneficiary Mitigation Plan incorporates guiding principles that include the intention to "[u]se a known method of implementation, including public process, project management, and competitive solicitations where appropriate" and "ensure accountability and transparency" [507]. Competitive solicitations tend to benefit larger program participants more familiar with preparation of proposals that meet detailed solicitation requirements. First-come, first-served funding tends to benefit potential program participants who are better informed, making it incumbent on the implementing agency to ensure that funding availability is well advertised to as broad an audience as possible. The rationale for choosing one process over the other depending on funding category should be made obvious in the implementation guidelines; use of more than one process should be avoided unless the need for multiples processes is evident.

The different Air Quality Management Districts should work together to align implementation procedures as much as possible. This will reduce the learning curve required by larger fleets that operate in multiple districts. The best recommendation is one that has been repeated several times already: Keep it simple to encourage the greatest participation by the greatest size range of fleet owners.

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List of Publications Produced

Kate Forrest, Michael Mac Kinnon, Brian Tarroja, Scott Samuelsen, Estimating the technical feasibility of fuel cell and battery electric vehicles for the medium and heavy duty sectors in California, Applied Energy, Volume 276, 2020, 115439, https://doi.org/10.1016/j.apenergy.2020.115439.

Glossary of Terms, Abbreviations, and Symbols

AB	Assembly Bill
ACC	Adaptive Cruise Control
ACT	Advanced Clean Trucks
AD	Anaerobic Digestion
ADAS	Advanced Driver Assistance Systems
AEC	Alkaline Electrolytic Cells
AF	Advanced Fuels
AFDC	Alternative Fuels Data Center
AFV	Alternatively Fueled Vehicle
BBD	Biomass-Based Diesel
BER	Battery Electric Range
BEV	Battery Electric Vehicle
BTC	Blender's Tax Credit
CACC	Cooperative Adaptive Cruise Control
CalHEAT	California Hybrid, Efficient and Advanced Truck Research Center
Caltrans	California Department of Transportation
CAP	Criteria Air Pollutants
CARB	California Air Resources Board
CARBOB	California Reformulated Gasoline Blendstock for Oxygenate Blending
CAV	Connected and Automated Vehicle
CB	Cellulosic Biofuels
CBEV	Commercial Battery Electric Vehicle
CCC	Conventional Cruise Control
CCM	Credit Clearance Market
CD	Charge Depleting
CDA	Cooperative Driving Automation
CEC	California Energy Commission
CH4	Methane
CI	Carbon Intensity
CNG	Compressed Natural Gas
CPR	Current Policy Reference
CRF	Capital Recovery Factor
CS	Charge Sustaining
CSR	Corporate Social Responsibility
CWC	Cellulosic Waiver Credit
CO2	Carbon Dioxide
CO2e	Carbon Dioxide Equivalent
DAC	Disadvantaged Community
DATP	Driver Assistive Truck Platooning
DC	Direct Current
DGE	Diesel Gallon Equivalent
DOE	Department of Energy
DOT	Department of Transportation

DSRC	Dedicated Short-Range Communication
E3	Energy and Environmental Economics, Inc.
E-CEM	Electrolytic Cation Exchange Modules
EER	Energy Economy Ratio
EIA	Energy Information Administration
EIN	Employer Identification Number
EMFAC	EMission FACtor (model)
EO	Executive Order
EPA	Environmental Protection Agency
EPAct	Energy Policy Act of 1992
EV	Equivalence Value
EVSE	Electric Vehicle Supply Equipment
F4F	Fleets for the Future
FCEV	Fuel Cell Electric Vehicle
FUF	Fleet Utility Factor
GHG	Greenhouse Gas Emissions
GJ	Gigajoule
GPS	Global Positioning System
GREET	Greenhouse Gases, Regulated Emissions, and Energy use in Transportation (model)
GVWR	Gross Vehicle Weight Rating
H2	Hydrogen
HDV	Heavy Duty Vehicle
HEV	Hybrid Electric Vehicle
HiGRID	Holistic Grid Resource Integration and Deployment tool (model)
HRS	Hydrogen Refueling Station
HVIP	Hybrid and Zero-Emission Truck and Bus Voucher Incentive Program
ICV	Internal Combustion Engine
INS	Internal Navigation System
ITS	Institute of Transportation Studies
kg	Kilogram
kWh	Kilowatt-hour
LCFS	Low Carbon Fuel Standard
LCOE	Levelized cost of energy
LDV	Light-duty vehicle
LiDAR	Light Detection and Ranging
LP	Linear Programming
LPG	Liquid Petroleum Gas
LR	Learning Rate
M2M	Machine-to-Machine
MDV	Medium Heavy Duty
MPG	Miles per Gallon
MPGe	Miles per Gallon Equivalent
MW	Megawatt
N2O	Nitrous Oxide
NACFE	North American Council for Freight Efficiency

NGVIP	Natural Gas Vehicle Incentive Project
NOx	Nitrous Oxides
NREL	National Renewable Energy Laboratory
OEM	Original Equipment Manufacturer
OPIS	Oil Price Information Service
OTEC	Ocean Thermal Energy Conversion
P2G	Power-to-Gas
PCC	Post-Combustion Capture
PEMEC	Proton Exchange Membrane Electrolytic Cell
PEMFC	Proton Exchange Membrane Fuel Cell
PEV	Plug-in Electric Vehicle
PFCEV	Plug-in Fuel Cell Electric Vehicle
RFS	Renewable Fuel Standard
PM	Particulate Matter
REC	Renewable Energy Credit
RF	Renewable Fuels
RIN	Renewable Identification Standard
RMSE	Root Mean Square Error
RNG	Renewable Natural Gas
RVO	Renewable Volume Obligation
SAE	Society of Automotive Engineers
SB	Senate Bill
SMR	Steam Methane Reformation
SNG	Synthetic Natural Gas
SOC	State-of-Charge
SoCAB	South Coast Air Basin
SOEC	Solid Oxide Electrolytic Cells
TCO	Total Cost of Ownership
TRACE	Transportation Affecting Cost and Emissions (model)
TRL	Technology Readiness Level
TW	Terawatt
UF	Utility Factor
ULSD	Ultra-low Sulfur Diesel
V2G	Vehicle-to-Grid
V2X	Vehicle-to-Everything
V2V	Vehicle-to-Vehicle
VMT	Vehicle Miles Traveled
VTO	Vehicle Technology Office
VW	Volkswagen
ZEV	Zero-Emission Vehicle

Appendix A: Heavy-Duty Vehicle Fuel Cost and Availability

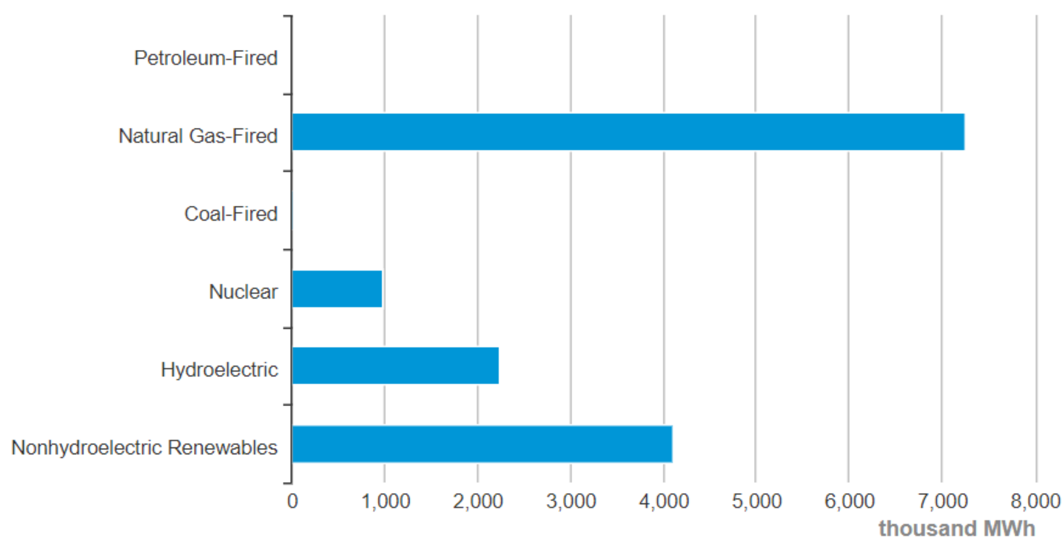
A.1 Additional Background

A.1.1 Background: Heavy-Duty Vehicle Fuel

Fuel Production: Electricity

Detailed electricity production discussion is outside the scope of this work for the reasons stated above. However, some general facts are important to note. Figure A-1 displays the electricity generation sources in California for February 2019 with data from the U.S. Energy Information Administration [508]. Natural gas is used in combustion electricity generators known as gas turbines. There are various evolutions of the gas turbine plant, including combined cycle plants which use waste heat of the gas turbine as heat input for a steam turbine to produce additional electricity from the same natural gas fuel input. Nuclear power, while somewhat significant in terms of power generated, is set to be phased out of California when the last nuclear plant at Diablo Canyon is shut down in 2025 [509]. Coal has been almost completely phased out, with only one plant still producing electricity from coal [510], and it is unlikely to return due to the strict environmental regulations of the State.

Figure A-1. Electricity Sources in California in February 2019, from U.S. Energy Information Administration [508]



Natural gas is a major feedstock for the California electric grid. The rest of the electricity comes from renewables such as solar and wind, hydroelectric, and nuclear power. As the last remaining California nuclear generators will be decommissioned in 2025 [509], natural gas, renewables, and hydroelectric plants will make up the demand that is now served by nuclear. Therefore, electricity either as a fuel or a fuel feedstock will either be associated with an emission-free technology such as renewables or hydroelectric plants, or it will come from a natural gas-powered plant, which does have emissions from combustion. However, it is possible that these natural gas-fueled electricity generators can start to use SNG which have varying emissions impacts, just as vehicles are set to use SNG instead of fossil-source natural gas. While these competing uses of biomass feedstocks are not considered in this work, it is important to keep in mind that the biomass feedstocks considered herein could potentially be used for broader electricity demand such as those of the commercial or industrial sectors.

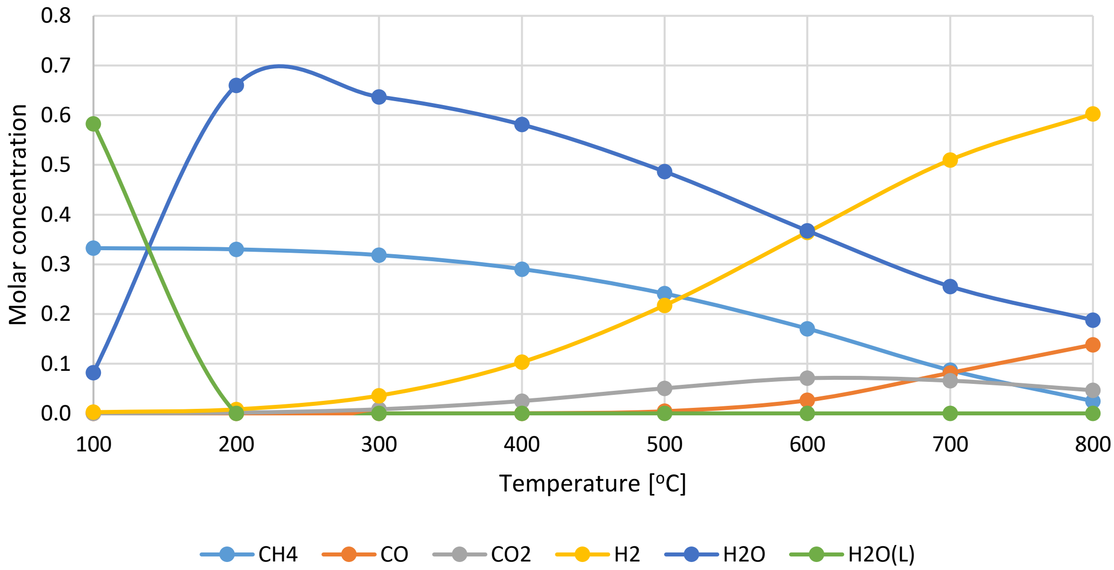
Fuel Production: Renewable Natural Gas

Because methanation can take place at a range of temperatures and its efficiency is benefitted by some pressurization, it is wise to include a range of temperatures and an above-ambient pressure in calculations [60]. An equilibrium analysis using NASA's Chemical Equilibrium with Applications code at 5 atmospheres of pressure at 400, 500, and 600^{o}C leads to an average methanation efficiency of 0.7904 [166]–[168]. This is calculated by analyzing the products of the Sabatier reaction at the given pressure and temperatures, and determining what fraction of the products is methane, the desired product.

Methanation is pressure dependent in such a way that it is more efficient at producing methane at higher pressures [511]. Methanation efficiency is highly dependent on reaction temperature. At 400^{o}C with a 4 to 1 molar ratio of hydrogen to methane input (the stoichiometric ratio of the Sabatier reaction), the methanator output is 92% methane; at 500^{o}C, the output is 81% methane; and at 600^{o}C, the output is 64% methane. Therefore, operating at a lower temperature would increase the amount of methane coming out of the methanator, which could also remove the need for any gas cleanup before injection into the natural gas pipeline. However, it is important to keep in mind other effects of lowering the temperature of the methanator. One major impact is there will be lower quality waste heat which would be used in other P2G processes to be expanded upon later. This could lower the overall process efficiency, even if the amount of methane is decreased. A more careful analysis would be needed based upon an individual plant design.

See Figure A-2 for equilibrium species concentration of a methanator at 5 atmospheres of pressure. Note that some methanators may not allow for the full expected conversion of carbon dioxide and hydrogen to methane due to time reacting. Because the calculations discussed are for equilibrium concentrations, and equilibrium takes time to achieve, actual methanation efficiency may be lower than calculated if time spent reacting in the methanator does not allow for equilibrium to be reached. Therefore, it is important to ensure reactor design does so, or account for the drop in conversion efficiency of the methanator used.

Figure A-2. Methanator equilibrium species concentrations at 5 atm



Lastly, the energy required for the methanation process itself as well as any necessary gas cleanup before injecting must be considered. Two steps are required: (1) carbon dioxide removal and (2) water removal. Carbon dioxide removal is accomplished using amines, organic compounds are used as solvents to capture carbon dioxide. This carbon dioxide can be recirculated back into the methanator to improve process efficiency. Water removal is accomplished through cooling of the gas mixture and collecting the water as it condenses back out. This water can be recirculated back to the electrolysis step, also improving process efficiency. These two cleanup steps produce gas that is able to be injected into the natural gas grid [512]. In some scenarios, simply a removal of the water is all that is needed to produce natural gas pipeline-quality gas [513]. According to Collet et al., when a nearly stoichiometric ratio of hydrogen and carbon dioxide are input to the methanator, the above two processes account for a mere 1.3% of the amount of energy input to the electrolyzer [514]. Therefore, these two processes can be assumed to be of negligible energy requirement for the overall P2G process. However, it is important to remember that gas cleanup will be needed, and that need increases as the methanator temperature increases because less methane will be output from the methanator as the temperature increases.

Post-combustion capture (PCC) pulls carbon dioxide from the exhaust stream of a power plant, a stream that is relatively dense in carbon dioxide compared to ambient air. Various solvents, sorbents, and membranes are used to capture the carbon dioxide from the exhaust stream as the carbon dioxide-containing exhaust flows through the PCC system. Solvents and sorbents capture carbon dioxide and release it under certain conditions such as heating or compressing. Membranes allow only specific molecules, such as carbon dioxide in the case of PCC, to pass through, and other molecules are blocked from passing [64], [65].

The relatively high concentration of carbon dioxide in the exhaust stream of a power plant makes capturing carbon more efficient compared to a less-concentrated source such as ambient air. Priority should be given to the largest sources of carbon dioxide, such as very large power plants, so these PCC installations can capture the most emissions with the least effort of installing systems.

direct air capture also involves a sorbent to capture carbon dioxide from the ambient air [66]. Because of the lower density of carbon dioxide in ambient air compared to the exhaust stream of a power plant, direct air capture is not as efficient as PCC.

Due to the nature of carbon dioxide's effect on climate change, direct air capture units can be placed anywhere and have the same impact. A given amount of carbon dioxide captured has the same effect on climate change no matter where that carbon dioxide is captured. However, it would be wise to place the direct air capture units in places with cheap and clean power to make operation more economical and more beneficial to the environment. Additionally, ambient air characteristics affect performance of the direct air capture systems, so placement should be done based on careful analysis. Humidity has a significant effect on performance due to the water molecules' interference with carbon dioxide capture. Similarly, other molecules in the air such as pollution can effect carbon dioxide capture by either their physical presence or chemical reactions with parts of the direct air capture system [66].

The electrolytic cation exchange module (E-CEM) technology is being pursued by the U.S. Navy and is promising due to its ability to capture both carbon dioxide and hydrogen from seawater [67]. Here, the carbon dioxide would be used as an input to the Sabatier reaction, and the hydrogen again is useful as a fuel or as more reactant for the Sabatier reaction. E-CEM was originally developed for jet fuel production in the sea to overcome the need for resupply of fuel on military missions involving aircraft carriers. However, the basic technology can be adapted to P2G by removing the final fuel synthesis step and instead stopping with carbon dioxide and hydrogen as the desired products, which are exactly what are needed for the methanation reaction.

The process is powered by ocean thermal energy conversion (OTEC), which uses the temperature difference in water at different depths. While circulating through the OTEC process, small amounts of the carbon in water, in the form of dissolved carbon dioxide, can be captured. Further carbon dioxide can be captured from the carbonates in seawater with additional capture materials and power from OTEC. Hydrogen is produced by PEMEC or AEC technology, using the electricity produced by OTEC [196]. While not mentioned in the report, SOEC technology could be used for hydrogen production as well.

The technology readiness level for E-CEM is low and therefore the option may not be ready in time for use in 2030 or 2050.

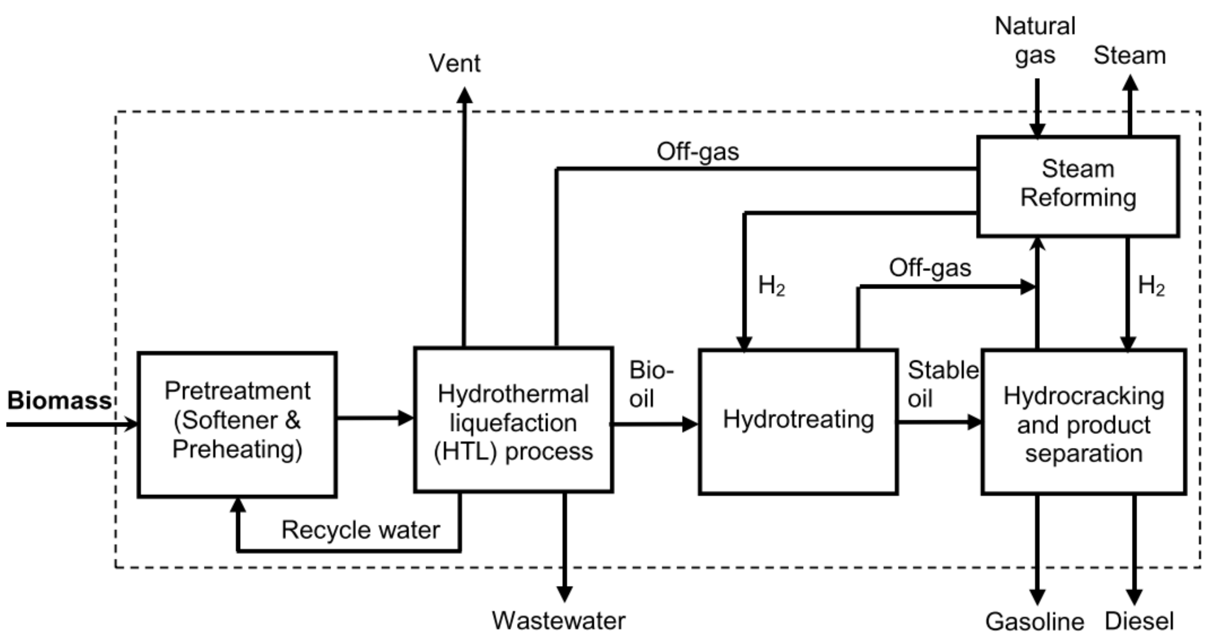
In an anaerobic digester, one could co-digest a lower-moisture content biomass feedstock such as a somewhat moist agriculture waste (for example, fresh yard trimmings). This would require the feedstocks be added in such a ratio as the overall slurry has a high enough moisture content to work in the AD [70]. The work of this dissertation is not spatially resolved, so this constraint is not able to be considered. Given the fact that this co-digestion is rare in the literature, this simplification should not have much impact on practical results. Therefore, only manure and food waste will be considered feedstocks for anaerobic digestion.

Fuel Production: Renewable Diesel

Liquefaction is a direct conversion from biomass to liquid oils, and it is not as technologically developed as some of the other liquid fuels production methods that will be discussed. It involves heating and pressurizing biomass without oxidant at roughly 250-325°C and 50-200 atmospheres of pressure. The result is a bio-oil which is then treated and refined to produce the desired hydrocarbon, renewable diesel. The treatment process involves removing oxygen through hydrotreating, creating hydrocarbon chains of desirable length through hydrocracking, and then distilling to get the desired spectrum of hydrocarbons [68], [104]–[106][201][515]. In this work, the desired product is gasoline or diesel, so the correct spectrum of hydrocarbons for either of these fuels is the design goal. A schematic of a liquefaction plant is shown in Figure A-3.

Note that each of the treatment processes described above is also present in fossil diesel, so lessons learned in these areas from the fossil fuel counterparts can be applied here for the renewable fuels.

Figure A-3. Liquefaction fuel production diagram for renewable diesel, from U.S. Department of Energy [201]



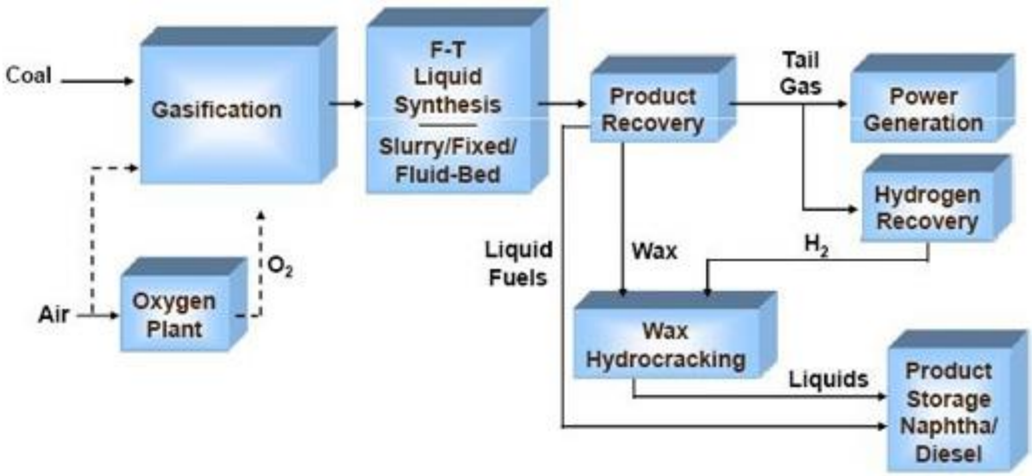
In addition to being used to make both hydrogen and SNG, gasification shows up again as the first step in a process to create renewable diesel. Gasification produces syngas (mainly hydrogen and carbon monoxide), and that syngas then goes through the Fischer-Tropsch (FT) process. FT converts the syngas into hydrocarbon chains of various lengths according to A1, where *n* is an integer. The overall process of gasification followed by FT will be referred to by the shorthand of gasification-FT hereafter.

Equation A-1. Fischer-Tropsch process, from [516]

$$(2n + 1)H_2 + n\,CO \rightarrow C_nH_{2n+2} + n\,H_2O$$

This process uses a catalyst to produce the hydrocarbon products. As before in liquefaction, the resulting products are hydrotreated, hydrocracked, and distilled for the final desired product of renewable diesel. See Figure A-4 for a flow diagram of the gasification and Fischer-Tropsch process.

Figure A-4. Gasification and Fischer-Tropsch production diagram for renewable diesel, from U.S. Department of Energy [516]



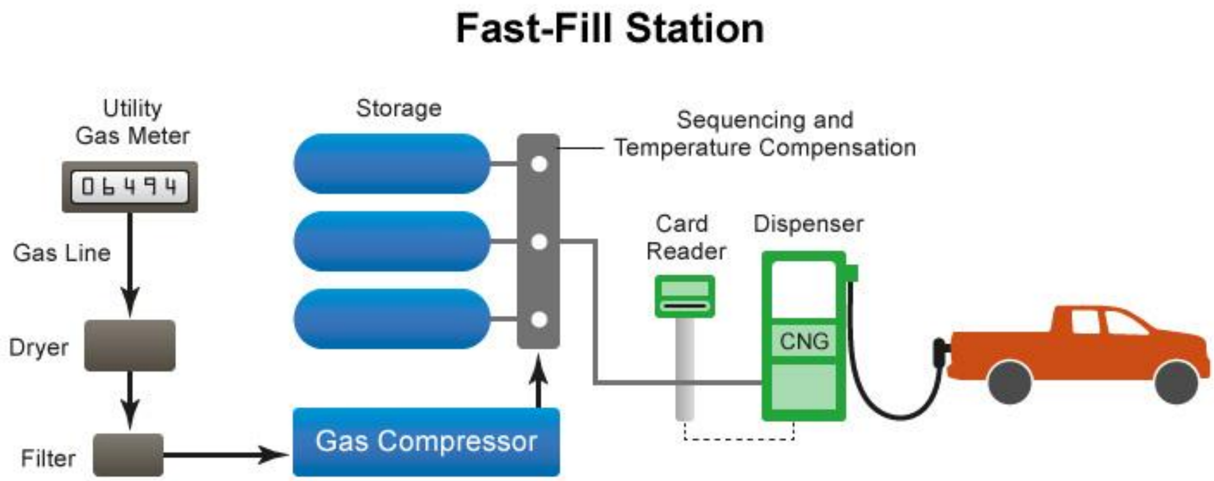
In pyrolysis, the dried biomass is pressurized to 1 to 5 atmospheres and heated up to 300-500^oC without an oxidant to produce bio-oils which are then refined to produce renewable diesel. Once again, the resultant bio-oil is hydrotreated, hydrocracked, and distilled to produce renewable diesel [68], [104]–[106].

In hydrolysis, the cellulose of biomass (a structural component of plant cell walls) is broken down by enzymes and water to produce hydrocarbons. These hydrocarbons can then be processed through the same hydrotreating, hydrocracking, and distilling to obtain renewable diesel. Like gasification, hydrolysis is relatively early in its development state. Unlike the other production methods, hydrolysis is a biochemical process due to the enzymes that convert the biomass [68], [104]–[106].

Fuel Dispensing: Substitute Natural Gas

A schematic representation of a SNG station is shown in Figure A-5, with the “gas line” input being the natural gas pipeline that is used for distribution of SNG. Recall that the hydrogen dispensing station is quite similar as well.

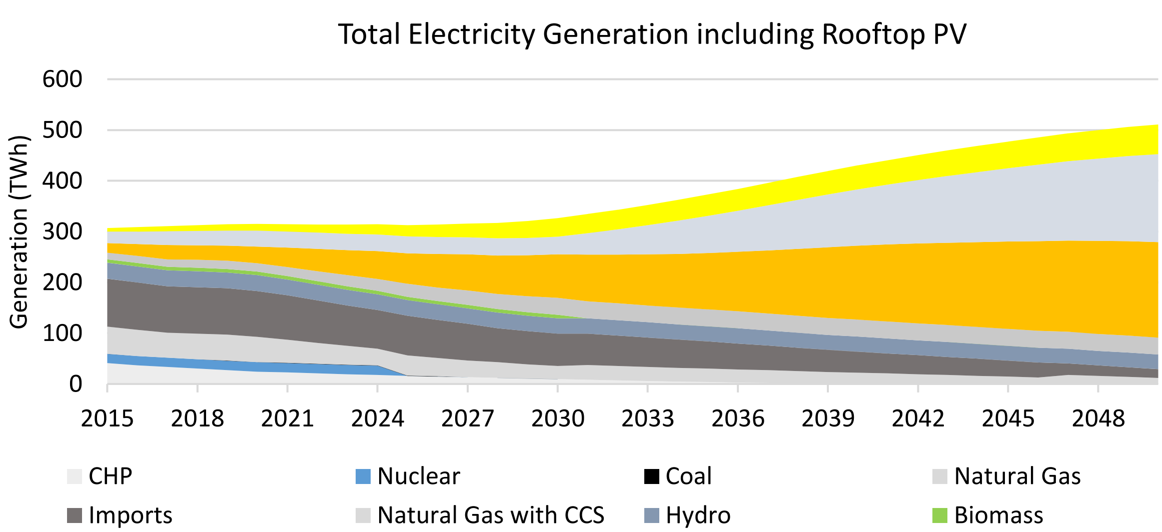
Figure A-5. SNG dispensing station schematic, from U.S. Department of Energy [517]



A.2 Heavy-Duty Vehicle Fuel Pathways Techno-Economics

A.2.1 Fuel Feedstocks: Electricity

Figure A-6. Electricity generation projections for California, from E3 PATHWAYS [41]

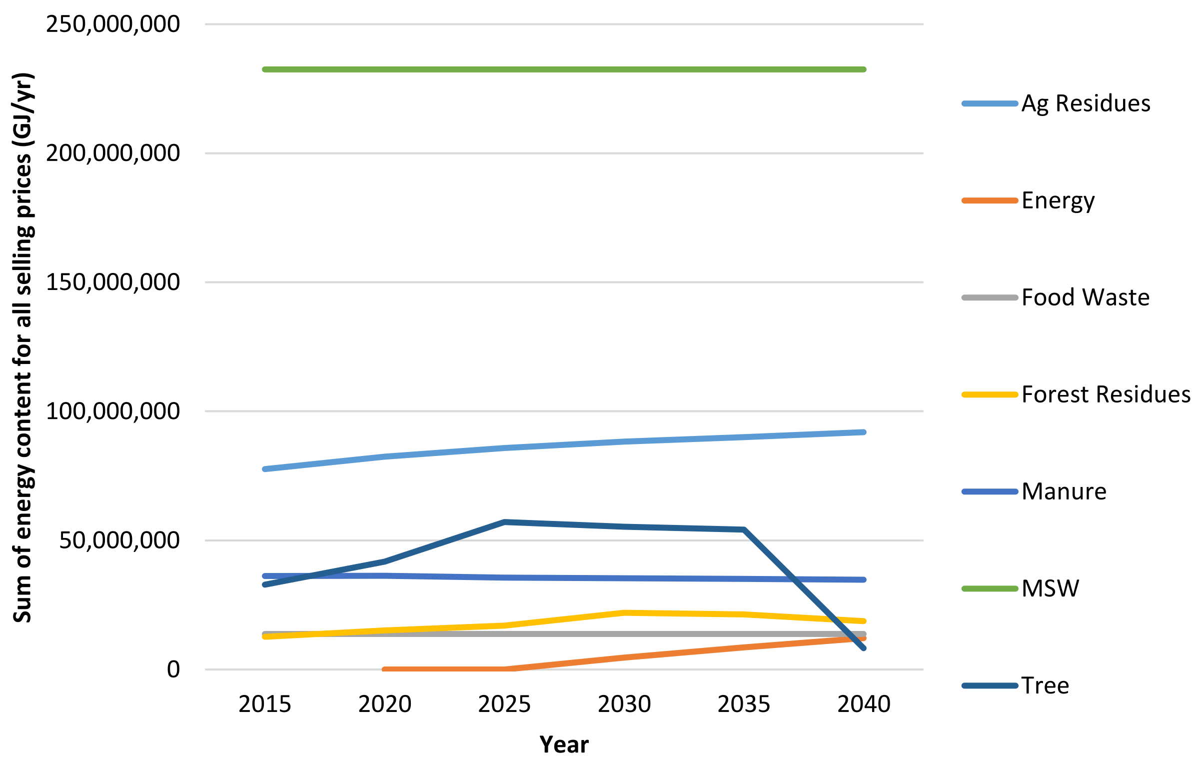


A co-feedstock one must consider with electrolytic fuels is water, as water is split to produce hydrogen and oxygen. Water can come from various sources, and it is scarcer in Southern California than Northern California. The Metropolitan Water District of Southern California lists water rates for water originating from Northern California at around $300 per acre-foot [518]. Using an average value from electricity costs of $0.0375/kWh, this leads to water accounting for on the order of 0.1% of total electrolytic fuel production (this involves data and calculations that are shortly to be detailed). Even at the extreme case of water produced by desalination, with the highest cost estimates of $5,000 per acre-foot [519], that leads to water costs of about 1.5% of total electrolytic fuel cost. Therefore, it is safe to assume water costs are insignificant for these electrolytic fuels, and water is not analyzed in the proceeding techno-economic work.

A.2.2 Fuel Feedstocks: Biomass

Here, a weighted average of heating value for the categories of food waste, manure, agriculture, waste, forestry, and energy crops is used to convert from dry ton of each individual biomass feedstock to energy content. Weighting is based on the capacity available according to the Billion Ton Report. Using the weighted average is justifiable for this conversion because the relative ratio of the specific biomass feedstocks within the above categories stays relatively similar throughout the years and prices considered, as shown in Figure A-7.

Figure A-7. Total biomass energy available by feedstock category, data from [40]



Some important notes from the biomass feedstock data are described below.

MSW is the feedstock with the highest availability, both at the lowest cost of $30/dry ton, as well as for every higher cost. This makes MSW an attractive biomass feedstock for the technologies that can use it, though emissions are another important factor that have yet to be discussed.

Energy crops, which are grown for energy purposes, do not show up as a feedstock option until 2030. Additionally, these energy crops are available only at the higher end of the cost scale, meaning they will not get used until the cheaper feedstocks are all used. Incentives could be introduced, like how corn is subsidized, but these incentives are outside the scope of the present work.

Tree biomass reaches a peak in 2025, slightly declines until 2035, and then dramatically reduces in 2040. One possible explanation for this is over-using this biomass in the earlier years and reduced forestation in future years, leading to less dead and fallen trees for use as a feedstock. This is an issue that should be further investigated to ensure sustainable use of this biomass feedstock.

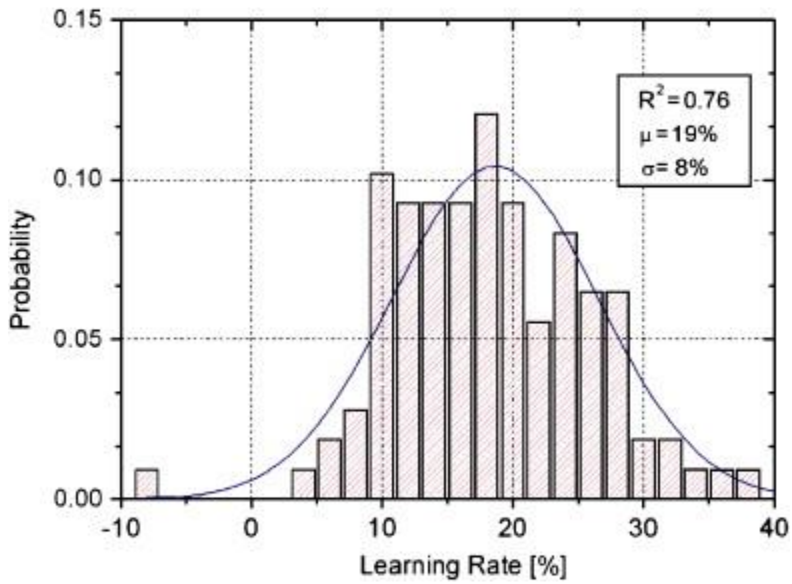
Lastly, some feedstocks have similar availabilities at all selling prices, while others have increasing availability as selling price increases. Crop types that do not increase in availability with selling price are food waste, forest residues, and manure. Crop types that do increase in availability with selling price are agriculture residues, energy crops, MSW, and trees. This behavior of increasing availability with selling price is indicative of the fact that increasing selling price opens the opportunity for more involved and costly extraction or collection procedures. For energy crops, which are expressly grown for energy uses, there is the additional factor that increasing selling price increases the number of market players willing to grow energy crops for profit. For the crop types that exhibit increased availability at increased selling price, all but energy crops increase in availability for the first two selling price increases, but thereafter stay constant in availability (or nearly constant in the case of agriculture residues). Energy crops have a more consistent increase in availability at increasing selling price, likely due to the above-mentioned factor of increasing market players.

Simplifications are made to reduce the number of separate cost brackets for each of the feedstocks. For example, agriculture residues are available at $30/dry ton up to $100/dry ton at different quantities for each $10/dry ton increment. However, looking at Figure 17, a reasonable simplification is to consider in 2020 that 5.8e7 GJ/yr of agriculture residues available for $30/dry ton, and 8e7 GJ/yr available for $50/dry ton. This is neglecting the slight increase in availability at $40/dry ton compared to $30/dry ton, and the slight increase in availability at prices higher than $50/dry ton. This same methodology is carried out for the rest of the years analyzed as well as the other feedstocks with varying availabilities at different costs.

A.2.3 Fuel Production

Figure A-8 shows the probability distribution of learning rates for various industrial technologies collected from 108 studies [121].

Figure A-8. Probability distribution of 108 studies that report learning rates in 22 industrial sectors from [121]



Fuel Production: Hydrogen

Table A- 1. Information on efficiency for SOEC, PEMEC, and AEC from literature

EC Type	Author	Year	Source Info	Stack LHV efficiency (%)
SOEC	Tang et al.	2016	[164]	83.9
	Ouweltjes et al.	2007	[165]	79-95
	Pan et al.	2017	[62]	73
	Paakkonen et al.	2018	[160]	95
PEMEC	Millet et al.	2010	[161]	71-72.5
	Gibson and Kelly	2008	[162]	75-77
	Siracusano et al.	2010	[163]	70
	Paakkonen et al.	2018	[160]	70
AEC	Campanari et al.	2009	[158]	60-90%
	Bolat and Thiel	2014	[159]	61-79%
	Paakkonen et al.	2018	[160]	70%

Two areas are important for cost: the first is current cost estimation, and the second is future cost projection. Literature was again consulted for these two areas, and the findings for current cost estimations are presented below.

Figure A-9. Information on cost for PEMEC and AEC versus time for references listed in Table 9

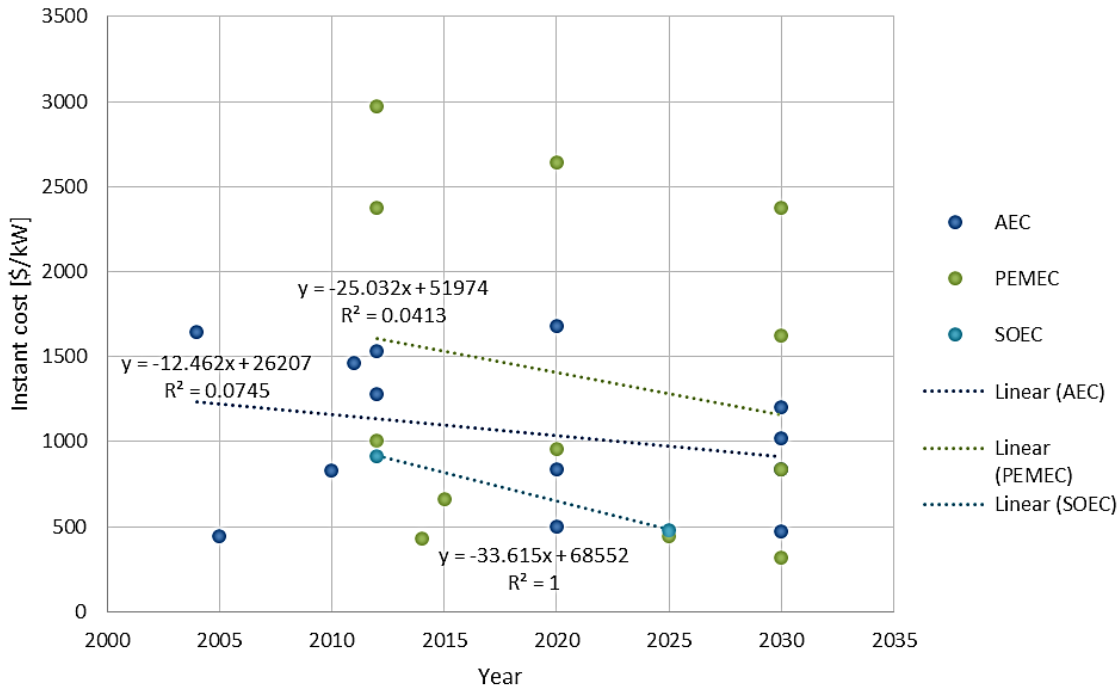
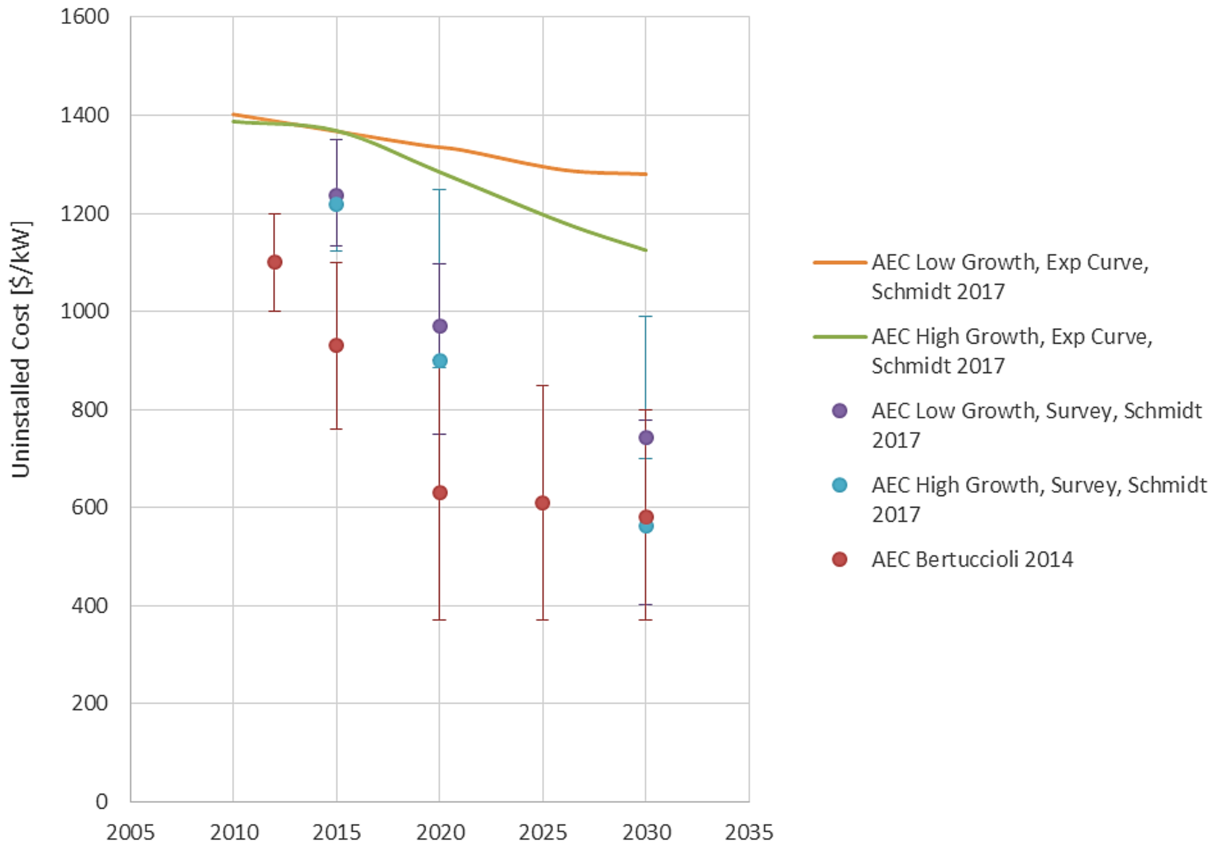


Table A- 2. Information on cost for PEMEC, SOEC, and AEC from literature

EC Type	Author	Year	Source Info	installed cost ($/kW)
SOEC	US DOE	2012	[192]	918
	US DOE	2025	[192]	481
PEMEC	Bertuccioli et al.	2012	[43]	2376-2970
	Bertuccioli et al.	2030	[43]	320-1626
	Godula-Jopek et al.	2015	[190]	665
	Schmidt et al.	2020	[150]	960-2640
	Schmidt et al.	2030	[150]	840-2376
	James (DOE, SAI)	2013	[189]	1008
	James (DOE, SAI)	2025	[189]	448
AEC	Mansilla et al.	2011	[188]	1464.
	Krewitt and Schmid	2005	[185]	445
	National Research Council	2004	[186]	1643
	Bertuccioli et al.	2012	[43]	1280-1536
	Bertuccioli et al.	2030	[43]	469-1024
	Schmidt et al.	2020	[150]	840-1680
	Schmidt et al.	2030	[150]	840-1200
	NEL/H2V Agreement	2020	[187]	~500

Figure A-10. More detailed information on cost for AEC versus time for [150] *and* [43] *to show difference between survey information and experience curve calculations*



Note that the cost for SOECs in the optimistic projection using the above learning rate methodology leads to very low future cost if production quantities are high enough. This is due to the learning rate methodology used and the projected cumulative SOEC production. Even early on, the SOEC costs decrease markedly due to early projected market size growth rates. To prevent SOEC costs from becoming unreasonably low, literature was consulted to determine the cost of an electrolyzer from a ground-up methodology, which would give end-game costs of the technology. Work from [193] determined the above for a solid oxide fuel cell, so the final cost per power capacity was divided by two to account for the same stack being able to operate at twice the power in electrolyzer mode compared to fuel cell mode. This is due to the fact that when a solid oxide cell is operated at a given current density, its voltage is approximately twice as high in electrolysis mode than in fuel cell mode, leading to twice the power for the same stack in electrolysis mode compared to fuel cell mode [191]. This methodology leads to a price floor for SOECs of $191/kW.

Figure A-11. Conservative projection of cost and representative electrolyzer market size

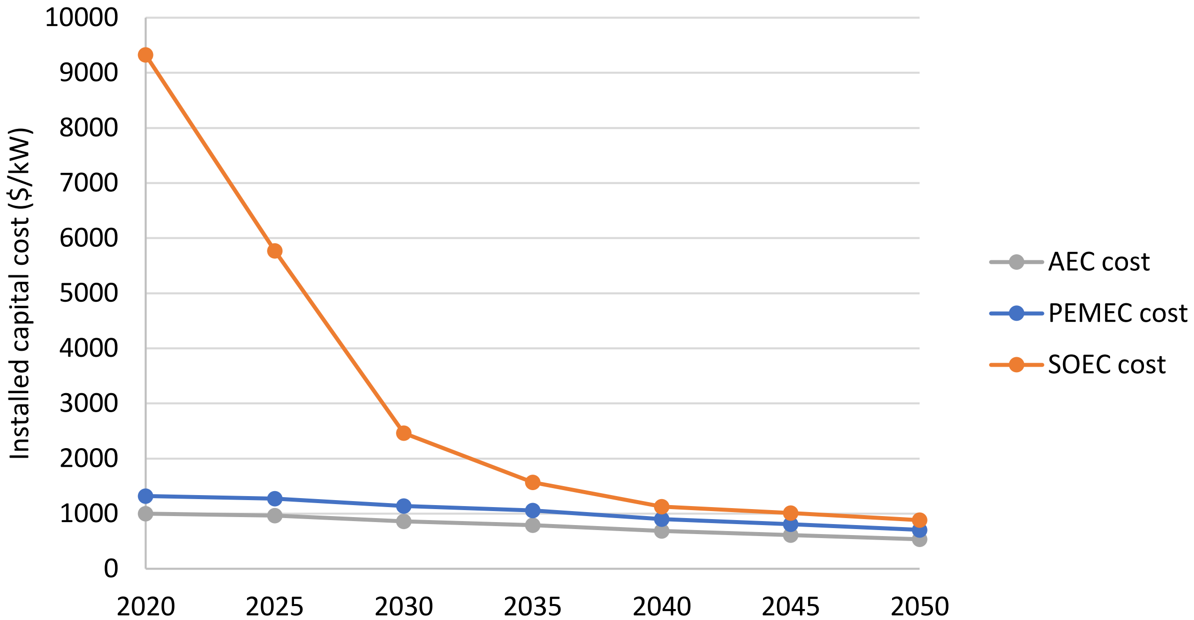


Table A- 3. Conservative projection of installed cost and representative electrolyzer market size

	AEC				PEMEC				SOEC			
	Pt [GW]	Ct [$/kW]	LR [%]		Pt [GW]	Ct [$/kW]	LR [%]		Pt [GW]	Ct [$/kW]	LR [%]	
2020	7.6	1000	14%		5.1	1320	14%		0.0011	9324	14%	
2025	9	964	14%		6	1274	14%		0.01	5768	14%	
2030	15	862	14%		10	1140	14%		0.5	2462	14%	
2035	22	794	14%		14	1060	14%		4	1566	14%	
2040	43	686	14%		29	904	14%		18	1129	14%	
2045	72	613	14%		48	810	14%		30	1010	14%	
2050	134	536	14%		90	707	14%		56	882	14%	

Figure A-12. Optimistic projection of installed cost and representative electrolyzer market size

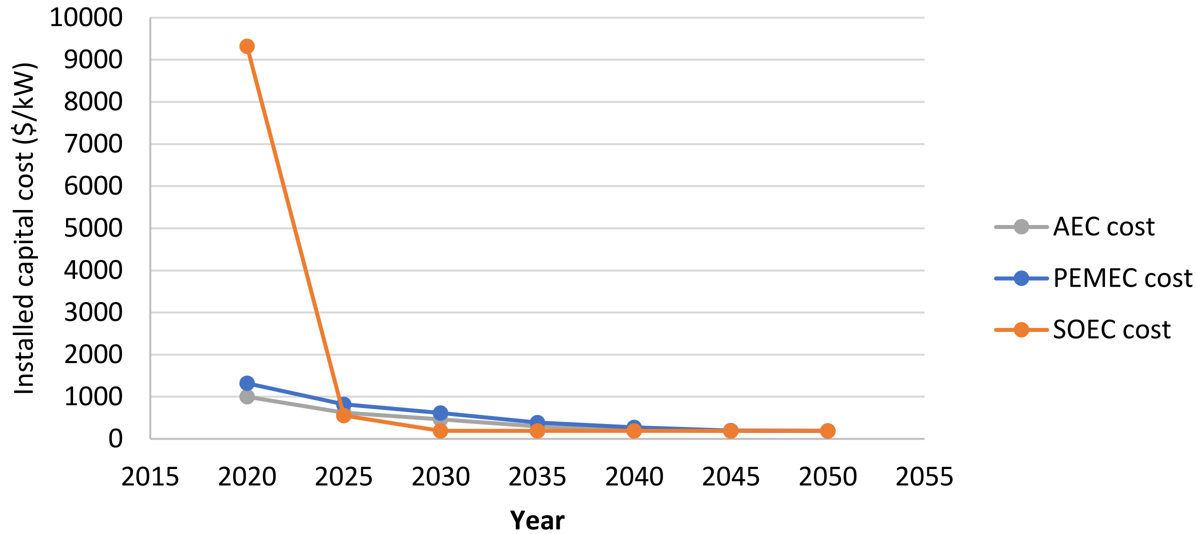


Table A- 4. Optimistic projection of installed cost and representative electrolyzer market size

	AEC			**PEMEC**			**SOEC**		
	Pt [GW]	**Ct [$/kW]**	**LR [%]**	**Pt [GW]**	**Ct [$/kW]**	**LR [%]**	**Pt [GW]**	**Ct [$/kW]**	**LR [%]**
2020	7.6	1000	25%	5.1	1320	25%	0.0011	9324	25%
2025	24	620	25%	16	821	25%	1	552	25%
2030	47.5	467	25%	31.68	619	25%	19.8	191	25%
2035	144	295	15%	96	390	15%	60	191	15%
2040	336	208	10%	223.68	275	10%	139.8	191	10%
2045	720	191	10%	480	200	10%	300	191	10%
2050	1313	191	10%	875.52	191	10%	547.2	191	10%

The projections are also shown alongside cost data from the literature as cited in Figure A-13 for the conservative scenario and Figure A-14 for the optimistic scenario. Note that the starting cost for SOECs is cropped out of frame to provide better perspective on the rest of the data.

Figure A-13. Conservative projection of installed cost compared with literature projections

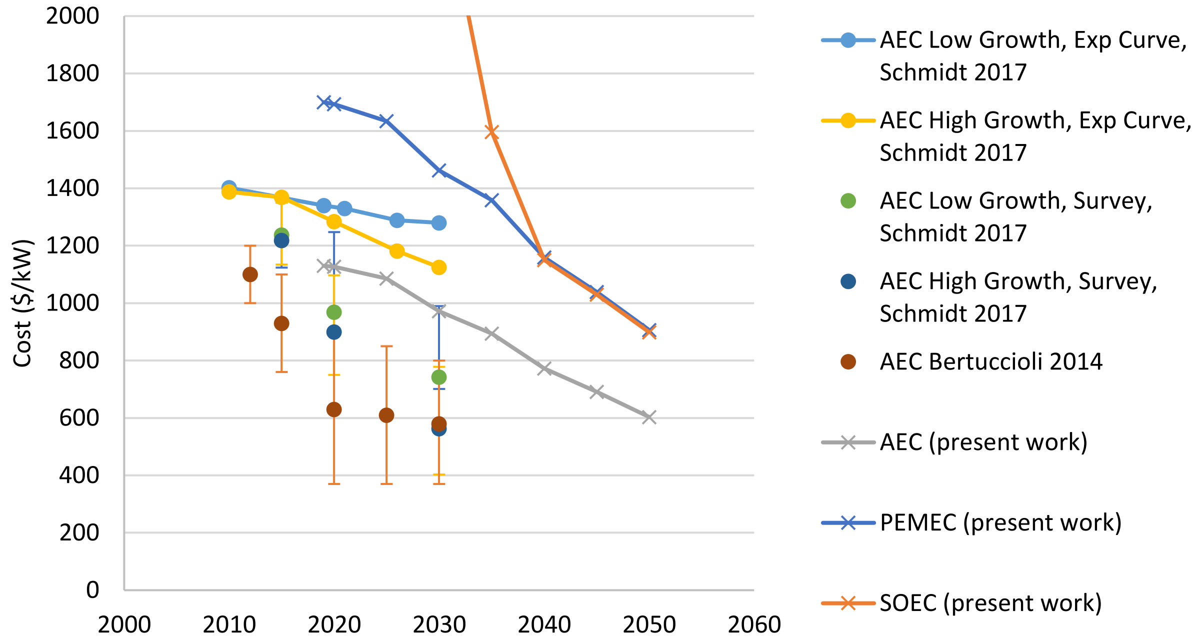
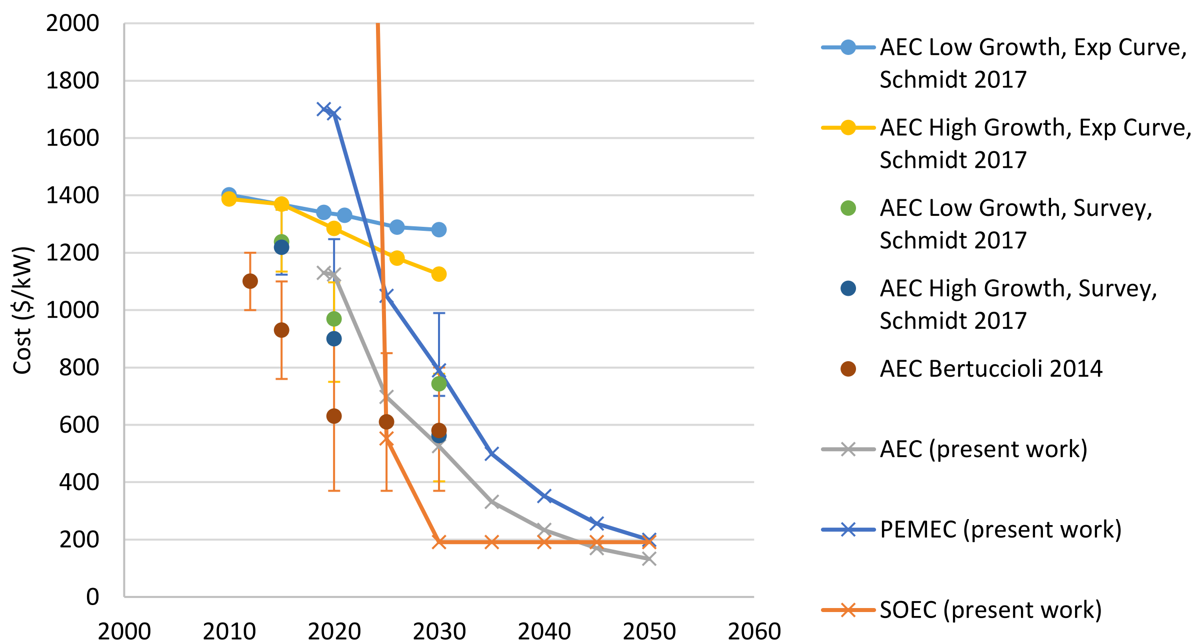


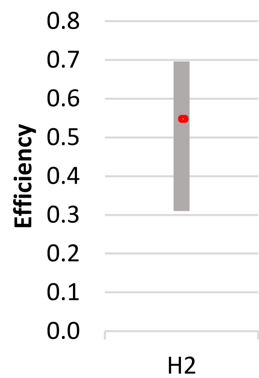
Figure A-14. Optimistic projection of installed cost compared with literature projections



Comparing the above projections to values from Schmidt et al. [150], the cost for AECs, PEMECs, and SOECs align well for 2020, with the conservative scenario yielding a value at the upper end of the ranges provided and the optimistic scenario yielding a value at the lower end of the ranges. For 2030, similar is true except for the optimistic SOEC scenario. In that scenario, the present work predicts a value that is slightly below the low range of values from Schmidt et al. [150]. Overall agreement between costs is encouraging here. Furthermore, the two scenarios (conservative and optimistic) bound the literature values well as originally intended.

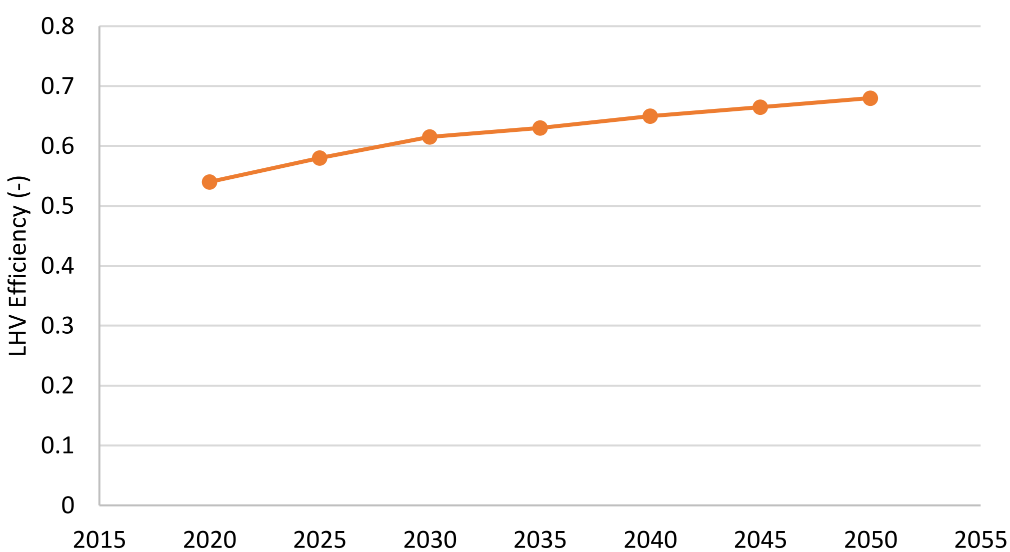
Shown in Figure A-15 are the range of values and the average for energetic efficiency of gasification technology for hydrogen production from the literature. Sources for the range of values are the following: [46], [47], [56], [57], [48]–[55].

Figure A-15. Gasification efficiency ranges and average for hydrogen production, data from [46], [47], [56], [57], [48]–[55]



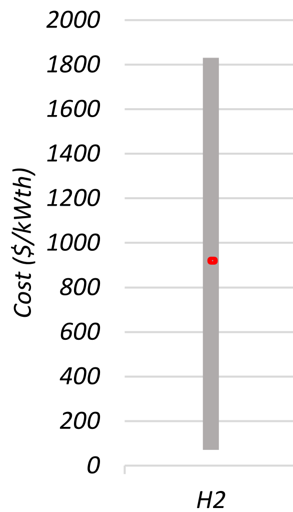
The method used for projecting gasification efficiency for hydrogen production is to start with the average literature value of 0.54 in 2020 and reach the high efficiency estimates by 2050. Progress is assumed to be about half by 2035. The modeled efficiency projections are shown in Figure A-16.

Figure A-16. Efficiency projections of gasification for hydrogen production



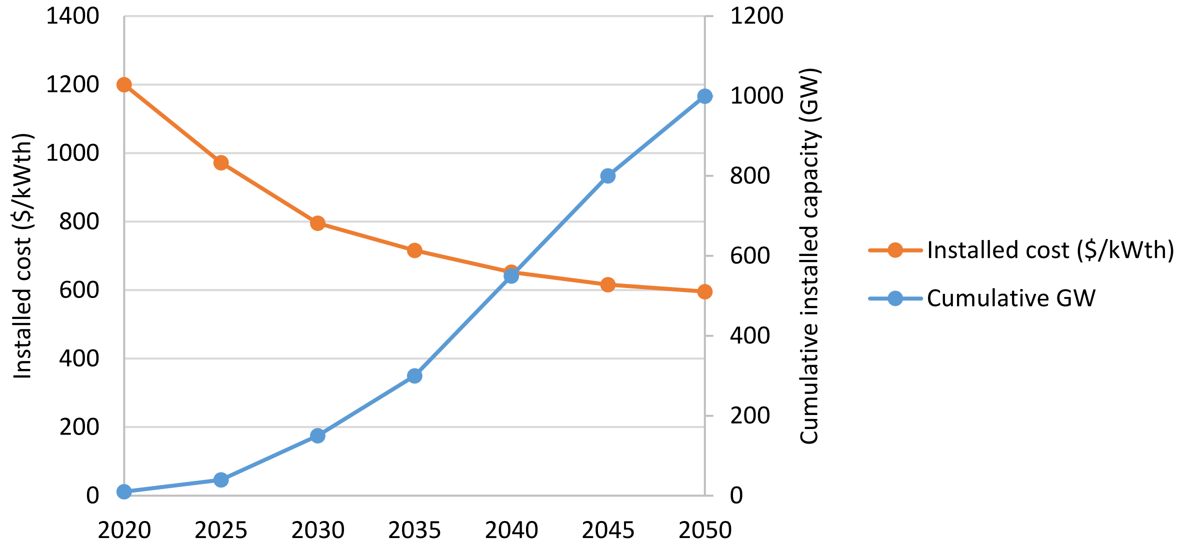
The cost range from the same literature cited for efficiency are shown Figure A-17, with the following sources: [46], [47], [56], [57], [48]–[55].

Figure A-17. Gasification cost ranges and average for hydrogen production, data from [46][47][48], [49][50]–[57]



The value used in modeling as the starting cost in 2020 is $1200/kW as some of the stronger references are around that value. Projections for the capital cost are calculated using the same learning rate methodology used for electrolytic technology described previously, using a learning rate of 10% due to the technology being a simpler and more mature and less likely to decrease drastically in cost compared to electrolyzer technologies. Representative cost projections are shown below. As with the electrolyzers, the production capacities and the years in which those are achieved are shown merely for illustrative purposes to display how installed cost is affected by cumulative installed capacity. Again, the modeling methodology introduced in Task 3 will dictate the actual capacities of this work.

Figure A-18. Cost projection for gasification production of hydrogen



FOM is estimated as $40/kW-yr and VOM is estimated as $6/kWh, using the same literature sources from which the capital costs are sourced [46][47][48], [49][50]–[57].

Fuel Production: Substitute Natural Gas

SNG can start much in the same way as hydrogen, but with the additional step of methanation. The required data for hydrogen are the same as electrolytic hydrogen production as previously detailed. The following is for the methanation requirement, which would be added on top of the electrolytic hydrogen production. SNG can also be made through AD and gasification.

SNG produced by electrolyzers (and the accompanying methanation equipment) and gasifiers are by plants of the scale of 50 MW. The AD plant is smaller, on the order of 500 kW.

Methanation efficiency is 79% as calculated previously in the Electrolytic SNG section of the Background. The efficiency drop for the carbon capture technology is neglected as the power requirement is small compared to that of the electrolyzer. Therefore, the overall efficiency of converting the electrolytic hydrogen to SNG is 79%.

The supporting P2G equipment cost is determined using the same learning rate methodology as for the electrolyzers. For these technologies, the learning rate is assumed to be 10% for the conservative scenario and 14% for the optimistic scenario as previously noted.

In Table A-5, the installed methanator capacities shown are determined by the capacity required for methane production corresponding to the installed electrolyzer capacity (which again is merely a hypothetical example to illustrate the dependence of cost on production). Capacities are given as GW of SNG output.

Table A- 5. Methanator cost projections by market size

	Methanator, conservative		**Methanator, optimistic**	
	Pt [GW]	Ct [$/kW]	Pt [GW]	Ct [$/kW]
2020	7.60	339.18	7.60	338.83
2025	8.99	330.68	24.55	262.56
2030	15.27	305.08	59.27	216.74
2035	23.95	284.90	179.61	170.28
2040	53.88	251.86	418.48	141.65
2045	89.803	233.05	898.03	119.97
2050	167.63	211.95	1638.00	105.26

For carbon capture technologies, which capture the carbon dioxide needed for the methanation reaction, the average electricity input required for the three carbon capture technologies is used to get a fleet-wide installed capacity. In Table A-6 and Table A-7, the installed carbon capture capacities shown are determined by the capacity required for methane production corresponding to the installed electrolyzer capacity. Capacities are given as GW of electricity input. Carbon capture cost is determined using the same learning rate methodology as for the electrolyzers, with a learning rate of 10% for the conservative scenario and 14% for the optimistic scenario. Two different costs are used at the initial year of 2020. For the conservative scenario, a high cost value from the literature is used. For the optimistic scenario ofA-7, an average cost value from the literature is used. Note that E-CEM, which is a low TRL technology, has only one initial cost associated with it as literature data is scarce.

Table A- 6. Conservative projection of carbon capture technology cost by market size

	E-cem, conservative		**pcc, conservative**		**dac, conservative**	
	Pt [GW]	**Ct [$/tonCO2/d]**	**Pt [GW]**	**Ct [$/tonCO2/d]**	**Pt [GW]**	**Ct [$/tonCO2/d]**
2020	0.2238	1.82E+06	0.2238	6.35E+04	0.2238	4.55E+05
2025	0.2645	1.77E+06	0.2645	6.19E+04	0.2645	4.44E+05
2030	0.4493	1.63E+06	0.4493	5.71E+04	0.4493	4.09E+05
2035	0.7048	1.53E+06	0.7048	5.33E+04	0.7048	3.82E+05
2040	1.5859	1.35E+06	1.5859	4.71E+04	1.5859	3.38E+05
2045	2.6432	1.25E+06	2.6432	4.36E+04	2.6432	3.13E+05
2050	4.9339	1.13E+06	4.9339	3.97E+04	4.9339	2.84E+05

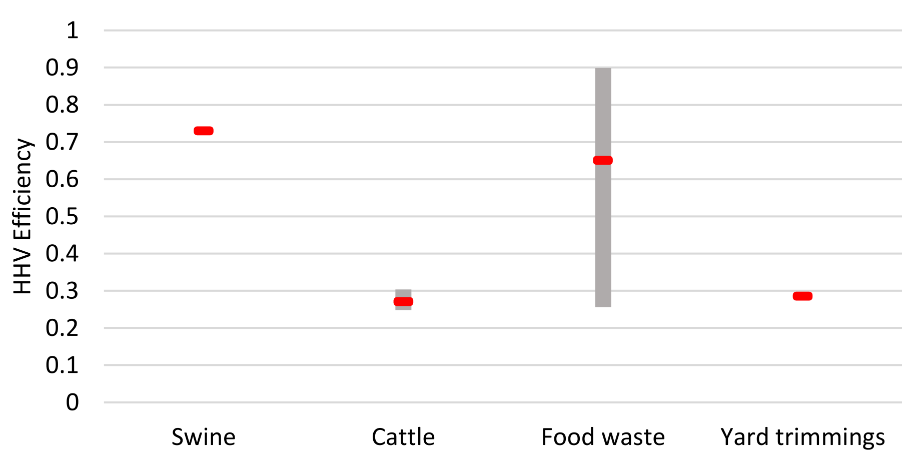
Table A- 7. Optimistic projection of carbon capture technology cost by market size

	E-cem, optimistic		pcc, optimistic		dac, optimistic	
	Pt [GW]	**Ct [$/tonCO2/d]**	**Pt [GW]**	**Ct [$/tonCO2/d]**	**Pt [GW]**	**Ct [$/tonCO2/d]**
2020	0.2238	1.81E+06	0.2238	4.36E+04	0.2238	3.15E+05
2025	0.7225	1.41E+06	0.7225	3.38E+04	0.7225	2.44E+05
2030	1.7445	1.16E+06	1.7445	2.79E+04	1.7445	2.01E+05
2035	5.2864	9.12E+05	5.2864	2.19E+04	5.2864	1.58E+05
2040	12.3173	7.58E+05	12.3173	1.82E+04	12.3173	1.32E+05
2045	26.4319	6.42E+05	26.4319	1.54E+04	26.4319	1.11E+05
2050	48.2117	5.64E+05	48.2117	1.35E+04	48.2117	9.77E+04

VOM for all scenarios, including the methanator, carbon capture source, and heat sink, is $0.01/kWh. FOM is estimated as $200/kW-yr for E-CEM scenarios, $10/kW-yr for PCC scenarios, and $8/kW-yr for direct air capture scenarios [154], [195], [196].

The efficiency of anaerobic digestion (AD) to produce SNG depends on the feedstock. Generally, the feedstocks are broken into two categories: (1) manure and (2) organic material. Efficiency estimates from the literature for each of these categories are shown in Figure A19, using data from [71], [169], [178]–[183], [170]–[177]. Note that swine and cattle both refer to types of manure, while food waste and yard trimmings are both organic material.

Figure A-19. Efficiency of anaerobic digestion, categorized by feedstock, with data from [71], [169], [178]–[183], [170]–[177]



The method used for projecting AD efficiency is to start with an average literature value in 2020 and reach the reasonable high efficiency estimates by 2050. Progress is assumed to be about half by 2035.

Figure A-20. Efficiency projections for anaerobic digestion of manure feedstocks

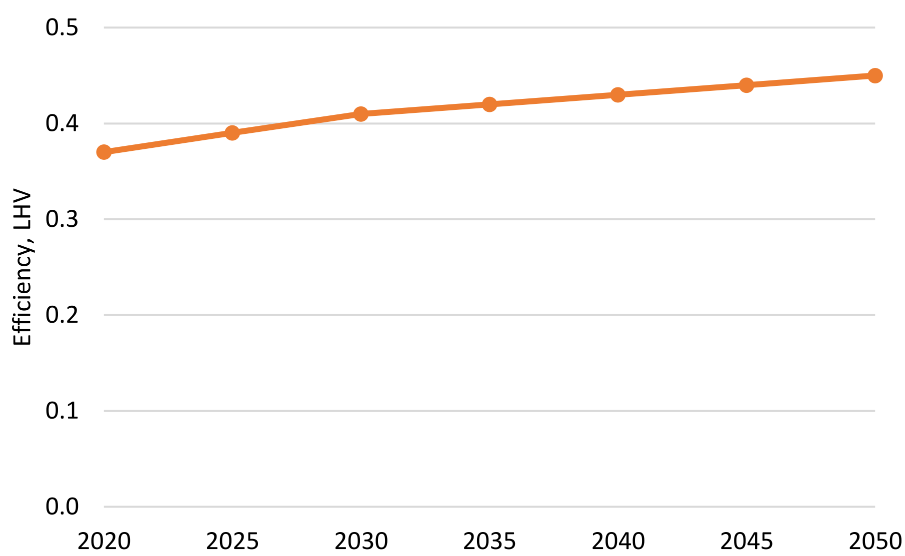
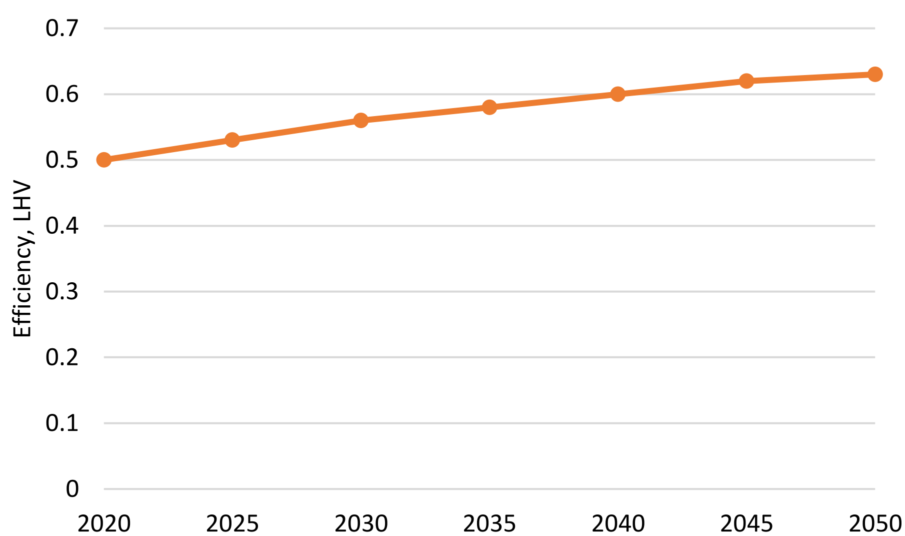
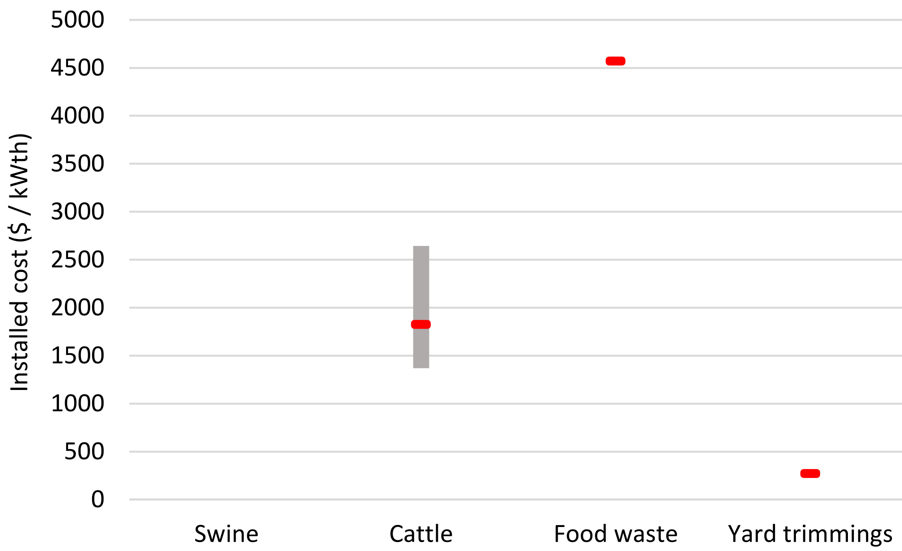


Figure A-21. Efficiency projections for anaerobic digestion of organic feedstocks



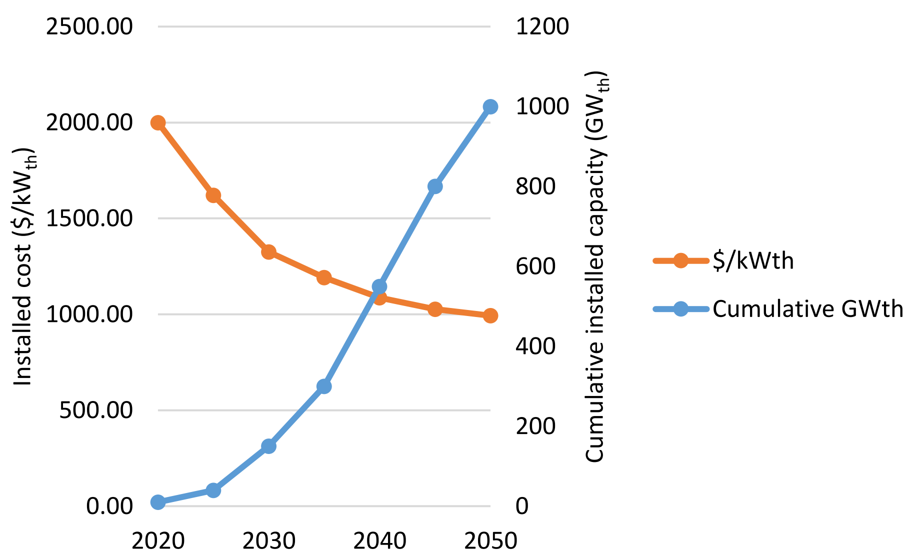
The cost data from the literature, also with distinction between feedstocks, are taken from [71], [169], [176]–[179], [197]–[200]. Note the very wide range of organic material AD cost in the literature.

Figure A-22. Installed cost of anaerobic digestion, categorized by feedstock, data from [71], [169], [176]–[179], [197]–[200]



Projections for AD costs take an average value of $2,000 per kW as the starting cost in 2020 for both manure and organic feedstocks. Again, the learning rate is modeled as 10%, and the cumulative installed capacities are merely examples to show how cost depends on capacity.

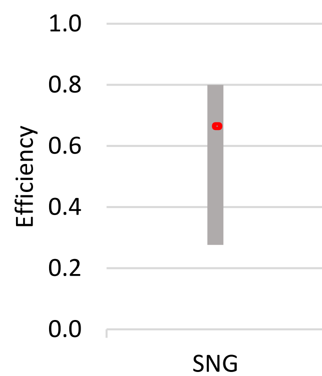
Figure A-23. Cost projections for anaerobic digestion



FOM for AD is modeled as $60/kW-yr and $0.01/kWh [71], [169], [176]–[179], [197]–[200]

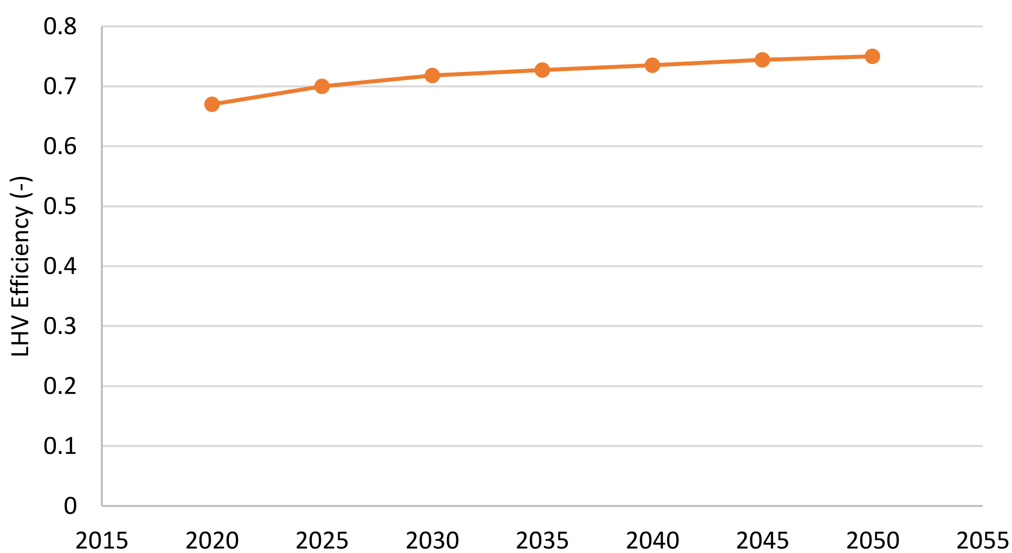
Next, onto gasification to produce SNG. Shown in Figure A-24 are the range of values and the average for energetic efficiency of gasification technology from the literature, specified by the fuel being produced. Sources for the SNG production data are the following: [73], [74], [83]–[91], [75]–[82][92], [93], [102], [103], [94]–[101]. The value used in modeling is 0.67. Again, a 50MW plant is used for design.

Figure A-24. Gasification efficiency ranges and average for SNG production, data from [73], [74], [83]–[91], [75]–[82][92], [93], [102], [103], [94]–[101]



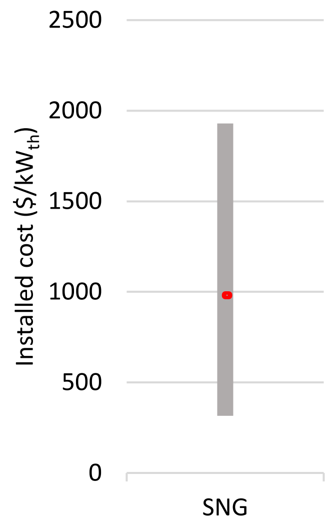
The method used for projecting gasification efficiency for SNG production is to start with the average literature value in 2020 and reach the reasonable high efficiency estimates by 2050. Progress is assumed to be about half by 2035.

Figure A-25. Efficiency projections for gasification for SNG production



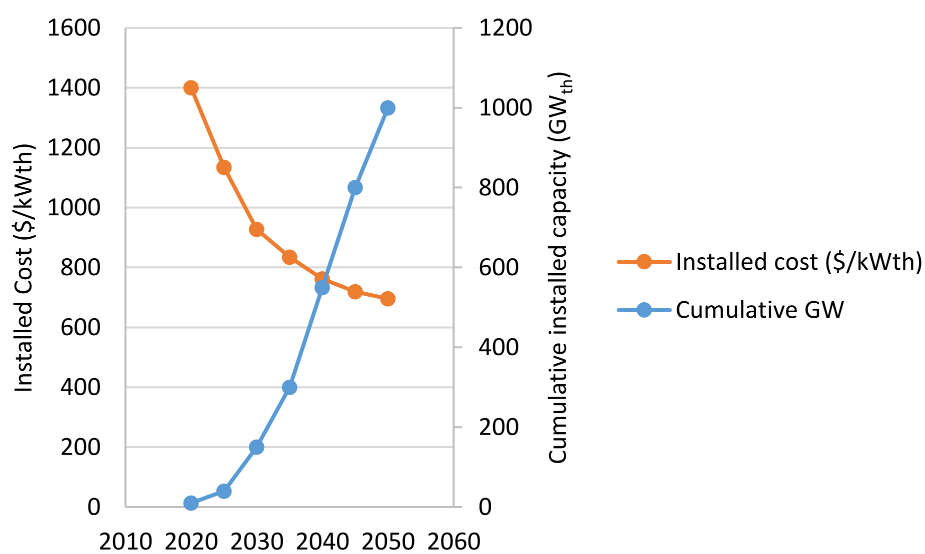
The cost range from the same literature cited for efficiency are shown in Figure A-26, with sources being the following literature: [71], [169], [176]–[179], [197]–[200]

Figure A-26. Gasification cost ranges and average for SNG production, data from [71], [169], [176]–[179], [197]–[200]



The value used in modeling is $1400/kW. The learning rate is taken to be 10% as for gasification with hydrogen as a product and hypothetical installed capacity growth for illustrative purposes.

Figure A-27. Cost projections for gasification for SNG production



FOM is estimated as $60/kW-yr and VOM is estimated as $0.013/kWh, using the same literature sources.

Fuel Production: Renewable Diesel

The numbers stated for efficiency and cost of the following renewable gasoline and diesel production methods are for plants on the order of 50 MW. There are limited data for efficiency projections into the future, so it is assumed there is a 2% efficiency improvement every 5 years for each of these production technologies, which is comparable to the improvements of the electrolyzer, gasifier, and AD equipment.

Note the brevity of the proceeding sections is due to the use of the same methodologies introduced in detail in the preceding sections, so there is no need to repeat.

The starting efficiency of liquefaction is modeled as 60% from Laser et al. [51], and a 2% efficiency improvement every 5 years is assumed. The starting cost for liquefaction is modeled as $1440.25 per kW input from Zhu et al. [201], and the learning rate is taken to be 10%.

The starting efficiency of gasification followed by FT is modeled as 55% from Laser et al. [51], and a 2% efficiency improvement every 5 years is assumed. The starting cost for liquefaction is modeled as $1,440.25 per kW input from Zhu et al. [201], and the learning rate is taken to be 10%.

The starting efficiency of pyrolysis is modeled as 0.6 from Laser et al. and Jahirul et al. [51], [184], and a 2% efficiency improvement every 5 years is assumed. The starting cost for pyrolysis is modeled as $817.43 per kW input from Vasalos et al. [203], and the learning rate is taken to be 10%.

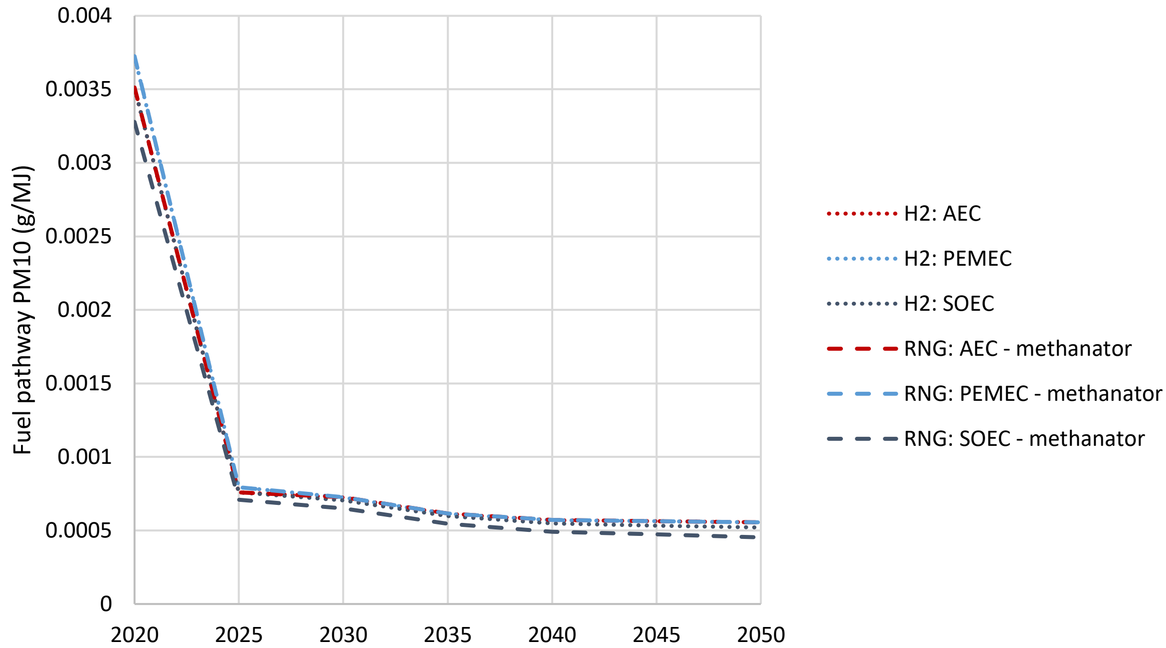
The starting efficiency of hydrolysis is modeled as 55% from Laser et al. [51], and a 2% efficiency improvement every 5 years is assumed. The starting cost for pyrolysis is modeled as $4,680 per kW input from Zhao et al.[202], and the learning rate is taken to be 10%.

A.2.4 Total Fuel Pathway Emissions

The PM_{10} emission factors for the electrolytic, gasifier, and AD production technologies are shown in Figure A-28, Figure A-29, and Figure A-30, respectively. The electrolytic fuel pathway PM_{10} emission factors shown are for the conservative efficiency projections. Results for the optimistic pathways are generally very similar, with up to 6.3% lower PM_{10}.

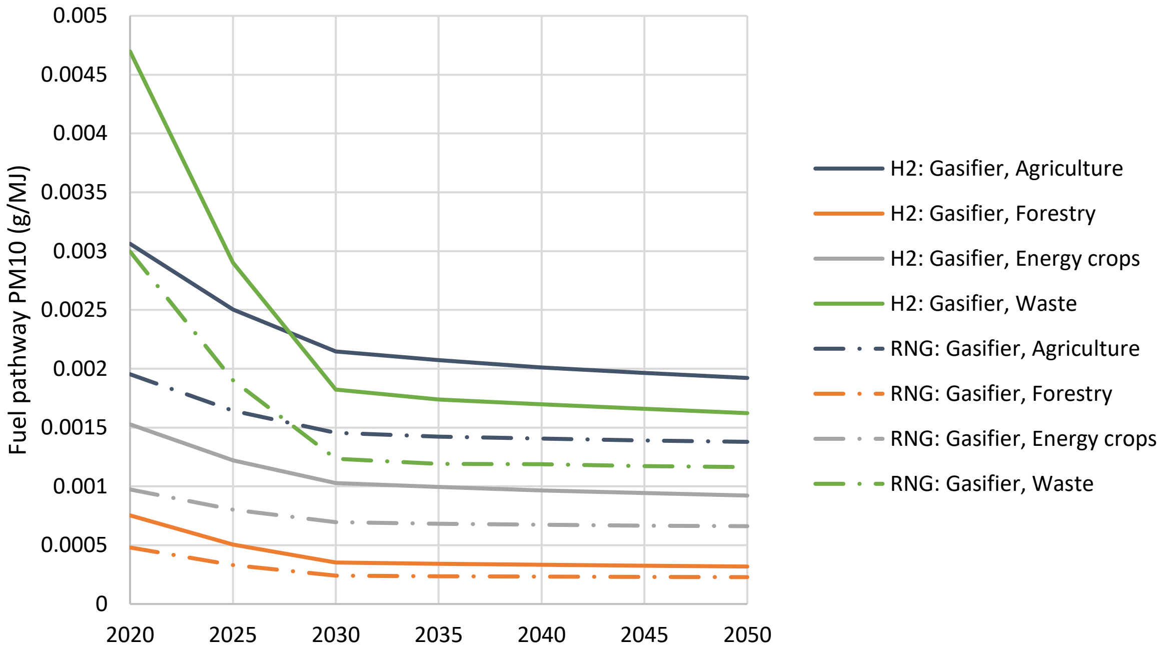
For electrolytic fuel pathways, unlike for carbon, there is no corresponding requirement for zero PM_{10} emissions by 2045. However, dramatic PM_{10} emissions reduction is projected by 2025, due primarily to reductions in from the electric grid rather than electrolyzer efficiency improvements. Minor reductions thereafter are due to electrolyzer efficiency improvements

Figure A-28. Electrolytic fuel pathway PM_{10} emission factors



For gasifier fuel pathways, PM_{10} emission factor trends closely mirror those of NO_x emission factor trends. All pathways generally follow the same trend in PM_{10} reduction over time, with most improvements occurring between 2020 and 2030, but the waste feedstock in particular is projected to have dramatic reductions by 2030. The more significant reductions from 2020 to 2030 are due primarily to improvements in biomass feedstock processes, while the more modest improvements from 2030 and beyond are due to gasifier efficiency improvements.

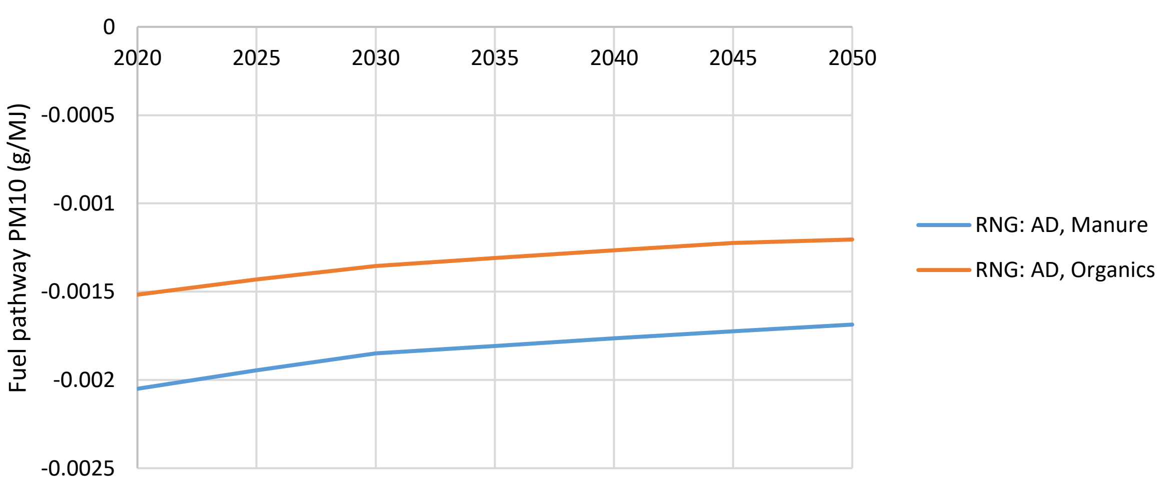
Figure A-29. Gasifier fuel pathway PM_{10} emission factors



For anaerobic digester fuel pathways, the PM_{10} emission factor trends closely mirror those of NO_x emission factor trends with one notable exception: these PM_{10} emission factors are negative rather than positive. Therefore, any reduction in PM_{10} emission factor caused by pathway efficiency improvement leads to less of a PM_{10} benefit through that fuel's adoption, something that may be counterintuitive.

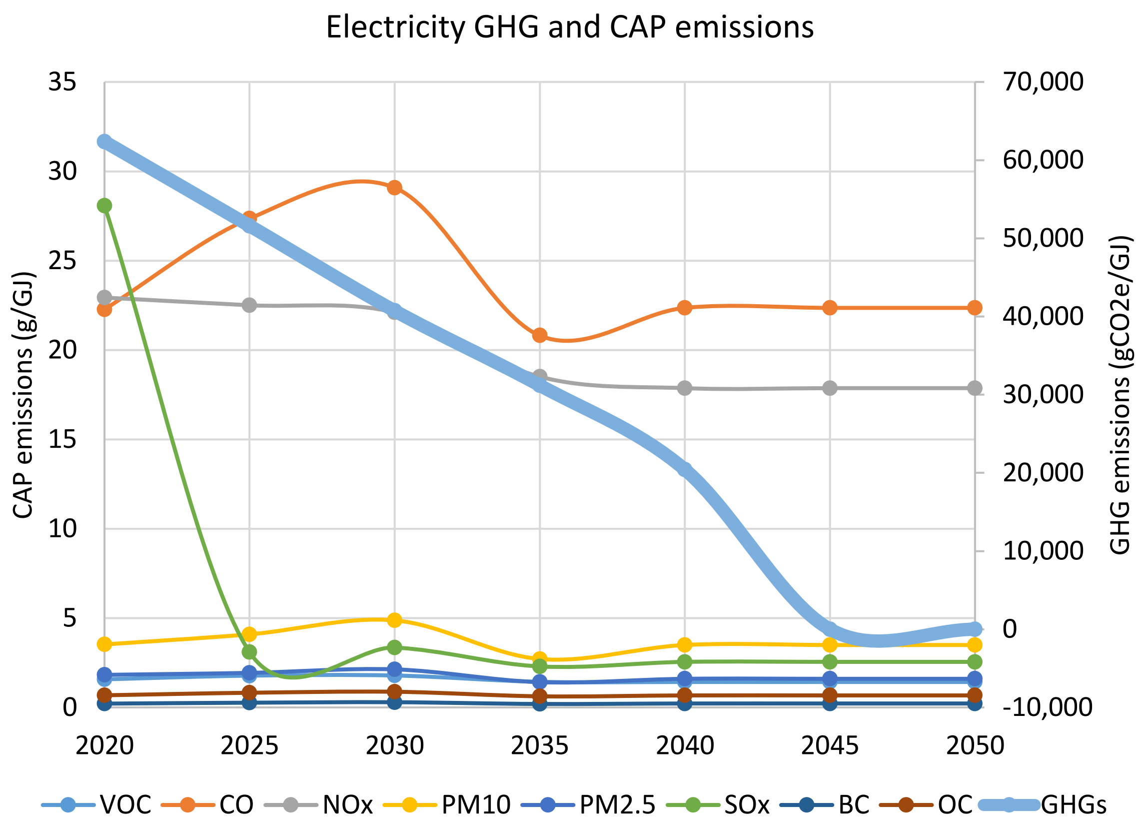
Negative PM_{10} emission factors are due that feedstock's use and processing for fuel leading to lower total PM_{10} emissions than would have occurred naturally if that feedstock had stayed untouched.

Figure A-30. Anaerobic digester fuel pathway PM_{10} emission factors

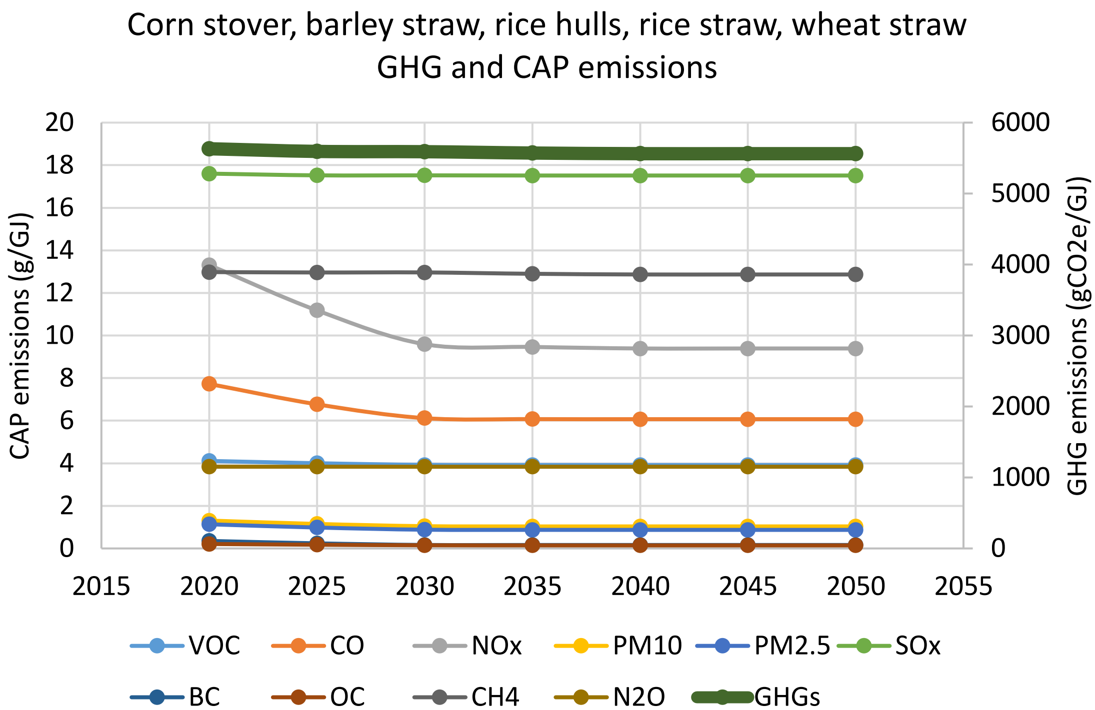


The following plots of Figure A-31 summarize the GHG and CAP emissions of each of the individual feedstocks used, with sources as cited.

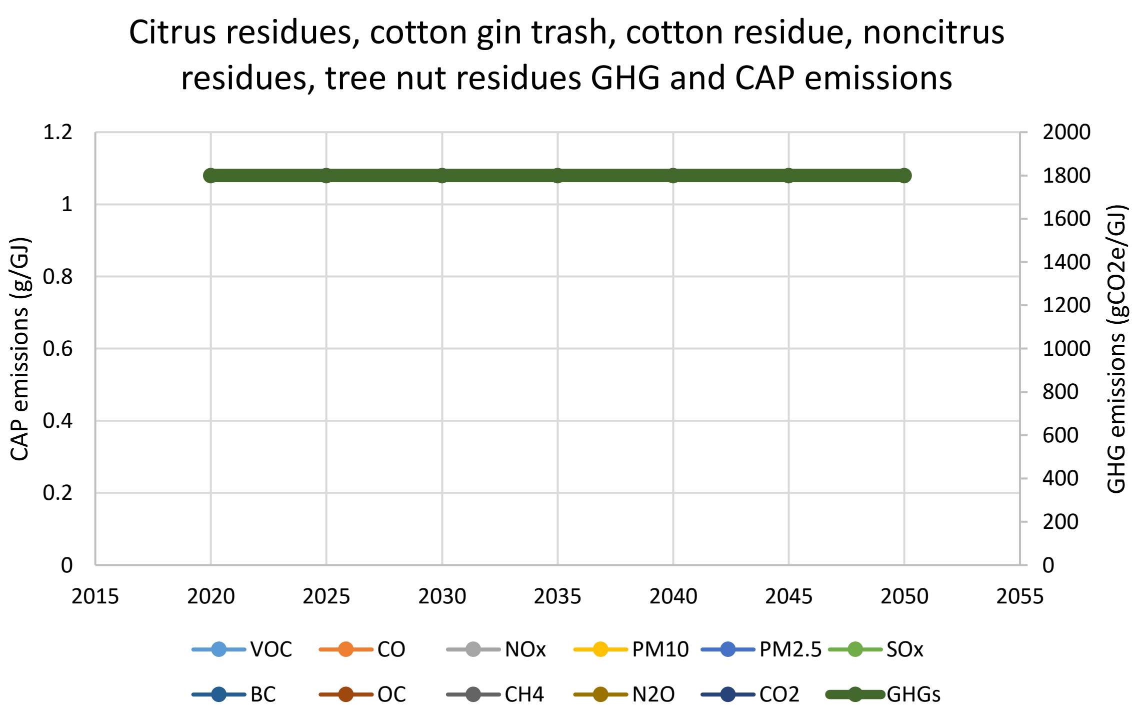
Figure A- 31. Electricity and biomass GHG and CAP emissions, data from [23], [40]–[42], [218], [219]



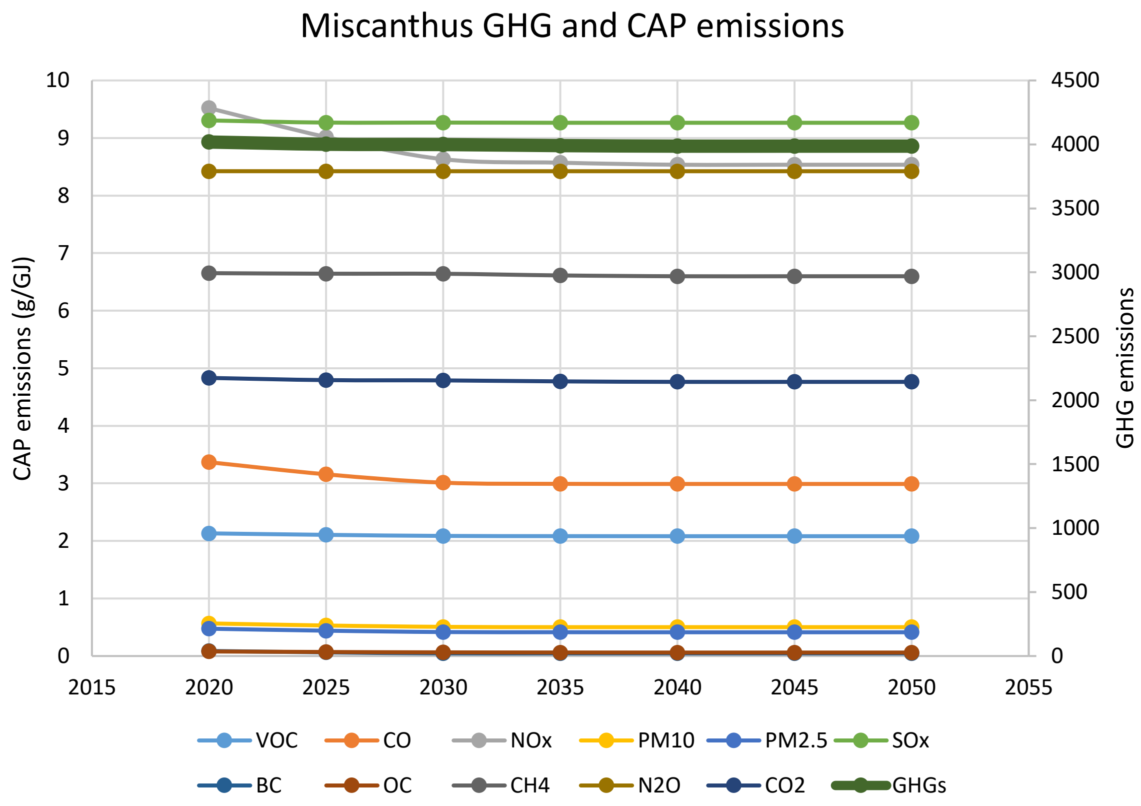
a)


Corn stover, barley straw, rice hulls, rice straw, wheat straw GHG and CAP emissions
CAP emissions (g/GJ)
GHG emissions (gCO2e/GJ)
20
18
16
14
12
10
8
6
4
2
0
6000
5000
4000
3000
2000
1000
0
2015
2020
2025
2030
2035
2040
2045
2050
2055
VOC
CO
NOx
PM10
PM2.5
SOx
BC
OC
CH4
N2O
GHGs

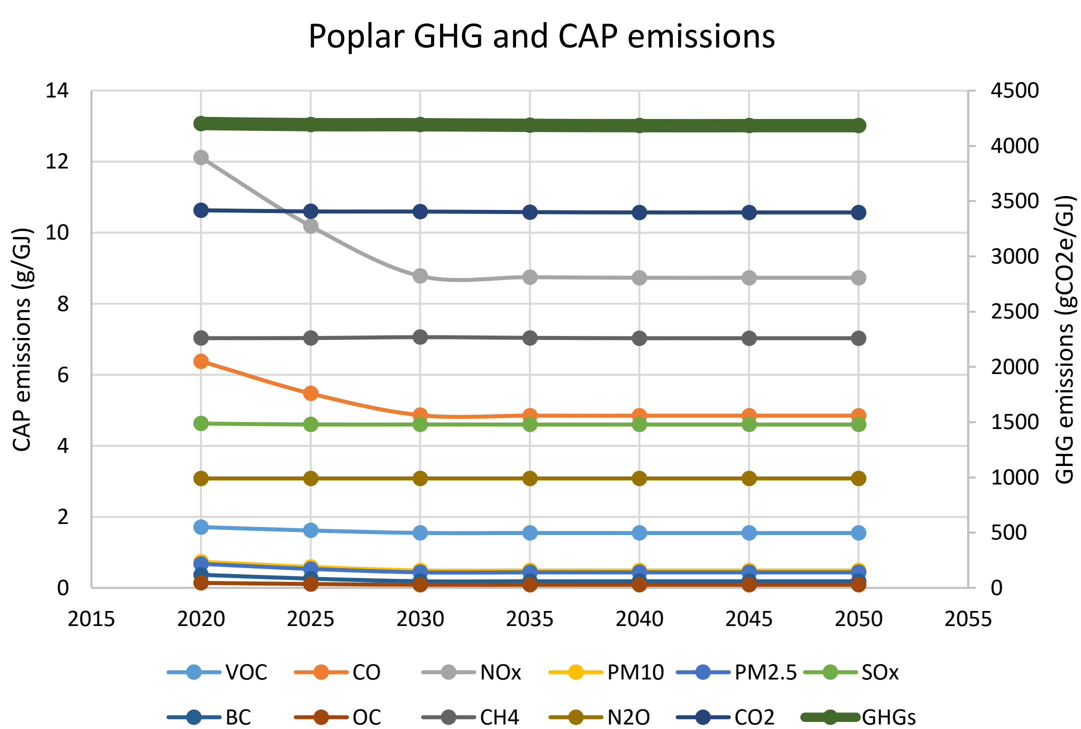
b)


Citrus residues, cotton gin trash, cotton residue, noncitrus residues, tree nut residues GHG and CAP emissions
CAP emissions (g/GJ)
GHG emissions (gCO2e/GJ)
1.2
1
0.8
0.6
0.4
0.2
0
2000
1800
1600
1400
1200
1000
800
600
400
200
0
2015
2020
2025
2030
2035
2040
2045
2050
2055
VOC
CO
NOx
PM10
PM2.5
SOx
BC
OC
CH4
N2O
CO2
GHGs

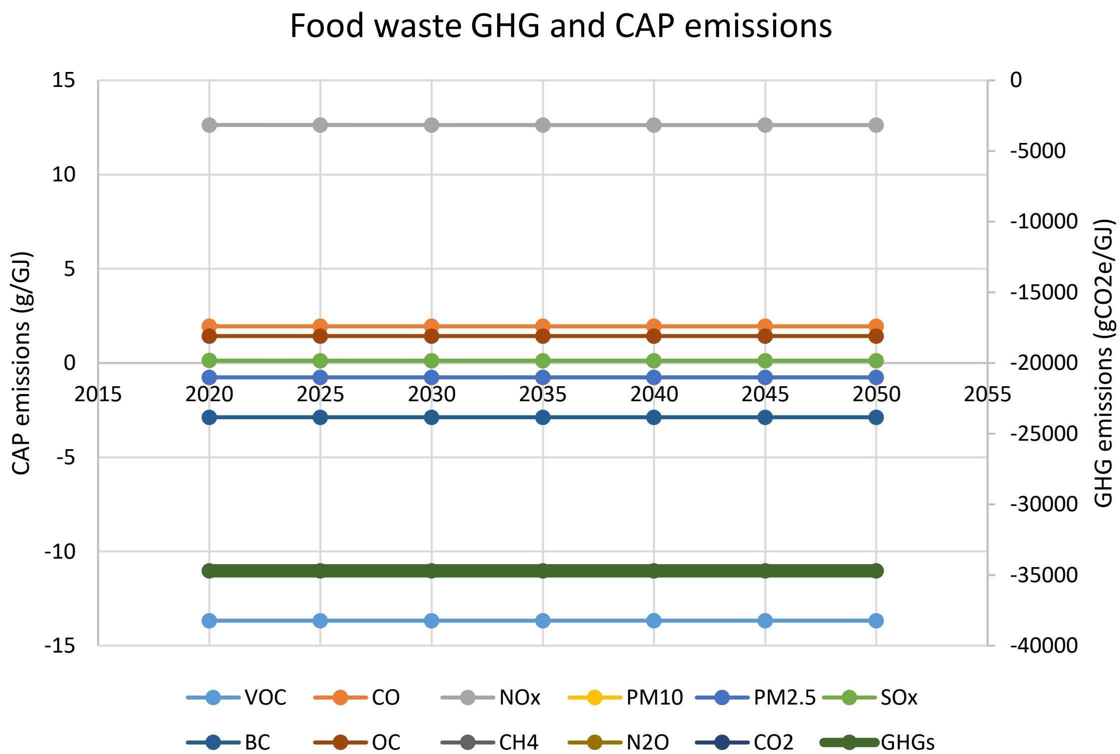
c)


Miscanthus GHG and CAP emissions
CAP emissions (g/GJ)
GHG emissions
0
1
2
3
4
5
6
7
8
9
10
0
500
1000
1500
2000
2500
3000
3500
4000
4500
2015
2020
2025
2030
2035
2040
2045
2050
2055
VOC
CO
NOx
PM10
PM2.5
SOx
BC
OC
CH4
N2O
CO2
GHGs

d)

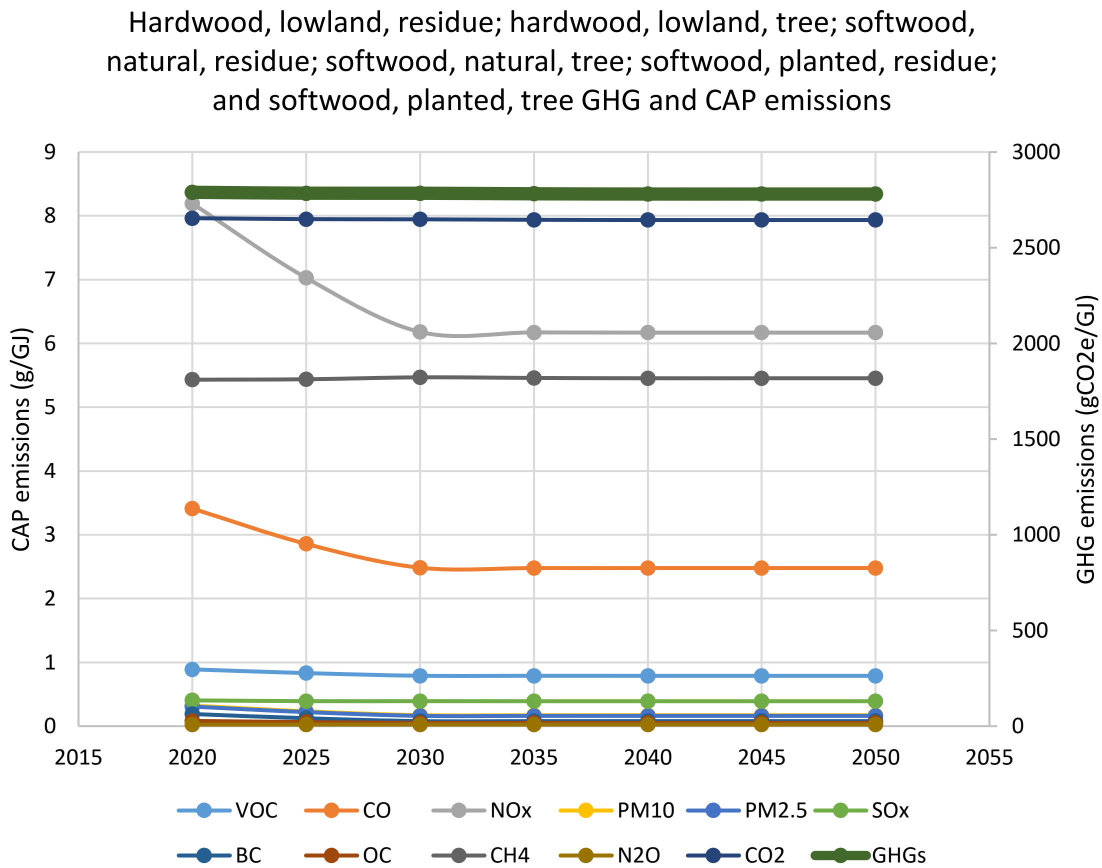

Poplar GHG and CAP emissions
CAP emissions (g/GJ)
GHG emissions (gCO2e/GJ)
0
2
4
6
8
10
12
14
0
500
1000
1500
2000
2500
3000
3500
4000
4500
2015
2020
2025
2030
2035
2040
2045
2050
2055
VOC
CO
NOx
PM10
PM2.5
SOx
BC
OC
CH4
N2O
CO2
GHGs

e)



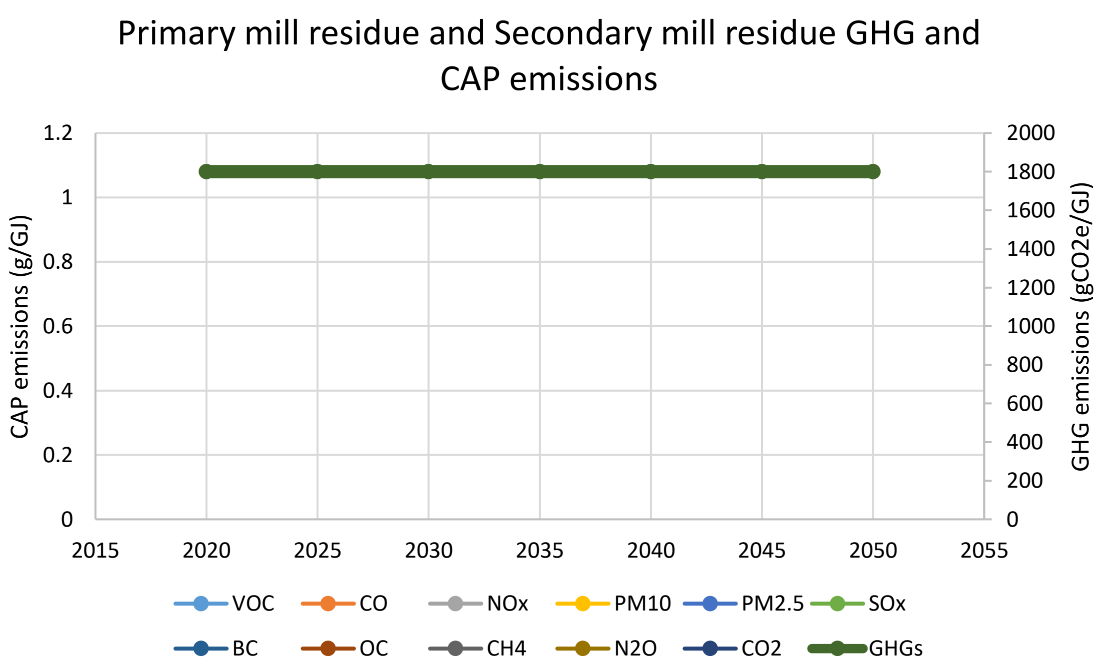
Food waste GHG and CAP emissions
15
10
5
0
-5
-10
-15
CAP emissions (g/GJ)
0
-5000
-10000
-15000
-20000
-25000
-30000
-35000
-40000
GHG emissions (gCO2e/GJ)
2015
2020
2025
2030
2035
2040
2045
2050
2055
VOC
CO
NOx
PM10
PM2.5
SOx
BC
OC
CH4
N2O
CO2
GHGs

f)



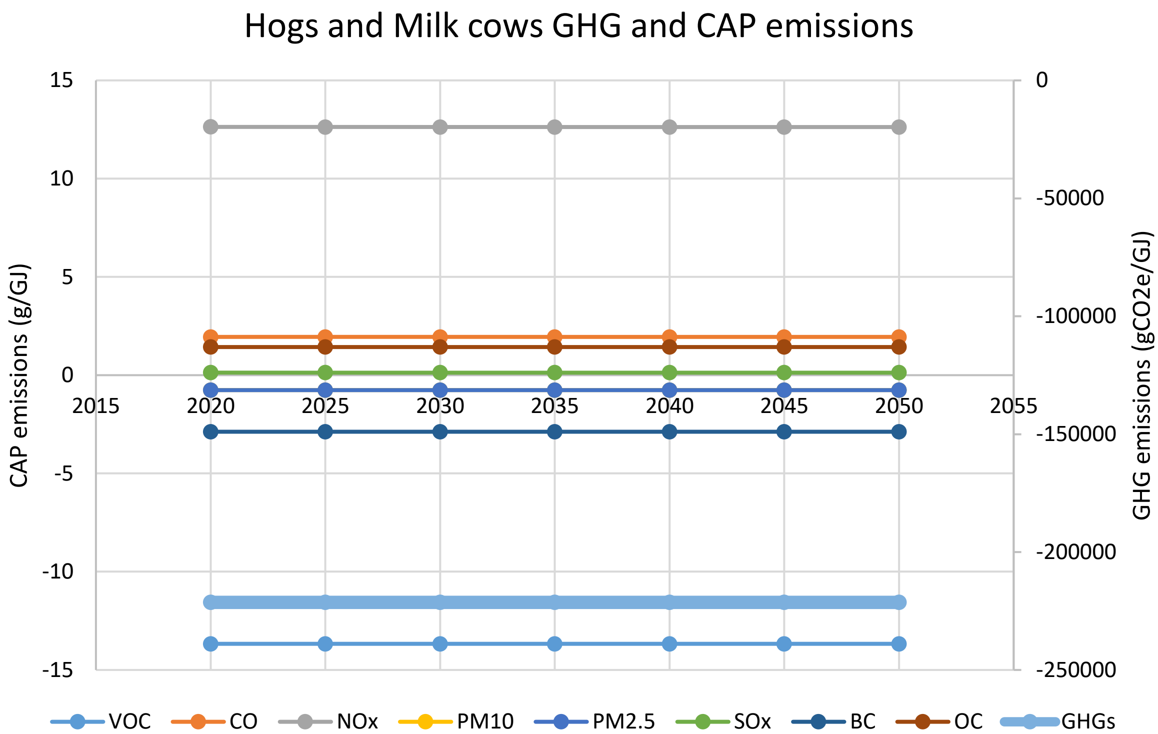
Hardwood, lowland, residue; hardwood, lowland, tree; softwood, natural, residue; softwood, natural, tree; softwood, planted, residue; and softwood, planted, tree GHG and CAP emissions
CAP emissions (g/GJ)
GHG emissions (gCO2e/GJ)
0
1
2
3
4
5
6
7
8
9
0
500
1000
1500
2000
2500
3000
2015
2020
2025
2030
2035
2040
2045
2050
2055
VOC
CO
NOx
PM10
PM2.5
SOx
BC
OC
CH4
N2O
CO2
GHGs

g)

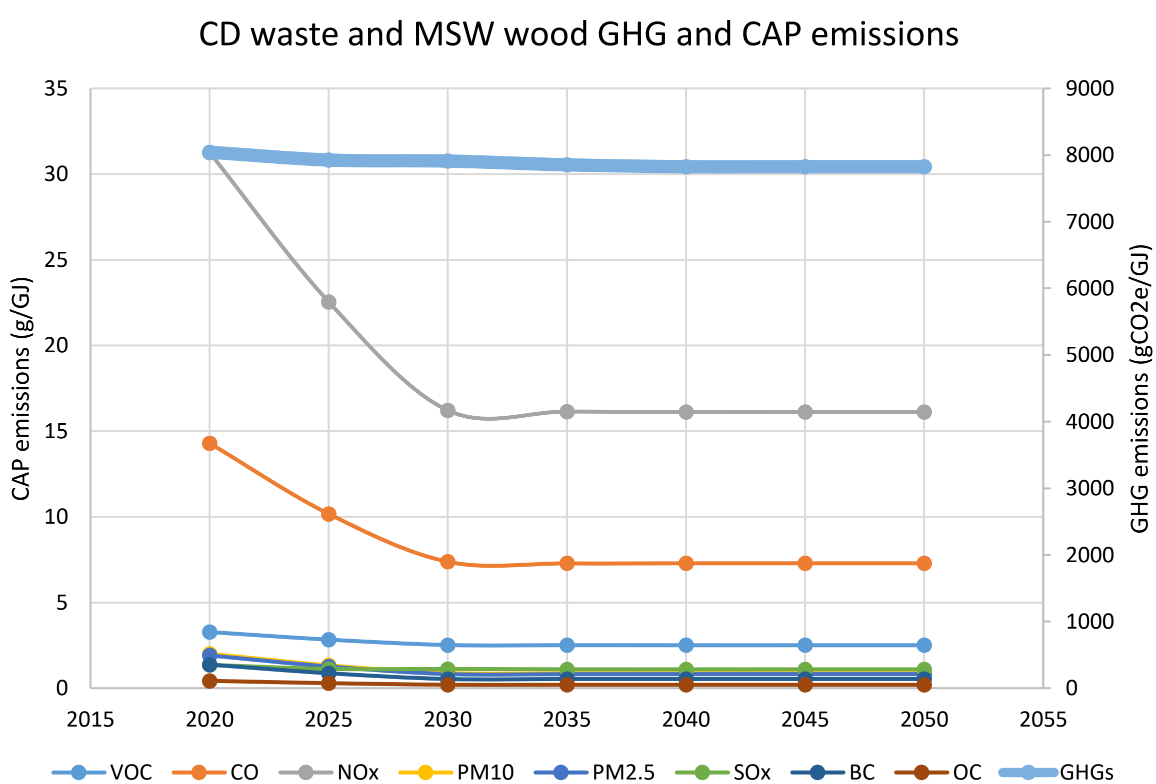


Primary mill residue and Secondary mill residue GHG and CAP emissions
CAP emissions (g/GJ)
GHG emissions (gCO2e/GJ)
0
0.2
0.4
0.6
0.8
1
1.2
0
200
400
600
800
1000
1200
1400
1600
1800
2000
2015
2020
2025
2030
2035
2040
2045
2050
2055
VOC
CO
NOx
PM10
PM2.5
SOx
BC
OC
CH4
N2O
CO2
GHGs

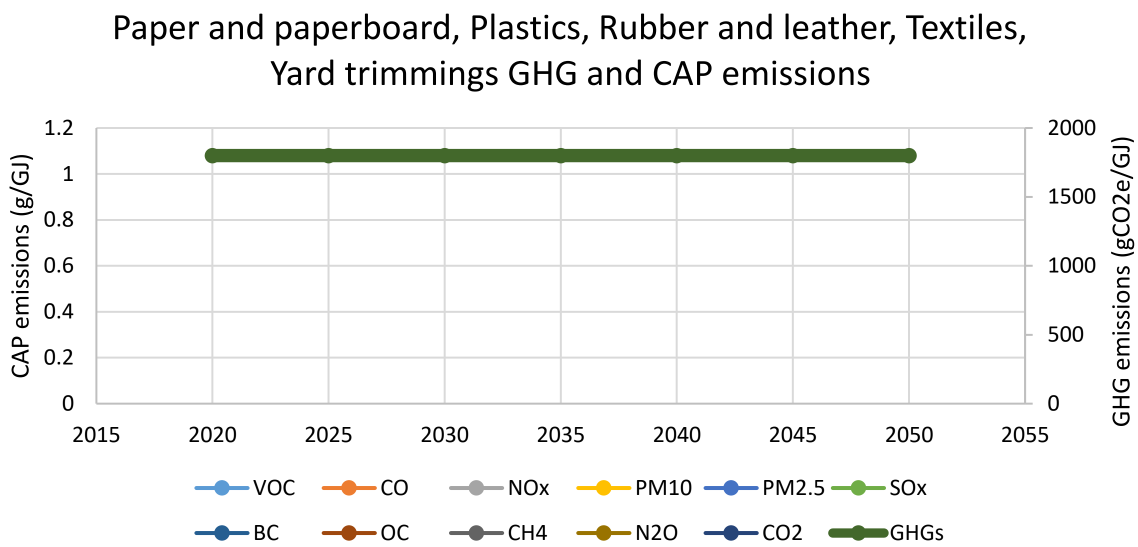
h)


Hogs and Milk cows GHG and CAP emissions
15
10
5
0
-5
-10
-15
CAP emissions (g/GJ)
0
-50000
-100000
-150000
-200000
-250000
GHG emissions (gCO2e/GJ)
2015
2020
2025
2030
2035
2040
2045
2050
2055
VOC
CO
NOx
PM10
PM2.5
SOx
BC
OC
GHGs

i)

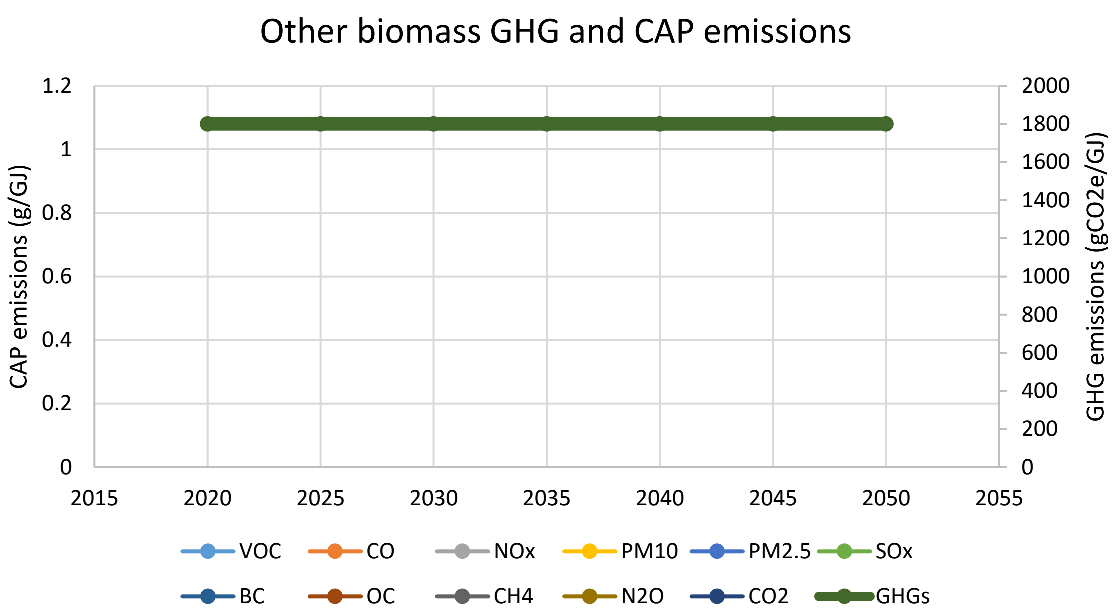

CD waste and MSW wood GHG and CAP emissions
35
30
25
20
15
10
5
0
CAP emissions (g/GJ)
9000
8000
7000
6000
5000
4000
3000
2000
1000
0
GHG emissions (gCO2e/GJ)
2015
2020
2025
2030
2035
2040
2045
2050
2055
VOC
CO
NOx
PM10
PM2.5
SOx
BC
OC
GHGs

j)



Paper and paperboard, Plastics, Rubber and leather, Textiles, Yard trimmings GHG and CAP emissions
CAP emissions (g/GJ)
GHG emissions (gCO2e/GJ)
1.2
1
0.8
0.6
0.4
0.2
0
2000
1500
1000
500
0
2015
2020
2025
2030
2035
2040
2045
2050
2055
VOC
CO
NOx
PM10
PM2.5
SOx
BC
OC
CH4
N2O
CO2
GHGs

k)



Other biomass GHG and CAP emissions
CAP emissions (g/GJ)
GHG emissions (gCO2e/GJ)
1.2
1
0.8
0.6
0.4
0.2
0
2000
1800
1600
1400
1200
1000
800
600
400
200
0
2015
2020
2025
2030
2035
2040
2045
2050
2055
VOC
CO
NOx
PM10
PM2.5
SOx
BC
OC
CH4
N2O
CO2
GHGs

l)

Appendix B: Connected and Automated Literature Review

Table B- 1. Literature Review of HD-CAV Research

Study	CAV Strategies	Application	Impact Assessment
[277]	Automatic control system	Off-road HDV	Experimental results show proposed system is effective
[278]	Navigation control with LiDAR, path tracking	Mining trucks	Simulation results confirmed effectiveness of developed algorithms; improved safety
[520]	Economic model predictive controller (EMPC) for autonomous path following	Construction truck	EMPC is more effective than the common pure pursuit controller MPC controller
[521]	Vehicle-following controller	HDV in mixed traffic	Simulations, emission analysis, and experimentation confirm enhanced performance in real-world driving conditions
[522]	Adaptive cruise control (ACC), Cooperative adaptive cruise control (CACC) for platooning	HDV	Controller developed for semi-autonomous operation and platooning
[523]	Autonomous navigation system using inertial sensor, odometer, and laser	Load, haul, and dump truck	More robust navigation that addresses vehicle slip
[524]	Autonomous navigation system	Load, haul, and dump truck in a mine	It can operate with no localization infrastructure
[525]	Evaluating sensors and sensing technologies	Underground mining	Experimental program evaluates two early navigation solutions
[526]	Sensory data, path planning methodology and hydraulic motor power	heavy duty, outdoor robotic tracked vehicle	Autonomous navigation in an initially unknown and time varying environment
[290]	"Look-ahead" with road slope database and GPS unit to optimize velocity	On-road HDV	Experimental results: fuel consumption reduced by 3.5% without increasing trip time.
[323]	Automated platoon: Lateral control based on computer vision lane marker detection, longitudinal control based on gap measurement by radar, LiDAR and V2V Communication	HDV	Fuel savings measured at about 14%
[322]	ACC, platooning	On-road HDV	Fuel savings: 4.7-7.7% with ACC and platooning; ACC alone saves 1%
[527]	Platooning	On-road HDV	Reduced traffic congestion
[304]	Full automated platooning	LDT, HDV	Fuel savings: 14-15%
[528]	Platooning, V2V	On-road HDV	Novel control system with errors less than 0.2 m, 0.3 m/s
[307]	Platoon, using radar, V2V, cameras, and a vehicle braking and torque control interface	Two HD Trucks	Lead HDV: + 2.7-5.3% fuel efficiency Following HDV: + 2.8-9.7% fuel efficiency
[319]	Electronic Tow Bar (driver assistance system for automated vehicle)	Two HD Trucks	Lead HDV: + 7% fuel efficiency Following HDV: + 17-21% fuel efficiency

[311]	Platoon, Optimal hybrid control	Three HD Trucks	Fuel savings: 13%
[267]	Centralized truck platoon coordinator	thousands of HD trucks	Fuel savings: 0-11%
[529]	Dynamic programming formulation which computes optimal sequence of gear shifts for fuel-efficient and smooth tracking	HDV in platoon formation	Demonstrated effectiveness in simulation
[530]	Optimization for platoon coordination	Two HD Trucks	Fuel savings: up to 6%
[320]	Platoons using Advanced Driver Assistance Systems (ADAS)	HD Trucks	Fuel consumption savings: about 10%
[275]	Platooning	Highway freight	65-77% of freight miles can benefit from platooning. Fuel savings: 4.2%
[310]	Platooning	Class 8 Tractor	fuel savings: 3.7% to 6.4% fleet-wide
[314]	Platooning, eco-routing	On-road HDV	Calculated routes to reduce fuel consumption by up to 10% at the platoon level
[269]	Platooning, wireless sensor data sharing	HDV	Improved traffic flow
[313]	Platooning	Two HD Trucks	Fuel savings: 4%
[308]	Coordinated automatic longitudinal control of a platoon	Three Class 8 tractor-trailers	fuel savings: 4-5% for lead truck, 10-14% for following trucks
[531]	CACC	HDV	Experiments determine control strategy is effective under normal operating conditions. CACC algorithm reacts too aggressively on these large distance errors.
[532]	two-layer control architecture for HDV platooning	HDV	Topographic data and V2V coordination can benefit both fuel efficiency and safety
[324]	CC, ACC, look-ahead platooning (LAP) controller	Two HD Trucks	14% fuel savings downhill, 0.7% uphill
[533]	Predictive Cruise Control (PCC)	HDV	PCC more efficient than CC
[534]	Level 4 CAV	Haul trucks-ICEV and BEV	Fuel savings: 5-7%
[312]	Driver Assistive Truck Platooning (DATP)		median savings: ~4%-7%
[309]	semi-automated truck platooning	HDV line-haul	Fuel savings: 5.3-9.7% Heavy payloads affect savings, but still result in fuel savings
[535]	Longitudinal control for short distance following	HDV	Controller is effective, but with time delay
[536]	Automated lane-change	3 Class 8 tractor-trailer trucks	Shorter lane-change durations
[537]	Connected cruise control	HDV	Fuel savings: 10.4-12.8%
[538]	Model simulation of vehicle platooning, CACC	3-truck HDV	Simulation within 1-5% of on-road test data
[316]	Platooning	HDV	Fuel savings: 2.5-4.4%

[539]	Connected eco-driving, Signal Phase and Timing (SPaT)	HDV	Fuel savings: 9% for acceleration events; 4% for deceleration events
[318]	Predictive cruise control, ACC constant distance (ACCCD), ACC constant time headway (ACCCH)	Class 8 line-haul	Fuel savings:4.3-15.4%
[296]	Energy management system (algorithm) for velocity prediction and SOC planning	Heavy duty HEV	Fuel economy improved 1.8%
[317]	ACC, Look-ahead cruise control in a platoon	HDV	Fuel savings: 5.9%, brake energy savings: 72.2%

Appendix C: Heavy Duty Vehicle Specifications

Table C- 1. Linehaul HDV Specifications

Component	ICV, diesel	ICV, SNG	HEV, diesel	HEV, SNG	BEV	FCEV
Glider, HDV (ea.)	1	1	1	1	1	1
ICE, diesel (kW)	324.00		233.18			
ICE, SNG (kW)		324.00		233.18		
Fuel cell (kW)						363.00
Traction battery (kwh)			15.00	15.00	500.00	2.28
Electric motor and inverter (kW)			120.00	120.00	400.00	400.00
Liquid fuel tank (GJ)	12.61		12.61			
SNG tank (GJ)		15.86		15.86		
Hydrogen tank (GJ)						10.91
Hybrid cost, HDV			1	1		1
Plug-in hybrid cost, HDV						

Table C- 2. Drayage HDV Specifications

Component	ICV, diesel	ICV, SNG	HEV, diesel	HEV, SNG	PHEV, diesel	PHEV, SNG	BEV	FCEV
Glider, HDV (ea.)	1	1	1	1	1	1	1	1
ICE, diesel (kW)	232.09		167.04		167.04			
ICE, SNG (kW)		232.09		167.04		167.04		
Fuel cell (kW)								247.00
Traction battery (kwh)			30.32	30.32	165.22	169.85	443.26	4.61
Electric motor and inverter (kW)			85.96	85.96	85.96	85.96	286.53	286.53
Liquid fuel tank (GJ)	11.20		11.20		9.35			
SNG tank (GJ)		14.09		14.09		12.08		
Hydrogen tank (GJ)								9.69
Hybrid cost, HDV			1	1				1
Plug-in hybrid cost, HDV					1	1		

Table C- 3. Refuse HDV Specifications

Component	ICV, diesel	ICV, SNG	HEV, diesel	HEV, SNG	PHEV, diesel	PHEV, SNG	BEV	FCEV
Glider, HDV (ea.)	1	1	1	1	1	1	1	1
ICE, diesel (kW)	237.6 6		171.04		171.04			
ICE, SNG (kW)		237.66		171.04		171.04		
Fuel cell (kW)								273.00
Traction battery (kwh)			30.00	30.00	115.87	123.84	428.57	4.56
Electric motor and inverter (kW)			88.02	88.02	88.02	88.02	293.41	293.41
Liquid fuel tank (GJ)	3.60		3.60		2.13			
SNG tank (GJ)		4.53		4.53		2.86		
Hydrogen tank (GJ)								2.66
Hybrid cost, HDV			1	1				1
Plug-in hybrid cost, HDV					1	1		

Table C- 4. Construction HDV Specifications

Component	ICV, diesel	ICV, SNG	HEV, diesel	HEV, SNG	PHEV, diesel	PHEV, SNG	BEV	FCEV
Glider, HDV (ea.)	1	1	1	1	1	1	1	1
ICE, diesel (kW)	172.68		124.27		124.27			
ICE, SNG (kW)		172.68		124.27		124.27		
Fuel cell (kW)								139.00
Traction battery (kwh)			18.19	18.19	85.81	89.04	299.20	2.76
Electric motor and inverter (kW)			63.95	63.95	63.95	63.95	213.18	213.18
Liquid fuel tank (GJ)	5.01		5.01		3.62			
SNG tank (GJ)		6.30		6.30		4.72		
Hydrogen tank (GJ)								3.68
Hybrid cost, HDV			1	1				1
Plug-in hybrid cost, HDV					1	1		

Appendix D: Further Information on Policies

Table D-1. Incentives, Rebates, and Financing Assistance for Heavy Duty Vehicles (HDVs) in California

RELEVANT AGENCY	INCENTIVES, REBATES, AND FINANCING ASSISTANCE FOR HEAVY-DUTY VEHICLES (HDVs)
California Air Resources Board (ARB); All 35 Air Quality Management Districts (AQMDs)	Carl Moyer Memorial Air Quality Standards Attainment Program (Carl Moyer Program) (1998): Replacement, new purchase, repower, and retrofit trucks to reduce near-term air emissions; scrappage required.
ARB; All 35 AQMDs	• Assembly Bill (AB) 671 (2017): Community Air Protection (CAP) Program
ARB; Rural Air Districts; CA Air Pollution Control Officers Association (CAPCOA)	• Rural Assistance Program: To enhance rural air district participation in the Carl Moyer Program.
ARB	Lower-Emission School Bus Program
ARB	2013 Optional Reduced Emissions Standards for Heavy-Duty Engines (Low NO_x standards of 0.1, 0.05, or 0.02 grams per brake horsepower-hour (g/bhp-hr.) vs. conventional 2010 0.2 g/bhp-hr. standard.)
ARB	Air Quality Improvement Program (AQIP): Focuses on reducing criteria pollutants, diesel particulate emissions, and concurrent GHG emissions.
ARB	• Low Carbon Transportation Program - AB 32 Cap & Trade revenues applied to clean vehicle and equipment projects (mostly) for long-term GHG emissions reductions; 20% to HDVs.
ARB	○ Advanced Technology Freight Demonstration and Pilot Commercial Deployment. Mostly port-related (including projects for ships at berth) with the following entities: Bay Area AQMD (BAAQMD); South Coast AQMD (SCAQMD); San Joaquin Valley Air Pollution Control District (SJVAPCD); San Bernadino County Transportation Agency (SBCTA); Los Angeles Harbor Department (Port of LA); Gas Technology Institute (GTI); CALSTART; Project Clean Air; Center for Transportation and the Environment (CTE); City of Long Beach Harbor Department (Port of Long Beach).
ARB	○ Hybrid and Zero-Emission Truck and Bus Voucher Incentive Program (HVIP): Started 2010; applicable to Medium Heavy-Duty Vehicles, HDVs, Urban Buses, and School Buses; reduces up-front cost of hybrid or zero-emission vehicles; added funding under Senate Bill (SB) 1204 (2014).
ARB	○ Low NOx Engine Incentives: Support deployment of engines that meet optional low NOx standards; part of SB 1204 (2014).
ARB	• Zero-Emission Truck and Bus Pilot Commercial Deployment Projects, funded through BAAQMD; SJVAPCD; Sacramento Metropolitan AQMD (SMAQMD); CTE; City of Porterville; and, Sunline Transit Agency.
ARB; CA Pollution Control Financing Authority (CPCFA)	○ Truck Loan Assistance Program (2009): Focus is on near-term diesel emission reductions; SB 1 allows only clean trucks to be registered with the CA Department of Motor Vehicles (DMV). Part of SB 1204 (2014) and applies only to HDVs subject to: In-Use Truck and Bus Regulation: HDVs > 26,000 lbs. require PM filters (either installed by the OEM or later retrofit), then replacement by 2010 or later model year engine; timing based on original engine model year.

RELEVANT AGENCY	INCENTIVES, REBATES, AND FINANCING ASSISTANCE FOR HEAVY-DUTY VEHICLES (HDVs)
ARB	Tier 4 Early Introduction Incentive for Engine Manufacturers
ARB	Diesel Particulate Filter Retrofit Replacements. Part of SB 1204 (2014).
ARB	Low Carbon Fuel Standard (LCFS)
ARB; U.S. Environmental Protection Agency (U.S. EPA)	Volkswagen Diesel Emissions Environmental Mitigation Trust: California's share of the $2.7 billion trust is $423 million, to fund zero-emission-vehicle-related vehicle replacement programs; 10 eligible vehicle classes including light-duty vehicles (LDVs), Classes 4-7 (Medium-Duty Vehicles (MDVs) + Buses) and Class 8 HDVs.
ARB	Zero-Emission Off-Road Freight Voucher Incentive Project
California Energy Commission (CEC)	Alternative and Renewable Fuel and Vehicle Technology Program (ARFVTP; 2007; AB 118): Improve HDV technologies, retrofit HDV fleets, expand infrastructure.
CEC (ARFVTP)	• Natural Gas Vehicle Incentive Project (NGVIP): Administered by University of California-Irvine Institute of Transportation Studies (UCI-ITS); provides incentives to reduce the purchase price of new on-road natural gas vehicles (NGVs). Individuals, firms, and public agencies operating in California at least 90% of the time for the past three years are eligible for NGVIP funds. Incentive amounts are tailored to gross vehicle weight (GVW) classes to reflect the increasing incremental cost of NGVs as gross vehicle weight increases. https://ngvip.its.uci.edu/
CEC (ARFVTP)	• Natural Gas Fueling Infrastructure Funding: The cost of natural gas fueling stations generally ranges from $500,000 for smaller compressed natural gas (CNG)-only stations to several million dollars for large combined (liquefied natural gas) LNG-CNG fueling stations. Cost depends on many factors, including compressor size, storage capacity, and LNG or CNG dispensing capabilities. http://www.energy.ca.gov/altfuels/2016-ALT-02/documents/
CEC	Vehicle-to-Grid Incentive and Funding Programs
California Public Utilities Commission (CPUC); CEC	Transportation Electrification (SB 305): Investor-Owned Utilities (IOUs) submit plans to CPUC, Publically-Owned Utilities (POUs) submit plans to CEC by 1/1/2019.
Bay Area AQMD	Mobile Source Incentive Fund program
Sacramento AQMD	Sacramento Emergency Clean Air and Transportation (SECAT) Program: Truck replacement program.
Sacramento Metro AQMD	Adopted Rule 1003 (Reduced-emission Fleet Vehicles/Alternative Fuels) in 1994 but never implemented it.
San Luis Obispo County APCD	AB 923 funding
SCAQMD	SCAQMD Fleet Rules (Rule 1186.1, 1191-1196): The SCAQMD adopted seven rules that will gradually shift public agencies and certain private entities to lower emissions and alternative fuel vehicles whenever a fleet operator with 15 or more vehicles replaces or purchases new vehicles. The alternative fuels include CNG, LNG, liquefied petroleum gas (LPG), methanol, electricity, or hydrogen for fuel cells. This rule applies to sweepers, refuse vehicles, transit buses, school buses, airport access vehicles, and public fleets operated in Los Angeles, San Bernardino, Riverside, and Orange counties. http://www.aqmd.gov/home/rules-compliance/rules/fleet-rules

RELEVANT AGENCY	INCENTIVES, REBATES, AND FINANCING ASSISTANCE FOR HEAVY-DUTY VEHICLES (HDVs)
SCAQMD	• SCAQMD AB 2766 Motor Vehicle Subvention Program: Incentivizes emission reductions from mobile sources, accelerates retirements and repairs.
SCAQMD	• SCAQMD Clean Fuels Program: Funds development, demonstration, and accelerated deployment of advanced technology vehicles and alternative fuel infrastructure.
SCAQMD	• SCAQMD Technology Advancement Program
SCAQMD	• SCAQMD Mobile Source Air Pollution Reduction Review Committee (MSRC) funding
U.S. DOE	Zero-Emission Drayage Truck Development and Demonstration: Accelerate the introduction/penetration of electric vehicle (EV) transportation technologies into the cargo/drayage transport sector.
U.S. EPA	Renewable Fuel Standard (RFS)
U.S. EPA	Targeted Airshed Grants
U.S. Federal Transit Administration (U.S. FTA)	Low or No Emission Vehicle Program; competitive funding for states and transit agencies for the purchase or lease of zero- or near zero-emission transit buses and related equipment.
U.S. FTA	Zero Emission Research Opportunity (ZERO); research, demonstrations, testing, and evaluation of zero-emission and related technology for public transportation applications.

Table D-2. Assessments, Plans, Programs, and Reports

RELEVANT AGENCY	ASSESSMENTS, PLANS, PROGRAMS, AND REPORTS
State Treasurer's Office	California Alternative Energy and Advanced Transportation Financing Authority (CAEATFA)
ARB; CEC	California Clean Truck, Bus, and Off-Road Vehicle and Equipment Technology Program (SB 1204)
ARB	• Zero- and Near Zero-Emission Freight Facilities Project: Supports HDVs, (fueling) infrastructure, and energy efficiency projects through commercialization; disadvantaged communities only; ***50% required cost share.***
State Treasurer's Office	California Pollution Control Financing Authority (CPCFA): Includes the California Capital Access Program (CalCAP)
California Department of Transportation (Caltrans); CA Transportation Agency (CalSTA)	California Freight Advisory Committee (CFAC)
Caltrans; CalSTA	California Freight Mobility Plan: Established 2014; updating in 2019.
Governor's Office; ARB; CEC; Caltrans	California Sustainable Freight Action Plan (CSFAP): Integrate investments, policies, and programs across several State agencies to achieve singular vision for California's freight transport system.
Caltrans	California Transportation Plan (CTP) 2040
Caltrans	Caltrans' Strategic Management Plan (2015)
CA DMV	Clean Air Decal Program (There is an income threshold that prevents fuel cell electric vehicles (FCEVs) from double-dipping under the CVRP; below that threshold, FCEVs may take advantage of both programs.)
Caltrans	Cooperative Adaptive Cruise Control (CACC): Truck platooning for fuel savings/efficiency.
CEC	Electric Program Investment Charge Program (EPIC): EV charging and vehicle-to-grid power transfer infrastructure.
Governor’s Office	Executive Order B-16-2012: 1.5 million zero-emission vehicles (ZEVs) in California by 2025. Motivated ZEV Action Plan.
Governor's Office	Executive Order B-30-15 (2015): 2030 target of 40% reduction in California's GHG emissions vs. 1990 levels.
Governor's Office	Executive Order B-32-15 (2015): GDP/CO2; ZEV; Competitiveness. Motivated CSFAP and Sustainable Freight Transport Initiative.
U.S. FTA	Fixing America's Surface Transportation Act (FAST)
ARB; All 35 AQMDs	Funding Agricultural Replacement Measures for Emission Reductions (FARMER) Program
Governor's Office	Governor Brown's 2016-2017 Funding Proposal
Governor's Office	Governor Brown's Climate Change Strategy: 50% petroleum reduction by 2030 and reduced short-lived climate pollutants.
Governor's Office of Business and Economic Development	ZEV program information on GO-Biz website: http://www.business.ca.gov/Programs/Zero-Emission-Vehicles-ZEV
ARB	Heavy Duty Technology and Fuels Assessment
CEC	Integrated Energy Policy Report Update (2014)

RELEVANT AGENCY	ASSESSMENTS, PLANS, PROGRAMS, AND REPORTS
ARB	Mobile Source Strategy (HDVs >8500 lbs make up 33% of CA NOx emissions, 25% of CA PM emissions, and significant GHG emissions.)
U.S. Department of Transportation (U.S. DOT)	National Multimodal Freight Network
CEC	Natural Gas Vehicle Research Roadmap
ARB; SCAQMD	On-Road HDVs Cleaner Technologies through Regulations, Partnerships, and Incentives
ARB; SCAQMD	Proposition 1B Goods Movement Emission Reduction Program (2006); 2015 Phase II final funds to SCAQMD projects through 2018 (ARB). Near-term emissions reductions; scrappage required; excludes refuse trucks. http://www.aqmd.gov/home/programs/business/business-detail?title=goods-movement-emission-reduction-projects-(prop-1b)&parent=vehicle-engine-upgrades
Local/Regional Governments	Regional Zero Emission Vehicle Readiness Plans
California Natural Resources Agency (CNRA)	Safeguarding California: Implementation Action Plans Report, Climate Adaptation Strategy, and Related Updates
Ports of LA and Long Beach	San Pedro Bay Ports Clean Air Action Plan (CAAP), including the Clean Truck Program (CTP)
ARB	SB 350 (2015): Accessible Clean Transportation Options for Low-Income Residents
ARB	Short-Lived Climate Pollutant Reduction Strategy
ARB; All 35 AQMDs; CNRA	State Implementation Plan under Federal Clean Air Act: Implemented in conjunction with ARB & Local AQMDs.
SCAQMD	Strategic Alliance Initiative: Identify and seek federal funding.
U.S. Department of Labor (U.S. DOL)	Surface Transportation Assistance Act (STAA): Funded by the federal gasoline tax; administered by the Occupational Safety & Health Administration (OSHA) of the U.S. DOL.
ARB	Sustainable Freight Pathways to Zero and Near-Zero Emissions Discussion Document (2014)
ARB	Technology and Fuels Assessment Report
Caltrans	Trade Corridors Improvement Fund (TCIF) - Phase II
CA Strategic Growth Council	Transformative Climate Communities (TCC) Program

Table D-3. Regulations and Standards

RELEVANT AGENCY	REGULATIONS AND STANDARDS
ARB	AB 32 Climate Change Scoping Plan and Updates
ARB	Advanced Clean Truck Regulation
ARB	Drayage Truck Registry: Required for all diesel-fueled trucks transporting cargo to or from California's ports & intermodal rail yards; requires model year 2007 or later until 2023, after which model year 2010 or newer is required.
ARB	Heavy Duty Vehicle Inspection and Periodic Smoke Inspection Programs (PSIP): Target = Reducing PM 2.5 emissions.
ARB	Innovative Clean Transit Regulation (Under development.)
ARB	Low-Emission Diesel Requirement
ARB	On-Board Diagnostics for HDVs phased in with 2013 model year for gasoline and diesel fuels; alternate fuels by 2018 model year.
ARB	Statewide Truck and Bus Regulation: Applicable to vehicles with GVW > 14,000 lbs.; all diesel shuttle buses must meet 2010 model year emissions standards by 1/1/2023; all diesel school buses must have a diesel PM filter installed.
ARB	Tractor-Trailer GHG Regulation (2008: Applicable to 53'+ length long-haul tractors and trailers.)
ARB	Vehicle Certification: HDVs may be engine-only, but full-vehicle certification possible under 2013 Heavy-Duty Hybrid-Electric Vehicles Certification Procedures.
ARB	Zero-Emission Airport Shuttle Bus Measure: Under development; goal of 100% fleet transformation to zero-emissions in 2031 via 2023 new purchase requirements & 2025 fleet turnover requirements.
ARB	2016 Innovative Technology Regulation: Flexible certification and on-board diagnostics (OBD) requirements for hybrid trucks.
U.S. EPA	2004 Optional NO_x + Non-Methane Hydrocarbons (NMHC) (vs. conventional 2.4 g/bhp-hr.)
U.S. EPA	Emissions Standards for Heavy-Duty Highway Engines & Vehicles
U.S. EPA	On-road (Highway) Diesel Fuel Standards: 2006-2010: Ultra-Low Sulfur Diesel (ULSD) phased in for on-road diesel; after 2010, all highway diesel must be ULSD & all highway diesel vehicles must use ULSD.
U.S. EPA	Interim Tier 4 (Interim Tier 4, Tier 4 Phase-Out, Tier 4 Phase-in/Alternate NOx) and Final Tier 4 emission standards
U.S. EPA/U.S. National Highway Transportation Safety Administration (U.S. NHTSA)	2011 Phase 1 GHG Standards & Fuel Efficiency Standards (2014 Model Year)
U.S. EPA/U.S. NHTSA	2016 Phase 2 GHG Standards & Fuel Efficiency Standards for MDVs and HDVs (2021-2027 phase-in; 2018 trailers); ARB implementation.

Table D-4 Programs and Regulations Not Applicable to HDVs

RELEVANT AGENCY	PROGRAMS AND REGULATIONS NOT APPLICABLE TO HDVs
ARB	At-Berth Regulation: 70% power reduction/visit, increasing to 80% in 2020. Likely to increase additional shore power installations in California.
ARB	Clean Fuel Reward Program: Statewide program for reduced prices on light-duty EV purchases or leases. Funded exclusively through LCFS proceeds generated by electric distribution utilities from electricity fuel.
ARB	Clean Off-Road Equipment (CORE) Voucher Incentive Program
ARB	Clean Vehicle Rebate Project (CVRP): Light-Duty Vehicles (LDVs) only. There is an income threshold that prevents FCEVs from double-dipping under the Clean Vehicle Decal Program; below it, FCEVs may take advantage of both programs.)
ARB	Large Spark-Ignition (LSI) Engine Fleet Regulation
ARB	Portable Equipment Registration Program (PERP): For portable equipment subject to Portable Engine Airborne Toxic Control (ATC) Measure.
ARB	Regulation for In-Use Off-Road Diesel-Fueled Fleets
ARB	Regulation for Mobile Cargo Handling Equipment at Ports and Intermodal Rail Yards (CHE Regulation): Requires emissions reduction from in-use equipment, mostly through early vehicle turnover.
ARB	2005 Statewide Railyard Agreement
ARB	Transportation Equity Programs: LDVs only.
ARB	• Clean Mobility in Schools Program: Promotes advanced clean transportation in disadvantaged communities.
ARB	• Enhanced Fleet Modernization Program (EMP) and EMP Plus-Up Pilot Project/Clean Cars 4 All: Augment existing vehicle retirement programs.
ARB	• Rural School Bus Pilot Project
SCAQMD	1998 South Coast Memorandum of Understanding (Limits funding eligibility for Class 1 freight railroad new purchase or engine remanufacture/ repower projects in the SCAQMD.)
SCAQMD	Surplus Off-Road Opt-In for NO_x (SOON) Program
U.S. EPA	Diesel Emissions Reduction Act (DERA): Fund projects to reduce diesel emissions from school buses.

Table D-5. EPA Renewable Fuel Standard: Approved Pathways

Fuel Type	D code	Feed Stock	Production Process	Pathway
Ethanol	D3 (cellulosic biofuel)	Cellulosic biomass	Any process that converts cellulosic biomass to fuel	K
Cellulosic diesel, jet fuel, heating oil	D7 (cellulosic biofuel or biomass-based diesel)	Specified sources of cellulosic biomass; biogenic components of separated MSW	Any process that converts cellulosic biomass to fuel	L
Renewable gasoline (fuel or blend stock); co-processed cellulosic diesel, jet fuel, heating oil	D3 (cellulosic biofuel)	Specified sources of cellulosic biomass (sources more limited than for D7)	Specified processes; any that uses biogas/biomass as the only process energy source for fuel conversion	M
Naphtha	D3 (cellulosic biofuel)	Switchgrass, miscanthus, energy cane, Arundo donax, Pennisetum purpureum	Gasification and upgrading processes that convert cellulosic biomass to fuel	N
Renewable natural gas (compressed or liquefied), renewable electricity	D3 (cellulosic biofuel)	Biogas from: (i) Landfills; (ii) municipal WWTP, ag, or separated MSW digesters; or cellulosic components of biomass processed in other waste digesters.	Any process	Q
	D5 (advanced)	Biogas from waste digesters		T
Biodiesel, heating oil	D4 (biomass-based diesel)	Canola/rapeseed oil	Trans-esterification using natural gas or biomass for process energy	G
Biodiesel, renewable diesel, jet fuel, heating oil	D4 (biomass-based diesel)	Soybean oil; oil from annual cover crops; oil from algae grown photosynthetically; biogenic waste oils/fats/ greases; *Camelina sativa* oil; distillers corn or sorghum oil (alone or commingled)	Trans-esterification, hydro-treating. ***Cannot co-process renewable biomass & petroleum***	F
	D5 (advanced)		Trans-esterification, hydro-treating. ***Must co-process renewable biomass & petroleum***	H
Ethanol, renewable diesel, jet fuel, heating oil, naphtha	D5 (advanced)	Non-cellulosic portions of separated food waste; non-cellulosic components of annual cover crops	Any process	P
Naphtha, LPG	D5 (advanced)	*Camelina sativa* oil; distillers corn oil or distillers sorghum oil (alone or commingled)	Hydro-treating	I
Ethanol	D5 (advanced)	Sugarcane; grain sorghum,	Fermentation; specified processes	J, S
Ethanol	D6 (renewable)	Starch from corn, crop residue, annual cover crops; grain sorghum	Specified processes	A, B, C, D, E, R
Butanol	D6 (renewable)	Corn starch	Specified processes	O

Table D-6. ARB Low Carbon Fuel Standard: Fuel Pathway Classifications

Fuel Type	Feed Stock	Production Process
I. LOOKUP TABLE PATHWAYS		
(1) Do NOT Require a Fuel Pathway Application		
(A) California Reformulated Gasoline Blendstock for Oxygenate Blending (CARBOB)		
(B) California Ultra-low Sulfur Diesel (ULSD)		
(C) Compressed Natural Gas (CNG)		
(D) Propane		
(E) Electricity (California grid-average)		
(2) DO Require a Fuel Pathway Application		
(A) Electricity	100% zero Carbon-Intensity (CI) renewable energy sources, excluding biomass, bio-methane, geothermal, and municipal solid waste (MSW)	
(B) Electricity	Electricity associated with smart-charging pathway for EV charging & smart electrolysis pathway for hydrogen production through electrolysis	
(C) Hydrogen (gaseous & liquefied)	North American fossil-based natural gas	Central SMR
(D) Hydrogen (gaseous & liquefied)	Bio-methane	Central SMR
(E) Hydrogen (gaseous)	California grid-average electricity	Electrolysis
(F) Hydrogen (gaseous)	Electricity from those sources defined in I.(2)(A)	Electrolysis
II. TIER 1 CLASSIFICATION EXAMPLES (NOT EXCLUSIVE)		
(1) Ethanol	Starch or fiber in corn kernels, grain sorghum, or sugarcane	
(2) Biodiesel	Oilseed crop-derived oils, rendered animal fat, distiller's corn/sorghum oil, used cooking oil, others	
(3) Renewable diesel	Oilseed crop-derived oils, rendered tallow, distiller's corn oil, used cooking oil, others	Hydro-treatment
(4) Liquefied natural gas & liquefied CNG	North American fossil-based natural gas	
(5) Bio-methane	North American landfill gas; anaerobic digestion of wastewater sludge, dairy and swine manure, food, urban landscaping waste, and other organic waste	
III. TIER 2 CLASSIFICATION EXAMPLES (NOT EXCLUSIVE)		
(1) Cellulosic alcohols		
(2) Bio-methane	Sources other than those sources defined in II. (3)	
(3) Hydrogen	Pathways other than those found in Lookup Tables	
(4) Electricity	Pathways other than those found in Lookup Tables	
(5) Drop-in fuels (renewable hydrocarbons)	Includes low-carbon feedstocks co-processed with fossil feedstocks in petroleum refineries. Excludes renewable diesel defined in II. (3)	
(6) Any fuel	Unconventional feedstocks (e.g., algae oil)	
(7) Tier 1 classification pathways	Methods: (i) Having one or more low-CI energy sources, (ii) using carbon capture & sequestration, or (iii) not accurately modeled using Simplified CI Calculators.	Innovative methods