Life Cycle Assessment of Environmental and Economic Impacts of Deploying Alternative Urban Bus Powertrain Technologies in the South Coast Air Basin

December 2018

A Research Report from the Pacific Southwest Region University Transportation Center

Analy Castillo Munoz, Graduate Student, UC Irvine

Brian Tarroja, Assistant Professional Researcher, UC Irvine

Scott Samuelsen, Professor, UC Irvine

Pacific Southwest Region UTC
University Transportation Center

UCI University of California, Irvine

[page intentionally left blank]

TABLE OF CONTENTS

Contents

About the Pacific Southwest Region University Transportation Center

The Pacific Southwest Region University Transportation Center (UTC) is the Region 9 University Transportation Center funded under the US Department of Transportation's University Transportation Centers Program. Established in 2016, the Pacific Southwest Region UTC (PSR) is led by the University of Southern California and includes seven partners: Long Beach State University; University of California, Davis; University of California, Irvine; University of California, Los Angeles; University of Hawaii; Northern Arizona University; Pima Community College.

The Pacific Southwest Region UTC conducts an integrated, multidisciplinary program of research, education and technology transfer aimed at *improving the mobility of people and goods throughout the region.* Our program is organized around four themes: 1) technology to address transportation problems and improve mobility; 2) improving mobility for vulnerable populations; 3) Improving resilience and protecting the environment; and 4) managing mobility in high growth areas.

U.S. Department of Transportation (USDOT) Disclaimer

The contents of this report reflect the views of the authors, who are responsible for the facts and the accuracy of the information presented herein. This document is disseminated in the interest of information exchange. The report is funded, partially or entirely, by a grant from the U.S. Department of Transportation's University Transportation Centers Program. However, the U.S. Government assumes no liability for the contents or use thereof.

Senate Bill 1 Disclaimer

The contents of this report reflect the views of the author(s), who are responsible for the facts and the accuracy of the information presented herein. This document is disseminated under the sponsorship of the State of California in the interest of information exchange. The State of California assumes no liability for the contents or use thereof. Nor does the content necessarily reflect the official views or policies of the State of California. This report does not constitute a standard, specification, or regulation.

Disclosure

Principal Investigator, Co-Principal Investigators, and others conducted this research titled, “Life Cycle Assessment of Environmental and Economic Impacts of Deploying Alternative Urban Bus Powertrain Technologies in the South Coast Air Basin” at the University of California, Irvine. The research took place from June 2017 to June 2020 and was funded by a grant from SB1 funds in the amount of $70,000. The research was conducted as part of the Pacific Southwest Region University Transportation Center research program.

Acknowledgements

This study was made possible through funding received by the University of California Institute of Transportation Studies from the State of California through the Public Transportation Account and the Road Repair and Accountability Act of 2017 (Senate Bill 1). The authors would like to thank the State of California for its support of university-based research, and especially for the funding received for this project. The authors would like to thank the State of California for its support of university-based research, and especially for the funding received for this project. The authors would also like to thank the Orange County Transportation Authority (OCTA) who provided data for driving cycles, and the Paul Scherrer Institute (PSI) for providing the Brightway2 LCA model.

Abstract

To address issues of air quality and greenhouse gas emissions in the South Coast Air Basin, local transit agencies are considering shifting their urban buses to battery electric buses (BEBs) and hydrogen fuel cell electric buses (FCEBs). However, each of these options vary in their effectiveness in reducing emissions over their life cycle, associated life cycle costs and environmental footprint, and ability to meet operational needs. Therefore, this project carried out a life cycle-based analysis and comparison of the environmental externalities associated with BEBs and FCEBs, taking into account their ability to meet operational constraints of the Orange County Transportation Authority. For environmental footprint, both FCEBs and BEBs had comparable benefits over conventional buses when fueled with renewable resources. When the electricity mix involved a non-trivial fossil fuel share, BEBs provided larger benefits than FCEBs, but overall benefit levels relative to conventional buses were lower, highlighting the need for fossil fuel-free fuel production. For total cost of ownership, both BEBs and FCEBs are currently more expensive than conventional alternative primarily due to higher initial purchase prices and additional infrastructure costs. Moving into the future, reducing these costs will be critical in enabling the adoption of BEBs and FCEBs.

Life Cycle Assessment of Environmental and Economic Impacts of Deploying Alternative Urban Bus Powertrain Technologies in the South Coast Air Basin

Executive Summary

The objective of this project is to perform a life cycle characterization of greenhouse gas emissions, criteria pollutant emissions, and costs of conventional and alternative urban bus powertrains. The findings of this project can help better inform transit agencies and government agencies in developing transition pathways for urban bus fleets to cost-effectively meet environmental objectives in California. Life cycle includes the stages of material extraction, material transport, manufacturing, use, and end-of-life.

Many municipalities and state governments have set targets for one or more of the following objectives: greenhouse gas reduction, compliance with air quality standards, and increasing renewable utilization. Changes in the transportation sector are a key part of these efforts due to the large contribution of this sector to greenhouse gas and criteria air pollutant emissions, as well as overall energy usage. While a large amount of attention has been focused on shifts in the light-duty transportation subsector by means of improving efficiency and proliferation of electric vehicle powertrains, the heavy-duty sector is also in need of emissions reduction strategies. Heavy-duty vehicles such as buses are not only a large contributor to criteria pollutant emissions but are also sources of emissions that are embedded within population centers, contributing to degraded urban air quality. This is especially important in California, and particularly in the South Coast Air Basin of the state where local geography combined with high populations give rise to significant air quality issues and difficulty in meeting federal ambient air quality standards. Policy efforts to address this with respect to buses are codified in regulations such as the California Air Resources Board Innovative Clean Transit measure, with the goal of transforming the statewide transit bus fleet by 2040 through phasing-in zero emission bus purchases.

Multiple options exist for transitioning the urban bus fleet technology portfolio to contribute to emissions reduction goals. These include but are not limited to: 1) fuel-switching to lower-carbon, cleaner burning fuels such as natural gas, 2) deployment of all-electric battery electric buses – both short-range with roadway recharging and long-range with large battery sizes, and 3) deployment of hydrogen fuel cell buses. However, each of these options vary in their overall effectiveness in reducing different emission types over their life cycle, associated life cycle costs, ability to meet operational needs of transit agencies, and life cycle environmental footprint. In order for transit agencies to determine the cost- and environmentally favorable pathways for transitioning urban bus fleets to reduce emissions, information regarding the life

cycle greenhouse gas and criteria pollutant emissions, costs, and environmental externalities such as water resource impacts for potential urban bus technologies must be provided.

This project provided needed insight using the following phases. The first phase focused on acquiring life cycle inventory data for different urban bus powertrain technologies by utilizing available life cycle databases and literature studies. The second phase modeled urban bus fleet operation to accurately capture operating energy needs and associated emissions in the context of powertrain characteristics and bus scheduling needs. The third phase focused on utilizing the Brightway2 LCA framework in combination with a to-be-developed economic model for performing full life cycle assessment of different urban bus powertrain options to determine per-mile greenhouse gas emission, criteria pollutant emission, cost, and environmental footprint performance. The final phase was to apply the methodology to the Orange County Transit District (OCTA) as an example of the utility and applicability of the methodology. The project provided insight for the OCTA on the life cycle performance of different powertrain options on multiple criteria for use by state agencies and transit agencies in more effectively planning the transition of urban bus fleets to meet environmental objectives.

From an environmental footprint perspective, the study found that:

- Both FCEBs and long-range BEBs have comparable impacts for global warming potential and particulate matter formation but when the FCEBs were fueled using renewable hydrogen.
- Using electricity from the current California grid mix to drive electrolysis to produce hydrogen for FCEBs produced only marginal benefits compared to current natural-gas fueled vehicles due to the low supply chain efficiency of this pathway.
- The mining of precious metals is a major contributor to environmental footprint categories for both BEBs and FCEBs.
- Both FCEVs and long-range BEBs provide significant reductions in environmental footprint compared to conventional diesel and natural gas buses.

From a cost perspective, the study found that:

- With current-day cost inputs, FCEBs and BEBs have comparable total cost of ownership, but both have slightly higher costs than diesel and natural gas buses.
- FCEBs have an equivalent total cost of ownership to BEBs when the electricity rate for charging is $0.24/kWh. Higher values render FCEBs as the cheaper option and lower values render BEBs as the cheaper option.

- The total cost of ownership of these technologies is highly sensitive to electricity costs, and the rapid evolution of the electricity system has strong implications for the economic comparison between BEBs and FCEBs.

Overall, the study finds that BEBs and FCEBs provide significant environmental footprint benefits compared to conventional powertrains, but also incur increases in total cost of ownership. The cost increases are largely due to increased initial purchase cost, cost of fuel / electricity, and to a lesser extent for BEBs, battery replacement at midlife. This may change in the future due to the rapid transformation of the electricity system and the falling costs of renewables, as well as economy-of-scale improvements for BEBs and FCEBs. At present, however, incentivizing adoption of BEBs or FCEBs by transit agencies will require policies that reduce the burden of initial purchase cost and electricity costs incurred by transit agencies. These policies can take the following forms:

- Tax credits or subsidies for the purchase of an FCEB or BEB by a transit agency, similar to the incentives currently in place for light-duty zero emission vehicles. These credits can last up to a certain volume of BEB or FCEB adoption and gradually wind down until incentives are no longer needed for total cost of ownership parity, and can be structured in size to compensate for the difference between state-of-the-art BEBs or FCEBs and current conventional bus units.

- Subsidized or discounted electricity rates for BEB charging or FCEB fuel production by transit agencies. These discounted rates can take the form of either wholly reduced electricity rates or the construction of electricity rate profiles that are tailored to the patterns of charging / fuel production loads

Introduction

Hydrogen Fuel cell electric buses and different configurations of battery electric buses (on-route charging or overnight charging) are being considered by several cities as a solution to replace fossil-based fuels in efforts to reduce local criteria pollutant and greenhouse gas emissions. However, when selecting a new bus technology, the environmental benefit cannot be quantified solely based on a comparison of tailpipe emissions. Only a detailed study of the entire life of a bus (cradle-to-grave or, ideally, cradle-to-cradle) and resources needed for manufacturing/operation/recycling allows a comprehensive comparison between competing technologies relative to a base case.

Because each zero-emission bus technology has different strengths and weaknesses, as well as unique operational requirements, the design of a life-cycle tool that can inform transit agencies about environmental and economic impact of their bus fleet would be highly valued. Research is required to develop a comprehensive life-cycle tool that can assist transit agencies in California answer the following question: Given our operating conditions, what zero-emission bus drivetrain configuration has the lowest cost of ownership with low environmental and health impacts?

The answer to such a question requires specifics about infrastructure and fuel/energy sources while guarantying to satisfy the transit agency’s operational requirements (e.g., route length, passenger demand, route schedule, space requirements).

One strategy is to develop an extended Life Cycle Assessment (LCA) methodology. The extended LCA would create a consistent framework across multiple powertrain types with the same operating conditions to assess energy consumption, operating emissions, and operation cost. To this end, the research methodology in this study consisted of three phases. The first phase focused on acquiring life cycle inventory data for different urban bus powertrain technologies by utilizing available life cycle databases and literature studies. The second phase modeled urban bus fleet operation to accurately capture operating energy needs and associated emissions in the context of powertrain characteristics and bus scheduling needs. The third phase utilized the Brightway2 LCA framework in combination with a to-be-developed economic model for performing full life cycle assessment of different urban bus powertrain options to determine per-mile greenhouse gas emission, criteria pollutant emission, cost, and environmental footprint performance. The project provided insight for the Orange County Transit Authority (OCTA) on the life cycle performance of different powertrain options on multiple criteria for use by state agencies and transit agencies in more effectively planning the transition of urban bus fleets to meet environmental objectives.

The goal of this project was to perform a life cycle characterization of greenhouse gas emissions, criteria pollutant emissions, and costs of conventional and alternative urban bus powertrains. This goal was accomplished by addressing the following objectives:

1. Life Cycle Inventory Database Development

Collect and create the necessary data to build database inventories of resources and materials relevant for conventional buses and ZEB technologies and the corresponding fuel supply chains.

2. Cost Inventory Database Development

Review of literature and demonstration projects to collect necessary data of operations, equipment, and fuel cost to conduct a total cost of ownership analysis.

3. Modeling of Urban Buses Energy Consumption and Use-Phase Emissions

Apply the methodology developed by Cox in [4] for the modeling of energy consumption and operating emissions for the relevant driving cycle for the corresponding transit agency. This requires specific modification to reflect emissions relevant to the selected temporal.

4. Environmental and Economic Life Cycle Analysis

Apply the principles of a cut-off allocation classification for the Life Cycle Assessment of bus technologies. Obtain the environmental impact from a life-cycle perspective, incorporating a diversity of energy supply pathways for hydrogen and electricity production. Conduct a cost analysis by characterizing the life cycle cost that includes acquisition, operation and disposal expenses.

5. Apply the Methodology to the Orange County Transit Authority

Demonstrate the methodology by an application to the Orange County Transit Authority (OCTA) to both test the utility and applicability of the methodology and to provide perspective and data in support of decision making within a major California transit district.

1. Life Cycle Inventory Database Development

The Life Cycle Inventory (LCI) is the list of all material and energy flows to and from the environment over the product or service's life cycle, which are quantified with the use of a life cycle database. The Ecoinvent database [1] is used as the LCA database in this thesis. The recycled content approach is used with the "allocation, cut-off by classification" system model for attributional LCA. Where possible, the life cycle inventories for transport technologies are built using datasets directly from the Ecoinvent database. Where the environmental burdens of a life cycle phase are significant and the Ecoinvent datasets are known to be lacking in some way, datasets are created based on literature review using the Ecoinvent database for the modelling of upstream processes. Datasets were specifically created to reflect manufacturing process in the US, as well as energy production and operations reflecting activities in California. Additionally, three main industry manufactures were contacted and agreed to provide proprietary data to validate/update manufacturing requirements and cost for the following components:

1. PEM Electrolyzer from Proton-on-site
2. PEM Fuel cells from Ballard
3. Hydrogen refueling infrastructure from Air Products

The information was provided under strict confidential agreements and should not be used nor published without the proper authorization, therefore, some information in the following sections will be redacted.

1.1. LCI for PEM electrolyzers

Data provided by Proton-on-site contains the list of materials for their M400 PEM electrolyzer, a 200 MW unit [2,3]. Based on the information provided by the manufacturer, the list of materials and electrolyzer configuration were updated to create a dataset in combination of the Ecoinvent database for the modelling of upstream processes. The Cell Pack, Hydrogen dryer & deoxidizer unit (HGMS) and Water purifier & feed water tank (WOMS) are the main components specific for a PEM electrolyzer. The list of materials for the additional components from the electrolyzer were leveraged from Simons, Andrew & Bauer, Christian. (2011) [4]. Table 1 describes the component for the electrolyzer unit and Table 2 shows the list of materials for three main modules.

Table 1. Components for one PEM electrolyzer by Proton-on-Site

Component name		
Electrolyzer cell package	1	unit
Hydrogen dryer and deoxidizer unit (HGMS)	1	unit
Water purifier and feed water tank (WOMS)	1	unit
Pumps for electrolyzer	1	unit
Transformer and rectifier unit, for electrolyzer	1	unit
Control panel, for electrolyzer	1	unit
Water purifier and feed water tank, for electrolyzer	1	unit
Heat exchange module, in electrolyzer	1	unit
Tubing and cables, for electrolyzer	1	unit

Table 2. Material list for electrolyzer cell pack, HGMS and WOMS modules

Material name	Mass (kg)	% of total	kg/KW of system
Stainless steel	[redacted]	[redacted]	[redacted]
Carbon steel	[redacted]	[redacted]	[redacted]
Aluminum	[redacted]	[redacted]	[redacted]
Copper	[redacted]	[redacted]	[redacted]
Titanium	[redacted]	[redacted]	[redacted]
Polyetherimide	[redacted]	[redacted]	[redacted]
Ethylene tetrafluoroethylene	[redacted]	[redacted]	[redacted]
Perfluoro sulfonic acid	[redacted]	[redacted]	[redacted]
Carbon	[redacted]	[redacted]	[redacted]
Styrene	[redacted]	[redacted]	[redacted]
Iridium	[redacted]	[redacted]	[redacted]
Platinum	[redacted]	[redacted]	[redacted]
Nickel	[redacted]	[redacted]	[redacted]
Silicon	[redacted]	[redacted]	[redacted]

Source: Proton-on-Site (confidential)

1.2. LCI for PEM fuel cells

Ballard Power was contacted to obtain proprietary data of their PEM fuel cell units. The information provided by them is also considered confidential and any publication or citation should be previously authorized. Based on the information provided by the manufacturer, the list of materials and configuration were updated to create the fuel cell dataset in combination of the Ecoinvent database for the modelling of upstream processes. The operational specifications for the HD-6 fuel cell module provided by Ballard is presented in Table 3.

Table 3. Ballard PEM fuel cell operation and cost specifications

Description	Unit
Product Lifetime	[redacted] hours
Preventative and Corrective Maintenance Cost	[redacted] per km
Product Cost (Price of Stack and System)	[redacted] $/kW
Stack Refurbishment Cost (At End of Stack Lifetime)	[redacted] $/kW
Platinum Content	[redacted] mg/cm2
Platinum Content (Kg/Kw)	[redacted] kg/kW
Hd-6 Module Power Density	[redacted] kW/m3

Source: Ballard Power (confidential)

The provided information by the manufactures was incorporated into the life cycle inventory of PEM fuel cells from Ecoinvent, with exception of the Platinum content. The platinum load provided by Ballard was found to be above the average of the available literature and other industry sponsored studies [5–7]. The technology used by Ballard is believed to be outdated and does not follow he most recent industry improvements in the fuel cell market. The platinum load was kept to 0.0002 kg/KW as initially assumed in current publications [8].

1.3. LCI for batteries

The life cycle inventory developed for batteries focused on lithium-ion technology. Depending on the end application and capacity, a variety of lithium-ion chemistries are being commercialized. Table 4 shows different battery chemistry types with their energy densities and existing applications.

Table 4. Lithium-ion Battery Chemistry Characteristics and Applications [9]

Battery Chemistries	Specific Energy (Wh/kg)	Life Span (Cycles)	Applications
Nickel Cobalt Aluminum (NCA)	160	2000+	Used in cars (e.g., Toyota Prius, plug-in hybrid, Tesla)
Nickel Manganese Cobalt Oxide (MNC)	150	2000+	Used in consumer goods, cars, and buses (e.g., Nissan Leaf, Chevrolet Bolt, Proterra, New Flyer)
Lithium Manganese Oxide (LMO)	150	1500+	Used in cars (e.g. Nissan Leaf)
Lithium Titanate (LTO)	90	5000+	Used in cars and buses (e.g., Honda Fit, Proterra)
Lithium Iron Phosphate (LFP)	140	5000+	Used in cars, buses, and trucks (e.g., BYD, TransPower, Siemens, Nova Bus, Volvo) and stationary energy storage systems

Because of the long-life span and high specific energy, three types of batteries, LFP, LTO, and NMC, are being developed in the application of medium- and heavy-duty vehicles. LFP batteries use graphite as the anode, and $LiFePO_4$ as the cathode. The electrolyte is a lithium salt in an organic solvent. In addition, the use of phosphate as a positive electrode significantly reduces the potential for thermal runaway [9].

Since LFP has higher discharge current and requires smaller battery size to achieve a given performance target, in addition to a superior thermal and chemical stability, this is the chemistry selected to model the performance of BEBs in this research work.

According to energy storage related patent activity from 1999 through 2008, LFP technology has been the focus of at least twice as much as LTO technology, and four times as much as NMC technology [10]. This battery technology is used in the TransPower BEV drayage truck, electric school bus demonstrations, and by BYD buses.

The battery configuration used by the twenty BYD buses that arrived at UCI in 2018 is used to define the parameters of the battery in the model. Table 5 shows the battery specifications for the BYD buses at UCI. However, a dynamic function is defined in Python to scale the battery capacity, power, and current to any battery size using the BYD's bus specifications as points to generate the function in combination with bus specifications of other manufacturers (Table 6). The disaggregation of the operational parameter for the battery allows to explore different bus configuration and sizes without relying on specifications unique to individual manufacturers.

Table 5. BYD battery specifications for buses at UCI

Bus specifications:		Units
Number of cells per battery system	384	
Number of modules per battery system	2	
Number of packs per battery system	2	
Battery system total energy storage	324	KWh
Battery power	300	KW
Nominal battery system voltage (OCV at 50% SOC)	550	V
Battery capacity	103680	Ah
Maximum current at full power	250	A
Recommended State of charge (SOC) defined by BYD	20%	
Battery specific energy	134	kWh/kg
Battery configuration (2 packs in parallel, 192 cells in series in a pack)	270	Ah cell
Battery system voltage (V)	600	V
Battery capacity (kWh)	324	kWh

Table 6. Battery Electric Bus Specifications from Various Manufacturers

	Model	Length (ft)	Battery size (KWh)	Max Power (KW)	Range	Top Speed (mph)	Battery Chemistry
BYD	K9M	40	324	300	155	65	-
Proterra [11]	XR	40	220	380	153	65	-
Proterra [11]	E2	40	440	380	270	65	-
GreenPower [12]	EV350	40	320	300	185	60	LiFePO4
New Flyer [13]	Xcelsior Charge 40	40	545	380	260	-	LiNiMnCb
New Flyer [13]	Xcelsior Charge 41	40	480	380	234	-	-
New Flyer [13]	Xcelsior Charge 42	40	200	380	87	-	-
Nova [14]	LFSE	40	-	230	-	-	LiFePO2

The function in Python uses a correlation between the battery sizes to estimate the range of the specified bus size in the model, Figure 1 shows the correlation.

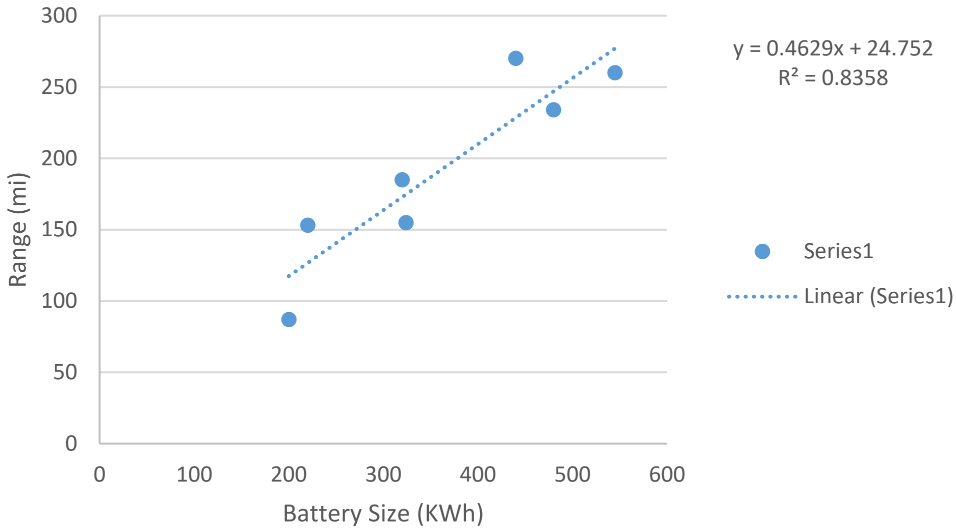


Figure 1. Correlation between battery size in KWh and bus range

1.4. Energy generation libraries for the WECC region and California

The life cycle inventories for the electricity generation and manufacturing activities were adapted to reflect operations in the Western Electricity Coordinating Council (WECC) region. The main data source for this adaptation came from existing inventories in Ecoinvent using the energy mix corresponding to WEEC [15]. An additional electricity generation mix was added, the grid electricity mix for California. The California grid mix was build based on information from the EIA and from the California Energy Commission for the year 2017 [16] [15]. This generation mix was used in the different scenarios for specific fuel generation in the different LCA scenarios, (e.g., electricity to power electrolysis or energy to charge batteries) and the WEEC mix was used to any secondary process for the production of the buses or related components.

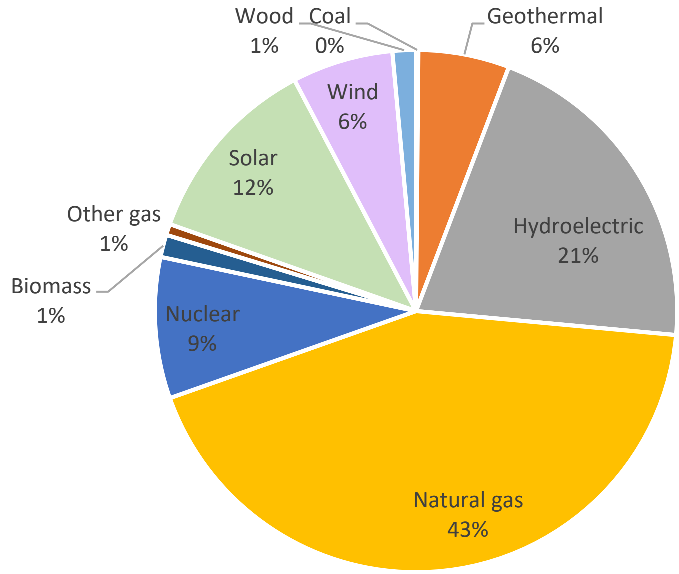


Figure 2. California Electricity Generation Mix 2017 ***[15]***

1.5. Life cycle impact assessment

Life Cycle Impact Assessment (LCIA) quantifies and groups the environmental burdens due to the LCI into categories associated with known environmental issues. In this thesis, ReCiPe 2008 LCIA method was used with the hierarchist perspective [17]. The environmental impact categories most relevant to passenger transport are discussed below.

Climate Change (CC) represents the contribution to climate change due to the emission of greenhouse gases such as CO2 and CH4. For this indicator it was selected the most recent global warming potential characterization factors from the IPCC 2013 as implemented by the Ecoinvent Centre [29, 31]. CC is quantified in kg CO2 equivalent.

Human Toxicity (HT) represents human exposure to toxic chemicals such as heavy metals and hydrocarbons. HT is quantified in kg 1,4 DB equivalent.

Photochemical Oxidant Formation (POF) considers the formation of ground level ozone due to the reaction of NOx with Non-methane Volatile Organic Compounds (NMVOCs). POF is quantified in kg NMVOC equivalent.

Particulate Matter Formation (PMF) considers the human health impacts of fine particles in the air that can enter the lungs. The method takes into account not only the direct emission of particulates, but also the formation of secondary particulates due to emissions such SO_x, NO_x, and ammonia (NH3). PMF is quantified in kg PM10 equivalent.

Mineral Depletion (MD) represents the impact on society due to depletion of mineral resources. MD is quantified in units of kg Fe equivalent.

Cumulative Non-Renewable Energy Demand (CED) includes all primary energy demand from fossil and nuclear sources. This method is extended to include also renewable energy sources such as solar, wind and hydro energy. CED is quantified in units of MJ.

1.6. Linking life cycle databases with integrated assessment models

One major weakness in prospective LCA is that no background databases are available that represent the current global economy used to produce a foreground system. While prospective LCA studies usually take pains to modify the most important foreground processes, for example in the LCA of a future electric bus the bus efficiency and the electricity grid technology mix used to charge the batteries would be modified for the future, the rest of the system is usually modelled using the current standard of technology [14, 15, 17, 33, 34]. That is, the future bus is produced using the current electricity system, with current steel production and so on. Some studies, however, have attempted to correct this simplification and include changes to key processes in the background, such as electricity, certain metals, and concrete production [35, 36]. However, the limitation of the NEEDS [35] and THEMIS [36] approaches is that they require significant manual work to create the future database, which makes model updates difficult and changes opaque. For this reason, the background databases developed in the NEEDS project have not been used in future work, and results from the THEMIS model are still published with the outdated Ecoinvent version 2.2 [37, 38].

The goal of the methodology established here is to create a framework that allows easy, reproducible, and transparent changes to LCA databases based on external data sources. The software should be written to enable updating the work for new versions of input data or background databases with minimal effort. Ideally a single well accepted source of future technology performance would be used to ensure data consistency. For the scope of this thesis, it was determined to limit the scope to only changes to the global electricity sector. Changes to the electricity sector are relevant as electricity contributes significantly to LCA results for most products, and the electricity sector is expected to change dramatically in the coming decades.

The methodology used to create a modified version of the Ecoinvent database using imported data from literature review is described in Figure 3. The creation of the modified version of Ecoinvent takes place in five steps as described below.

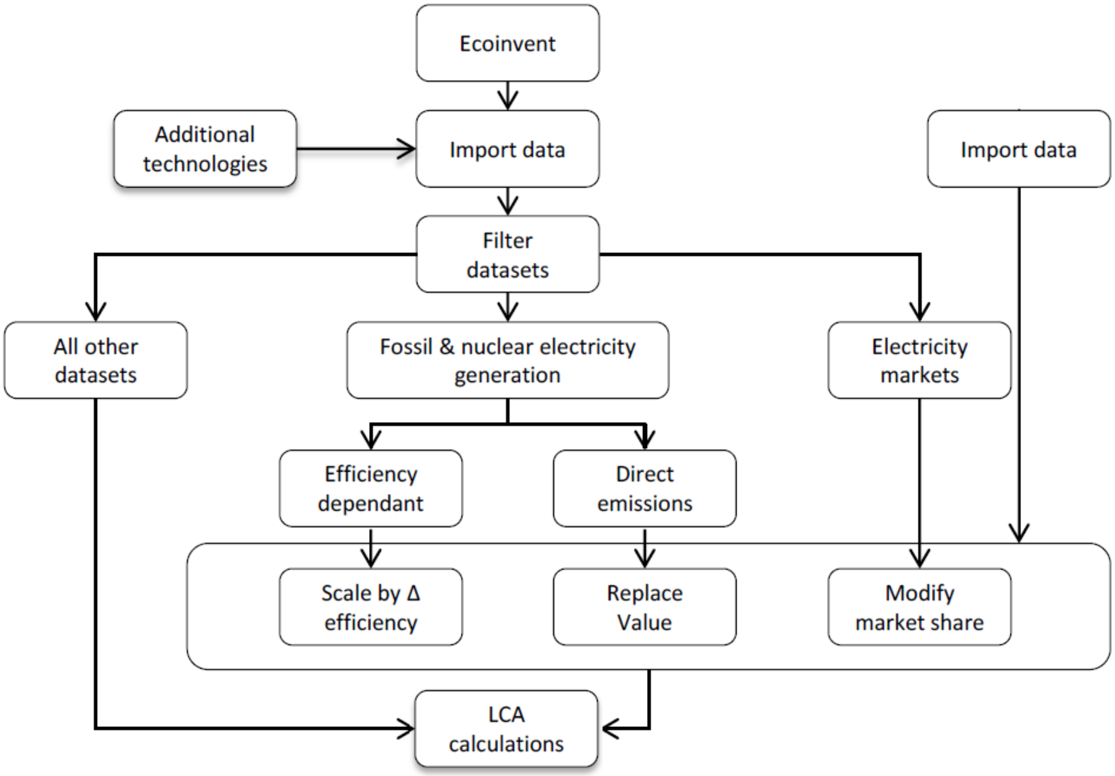


Figure 3. Schematic of procedure to modify Ecoinvent using integrated assessment model *[18]*

Data preparation

In the first step, the allocated Ecoinvent database is imported into a list of single output unit processes that can be modified. Additionally, LCI data for electricity generation with carbon capture and storage from fossil fuels and biomass are imported from Volkart, Bauer [42].

In a parallel step, external data collected from literature review are imported into the python data analysis library pandas.

Modifying electricity production datasets

In the next step, electricity generation datasets for all fossil fuels, nuclear and biomass are modified in two ways:

1. Direct emissions of substances such as NOx, SOx, methane, and carbon monoxide are modified directly in Ecoinvent. As no clear relationship between black carbon and PM emissions could be included, PM emission reductions are included using method two described below.

2. All other processes, such as the power plant infrastructure and fuel consumption are assumed to scale with the changing efficiency of the process. That is, we take the Ecoinvent values as the base, and if the external model results show a 10% efficiency improvement compared to the Ecoinvent value (relative), the value in the Ecoinvent unit process is decreased by 10%.

As the Ecoinvent dataset does not contain explicit assumptions regarding the improved efficiencies of renewable electricity generation technologies, such as wind or solar, these technologies are left unchanged. Capacity factors of all electricity generating technologies are also left unchanged.

Modifying electricity market datasets

Following this, the average market electricity for each region in Ecoinvent is adapted using WECC and California specific data [19,20]. First, a list of Ecoinvent unit processes is created for each electricity generation technology. For example, the technology "Coal steam turbine" is matched to two Ecoinvent processes:

- electricity production, hard coal
- electricity production, lignite

When matching Ecoinvent datasets to generation technologies, all Ecoinvent datasets have been used that match the generation technology description without judgement of whether that specific technology will be important in the future.

Next all Ecoinvent high voltage electricity market datasets are modified in turn in the following four steps:

1. All electricity supply exchanges are deleted from the dataset. Exchanges for the transmission grid, transmission losses, supervision and emissions are not modified.

2. The Ecoinvent location is matched to a region, WECC or California.

3. For each electricity technology to be included in the market, a list of Ecoinvent processes is created. The first choice is to select Ecoinvent processes that match the generation technology and have the same Ecoinvent location as the market dataset. If this is not possible, the second choice is to select all matching technologies in the same region as the market dataset. If more than one technology is matched, the electricity contribution is shared equally between them.

4. The total electricity produced is confirmed to sum to one kilowatt hour.

In the last step for electricity market modification, all additional electricity suppliers and electricity imports to medium and low voltage electricity markets are removed, as the simplifying assumption was made that all technologies feed into the high voltage network.

2. Cost Inventory Database Development

For all the bus technologies considered in this dissertation work the life cycle cost (LCC) is defined as a method to estimate total cost of ownership. The costs associated with acquiring, operating, maintaining, and disposing of a bus fleet with corresponding refueling infrastructure are organized into the following Table 7.

Table 7. Life Cycle Cost Factors

Capital Cost	Bus Purchase	Price for onboard equipment and standard warranty
	Fueling Facilities	Cost to build new fueling station
	Staff Training	Not considered in model
	Equipment upgrade	Facility modifications and new tools to service new technologies
	New spare parts	Not considered in model
Operation and Maintenance Cost	Bus Maintenance	Schedule: Parts and labor cost for regular preventive maintenance Non-schedule: Parts and labor for other failures
	Fuel Station O&M	Station's operation and maintenance cost
	Fuel Use and Cost	Fuel price are set based on historical data and adjusted due to inflation for 12 years of operation. Fuel economy is calculated based on the methodology that will be described in the following section Other operational costs are neglected, like driver's cost, since it will be the same for all technologies
	Rehabilitation/ Replacement	Cost of replacement with new or rebuild according to mandated overhauls by the FTA or due to technology lifetime
	Residual Values	Not considered in model

Only those costs within each category that are relevant to the decision and significant in amount are considered in the life cycle cost analysis. Costs are relevant when they are different for one alternative compared with another; costs are significant when they are large enough to make a credible difference in the LCC of a bus technology alternative. All costs are entered as base-year amounts in today's dollars; the LCCA method escalates all amounts to their future year of occurrence and discounts them back to the base date to convert them to present values considering 3% inflation [21].

2.1. Life cycle cost for Compressed Natural Gas (CNG) buses

CNG refueling infrastructure

Cost estimations for refueling stations were leveraged from cost reports of stations built for transit agencies that transitioned from diesel to CNG, in addition to reports from private consultant firms and research institutions. The following station configurations are what is reflected on the cost estimations.

CNG Station Configuration

A buffer fast-fill station configuration is selected since its ideal for high fuel use vehicles that require immediate refueling, one after another [22]. Transit buses frequently utilize this configuration due to their need to consecutively refuel and due to overall fuel demand. Buffer systems primarily fuel directly from the compressor into the vehicle, thus requiring less storage. For fast-fill configuration the demand is set primarily by the hourly flow rate of the compressor(s).

Typical components of a buffer fast-fill CNG system include those for a fast-fill (Figure 4) with the priority panel and sequencing valves replaced by a Buffer Control Panel that routes fuel directly from the compressors to the dispensers using stored fuel only if compressor capacity is exceeded.

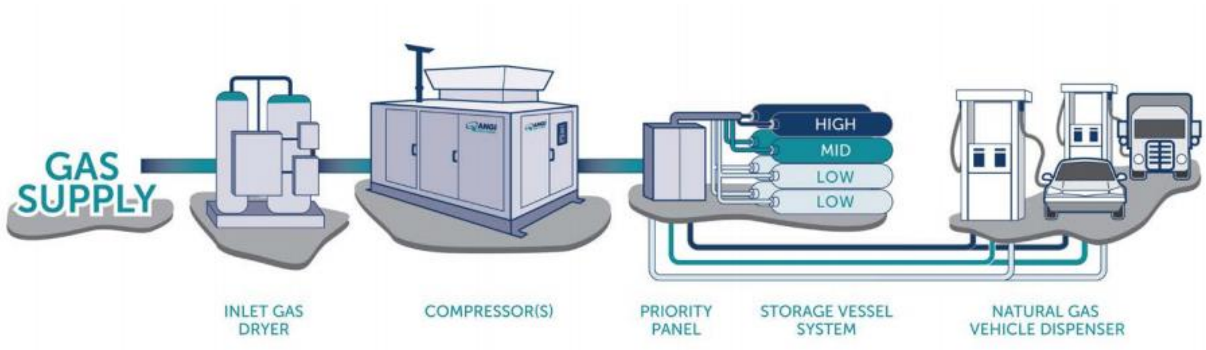


Figure 4. CNG fast-fill refueling configuration *[23]*

Only the equipment that was identified to drive the total cost of the station was considered in the cost calculations, this includes:

- Compressor
- Dispenser
- Storage
- Dryer
- Generator
- Transformer

The price for these components directly depends on the desire capacity, which simultaneously depends on the fuel demand from the transit agency. It was decided to create a dynamic cost model that could provide personalized cost estimations based on the fleet size at each depot of the transit agencies. The first calculation of the cost model is to determine the number of compressor and compressor's capacity based on the filling capacity (FC), also known as flow rate, required at each base. If the filling capacity is not an input for the model, the require number of buses at each base is required and then the following calculation is considered:

$$\mathrm{FC} = \gamma \; \frac{buses}{base} * \frac{45\; GGE}{bus} * \frac{1}{3\; hr} * \frac{1hr}{60\; min} * \frac{125\; scf}{1\; GGE} = x \; \frac{scfm}{base} \qquad \text{Eq. (1)}$$

Eq. (1) calculates the fill capacity (FC) required at each base, expressed in standard cubic foot per minute (scfm), this capacity directly correlates to the compressor capacity. The following assumptions are considered for Eq. (1):

- The input of buses per base is presented in the equation as "γ"
- The average tank capacity for CNG buses is 170 GGE [24], however, not all buses use the entirely mileage range every day. From observations of data provided by OCTA it was concluded that, on average, at each base 45 GGE of CNG are filled per bus. Some buses use as much of 95% of its tank capacity, while others less than 20%, therefore, the 45 GGE/bus represents the average fueling [25].
- Fast-filling can be selected in the model for fleets larger than 170 buses/base. It's assumed that a window of 3 hours is the time available to completely refueling of the fleet. Even if the fueling window is more than three hours, this number is used as the critical refueling window to calculate the minimum compressor capacity [25].

- Conversion factor: one gasoline gallon equivalent (GGE) of CNG is equivalent to 125 standard cubic foot (scf) [26].

The calculated fill capacity (FC) is then used to determine the number of compressors required per depot Eq. (2).

$$n = \frac{FC}{\varepsilon} \qquad \text{Eq. (2)}$$

If γ > 170 buses → ε = 2,000 scfm; Eq. (3)

Where

n = number of compressors

x = depot fill capacity (flow rate) in scfm/depot

ε = compressor capacity in scfm

γ = number of buses per depot

The compressor capacity has been set as a depending variable of the number of buses per depot. It's also depending on the fueling method, in this case it's specific for fast-filling. Eq. (3) it's the conditional used to set the compressor capacity and the assumptions are based on compressors installed in real depots [27,28].

Cost of CNG refueling station

The cost of compressors drives the station cost and it correlates with the number of dispensers, another primary cost factor. Eq. (4)describes how for fast filling station the number of compressors is equal to the number of one-hose dispensers (δ). If the number of hose/dispenser ratio increases, then the filling time would increase, and the three-hour filling window would no longer be part of the configuration assumptions.

$$n = \delta \qquad \text{Eq. (4)}$$

Installation cost is the third main factor that drives the total cost of the refueling station. Since the installation cost can vary depending on biding and from contractor to contractor, estimations from consulting reports were used. It's assumed that 65% of the total cost of equipment is equal to the cost of installation [29].

A comprehensive literature review was completed to compare the cost and specifications of equipment required at a CNG fueling station. Table 8 presents the compilation of equipment and range of cost found in the literature.

Table 8. Compilation of equipment cost used at CNG fueling stations

Equipment	Flow Rate (scfm)		Price ($)		Source
	Low	High	Low	High	
Backup Power Generator			$ 150,000	$ 250,000	[29,30]
Compressors	1	650	$ 4,000	$ 550,000	
	1	8	$ 4,000	$ 22,000	
	20	40	$ 5,000	$ 90,000	
	50	75	$ 80,000	$ 150,000	
	100	150	$ 100,000	$ 250,000	
	250	650	$ 200,000	$ 550,000	
	1700	2000	$ 500,000	$ 600,000	[23,28,31]
Dispenser fast fill			$ 25,000	$ 60,000	[29]
Dual-hose time-fill post			$ 4,000	$ 7,000	[24,29]
Storage tank			$ 70,000	$ 130,000	
Card Reader			$ 10,000	$ 30,000	
Gas Dryer			$ 10,000	$ 300,000	

Using the values from Table 8 and reports from transit agencies that transitioned from diesel to CNG [28,32] the following equations were formulated to estimate the cost of equipment, and ultimately, the total cost of investment for a CNG fueling station. It is important to note that all the values for Table 8 were dated prior to 2012, therefore, an adjustment for the future value considering inflation was applied [33].

Total cost of CNG compressors:

$$C_{CNGcompr} = n * \$700{,}000 \quad \text{Eq. (5)}$$

Total cost of one-house dispensers in station:

$$C_{CNGdisp} = \delta * \$70{,}000 \quad \text{Eq. (6)}$$

Cost of backup generator[1]:

$$\text{if } \varepsilon = 2{,}000 \text{ scfm} \rightarrow C_{CNGgen} = \frac{n}{3} * \$200{,}000 \quad \text{Eq. (7)}$$

Cost of storage:

$$C_{CNGstore} = \$550{,}000 \quad \text{Eq. (8)}$$

Cost of gas dryer:

$$\text{if } \varepsilon * n > 6{,}000 \text{ scfm} \rightarrow C_{CNGdryer} = \frac{\varepsilon * \mathrm{n}}{6{,}000} \$80{,}000 \quad \text{Eq. (9)}$$

ε = compressor capacity in scfm

n = number of compressors

Total cost of a CNG filling station is calculated with Eq. (11), where the cost of equipment and installation is included by a factor of 65% of the total cost of equipment [29]. Eq. (10) includes the numerical values for each of the factors that contribute to the cost of the CNG station.

$$C_{CNGstation} = [C_{CNGcompr} + C_{CNGdis} + C_{CNGgen} + C_{CNGstore} + C_{CNGdryer} + C_{CNGtransforme}] * 1.65 \quad \text{Eq. (11)}$$

$$C_{CNGstation} = [n * \$616{,}500 + \delta * \$60{,}000 + \$130{,}000 + \$300{,}000 + \$550{,}000 + \$80{,}000] * 1.65 \quad \text{Eq. (12)}$$

[1] 1,500 kW Ultra-low sulfur diesel generator [71].

- **Maintenance and operation cost for CNG filling station**

The estimated annual maintenance and operation (M&O) costs used in the model are 5% of the upfront cost of a large station and 8% of the upfront costs of a small station. This assumption, provided by Rob Adams of Marathon Technical Services [34], was selected because the value averages the M&O estimates received from other sources. The estimates from other sources vary as a result of contractor's reliance on station-specific circumstances that were not available for these general estimates.

Cost of CNG Bus Maintenance

The total cost of maintenance for CNG, including preventive maintenance and unscheduled repairs, was reported by OCTA to be $0.59 per mile. A similar value was reported by NREL for a combination of CNG buses used at Massachusetts Bay Transportation Authority (MBTA), OCTA, and SunLine (Table 9) [35]. Data for the maintenance cost were collected for CNG buses with year models between 2008 and 2013. For the total cost of ownership simulation, the maintenance cost was model as a total cost of $0.57 per mile.

Table 9. Maintenance cost per mile by system component for CNG buses [35]

System	Cost per Mile ($)
Car, body, and accessories	0.26
Propulsion-related	0.10
Preventive Maintenance Inspection	0.07
Brakes	0.03
Frame, steering, and suspension	0.04
HVAC	0.03
Lighting	0.01
Tires	0.01
Total	0.54

CNG Bus Purchase Price

A literature review was conducted to investigate the purchase price of CNG buses offered by different manufacturers (see Table 10). The purchase price by ElDorado was adjusted with an inflation rate of 3.5% and then used to estimate the average price for a CNG bus. The total cost used for the model was set to $650,000 per CNG bus.

Table 10. CNG bus purchase price by different manufacturers

Manufacturer	Unit Price ($)	Source
ElDorado National 2003	205,185.33	[36]
NABI	575,000.00	[37]
MTA	683,304.35	[38]

Price of CNG fuel

The default liquid fuel prices used for this dissertation are national commercial retail averages and come from the U.S. Energy Information Administration (EIA) Gasoline and Diesel Fuel Updates [39]. Fuel prices are reported weekly and provide national and regional retail averages for conventional fuels such as gasoline and diesel.

The price of CNG was calculated based on the 6-month California average price of commercially delivered natural gas [40]. This value was then converted from $/ft3 to $/GGE using EIA conversion factors of 1,023 Btu/ft3 and 124,238 Btu/gasoline gallon resulting in an average cost of $1.06 per GGE of CNG.

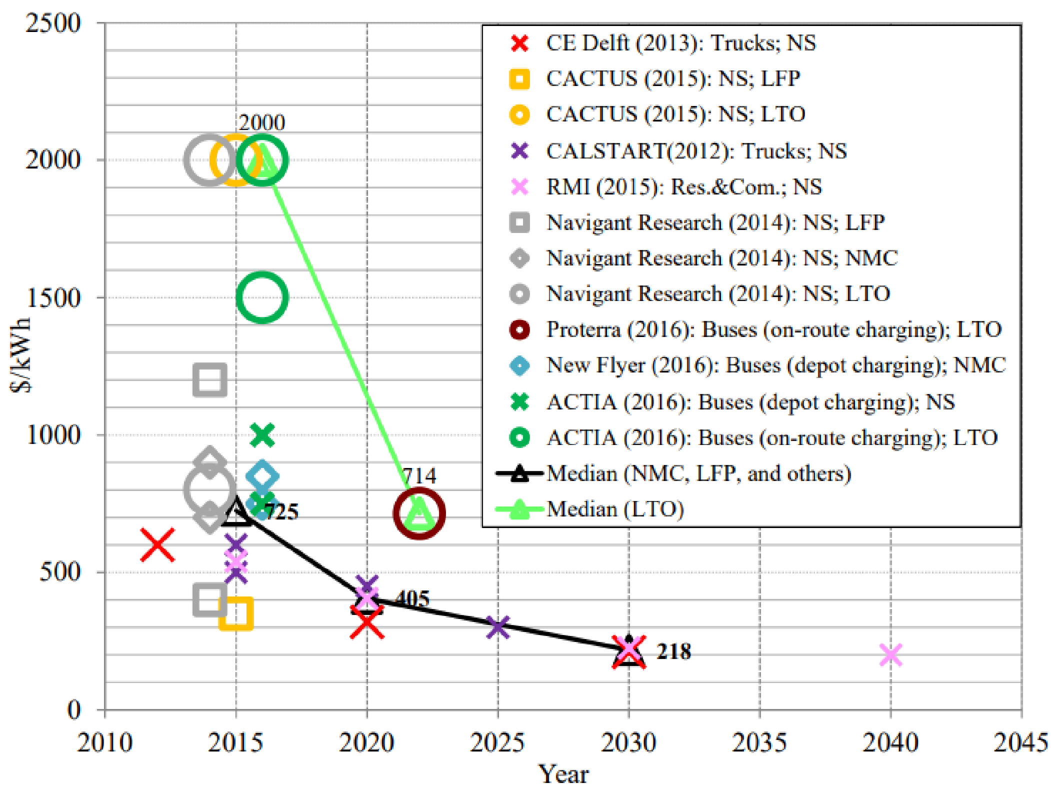
The price of CNG was validated with data collected at Foothill. During 2018, Foothill Transit paid an average of $0.90/GGE for CNG [41] or $0.93/DGE.

2.2. Cost Inventory for Battery Electric Buses

Cost of Batteries

The Electric Power Research Institute (EPRI) has identified three key cost dependencies: cell size, cell production volume, and standardization of battery components. Studies from Argonne National Laboratory (ANL) noted that estimates of battery costs vary with power to energy (P/E) ratio, production sale, and thermal management systems. To accurately model the cost of batteries, detailed information was required regarding these cost driving factors. Much of the information available concerning cost models of batteries is specific to light-duty batteries and although some batteries used for heavy-duty electric vehicles share similar chemistry as light-duty ones, battery pack costs per kWh for heavy-duty battery electric vehicles (BEVs) are currently higher, mainly because of different packaging, thermal management systems, and lower purchase volumes [9].

It is currently challenging to estimate battery cost for heavy-duty BEVs due to the following three reasons: (1) battery costs vary widely with chemistry, yet most estimates are for all types of lithium-ion batteries lumped into one group; (2) most published estimates are applicable for light-duty BEVs and not for heavy-duty vehicle applications; and (3) a lack of information about explicit relationships between production volume and battery cost for heavy-duty vehicle applications [9]. However, the estimated costs from various studies can be used as a reference to model the battery costs as a function of capacity. An ARB report [9] contained the most relevant and well-summarized data. Battery cost ranges from different literature sources, evaluated for the report, included studies such as CE Delft (2013), CACTUS (2015), CALSTART (2012), Rocky Mountain Institute (RMI) (2015), Navigant Research (2014), and cost estimates from OEMs as summarized in Figure 5.



Sources: CE Delft, 2013; CACTUS, 2015; CALSTART, 2012; RMI, 2015; Navigant Research, 2014; Proterra, 2016; New Flyer, 2016; ACTIA, 2016

Figure 5. Battery Cost Estimates and Projections from Different Sources [9]

Since a disaggregated cost model of the batteries was not possible, the cost was instead designated based on levelized average costs of batteries with the same chemistry and with calculated future values for the year 2018. As described in Section 1.3, Lithium Iron Phosphate (LFP) was selected as the default for the chemistry of the batteries in the model. The calculated cost of this battery was set to $700 per KWh.

Battery Electric Bus Purchase Cost

Ideally, the purchase price for zero-emission buses should be desegregated to have the price per component so that the price of different bus sizes and configurations can be accurately estimated. However, little to no data have been made available by bus manufacturers. Instead, a literature review was conducted to investigate the purchase price of plug-in (versus route-charging) BEBs offered by different manufacturers (see Table 11).

Table 11. Purchase prices of 40-foot long plug-in BEBs by different manufacturers

Manufacturer	Unit Price ($)	Source
BYD	$ 529,400.00	[42]
BYD for UCI	$ 824,262.00	
Proterra	$ 825,000.00	[37]
	$ 789,000.00	
	$ 904,490.00	
Green Power	$ 850,000.00	[43]

Even though the size of the buses is the same for all the buses in Table 11, battery and motor configurations vary across manufacturers. To standardize the bus price for the model, the following approach was applied:

- All the unit price of the buses from Table 11 were converted from the year of publication to the year 2018 using a future value formula with an inflation rate of 3.5% [33].
- For each unit price of the different bus manufacturers, the cost of the battery size was subtracted. The battery price was determined following the methodology described in the section above. This yields the cost of chassis, motor (including cooling system), auxiliary components, and any personalized modifications to the bus.
- Cost of personalized modifications was subtracted when details are available.
- An average of the bus price was calculated to obtain the standardized bus price without the cost of the battery.
- The standardized bus price was then added to the model to a function that adds the cost of the battery based on the desire battery capacity, which was set as an input for the model. Eq. (13) describes the function in the model where $C_{Battery}$ is the cost of the battery in $/KWh as described in the previous section.

$$C_{BEB} = C_{standarBus} + B_{capacity} * C_{Battery} \quad \text{Eq. (13)}$$

Following the describe calculations, the unit price calculated by the model for a 40-foot BEB with a 320-kWh battery size is of $780,000. This price excludes the financing cost since that factor was calculated in the total cost of ownership calculations at a 3.44% interest rate and a 3.5% inflation rate.

The bus price for BEBs that charge on-route, however, differs in the motor configuration and other auxiliary systems. Therefore, the price for on-route BEBs was calculated using the same calculations described above but using the data presented in Table 12, obtained from the literature review.

Table 12. Purchase price of on-route charging BEBs

OEM - Operator	Bus Cost	Source
BYD - AVTA	$ 770,000.00	[42]
Proterra - King county	$ 797,882.00	[37]
Proterra - Foothill	$ 789,000.00	[37]

Cost of Charging Infrastructure

Modeling the cost of charging infrastructure becomes complex since the level of electric modifications necessary to install equipment can widely vary depending on the depot location and current equipment. Additionally, the different arrangements with the utility company and equipment manufacturer have proven to drastically affect the investment cost.

The conducted literature review regarding the cost of charging infrastructure of different demonstration projects presents combined installation costs without making distinctions between the cost of labor or electric equipment - such as transformers, generators, etc. Furthermore, the data collection shows a lack of reporting on the cost of chargers for operators since often the purchase contract combines the cost of vehicle and cost of chargers.

The twenty plug-in buses delivered to UCI had a well-documented deployment process and data collected during the period of this dissertation and were used as a reference point to average cost values found in the literature. According to reports from UCI Anteater Express, the installation of twenty chargers with individual connector, including connection to the UCI micro-grid and preparation of the lot, cost $1.52 million. However, specific details of the construction process and installed equipment remain confidential for safety reasons.

An average cost per charger was estimated based on literature data presented in Table 13 and Table 14, and it was levelized using information from Anteater Express. For plug-in or depot chargers, the cost equipment was set to $40,000 for one connector charger with installation costs of $70,000 per bus. For on-route chargers, the equipment cost was set to $500,000 per charger with $250,000 for installation per charger (dual charger).

Table 13. Cost of depot charging BEBs and charging infrastructure

OEM - Operator	Bus Unit Price	Equipment Cost per Depot Charger	Installation Cost per Depot Charger
BYD - AVTA	$ 770,000	$ 19,000	$ 55,000
BYD - UCI	$ 784,262	$ 40,000	$ 76,500
Proterra - King county	$ 797,882	$ 60,000	---
Center for Transportation and the Environment (CTE)	$ 887,308	$ 50,000	$ 17,050

Table 14. Cost of on-route charging BEBs and charging infrastructure

OEM - Operator	Bus Unit Price	Equipment Cost per on-route Charger	Installation Cost per on-route Charger
BYD - AVTA	$ 770,000	$ 350,000	$ 250,000
Proterra - King county	$ 797,882	$ 600,000	$ 241,510
Proterra - Foothill	$ 789,000	$ 500,000	$ 200,000
Center for Transportation and the Environment (CTE)	$ 887,308	$ 495,636	$ 202,811

Maintenance Cost of BEBs

The total cost of maintenance for BEB was reported by CTE to be $0.64 per mile[44]; this includes scheduled and unscheduled repairs. A similar value was reported by NREL for the BEB deployed at Foothill [37]. Data for the maintenance cost were collected for BEBs that started service since 2014.

Table 15 presents the maintenance cost by system type, but for the total cost of ownership simulation, the maintenance cost was model as a total cost of $0.60 per mile.

Table 15. Maintenance cost per mile by system component in battery electric buses [37]

System	Cost per Mile ($)
Cab, body, and accessories	0.109
Propulsion-related	0.199
Preventive Maintenance Inspection	0.085
Brakes	0.002
Frame, steering, and suspension	0.022
HVAC	0.010
Lighting	0.013
Axles, wheels, and drive shaft	0.000
Air, general	0.156
Tires	0.0.18
Total	0.610

In Table 15 the propulsion-related repairs for the BEBs include low-voltage batteries, battery equalizer, cooling system, DC-DC converter.

Electricity Prices

Through collaboration with Anteater Express, it was possible to obtain the electricity invoice of their depot. The electric bill reflects the operations, demand chargers, and corresponding rate. The electric bill was obtained for the summer and winter months of 2018, reflecting the different rates throughout the year. An average of the year 2018 was used to calculate the average electricity price, which resulted in an average of $0.14 per KWh. However, it's important to note that the Anteater Express charging lot is connected not to a utility company, but rather to the UCI microgrid with an associated rate structure unique from the local utility.

Since transit agencies will be subject to prices of electricity based on different tiers from utilities as well as different electricity rates for summer and winter months, it was necessary to consider such factors in the fuel price estimations. One of the best-documented pilot projects for BEBs is the case of Foothill. The electricity rates have been recorded by NREL since early 2014, but a recent change in rate structure (from TOU-GS-1-A to TOU-EV-4) provides the most relevant information from 2016 to 2018 [41,45].

Figure 6 shows the monthly electricity cost at Foothill Transit agency under tier TOU-EV-4. Transit pays different electricity rates for the summer and winter months. During the reporting period for Foothill, the average price was $0.16 per kWh for the winter months (October–May) and $0.21 per kWh for the summer months (June–September). The average rate under TOU-EV-4 rate structure is $0.18/kWh, and this was the assumed value for the total cost of ownership simulation [41,45]. The assumption was that no demand chargers are applied due to charge management strategies and was assumed that the monthly demand is between 20 kW and 500 kW.

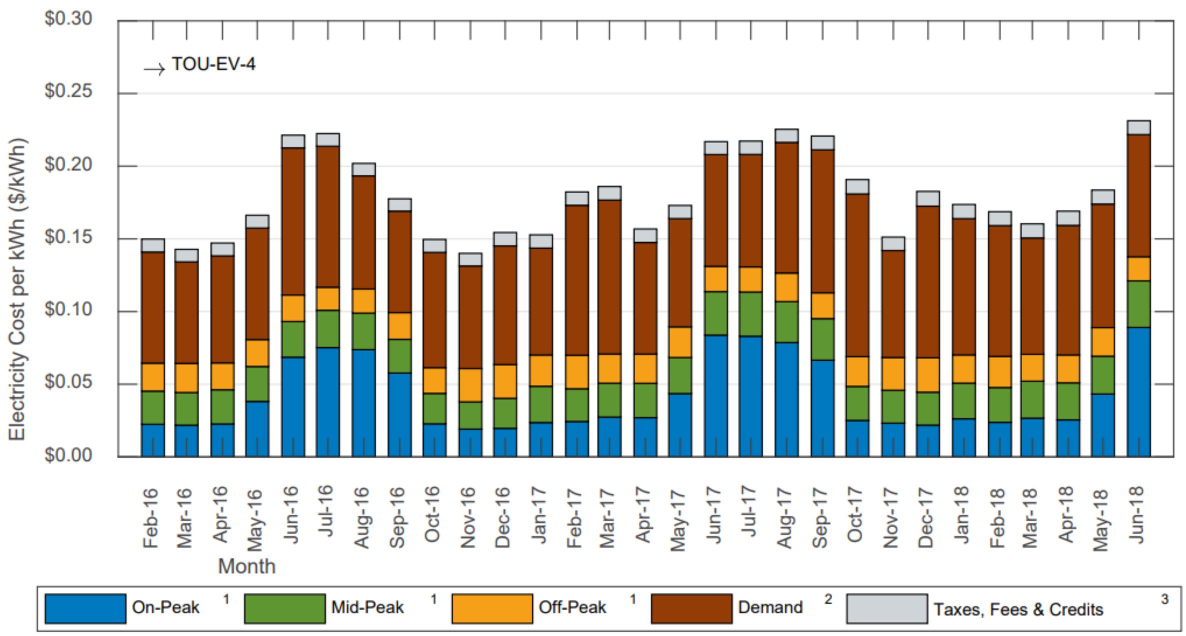


Figure 6. Monthly Electric Utility Cost at Foothill Transit Agency to Charge BEBs [41]

It is anticipated that different cities across southern California will be subject to different electricity rates depending on the operating utility company. Figure 7 presents the electricity cost estimations for different utility companies. Southern California Edison (SCE) customers, served on Schedule TOU-EV-4, will continue to be billed under their current rate structure until their next scheduled billing date following March 1, 2019. This Schedule will be withdrawn once all customers are transitioned to their applicable option, and existing eligible customers shall be transferred to Schedule TOU-EV-8 [46]. The cost model has an internal library with a different electricity rate so that the user can select the electricity price based on the area of service, but for this research work, an average electricity price of $0.18 per KWh was selected as defaulted input for on-route charging which uses on-demand charges in its majority.

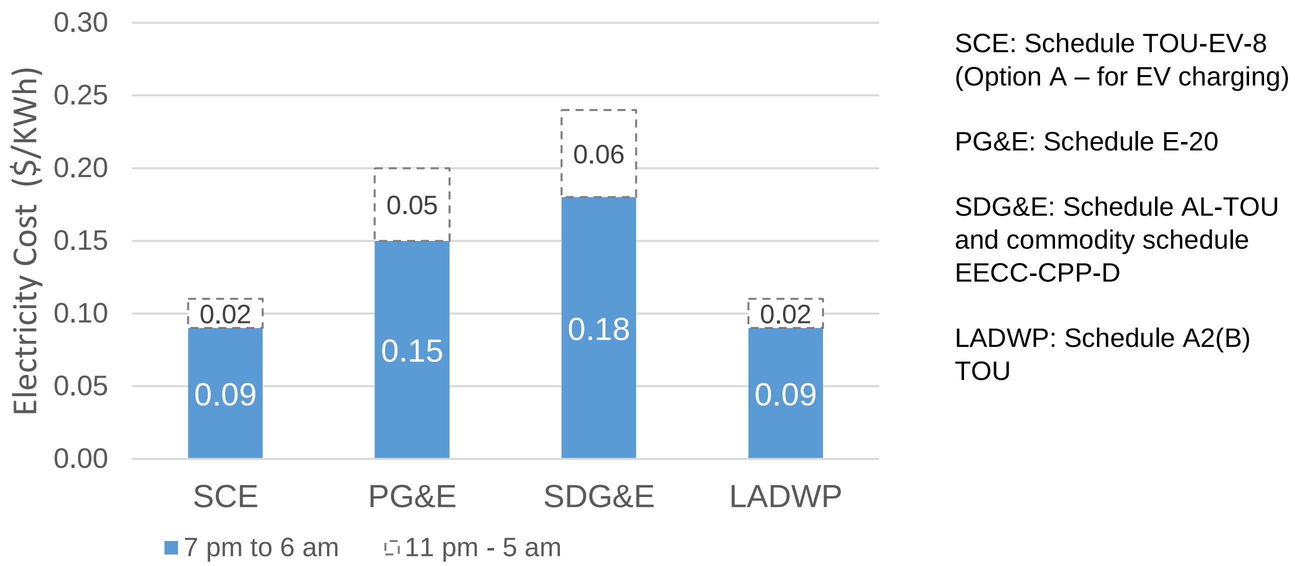


Figure 7. Charging Electricity Cost for Different Utility Companies [44]

Overhaul cost for Battery Electric Buses

The main component that was anticipated to require a mid-life overhaul is the battery pack. For both plug-in and on-route charging BEBs, the cost of battery replacement was set to $700 per KWh.

2.3. Cost Inventory for Fuel Cell Electric Buses

Fuel Cell Bus Purchase Price

Anteater Express received its fuel cell electric bus (FCEB) in 2014. At the time, the bus was valued at approximately $1.8 million. Since then, the bus prices have dropped to $1.34 million as reported by New Flyer [47]. Similar to the calculation of the purchase price of BEBs, it would be ideal to have a cost breakdown for the major components of the FCEBs. However, the lack of published data does not make this task possible. The trend in the price drop, in combination with price pledges made by Proterra [11], were used to estimate a purchase price of $1 million for a standard 40-foot long FCEB.

Maintenance Cost of FCEBs

The total cost of maintenance for the FCEB was reported by UCI to be $0.64 per mile[44]; this includes scheduled and unscheduled repairs. A similar value was reported by NREL for the 2018 Current Status report of FECBs [35]. Data for the maintenance cost were collected for FCEBs that started service since 2012. Table 16 presents the maintenance cost by system type, but for the total cost of ownership simulation, the maintenance cost was model as a total cost of $0.48 per mile.

Table 16. Maintenance cost per mile by system in FCEBs [35]

System	FCEB $/mile
Propulsion Related	0.09
Car, body, and accessories	0.21
PMI	0.09
Brakes	0.02
Frame, steering, and suspension	0.04
HVAC	0.02
Lighting	0.00
General air system repairs	0.00
Axles, wheels, and drive shaft	0.01
Total	0.48

Hydrogen Refueling Infrastructure

The cost of hydrogen refueling stations will vary largely depending on the hydrogen generation path and installed capacity. The challenge of estimating the infrastructure cost for hydrogen relies on how to scale the costs. Data collection from literature reviews (showed in Table 17) resulted in a max reported-capacity of 350 kg/day while projections for a large transit agency show that it would require at least 4,000 kg/day per depot [48].

Table 17. Cost of hydrogen refueling stations [49]

Station Type	Installation Year	Cost per Capacity ($/kg/day)	Capacity (kg/day)	Capital Cost ($)
GH2 Truck Delivery	2012	10,000	100	1,000,000
		6,000	250	1,500,000
	2013	10,210	180	1,837,800
		12,533	180	2,255,940
	2014	9,000	100	900,000
		5,600	150	840,000
		12,702	180	2,286,360
		8,000	350	2,800,000
	2015	5,000	100	500,000
		3,600	250	900,000
		3,750	400	1,500,000
LH2 Truck Delivery	2013	10,889	240	2,613,360
		8,326	240	1,998,240
	2014	11,111	180	2,000,000
		12,170	200	2,434,000
		7,209	350	2,523,150
On-site electrolyzer	2010	21,240	100	2,124,000
	2014	43,956	105	4,615,380
		19,801	105	2,079,105
		26667	120	3,200,000

The H_2CAT cost module [48] provides a cost analysis to inform the decision-making process by adding information about the economic delivery pathway and estimations about the total cost of hydrogen. This section contains a brief description of the methodology used for this module and how it was adapted for the life cycle cost modeling.

Figure 8 describes what was considered in the cost analysis, and it shows that designed to only evaluate the capital cost and price per kilogram variation of four distribution pathways:

- Liquid Truck
- Gas Truck
- Pipeline
- Distributed generation

For distribution from a centralized location, the module assumes a levelized production cost of hydrogen of $3.42 per kilogram. This assumption was made considering centralized SMR units with natural gas as the feedstock, and it was obtained using the H2A Production Analysis Tool from the Department of Energy [50].

The price of feedstock cost per truck and additional cost assumptions regarding the station and dispensing were adjusted based on literature review and data from other transit agencies with current hydrogen buses demonstrations. Table 18 presents these assumptions and the correspondent reference.

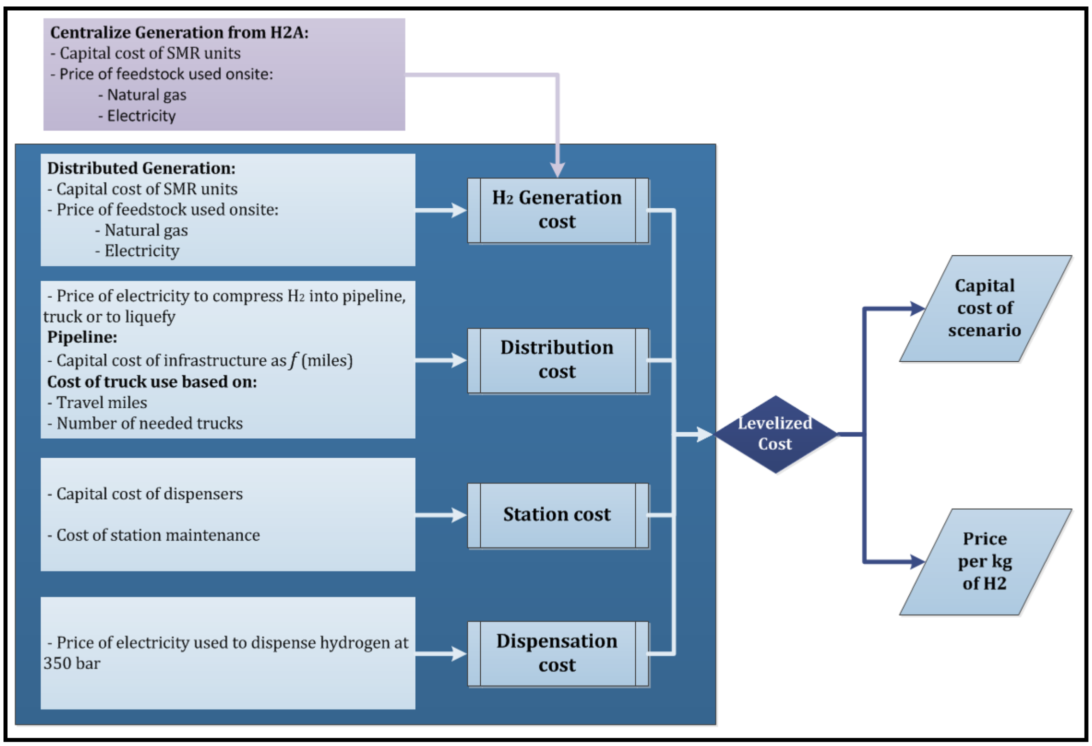


Figure 8. Considerations of H_2CAT Cost-Analysis module [48]

Table 18. Variables for hydrogen stations and distribution pathways

Detail	Units		Reference
Cost of electricity	0.118	\$/KWh	[51]
Well-to-product cost of Hydrogen	3.42	\$/kg of H_2	[50]
Liquid Hydrogen			
Liquid truck capacity	4,500	Kg of H_2/truck	[52]
Cost of liquefaction equipment	1.03	\$/kg of H_2	[61]
Cost of travel	4	\$/mile traveled per truck	[52]
Electricity requirement for liquefaction	8.27	KWh/kg of H_2	[53]
Gaseous Hydrogen			
Electricity req. to compress into truck	2.5	KWh/kg of H_2	[52]
Gas truck capacity	650	Kg of H_2/truck	[50,52]
Cost of travel	4	\$/mile traveled per truck	[52]
Pipeline			
Capital cost of infrastructure	358,507	\$/mi	[50,52]
Electricity req. to compress into pipeline	0.50	KWh/kg of H_2	[54,55]
Distributed generated Hydrogen			
Capital Cost of SMR units	2,862,300	\$/unit	[52,56]
Storage capacity	3,000	kg of H_2	[57]
Natural gas req.	0.172	MMBTU/kg of H_2	[58]
Cost of natural gas	7.5	\$/MMBTU	[52]
Electricity req. for storage	2.27	KWh/kg of H_2	[55]
Dispensing details			
Electricity req. for dispensing at 350bar	3.03	KWh/kg of H_2	[54,55]
Station details			
Maintenance cost	142,000	\$/year	[59]

Capital Cost

Eq. (14) is a regression designed to adjust the capital cost of light-duty vehicles hydrogen stations to the predicted cost for large fleet stations. The data upon which the equation were obtained from includes several reports of stations cost, cost of bus stations from demonstration projects, and H2A delivery [50,52–54,56,60]. The capital costs that this equation considers include storage, compressors, dispensers, and investment in infrastructure to comply with safety requirements. The required inputs for the model are:

- Travel miles for trucks
- Travel length of pipeline
- Well-to-product cost of hydrogen can be adjusted
- Number of Hydrogen fuel cell buses

$$CC_{Hstation} = 101{,}849 * (kg/day)^{0.5516} + (Number\ of\ Dispensers) * 26{,}880$$

Eq. (14)

Price per Kilogram of hydrogen

With the levelized capital cost with the defined variables from Table 18 and the above inputs, the tool can calculate the levelized capital cost based on the present value of the capital cost for a period of 12 years with an 8% debt rate (Table 19). The cost, in addition to other fixed costs and variant costs presented in Table 20 are used to calculate the breakeven for the hydrogen price.

Table 19. Financial and operational assumptions for levelized hydrogen cost

Financial assumptions	
8%	Debt rate
312	Days in a year
12	years to pay back
Operational assumptions	
250	miles per day for one bus
6.5	Fuel economy mi/kg
Delivery assumptions	
35	miles travel (one-way)
35	miles of pipeline
3.42	\$/kg of H_2 well-to-product price

Table 20. Fixed and variant cost used for the breakeven cost of hydrogen

Fixed Cost	**Variant Cost**
Levelized C.C. of the station per year	Cost of Transportation per kilogram of hydrogen transported
Maintenance cost of H_2 station per year	Production of hydrogen (well-to-wheels price)
	Cost of electricity for compression into storage and dispensing

Table 21 shows the prices for electricity, hydrogen, diesel, and CNG calculated from the assumptions described in this section and that are used for the scenarios analyzed in this dissertation work.

Table 21. Fuel Prices used for life-cycle cost calculations

Fuel type	Price
Diesel	\$3.80 per gallon
CNG	\$1.06 per GGE – 1.20DGE
Electricity	\$0.18 per KWh
Hydrogen	H_2CAT

Liquid vs. gas delivery trucks

In the state of California, 33% of the hydrogen dispensed must be sourced from renewable sources. For the purpose of this research, this requirement was assumed to be satisfied by operating the SMR by a combination of natural gas and biogas. Diagrams with the components necessary for liquid truck and gaseous truck delivered are presented in Figure 9 and Figure 10, respectively.

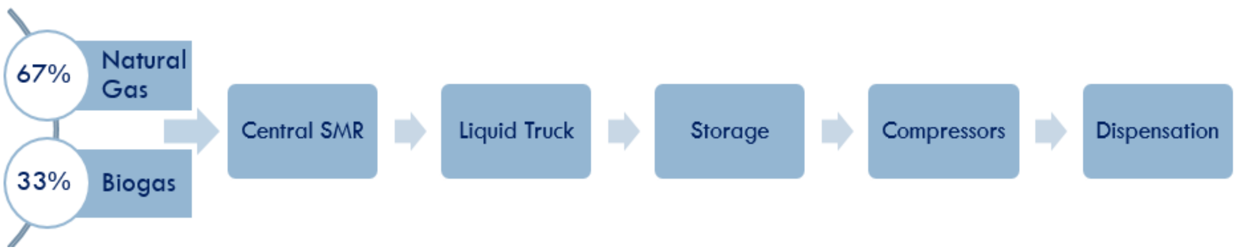


Figure 9. Components necessary for liquid truck delivery of hydrogen

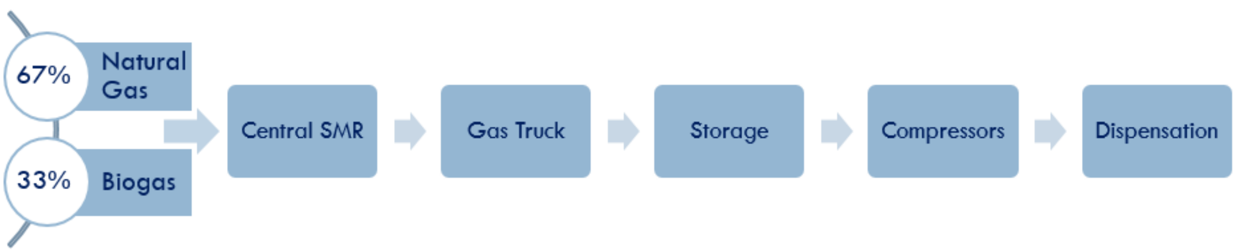


Figure 10. Components necessary for gaseous truck delivery of hydrogen

An accurate estimation of the capital cost for the different hydrogen supply chain pathways is a key component of the cost inventory that will be used to calculate the life cycle cost of hydrogen buses. The capital cost calculated using Equation Eq. (14) considers:

- Storage
- Compressors
- Dispensers
- Investment of infrastructure to comply with safety requirements
- Vaporizers

The capital cost for hydrogen as a function of the number of buses that can be filled at the station was calculated with the methodology described above and is presented in Figure 11 and Figure 12 for hydrogen delivered as a liquid and in a gaseous state, respectively. The more buses are filled, the more capacity the station will have and the more expensive it will be until reaching a low slope growth.

The capital cost is presented as a function of the number of buses to help identify the capital cost for different penetration percentage of hydrogen buses into a fleet. Figure 11 and Figure 12 show that for 300 buses to be filled by a hydrogen station, an initial capital cost of $21.4 million would be required for liquid hydrogen delivery and $18 million if gaseous hydrogen is delivered.

When hydrogen is delivered as a liquid, the hydrogen first is vaporized and compressed by the main compressor to 54MPa and stored in storage tubes, when the bus is filled the hydrogen is cascaded directly from the 54MPa storage tubes to the bus tank. For hydrogen delivered as a gas, no need for vaporizers is necessary, and this is one of the reasons why the capital cost for a station that gets hydrogen delivered as gas is lower than for when it’s delivered as a liquid.

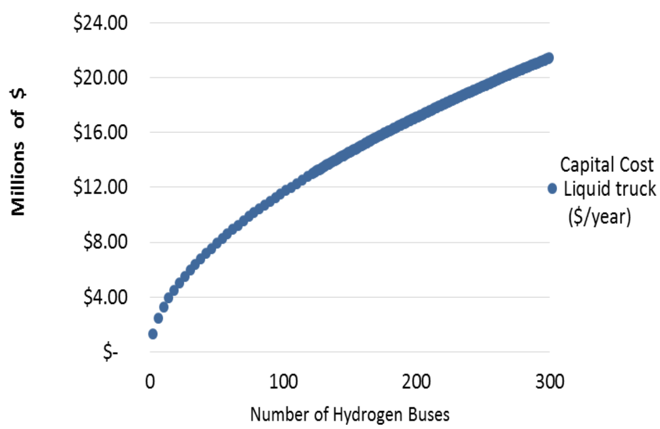


Figure 11. Capital cost of distribution via liquid trucks

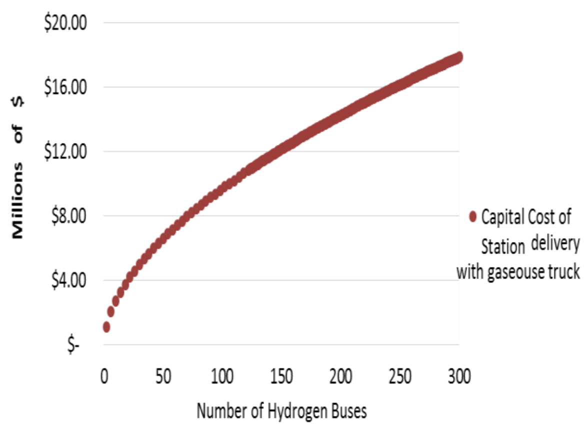


Figure 12. Capital cost of distribution via gaseous trucks

The hydrogen demand for 300 buses assuming an average of 250 daily miles is of 11,500kg of hydrogen per day; for such demand, and based on the current market equipment specification, six dispensers will be required to fill 300 buses in a period time of 6 to 8 hours. To storage gas hydrogen at 3,190psi, it would require four sets of eight vessels (8 x 40' ABS skids [57]) with a total area of 1,100 ft^2.

The price per kilogram of hydrogen that is generated at a centralized SMR plant and distribution with liquid trucks is presented in Figure 13, and it reflects the well-to-pump price of hydrogen that complies with the 33% renewable hydrogen requirement that some states are implementing. The price of hydrogen can be lower than $7.00 per kilogram of hydrogen when more than 150 buses are deployed and as low as $6.65 per kilogram of hydrogen when 300 buses or more are deployed.

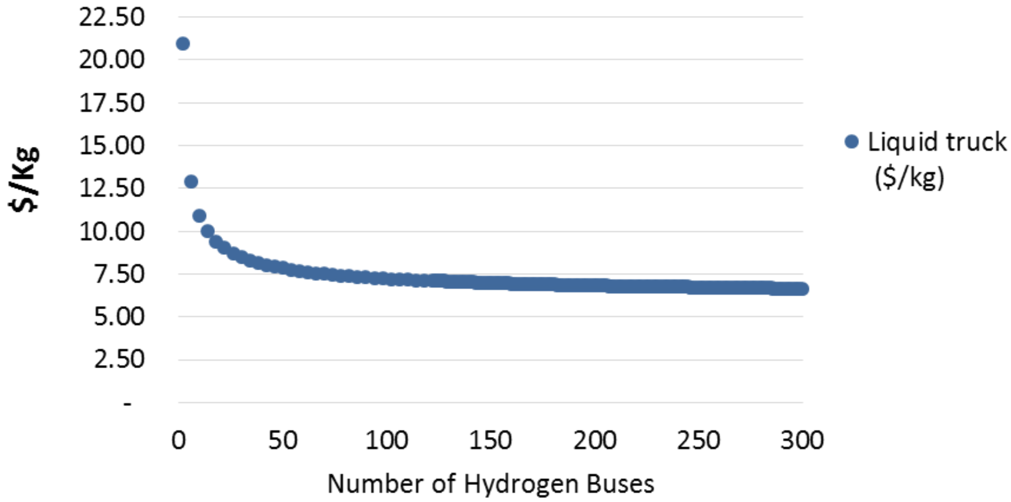


Figure 13. Cost per kilogram of H_2 from central SMR and distribution via liquid trucks

The price per kilogram of hydrogen produced from centralized SMR and distribution with gas trucks is presented in Figure 14. The price of hydrogen can be lower than $5.20 per kilogram of hydrogen when more than 150 buses are deployed at and as low as $5.00 per kilogram of hydrogen when 300 buses or more are deployed.

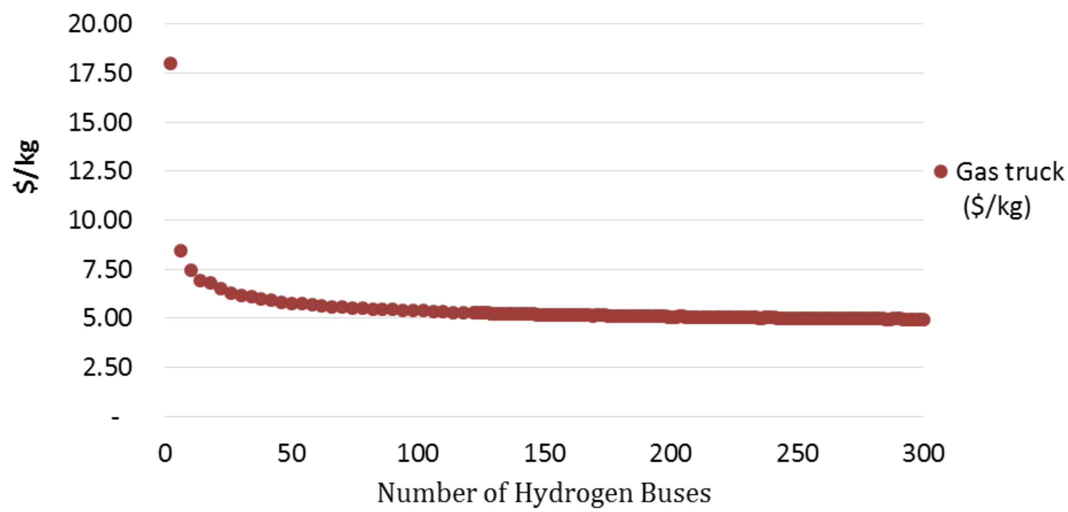


Figure 14. Cost per kilogram of H2 from central SMR and distribution via gas trucks

Even when the capital cost of gas delivery trucks is lower than for liquid delivery, the feasibility of the gas distribution pathway has its limitations. One of the outputs of the tool is the number of trucks that will be required for the delivery of hydrogen, for both gas and liquid. Figure 15 compares the hydrogen price for both pathways and shows the number of gas tube trucks that will be required to deliver the hydrogen in the function of the number of buses that are deployed by a transit agency. From this figure, the gas tube trucks are shown to be not feasible since, to supply the demand of 300 buses, 18 tube trucks per day will be needed to supply the three bases. Considering logistics and space available at most transit agencies, delivery using only compressed gas hydrogen is cheaper but not feasible when more than three tube trucks need to arrive per day, which occurs when 35 hydrogen buses are in service.

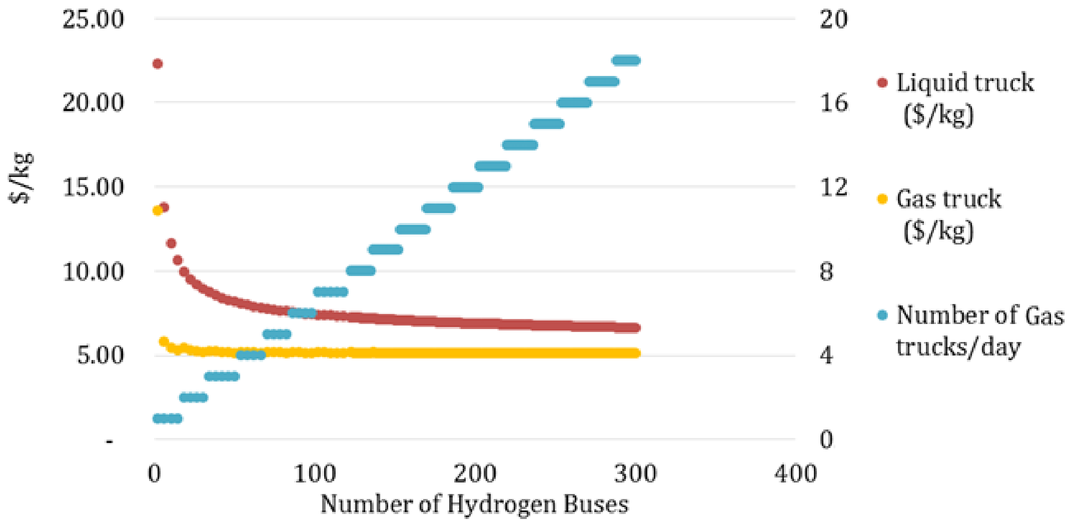


Figure 15. Comparison of liquid truck and gas truck distribution pathways for centralized SMR generation scenario

Pipeline vs. distributed generation

Specific diagrams with the description of the components necessary to deliver hydrogen using pipelines and for hydrogen produced locally (distributed generation) are presented in Figure 16 and Figure 17.

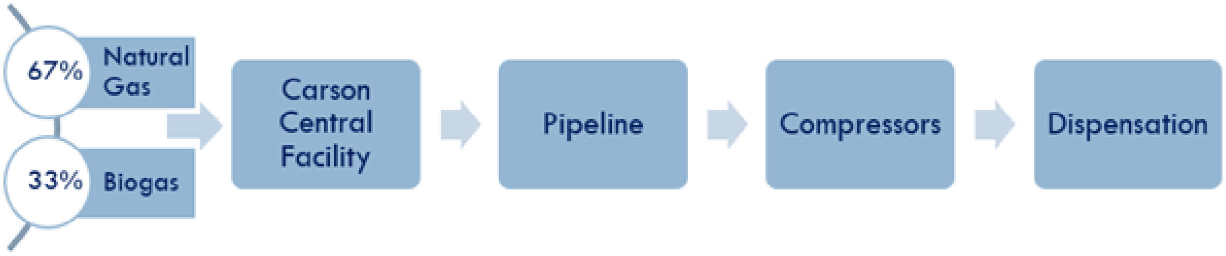


Figure 16. Components of pipeline delivery hydrogen scenario

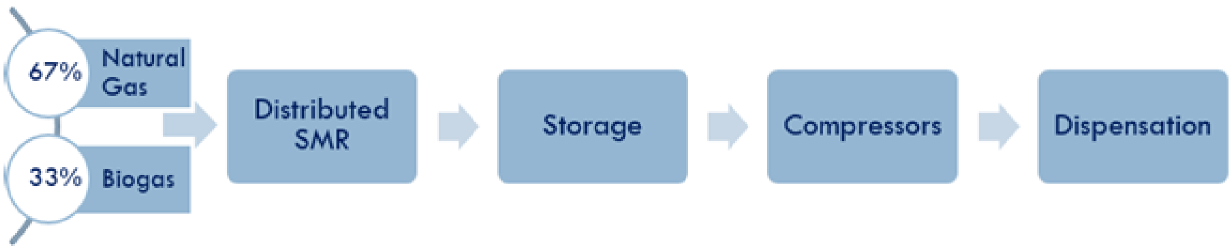


Figure 17. Components distributed generation hydrogen scenario

Similar to the comparison between liquid and gas truck delivery, this comparison includes the initial capital cost and the total price of hydrogen per kilogram. The tool took the same inputs, and the same financial assumptions described in this section.

The suggested infrastructure for the pipeline (red) was obtained from using H_2AT to identify the nearby resources to the bases of Orange County Transit Authority (OCTA). With the outputs from H_2AT and ArcGIS, the spatial allocation of the preferable refinery and layout of suggested pipeline infrastructure were obtained (Figure 18). The outputs from H_2AT utilized the current layout of natural gas pipelines to generate the 35 miles of hydrogen pipelines needed to interconnect a refinery in Carson with the three main bases at OCTA.

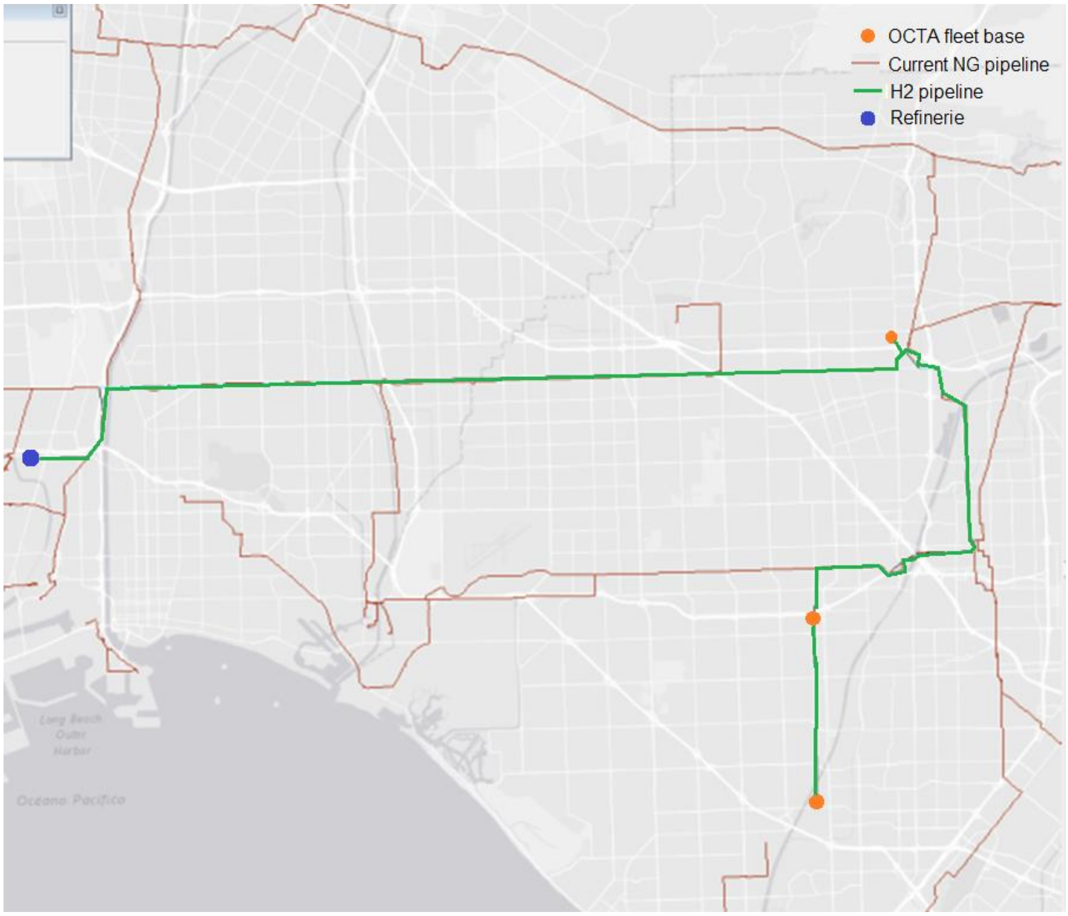


Figure 18. Spatial allocation of suggested pipeline between Carson refinery and OCTA bases

The capital cost for hydrogen delivered using pipelines has a similar trend line to the capital cost of the tube truck delivery pathways, namely increasing in a linear tendency after reaching a capacity to serve 100 buses. The capital cost for the pipeline pathway is presented in Figure 19 and includes the cost of:

- Pipeline infrastructure investment
- Dispensers
- Compressors
- Investment of infrastructure to comply with safety requirements

It considers storage only for an emergency which price is almost irrelevant in comparison to the other considerations.

The capital cost for the pipeline infrastructure is $10.8 million, and it remains independent on the hydrogen demand (buses in service). Figure 19 shows that an initial capital cost of $18 million is needed when other equipment is added to service 300 buses at a hydrogen station that receives the fuel via pipeline. The capital cost is lower than for the tube truck delivery because the storage equipment is almost eliminated as well as the vaporizers.

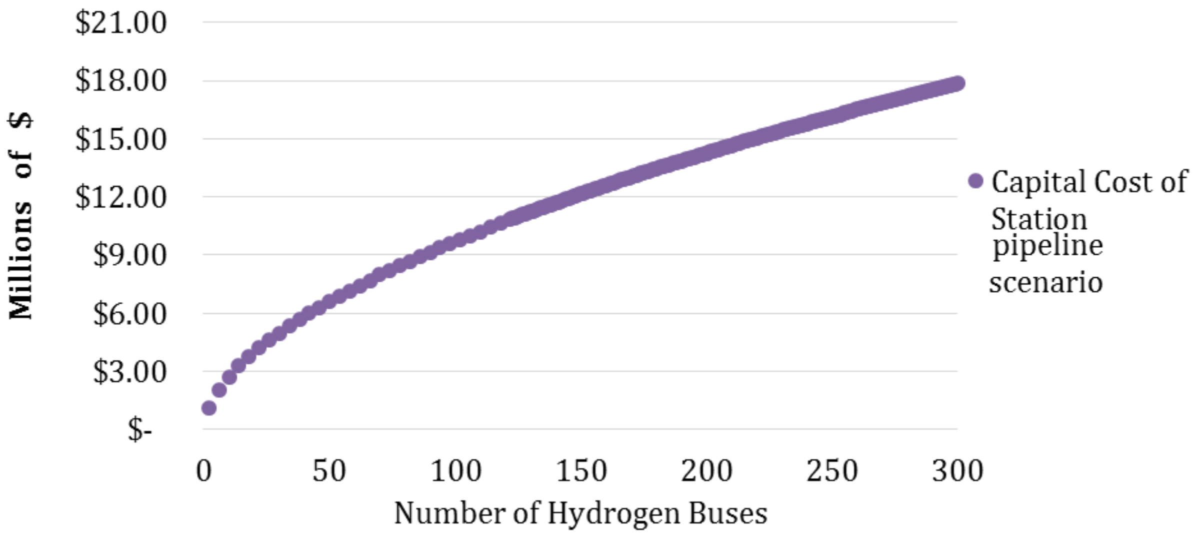


Figure 19. Capital cost of distribution via hydrogen pipelines.

The total cost of hydrogen per kilogram was estimated for the pipeline delivery pathway. Figure 20 shows the price of hydrogen as a function of the buses deployed for central SMR distributed via pipelines. If this scenario were to be implemented at OCTA when they have less than 50 buses, then the price for hydrogen would not be lower than $10. Therefore, investing in pipeline infrastructure is not recommended for 12 years, unless more than 50 buses are to be deployed. A positive aspect about this pathway is that the cost of hydrogen can be as low as $4.96 per kilogram if more than 300 buses are deployed at OCTA.

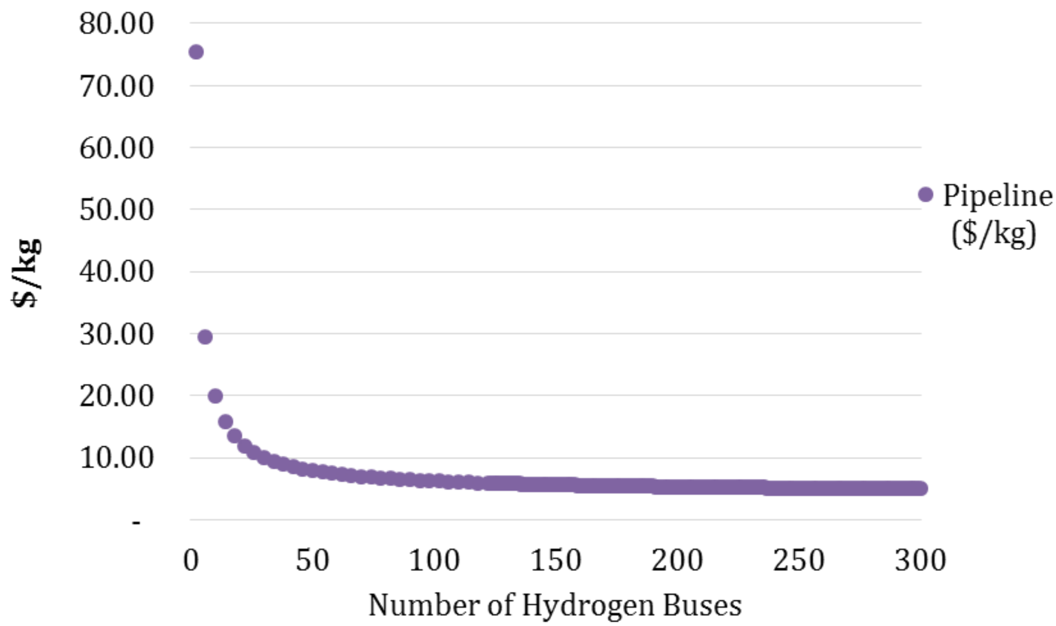


Figure 20. Cost per kilogram of hydrogen from central SMR and distribution via pipeline

The capital cost of hydrogen using distributed SMR units has a different tendency than the other distribution pathways. Unlike the other distribution pathways, the capital cost is continuous until a new SMR unit or more storage vessels need to be added because of the hydrogen demand scales up. Figure 21 shows that the capital cost can be as high as $50 million for stations that could accommodate the hydrogen demand of 300 FCEB. The capital cost is significantly higher with respect to the other pathways because it includes the production cost and not just the station itself. The cost of production is levelized in the other scenarios in the well-to-product price of $3.50 per kilogram of hydrogen. Therefore, this should not be a point of comparison between the other scenarios; the comparison can be made concerning the total price of hydrogen per kilogram. But even when the total price per kilogram will be a fair point of comparison, the capital cost for this delivery/production method is critical because it represents an initial investment that the transit agency will need to make in addition to the investment for the refueling station for the deployment of the buses.

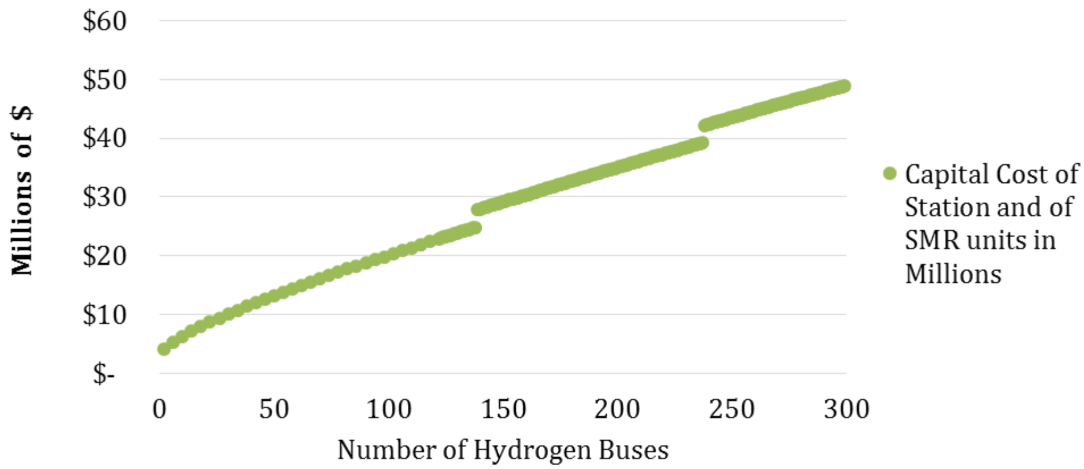


Figure 21. Capital cost of hydrogen from distributed SMR with natural gas and biogas

For the distributed SMR pathway, the price per kilogram of hydrogen is dependent on the feedstock prices of the directed biogas from wastewater treatment plants and of the price of the natural gas. But unlike the other pathways, is independent of third parties that could control the well-to-product price of the hydrogen.

Figure 22 shows the total price of hydrogen by kilogram when produced on-site with SMR distributed units. Similar to the pipeline pathway, the price of hydrogen is high if less than 50 FCEB are deployed with the difference that the higher price for this distribution pathway is $37 per kilogram in comparison to $75 for the pipeline case. The hydrogen price for the distributed generated SMR can be as low as $3.87 if more than 300 are deployed at OCTA.

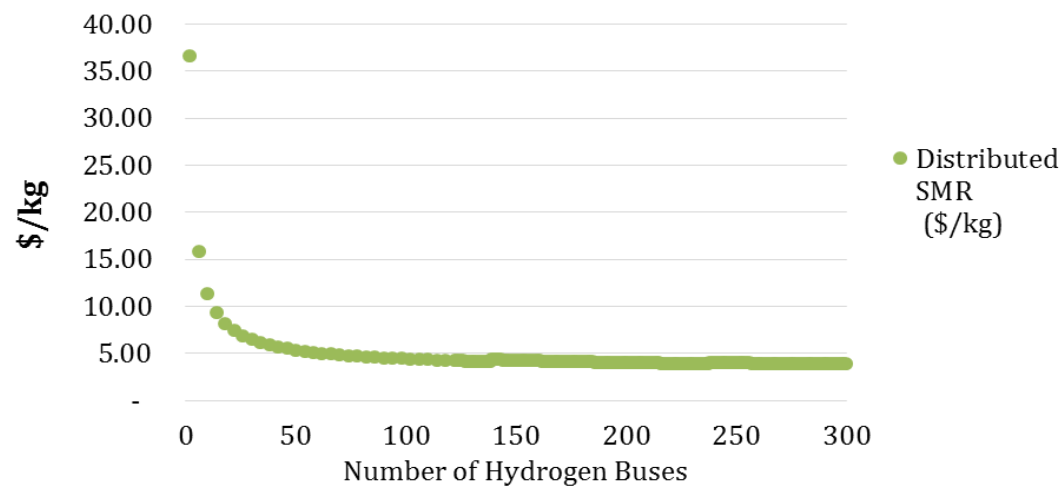


Figure 22. Cost per kilogram of hydrogen from distributed generation via SMR

As established in the section above, the distribution pathway involving gas delivery trucks presents restrictions on the number of trucks that can be managed by the bases at OCTA, therefore is not included as a viable scenario for full FCEB deployment.

Figure 23 shows the price per hydrogen for three distribution pathways: 1) delivery by liquid trucks 2) pipeline infrastructure and 3) distributed generation via SMR units. The on-site generation scenario is the pathway with a lower total price of hydrogen but also the one with higher investment. It can also be inferred that when 25 or more FCEBs are in service, pipeline infrastructure is preferable over liquid trucks.

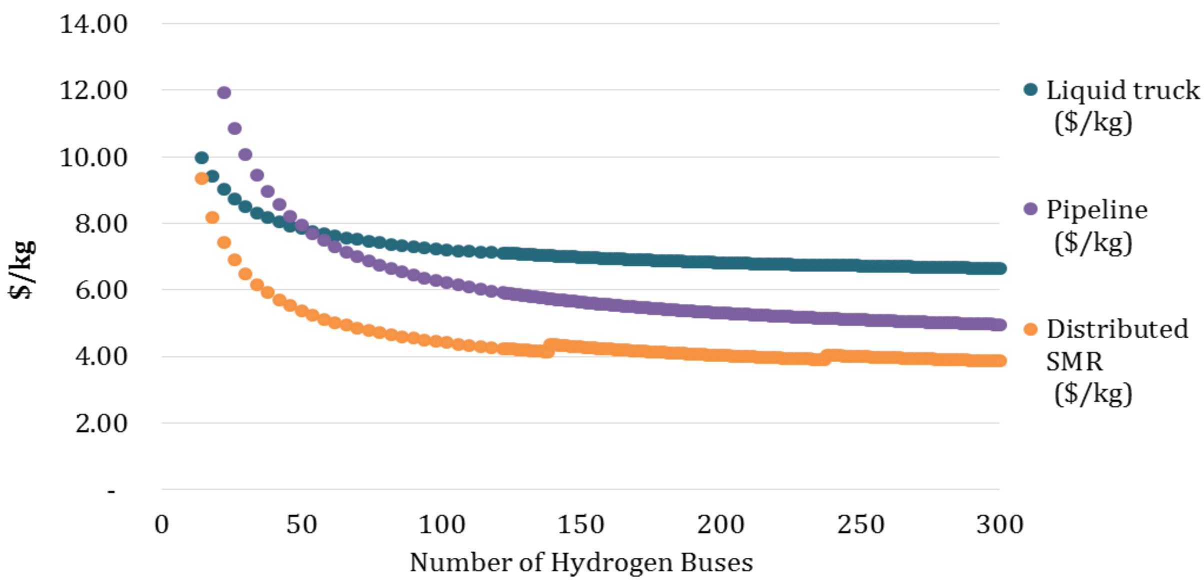


Figure 23. Cost per kilogram of hydrogen for three different distribution methodologies

3. Modeling of Urban Buses Energy Consumption and Use-Phase Emissions

According to the National Renewable Energy Laboratory, FCEB and BEB designs are considered to be at a technology readiness level (TRL) 7 to 8 (e.g., full-scale validation in a relevant environment) [35,37]. As a result, several manufacturers have emerged in the market, and a wide range of bus configurations are currently available.

This variety has created several opportunities, as well as challenges. For example, the standardization of bus chargers for BEBs concerns transit agencies that might seek to acquire buses from more than one manufacturer (e.g., the difference in fuel cell size and battery capacity can result in different driving ranges). Additionally, the variance among bus manufactures go beyond drivetrain configuration and include different bus weight, passenger capacity, auxiliary power demand, and regenerative braking configurations.

The variety in bus configurations adds to the already difficult comparison between technologies that transit agencies need to perform when transitioning to zero-emission fleets. Since the operating duty cycle of a bus has a significant effect on fuel economy, only a comprehensive evaluation of bus technologies can standardize non-drivetrain components and thereby allow end users to examine which technology can truly answer their operative demands. The model presented in this chapter provides the ability to compare different powertrains, given that the driving cycle, vehicle configuration, and auxiliary loads are consistent.

The simulation starts by assessing the mechanical energy demand for a specific bus type and driving cycle. In this context, the bus type will include fuel cell electric, battery electric, compressed natural gas, and diesel powertrains with a defined weight, frontal area, aerodynamic drag, and rolling resistance coefficient.

A driving cycle, represented as speed versus time profile, was used for the simulation of vehicle performance and energy use. In this research work, the Orange County transit bus cycle (OCTA) was the reference driving cycle for the calculation of energy use. The OCTA cycle is based on a chassis dynamometer test cycle for transit buses operated by the Orange County Transit Authority in California that was developed by West Virginia University [31] (see Figure 24).

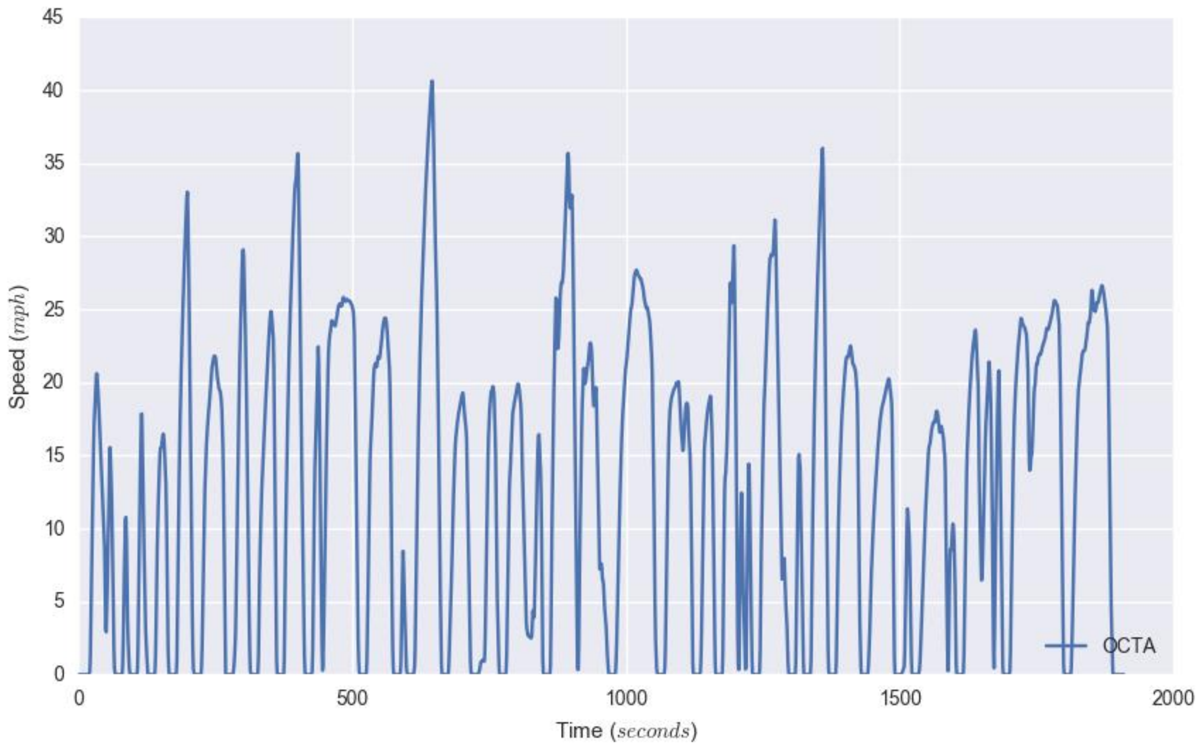


Figure 24. OCTA driving cycle [61]

Based on the parametric calculation of mechanical energy demand, an analytic simulation method was used to calculate conventional and electric vehicle configuration and power requirements [62].

The methodology developed calculates wheel traction power demand given a velocity (v) versus time profile and assumptions about mass, vehicle' frontal area, coefficient of aerodynamic drag (C_{drag}), air density (ρ_{air}), and rolling resistance ($C_{rolling}$) according to the following equations:

$$F_k = acceleration * mass \qquad \text{Eq. (15)}$$

$$F_{rolling} = mass * C_{rolling} * g \qquad \text{Eq. (16)}$$

$$F_{air\_res} = {(v^2 * Af * C_{drag} * \rho_{air})}/{2} \qquad \text{Eq. (17)}$$

$$F_T = \sum F = F_k + F_{rolling} + F_{air\_res} \qquad \text{Eq. (18)}$$

$$Power = F_T * velocity \quad \text{Eq. (19)}$$

$$Power_{wheels} = \left(\frac{v^2 * Area * C_{drag} * \rho_{air}}{2} + 9.8 * m * C_{rolling} + m * \dot{v} \right) v \quad \text{Eq. (20)}$$

Eq. (15) calculates the kinetic force; Eq. (16), and Eq. (17) calculate the force to overcome rolling resistance and air resistance, respectively. In Eq. (18) the sum of all the forces is the total force that is required to move the vehicle and Eq. (19) and Eq. (20) show the total power requirement at the wheels. In addition to propulsive energy use, auxiliary loads for interior climate control (HVAC) and electronic appliances were considered. An analytic expression was used to evaluate vehicle component sizes and energy use as a function of configuration parameters such as range, and technical parameters such as battery specific energy [63,64].

Integrating the power requirement over the whole cycle and dividing by the total distance traveled yielded energy consumption per mile traveled (Figure 25), which was then used to calibrate the model with measured values found in the literature and from data collected at UCI. The high level of integration between technical assessment and powertrain simulation enabled a consistent comparison of the bus vehicle technologies.

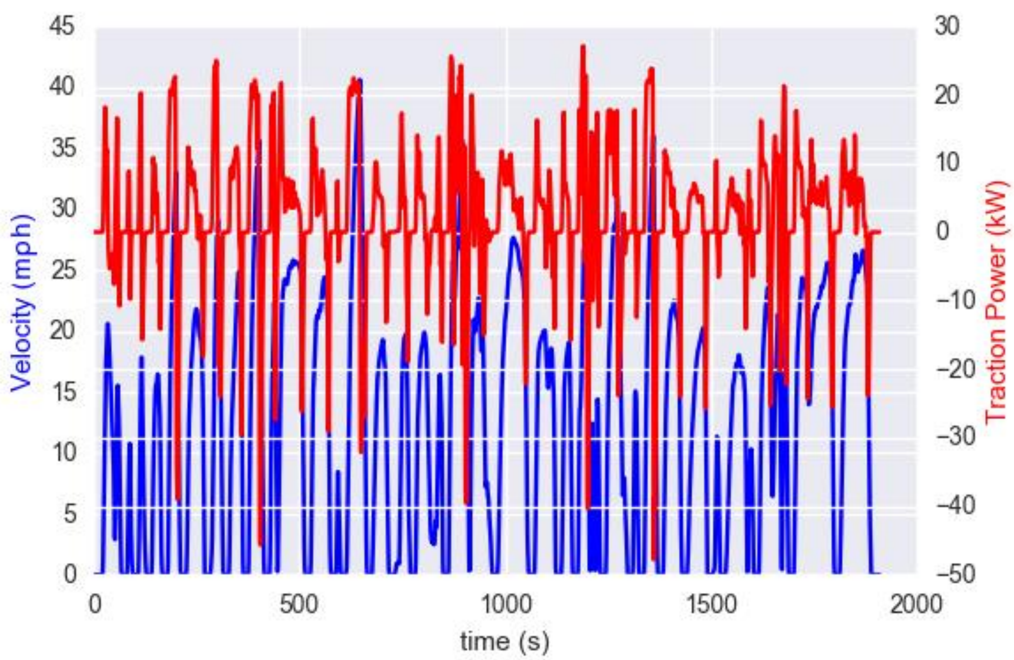


Figure 25. Power requirement for OCTA driving cycle

Figure 26 shows the energy consumption for different powertrains including hydrogen fuel cell bus (FCEB), battery electric bus (BEB) that includes short range (SR) and long range (LR), diesel (ICEV-D), compressed natural gas (CNG), and diesel hybrid electric (HEV-D).

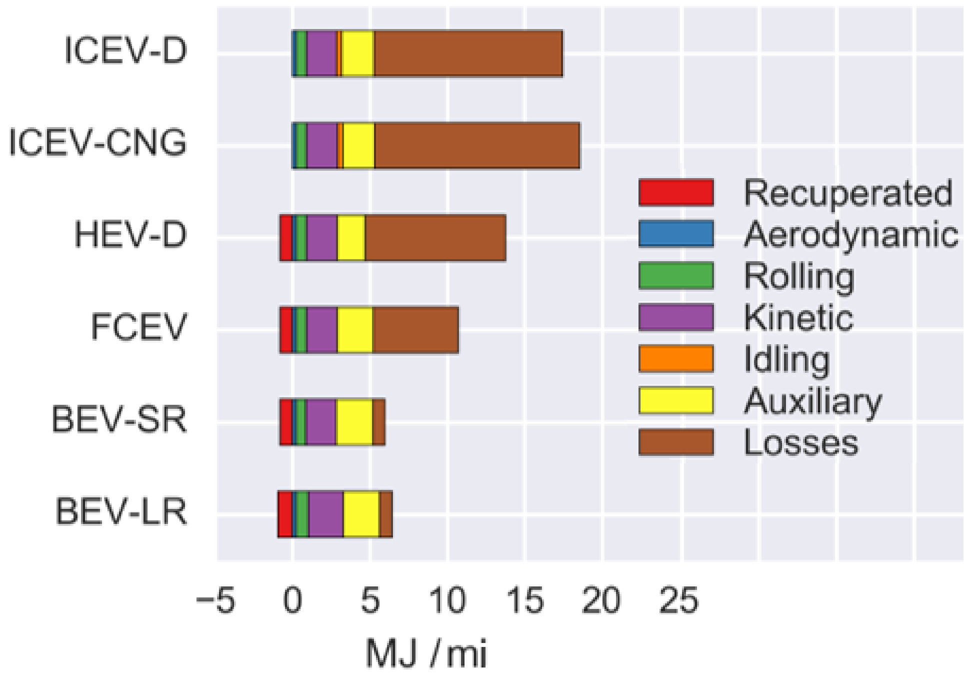


Figure 26. Tank-to-Wheel energy consumption for different powertrains calculated by Fuel Efficiency Model

4. Life Cycle Assessment of Zero Emission Buses

The long-term transition to zero-emission technologies for California transit agencies is under consideration with the Innovative Clean Transit (ICT) regulation proposal [106]. The regulation proposes to eliminate on-road emissions from buses by 2040 and to eliminate fossil-fuels dependency with the overall goal to minimize impacts on the environment and health effects in communities.

Transport authorities required to adopt a zero-emission fleet are faced with a decision between multiple bus technologies, each with different strengths and weaknesses as well as infrastructure requirements. This decision is made more difficult because the performance of the buses depends strongly on operating conditions which cannot be predicted in advanced from manufacturer information or deployment of similar demonstration projects.

To support transit agencies and decision makers in this transition, an extended LCA framework was developed that allows a consistent comparison of different bus powertrains and energy chain configurations. Furthermore, only a comprehensive life cycle assessment can potentially predict the extent of environmental benefits or hidden risks found in transitioning to zero-emission fleets.

Data inventories described in Chapter 4 are used together with component sizes and vehicle energy consumption to calculate aggregated LCIA results for the complete vehicle life cycle; essentially disaggregating every major bus component to then standardize everything except the different types of powertrains. The model framework allows for the simulation of a wide range of different vehicle size and performance classes. Additionally, the modeling methodology for the fuel energy consumption described in Chapter 6, provides the foundation for a consistent comparison of different bus powertrains and energy chain configurations when utilizing life cycle assessment.

The full simulation using the approach presented here is implemented in an interactive Python tool in which the user can modify scenario assumptions and access the full set of results. For this dissertation, an extensive model is demonstrated by showing the results for the 40-foot 'Maxi' long bus of average performance, and the following powertrain variants were considered in the calculations:

- Diesel (ICEV-D),
- Diesel hybrid (HEV-D),
- Compressed natural gas (ICEV-CNG),
- Fuel cell electric (FCEV),

- Battery electric with short range from opportunity charging (BEV-SR),
- Battery electric with long-range from plug-in charging (BEV-LR).

Though calculations in this section refer to 2018 and 2040 bus construction years, the model includes all construction years from 1990 to 2050.

The novelty of this modified LCA approach lies in the use of a consistent framework to compare multiple powertrain types under the same operating conditions in order to evaluate energy consumption and operating emissions, as well as health/risk impacts.

4.1. Life Cycle Assessment Approach

Life Cycle Assessment of different zero-emission bus technologies were analyzed with regard to several criteria of interest. As illustrated in Figure 27 (adapted from [63,64]), the modeling framework considered exogenous and endogenous criteria. Exogenous criteria are aspects related to vehicles performance such as size, range, and acceleration. Those exogenous criteria were necessary input parameters to specify a bus, execute the vehicle simulation, and perform the LCA. Endogenous criteria were the simulation results, such as vehicle mass and energy use. The technology options were selected to be independent (i.e., they can be combined in every possible way) to study the range of resulting criteria and to better understand the interdependencies between technology and fuel options, future developments, and environmental impacts [65]. For the LCA calculations reported herein, the technology options were split into powertrain and fuel type, vehicle size, range and performance, primary energy source, and vehicle model year.

The cradle-to-grave life cycle assessment was performed using the Ecoinvent 3.2 database with the cut-off system model [1] and the Brightway2 software [66]; this included the entire bus material cycle, from production to regular maintenance and end-of-life, as well as the entire fuel cycle and operating emissions. The functional unit of the study was vehicle miles traveled (VMT).

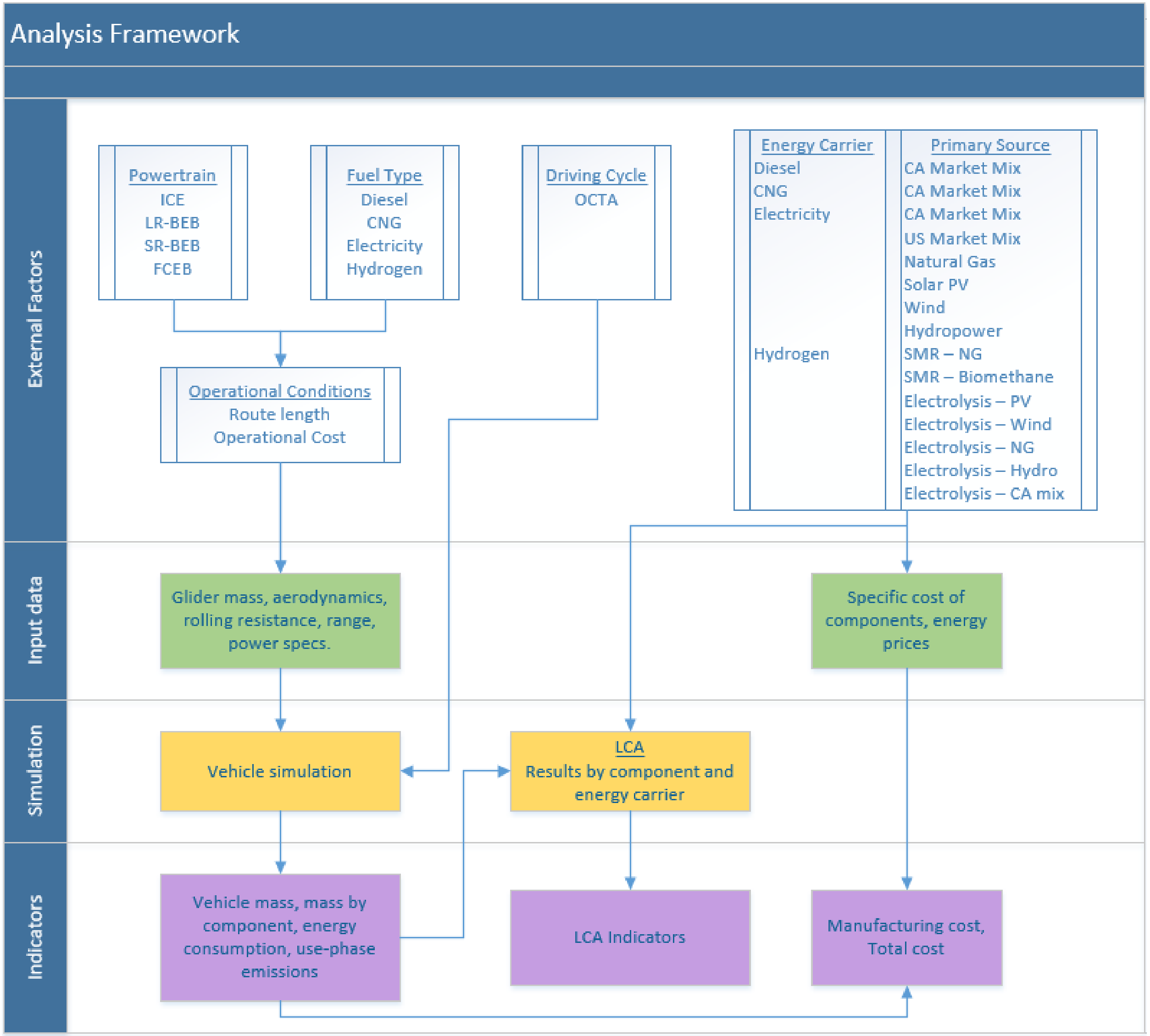


Figure 27. Modeling of energy consumption and LCA framework (Adapted from [63,64])

Life cycle impact assessment (LCIA) translates emissions and resource extractions into a limited number of environmental impact scores that are calculated by using characterization factors. ReCiPe was selected as the method for the impact assessment (LCIA) in the LCA. The two options to use the ReCiPe characterization factors are at midpoint level and at endpoint level (Figure 28).

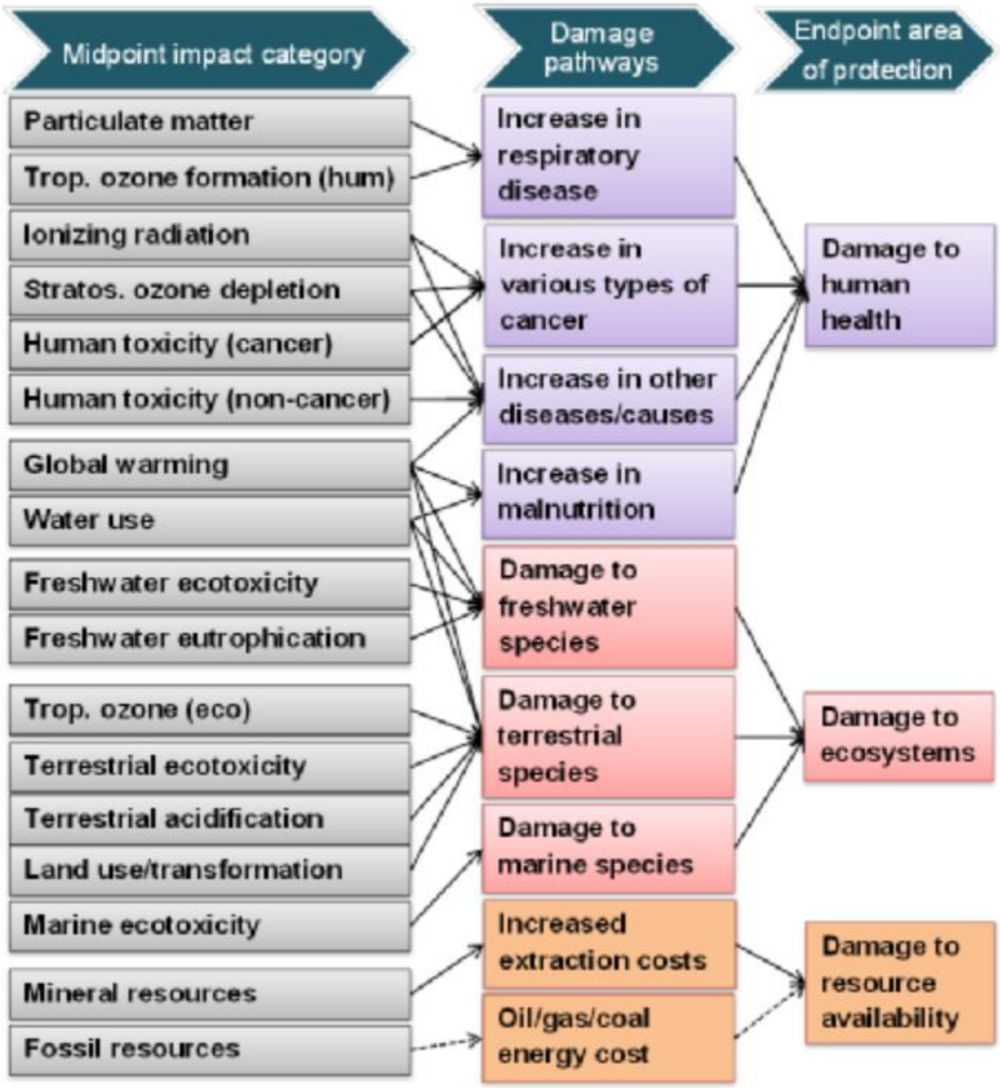


Figure 28. Relationship between LCI parameters (left), midpoint indicator (middle) and endpoint indicator (right) [17].

Midpoint indicators focus on single environmental problems, for example, climate change or acidification. Endpoint indicators show the environmental impact on three higher aggregation levels, being the 1) effect on human health, 2) damage to the ecosystem, and 3) resource availability. Figure 28 provides an overview of the structure of ReCiPe.

Even when the calculation of endpoint indicators involves interpretation of LCIA results, which can be subject to criticism, ReCiPe endpoint indicators were used in this research work for the purpose of internal comparison among powertrains and not to directly use numeric values as projections. Only the following categories were selected to be presented in this research work based on its relevance for public urban transportation:

Global Warming Potential (GWP)

GWP represents the contribution to climate change due to the emission of greenhouse gases such as CO2 and CH4. The most recent global warming potential characterization factor was selected from the IPCC [31], as implemented by the Ecoinvent center. GWP is quantified in kg CO2 equivalents using a 100-year reference time period.

Particulate Matter Potential Formation (PMPF)

PMFP considers the human health impacts of fine particles in the air. Not only was the direct emission of particulates considered, but also the formation of secondary particulates due to emissions such as SOx, NOx, and ammonia (NH3). PMFP is quantified in kg PM 10 equivalents. This indicator is calculated using the ReCiPe 2008 method with the hierarchical perspective [17]. PMFP is used to represent the urban air quality aspects of bus operation, as NOx and particulate emissions are among the most important emissions from buses.

Terrestrial Acidification Potential (TAP)

Acidic gases such as Sulphur dioxide (SO2) react with water in the atmosphere to form acid deposition, also known as "acid rain." Acid deposition causes a decrease in plant performance and biodiversity losses [67]. Acidification potential is expressed using the reference unit kg SO2 equivalent, and it accounts only for acidification caused by SO2 and NOx.

Photochemical Oxidant Formation (POFP)

The photochemical oxidants are secondary air pollutants formed by the action of sunlight on nitrogen oxides and reactive hydrocarbons, their precursors. The most important phytotoxic components produced by these atmospheric photochemical reactions are ozone and peroxyacetyl nitrate[68]. POFP are implicated in problems of smog and crop damage. This impact category is quantified in kilograms of Non-Methane Volatile Organic Carbon (NMVOC). The indicator name for this impact category is Photochemical Ozone Concentration

Mineral Depletion Potential (MDP)

MDP refers to the decreasing availability of natural resources, specifically minerals. These midpoint factors are given as kg of Fe-equivalents. This indicator is calculated using the ReCiPe 2008 method with the hierarchical perspective [17]

Human Toxicity Potential (HTP)

Use to express the potential harm of a unit of chemical released into the environment. HTP includes both inherent toxicity and generic source-to-dose relationships for pollutant emissions. HTP is calculated by adding the releases, which are toxic to humans, to three different media, i.e., air, water, and soil. The chemical 1,4-dichlorobenzene is used as a reference substance for these midpoint calculations (kg 1,4 DB equivalent).

Cumulative Energy Demand of Non-Renewable

The aim of the method is to quantify the primary energy usage throughout the life cycle of a good or service. The method includes the direct and indirect uses of energy, but not the wastes used for energy purposes. The calculations are based on the method published by the Ecoinvent Centre [1]. Non-renewable resources include fossil, nuclear, and primary forest, all quantified in MJ.

Freshwater Ecotoxicity Potential (FEP)

Assessment of toxicity has been based on maximum tolerable concentrations in water for the ecosystem since the emission of some heavy metals can have an impact on the ecosystem. This impact category provides a method for describing fate, exposure, and the effects of toxic substances on freshwater bodies. Characterization factors are expressed using the reference unit, kg of 1,4-dichlorobenzene equivalent (1,4-DB)

Ozone Depletion Potential

The characterization factor for ozone layer depletion accounts for the destruction of the stratospheric ozone layer by anthropogenic emissions of ozone depleting substances (ODS). ODS are chemicals that contain chlorine or bromine atoms because of their long atmospheric lifetime. The Ozone Depletion Potential (ODP) uses CFC-11 (trichlorofluoromethane) as a reference.

ReCiPe Endpoint

At the endpoint level, most of these midpoint impact categories are further converted and aggregated into the following three endpoint categories:

- ReCiPe Endpoint Human Health
- ReCiPe Endpoint Ecosystem Quality
- ReCiPe Endpoint Resources Availability

The single-score (ReCiPe Endpoint Total) aims to aggregate and normalize all the mid-point categories to present an overall score. However, the single-score calculation method does not account for either the effect of alternatives having high values across all endpoints or the interdependency of the indicators being aggregated. Furthermore, despite the risks of over interpreting or even misinterpreting normalized and weighted results, the Endpoint Total is used as a comparison point among different powertrains.

4.2. Bus Modeling

The focus on the vehicle type for the calculations was on standard 40-foot long buses. All buses were assumed to have a lifetime of 12 years and travel a total of 520,000 miles during their lifetime. A description of the 6 different bus powertrain types is presented below:

- **ICEV-D**: Internal Combustion Engine Vehicle – Diesel. This is a standard diesel-powered bus that meets CARB emissions regulation. It has a 230-kW engine.
- **ICEV-CNG**: Internal Combustion Engine Vehicle – Compressed Natural Gas. This is a standard compressed natural gas-powered bus, also with a 230-kW engine.
- **HEV-D**: Hybrid Electric Vehicle – Diesel. Hybrid bus configuration with a 185-kW diesel engine that operates a generator. The wheels are powered by two 75 kW electric motors that are capable of recuperative braking and 150 kW of lithium ion power batteries (15 kWh storage capacity). The bus does not have the ability to recharge batteries from the electricity grid, not a plug-in to charge the vehicle
- **FCEV**: Fuel Cell Electric Vehicle. This is a Proton Exchange Membrane (PEM) fuel cell powered bus that operates on hydrogen. The fuel cell has a net power output of 150 kW, and 80 kW of lithium ion power batteries (11 kWh) are used to balance the load. Two 75 kW electric motors that are capable of recuperative braking are used to power the wheels.
- **BEV-SR**: Battery Electric Vehicle – Short Range. A battery electric bus powered by lithium ion batteries. This bus was assumed to have a range of only 20 miles with regular recharging events along the route with inductive charging. The wheels are powered by two 75 kW electric motors that are capable of recuperative braking.
- **BEV-LR**: Battery Electric Vehicle – Long Range. A battery electric bus powered by lithium ion batteries. This bus is assumed to have a range of 150 miles from a 320-kWh stack of batteries and is assumed to charge once per day. The wheels are powered by two 75 kW electric motors that are capable of recuperative braking.

For all the bus performance modeling, the basic parameters were kept the same. As a result, no constraints due to operational differences were considered. All the buses were assumed to travel the same daily distance, the same number of stops, no difference in route due to charging events, same passenger load, same driving cycle and no changes in the power requirements, the only difference relied on the efficiency of each powertrain and the fuel used to power the bus. Table 22 presents a summary of all the relevant parameters used in the modeling of each powertrain type.

Table 22. Summary of relevant bus parameters for LCA calculations

			Diesel	HEV-D	CNG	FCEV	BEB-SR	BEB-LR
Bus mass	lb.	2018	23,958	24,112	24,310	30,310	26,584	28,896
	lb.	2040	23,606	23,672	23,958	29,254	25,726	27,102
Maximum Range	Mi	2018	400	400	311	340	7	140
	Mi	2040	400	400	311	340	7	140
Traction energy demand	MJ/mi	2018	8.5	6.3	8.5	7.1	7.1	7.6
	MJ/mi	2040	7.7	5.6	7.7	6.3	6.3	6.4
Onboard Energy Storage	kWh	2018	2,420	1,800	2580	1480	86	380
	kWh	2040	2,100	1,570	2230	1230	75	325
Auxiliary Power	kW	2018	7	5.3	7.00	5.30	5.30	5.30
	kW	2040	5.4	4.9	5.4	4.9	4.9	4.9
HVAC Power	kW	2018	5.3	5.3	5.3	8.5	8.5	8.5
	kW	2040	4.1	4.1	4.1	6.6	6.6	6.6
Tank to Wheel Efficiency	%	2018	29	30	35	46.1	85	85
	%	2040	30.2	31.2	36	49.3	85.6	85.6
Charging Efficiency	%	2018	-	-	-	-	85	90
	%	2040	-	-	-	-	85	90
Recuperation Efficiency	%	2018	-	50	-	50	50	50
	%	2040	-	53	-	53	53	53
Total Energy Consumption	MJ/mi	2018	28.2	20.8	35	17.1	8.2	7.9
	MJ/mi	2040	24.3	18.2	30	14.3	7.2	7.6

Two scenarios were investigated to analyze the environmental effect of deploying zero-emission buses. The first scenario was specific for the conditions of one of the bases operated by Orange County Transportation Authority (OCTA). The second scenario analyzed the present and future benefits of ZEB without specifics of operation from a given transit agency.

4.3. Results for OCTA Scenarios

It was necessary to conduct the analysis considering operations per maintenance base hub and not for the entire bus fleet since the refueling infrastructure needs to be specific to each hub. Since OCTA has three bases with a similar number of buses at each base, the results from the economic and LCA analysis can be multiplied by 3 to obtain the deployment plant of the transit agency. Additionally, for the optimization section, it was necessary to analyze the route length and scheduling of the buses, which is easier to accomplish if the analysis is done per base and not for the entire fleet. Therefore, the first scenario was conducted per base hub in order to include these LCA results in the objective function of the optimization.

The bus specifications are the same as the ones described in Table 22. Additionally, the operation conditions that were included in the OCTA scenario are reflected in Table 23. No BEV-SR were considered in the OCTA scenario since the logistics required for the installation of on-route chargers cannot be account for due to the large number of cities that need to be considered.

Table 23. Specific conditions for OCTA scenario

Aspect	Description
Buses per base	150 buses
Route length assignment	24% of fleet above 140 VMT a day
Powertrains options	ICEV-NG ICEV-D Hybrid-D BEB (LR) FCEB
Fuel generation options	1. Electricity generation using CA grid mix 2. Electricity generation from hydropower 3. Electricity generation from natural gas using combined cycle power plant 4. Hydrogen generated from electrolyzer using CA grid mix 5. Hydrogen generated from an electrolyzer powered by hydropower 6. Hydrogen generated from an electrolyzer powered by CA grid mix 7. Hydrogen generated from SMR using natural gas
Year of calculations	2018

Figure 29 presents the global warming potential results for the OCTA scenarios. For the FCEVs, generating electrolytic hydrogen yields the lowest GWP score (0.4 kg of CO_2 eq per mile). The low impact on this category is only improved if BEVs are charged using electricity generated by wind (0.3 kg/VMT). Even when the California grid mix uses less than 45% of fossil-fuels, relying on the grid generates the lowest GWP score when directly used to charge BEVs or to generate hydrogen using electrolysis. It's important to note that the hydrogen generated via steam methane reformation is considering the 33% renewable required in the state of California. Additionally, for all zero-emission buses with their fuel generation pathway, the GWP score is below the baseline of the CNG buses operated by OCTA.

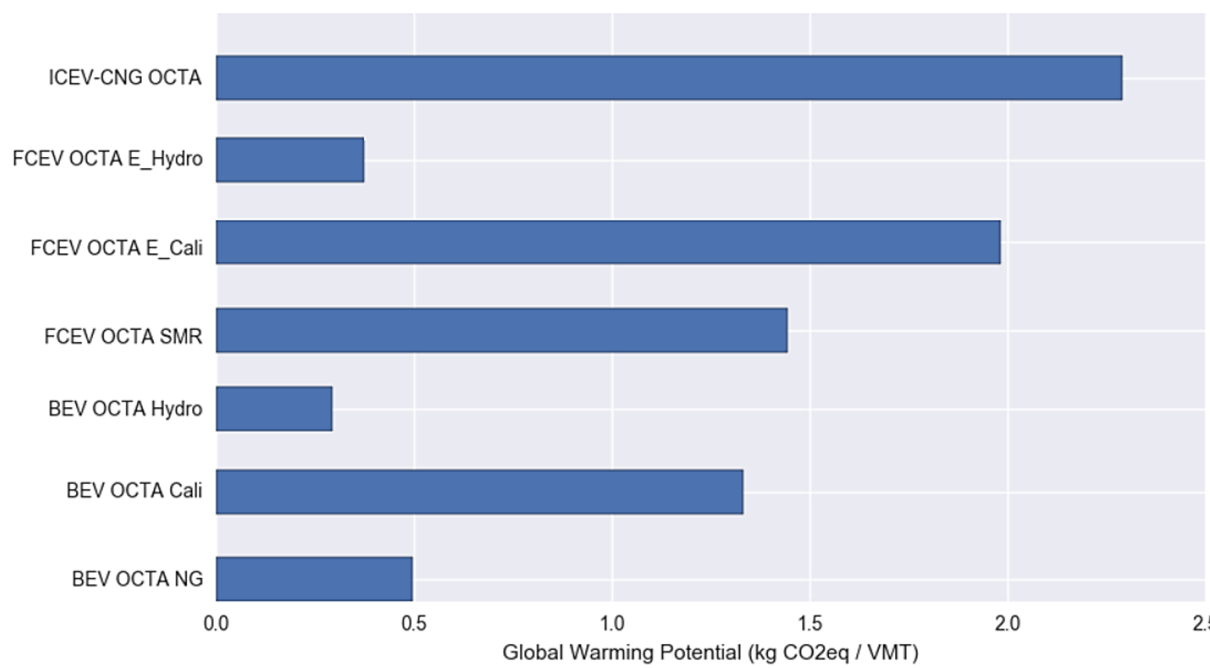


Figure 29. Global Warming Potential result for OCTA 2018 scenarios

Results for the terrestrial acidification are found in Figure 30. The scenarios that rely on the California grid mix for fuel generation (electricity or hydrogen) have the highest kilograms of SO_2 equivalent per vehicle mile travel. A portion of the emissions can be attributed to the operation of natural gas power plants, and the small share from coal fired PP. A sulfur compound, added to natural gas as an odorant in case of leaks, results in the emission of SO_2 from power plants powered by natural gas. This is also the case for the scenario that uses natural gas to generate electricity and power BEVs. However, the difference in emissions between the California grid mix and pure NG for electricity generation relies on the small portion of coal and biomass that is used in the CA grid mix. "Sulfur dioxide (SO_2) emissions produced in the generation of electricity at power plants in the United States declined by 73%

from 2006 to 2015, a much larger reduction than the 32% decrease in coal-fired electricity generation over that period. Nearly all electricity-related SO2 emissions are associated with coal-fired generation" [69].

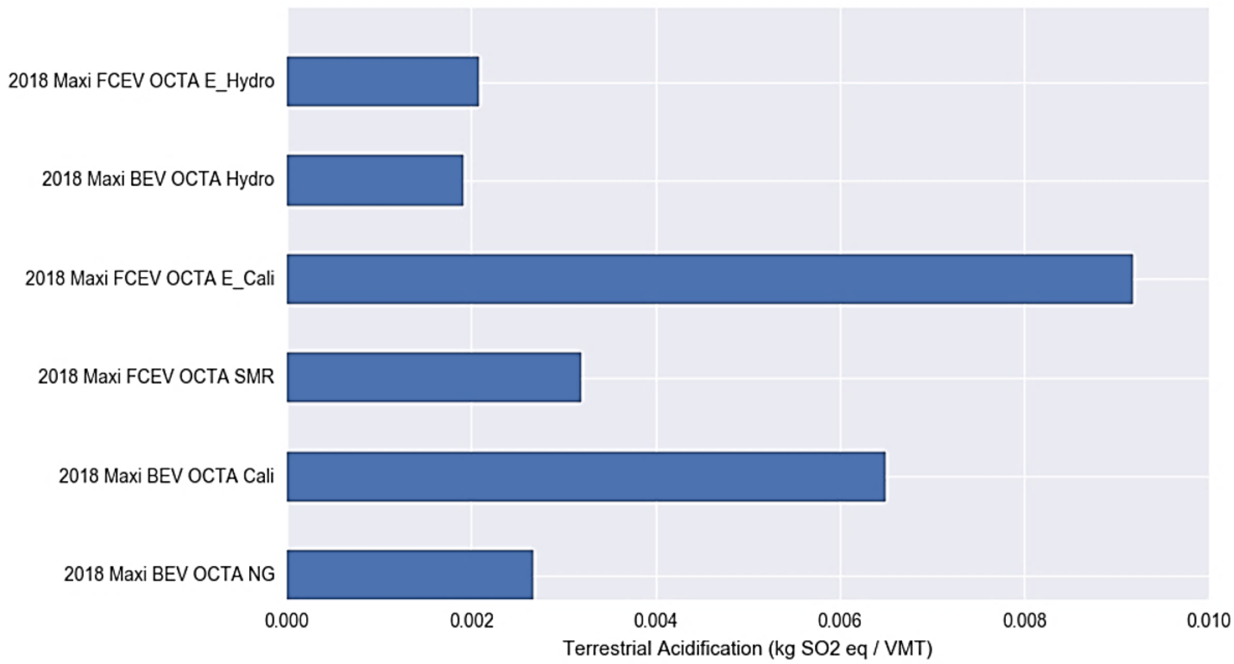


Figure 30. Terrestrial Acidification Potential for OCTA scenarios

When analyzing photochemical oxidant formation, the same patterns as for terrestrial acidification were observed, namely scenarios that depend on the California grid mix for fuel generation have higher emission rates than when using hydropower (Figure 31).

Figure 30 and Figure 31 reveal a second pattern related to the difference between using the California grid mix to power electrolyzers or to directly charge BEVs. The difference in SO_2 equivalent emissions per vehicle mile travel is a direct reflection of the efficiency in the fuel generation process. The efficiency to generate electricity using the CA grid mix is the same for both scenarios (FCEV E_Cali and BEV NG). However, the efficiency of the hydrogen conversion process via electrolysis is a lot lower than the efficiency to charger the battery electric buses, in addition to efficiency losses due to transportation and storage of hydrogen.

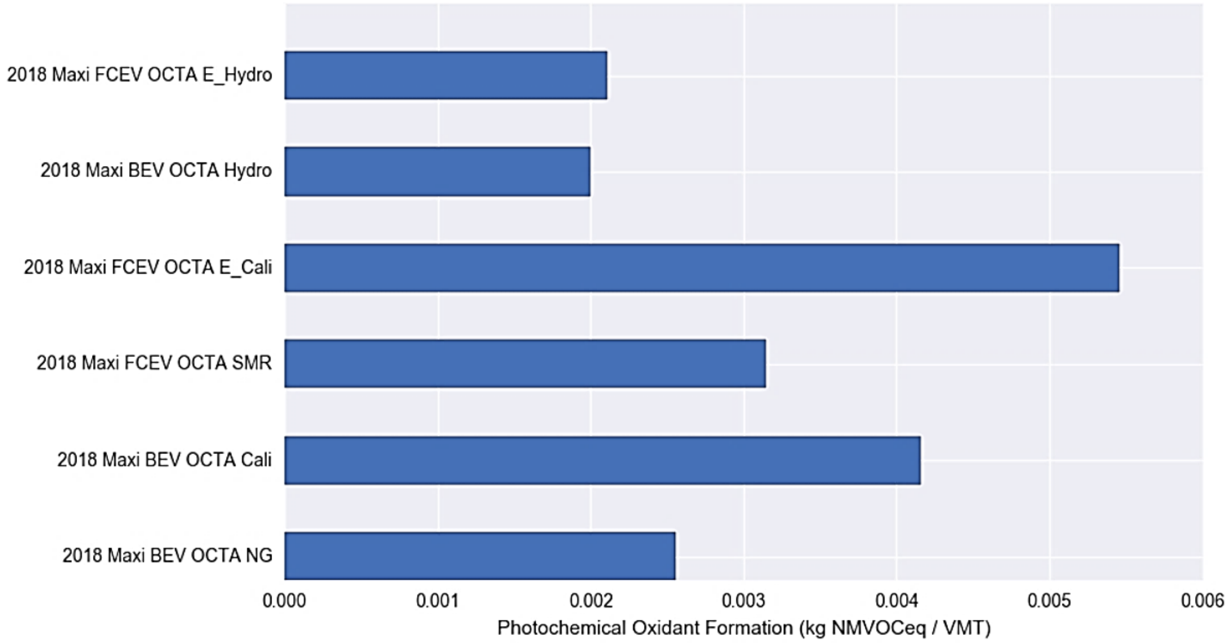


Figure 31. Photochemical Oxidant Formation results for OCTA Scenarios

The results for particulate matter formation are presented in Figure 32. Fuel cell and battery electric buses, dependent on hydropower as their feedstock, present the lowest kilograms of PM10 equivalent per vehicle mile traveled. Using natural gas to generate hydrogen via SMR results in lower PMF than using natural gas to generate the electricity that is used to charge BEVs. Finally, the PMF emissions generated from using the CA grid to generate hydrogen via electrolysis results in almost three times the emission than if hydropower is the feedstock.

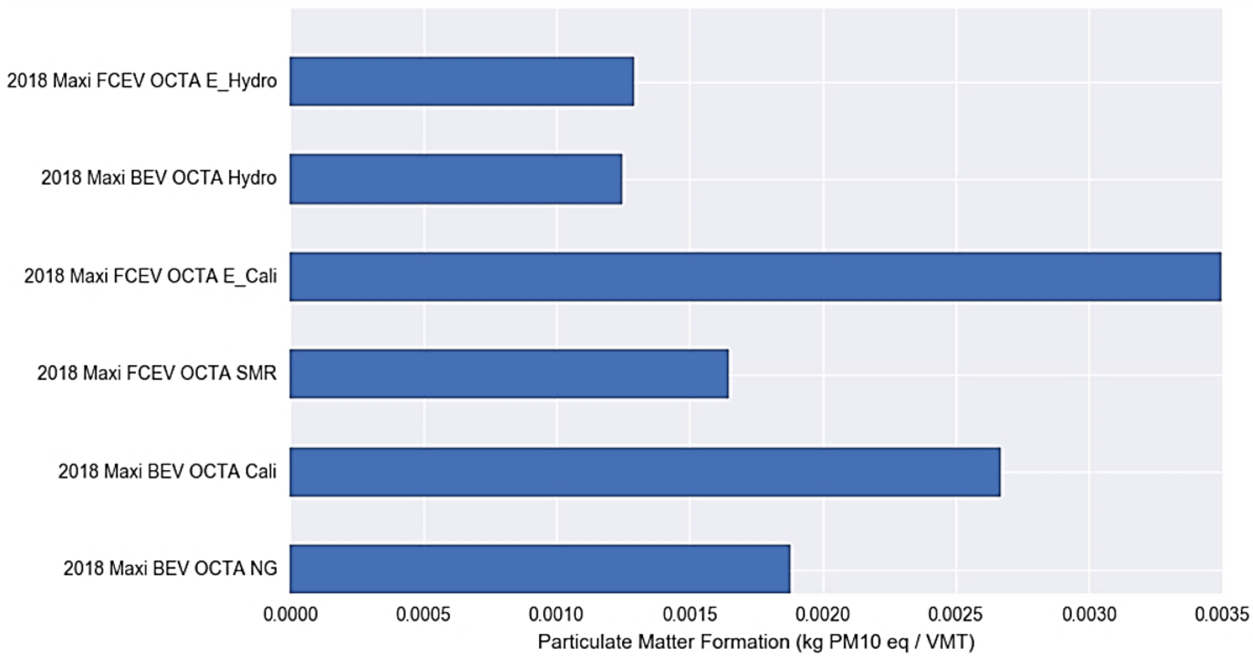


Figure 32. Particulate Matter Formation results for OCTA scenarios

Figure 33 shows the ReCiPe Endpoint Total score for zero-emission buses operated at OCTA under different fuel generation scenarios. The Endpoint Total aggregates and normalizes all the mid-point categories to present an overall score. Therefore, under such a definition, producing hydrogen to operate fuel cell electric buses via electrolyzer powered with hydropower has the lowest impact in the environment, human health, and resources depletion; even more than using that hydropower to charge battery electric buses. If considering the Endpoint Total results as only deployment parameter, using the current California grid mix results in a higher impact on the environment and human health than the current bus baseline of CNG buses at OCTA. However, this category does not account for either the effect of the alternatives having high values across all endpoints or the interdependency of the indicators being aggregated. Specifically, the categories related to terrestrial acidification, photochemical oxidation, and freshwater ecotoxicity have scores above base-case scores due to the mining of precious metals for the construction of fuel cells and batteries.

In conclusion, the selection of an alternative powertrain and fuel supply chain needs to take into consideration where proper weights/relevance is assigned to each factor. It is recommended, for example, to perform a spatial analysis of such categories to determine the direct impact to communities and, thereby establish the priority of each factor.

By analyzing each factor independently, the fuel cell and battery electric bus with fuel generation derived from hydropower have the lowest score/measurement for the majority of LCIA factors. Analyzing the best-case scenario of fuel generation was beneficial since it revealed that categories with high measurement per mile traveled were independent of the fuel generation and linked to the production of powertrain; as it was the case for Photochemical Oxidant Formation, Terrestrial Acidification, and Freshwater Ecotoxicity.

Furthermore, the analysis of OCTA specific operation conditions in combination with three fuel feedstocks (hydropower, natural gas, California mix grid) documented evidence of the importance to continue incorporating renewable into the CA grid mix and thereby reduce emissions throughout the life cycle of zero-emission buses.

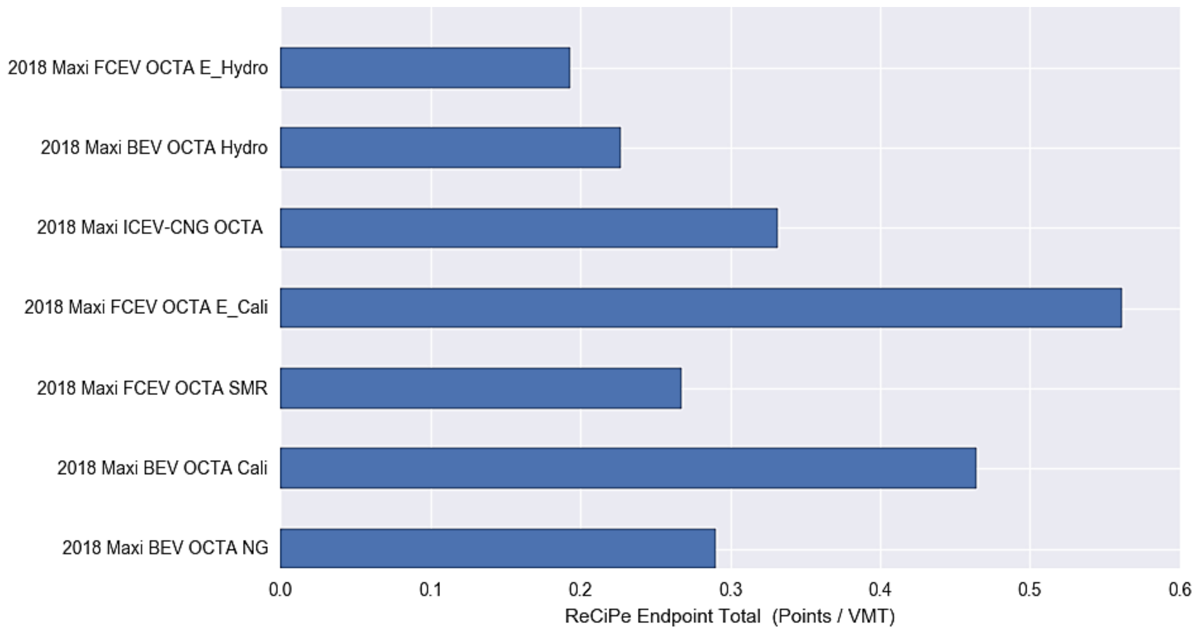


Figure 33. ReCiPe Endpoint Human Toxicity for OCTA 2018 scenarios

5. Life Cycle Economic Analysis

Life Cycle Costing (LCC) is a technique to establish the total cost of ownership; it is a structured approach that can assist in the selection process that transit agencies will be facing in the transition to zero-emission fleets. Total Cost of Ownership (TCO), as defined by Wouters et al. (2005, p. 167), is an application of activity-based costing (ABC) that quantifies the costs that are involved in acquiring and using purchased goods; that could include maintenance, asset disposal, training, cost of upgrades, energy consumption, resources used in manufacture, and cost of operations.

The total cost of ownership was applied in this research work as a philosophy for understanding all relevant supply chain related costs to the acquisition and operation of public transit buses. TCO does not actually require the precise calculation of all costs but looks at major cost issues, and costs that may be relevant to the decision at hand [70]. Price is one element of the total cost of ownership, and often the largest single element, but still only one piece of TCO.

The total life-cycle cost for each of the zero-emission bus technologies studied in this work included the calculation of the total cost of ownership considering the following mayor expenses (Figure 34):

- Bus purchase cost
- Midlife overhaul
- Capital cost of fueling infrastructure
- Operation and maintenance
    - Cost of schedule maintenance
    - Cost of unscheduled maintenance
- Cost of operation
    - Cost of fuel
    - Driver’s wages

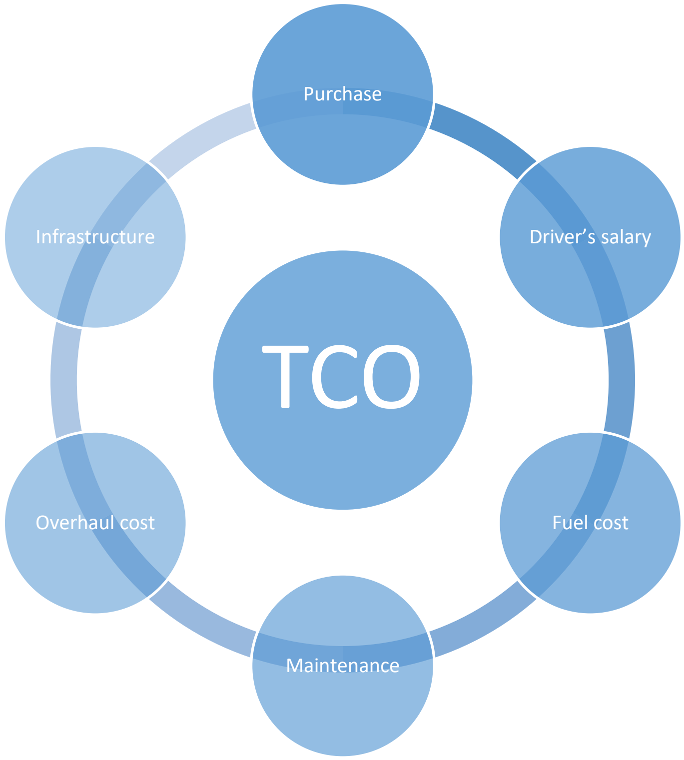


Figure 34. Factor considered in the total cost of ownership calculations

Table 24 shows the main parameters for the TCO calculations, and Table 25 summarizes the cost parameter used in the TCO calculations. Detailed explanations, justification, and documentation for each of these assumptions can be found in the "Cost Inventory Database" section.

Table 24. Simulation Parameters for TCO calculations

Assumptions
12 years of life spam for buses
3.44% interest rate
3.5% inflation rate
Fueling station design for a minimum of 150 buses
520,000 Vehicle Miles Traveled (VMT)
Midlife overhaul at 260,000 miles

Table 25. Cost parameters for total cost of ownership calculations of transit buses

	BEB-LR	BEB-SR	FCEB	CNG	Diesel
Bus Purchase Price	$780,000	$800,000	$1,000,000	$650,000	$480,000
Maintenance Cost	$0.61	$0.61	$0.48	$0.57	$0.85
Fuel Price	$0.15/KWh $5.66/DGE	$0.18/KWh $6.77/DGE	H_2CAT	$0.93/DGE	$2.21/DG
Overhaul Cost	$700/KWh	$700/KWh	$67,300	$70,500	$50,000
Fueling Equipment cost per charger	$40,000	$500,000	H_2CAT	$5,168,000	$100,000
Fueling Installation cost per charger	$70,000	$250,000			
Driver Hourly Wage	$27/hr.	$27/hr.	$27/hr.	$27/hr.	$27/hr.

The fuel efficiency for each bus powertrain used to model the TCO was calculated based on a dynamic model that standardizes the bus operations to have a comprehensive cost comparison, as described in the "Modeling of Urban Bus Energy Consumption" section. This methodology was used instead of reported fuel efficiency values that are affected by operational conditions like different driving speed, diversity of driving terrains, load factor, and bus configurations. By standardizing operation conditions and any other bus component besides the main powertrain, estimated fuel efficiencies were obtained that allow for an apples-to-apples comparison when applying a life cycle cost analysis.

5.1. BEBs Total Cost of Ownership

The two types of battery electric buses considered were over-night charging plug-in buses that have a long range (BEB-LR) and short-range buses (BEB-SR) that can charge on-route. Figure 35 shows the total cost of ownership for these two types of battery electric buses; the TCO presented is per unit vehicle. The main cost difference in the TCO analysis between these buses is the midlife overhaul and infrastructure costs. Since the size of the battery differs around 200KWh between BEB-LR and BEB-SR, the cost of replacing the batteries at midlife for BEB-LR is higher than for BEB-LR. However, the installation and equipment cost of BEB-SR is higher than for BEB-LR, which makes up for some of the midlife-overhaul cost difference. Furthermore, given that BEB-SR needs to charge while on-route, the purchase of electricity can be subject to demand chargers, resulting in a higher cost of electricity. From the results presented in Figure 35 can be concluded that the total cost of ownership for battery electric buses deployed in Southern California is around $2.84 million for both types of electric buses, plug-in, and on-route charging.

The allocation of on-route charges installed in the service routes of BEB-SR is a complex problem, and it can be subject to extensive simulations to minimize costs. For this research work, the calculations were simplified by assuming that for any route shorter than 50 miles one charger is allocated for each direction of the route (total of two chargers per route). Additionally, if more than eight buses are allocated to the same route, then an additional set of chargers needs to be installed in such route to avoid long waiting periods for charging.

The TCO calculation for plug-in electric buses (BEB-LR) in Figure 35 does not take into consideration the range limitations of the bus to cover the route length. From internal data collected with OCTA, over 44% of the routes covered by this agency have above 120 miles in length. To consider the cost implications that a transit agency needs to incur to accommodate the operational constraints that range limitations causes, an additional scenario was modeled for the TCO of BEBs. It's was assumed that, if a route length is above 140 miles, one additional BEB-LR needs to be purchased and assigned to such route. While not practical since increasing the number of buses in a fleet is usually not viable for transit agencies due to space limitations, lack of operators, and FTA funds, this additional scenario sought to consider operational constraints and quantify the economic impact of such limitations. This additional scenario is presented in Figure 35 under the label "BEB w/extra buses."

Incorporating additional buses to a fleet has cost implications. Even when the total cost of ownership is expressed per bus unit, the cost of wages and costs of operations increases the overall life-cycle cost. The total cost of ownership for this scenario is $3.08 million, as shown in Figure 35. The calculations of the extra buses to compensate range limitations was only calculated using plug-in BEBs since the limitation is eliminated with on-route charging. Even when this scenario considers great simplifications to the logistics of increase the number of buses in a fleet, it's a more accurate reflection of the LCC for BEBs-LR, and the results should be of more relevance to stakeholders than results that do not take into account operational constraints from range limitations.

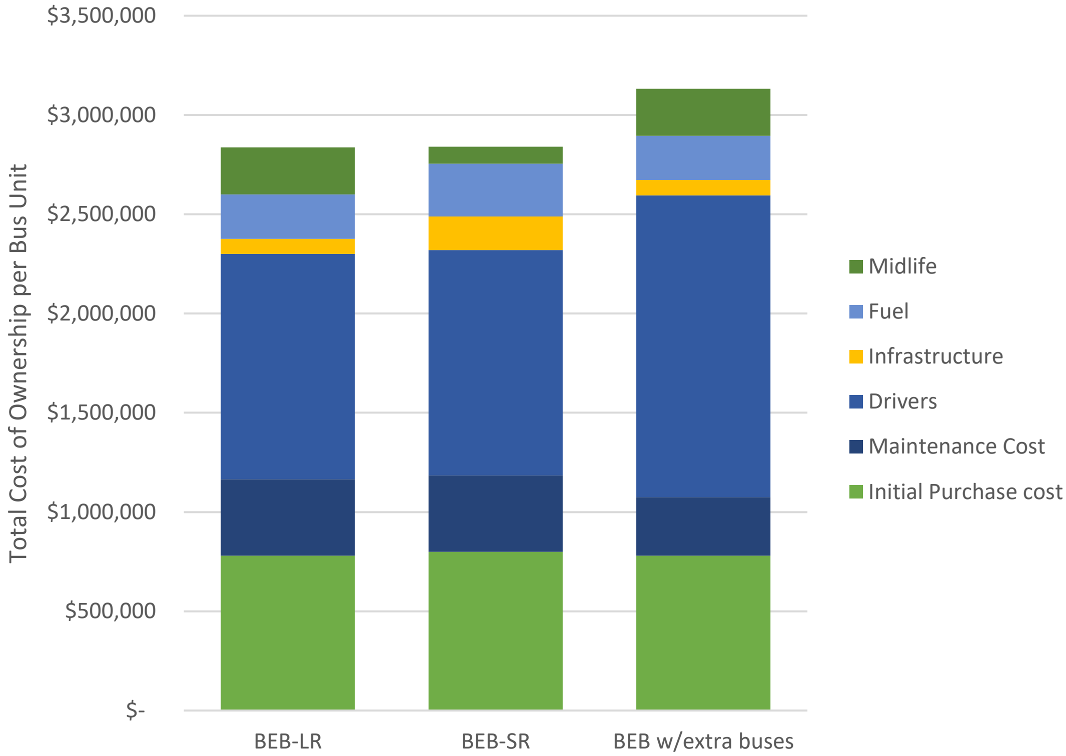


Figure 35. Total Cost of Ownership of Battery Electric Buses

The fuel price, one of the driving factors in the TCO calculations, has uncertainty that needs to be considered. In particular, the price assigned per kilowatt-hour can drive the cost estimations in favor of a given bus powertrain and can be the determining factor of adoption for transit agencies. Transit agencies adopting zero-emission fleets find themselves transitioning from simple supply contracts that are only subject to market variations to negotiating long term electricity tariffs with their utility company, state regulatory bodies, and the state utility commission. Because of the (1) large power demand that battery electric buses represent for an agency, and (2) a changing grid mix that is adjusting to an increasing present of renewables, it is a challenge to project long-term electricity costs.

The variation in electricity rate charges and its effect on the total cost of ownership was studied. Figure 36 presents the TCO of BEB-LR under different electricity rates, and Table 26 provides details of cost assumptions for each scenario.

Table 26. Electricity Costs Depend on Utility Rate and Charging Pattern

Utility Company	Cost of Electricity at Depot charge $/KWh	$/DGE
SCE	0.18	6.77
PGE	0.24	9.03
SDGE	0.34	12.80
LADWP	0.20	7.53
BEB-SR	0.18	6.77

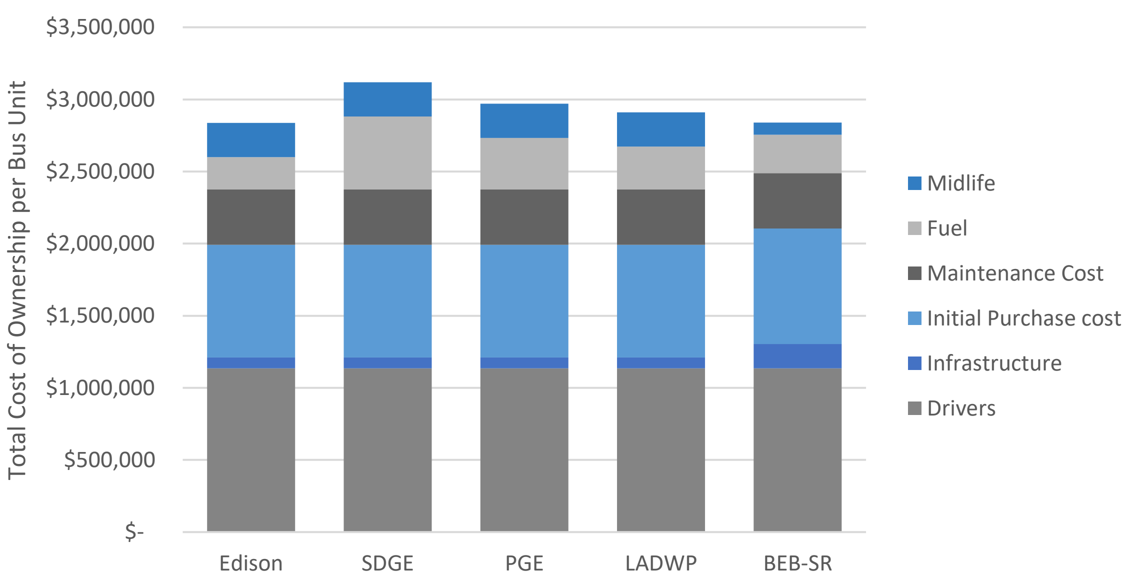


Figure 36. Total Cost of Ownership for BEBs with different electricity rate charges

The TCO for a plug-in battery electric bus (BEB-LR) can be as low as $2.84 million per bus or as high as $3.12 million when the electricity price range is between eighteen cents and thirty-four cents per kilowatt-hour. The variation in TCO can be even more drastic for on-route charging buses (BEB-SR) since they can be subject to demand chargers. However, an electricity use model that can capture the effect of demand chargers requires detailed information on the daily schedule for an entire fleet.

5.2. FCEB Total Cost of Ownership

When modeling the life cycle cost of fuel cell electric buses, it's necessary to investigate the impact that the different fuel supply pathways have on the total cost. Applying the same methodology used to calculate the TCO of BEBs, the total cost of ownership was estimated for three different hydrogen distribution methods (liquid delivery, distributed SMR, pipeline) and compared to the hydrogen price target stablished by the FTA of $4 per kilogram.

As described in the Cost Inventory Database section, the model H_2CAT [48] was used to project the price of hydrogen under different generation and distribution pathways. H_2CAT considers the cost of equipment, maintenance, and operation of the station, inflation and interest rate, and all the costs are levelized and integrated to calculate the final price of hydrogen in dollars per kilogram. The cost per kilogram of hydrogen calculated with H_2CAT for each distribution scenario is shown in Table 27; the cost of hydrogen was then used to calculate the TCO for the corresponding scenarios.

Figure 37 presents the TCO results for FCEBs. The fuel supply pathways with lower TCO are distributed SMR with $2.86 million per bus and hydrogen delivered via pipeline with $2.89 million per bus. These two scenarios have the same cost for all the other categories (purchase, M&O, and midlife overhaul) with the only difference in the levelized price of hydrogen.

Delivery of liquid hydrogen to supply FCEBs resulted in a TCO of $3.02 million per bus, which is $29,000.00 above the TCO of the FTA target that assumed a hydrogen price of $4 per kilogram.

The cost bars in Figure 37 do not show the cost of infrastructure since the capital cost, and operation cost of the station is already reflected in the price per kilogram of hydrogen for all the scenarios, except for the FTA scenario.

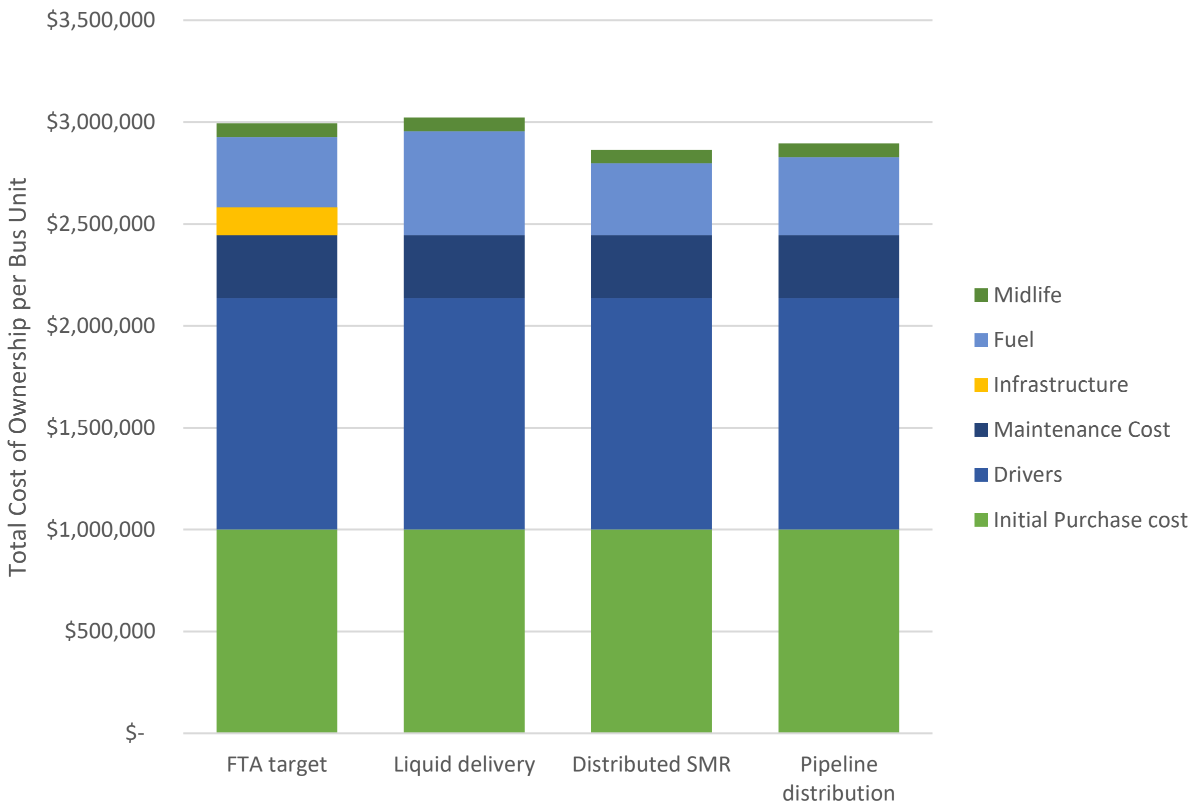


Figure 37. Total cost of ownership of Fuel Cell Electric Buses with different hydrogen distribution pathways

Table 27. Minimum Cost of Hydrogen for different distribution pathways from H_2CAT

Distribution Pathway	Cost of Hydrogen ($/kg)
Pipeline	$ 4.43
Distributed SMR	$ 4.08
Liquid Hydrogen	$ 5.91
FTA goal (without infrastructure)	$ 4.00

To further analyze how the variation in fuel price impacts the total cost of ownership, Figure 38 presents the TCO for fuel cell, and battery buses with the mean and variability resulted from different fuel prices. The middle line of the box represents the median, $2.94 million for FCEB and $2.91 for BEBs. The mean for FCEBs is the same value as the median, $2.94 million; and for BEBs, the median TCO value is also $2.94 million. Because the set of information used to calculate TCO of BEBs is based on possible electricity rates and no actual data points from a population, the mean is a better-expected value of TCO for BEBs. Meaning that if we take into consideration variations in the fuel prices for both hydrogen and electricity, the total cost of ownership for FCEBs and BEBs can be expected to be the same, $2.94 million per bus.

The median divides the data set into a bottom half and a top half. The bottom line of the box represents the median of the bottom half or 1st quartile; in millions, $2.87 for FCEB and $2.84 for BEB. The top line of the box represents the median of the top half or 3rd quartile; $3.02 for FCEB and $3.08 for BEB. The whiskers (vertical lines) extend from the ends of the box to the minimum value and maximum value. Therefore, the total cost of ownership for fuel cell electric buses can be expected to be between $2.86 million and $3.02 million per bus; as for battery electric buses, it can be expected to be between $2.84 million and $3.12 million.

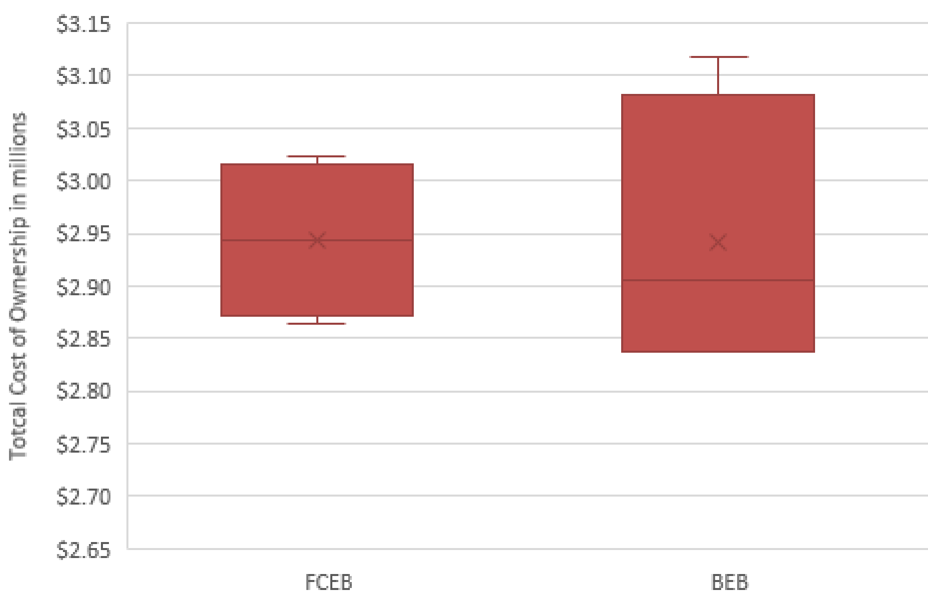


Figure 38. Total Cost of Ownership of FCEBs and BEBs with mean and variability

5.3. Total Cost of Ownership of zero-emissions and conventional fuel transit buses

The life cycle cost of conventional-fuel buses was calculated in the form of the total cost of ownership to compare with the cost of zero-emission buses. Figure 39 presents the TCO for all the powertrains considered in this research work. CNG buses have the lowest TCO with $2.46 million per bus; diesel buses follow with a TCO of $2.55 million. Battery electric buses – both LR and SR - have a TCO of $2.84 million, which is an increase of $382 thousand with respect to CNG buses. However, as it was analyzed in prior sections, the TCO of BEB-LR does not take into consideration the range limitations that impose operational constraints. If takin into consideration that additional battery electric buses are required to provide the same service coverage, then the TCO of $2.89 million required by fuel cell buses is lower than for BEBs ($3.08 million).

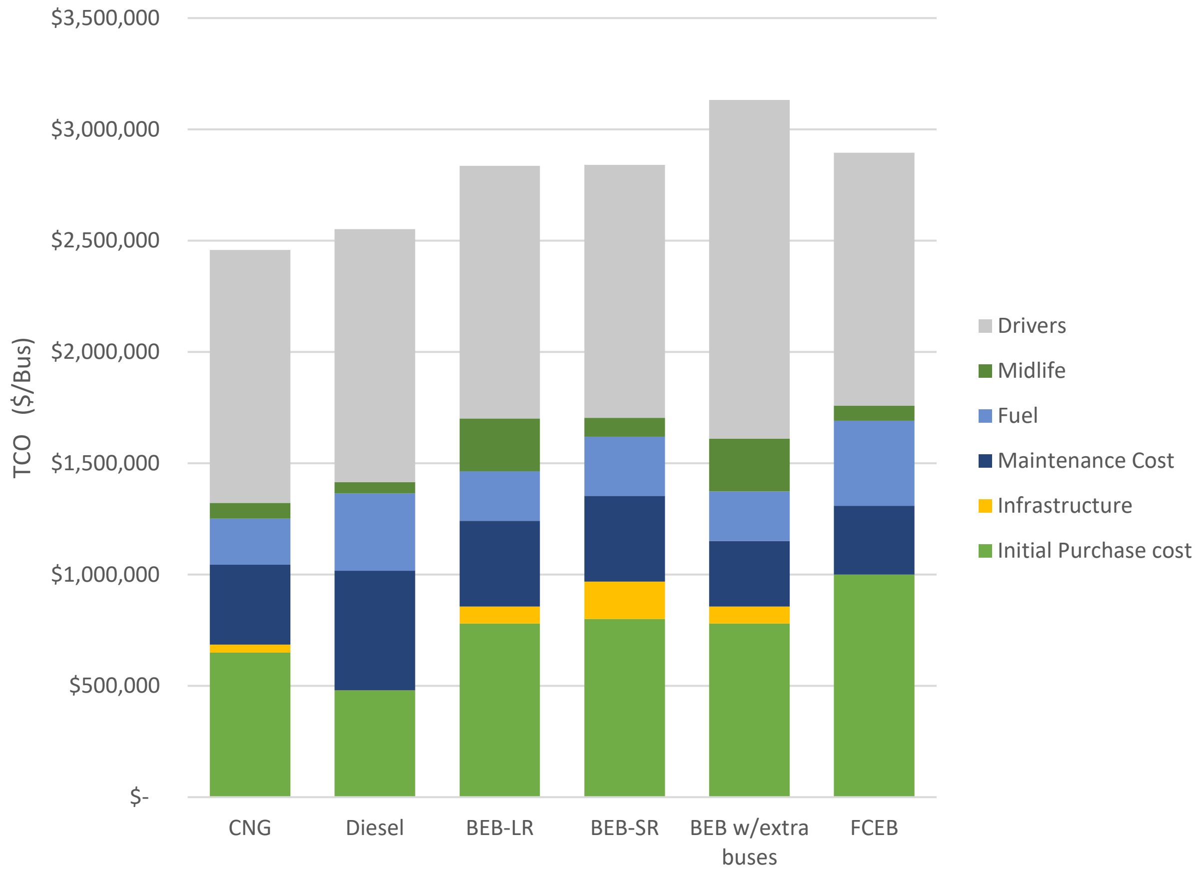


Figure 39. Total Cost of Ownership of zero-emission and conventional-fuel buses

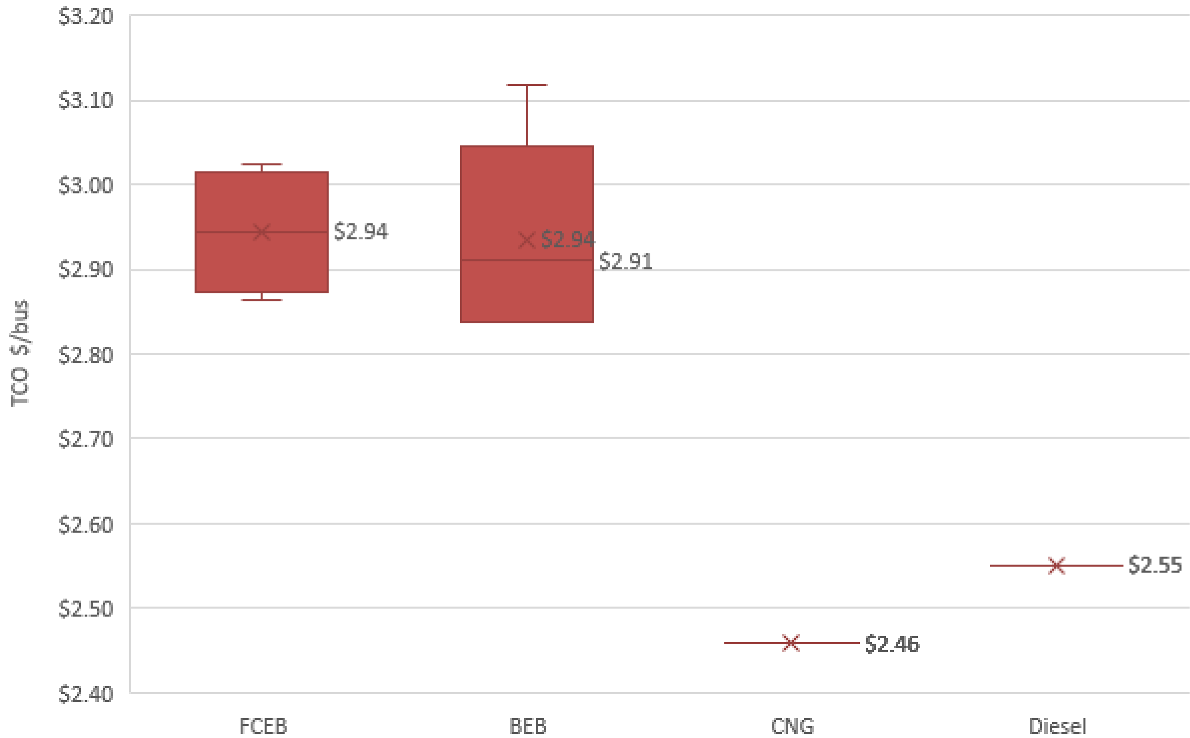


Figure 40. Total Cost of Ownership of transit buses with mean and variability [$million/bus]

6. Conclusions

The study findings and conclusions are summarized here.

- General Methodology Conclusions:
  - When renewable sources are the feedstock for hydrogen (such as electrolytic hydrogen), and electricity generation (such as hydropower), the Global Warming Potential emissions, Particulate Matter Formation, and the ReCiPe Endpoint Total score are the same for FCEBs and BEBs-LR.
  - Using electricity from the current California grid mix to drive electrolysis to produce hydrogen for FCEBs produced only marginal benefits compared to current natural-gas fueled vehicles due to the low supply chain efficiency of this pathway.
  - The mining of precious metals for the manufacturing of BEBs and FCEBs powertrains were among the factors that contributed the most in the emissions associated with the following LCI categories: Terrestrial Acidification, Photochemical Oxidant Formation, and Freshwater Ecotoxicity.
  - Both FCEVs and long-range BEBs provide significant reductions in environmental footprint compared to conventional diesel and natural gas buses.
- Orange County Transit District Conclusions:
  - With current-day cost inputs, FCEBs and BEBs have comparable total cost of ownership, but both have slightly higher costs than diesel and natural gas buses.
  - FCEBs have an equivalent total cost of ownership to BEBs when the electricity rate for charging is $0.24/kWh. Higher values render FCEBs as the less expensive option and lower values render BEBs as the less expensive option.
  - The total cost of ownership of these technologies is highly sensitive to electricity costs, and the rapid evolution of the electricity system has strong implications for the economic comparison between BEBs and FCEBs.

Overall, this study finds that BEBs and FCEBs provide significant environmental footprint benefits compared to conventional powertrains, but also incur increases in total cost of ownership. The cost increases are largely due to increased initial purchase cost, cost of fuel / electricity, and to a lesser extent for BEBs, battery replacement at midlife. This may change in the future due to the rapid transformation of the electricity system and the falling costs of renewables, as well as economy-of-scale improvements for BEBs and FCEBs. At present, however, incentivizing adoption of BEBs or FCEBs by transit agencies will require policies that reduce the burden of initial purchase cost and electricity costs incurred by transit agencies. These policies can take the following forms:

- Tax credits or subsidies for the purchase of an FCEB or BEB by a transit agency, similar to the incentives currently in place for light-duty zero emission vehicles. These credits can last up to a certain volume of BEB or FCEB adoption and gradually wind down until incentives are no longer needed for total cost of ownership parity, and can be structured in size to compensate for the difference between state-of-the-art BEBs or FCEBs and current conventional bus units.

Subsidized or discounted electricity rates for BEB charging or FCEB fuel production by transit agencies. These discounted rates can take the form of either wholly reduced electricity rates or the construction of electricity rate profiles that are tailored to the patterns of charging / fuel production loads

References

[1] Wernet G, Bauer C, Steubing B, Reinhard J, Moreno-Ruiz E, Weidema B. The ecoinvent database version 3 (part I): overview and methodology. Int J Life Cycle Assess 2016;21:1218–30. https://doi.org/10.1007/s11367-016-1087-8.

[2] Proton OnSite. M Series 2011:4–5. https://www.protononsite.com/sites/default/files/2017-04/PD-0600-0119 REV A.pdf.

[3] M Series Hydrogen Generation Systems MODEL M100 M200 M400 2011.

[4] Bauer C, Hofer J, Althaus HJ, Del Duce A, Simons A. The environmental performance of current and future passenger vehicles: Life Cycle Assessment based on a novel scenario analysis framework. Appl Energy 2015;157:871–83. https://doi.org/10.1016/j.apenergy.2015.01.019.

[5] Fuel Cell Today. The Fuel Cell Industry Review 2013. 2013.

[6] Spendelow J, Marcinkoski J, Fuel Cell Technologies Office D. DOE Hydrogen and Fuel Cells Program Record Title: Fuel Cell System Cost -2014 2014.

[7] Devaal J, Niroumand A, Fellow P, Golnaraghi F, Description P. Heavy Duty Fuel Cell System Improvements n.d.

[8] Cox BL, Mutel CL. Environmental and economic life cycle assessment of current and future motorcycles. n.d.

[9] California Air Resources Board. Advanced Clean Transit Battery Cost for Heavy-Duty Electric Vehicles. 2016.

[10] Boston Consulting Group. Batteries for Electric Cars: Challenges, Opportunities, and the Outlook to 2020. 2012.

[11] Proterra. Proterra Catalyst Specifications: 40 foot Bus. 2016.

[12] Bus G. GreenPower Battery Electric Bus EV350 Specs. 2019.

[13] New Flyer Electric Bus XCelsior Specs n.d.

[14] NovaBus. Nova Electric Bus LFSE Specs 2017. https://novabus.com/wp-content/uploads/2017/09/LFSe_EN_Sept2017-1.pdf.

[15] US Energy Mapping System Energy Information Administration (EIA) n.d.

[16] U.S. Energy Information Administration (EIA). California - State Energy Profile Data n.d.

[17] Goedkoop M, Heijungs R, Huijbregts M, Schryver A De, Struijs J, Zelm R Van. ReCiPe 2008 - A life cycle impact assessment method. 2013.

[18] Cox BL, Mutel CL. The environmental and cost performance of current and future motorcycles. Appl Energy 2018;212:1013–24. https://doi.org/10.1016/j.apenergy.2017.12.100.

[19] EIA. California - State Energy Profile Overview - U.S. Energy Information Administration (EIA) n.d.

[20] U.S. Energy Information Administration (EIA). Eia.gov - Data - U.S. Energy Information Administration (EIA) Energy Consumption by Sector n.d.

[21] Thuesen HG (Holger G, Fabrycky WJ (Wolter J., Thuesen GJ. Engineering economy 1977:589.

[22] Drive Natural Gas Initiative, ANGA, AGA. CNG Infrastructure Guide for the Prospective CNG Developer. n.d.

[23] Clean Cities. Clean cities CNG infrastructure cost webinar 2014. https://cleancities.energy.gov/files/u/news_events/document/document_url/18/cng_infrastructure.pdf.

[24] Mitchell G. Building a Business Case for Compressed Natural Gas in Fleet Applications. 2015.

[25] Octa. OCTA Operational Data. 2014.

[26] Nat G CNG Solutions, LLC. – CNG Units Explained n.d. http://www.nat-g.com/why-cng/cng-units-explained/.

[27] Air Pollution Reduction Review Committee for the Clean Transportation Funding. Construct CNG Refueling Station and Maintenance Facility Modifications | Mobile Source Air Pollution Reduction Review Committee 2005.

[28] Air Pollution Reduction Review Committee for the Clean Transportation Funding. Construction of New Compressed CNG Refueling Station at OCTA n.d.

[29] Smith M, Gonzales J. Costs Associated With Compressed Natural Gas Vehicle Fueling Infrastructure. 2014.

[30] De Tapia J, Jansen J, Zobel B, Hut D, Donaldson D, Hoyt C, et al. Trillium CNG Program for

Miami-DADE Transit. n.d.

[31] National Renewable Energy Laboratory. NREL DriveCAT - Chassis Dynamometer OCTA Drive Cycle n.d.

[32] Clean Transportation Funding. Construction of New Compressed Natural Gas Refueling Station | Mobile Source Air Pollution Reduction Review Committee n.d.

[33] CPI Inflation Calculator n.d. https://data.bls.gov/cgi-bin/cpicalc.pl.

[34] Adams R. Upgrading a Facility for CNG. Marathon Corp 2014.

[35] Eudy L, Post M. Fuel Cell Buses in U.S. Transit Fleets: Current Status 2018. 2018.

[36] OCTA. Transit Division Performance Measurements Report Fiscal Year 2011-2012 Third Quarter 2012:1–33.

[37] Eudy L, Jeffers M. Foothill Transit Battery Electric Bus Demonstration Results: Second Report. 2015.

[38] MTA. MTA Capital Dashboard | Home Page n.d.

[39] EIA. Gasoline and Diesel Fuel Update - Energy Information Administration n.d.

[40] EIA. Natural Gas Commercial Price 2017. https://www.eia.gov/dnav/ng/ng_pri_sum_a_EPG0_PCS_DMcf_m.htm.

[41] Eudy L, Jeffers M. Foothill Transit Agency Battery Electric Bus Progress Report, Data Period Focus: Jan. 2018 through Jun. 2018. 2018.

[42] Anaheim Resort Transportation. Anaheim Transportation Network Electric Bus Purchase. n.d.

[43] Your Central Valley. Porterville goes green with electric buses n.d.

[44] Matt Boothe - CTE. Critical Answers for Smart Deployments. n.d.

[45] Southern California Edison. Schedule TOU-EV-4 2019.

[46] Southern California Edison. Schedule TOU-EV-8 2019.

[47] Hursh MA. Alameda-Contra Costa Transit District Staff Report. 2017.

[48] Castillo-Munoz A. Deployment of Fuel Cell Electric Buses in Transit Agencies : Hydrogen Demand Allocation and Preferable Hydrogen Infrastructure Rollout Scenarios. University

of California Irvine, 2016.

[49] Melaina M, Nrel MP. Hydrogen Station Cost Estimates. Natl Renew Energy Lab NREL 2013:1–36.

[50] Mintz M, Gillette J, Elgowainy A. H2A DELIVERY SCENARIO ANALYSIS MODEL VERSION 1.0 * USER ' S MANUAL 2006:1–32.

[51] Santa Ana, CA Electricity Rates | Electricity Local 2017. https://www.electricitylocal.com/states/california/santa-ana/.

[52] Brown T, Schell LS, Stephens-Romero S, Samuelsen S. Economic analysis of near-term California hydrogen infrastructure. Int J Hydrogen Energy 2013;38:3846–57. https://doi.org/10.1016/j.ijhydene.2013.01.125.

[53] Shayegan S, Hart D, Pearson P, Joffe D. Analysis of the cost of hydrogen infrastructure for buses in London. J Power Sources 2006;157:862–74. https://doi.org/10.1016/j.jpowsour.2005.12.065.

[54] Brown T, Stephens-Romero S, Scott Samuelsen G. Quantitative analysis of a successful public hydrogen station. Int J Hydrogen Energy 2012;37:12731–40. https://doi.org/10.1016/j.ijhydene.2012.06.008.

[55] Stephens-Romero SD. Development of a Spatially and Temporally Resolved Planning Tool for Deployment of Hydrogen Infrastructure. UCI Diss 2011:223.

[56] Eudy L, Chandler K. SunLine Transit Agency Advanced Technology Fuel Cell Bus Evaluation : Fourth Results Report. 2013.

[57] Canning F. FIBA Canning Hydrogen Storage and Delivery n.d.

[58] California Air Resource Board. Detailed California-Modified GREET Pathway for Compressed Natural Gas (CNG) from Landfill Gas n.d.

[59] Eudy L. Zero Emission Bay Area (ZEBA) Fuel Cell Bus Demonstration : First Results Report. NREL Tech Rep 2011.

[60] Eudy L, Post M. Zero Emission Bay Area (ZEBA) Fuel Cell Bus Demonstration Results : Third Report. Natl Renew Energy Lab 2014.

[61] NREL, Duran A. DRIVE Analysis Tool Generates Custom Vehicle Drive Cycles Based on Real-World Data From Raw Data to Custom Drive Cycles. NRELGov 2014.

[62] Wipke KB, Cuddy MR, Burch SD. ADVISOR 2.1: A user-friendly advanced powertrain

simulation using a combined backward/forward approach. IEEE Trans Veh Technol 1999;48:1751–61. https://doi.org/10.1109/25.806767.

[63] Miotti M, Hofer J, Bauer C. Integrated environmental and economic assessment of current and future fuel cell vehicles. Int J Life Cycle Assess 2017;22:94–110. https://doi.org/10.1007/s11367-015-0986-4.

[64] Stefan H. Opportunities and challenges for electric mobility : an interdisciplinary assessment of passenger vehicles. 2016.

[65] Cox BL. MOBILITY AND THE ENERGY TRANSITION: A LIFE CYCLE ASSESSMENT OF SWISS PASSENGER TRANSPORT TECHNOLOGIES INCLUDING DEVELOPMENTS UNTIL 2050. ETH Zurich, 2018.

[66] Mutel C. Brightway2 Advanced life cycle assessment framework n.d.

[67] Acero AP, Rodríguez C, Ciroth A. LCIA methods Impact assessment methods: Life Cycle Assessment and their impact categories. OpenLCA 2014:1–23.

[68] Development O of R&. EFFECTS OF PHOTOCHEMICAL OXIDANTS ON PLANTS n.d.

[69] EIA. Sulfur dioxide emissions from U.S. power plants have fallen faster than coal generation - Today in Energy - U.S. Energy Information Administration (EIA) n.d.

[70] Ellram LM. Total Cost of Ownership. Handb. Ind. Beschaffungsmanagement, Wiesbaden: Gabler Verlag; 1999, p. 595–607. https://doi.org/10.1007/978-3-322-99462-2_33.

[71] Capitol Equipment. Generac 1500kW Diesel Generator SD1500 for sale in Manchester, CT. Capitol Equipment Manchester, CT (860) 643-7958 n.d.

Data Management Plan

Products of Research

The data collected to carry out the study are categorized into two types.

The first data type are scalar parameters that are used as inputs to the models adopted for the study. These include costs, efficiencies, capacities, and other parameters associated with the different bus types assessed in this study (BEB, FCEB, CNG, Diesel) and the associated infrastructure for supporting these vehicles. These data types were gathered from a combination of manufacturer specification sheets, government reports, and the academic literature and are publicly accessible. For these data types, the data are explicitly presented with the source for the data identified.

The second data type is proprietary or licensed data that were collected to conduct the life cycle analysis portion of this study. Specifically, three data sources fall into this category:

- The materials composition list, costs, and performance parameters for the electrolyzers used to produce the hydrogen fuel for the fuel cell buses by Proton-on-Site.
    - These data are proprietary by the manufacturer (Proton-on-Site). The redacted versions of these data are presented as Table 2 and Table 3 in this final report document.
- The EcoInvent life cycle inventory database used to capture the life cycle emissions and subsequent environmental impacts of the materials and processes used in the life cycle of each bus type.
    - This database requires a paid subscription to access and sharing in the public domain is a violation of the data use agreement.
- The drive cycle data for bus routes that are specific to the transit authorities assessed in the study.
    - The time-speed data for buses operated by the UC Irvine Anteater Express and the Orange County Transportation Authority are summarized in the report but sharing of the raw data is currently restricted.

Data Format and Content

For the first data type, these are presented explicitly as tables within this final report document along with description and referencing in the text.

For the second data type, the materials composition lists, costs, and performance parameters for electrolyzers and fuel cells are provided as tables in the report. The drive cycle data for buses operated by the UC Irvine Anteater Express and the Orange County Transportation Authority are contained in comma-delimited (.csv) files, but are not submitted here due to restrictions from the providing entities on sharing at this time.

Data Access and Sharing
For the first data type, the data are explicitly available in the final report. Other entities and researchers can access these data this report.

For the second data type:
- The materials composition list, costs, and performance parameters for electrolyzers can only be accessed with permission from the manufacturers of the equipment under a non-disclosure agreement.
- The EcoInvent database can only be accessed via a paid subscription for the database, either as a standalone or as part of a life cycle analysis software package (i.e. SimaPro).
- The drive cycle data need to be requested from the respective entities that provided them: the Orange County Transportation Authority and the UC Irvine Transportation and Distribution services with a request and justification for the use of the data.

Reuse and Redistribution
For the first data type, these data can be reused and redistributed with proper referencing and attribution.

For the second data type, these data cannot be reused or redistributed unless permission from the manufacturers are obtained (for the materials composition lists), the data are shared with another entity that has an EcoInvent subscription (for the EcoInvent database), or permission is provided the Orange County Transportation Authority or the UC Irvine Transportation and Distribution Services.