A TECHNO-ECONOMIC COMPARISON OF BATTERY ELECTRIC AND HYDROGEN FUEL-CELL TRANSIT BUS FLEET OPTIONS FOR HUMBOLDT COUNTY, CALIFORNIA

By

Aditya S Kushwah

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Committee Membership

Dr. Arne E Jacobson, Committee Chair

Dr. Charles Chamberlin, Committee Member

Dr. Peter Alstone, Committee Member

Dr. Margaret Lang, Graduate Coordinator

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ABSTRACT

A TECHNO-ECONOMIC COMPARISON OF BATTERY ELECTRIC AND HYDROGEN FUEL-CELL TRANSIT BUS FLEET OPTIONS FOR HUMBOLDT COUNTY, CALIFORNIA

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This study analyzes the techno-economic feasibility of converting the conventional transit bus fleet of the Humboldt Transit Authority (HTA) into a battery-electric or a hydrogen-fueled bus fleet. The study identifies which of these technologies represents the more economically viable investment for HTA by analyzing the costs and benefits associated with each pathway. Both pathways involve zero-emission or low-emission technologies.

The study outcomes suggest that the conversion of the HTA's current conventional fleet to an electric fleet is more feasible than conversion to a hydrogen fuel cell bus fleet. The total discounted cost (3% rate) of converting the 21-bus conventional fleet to electric or hydrogen buses during the period from 2021-2040 is $27 and $62 million, respectively.

Currently, HTA's total cost of the current conventional fleet is $110 per hour of operation (excluding capital cost, as the buses are in service). The capital cost to purchase a new set of conventional buses is reportedly $71/hr. The corresponding estimated costs for battery-electric and hydrogen-fueled fleets including capital costs are $167/hr and $390/hr, respectively. The total cost of conversion includes various cost components,

such as the capital cost of buses and charging/refueling infrastructure, the operation and maintenance (O&M) cost of buses and associated charging/refueling infrastructure, revenue generated by low carbon fuel standard (LCFS) credits, and other related costs for the period from 2021-40. This period is consistent with the timeline recommended by the California Air Resources Board (CARB).

The transition to zero-emission buses is proposed to be carried out in two phases for both technologies, with Phase I occurring from 2021 to 2025 and Phase II from 2025 to 2030. For the battery electric bus option, the study also analyzed the optimized charging time for the buses while keeping demand below 750 kW with continuous charging during non-peak hours.

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CHAPTER 1: INTRODUCTION

The increase in greenhouse gas (GHG) emissions is a global question, and countries around the world are struggling to tackle this challenge. Increased GHG emissions cause a warming effect that contributes to severe weather that we are witnessing these days, such as droughts and epidemic diseases (Laaksonen, 2010) (NRDC, 2021).

The world experienced an increase in temperature after the beginning of the industrial era in the early 1900s, and it has been growing since then. However, half of this increase was generated in the last five decades alone (Denchak, 2019) (The National Academies Press, 2010). The average global temperature rose by 1.4° Fahrenheit since 1880 due largely to increased GHG emissions (Lindsey, 2020) (U.S. Environmental Protection Agency, 2010). The primary emissions that contribute to global warming are generated by fossil fuel combustion (especially in the developed world) to maintain the economic growth. This fossil fuel combustion increased substantially in last ten decades (Center For Climate and Energy Solution, 2018).

One of the prominent contributors to fossil fuel consumption is the transportation sector. The global demand for transportation drives the combustion of petroleum-based fuels, namely gasoline and diesel, that adds to the emissions. Countries and organizations across the globe are working together to reduce these emissions by making very ambitious and aggressive targets of GHG reductions. For, example, the U.S. government has set a target of becoming carbon neutral by 2050, with support of regulatory mandates

and policies for carbon pricing in different sectors in some states (World Economic Forum, 2021). California, which accounts for approximately 15% of the U.S. economy, also implemented policies to adhere with the national and state goals (CARB, 2018a). In addition, California established several state-wide laws to contain emissions by adopting renewable and more sustainable alternatives in every sector including the transportation sector (U.S. DOE Office of Energy Efficiency and Renewable Energy's, 2020). The state of California passed a statewide bill requiring all public transit agencies to gradually switch to 50% zero-emission buses (ZEBs) by 2025 with a goal for the full conversion to ZEBs by 2040 (CARB, 2018a) (CARB, 2019; CARB, 2018b).

The Innovative Clean Transit (ICT) regulation requires transit agencies in California to replace conventional buses with ZEBs. However, adoption of this law raises several questions for transit agencies across the state. One question is, which technology would be more techno-economically appropriate and provide more benefits to the county or municipality? Many transit agencies across California find this question monumental and demanding of prompt action. The decision makers at the Humboldt Transit Authority (HTA), a transit agency operating in Humboldt County, California (a county in far northwestern California), are committed to finding avenues to be compliant with this state mandate while providing convenient, affordable, hassle-free transit services to Humboldt County's residents. A key question for HTA is how they intend to pursue these technologies. This project intends to help informing such questions with a goal of helping to guide HTA's decisions and to help them comply with the evolving regulatory norms of California's transportation sector.

The objective of this study is to identify a technological solution for Humboldt County (specifically HTA) that not only reduces its carbon footprint but also determines the economically optimal pathway for the transition to a ZEB fleet (battery-electric or hydrogen fuel cell). This project has also compared the costs of adding new infrastructure (battery-electric or hydrogen fuel cell) to identify the most cost-effective solution for decarbonizing public transit in the Humboldt County. Vehicles utilizing both battery electric and hydrogen fuel cell technologies are certified as having zero or near to zero tail-pipe emissions, and other California counties are also adopting these technologies for their transit systems. This study will help determine which technological infrastructure represents a preferable investment option with the help of a conversion model.

The model in the study incorporates various parameters such as routes information, charging time, miles covered by conventional buses, and other factors to compute and compare various cost parameters associated with battery charging and hydrogen refueling infrastructure. It also includes government credits, capital costs, infrastructure costs, operation and maintenance (O&M) costs, equipment costs, daily fueling/charging costs, and the number of required charging/fueling stations. The model compares the two fleet types for their economic benefits and for the resiliency of the public transit network. The outcomes of this study are informed by reports and papers from various organizations, including the National Renewable Energy Laboratory, Schatz Energy Research Center, CARB, Stark Area Regional Transit Authority (SARTA), HTA, AC Transit, and Argonne National Laboratory (ANL).

Additionally, a few models are utilized to estimate cost factors, such as the Heavy-Duty Refueling Station Analysis Model (HDRSAM) (Argonne National Lab, 2017), CARB's ZEB model (CARB, 2018e), and CARB's Low Carbon Fuel Standard (LCFS) credit calculator (CARB, 2018b). These resources are used to create a database to provide inputs to the model, including cost parameters, a mapping of routes for HTA (miles covered by each bus/day), and other assumptions used in the analysis.

This project calculates the life cycle cost of the buses and infrastructure deployment scenarios from 2021 to 2040 and provides a comparison of both technologies. The model also helps to predict the life cycle cost for converting the entire fleet in the future. In addition, the study provides information about how these technologies can help reduce GHG emissions from the public transit sector and provide a path for the transition to ZEBs while fulfilling state and federal regulations by 2040.This project is structured as follows.

Chapter 2 presents the findings of a literature review, including background studies on the GHG emissions from the transport sector and California and the federal government plans and policies to reduce these emissions. The chapter also covers the zero-emissions technologies considered in this project, their impacts, and the required infrastructure developed by other counties such as electric charging stations and hydrogen refueling stations. The literature review is followed by Chapter 3, which discusses the methodology used to develop the model, including assumptions, data

collection, and calculations. It also describes how the model calculates the costs of technology and infrastructure deployment.

Chapter 4 summarizes the results of the study, which includes the detailed analysis and outcomes of the model. This chapter also discusses the details of the most cost-effective solution for HTA. The Results section is followed by conclusions and recommendations, presented in Chapter 5. This section discusses the outcomes of the model and how to interpret the results. It also contains recommendations to HTA for reducing GHG emissions and becoming a net-zero carbon emission transit agency by 2030.

CHAPTER 2: BACKGROUND AND LITERATURE REVIEW

Despite knowing that climate change is a worldwide concern, very few robust policies have been introduced to heal the earth's environment. Multiple climate organizations and scientists concluded in their studies that the GHG emissions are the result of activity conducted by humans to fulfill their personal growth over the last 150 years (U.S. Environmental Protection Agency, 2010). In the 20th century, the anthropogenic changes affected climate and inevitably led to global warming. The trend of global increase in the temperature based on land and ocean measurements is shown in Figure 1.

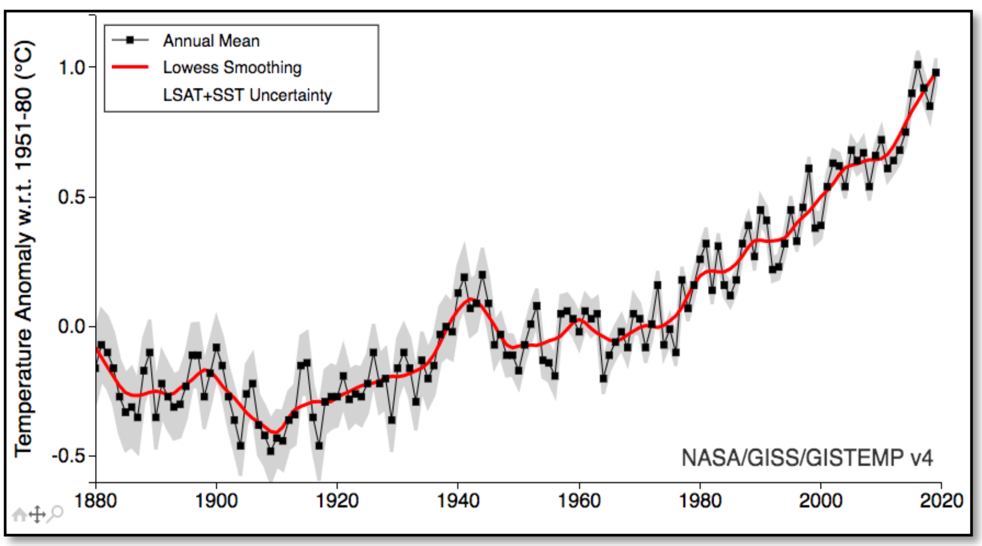

Figure 1. Rise in global temperature, land and ocean. Source: (NASA, 2020)

Some reports indicate the average surface temperature of earth increased by 1.0^{o} F over the last 100 years, with much of the increase occurring in last 40 years. Notably, 1995 was the warmest year on record in the 20th Century (The White House, 2000).

GHG emissions are mainly comprised of carbon dioxide, methane, nitrous oxide, and fluorinated gases. The influence of GHG emissions on global warming depends on three key factors: how much time these emissions stay or exist in the atmosphere, the concentration of these emissions, and how effectively the molecules of the emissions can trap heat. The combination of these factors is used to determine the global warming potential of a given greenhouse gas (U.S. Environmental Protection Agency, 2020) (GHG Mangement Institute, 2010). It is important to note that the behavior of different GHG gases uniquely depends on the factors mentioned previously. The most abundant GHG is carbon dioxide or CO_2, which is responsible for most global warming. Other GHGs also contribute to global warming, and their contributions are generally estimated in CO_2 equivalents (Neelnayana Kalita, 2016). Some chlorofluorocarbons (CFC) are considered to have high heat-trapping potential and are also liable for ozone depletion (RTI International, 2019).

The impact of GHG emissions on global warming depends on the time they exist in the atmosphere, which varies according to the GHG type. For instance, methane has a relatively shorter lifetime than CO_2 and some other GHGs. However, it has 28 times more global warming potential than CO_2 on a100- year time scale (IPCC, 2014)..These emissions stay in the environment for an extended time and mix globally in the atmosphere, making it a more concerning issue. Moreover, these global emissions are driven by activity across the world economy and associated global economic growth rather than on just a single country's actions, so the control of emissions requires global coordination. Per capita GHG emissions of developed and developing countries for the

year 2017 reported by the climate agencies are shown in Figure 2 (Center For Climate and Energy Solution, 2018).

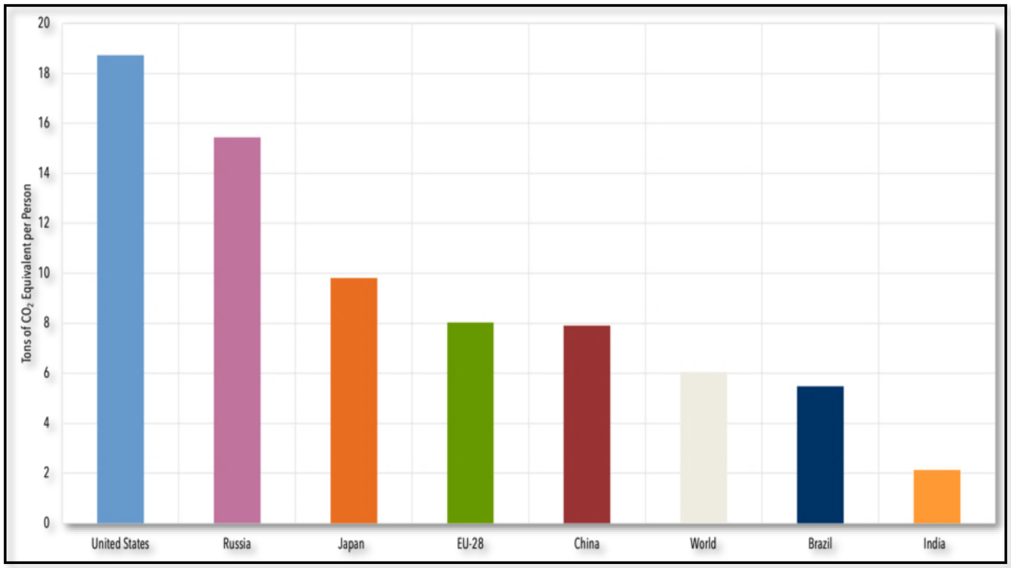

Figure 2. Per capita GHG emissions of developed and developing countries in 2017. Source: (Center for Climate and Energy Solutions, 2018)

GHG emissions are responsible for disrupting the fragile balance of nature. They disturb Earth's temperature by increasing the heat trapping capacity of Earth's atmosphere, thereby disturbing the harmonious balance of gases. This imbalance has already altered temperature, precipitation, agriculture, transpiration regimes, occurrence of weather-related calamities, and growth of unwanted weeds and pathogens, and can continue to do so in the absence of significance counter measures. In addition to the warming impact, these emissions significantly contribute to air pollution and make air more polluted day by day (U.S. Environmental Protection Agency, 2010).

Recently, the World Health Organization (WHO) confirmed that nine out of ten people worldwide breathe polluted air because of increase in pollutants (NO_x, SO_x,

particulates, CO, etc.) that lead to poor air quality (WHO, 2018). These pollutants are generated, in part, by combustion of fossil fuel. In addition, studies have also noted that GHG emissions can contribute to degraded water quality. For example, a rise in temperature reduces the concentration of dissolved oxygen in water, with corresponding impacts on many aquatic species (U.S. Environmental Protection Agency, 2010). Bad water and air quality directly contribute to air and water borne diseases (U.S. Environmental Protection Agency, 2010). Figure 3 shows the effects of climate change on water resources.

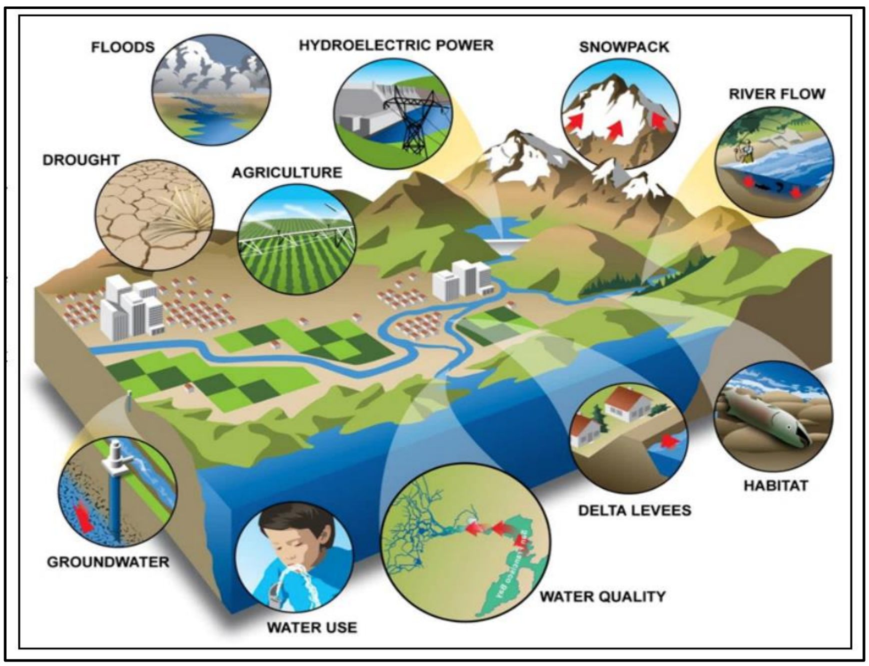

Figure 3. Effect of climate change on water sources. Source: (U.S. Environmental Protection Agency, 2010)

Human activities like deforestation, burning fossil fuels, and industrialization have increased GHG concentrations in our atmosphere to more than 400 parts per million (ppm). Between 1750 and 2011, the atmospheric concentration of carbon dioxide increased by 40 percent, nitrous oxide by 20 percent, and methane by 150 percent

(Denchak, 2019). As noted by the U.S. Environmental Protection Agency (EPA), GHG emissions in the United States come primarily from the following sectors: transportation (29% of 2019 GHGs), electricity production (25% of 2019 GHGs), industries (23% of 2019 GHGs), commercial and residential (12.6% of 2019 GHGs), agriculture (10% of 2019 GHGs), and U.S. territory (0.4% of 2019 GHGs), as shown in Figure 4.

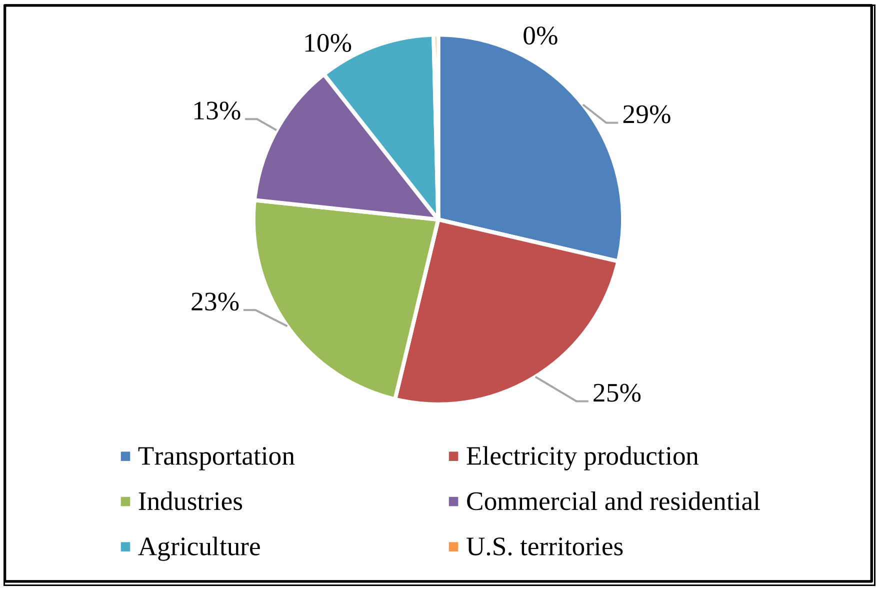

Figure 4. GHG emission from different sectors in the U.S. Source: (EPA, 2021)

The recent inventory of GHG emissions in the U.S. for the period from1990 to 2019 shows that the transport sector leads all areas with respect to GHG emissions, including power, industry, and agriculture (EPA, 2021). The U.S. transport sector accounted for 1.81 gigatons of CO_2 equivalents in direct GHG emissions in 2019 (Yale Enviroment 360, 2017) (EPA, 2021). As shown in recent studies, the global transport sector accounts for 14% of 2010 global GHG emissions (EPA, 2021). In 2018, the U.S. produced the second-highest CO_2 emissions after China (Union of Concerned Scientists, 2020).

EPA also reported that the gross GHG emissions from the U.S.'s transportation sector has increased by an average of 1.4% per year from 1990 to 2007. They significantly decreased from 2007-2012 and again increased from 2013-2019, as shown in Figure 5. However, the net impact from 2007-2019 was a decrease of 0.5% per year.

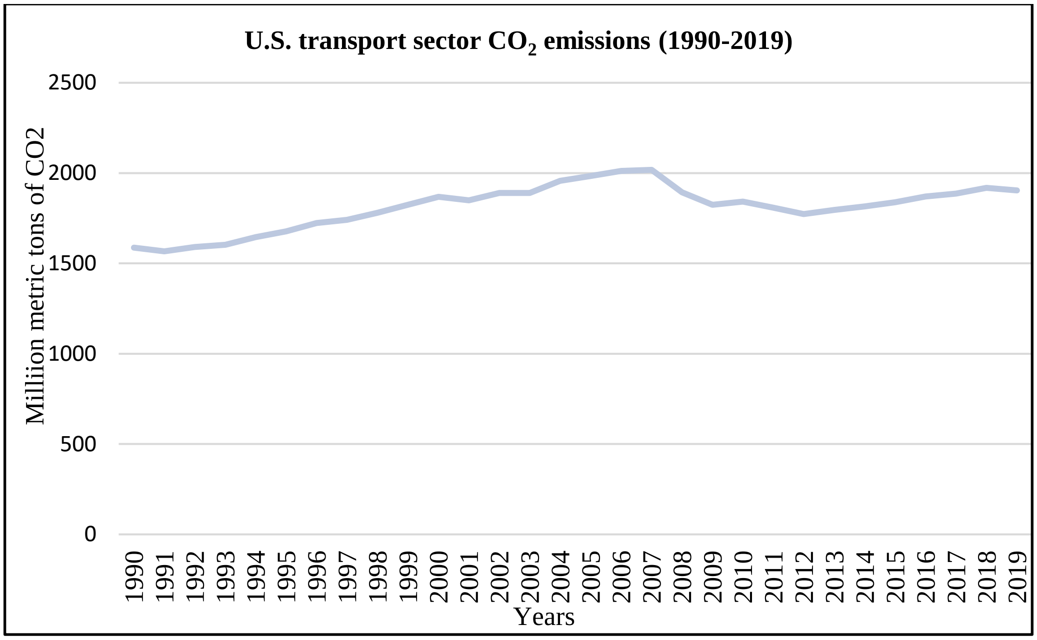

Figure 5. CO_2 emissions from the U.S. transportation sector from 1990 to 2019. Source: (U.S. Energy Information Administration, 2020)

Cumulatively the emissions from the transportation sector grew by an average of 0.6% per year between 1990 and 2019 (U.S. Energy Information Administration, 2020). That makes the transport sector one of the most significant contributors to increasing emissions in the U.S.

The combustion of carbon-based fuels, namely diesel, gasoline, and other petroleum products, powers the overall demand of the transportation sector. Rapidly increasing emissions from the transport sector, mainly driven by increasing demand for transportation, has motivated efforts to achieve a large-scale shift from petroleum fuel-

based internal combustion (IC) engines to alternative fuels from low-carbon energy sources. These transportation related emissions consist of mostly CO_2, along with a small amount of methane and nitrous oxide (Denchak, 2019). But since methane and nitrous oxide have higher global warming potential (GWP) values than CO_2, they make the planet warmer and lead to greater global warming, and thereby climate change.

As mentioned above, the transport sector of the U.S. makes the largest contribution to national GHG emissions. Federal and state governments are leading aggressive efforts to reduce and eventually eliminate emissions from the transport sector with the help of policies and incentives such as carbon taxes and low carbon fuel standards. The U.S. also joined the Paris Agreement in 2015, which is intended to reduce carbon emissions, but it later announced intent to withdraw in 2017. However, the U.S. rejoined the Paris accord under the Biden Administration on January 20^{th}, 2021 (U.S. Department of State , 2021).

In addition, to expedite its effort, the current administration also pledged to achieve net-zero emissions no later than 2050, along with other countries (The White House, 2021). Greenhouse gases emissions need to be reduced to eliminate the destructive global outcomes and to achieve a safer environment (Kalita, 2016).

Worldwide, organizations are working to develop ways to efficiently harness energy from different renewable energy resources and are researching low-emission technologies to satisfy economic development needs while reducing the impact of GHG emissions. New sustainable technology alternatives and mitigation measures, such as the conversion of fossil fuel-based transportation to zero emission vehicles (ZEV) and the

conversion to renewable electricity based on green infrastructure and measures such as adoption of efficient heating, ventilation, and air conditioning systems have the potential to reduce energy demand and GHG emissions (Kalita, 2016).

Studies from the IPCC and other organizations analyzed the relationship between gross domestic product (GDP) growth and emissions from the transportation sector. Figure 6 shows a correlation between the share of emissions from the transport sector and per capita GDP (IPCC, 2014).

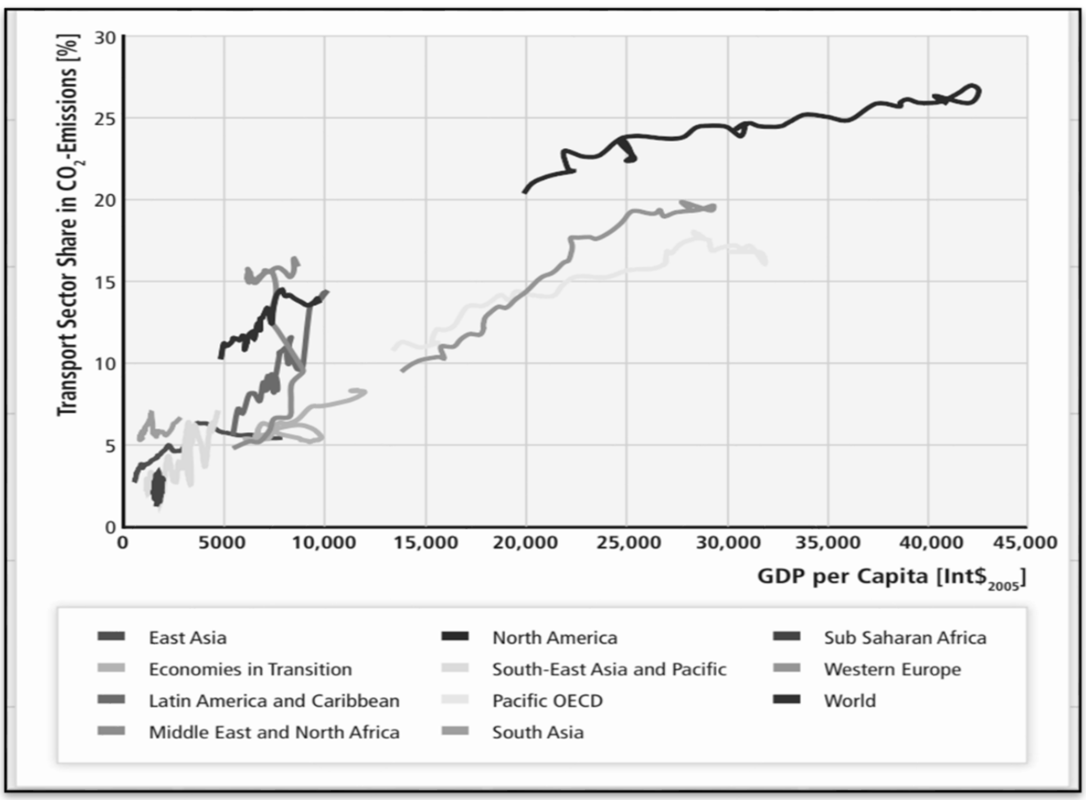

Figure 6. Relationship between GDP growth and transport sector emissions of North America and other countries. Source: (IPCC, 2014)

It is crucial to implement effective policies in all the regions to decouple GHG emissions in the transport sector from economic growth. The U.S. and California

governments are also working to decrease their GHG emissions with aggressive and sustainable policies. One approach to reduce transportation sector emissions involves mandates that require transit agencies to work actively to implement GHG reduction compliance measures. Currently, approximately 100 transit agencies are operating or planning to introduce ZEBs into their fleets in California (TransitWiki, 2021) (Deliali, 2018).

2.1 Plans and Policies to Overcome Transport Sector Emissions

The transport sector of the U.S. will face various challenges, such as impacts on economic growth, if it proceeds to seek to decouple all vehicles from petroleum-based products. Studies reported that, due to significant regulations, GHG emissions decreased from 2007-2012, increased from 2013-2019, and again decreased from 2019 to present due to the impact of COVID-19. However, this recent reduction in GHG emission is not significant (Nature, 2021). Emissions from the transportation sector not only increased but also surpassed emissions from the U.S.'s power sector (Lashof et al., 2020). The increased emissions were linked to demand for transportation services in relation to economic growth (Lashof et al., 2020). These emissions from the transport sector can be classified into three categories (Lashof et al., 2020).

- Emissions from light-duty vehicles that account for 59%.
- Emissions from heavy-duty vehicles that account for 23%.

- Emissions from all other modes of transport, including aircraft, rail, shipping, and others, which together account for the remaining 18%.

To mitigate the transport sector's emissions in California, CARB is implementing different programs to reduce the emissions from heavy-duty vehicles.

2.1.1 Innovative Clean Transit Program

A significant policy that motivates this study is the one adopted by through “CARB’s Innovative Clean Transit (ICT) Program,” requiring all California transit agencies to gradually transition to 100% ZEB fleet services by 2040. CARB requires public transit agencies to submit rollout plans by 2023. These plans outline strategies for converting from a conventional fleet to a ZEV fleet (Green Car Congress, 2018). CARB’s ICT regulations mandate all public transit agencies operating in California to become carbon free by 2040 (CARB, 2018a) which is a main driver for this study too. This mandate and related polices have aggressively accelerated the implementation timelines of the ICT Program (CARB, 2018a):

- Action Plan for California ZEVs: Maximize the use of ZEVs by transit agencies.
- EO-B-30-15: Statewide GHG reduction target of 40% below 1990 levels by 2030.
- EO-B-48-18: Goal of 5 million ZEVs on the road by 2030.

Recent studies show that implementing the ICT regulations will result in a reduction of 19 million metric tons of GHG emissions from California, 7,000 tons of nitrogen oxides (NO_2), and 40 tons of particulate matter (PM) relative to the 2019

emissions by 2050. This change will be equivalent to taking more than 4 million cars off the road in California (CARB, 2018a). The ICT regulations, driving the conversion of conventional buses to ZEBs, however they are also supported with other policies such as LCFS credits, that helps to make this conversion more economical feasible, by generating revenue to offset the high cost associated with ZEBs.

2.1.2 Low Carbon Fuel Standard

Low-carbon fuel standards are one of the regulatory policies adopted by multiple states in the U.S. to help mitigate carbon emissions and incentivize users to reduce GHG emissions in the transportation sector. These policies play an essential role in public transport since they allow transit agencies to generate revenue for the government while promoting the use of low or zero-emission vehicles, depending upon the fuel used. The LCFS policy is technology-neutral and designed to increase the use of low-carbon and alternative renewable fuels in the sector and support the ICT regulations mentioned in the above section by making the adoption of ZEBs more economical to make a transition. The California LCFS policy and the ICT targets both aim to reduce the petroleum-based fuel dependency of the transport sector and help to achieve better air quality (CARB, 2021).

The LCFS is expressed in carbon intensity of fuels, which allows the entities to generate credits using more renewable fuel by reducing the carbon intensity. The LCFS applies to the transportation fuel used, supplied, or offered for sale in California. The fundamental mechanism of LCFS is to calculate the carbon intensity of the fuel on a life

cycle basis. California enacted the LCFS through Executive Order S1-07 on January 18, 2007, to reduce the carbon intensity of passenger vehicle fuels statewide by a minimum of 10% by 2020 (Center For Climate and Energy Solutions, 2008). The LCFS policy will also help agencies like HTA to generate revenue through credits on each mile covered by BEBs and/or HFCBs. The calculation methods for estimating the credit values are discussed in Chapter 3.

As per the ICT regulation, all larger transit agencies must submit a model and a plan by 2020 for making a successful transition towards ZEB fleets by 2040. However, small transit agencies can submit these plans by 2023, as shown in Table 1.

Table 1. Schedule of converting conventional transit fleets into zero emission fleets in California.

Year	Large Transit Systems (% of operating buses)	Small Transit Systems (% of operating buses)
2023	25%	-
2024	25%	-
2025	25%	-
2026	50%	25%
2027	50%	25%
2028	50%	25%
2029	100%	50%
2030	100%	100%

Source: (CARB Regulation, 2019)

This study principally concentrates on identifying strategies that HTA can use to reduce carbon emissions from their heavy-duty vehicles. With the help of a model, it also determines which approach is most cost-effective at enabling HTA to meet the CARB mandates and to provide affordable and reliable transportation services to the county's residents.

Currently, there are 21 conventional buses in Humboldt County that provide public transportation services on identified routes, as per information obtained from HTA

(Humboldt Transit, 2021). Table A-1 of Appendix A lists the miles covered in a week by buses operating on these routes. The current route map of HTA is shown in Figure 7.

Figure 7. HTA public transit route map. Source: (Humboldt Transit Authority, 2021)

<u>2.2 Zero Emissions Technologies for Transit Agencies</u>

There are various technologies available in the market that can be used to reduce the tailpipe emissions from conventional fossil fuel transit buses, such as compressed natural gas (CNG) or liquid natural gas (LNG), clean diesel, and hybrid technology. These technologies could potentially reduce tailpipe emissions, but they cannot ultimately reduce the emissions to zero. Two clean technologies that can be considered as zero emission are BEBs and HFCBs (Calstart, 2019). These buses do not consume fossil fuel directly, thereby these buses are acknowledged as zero emission or near-zero-emission buses by federal and state regulatory agencies. This makes them the two most

suitable choices for integration into Humboldt's public transit network, and they are therefore considered in this study. The introduction of all-electric vehicles or fuel cell vehicles can significantly reduce tailpipe emissions to zero. This study is designed to help the HTA to determine which technology is more economically viable and would add more resiliency to HTA and local public transit network. Example of a BEB and HFCB currently operating in California are shown in Figure 8. Even though these are some of the best alternatives to conventional buses, there are still indirect emissions associated with these technologies, such as emissions from generating the electricity used to charge the BEBs and the emissions associated with manufacturing the buses. However, these emissions can be avoided (except the emissions associated with manufacturing the buses) if the electricity used to charge the BEBs or to produce the hydrogen through electrolysis is sourced from 100% renewable energy sources, such as solar or wind. For this study, it is assumed that the electricity used to charge the batteries of BEBs and in hydrogen generation process matches PG&E’s standard grid mix. HTA could choose to instead purchase a 100% renewable energy grid mix, but this would increase the cost of the electricity. The following section describes the technologies and required infrastructure.

Figure 8. BEB and HFCB models operating in California. Source: (Hao K., 2018) (Eudy et al., 2019)

2.2.1 Battery Electric Buses

These buses carry an on-board electric motor, controller, batteries, a battery management system (BMS), and supporting charging infrastructure (depot and on-route charging). These are the primary and only significant power system components in BEBs. Due to significantly fewer components, BEBs are easier to maintain then conventional buses. In BEBs, the current from the battery pack is controlled via the BMS (i.e., it controls the current drawn or given to the battery at any time). The motor receives the current via a controller, which provides the initial torque to the axle. The range of these vehicles depends on the battery pack's capacity, the conversion efficiency of the power train, and various other conditions such as weather, on-road condition, and driving style.

The fuel for these buses is electricity, stored in the on-board batteries, resulting in zero tail-pipe emissions. The buses usually charge from zero to full in approximately 6~8 hours with conventional Level-3 chargers (refer to Section 2.1.1.A below for charging strategies of bus). However, these buses can also charge in 1 to 3 hours using rapid chargers, with the timing depending on the bus's battery capacity and the charger type. These buses are currently available primarily in two types: short-range and long-range. Short range versions are typically capable of covering 50-80 miles and long-range BEBs can cover up to 260 miles in a single charge. Several companies in the U.S. manufacture battery-electric buses, such as Proterra, Build Your Dreams (Chinese company, but they have U.S.-based manufacturing/assembly for buses), Complete Coach Works, and New Flyer. While these buses can be used to reduce emissions, their use involves some financial and performance concerns with regard to their capital cost and range (miles

covered in single charge) (The National Academies of Sciences, Engineering, and Medicine, 2020). These concerns raise questions about their adoption, but with proper infrastructure and economies of scale it may be possible to address these concerns. For example, technologies such as on-route fast charging, as described in the following sections, and robust nationwide policy support, can help reduce the cost and the range anxiety associated with their use by transit agencies (Salah, 2016).

2.2.1.A. Type of chargers and charging infrastructure/ facilities for HTA.

Battery capacity and charging also play a significant role in determining the adoption of BEBs by transit agencies with enough charging. Battery charging is one of the crucial requirements for BEBs, which makes these technologies more viable and influences their acceptability by transit agencies and feasibility for use on long routes. As mentioned above, the BMS plays a key role by synchronize the way of charging of a battery that allows maximizing the battery pack's efficiency in different weather conditions (U.S. DOE, 2019).

Currently, long charging times are one of the significant hurdles for transit agencies. Strategies to address this issue include deployment of supporting technologies such as fast charging, battery swapping, and/or on-route charging (fast and slow), which can increase the resilience of the operations.

There are three main types of charging facilities/infrastructure available in the U.S.: plug-in charging, conductive charging, and inductive charging. It is also important

to note that the battery design and BMS configuration are dependent on the type of charging and on the requirements of transit agencies (EV town, 2021).

One of the significant parameters in BEB performance is battery temperature, which affects the cell's efficiency. It is essential to maintain a relatively consistent temperature across the cells while charging (U.S. DOE, 2019). Fast charging without a proper configuration with the BMS can lead to high battery temperature and ultimately lead to an accident such as a battery explosion. The basic layouts of chargers that are currently operating in the U.S. are shown in Figure 9 (Deliali, 2018) (Johnson et al., 2020).

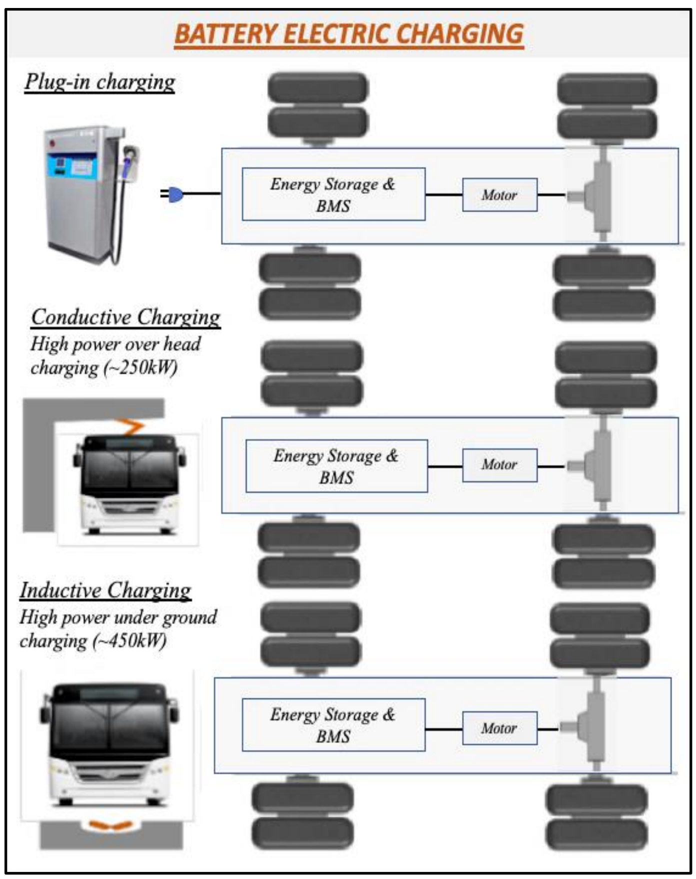

Figure 9. Summary of charging infrastructure for BEBs. Source: (Deliali, 2018)

2.2.1.A.1 Plug-In Charging

Plug-in charging is often used for charging during non-peak hours, which can be done to reduce utility costs. Therefore, it is regarded as a one of the more cost-effective modes of charging. Moreover, plug-in chargers 50,150,350 kW (refer to Table 2) are available at very reasonable prices for buses with a minimal maintenance cost. One major drawback associated with adopting plug-in charging is the procurement of additional buses to cover for the buses that are charging, which can thereby result in an increase in the transit agency's capital costs. However, the agencies can choose to reschedule timing of their services to accommodate the charging schedule (Li, 2016). Plug-in charging can be further classified into Level-1, Level-2, and Level-3 charging based on the power rating of the charging system as discussed below.

2.2.1.A.2 Level-1 Chargers

As mentioned above, plug-in chargers can be subdivided into three categories. First, Level-1 charging provides charging through a 120-volt (V) circuit with alternating current (AC) supply, as shown in Figure 10. Level-1 chargers provide slow charging, and they are generally used in homes for low-load EVs such as electric two-wheelers and electric wheelchairs. These types of chargers come with a standard, three-prong household plug and cord. Due to larger charging time these chargers are not recommended for charging electric buses It takes approximately 8-10 hours of standard charging to charge an electric two-wheeler or low load electric wheel chairs. Level-1 chargers do not require any installation at the home, as they can normally plug-in

household power outlets (EV town, 2021). These chargers are not considered in this study for charging buses due to their slow charging capabilities.

Figure 10. Level-1 EV charger. Source: (Indiamart, 2021)

2.2.1.A.3 Level-2 Chargers

Level-2 chargers offer charging with 240 V of AC supply and require installation by an electrician for use in homes and commercial spaces. Depending on battery technology, capacity, and chemistry, this charger takes approximately 6-7 hours to fully charge for small applications such as cars. Level-2 chargers are commonly used to charge electric cars but it would take much longer to charge a bus given their larger battery capacity. Therefore, they are also not considered in this study. A Level-2 charger is shown below in Figure 11 (EV town, 2021).

Figure 11. Level-2 EV charger. Source: (Ohio Statehouse, 2020)

2.2.1.A.4 Level-3 Charger

Level-3 chargers, which are commonly known as DC fast chargers (DCFC). These charges are based on the CHAdeMO technology and can charge up to 80% of the on-board battery of a car in around 30 minutes as shown in Figure 12, below (EV town, 2021). The CHAdeMO technology is DC rapid charging technology developed by 5 major Japanese auto manufacturers, including Toyota, Mitsubishi, Fuki (Subaru), Nissan, and Tokyo Electric Power Company in 2010. This technology was included in an automotive standard in 2010 (CHAdeMO, 2021) (Ayob A., 2014). These chargers allow for charging rates of up to 400 kW at 1000 V, which corresponds to a current of 400A DC. The charging time is subject to the capacity and power rating of the battery. It is also important to note that these chargers are not compatible with all vehicles considered in this study. Currently these chargers are used in a few electric cars and for charging heavy-duty buses.

Figure 12. Level-3 EV Charger. Source: (Wikipedia, 2021)

2.2.1.A.5 Conductive and Inductive Charging

Conductive and inductive chargers can provide quick and fast charging to the buses. These chargers work electrically on the induction phenomenon. In these charging systems, an overhead or on-ground energized line is used to continuously charge the buses. Generally, these chargers are connected overhead or at the bottom of buses, and the bus charging system draws into the battery charging circuit. These chargers, such as the Pantograph Charger, use electromagnetic coupling for transferring the energy from the grid to batteries**.** The Pantograph Charger has electromagnet coils that act as half of the transformer, and the remaining half of the coil are mounted on the buses, as shown in Figure 9. Combining these two electromagnet coils makes a full transformer that can transfer power at a high voltage and current directly from the grid to the bus's battery pack, making fast charging possible (Ayob A., 2014). The chargers can frequently give 20 to 30 miles of range in just 15-20 minutes of fast charging; therefore, these chargers are also considered in this study. The major advantages of these inductive chargers are as follows (Ayob A., 2014):

1) They are very safe in a variety of weather conditions.
2) These chargers can allow for a reduced battery size to meet the same route requirements by enabling frequent fast charging.
3) They can enable the use of buses with smaller on-board batteries than would otherwise be required to complete a route, and this can significantly reduce the manufacturing and up-front capital cost of the bus.

However, frequent on-route fast charging during operational hours can increase the electric demand during peak rate periods (depending on when charging takes place and the rate schedule), and, therefore, the total electricity cost. This is regarded as a major disadvantage. Additional disadvantages associated with these chargers are (Ayob A., 2014):

1) They usually have high power consumption (250 to 350 kW).
2) They have a high capital cost, which is around $200,000, making them more expensive than plug-in chargers.

All the supporting chargers which are used in this study are listed in Table 2. It should be noted that reducing the charging time of BEBs by opting for fast charging can significantly influence the battery performance and utility cost, thereby increasing the cost of ownership for BEBs. Additional factors associated with utility cost of BEBs are discussed in the following section.

Table 2. Characteristics of BEBs charges considered in this study

Plug-in Chargers	**Power Rating (kW)**	**Capital Cost ($/charger)**	**Installation Cost ($/charger)**	**Maintenance Cost**	**Useful life (yrs.)**
Level 3, 50 kW, DCFC	50	$37,000	$22,626	$500/charger/yr.	28
Level 4, 150kW, DCFC	150	$45,000	$22,626	$500/charger/yr.	28
Level 5, Conductive, DCFC, 500kW	500	$349,000	$250,000	$0.026/kWh	28

Source:(Johnson et al., 2020) (Siemens, 2021)

2.2.1.B <u>Utility Cost and BEBs Performance</u>

Electric cost is one of the crucial aspects of BEBs. As described above, plug-in overnight charging can reduce the need for on-route chargers. However, charging all buses simultaneously via plug-in electric charging can significantly increase the facility's

electricity utility bills through a combination of energy and demand charges because most of the buses are charging at the same time during off-peak hours. Unlike energy charges, demand charges are not based on cumulative use, but are instead determined by the maximum power demand during the billing period, usually estimated as the average peak demand over 15-minute intervals (Liu et al., 2019). Charging all the buses at the same time can significantly increase the facility's demand, and this can lead to high demand charges. Therefore, it is crucial to design charging strategies that minimize the maximum hourly demand charges to reduce the utility cost for any transit agency. For example, in this study, the maximum demand (kW) during plug-in charging is constrained to an upper limit of 750kW to make BEBs more cost-efficient. A charging regime was designed in this study to distribute demand to the degree possible throughout the plug-in charging period.

A charging routine of BEBs involving plug-in and on-route charging is defined in this study (refer to Section 3.3.2.A) so all these buses can cover their daily routes successfully. For this study, the selection of buses and type of plug-in charging (refer to Table 2) is conducted in such a way that almost every bus on short routes (see all current route information in Section 2.5) is scheduled to return to the depot with at least 10% state of charge after completing their required daily miles. In addition to plug-in chargers, an inductive on-route charger is also considered for longer routes (more then 250 miles per day), such as buses making multiple trips between Arcata and Willow Creek in a day. These inductive on-route chargers possess higher charging capabilities and can be used to help ensure uninterrupted services (Harvard Kennedy School, 2018). The details of all

active routes are discussed in Section 2.5, Overview of HTA. Also, it is important to note that the range of these buses is based not only on the type of charging but also on driving patterns, weather conditions, and driving style. BEBs are almost twice as efficient as conventional diesel/CNG buses. The fuel economy of BEBs is often reported between 8 to 29 miles per diesel gallon equivalent (mpdge). This makes them more efficient than conventional diesel buses, which have a fuel economy of 5 to 6.5 miles per gallon (Deliali, 2018). As mentioned earlier, the only significant disadvantage of batteries used in BEBs is that they work more efficiently in moderate weather conditions. The efficiency of the batteries can significantly drop during cold and hot seasons (ThoughtCo., 2019). To overcome the disadvantage, automotive batteries now come with a thermal management system that uses a circulating glycol solution to help batteries maintain a moderate temperature around the cells regardless of the outside temperature (ThoughtCo., 2019). The glycol solution increases the efficiency and durability of these BEBs onboard batteries, even while working in extreme weather conditions. Also, because they have fewer mechanical components than conventional buses, for example these buses do not have engines and other mechanical components like a crank shaft, these buses do not require significant maintenance except in the case of an electric system failure (UC ITS, 2017). The controller and BMS systems are capable of reboot itself during any failure, just as a cell phone reboots (Texas Instruments, 2017).

2.2.2 Hydrogen Fuel Cell Buses

HFCBs are known for having zero tail-pipe emissions. These buses do not produce GHG emissions like conventional or hybrid buses. The buses have an onboard

fuel cell and batteries working seamlessly together to generate power. Unlike BEBs, HFCBs have a range equivalent to conventional buses, and they have a short refueling time that makes them more comparable to heavy duty commercial transport sector vehicles. HFCBs require more maintenance than BEBs, but they are continuing to improve in ways that may decrease the overall maintenance cost of HFCBs in the future (Goverment Technology, 2019) (Eudy & Post, 2020). HFCBs have fuel cells and hydrogen storage cylinders to generate the electricity that charges the onboard battery pack (Ballard, 2020).

Fuel cells convert chemical energy into electric energy on the principle of an electrochemical reaction mechanism and produce water vapor as the by-product. Fuel cells use hydrogen as an input fuel that breaks into two protons (H^+) in the presence of a catalyst, usually platinum. The protons further react with oxygen in the fuel cell with the help of electron movement and make H_2O and release energy in the form of electron movement or electrical current that can be used to run an electric motor. The most significant advantage of the fuel cell is that the produced electricity is entirely CO_2-free and produces zero-tail emissions. Disadvantages associated with fuel cells include less efficiency then battery charging and discharging process, release of heat, making it quite hot, which could destroy the fuel cell, so that it needs a continuous cooling system to maintain the system's normal temperature. One of the significant disadvantages of hydrogen powered vehicles that they are less energy efficient then electric vehicles (EVs). It is reported that the well to wheel efficiency of EVs is somewhere around 60-80%, and hydrogen powered vehicles requires 2-3 times more energy to drive the same

distance, with a resulting well to wheels efficiency on the order of 25 to 35% (InsideEVs, 2020).

The other disadvantage of this system is the high capital cost of the fuel cell, which is related in part to the cost of the platinum catalyst. However, most modern fuel cells come with a polymer electrolyte membrane (PEM). The PEM technology significantly reduces the amount of catalyst as the membrane is coated with a catalyst layer instead of a thicker platinum catalyst core. A basic layout of a PEM fuel cell is shown above in Figure 13 (Fessler D., 2020).

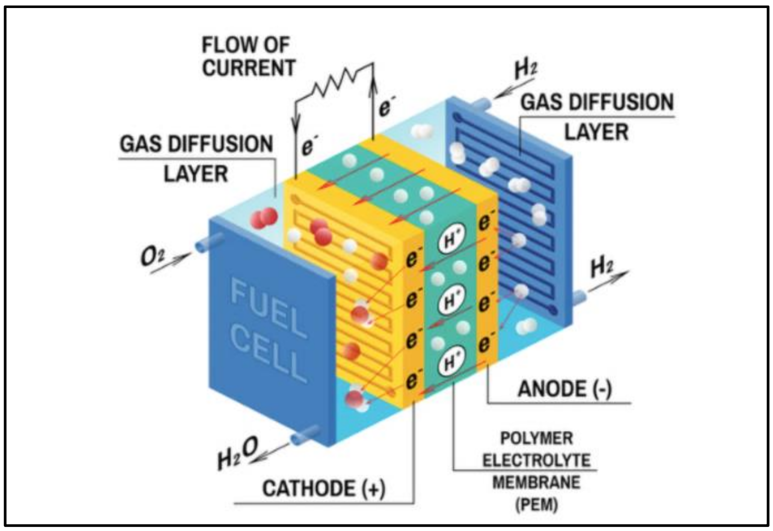

Figure 13. Polymer electrolyte membrane hydrogen fuel cell. Source: (Fessler D., 2020)

As mentioned, HFCB buses use hydrogen as fuel and a small, high voltage battery, which provides the peak traction power. These buses do not use chargers like the BEBs but instead require refueling stations. The hydrogen storage tanks in HFCBs offer higher energy density compared to the batteries, which provides more range to HFCBs in comparison to BEBs (Graham, 2020). Also, this technology reduces the size of the required battery pack, which helps reduce the weight of the entire bus, and finally helps

increase the range of the HFCBs relative to the BEBs (Alexandria, 2009). However, they are still more expensive than BEBs, as hydrogen production technology is not yet as mature as battery technology. As hydrogen production becomes less expensive in upcoming years, HFCBs will also become more affordable. Ballard a HFCB manufacture company estimated that hydrogen powered buses will be less expensive than BEBs by 2024 (Ballard, 2020).

2.2.3 Hydrogen Production Techniques

Currently, the mass production of hydrogen is most commonly done by steam methane reforming (SMR) of natural gas or by electrolysis of water. These methods of hydrogen production are shown in Figure 14. SMR uses natural gas to generate hydrogen with a 74% efficiency (Rodl, 2018). However, SMR technology produces some GHG emissions, and because the relevant policy mandates in California require use of green hydrogen from renewable sources, this method is not considered in this analysis (California Legislative Information , 2020). If a zero-emission electricity source is used, the electrolysis of water is a production method that can make hydrogen without any GHG emissions or other toxic byproducts. Electrolysis is one of the most common hydrogen production methods. Hydrogen can be produced using PEM electrolysis. This process is considered as 65% efficient (Rodl, 2018).

Hydrogen can be produced at a small facility on-site or at a large-scale, off-site facility that would require large tanker trucks or pipelines to deliver the gas to the refueling stations.

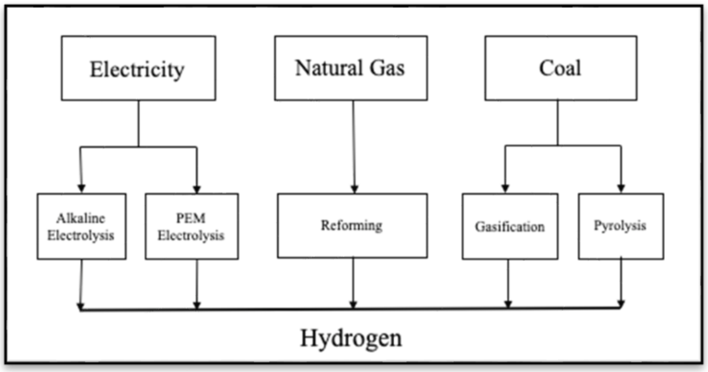

Figure 14. Basic layout of hydrogen production options. Source: (Apostolou, 2019)

Large and small on-site production units can produce up to 750,000 kg/day and 1,500 kg/day, respectively (Rodl, 2018). In this project, it is estimated that HTA would require under 600 kg/day (see Section 3.3.1) to support their current routes with HFCBs. However, it is based on the current sizing and routes of HTA fleet (refer to section 4.5). A small (600 kg/day) on-site production unit could fulfill the current and upcoming future demand. The integration of renewable power generation, for example from solar or wind energy with a battery bank, could eliminate the carbon emissions of HTA's transit bus fleet. Thus, HFCBs could facilitate a complete transformation to a zero-emission fleet.

2.2.3.A <u>Refueling Strategies, Facilities, and Assumptions</u>

A hydrogen refueling station differs from a conventional gas station in many ways. For example, hydrogen stations use gaseous fuels instead of liquid fuels, and hydrogen can be produced on-site (at refueling stations), unlike gasoline/diesel which needs to be transported to the gas station. In addition, a hydrogen refueling station requires equipment such as compressors and a refrigerator for H_2, which are not required at a conventional gas station. As discussed in the previous sections, due to climate

regulation, the most-used method of carbon-free hydrogen production is electrolysis. Hydrogen can be manufactured either on-site or off-site depending on the daily requirements. If production is off-site, then the vehicles or pipeline used to transport the H_2 to the site would also need to use carbon-free fuels. The hydrogen production system requires the following components shown in Figure 15, below (Apostolou, 2019):

Production unit (on-site electrolysis/off-site electrolysis).

1. Purification to ensure that the hydrogen purity meets the standards for supplying fuel cells (purity above 99.97%).
2. Low-pressure hydrogen storage tank.
3. A high-pressure compressor unit to boost pressure from 350 to 700 bar to storage in high pressure (high pressure storage inside the station's main H_2 tanks)
4. A high-pressure storage tanks.
5. A hydrogen compressor to achieve the pressure needed to deliver H_2 to the bus's storage system.
6. Refrigeration unit to maintain the hydrogen temperature at −40°C to ensure the safety.
7. Mechanical and electric equipment such as piping, control panels, and high voltage connections, sensors, and safety valves.
8. A dispenser unit to refuel the empty vehicles.

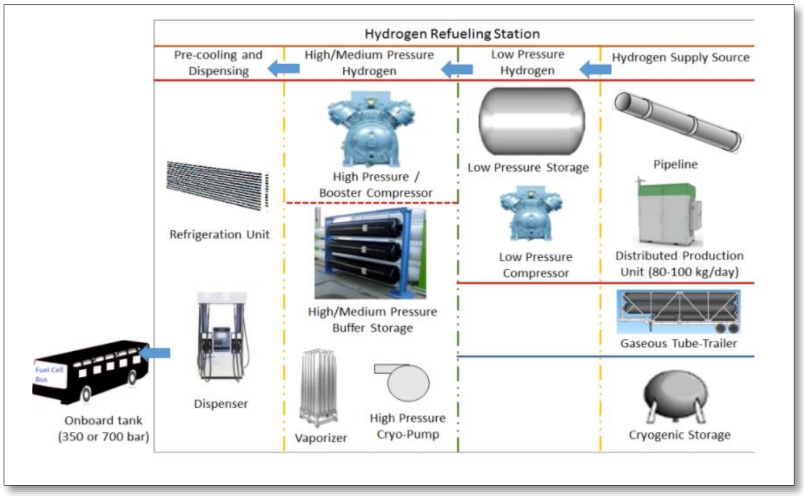

Figure 15. Layout of fueling station hydrogen and delivery system. Source: (Argonne National Lab, 2017)

2.2.3.A.1 Refueling Stations with On-Site Hydrogen Production

As mentioned earlier, one method of hydrogen production is on-site, in which hydrogen is produced locally. In this process, water is used in the electrolysis process, and on applying a direct voltage across the electrodes, the water (H_2O) breaks down into hydrogen and oxygen. The common processes are alkaline electrolysis and PEM electrolysis. In both processes, deionized water is delivered to the electrolyzer inlet. A constant cooling device maintains the operating temperature of the electrolyze between 65°C to 100 °C for safety reasons. The hydrogen produced from electrolysis via PEM is typically clean. However, it is recommended to add a purification system to achieve the purity above 99.97% before it gets stored (U.S. Department of Energy , 2016). Figure 16 shows the systematic step-by-step process of on-site production of hydrogen by using electrolysis (Apostolou, 2019).

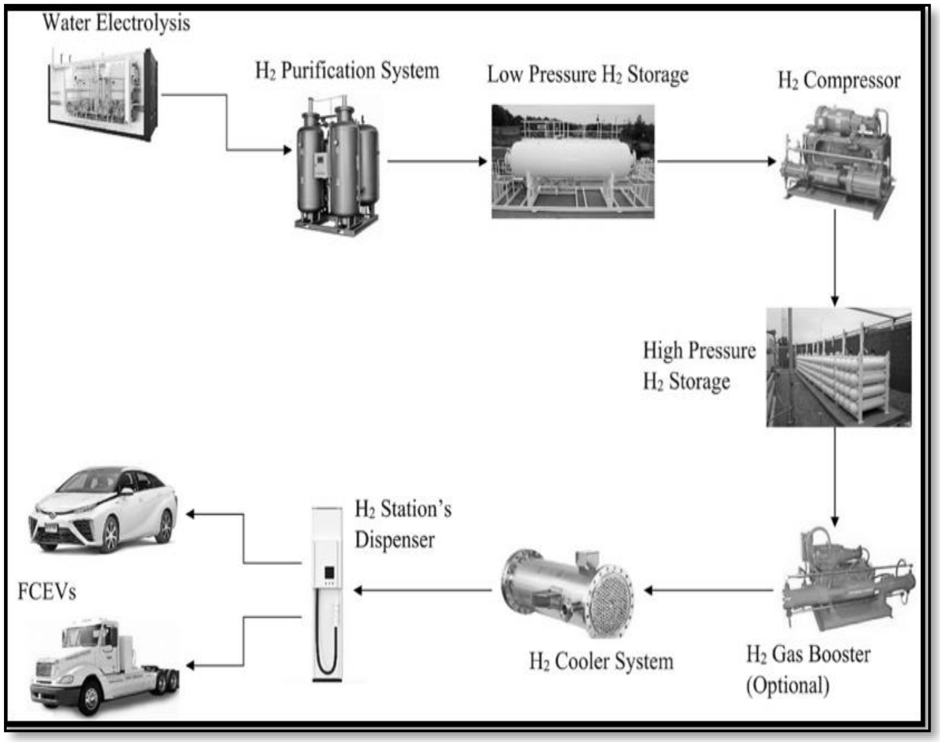

Figure 16. On-site hydrogen production via electrolysis. Source: (Apostolou, 2019)

The hydrogen produced from electrolysis is at a very low-pressure (20-30 bar or 290-435 psig), which is not appropriate for delivery to the vehicles. To ensure the proper pressure, the hydrogen needs to pass through a compressor, which compresses the hydrogen isothermally from 20 bar to 350 bar (5,000 psi or ~35 MPa). The compressor requires 1.05 kWh/kg H_2 to deliver at 350 bar and only 1.36 kWh/kg H_2 to deliver at 700 bars (10,000 psi or~70 MPa) (Gardiner M., 2009). It is reported that the reciprocal compressor typically used to compress hydrogen has an isentropic efficiency of 56% and a motor efficiency of 92% (Gardiner M., 2009). After compression, the high-pressure hydrogen can be stored in high-pressure tanks. This hydrogen gas can then be passed through the hydrogen cooling system and delivered to on-vehicle storage via a dispenser (Apostolou, 2019).

2.2.3.A.2 Refueling Stations with Off-Site Hydrogen Production

Alternatively, the hydrogen can be produced off-site at a central production location and delivered via pipeline or heavy-duty trucks with a tube trailer to the retail or distribution station. Figure 17 shows the basic layout of off-site hydrogen production. This process is like on-site production, except that the hydrogen is delivered at a pressure of up to 140 bar (~2000 psig).

Alternatively, the hydrogen can be delivered as liquid hydrogen, which is a costlier method and requires specialized tanks (i.e., Dewar flasks) that can be maintained at temperatures of -253 °C for long distances (Apostolou, 2019). This study assumes on-site production of hydrogen for refueling the buses operated by HTA, as discussed in Section 3.3.1.

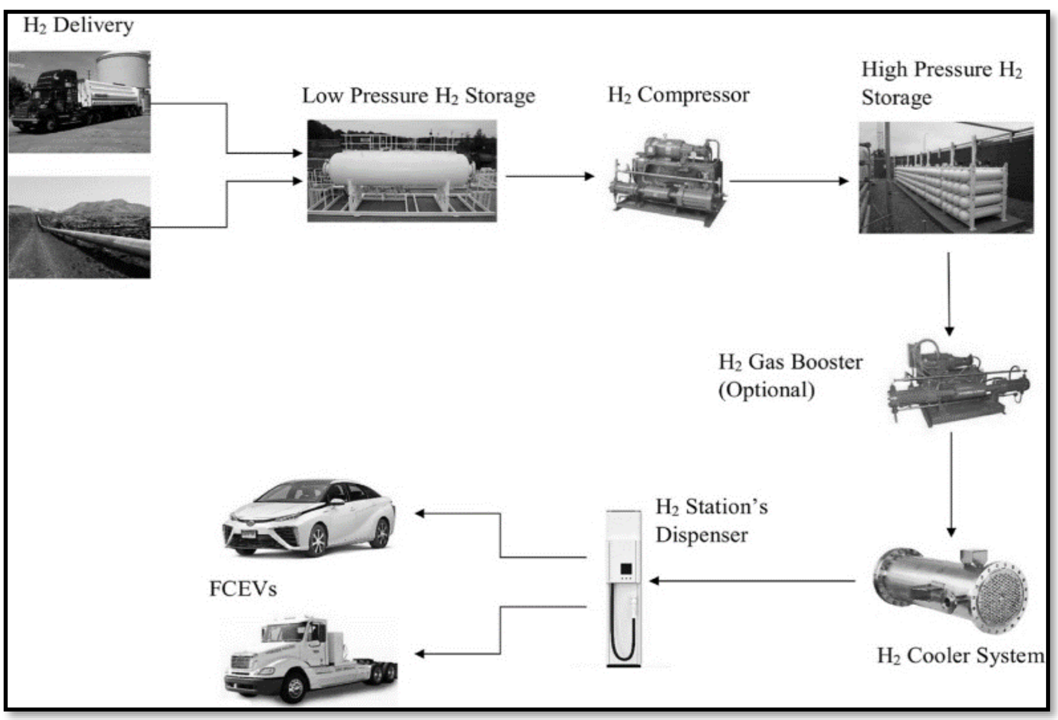

Figure 17. Basic layout of off-side hydrogen production. Source: (Apostolou, 2019)

2.3 Overview of Humboldt Transit Authority

HTA has been a transit service provider in Humboldt County since 1975. HTA is a joint powers authority involving the cities of Arcata, Eureka, Fortuna, Rio Dell, and Trinidad. Currently, HTA operates, maintains, and provides services in 5 transit systems across the county, including the Redwood Transit System (RTS), Willow Creek Transit Service (WTS), Southern Humboldt Transit Systems (SHTS), Eureka Transit Service (ETS), and Arcata & Mad River Transit System (A&MRTS) (Humboldt Transit Authority, 2021). Apart from public buses, HTA also provides dial-a-ride transportation options that allow access throughout Humboldt County. The RTS, WTS, and SHTS come directly under the authority of HTA. The fixed route of ETS are currently operated by HTA. This does not include services such as (dial-a-ride/dial-a-lift), which are operated by the City Ambulance of Eureka.

Apart from these services, the Blue Lake Rancheria Transit System (BLRTS) is also a service provider. It is maintained and operated by the Blue Lake Rancheria Tribe (a federally recognized tribe in Humboldt County). BLRTS coordinates with HTA to provide bus service between the City of Blue Lake and the City of Arcata (Humboldt Transit Authority, 2021). BLRTS is also considered in this study.

To fulfill the county requirements for public transportation, 21 different buses function across the county on different routes, listed in, Table A-1 Appendix A. Currently, only 20 of the buses are operating. This analysis considered that all 21 buses would function in the near future.

Based on the data collected from HTA and calculations performed in this study, all 21 buses cumulatively travel 1.3 million miles annually and emit approximately 2.67 metric tons of CO_2 emissions. These emissions are only from scheduled buses and do not include any other emissions from HTA services. The methods used to identify the technoeconomic feasibility of converting these buses to HFCBs or BEBs are explained in Chapter 3.

CHAPTER 3: METHODOLOGY

This chapter describes the methods used to develop the model and other supporting assumptions that are considered to analyze the techno-economic feasibility of transitioning the HTA bus fleet from conventional buses to ZEBs. As mentioned above, two types of ZEBs are considered in the model: BEBs and HFCBs. The model has provision to analyze these two options separately, as described later in this section, and to provide results that are further used to make recommendations regarding which system (BEB or HCFB) is the most cost-effective solution for Humboldt County.

The model is developed in a spreadsheet tool that has the following two components. In addition to these two components, the model is supported with an instruction file that introduces the model and provides the instructions to operate the model.

1. Common inputs: This section allows HTA to provide inputs to the model to run its calculations, such as route information, days of operations, LCFS credits, and others. The inputs are predefined in a dataset to support the cost calculations. Currently, the common inputs are designed for HTA, but they can be modified to incorporate future changes (expansion of routes, schedule change etc.). The following section introduces the model and its inputs.
2. Results: This section of the model complies all the calculated costs and displays the results in the form of the total cost associated with the HFCBs and BEBs based on the user-provided inputs. As mentioned earlier, the results are based on

the user inputs. In the context of this analysis, the conversion of the buses is completed in two phases (i.e., Phase-I and Phase-II). Half of the fleet is selected for conversion to either HFCBs or BEBs in Phase-I (2021-2015), and the other half is converted in Phase-II (2025-2030). Additional details related to the selection of buses are further discussed below in Chapter 4.

3.1 Introduction to the Model

The study's key objective is to identify the techno-economic feasibility of the conversion to ZEBs as determined through the model and to identify which is the more cost-effective solution for HTA. The general framework of the model is shown in Figure 18. The technical feasibility of BEBs and HFCBs is illustrated in Section 2.2. HTA has expressed interest in ZEB alternatives (BEBs and HFCBs); hence their economic feasibility is analyzed through the model. To identify the economic feasibility, the model calculates the total cost associated with the conversion for both technology options (BEBs and HFCBs). The total cost is identified by aggregating various cost components for both technologies (BEBs and HFCBs), such as capital cost of infrastructure and buses, annual O&M cost of infrastructure and buses, acquisition cost, mid-life maintenance cost of buses, and the LCFS credits as shown in Figure 18. Table 3 below also shows the all the costs considered in the model to identify total costs. The model is currently designed in a manner that is specific to HTA's situation, but it can be replicated for other transit agencies by changing some data inputs related to the bus routes.

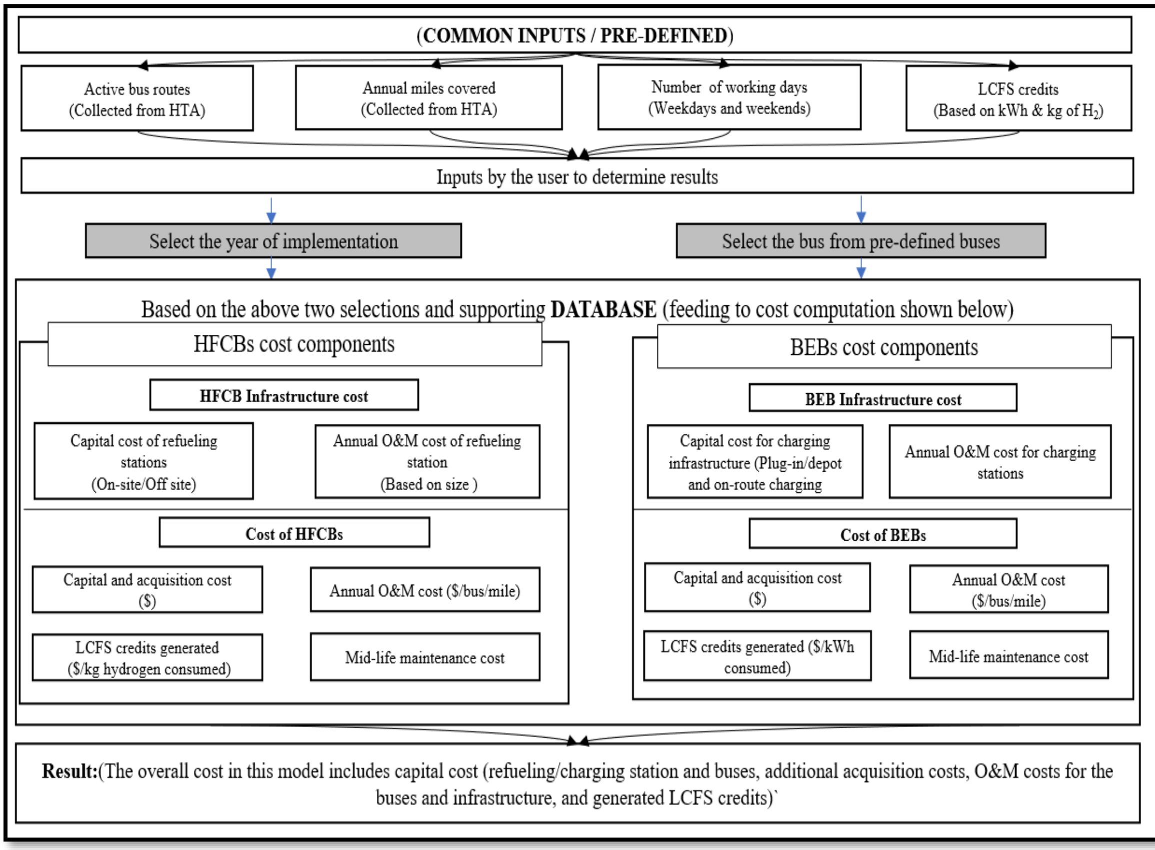

Figure 18. General framework of the model

As discussed, with the route information in place, the model takes two key inputs from the user (in the current case HTA), which are the "year of implementation" that is specific to each bus that needs to be converted and "selection of type of bus" (from a list of pre-defined buses in the model, either HFCB or BEB). Based on these inputs, all the cost components are determined for each route which are further aggregated to estimate total cost of converting the conventional buses to HFCBs or BEBs. It is important to note that some of the costs are applicable for both infrastructure and buses (capital and O&M cost), and some are only for buses (acquisition costs, which covers miscellaneous expenses, including training, administration, professional services, contracting, and other

miscellaneous costs, and mid-life maintenance costs of buses). LCFS credits are earned as revenue based on energy consumed as ($/kWh) for BEBs and ($/kg) of hydrogen fuel for HFCBs. The LCFS credits are calculated based on CARB's calculator based on the value in 2021.

Table 3. Cost components for both technologies (BEBs and HFCBs)

Cost components	**BEB infrastructure**	**BEB**	**HFCB infrastructure**	**HFCB**
Capital	Y	Y	Y	Y
Annual O&M	Y	Y	Y	Y
Bus mid-life maintenance		Y		Y
Bus acquisition		Y		Y
LCFS credit (revenue)		Y		Y

The model calculates these cost components separately for BEBs and HFCBs, described later in this chapter. These cost components are the function of variables such as HTA's annual miles covered currently by conventional buses, active route information, number of operational days, O&M cost of buses and infrastructure, and LCFS credits, and this information is collected from HTA to conduct this study.

As mentioned in the above section, the model also provides provisions for the user (currently HTA) to choose the year of implementation and implementation regime for converting their conventional fleet to ZEBs. For example, the user can determine whether to convert all its conventional buses to ZEBs in just one year or over a period.

These parameters are designed as inputs to the model to add more flexibility (by creating a database) and can be modified as needed. As mentioned, some of the inputs are common for both technologies, such as HTA route information, active route information, and number of operational days. They can therefore be regarded as "common inputs to the model" in this study.

The database created to support the model consist of datasets. These datasets are created from the information gathered from various resources described in the following sections. These datasets are used to provide cost estimates of converting conventional buses to ZEBs. In addition, the database also includes a dataset of specification of HFCBs and BEBs considered for this study. This includes 11 different makes and bus models for BEBs (refer to Table 6) and two different makes and bus models for HFCBs (refer to Table 9) that are available in the market. However, the number of included buses can be expanded to include more bus types in the future. It is expected that bus suppliers will introduce more efficient and longer-range models in the upcoming future.

It is important to note that this model can calculate results based on several combinations of inputs, such as different years of implementation, selected bus model types, priority of routes, refueling station type (i.e., on-site and off-site hydrogen production; this is only applicable for HFCBs), and by introducing a new utility rate structure or changing the charging regime by changing optimization parameters such as constraints, variables and objective in the optimization tool. The objective of the optimization tool is to keep the maximum electricity demand of HTA lower than 750kW while buses are charging at the depot. The tool optimizes the charging time of the buses (variable) to ensure continuous charging of the buses (constraint). However, to derive the results and to identify a cost-effective option for HTA, only a specific combination of inputs is used. Additionally, the model identifies the reduction in GHG emissions achieved over the conversion period.

3.2 Data Collection and Model Calculations

This section explains the datasets created to support the model, the application of datasets in the model calculations to determine the associated cost, and the methods used to calculate life cycle costs of both the technologies.

The database used in the model includes information related to active route information, miles covered by conventional buses, days of operation, year of implementation, LCFS credits, and the make and model of various ZEBs for both technology types (BEBs and HFCBs), along with data gathered from the HDRSAM model, NREL reports, and other literature related to hydrogen refueling infrastructure. The model works on user-provided inputs that include some metrics that are in common and others that are technology specific. This section describes the common and technology-specific datasets separately in the following subsections.

3.2.1 Data Collection for Common Inputs Dataset

As mentioned in Section (3.1), the model requires the user to provide a set of common inputs to run its calculations. A database is created to define the possible common inputs. The database includes active bus route information, annual miles covered by conventional buses, days of operation (weekend and weekdays), LCFS credits, and the year of implementation. Refer to Table 4 for a list of active buses and route information. The datasets are discussed in following sections. Additional information is shown in Appendix Table B-4, including days of operation.

<u>Dataset 1</u>: This dataset contains the information on active bus routes, annual miles covered by conventional buses, and days of operation (weekend and weekdays). This information was collected from HTA and utilized to compute costs for both technologies (BEBs and HFCBs). These values are considered as common inputs for this model.

Table 4. List of all active routes

Bus number	Name of HTA Routes	Overall weekly miles[1]	Annual miles
100 & 101	Redwood Transit System	1,916	99,614
102 & 116	Redwood Transit System	1,684	87,566
104 & 105	Redwood Transit System	2,130	110,734
106 & 107	Redwood Transit System	2,117	110,107
110 & 123	Redwood Transit System	1,319	68,598
112 & 115	Redwood Transit System	1,925	100,116
118 & 119	Redwood Transit System	1,236	64,272
410	Southern Humboldt Intercity	2,076	107,939
512	Southern Humboldt Intercity	1,069	55,594
714	Willow Creek	1,897	98,657
108	Redwood Transit System	1,076	55,929
428	Blue Lake Rancheria Transit System[2]	915	47,586
2552150	Arcata Mad River Transit System	816	42,411
66	Eureka Transit System	719	37,385
120	Redwood Transit System	689	35,844
67	Eureka Transit System	712	37,015
68	Eureka Transit System	642	33,362
25500	Arcata Mad River Transit System	660	34,299
69	Eureka Transit System	618	32,136
Total Annual Miles		**20,698**	**1,259,164**

Source: HTA

Overall, these buses cover around 20,700 miles throughout the week, although these miles do not account for some special rides offered during weekdays and weekends.

[1] Overall weekly miles include miles covered during Monday to Friday and miles covered during weekends or reduce services.
[2] Working independently with coordination with HTA.

These weekly miles are further transformed into annual miles by considering the number of days of operation to calculate the yearly cost. The extra miles covered by spare buses during maintenance events or the failure of the any on-route buses are not considered in this analysis, as the miles are less than 1% of the total annual miles covered by spare buses. As of December 2020, a variety of different buses were functional across Humboldt County under the various transit agencies. Most of these transit agencies fall under HTA, while the BLRTS operates independently. All the current existing buses are considered in this analysis (refer to Table 4).

Dataset 2: This dataset includes information about LCFS credits for both technology types (BEBs and HFCBs) from 2021 to 2040. The LCFS credits are considered in both technologies and generate yearly revenue from the year of implementation of ZEBs. For this study, the LCFS credits for HFCBs and BEBs are calculated based on the year 2021, but, the LCFS credits potentially change with time. Therefore, the amounts could change in the future (EcoEngineer, 2021). Information about the credits for HFCBs and BEBs are listed in Table 5.

Table 5. LCFS credits for HFCBs and BEBs from 2021-2040

Year (2021-40)	Credit	Source	Fuel Switch	Energy Economy Ratio	Credit Price ($ / metric ton of CO_2e)
HFCBs	2.64 $/kgH_2$	LCFS credit calculator	Diesel to Hydrogen	1.9	150
BEBs	0.17 $/kWh	LCFS credit calculator	Diesel to Battery	5.0	150

Source: (CARB, 2018b) (CARB, 2021)

The implementation year ranges from 2021-2040; the user (currently HTA) can choose any year for conversion between (2021-2040) as per their requirements and budget. This study assumes the conversion of 10% of the fleet (two conventional buses)

to ZEBs beginning in 2021, with an intention to convert 100% by 2030. However, the overall cost and generated revenue are estimated through 2040. The conversion ratio is considered 1:1 for both technologies (i.e., one conventional bus replaced by one ZEB, either by a HFCB or BEB; all 21 buses will be 21 ZEBs by 2030). After 100% conversion, the total route miles associated with the old buses are covered by ZEBs. In addition, the database also includes information specific to BEB and HFCB technologies in separate datasets. These datasets are specific to the technology type and used to provide technology-specific inputs to the model. This includes information related to hydrogen gas production technology (on-site and off-site, only for HFCBs), charger types (only for BEBs), technology-specific cost factors for both these technologies, make and model of BEBs, and HFCBs and their specifications. For BEBs, CARB's ZEB model and NREL reports are utilized to structure the database for appropriate and calculations. The data gathered from the HDRSAM model is further utilized for calculating the cost components of hydrogen refueling infrastructure. These datasets are described in the following sections.

3.2.2 Data Collection for BEB Technology

Dataset 3: For the conversion of conventional buses to BEBs, the model provides an option to select from 11 buses (different makes and models) that are included in the dataset and mentioned in Table 6. Most of these buses can cover the daily mileage requirements for HTA routes in a single charge without any disturbance in daily operation. However, a few routes would need to use an on-route charger to complete their routes successfully. Most of these buses are supplied by U.S. manufacturers such as

Proterra and New Flyer, and some of them are provided by companies from other countries such as BYD, which has a manufacturing facility in the U.S. The various parameters such as range, on-board battery storage, fuel efficiency, capital costs, and battery life are used as inputs for cost calculations are listed in Table 6, below.

Table 6. Details of BEBs considered in the model.

Bus model type	**Range**	**Battery capacity**	**Fuel economy**	**Battery warranty**	**Capital cost 2020**
	(mi)	(kWh)	(kWh/mi)	(Yrs.)	$/bus
BYD K9	155	324	2.09	12	$720,000
BYD K9S	145	352	2.43	12	$720,000
BYD K7	137	180	1.31	12	$720,000
New Flyer Xcelsior	160	311	1.94	12	$730,000
New Flyer Xcelsior	160	311	1.94	12	$730,000
New Flyer Xcelsior	195	388	1.99	12	$730,000
New Flyer Xcelsior	195	388	1.99	12	$730,000
New Flyer Xcelsior	225	466	2.07	12	$730,000
New Flyer Xcelsior	135	466	3.45	12	$730,000
Proterra ZX Max	329	675	2.05	12	$800,000
Proterra	225	466	2.07	12	$800,000

Source: (Proterra, 2020) (New Flyer, 2020) (BYD, 2020)

Dataset 4: Another significant cost factor for BEBs is the charging/utility cost, which is determined by the cost of electricity consumed by BEBs while charging. The cost of electricity depends on the electricity rate structure. Currently, HTA is on Pacific Gas & Electric’s (PG&E) NEM-A-1-B rate structure. HTA is eligible to use this rate because they have a rooftop solar generation system at the depot, and their monthly consumption is lower than 5,000 kWh. Due to their low energy usage, HTA is not currently paying any demand charges under this rate structure. However, once the HTA fully or partially switches to BEBs, it is estimated that electricity consumption will increase by a factor of 100 or more, and, due to very high energy use, they will no longer be able to use the current rate structure.

To determine the suitable rate structure for HTA to convert the conventional fleet to BEBs, this study involved review of various rate structures available through PG&E, relevant pieces of literature, and information from other transit agencies in PG&E territory. Based on input from HTA and after analyzing electric energy and demand during charging, the BEV-2-P rate structure is used in this model. Table 7 provides elements of the BEV-2-P rate structure, whereas Table A-2 in Appendix A, shows more detailed information. In addition, all the necessary cost factors and resources examined to estimate the overall cost associated in converting the conventional buses to BEBs are compiled in Table 8 below.

Table 7. BEV-2-P rate structure energy and demand charges

Status	Energy Charges ($/kWh)	Demand Charges ($/kW)
Super Off-peak	0.10041	1.72
Off-peak	0.12307	1.72
Peak	0.33195	1.72

Source: (PG&E, 2020)

Table 8. Summary of factors and resources used for cost calculation of BEBs.

Cost Components	Cost	Source
BEB capital cost	Manufacture's Website, Table 6	(Proterra, 2020) (New Flyer, 2020) (BYD, 2020)
BEB acquisition cost	2.5% of capital cost	CARB ZEB model
BEB maintenance cost	$0.60/mile/bus	(Johnson et al., 2020)
BEB operating cost	PG&E's BEV-2-P rate structure	(PG&E, 2020)
BEB midlife maintenance cost	$227/Battery nameplate capacity	CARB ZEB model (UC ITS, 2017)
Charger capital cost	50/150 kW, Table 2	(Johnson et al., 2020) (Siemens, 2021)
Charger O&M cost	Refer to Table 6	
LCFS credit	$0.17/kWh	(CARB, 2018b)

The applied rate structure is for customers that have kW usage at or above 100 kW. The rate structure includes demand charges (refer to Section 3.3), time of use (ToU) energy charges, and subscription charges.

3.2.3 Data Collection for HFCB Technology

As mentioned above, the other alternative for the conversion of conventional buses is HFCBs. In this conversion, the model includes two options (i.e. different makes and models) that are included in the model the Dataset 3. The specifications of the two available buses are shown in Table 9. Only two HFCBs (Ballard's New Flyer and El Dorado National fuel cell buses) are considered for the study as they meet the daily range requirements of HTA. The major specifications of these buses are shown Table 9.

Table 9. Details of HFCBs considered in the study

Model specification	New Flyer	El Dorado National
Economy (mi/kg of H_2)	5.5	6
Storage capacity(kg)	37.5	50
Midlife maintenance(yrs.)	7	7
Range(miles)	206	300
Capital cost ($)	850,000	900,000
Acquisition cost (%)	2.5	2.5
Midlife maintenance cost ($/fuel cell)	200,000	200,000
Maintenance cost ($/bus/mi)	0.77	0.77

Source: (Ballard, 2019) (Ballard, 2020) (California Transit Association , 2019) (New Flyer, 2019) (Eudy & Post, 2020)

The annual miles covered by HTA as shown in Table 4 above are used to estimate the yearly required hydrogen gas by considering the average fuel economy of the buses (6 miles/kg for the El Dorado and 5.5 miles/kg for the New Flyer). The Argonne National Laboratory's HDRSAM model is then utilized to identify technical and cost parameters such as the daily and annual requirement of hydrogen gas for 21 buses and necessary equipment such as the number of dispenser units, cooling units, and compressors for the required hydrogen fueling infrastructure. The parameters used in the HRDSAM model matched HTA requirements when calculating these factors. The inputs used to run the HDRSAM model are shown in Table 10, below. The technical and cost parameters

obtained from the HDRSAM model used to create the database, which feeds into the model to identify the capital cost of the refueling station and various other cost parameters such as hydrogen fuel cost ($/kg) for both onsite and off-site hydrogen production, are shown in Table 11. The inputs of the HDRSAM model and associated results are shown in Figure 19, below.

Table 10. Key inputs of the HRDSAM model

Station Type	Gaseous hydrogen refueling station
Fleet Size	21
Dispensing method to vehicle tank	700 bars via vaporization/compression
Year of implementation	2021
Construction period (year)	1
Year (for all cost estimates)	2016
Analysis period (years)	20
Maximum dispensed hydrogen per vehicle (kg)	50
Fueling rate (kg/min)	7.2
Number of dispensers (Hoses)	1
Max annual utilization of H_2 station (% of capacity)	100
Onboard storage type	IV
Max number of HFCBs fills in one hour	10

Source: (Argonne National Lab, 2017)

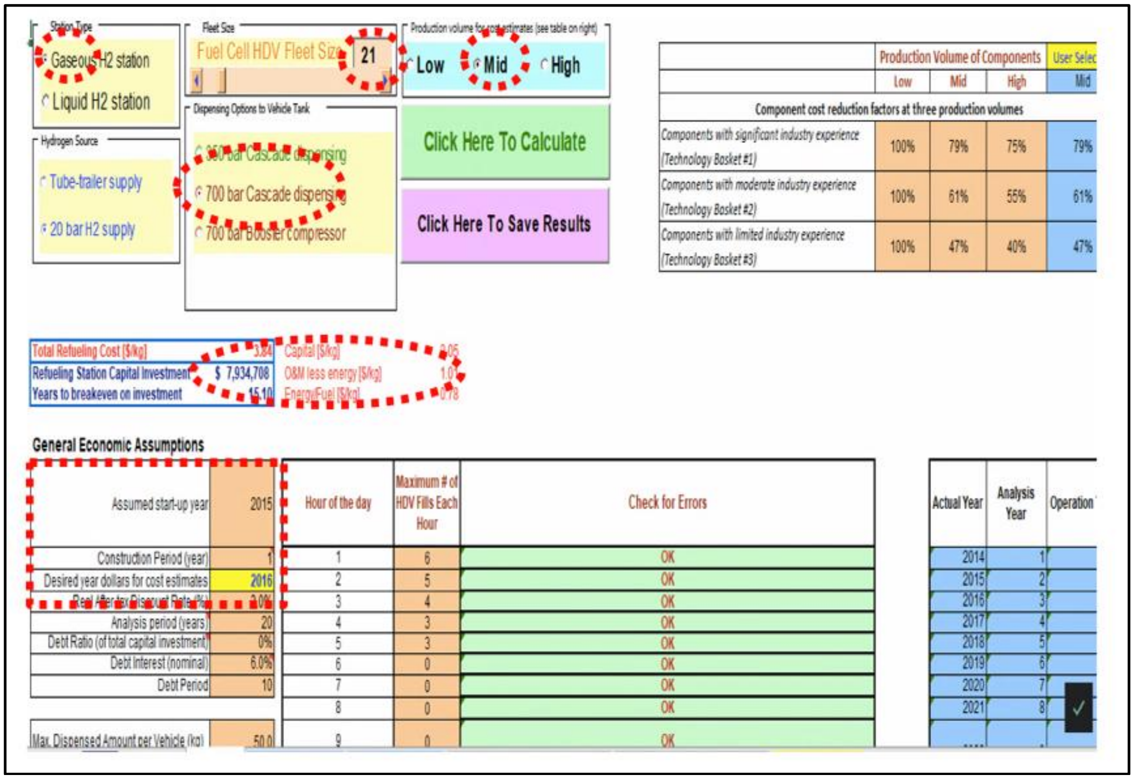

Figure 19. Key input and outputs of HDRSAM model. Source: (Argonne National Lab, 2017)

Table 11. Key inputs for hydrogen refueling infrastructure (both production techniques)

Type of refueling station	**Fueling rate**	**Maximum storage size**	**Capital + installation cost contribution to the gaseous refueling station**	**Station operating cost contribution**	**Energy/Fuel contribution in station**	**Final fuel cost**
Type/Units	**kg/mi**	**kg**	**$/kg**	**$/kg**	**$/kg dispensed**	**$/kg**
On-site production	7.2	1050	3.84	1.79	1.16	6.78
Off-site production	7.2	1050	3.37	1.58	2.03	6.98

Source: (Argonne National Lab, 2017)

For hydrogen production, two different production methods (on-site/off-site) are considered, and the user can select out of the two methods. In on-site production, hydrogen production plants are installed at refueling stations, while in off-site production liquid hydrogen is transported to the refueling station and then converted to gaseous

hydrogen before filling it to the vehicles. The inputs that are used for calculating costs of refueling infrastructure for both production techniques are also derived from the HDRSAM model and shown in Table 11. The model also allows adding more buses to the database with their required specifications and can provide the results based on new inputs to the database. The user would need to pre-define the inputs of each added bus, such as the capital cost, fuel efficiency, midlife maintenance cost, and onboard storage capacity to be able utilize the new buses to generate results. The collected data inputs and cost factors to estimate the overall costs for HFCBs are summarized in Table 12, below.

Table 12. Summary of key costs and sources for HFCBs

Cost Components	**Cost**	**Source**
HFCB capital cost	Manufacture’s Website, Table 7	(Proterra, 2020) (New Flyer, 2020) (BYD, 2020)
HFCB acquisition cost	2.5% of capital cost	CARB ZEB model
HFCB maintenance cost	$0.77/mile/bus	(Johnson et al., 2020)
HFCB operating cost	PG&E’s BEV-2-P rate structure	(PG&E, 2020)
HFCB midlife maintenance cost	$227/Battery nameplate capacity	CARB ZEB model (UC ITS, 2017)
Refueling station capital cost	50/150 kW, Table 2	(Johnson et al., 2020) (Siemens, 2021)
Refueling station O&M cost	Refer to Table 7	Refer to Table 7
LCFS credit	$0.17/kWh	(CARB, 2018b)

Source: (Ballard, 2019) (Ballard, 2020) (California Transit Association , 2019) (Argonne National Lab, 2017)

As mentioned above, to complete this analysis, the specifications, and other detailed inputs from two hydrogen-powered buses are further utilized to calculate the various cost components for each route. The overall cost for each route includes a capital cost (one-time cost), added acquisition cost (one-time cost), midlife maintenance cost, and overall generated LCFS credits for the period of analysis. Some of these costs are one-time costs, further discussed in the Section 3.3.1. All the mentioned cost parameters

are the key inputs considered to calculate the total cost of converting the conventional fleet to a hydrogen fleet.

The model utilized the gathered data described in the above sections for both technologies (HFCB/BEB) to calculate the overall cost of converting conventional buses to HFCBs or BEBs described in the following sections. The overall cost results are then used to conclude which conversion approach is more techno-economically feasible for Humboldt County.

3.3 Economic Analysis

Based on the common inputs and data compiled from various sources explained above (HTA, NREL, HDRSAM, Schatz Center, etc.), the model calculates various cost components for both technologies (BEBs and HFCBs) separately, including the cost of buses, infrastructure, and LCFS credits for both the HFCBs and BEBs. To perform the calculations, the model assumes the conversion of two buses every year beginning in 2021 and ending in 2030. This is broken into Phase-I (2021~2025) and Phase-II (2026~2030) for both technologies to enable a sequenced transition for HTA.

The model calculates the cost of buses with the help of only one bus model for each route for both technology types (one out of 11 BEBs in the database and one out of 2 HFCBs in the database for each route). However, the model can calculate results for any given combination of inputs. It also identifies costs associated with the infrastructure for both technology options separately. To identify the cost associated with the hydrogen refueling infrastructure, the model calculates results for both production techniques (on-

site and off-site). For charging infrastructure required for BEBs, it includes both plug-in and on route-charging options. Additionally, the model optimizes the charging schedule of BEBs to minimize demand charges with the help of an optimization tool based on Microsoft Excel's solver add-in feature (this is applicable for BEBs only). Finally, the model calculates the total cost by aggregating the cost of buses, infrastructure, and revenue generated from the LCFS for both BEBs and HFCBs. It then utilizes the overall cost calculated to identify the most cost-effective option for each technology type. The method used to calculate the cost components and total costs for both BEBs and HFCBs options are as follows:

First, the daily weekday and weekend miles covered by each bus (21 buses) are converted into annual miles with the help Eq. 1 as it is the common input for both technology options. These miles include the operational days of HTA (Holidays are not considered)

$$\begin{aligned} &Annual\ miles\ covered \\ &= (miles\ covered\ in\ week\ days) * (number\ of\ operational\ weekdays) \\ &+ (miles\ covered\ in\ weekends) \\ &* (number\ of\ operational\ weekend\ days) \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (1) \end{aligned}$$

3.3.1 <u>Economic Analysis for HFCBs</u>

To calculate the total cost of converting conventional buses to HFCBs, the model estimates daily fuel demand (i.e. hydrogen fuel requirement for the HFCBs). This is determined with the help of Eq. 2, considering the bus fuel efficiency of the selected bus

and the daily miles covered by each bus. The hydrogen fuel requirement for HTA is then utilized to estimate the of hydrogen storage capacity.

$$Daliy\ fuel\ demand\ (kg) = \frac{Daily\ mileage\ (Mi)}{Fuel\ economy\ of\ selected\ bus\ (\frac{Mi}{kg})} \dots\dots\dots\dots\dots (2)$$

The HFCBs considered for the calculation have a storage capacity of 50 kg, and based on the daily fuel demand, it is estimated that some buses must refuel twice a day to complete their daily routes. Therefore, the model calculates the refueling time with the help of Eq. 3. The refueling rate for calculations is assumed as 7.2kg/min/dispenser (refers to Table 12) based on the results of HDRSAM model. This value is used to determine the refueling time of the HFCBs as shown in Eq. 3. The refueling time also helps in estimating the number of buses that can refuel during operational hours without hampering daily operations.

$$Refueling\ time\ (min) = \frac{Daily\ fuel\ demand\ (kg)}{Fueling\ rate\ 7.2\,\frac{kg}{min}} \dots\dots\dots\dots\dots (3)$$

The required daily hydrogen for normal operation for HTA is calculated as 580kg/day. Using Eq. 3, above, the refueling time of all buses was determined to be under 10 minutes (i.e., each bus takes approximately 7-8 minutes and no bus had a refueling time more than 10 minutes). This allows bus refueling during operational hours without hampering daily operations. These parameters are calculated to perform cost calculations for HFCBs.

As mentioned above, the total cost of converting the conventional buses to HFCBs is identified by aggregating the cost of converting the buses for each route, which include three cost components 1) cost associated with the HFCBs 2) cost of refueling infrastructure and 3) LCFS credit. The total cost of conversion for each route is calculated using Eq. 4. These cost components are described in the following sections. Since the cost related to each specific route is calculated separately, it can also be used by HTA to identify the cost of converting the conventional buses to HFCBs for any specific routes for any transit agency that come under HTA.

$$\begin{aligned} &Total\ Cost\ of\ each\ route(\$) \\ &\quad = Cost\ of\ HFCBs(\$) + Cost\ of\ refueling\ infrastructure(\$) \\ &\quad - LCFS\ credits(\$) \ldots \ldots \ldots \ldots (4) \end{aligned}$$

The total cost of HFCBs is determined by considering the capital cost, acquisition cost, mid-life maintenance cost, and annual bus O&M cost as shown in Eq. 5 and described in the following sections.

$$\begin{aligned} &Cost\ of\ HFCBs\ (\$) \\ &\quad = HFCB\ capital\ cost(\$) + \ HFCB\ acquisition\ cost(\$) \\ &\quad + HFCB\ midlife\ maintenance\ cost(\$) \\ &\quad + HFCB\ annual\ O\&M\ cost\ (\$) \ldots \ldots \ldots \ldots \ldots\ (5) \end{aligned}$$

The cost of the refueling infrastructure includes the refueling station capital cost and annual O&M cost for hydrogen infrastructure. The cost of the refueling station is computed using Eq. 6. This is further described in the following sections.

$$Cost\ of\ refueling\ infrastructure(\$)$$
$$= Captial\ cost\ of\ refueling\ station(\$)$$
$$+ O\&M\ cost\ of refueling\ sation(\$) \dots \dots \dots \dots\ (6)$$

3.3.1.A Cost of HFCBs

As shown in Eq. 5 above, the cost of HFCBs includes capital, acquisition, O&M, and mid-life maintenance costs of the buses. These cost components are described as follows.

(A). **Capital Cost**: The capital cost to obtain buses is the upfront cost and varies with the manufacturer. The capital cost for different HFCBs included in the model are listed in Table 9.

(B). **Acquisition cost:** This is a one-time cost that covers miscellaneous expenses, including training, administration, professional services, contracting, and other miscellaneous costs. It is included during the first year of implementation. The acquisition cost for the hydrogen bus is assumed to be 2.5% of the capital cost and is calculated with the help of Eq. 7, also as shown in Table 12 (CARB, 2018d).

$$Acquisition\ cost(\$)\ = 2.5\% * (Capital\ cost\ of\ HFCB\ (\$)) \dots (7)$$

(C). **Annual O&M costs**: This cost has two components, the maintenance cost and the operation cost. Maintenance is a significant cost component of the transit fleet, and it depends on the miles covered by these buses. The calculations did not consider miles covered when buses are deployed to take over for the regular bus when it fails

while completing its route. For hydrogen buses, the annual bus maintenance cost factor is $0.77/mile (Eudy et al., 2019) (Eudy & Post, 2020). This cost is added every year, starting with the commencement of HFCB deployment as mentioned in Eq. 8.

$$Maintenance\ cost\ (\$) = 0.77(\frac{\$}{mi}) * (annual\ mile\ covered(mi)) \ldots (8)$$

Operating/Running Cost: The operation cost is identified as the annual cost of fuel for the buses. The primary factor used to determine this cost is obtained from the HDRSAM, which is $6.78/kg for onsite production and $6.98/kg for offsite production (including the cost of electricity used to generate the hydrogen through electrolysis). Further, this factor is converted to $/day by multiplying by the daily hydrogen consumption for the simplicity of annual calculation using Eq. 9. All these cost factors are derived from the HDRSAM model and are discussed in Table 12. The HDRSAM model uses different electricity rates to calculates these factor (energy charges $.102/kWh, demand charges $12.94/kW) and these charges cannot be modified while running the model. In addition, as referenced in Section 2.2, the electricity used for generation of hydrogen for electrolysis is considered to have the standard PG&E grid mix. These factors will change if the delivered electricity is from 100% renewable energy sources. Since these are not comparable to the rates in the BEV-2-P rate structure (refer Table, 7), this project also calculates the costs of operating cost of BEBs with the charges considered in the HDRSAM model for comparison purposes. The results of this comparison are discussed in the Section 4.5 below.

$$Operating\ cost\ (\frac{\$}{year})$$

$$= \Big(Fuel\ cost\ based\ on\ production\ method(\$\ /Kg)$$

$$*\ (daily\ fuel\ demand(\frac{kg}{day})\Big) * HTA\ operational\ (\frac{days}{year}) \ldots (9)$$

This cost is estimated for the 2021- 2040 period. The operation cost is also calculated separately to prioritize any routes. The fuel cost is linked to market expansion and government supporting policies that can help reduce the cost of associated equipment (such as PEM electrolyzers and compressors). It is expected that as the market expands, the overall cost of the hydrogen fuel will be reduced, which will lead to a corresponding drop in the operating cost of HFCBs. However, it is worth considering that the cost of electricity is an important factor influencing the cost of hydrogen, and it will not necessarily decline as the use of hydrogen vehicles expands (Green Car Reports, 2020).

(D). **Midlife Bus Maintenance Cost**: The midlife maintenance cost includes the cost associated with ensuring the proper functioning of HFCBs throughout their life period. This cost includes replacing major HFCB components around the midlife of the buses, including fuel cell stacks, on-board high voltage batteries, and other maintenance requirements due to continuous wear or any deterioration over the years. The midlife maintenance cost is included in this model after either 300,000 miles of running or 12 years after purchase (whichever earlier). The midlife maintenance cost used in the model is $200,000 for HFCBs. The model calculates the annual cumulative mileage, which is then utilized to identify the mid-life maintenance cost. The model includes the mid-life

maintenance cost in its calculations as soon as the cumulative mileage exceeds 300,000 miles for each bus or the bus completes 12 years in service.

The above-mentioned costs are calculated for HFCBs. The cost related to the refueling infrastructure for HFCBs is discussed in the following sections.

3.3.1.B Cost of Refueling infrastructure for HFCBs.

(A) **Capital and Installation Cost of Refueling Station:** The capital cost of infrastructure is the one-time upfront cost for setting up the hydrogen refueling station. In this model, the refueling station is designed to produce enough hydrogen to fulfill the current HTA demand without hampering supply. As mentioned in Section 3.1, the capital cost of refueling infrastructure is estimated using the HDRSAM model. The HDRSAM provides two options that can be used to estimate the capital cost of refueling stations. Option 1: A value based on overall capital cost of the hydrogen production equipment for 1050 kg of daily production capacity. Option 2: a value for the capital plus installation cost based on the levelized hydrogen cost ($/kg H_2) generated by the station. This study estimates the capital and installation cost using the second option, as HTA's daily maximum hydrogen requirement (~600 kgs) is less than the total daily hydrogen production reported by the HDRSAM model (i.e. 1050 kgs) for its current fleet (Schatz Energy Research Center, March 2021). Equation 10 shows the calculation of capital and installation cost based on the hydrogen generated ($/kg $H_{2,}$), consistent with Option 2 described above. The HDRSAM model provides the levelized hydrogen cost ($/kg H_2) for both production methods (on-site and off-site, shown in Table 11 as $3.84/kg of on-

site and $3.37/kg for onsite). Therefore, the fuel cost is calculated separately for both production methods.

$$Captial\ \&\ install\ cost(\$) = \left(Cost\ per\ kg\ produced\ \left(\frac{\$}{kg}\right) * Total\ hydrogen\ generated\ from\ 2021\ to\ 2040(kg)\right) \ldots (10)$$

(B). **Annual O&M cost of refueling stations:** The O&M cost reflects the contribution of expenses for repairing broken components and the cost of labor. Like the capital costs factors, the O&M cost factors are also identified from the HDRSAM model and are used to calculate annual O&M costs. The yearly cost is aggregated from the year of conversion of each bus until 2040 to identify the total O&M cost for refueling infrastructure of the HFCBs. The O&M cost for each route is calculated separately using Eq. 11. The factors considered for on-site and off-site production are $1.79/kg/year and $1.58 /kg/year, respectively, for on-site and off-site production (refer to Table 11).

$$Annual\ O\&M\ cost\ of\ refueling\ stations(\$/year) = \left(Cost\ per\ kg\ per\ year\ (\$/kg/year\ ) * (Daily\ fuel\ demand\ (\frac{kg}{day})) * HTA\ operational\ (\frac{days}{year})\right) \ldots (11)$$

3.3.1.C LCFS credit for HFCBs

LCFS Credit: As mentioned in the previous section, the LCFS is the regulatory mechanism to incentivize low carbon emitting fuels and associated technologies in the

transportation sector. The policy aligns with the state's targets to reduce the carbon intensity within the 2030 timeframe. As a part of zero-emission vehicle technology, hydrogen fuel cell buses also qualify for LCFS credits. These credits accrue based on the number of miles driven by the HFCBs, and the revenue from selling the credits can be used to offset costs associated with deploying and operating the buses. To calculate the LCFS credit, CARB's LCFS credit calculator is used. The assumptions considered when running the calculator are as follows (CARB, 2018b) (State of Oregon Department of Environmental Quality, 2020).

- Vehicle Fuel EER[3]: 1.9[4] (Hydrogen used in a Heavy-Duty Fuel Cell Vehicle)
- Carbon Intensity (CI): 81g CO_2e/MJ (Note: LCFS calculator has preset carbon intensities that are defined for each year) (CARB, 2018b)
- Credit price per metric ton of CO_2e: $150 (CARB, 2018b)
- Switched fuel: Diesel to Hydrogen.

The CARB calculator is used to calculate the per mile credit, which is $2.64/kg of hydrogen consumed. This factor is used to determine the annual revenue that HFCBs will generate after their commencement for each route annually. This annual revenue for each bus is aggregated to identify the total LCFS revenue generated until 2040. The revenue generated from these buses is subtracted from the cost to identify the total cost as described in Section 3.3.1.A.

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[3] Energy Economy Ratio: Distance an alternative-fueled vehicle travels divided by the distance an internal combustion engine vehicle travels using the same amount of energy (The National Academic Press, 2015).
[4] Fuel efficiency varies with different vehicles. The EER provides credits to efficient vehicles for the conventional fuel displaced by using clean vehicles

All the cost components mentioned above are considered to calculate the total cost of converting the conventional fleet to a hydrogen fleet and the results of hydrogen model calculation are discussed in the Chapter 4.

Finally, as these costs are life cycle cost of HFCBs, the total cost of converting the conventional buses to HFCBs are discounted using a 3% annual net discount rate. The discounted prices are calculated using Eq. 12.

$$\begin{aligned} &Discounted\ price\ for\ HFCBs(\$) \\ &\qquad = Overall\ cost\ in\ 2021(\$) \\ &\qquad + NPV\left(3\%, of\ Overall\ future\ cost(2022\ to\ 2040)\ (\$)\right) \ldots (12) \end{aligned}$$

3.3.2 Economic Analysis for BEBs

The BEB model calculates cost of converting the HTA conventional fleet to BEBs using an approach that is identical to the one used for the HFCB model and by aggregating the cost of converting buses for each route. Buses with smaller on-board batteries are selected to cover shorter routes, and buses with large on-board batteries are selected for longer routes as shown in Table 6. The model uses information about the 11 different electric buses in the database. All the recommended buses are from different manufactures in the U.S. The efficiency of the buses is one of the key factors determining the amount of charge/energy required to complete their respective daily routes. The fuel economy of the buses is used to determine the amount of electrical energy required for each bus to complete its daily route. This amount of energy required is used to determine the charging needs for each bus with the help of various assumptions. The amount of energy required to complete the route contributes to the cost for this transition, and the

fuel economy of buses (kWh/mi) is collected from the manufacturer's data. Table 6 shows information about the onboard battery capacity and fuel economy specifications of the BEBs. These assumptions, which are listed below, influence the number of charging events required to complete the daily route.

1) The primary charging methods for all the buses is plug-in charging at the depot. However, a few of the buses use overhead on-route charging during their routes, thereby allowing them to complete the route with at least 10% of their charge remaining.
2) All calculations are performed assuming the bus on-board battery capacity is 80% of the battery nameplate capacity. The performance of BEBs depends on the condition of the route and various parameters such as the number of on-board passengers, environmental conditions, route characteristics, and driving practices. Due to these factors, the actual range of these buses is generally decreased by 20 to 30% relative to the nameplate range, as reported by Altoona Testing Agency (Mass Transit, 2015). To account these factors, only 80% of the claimed (nameplate) range of these buses is considered in this calculation. This factor also helps address any errors or overestimation in the calculations.
3) The BEV-2-P (Primary/Transmission) rate structure from PG&E is used in this study to determine the operating/running cost.
4) Plug-in charging of these buses will take place from 9 pm to 8 am (during non-peak hours). With the help of the optimization tool (refer to Section

3.3.2.A), the charging regime is identified (i.e. when the bus needs to plug in for charging and when it needs to be removed from charging) to minimize demand charges. The optimization tool helps to determine the recommended charging pattern used during plug-in charging (i.e., once the optimization tool selects the bus for charging, the bus stays connected to charging until it got fully charged).

5) Any needed on-route charging will be arranged from 9 am to 2 pm during super off- peak hours.
6) It is assumed that while charging, all the chargers are operated at maximum power.
7) The optimization tool only helps to determine the timing of plug-in charging events.
8) LCFS calculations are performed by using LCFS credit factor provided in CARB's LCFS calculator (CARB, 2021) (Note: These numbers are not based on 100% renewable energy; the CI is predefined in the calculator based on the selection of the year and the fuel type.

The above mention assumptions are used to determine the cost associated with developing the charging infrastructures and estimating the total cost. The annual costs associated with a transition to BEBs for each route are determined using the methods described here. This approach helps to enable prioritization of routes and to determine the transition cost for each individual route by considering individual route information.

The overall cost associate with BEBs includes the capital cost, running cost, maintenance cost, and LCFS credits. As most buses will charge during the night with cheaper electricity, HTA would require multipoint charger outputs to charge the BEBs. The model identifies that a minimum of 12 depot chargers would be required to charge the buses. These buses will charge at a different time with the help of different chargers to make sure HTA would not need to change its daily operational hours. However, additional on-route charging events are considered for a few specific buses. These buses, which are the ones with long routes, can charge using an on-route charger at the Arcata Transit Center. These buses stop for two to three times daily for 10-12 minutes at the Arcata Transit Center. This time will be used to charge them using an on-route charger. The plug-in charging regime is designed so that these buses need to charge up to 20 or 30 minutes per day in total (i.e. over several stops of 10-12 min each) during the super-off-peak period (9 am to 2 pm) at the Arcata Transit Center during their daily route. This charging will help ensure the unhampered business hours of these buses.

The cost of converting the conventional buses to BEBs for each route has three cost components, including 1) the cost associated with purchasing the BEBs, 2) the cost of charging infrastructure, 3) and the LCFS credit. The total cost per bus is calculated with the help of Eq. 13.

These cost components are described in the following sections. Since the cost related to the specific route is calculated separately it can also be used by HTA to identify the cost of converting the conventional buses to BEBs for specific routes for any transit agency that come under HTA.

$$Total\ Cost\ of\ each\ route\ (\$)$$
$$= Cost\ of\ BEBs\ (\$) + Cost\ of\ charging\ infrastructure\ (\$)$$
$$- LCFS\ credits\ (\$) \ldots\ldots\ldots\ldots (13)$$

The total cost of BEBs is determined considering the capital cost, acquisition cost, mid-life maintenance cost, and annual bus O&M cost as shown in Eq. 14 and described in the following sections.

$$Cost\ of\ BEBs(\$)$$
$$= BEB\ capital\ cost\ (\$) + \ BEB\ acquisition\ cost\ (\$)$$
$$+ BEB\ midlife\ maintenance\ cost(\$)$$
$$+ BEB\ annual\ O\&M\ cost(\$) \ldots\ldots\ldots\ldots\ldots. (14)$$

The cost of the charging infrastructure includes the capital cost of plug-in and on-route chargers, utility upgrade cost for installing the on-route charger at the Arcata Transit Center, and annual O&M cost for plug-in and on-route chargers. The cost of the charging infrastructure is computed using Eq. 15. In addition, an upgrade to the utility (electrical infrastructure at the Arcata Transit Center) may be needed, but estimating it is beyond the scope of this analysis. This is further described in the following sections.

$$Cost\ of\ charging\ infrastructure(\$)$$
$$= (Captial\ cost\ of\ plug - in\ and\ onroute\ chargers(\$)$$
$$+ O\&M\ cost\ of\ plug$$
$$- in\ and\ onroute\ chargers(\$)) \ \ldots\ldots\ldots\ldots\ldots\ldots\ldots (15)$$

3.3.2.A Cost of BEBs

As shown in Eq.15, the cost of BEBs is comprised of several cost components such as capital, acquisition, mid-life maintenance, and O&M costs. These cost components are calculated as follows:

(A) BEBs Capital Cost and Acquisition Cost: To determine the cost associated with BEBs, the model uses cost information (provided by manufacturer) about the 11 different electric buses as compiled in the database. The capital cost of BEBs is a one-time cost added in the model at the time of their purchase, which occurs between 2021 and 2030 depending on the route. Since the capital cost varies with make and model, the total capital cost depends on the cost of the selected buses for the various routes shown in Table 6. In addition to the capital cost, the model also adds the acquisition cost in the year of purchase (when the bus starts service). The acquisition cost for each bus is 2.5% of the bus's capital cost as shown in Eq. 16.

$$Accquisition\ cost(\$) = 2.5\% * Capital\ Cost(\$) \ldots\ldots\ldots\ldots..(16)$$

(B) BEB annual O&M Cost: This cost has two components, the maintenance cost, and the operation cost explained as follows:

Annual Maintenance Cost: The annual maintenance cost is associated with the proper and regularly planned maintenance of the buses, not including any unplanned maintenance costs for the BEBs when the buses are deployed to cover the route of any other bus. Because BEBs have relatively few mechanical components and are more reliable than conventional buses, they have a relatively low failure rate (UC ITS, 2017). The maintenance cost for the BEBs includes maintenance, repairs for broken

components, the cost of labor, and other related costs. The factor used for O&M costs for the buses in this model is \$0.60/mile/bus (Johnson et al., 2020). The cost is calculated using Eq. 17.

$$Maintenance\ cost = 0.60\left(\frac{\$}{mi}\right) * \left(annual\ miles\ covered\ in\ each\ route(mi)\right) \ldots\ldots\ldots (17)$$

<u>**Annual Operation Cost**</u>: The operating cost of these buses depends significantly on the electricity rate structure and the time of charging. Utility companies provide electricity under various rate structures, typically offering different rates for various customer types and use patterns. It is important to use the correct rate structure to eliminate any uncertainty in future calculations. The electricity cost is comprised of energy consumption charges and demand charges that can be identified from the electricity rate structure. Notably, the demand charges specified in the rate structure are an important element and account for a significant share at around 25% of the electric bill. Currently, HTA falls under the NEM-A-1-B rate structure, as their total is lower than 5000 kWh and they have roof-top solar generation. Their current rate structure does not have a demand charges component. As per the model, once HTA fully transforms its fleet to electric buses, its total daily energy consumption would increase to 7,000 kWh a month.

Once HTA fully coverts to an electric fleet, they would likely use the PG&E BEV-2-P rate structure. This rate structure has demands chargers. This model considers non-peak (night-time) charging of buses using two types of plug-in chargers, rated at 50

and 150 kW, respectively. However, charging of all the buses will drastically increase the electric demand (kW) during those hours. The increase in hourly demand influences demand charges in the electric bill. To calculate the operating cost, energy charges and demand charges are calculated separately and added to estimate the total energy charges.

As noted in Section 3.2.2, the PG&E BEV-2-P rate structure is used to calculate these charges. The TOU periods shown in Table 13 are used to identify the energy consumption in Peak, Off-Peak and Super Off-Peak periods.

Table 13. ToU of the PG&E's BEV-2-P Electric Rate Schedule

ToU period	**Times**	**Days**	**Energy charges ($/kWh)**	**Demand charges ($/kW)**
Peak	4:00 - 9:00 p.m.	Everyday including weekends. and federally recognize holidays	0.33195	1.72
Off-Peak	9:00 p.m.- 9:00 a.m. 2:00 - 4:00 p.m.	Everyday including weekends and federally recognize holidays	0.12307	1.72
Super Off-Peak	9:00 a.m. - 2:00 p.m.	Everyday including weekends and federally recognize holidays	0.10041	1.72

Source: (PG&E, 2020)

The operating cost is a combination of energy charges and demand charges, as mentioned in Eq. 18. The energy and demand charges are calculated using the rates of the BEV-2-P rate structure. Energy charges are calculated using Eq. 19.

$$Operating\ cost(\$) = Energy\ charges(\$) + Demand\ Charges(\$) \ldots \ldots \ldots \ldots (18)$$

$$Energy\ charges(\$) = Energy\ price\ during\ the\ hour \left(\frac{\$}{kWh}\right) * Hours\ of\ charging(hr) * \left(Power\ rating\ of charger(kW)\right) \ldots \ldots \ldots \ldots \ldots \ldots (19)$$

The BEV-2-P rate structure also has demand charges, shown in Table 13. The detailed rate structure is also mentioned in Table A-2 in Appendix A.

Demand charges are calculated using Eq. 20. The BEV-2-P rate structure also allows the customer to pre-define the demand in a manner that helps reduce the demand charges. The relation between the demand charges and block size for BEV-1-2-P rate structure are as shown in Figure 20 below. Demand chargers for HTA BEB charging are calculated from Eq.20.

$$Demand\ charges\ (\$) = Maximum\ power\ demand\ while\ charging(kW) * Demand\ charges\ (\$/kW) \ldots \ldots \ldots (20)$$

Due to unavailability of buses during the daytime, most of the charging is planned from 9 pm to 8 am during off-peak hours at the depot with plug-in charging. However, some buses will also use overhead charging due to long routes. Simultaneous charging of all buses during the night can spike up the facility demand, thereby increasing demand charges.

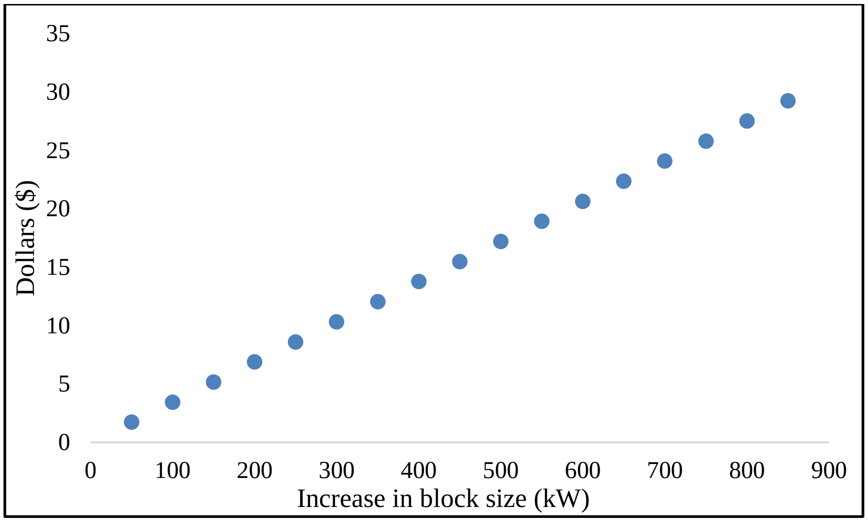

Figure 20. Demand charges based on block size. Source: (PG&E, 2020)

After analyzing the projected future demand of HTA and in consultation with my project committee, work colleagues, and a representative from HTA, the BEV-2-P rate structure was selected for use in the analysis. PG&E's BEV rate schedule is a specially designed commercial electric rate structure that allows current NEM customers to use the BEV rate if they meet the BEV eligibility requirements. These requirements include that the facility must engage in high-level commercial BEV/ plug-in hybrid vehicle charging (PG&E, 2020). The rate structure has two options, BEV-1, which is applicable to customers with usage at or below 100 kW, and BEV-2, which is applicable to customers with usage at or above 100 kW. The BEV rate structure is shown in Figure 21, and additional information about the rate structure is included in Table A-2 in Appendix A.

RATES:(Cont'd.)

TOTAL RATE

Total Energy Rates ($ per kWh)	BEV-1		BEV-2-S (Secondary)		BEV-2-P (Primary / Transmission)	
Peak	$0.32455	(R)	$0.33974	(R)	$0.33195	(R)
Off-Peak	$0.13254	(R)	$0.12651	(R)	$0.12307	(R)
Super Off-Peak	$0.10588	(R)	$0.10324	(R)	$0.10041	(R)
Block Size (kW)	10		50		50	
Subscription Charge (per block)	$12.41		$95.56		$85.98	
Subscription Charge ($ per kW)*	$1.24		$1.91		$1.72	
Overage Fee ($ per kW)	$2.48		$3.82		$3.44	

Total bundled service charges shown on a customer's bills are unbundled according to the component rates shown below.

Figure 21. Snapshot of PG&E's BEV Electric Rate Schedule. Source: (PG&E, 2020)

The customer pays a monthly fee which is based on the number of blocks in their subscription. PG&E allows their customers to pre-determine the subscription level.[5] Before enrolling in the rate structure this amount can be increased or decreased as needed. For the BEV-2 rate, this subscription comes in blocks of 50 kW. However, if the hourly demand increases beyond the pre-determined subscription level, the customer must pay an overage fee[6] as per the rate structure as shown in Figure 21. Therefore, an optimization tool (based on Microsoft Excel Solver application) is used to develop a charging regime for BEBs while minimizing the maximum demand of the facility.

[5] The customer needs to pay the subscription charges of $85.98/block based on the BEV-2-P rate structure, and the size of the block must be pre-determined. This amount can be increased or decreased based on the requirement of the block size (PG&E, 2020).

[6] The overage fees ($/kW) will be calculated based on 15-minute intervals of readings of the average kW usage (PG&E, 2020).

3.3.2.A.1 Optimization of demand Charges

As discussed in the Section 2.2.1.B, the number of buses getting charged at a time can significantly increase the overall demand chargers. It is therefore necessary to plan the charging time in an optimized way that maintains the lowest possible peak demand while charging all the buses. The optimization tool identifies charging patterns in the form of binary outputs (which BEB and how many hours it will charge) to minimize the maximum demand, thereby demand charges. The optimization tool identifies an optimal charging pattern for the BEBs using the objective, variables, and constraints as listed in Table 14 below. This tool helps determine the number of buses that can be charged between 9:00 pm and 8:00 am while keeping the maximum demand equal or lower than 750 kW. It also ensures continuity in the charging with the help of binary outputs (i.e., if a bus is selected for charging, the tool will ensure the charging will continue until the battery is fully charged). Finally, the optimized charging schedule is used to calculate the energy cost of plug-in charging, which is further used to estimate the operating cost of charging. An example of the optimization tool is shown in Table B-1 in Appendix B.

Table 14. Objective, Variables, and Constraints for bus charging optimization

Parameters	Detailed Notes
Objective	Maximum demand <= 750kW, Minimize the peak demand during plug-in charging (by distributing the charging of buses over a 11-hr. duration.
Variables	Off- peak charging hours
Constraints	1). Maximum hourly demand should not go beyond 750kW. 2). Maintain continuity while charging (i.e., once a bus is selected to charge, it should continuously charge up to 90%. The calculation is completed in binary format (i.e.,1 is charging and 0 is not charging during the interval). 3). The bus cannot be charged beyond its battery storage capacity.

(C) **Mid-life Maintenance Cost:** The midlife bus maintenance costs are utilized to cover rebuilding, refurbishing, or replacing major propulsion components due to wear

or deterioration to sustain the vehicle's useful life, such as major faults in the electric motor or planned replacement of the vehicle on-board battery after it has completed its life cycle. This study considers buses manufactured by Proterra, New Flyer, and BYD. These companies claim a battery life of approximately 12 years for BEBs with proper maintenance (Proterra , 2019) (Ambrose H., 2017). It is also reported from various sources that the cost of battery replacement for battery capacities up to 250 kWh is between $50K and $75K. Various literature sources have found that the midlife maintenance costs vary between $200-$300/ kWh of on-board battery capacity (Ambrose H., 2017) (Johnson et al., 2020) (UC ITS, 2017) (MJB&A, 2020).

In this study, the cost of mid-life maintenance cost is estimated to be $227/kWh of the battery's nameplate capacity, which will be applied after every after 300,000 miles from the year of implementation. This cost will ensure the proper life cycle and battery health life. The mid-life maintenance cost is calculated using Eq. 21.

$$Midlife\ maintenance\ cost\ (added\ when\ bus\ completes\ 300{,}000\ miles)$$
$$= \$227/kWh$$
$$* (Name\ plate\ capacity\ of\ bus\ battery\ in\ (kWh)) \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (21)$$

The above-mentioned cost components are added together to identify the life cycle cost of BEBs. All the cost that are comes between 2022 to 2040 are further discounted by 3% (refer to Eq. 26). The cost of charging infrastructure is identified as follows.

3.3.2.B Cost of BEB Charging Infrastructure

The fuel economy of the buses is one of the key factors determining the amount of charge/energy required to complete their respective daily routes as shown in Eq. 22.

$$Energy\ required\ for\ each\ route\ (kWh)$$
$$= BEB\ fuel\ economy\ \left(\frac{kWh}{mile}\right)$$
$$* Miles\ covered\ in\ each\ route\ (mile) \ldots\ldots\ldots\ldots (22)$$

The fuel economy of buses (kWh/mile) is collected from the manufacturer's data. Table 6 shows information about the onboard battery and efficiency specifications for these buses. A 150-kW charger is used to charge the buses with large energy demand, and a 50-kW charger is used to charge the buses with smaller energy demand.

As mentioned in the assumptions, the performance of the BEBs is influenced by the condition of the route and various parameters such as the number of on-board passengers, environmental conditions, and driving practices. Therefore, the range covered by the buses is calculated as the 80% of the nameplate range to account for losses to cover for route characteristics as shown in Eq. 23.

$$Actual\ miles\ covered\ by\ BEBs(mi)$$
$$= 80\% * (claimed\ miles\ per\ full\ charge(mi)) \ldots\ldots (23)$$

The total cost of charging infrastructure includes the capital and O&M costs of the chargers. As most buses will charge during the night with cheaper electricity, HTA would require multipoint charger outputs to charge the BEBs. The model identifies a minimum of 13 depot and 1 on-route chargers would be required to keep the buses

running. The buses will charge at a different time with the help of different chargers to make sure HTA would not need to change their daily operational hours.

(A) Charger Capital Cost: As discussed in Section 2.2.1.A, two types of chargers are considered in this model. A 50-kW and 150-kW charger are considered for plug-in charging, and a 500-kW charger is considered for on-route charging. These chargers are selected by looking at the charging requirements of BEBs. The capital cost and installation of the required charger are shown in Table 2. These costs are one-time upfront costs that are added in the cost in the year of implementation.

(B) Charger Maintenances Cost: The annual O&M cost per year of the plug-in charger is considered as $500/year as shown in Table 2. The total O&M cost associated with the chargers' cost is calculated using of Eq. 24 for every year from the year of selection.

$$O\&M\ cost\ of\ plugin\ chargers\ (\$)$$
$$= 500\ (\frac{\$}{year}) * number\ of\ operating\ years \ldots \ldots .(24)$$

The O&M cost for the on-route charger is calculated based on the amount of electrical energy transferred from the charger to the battery, as shown in Eq. 25.

$$O\&M\ cost\ of\ onroute\ chargers(\$)$$
$$= daily\ electric\ energy\ used\ (kWh) * 0.026(\frac{\$}{kWh}) \ldots \ldots \ldots (25)$$

The total cost of the chargers is calculated by combining the capital cost and the O&M cost of the chargers.

3.3.2.C LCFS credit for BEBs

LCFS credits: As discussed, the LCFS credits are based on a policy intended to promote low carbon fuels and technologies by generating credits in association with their use. The credits help make the associated low-carbon transportation technologies more economically competitive with conventional diesel buses. Electric buses are eligible to generate LCFS credits for each kWh consumed. These credits can be sold and used to offset the cost of operating the buses. The LCFS credit calculator is used to calculate the net value of these credits in terms of a dollar value (CARB, 2018b). The following assumptions are used to run this calculator (CARB Regulation, 2019) (CARB, 2021)

- Vehicle Fuel EER[7]: 5.0[8] (Electricity Used in a Battery Electric (BEV) or Plug-In Hybrid Electric (PHEV) Heavy-Duty Truck or Bus (CARB, 2018b).
- Carbon Intensity (CI): 81g CO_2e/MJ (CARB, 2018b).
- Diesel energy intensity:135 (MJ/gal) (CARB, 2018b)
- Switched fuel: Diesel to Battery

With the help of the CARB LCFS credit calculator, the LCFS credit amount is estimated as $0.17/kWh. This credit amount is then used to calculated the daily credit for each route. Every day's credit is calculated based on the daily kWh consumption to identify annual credits that are aggregated to determine the total LCFS credits.

[7]Energy Economy Ratio: Distance an alternative-fueled vehicle travels divided by the distance an internal combustion engine vehicle travels using the same amount of energy (The National Academic Press, 2015).
[8] Fuel efficiency varies with different vehicles. The EER provide credits to the efficient vehicle for the conventional fuel displaced by using the clean vehicles (CARB, 2018b).

For the life cycle cost calculation, the total cost of converting conventional buses to BEBs is determined with Eq. 26 using a net discount rate of 3%. Chapter 4 discusses the results of the analysis.

$$\begin{aligned} &Discounted\ price\ for\ BEBs\ (\$) \\ &\qquad = (Overall\ cost\ in\ 2021(\$) \\ &\qquad + NPV\ \ (3\%, Overall\ future\ cost\ (2022\ to\ 2040)\ (\$)) .. (26) \end{aligned}$$

CHAPTER 4: RESULTS & DISCUSSION

This chapter summarizes the results of this study, including insights related to the cost components associated with both (HFCB and BEB) conversion options. The outcomes of the model for both technological solutions are discussed in this section. These results help determine which technology represented the most cost-effective alternative to convert HTA's conventional bus fleet to a zero-emission fleet, considering both the cost components and credits.

As per the analysis, 600kg/day (considering a 5% safety margin) of H_2 storage would be needed to support operation of HFCBs considering the current set of bus routes. However, any miles covered by buses deployed to replace buses that have experienced a failure while completing their daily route are not considered in this calculation, as these are less than 1% of the annual miles reported by HTA.

As mentioned in Section 2.2.1.A, a minimum of 13 depot chargers (50kW *7 and 150 kW*6) would be required to charge the BEBs considered in this study. These buses will charge at different times (mostly off-peak hours at the HTA depot) using the various chargers to make sure HTA would not need to change its daily operational hours. In addition to the depot charger, the charging infrastructure would also be supported by one on-route (500kW) charger situated at the Arcata Transit Center. The power requirements of the on-route charger may trigger a need for an upgrade to the local distribution infrastructure, but this cost is not considered in this analysis. All the buses that need on-route charging have a daily stop at Arcata Transit Center, making it an ideal location for

an on-route charger. Since the current infrastructure of the Arcata substation does not have the capacity to provide the necessary power for a 500-kW charger, a substation upgrade is required. The substation upgrade cost is included in the analysis.

As described in the Section 2.1.1, the conversion timeline considered in this project aligns with the CARB's ICT plan,[9] with a 1:1 conversion ratio (i.e., one conventional bus will be replaced by either a HFCB or a BEB, which makes the study more realistic and adoptable for HTA. The outcomes of the model for both technological solutions are discussed in the following sections.

4.1 Cost of Conversion in Phase-I (HFCBs and BEBs)

As mentioned above, the conversion would follow CARB's timeline, with half of the HTA fleet being converted from 2021 to 2025 (Phase-I) and the second half being converted from 2026 to 2030 (Phase-II). In addition, the cost associated with this conversion is calculated separately for both the technologies, but the combined results are shown to draw comparison between the two technology alternatives (HFCBs and BEBs)

For the Phase-I conversion, the buses traveling longer distances in their daily routes are selected and compared due to their larger contribution to GHG emissions. All these long routes have the potential of cutting down a significant portion of GHG

[9] The CARB requires all transit agencies to convert 50% of their conventional fleet to a zero-emission fleet by 2025, also known as (Phase-I). The remaining half of the fleet will be converted in the next five years, i.e., 2030 (Phase-II) for technology options, as shown in Table 1. Therefore, by 2030, the entire public transportation fleet in Humboldt County will convert to zero-emission

emissions by 2025, thereby enabling HTA to maximize generation of LCFS credit. This creates revenue that can be used to reduce the total cost of conversion.

For Phase -I conversion, 10 of the 21 buses are selected. The selected buses traverse longer routes in comparison to the others and span several different transit systems affiliated with HTA. The buses that are selected for the Phase-I conversion are shown in Table 15 below.

Table 15. Buses considered in Phase-I conversion

Bus number (ID)	Routes under HTA	Year	Annual distance (mi)
104 & 105	Redwood Transit System	2021	110,734
106 & 107	Redwood Transit System	2021	110,107
410	Southern Humboldt Intercity	2022	107,939
112 & 115	Redwood Transit System	2022	100,116
100 & 101	Redwood Transit System	2023	99,614
714	Willow Creek	2023	98,657
102 & 116	Redwood Transit System	2024	87,566
110 & 123	Redwood Transit System	2024	68,598
118 & 119	Redwood Transit System	2025	64,272
512	Southern Humboldt Intercity	2025	55,594

Source: HTA

The overall estimated cost of converting the 10 buses listed in Table 15 to HFCBs and BEBs by 2025 is $57.91 million and $21.8 million, respectively. This cost includes the capital cost of the buses and associated infrastructure, the O&M costs for the buses and infrastructure, and the LCFS credits from the year of implementation until 2040. This does not consider any discounting of future costs. However, with a 3% discount rate, the present value of the overall costs are around $44.91 million and $18.52 million for HFCBs and BEBs, respectively. The cost of Phase-I conversion for both technology alternatives is shown below in Table 16.

Table 16. Phase-I Cost of Conversion for HFCBs and BEBs ($ million)

Transit	HFCBs Non-discounted cost	HFCBs discounted cost (3%)	BEBs Non-discounted cost	BEBs discounted cost (3%)
Redwood Transit System	$41.4	$32.2	$16.1	$13.7
Southern Humboldt Intercity	$10.4	$8.0	$3.6	$3.1
Willow Creek	$6.1	$4.7	$2.1	$1.7
Total (million dollars)	$57.9	$44.9	$21.8	$18.5

As described in Chapter 3, Section 3.1, the total cost of converting the HTA's conventional fleet to ZEBs (HFCB or BEBs) is comprised of six cost and credit components. This includes the 1) capital cost of buses, 2) capital cost charging or refueling stations infrastructure, 3) O&M cost of buses, 4) on going fueling costs for electricity or hydrogen, 5) midlife major maintenance costs of buses, and 6) LCFS credits for both technology types. These LCFS credits are generated by either HFCBs or BEBs and are considered as a source of revenue until 2040. The cost components for HFCBs and BEBs are listed in Table 17 below.

It is evident from Table 17 that the cost of acquiring the HFCBs (capital and acquisition cost of buses) is 5% more than the cost of acquiring BEBs. However, the operating cost of HFCBs is 55% more than BEBs. These costs include the operating, maintenance, and midlife maintenance costs and the LCFS credits. A summary of the cost components of Phase-I conversion are shown in Table 17. It is also important to note that deploying refueling infrastructure for HFCB operation is more expensive than deploying BEB chargers. The model calculated that setting-up of a hydrogen refueling station is 90% more expensive than installing the EV chargers for the operation of the BEBs. While the capital and operating costs of the HFCBs are more than the

corresponding costs for BEBs, the acquisition cost is approximately same for both technologies as mentioned in Table 17.

Table 17. Cost components of Phase-I conversion of BEBs and HFCBs ($ million)

Phase-I[10]	**RTS HFCB**	**RTS BEB**	**SHT HFCB**	**SHT BEB**	**Willow Creek HFCB**	**Willow Creek BEB**	**Total HFCB**	**Total BEB**
Number of Buses	7	7	2	2	1	1	10	10
Charging stations	NA	150	NA	50	NA	50	NA	200
Hydrogen required (kg/day) (kW/per bus)	292	NA	75.50	NA	45	NA	412.5	NA
Capital cost (Bus)	5.97	5.86	1.67	1.49	0.85	0.75	8.49	8.1
Acquisition cost (Bus)	0.15	0.15	0.04	0.04	0.02	0.02	0.21	0.21
Maintenance cost (Bus)	7.26	5.45	1.68	1.31	1.01	0.79	$9.96	$7.71
Midlife maintenance cost (Bus)	5.00	1.36	1.18	0.28	0.73	0.20	6.91	1.84
Operating cost (Bus)	5.57	2.51	1.40	0.55	0.84	0.36	7.81	3.42
Infrastructure capital cost	9.84	1.48	2.47	0.18	1.49	0.06	13.80	1.72
Infrastructure maintenance cost	2.60	0.05	0.65	0.01	0.39	0.01	3.64	0.07
LCFS credit	-4.21	-3.13	-1.06	-0.80	-0.64	-0.46	-5.91	-4.39
Total ($ million)	32.17	13.73	8.04	3.06	4.70	1.73	44.91	18.52

A graphical representation of the Phase-I conversion costs for the HFCBs and BEBs is shown in Figure 22, and a representation by transit system is shown in Figure 23. The buses selected in Phase-I cover long distances. For HFCBs, a significant portion of the cost is associated with the hydrogen fuel. Different costs are considered at different times during the 20 years period. For example, the capital cost is only considered in the implementation year, whereas the O&M costs are considered in intervals as mentioned in

[10] Number of buses, charging stations, hydrogen required are not costs, they are the specifications related to infrastructure considered for these buses.

Table 3 in Section 3.1. A graphical representation of the Phase-I conversion costs for HFCBs and BEBs is shown in Figure 22, and a representation by transit system is shown in Figure 23.

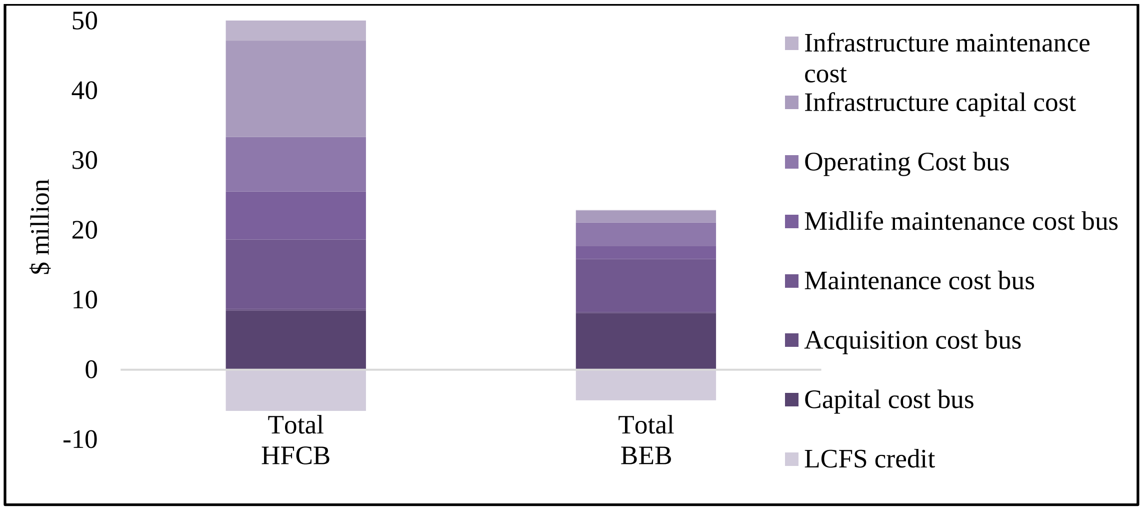

Figure 22 Phase-I cost of conversion for HFCBs and BEBs.

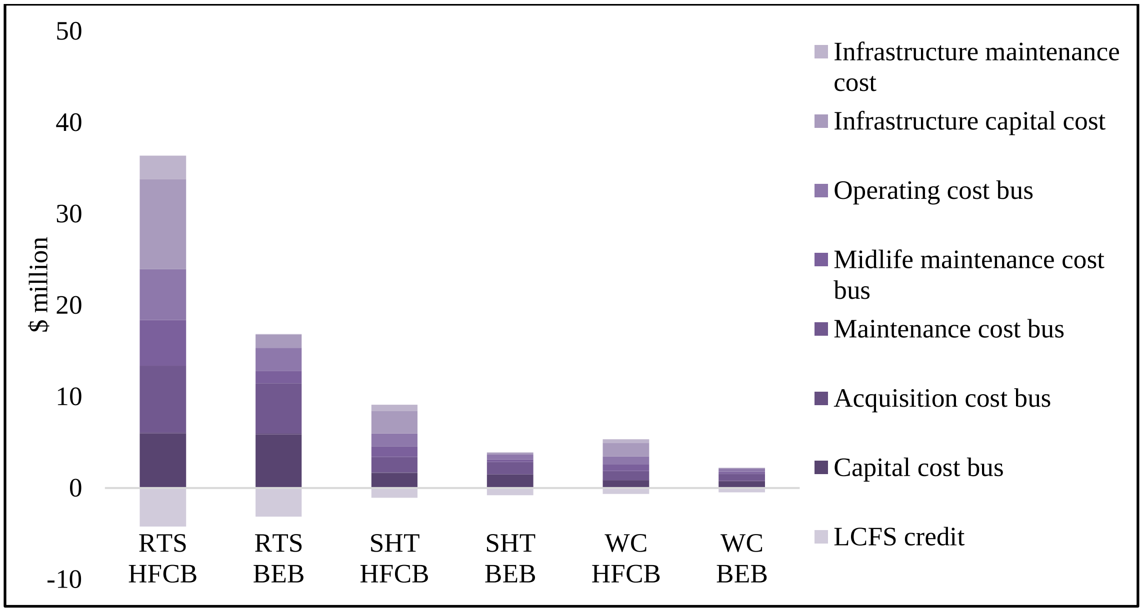

Figure 23. Phase-I costs of conversion by transit agencies for HFCBs and BEBs

The buses selected in Phase-I cover long distances. For HFCBs, a significant portion of the cost is associated with the hydrogen fuel. Different costs are considered at

different times during the 20 years period. For example, the capital cost is only considered in the implementation year, whereas the O&M costs are considered in intervals as mentioned in Table 3 in Section 3.1.

4.2 Cost of Conversion in Phase II (HFCBs and BEBs)

The Phase-II conversion involves converting the remaining 11 buses of the HTA and BLRTS fleets into BEBs or HFCBs during the period from 2026 to 2030. These buses traverse comparatively shorter routes and emit less GHG emissions, as described in later sections. The buses that are selected for the Phase-II conversion to BEBs or HFCBs are shown in Table 18 below.

Table 18. Buses considered for Phase II conversion of every transit agency in HTA.

Bus number (ID)	Routes under HTA	Year	Annual distance (mi)
108	RTS	2026	55,929
428	BLRTS	2026	47,586
2552150	AMRTS	2027	42,411
66	ETS	2027	37,385
120	RTS	2028	35,844
67	ETS	2028	37,015
68	ETS	2029	33,362
25500	AMRTS	2029	34,299
69	ETS	2030	32,136

The total cost for the Phase-II conversion will add another $17 million for the case of HFCBs and $9 millions for BEBs considering discounting of future costs. These amounts include the capital cost of buses selected for Phase-II conversion, along with infrastructure costs, O&M, and mid-life maintenance costs for the buses. The buses also generate revenue from LCFS credits, and these credits are deducted from the costs to generate an overall net amount. Table 19 shows the total cost of the Phase-II conversion.

Table 19. Transit agencies cost for Phase II.

Transit System	HFCB Non-Discounted Cost	HFCB Discounted cost (3%)	BEBs Non-Discounted cost	BEBs Discounted cost (3%)
AMRTS	4.6	3.38	2.38	1.84
BLRTS	3.19	2.38	1.25	1.01
ETS	8.61	6.27	4.5	3.95
RTS	6.61	4.86	3.17	2.01
Total	23.01	16.89	11.3	8.81

The cost of acquiring the HFCBs (capital and acquisition cost of buses) is 17% more than the cost of acquiring BEBs for Phase II. However, operating HFCBs in Phase II is 59% more expensive than operating BEBs. This cost includes the operating, maintenance, and mid-life maintenance costs of buses adjusted for the LCFS credit. Similarly, deploying the refueling infrastructure for HFCB operation is more expensive than deploying BEB chargers. The model calculated that setting-up the hydrogen refueling station is 70% more expensive than installing the EV chargers for BEB operation. While the capital and operating costs of HFCBs are more than BEBs, the acquisition cost is approximately constant for both technologies. A graphical representation of the Phase II conversion costs for HFCBs and BEBs is shown in Figure 24.

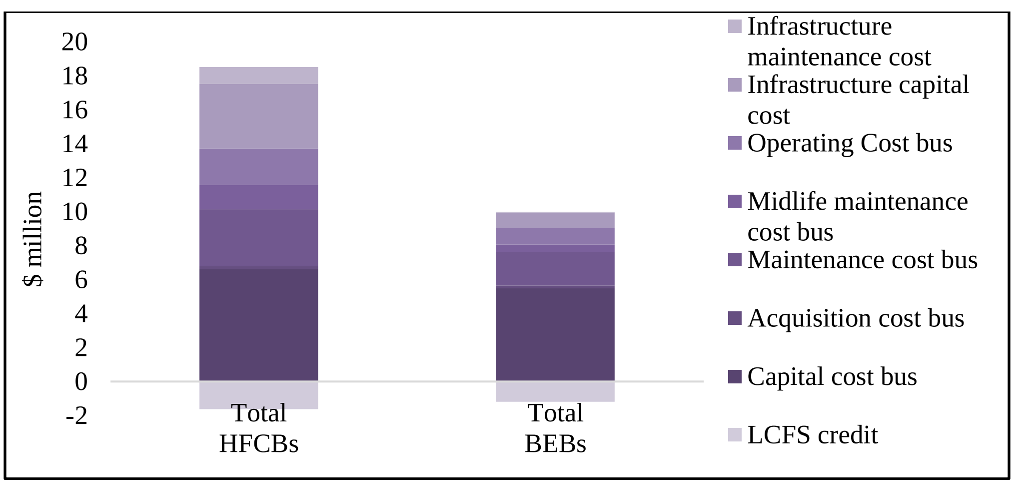

Figure 24. Phase-II cost of conversion to HFCBs and BEBs

A summary of the cost components of Phase-II conversion is shown in Table 20 and a graphical representation of the Phase-II conversion costs by transit systems for HFCBs and BEBs is shown in and Figure 25.

Table 20. Discounted Cost components of Phase-II conversion for HFCBs and BEBs

Phase-II[11]	**AMRTS HFCB**	**AMRTS BEB**	**BLRTS HFCB**	**BLRTS BEB**	**ETS HFCB**	**ETS BEB**	**RTS HFCB**	**RTS BEB**	**Total HFCB**	**Total BEB**
Number of Buses	2	2	1	1	4	4	3	3	10	10
Charging stations (kW/per bus/per charger)	NA	50	NA	50	NA	50	NA	150	NA	200
Hydrogen required (kg/day)	35.17	NA	25.67	NA	64	NA	60	NA	185	NA
Capital cost (Bus)	1.46	1.24	0.78	0.62	2.89	2.37	1.51	1.28	6.63	5.51
Acquisition cost (Bus	0.04	0.03	0.02	0.02	0.07	0.06	0.04	0.03	0.17	0.14
Maintenance cost (Bus	0.53	0.41	0.39	0.30	0.92	0.72	1.50	0.55	3.34	1.98
Midlife maintenance cost (Bus	0.26	0.09	0.27	0.05	0.50	0.19	0.41	0.11	1.43	0.44
Operating cost (Bus)	0.44	0.19	0.38	0.17	0.76	0.36	0.57	0.24	2.15	0.96
Infrastructure capital cost	0.78	0.10	0.67	0.05	1.34	0.67	1.00	0.10	3.79	0.92
Infrastructure maintenance cost	0.20	0.01	0.18	0.01	0.35	0.02	0.27	0.01	1.00	0.05
LCFS credit,	-0.33	-0.23	-0.29	-0.21	-0.58	-0.44	-0.43	-0.31	-1.62	-1.19
Total (million dollar)	3.38	1.84	2.38	1.01	6.27	3.95	4.86	2.01	16.89	8.81

[11] Number of buses, charging stations, hydrogen required are not costs, they are the specifications related to infrastructure considered for these buses.

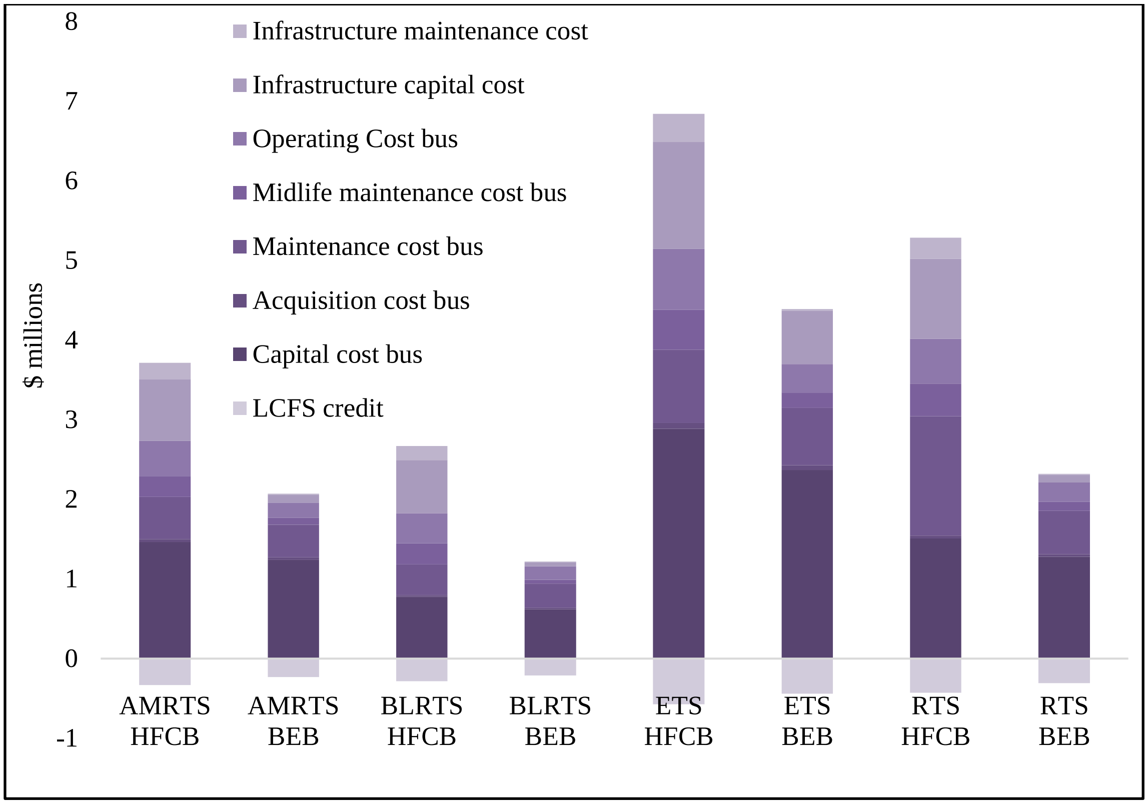

Figure 25. Phase-II costs of conversion by transit agencies for HFCBs and BEBs

4.3 Total Cost of Conversion (Phase-I + Phase- II)

This study identifies that the total costs associated with fully converting to HFCBs or BEBs without considering any discount factor are $81 million and $33 million, respectively. The discounted costs are estimated to be $62 and $27 million, respectively (refer to Table 20). A summary of the total costs associated with Phase-I and Phase-II conversion for BEBs and HFCBs are presented in Table 21. The overall costs by component for HFCB and BEB conversion are shown in Table 22 and Figure 26.

Table 21. Total cost associated with ZEV conversion in Phase-I and Phase-II ($ Million)

Phase	BEB Non-discounted	BEB with 3% discount factor	HFCB Non-discounted	HFCB with 3% discount factor
Phase-I	$21.8	$18.52	$57.91	$44.91
Phase-II	$11.3	$8.81	$23.01	$16.89
Total	$33.10	$27.33	$80.92	$61.80

The operating cost of HTA's conventional buses is $110/hr., as reported by HTA. If HTA replaces their conventional buses with HFCBs and BEBs, the costs will be $501/hr. and $205/hr. respectively, without discounting future costs. Similarly, if HTA converts their fleet to HFCBs and BEBs, this cost is estimated as $390/hr. and $167/hr., respectively, with discounting of future costs. A detailed comparison for full conversion is shown in Table 22 and Figure 26. A cost comparison of both the technologies based on each transit is also mentioned in Table 23 and Figure 27.

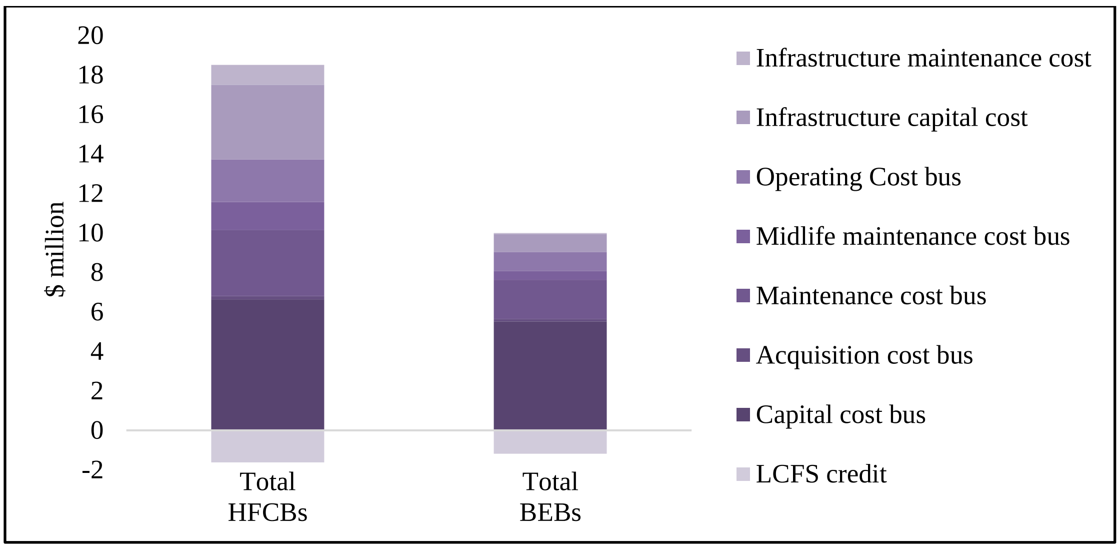

Figure 26. Detailed cost comparison of HFBs and BEBs for (Phase I and Phase II)

Converting HTA's conventional bus fleet to HFCBs is approximately $35 million more expensive than converting the fleet to BEBs for the calculation that does not consider the 3% discount factor over the estimated lifetime of the buses.

Table 22. Total cost associated with ZEV conversion in Phase I and Phase II (millions)

Cost components	HFCB Discounted cost (3%)	BEB Discounted costs (3%)
Capital cost (Bus)	$15.13	$13.61
Acquisition cost (Bus)	$0.38	$0.35
Maintenance cost (Bus)	$13.30	$9.53
Midlife maintenance cost (Bus)	$8.34	$2.28
Operating cost (Bus)	$9.96	$4.38
Infrastructure capital cost	$17.59	$2.64
Infrastructure maintenance cost	$4.64	$0.12
LCFS credit	-$7.53	-$5.58
Total	$61.80	$27.33

Table 23. Total cost of ZEV (transit wise) conversion for (Phase I and II), in millions

Transit System	HFCB Non-Discounted cost	HFCB Discounted cost (3%)	BEB Non-discounted cost	BEB Discounted cost (3%)
A&MRTS	$4.6	$3.4	$2.4	$1.8
BLRTS	$3.2	$2.4	$1.3	$1.0
ETS	$8.6	$6.3	$4.5	$4.0
RTS	$48.0	$37.0	$17.7	$15.7
SHI	$10.4	$8.0	$3.5	$3.1
Willow Creek	$6.1	$4.7	$1.8	$1.7
Total	$80.9	$61.8	$31.1	$27.3

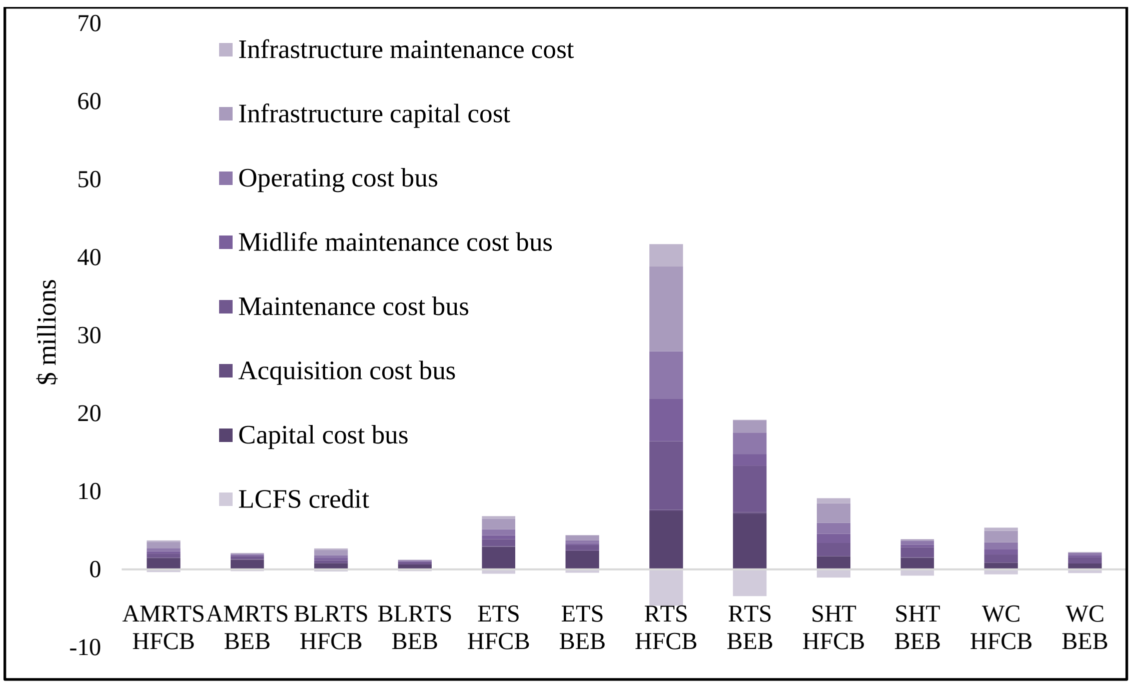

Figure 27. Total cost (Phase-I + Phase-II) of conversion to HFCBs and BEBs

The LCFS credits earned for HFCBs and BEBs are \$9.5 million and \$7.5 million, respectively. A large fraction of this amount is earned for buses converted during Phase-I, at \$7.5 million (HFCBs) and \$6.5 million (BEBs). The Phase-I amounts are large because the credits are generated on a per-mile driven basis, and the buses with longer routes were selected for Phase-I conversion

The study calculates that the LCFS credit for HFCBs can generate \$0.04/mi from 2021-2040, while the BEB credit can generate \$0.03/mi over this period. The generation of LCFS credits during Phase I and Phase II for both technology types is shown in Figure 28, below.

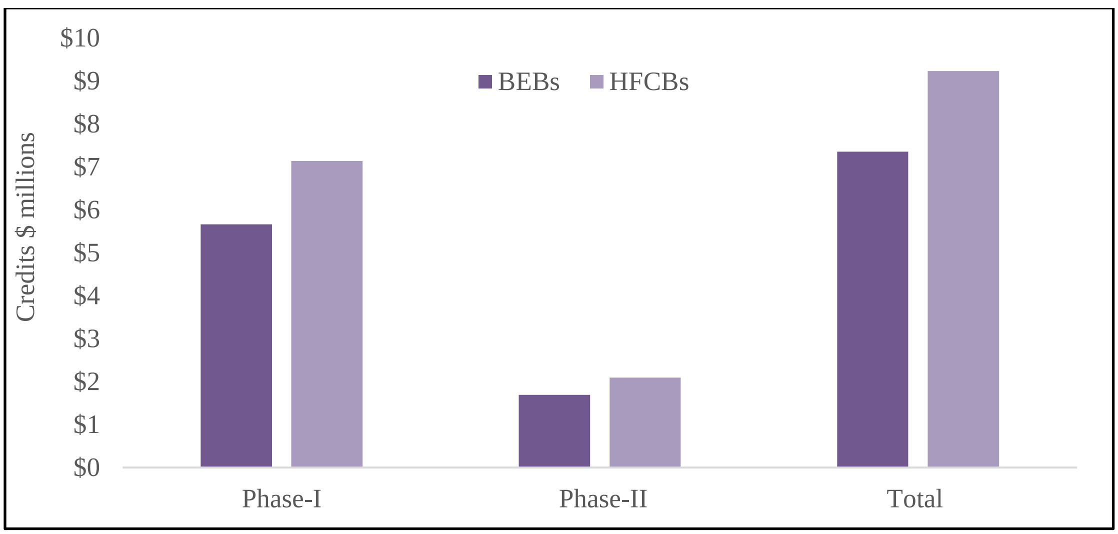

Figure 28. LCFS credits earned by BEBs and HFCBs

4.4 Reduction in GHG Emissions Phase I + Phase II (HFCBs and BEBs)

As mentioned in Section 2.5, the current conventional HTA bus fleet emits approximately 2.6 megatons of CO_2 emissions annually. Converting the fleet to zero-emission vehicles will cut these emissions significantly. The reduction of GHG emissions

over time in shown in Figure 29. The conversion results in a reduction of 1.8 MT of CO_2 emissions, which is approximately 70% of the current GHG emissions. Further, by the end of the year 2030, the emissions from these buses can be zero if HTA decides to procure electricity sourced only from renewable energy for its buses, but that would be more expensive than the costs calculated in this project.

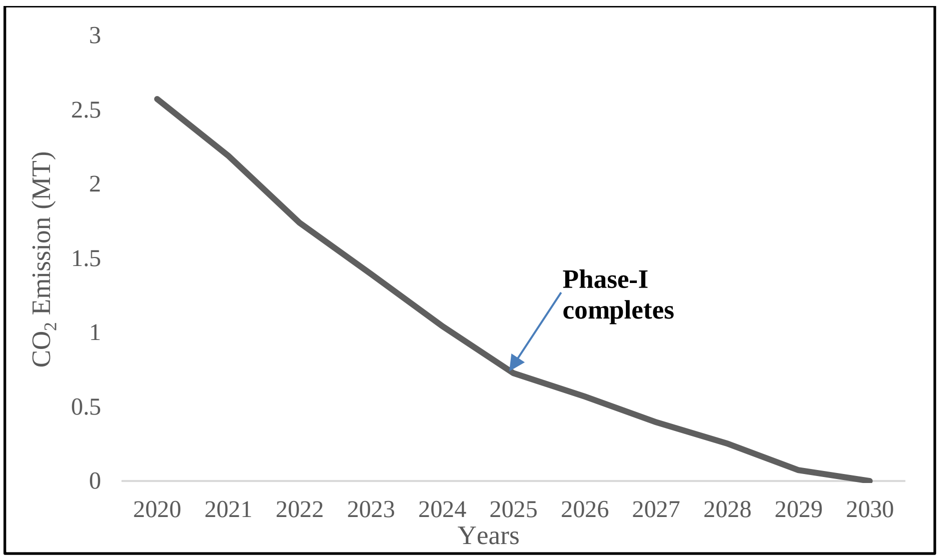

Figure 29. Reduction in HTA's GHG emission by adopting HFCBs or BEBs.

As mentioned earlier, the results calculated in this study are only applicable to the transit agencies that come under HTA together with BLRTS, which is owned and operated by the Blue Lake Rancheria Tribe. However, the model can also be used for other transit agencies and counties by changing the database mentioned in the Chapter 3.

4.5 Discussion

This section discusses the inferences that can be drawn from the study. It also identifies the areas of uncertainties that can impact the results. As shown in the results, the cost of converting the HTA fleet to HFCBs is approximately twice as expensive as converting it to BEBs. The cost of converting to HFCBs is higher mostly due to the capital cost of the buses, the refueling infrastructure, and O&M costs, including the midlife maintenance cost. The total cost (Phase I and Phase II) of acquiring BEBs and HFCBs are estimated to be $14 million and $15.5 million, respectively. This cost includes capital and acquisition cost of buses. This is approximately 51% and 28% of the total cost of conversion to BEBs and HFCBs, respectively.

The other considerable cost component is the total O&M of HFCBs and BEBs through 2040. The total O&M costs of BEBs and HFCBs after accounting for the LCFS credits are calculated to be $11 million and $28 million, respectively. This includes the operating and maintenance cost of the buses and infrastructure, the midlife maintenance cost, and the LCFS credit. These amounts come to approximately 39% and 46% for BEBs and HFCBs, respectively as shown in Figure 30.

The total O&M cost includes the cost of fuel for each technology type. The operating costs (cost of fuel) of HFCBs and BEBs over 20 years are $10 million and $4.4 million, respectively, which is about 16% of the total conversion cost for both technologies.

The fueling and charging infrastructure for these buses also contributes significantly to the total cost. The total cost (capital and O&M cost of infrastructure) of the hydrogen refueling infrastructure is $22 million, which is approximately 36% of the total cost of converting the conventional fleet to HFCBs. By comparison, the total cost (capital and O&M cost) of the charging infrastructure for the BEB conversion is around $2.8 million, which is approximately 10% of the total cost of converting the bus fleet to BEBs, as shown in Figure 30.

These results show that HTA will need to invest eight times more to build the needed hydrogen refueling infrastructure to serve Humboldt County than to build the corresponding BEB charging infrastructure.

This study also helps in determining that the total costs per mile of driving for HFCBs and BEBs are $0.32/mi and $0.14/mi once adjusted for LCFS credits, respectively, as shown in Figure 30. The costs of acquiring buses per mile of HFCBs and BEBs are $0.08/mi and $0.07/mi, respectively. The O&M costs per mile of HCFBs and BEBs are estimated at $0.16/mi and $0.08/mi, respectively. The cost of infrastructure per mile of HFCBs and BEBs are $0.11/mi and $0.014/mi, respectively. The HFCBs and BEBs generate revenue of $0.04/mile and $0.03/mile through LCFS credits, respectively. These costs are shown in Figure 30. As mentioned in Chapter 3, all these factors are based on the miles covered after the Phase-I and Phase-II conversions, and they can change based on the selection of buses during Phase I and Phase II.

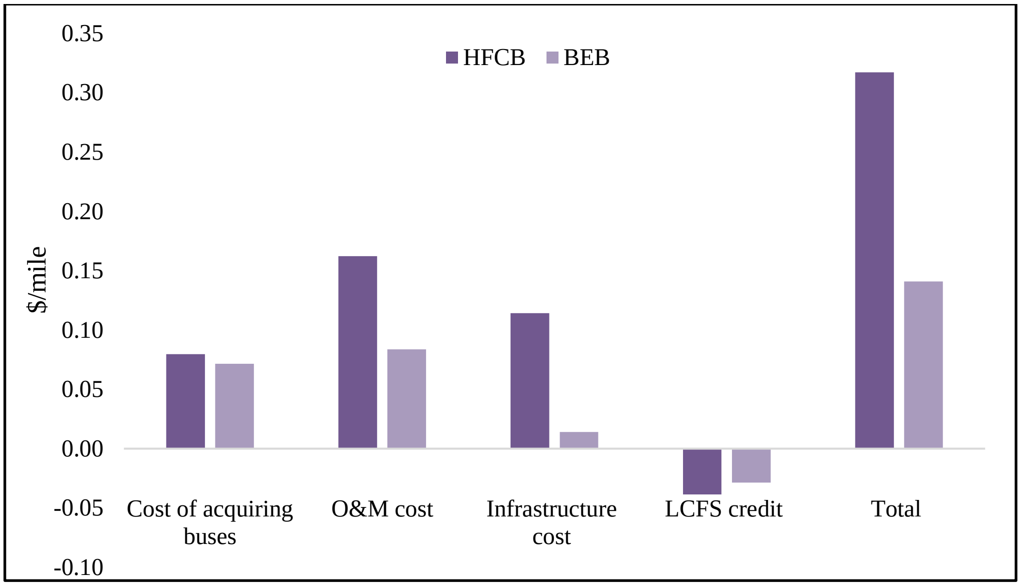

Figure 30. Comparison of per mile costs for BEBs and HFCBs

The overall costs per mile of complete conversion to HFCBs and BEBs are estimated for each active bus route and are shown in Table 24, respectively. These parameters include the average cost of fuel (H_2 and electricity) per mile for HFCBs and BEBs, the mid-life maintenance cost of the buses, and the generated LCFS credit per mile are shown in Appendix A, Tables A-3 and A-4.

It can also be noted that the cost of Phase-I conversion is more than Phase -II conversion. This is due to two factors. First, the buses selected for Phase -I conversion cover longer routes. As a result, several key cost components (capital, O&M, acquisition, and midlife maintenance costs) are higher. Second, the cost of adding additional infrastructure in Phase-II is lower than Phase-I as some of the fueling / charging infrastructure installed during Phase I is also used to support buses deployed in Phase II, making the need for additional fueling / charging infrastructure comparably smaller in Phase II.

Table 24. Cost per mile of ZEBs

Cost per mile	HFCB ($/mile)	BEBs ($/mile)
Capital cost bus	0.08	0.07
Acquisition cost bus	0.001	0.001
Maintenance cost bus	0.07	0.05
Midlife maintenance cost bus	0.04	0.01
Operating cost bus	0.05	0.02
Infrastructure capital cost	0.09	0.01
Infrastructure maintenance cost	0.02	0.001
LCFS credit	-0.04	-0.03
Total (dollars)	**0.32**	**0.14**

The main three cost components are the capital cost of the buses, the maintenance costs, and the fueling / charging costs of these buses. However, in the case of the BEBs, the charging regime is designed to minimize costs by charging most buses by plug-in charging and completing daily routes without any additional overhead charging. In total, six of the buses require overhead charging to complete their daily routes. The on-route charging could be carried out during super off-peak periods which again reduces the demand charges. The addition of more buses to existing infrastructure is more cost-efficient than building completely new infrastructure. Building the fueling / charging infrastructure in stages also allows for a smooth transmission to ZEV buses.

As per the current bus fleet size of HTA, the BEV-2-P rate structure matches HTA's requirements while also leaving some limited room for growth in electricity demand. In the current analysis based on the existing fleet, the maximum demand can be kept below 750 kW. However, if only two more buses were added to the fleet, HTA’s demand could exceed 1 MW, which would mean that HTA could no longer use the BEV-2-P rate. In that case, HTA would need to work with PG&E to identify another suitable rate structure. This would likely increase the running and operational costs for electric

buses. In addition, as mentioned above, the electricity rate used in this project (BEV-2-P electric rate schedule) uses the PG&E's standard grid mix. However, if HTA decides to utilize 100% renewable energy to charge their buses this would increase the cost of energy, and therefore the operating costs. The current BEV-2-P electric rate schedule does not include 100% renewable energy charges.

Additionally, the LCFS credits for BEBs and HFCBs are $0.17/kWh and $2.64/kg of H_2, respectively. These factors are derived from the LCFS calculator. The calculation of credits is based on assumptions outlined in Section 3.1.1. The generation of LCFS credits is a function of miles covered by the ZEBs through 2040, which, in turn, depends on the route length and the year of conversion. The analysis presented in this document maximized the LCFS credits by selecting longer bus routes for early conversion. If the year of selection of buses changes, then the generated revenue will also change. This could increase the net cost associated with conversion to ZEBs. Another factor which can affect the LCFS credit amounts is the fact that their value could change with time. Currently, the LCFS credits are calculated using CARB's calculator for the year 2021, and the calculated values will vary in the future. This introduces some uncertainty in the in the revenue generated by LCFS credits in the future. The following section discusses the possible avenues of uncertainty and error in this study.

4.6 Uncertainty

As described in Chapter 3, the model calculations are based on the data gathered from different sources that create a database of inputs for the model. Potential changes in

the data inputs create a level of uncertainty for the abovementioned analysis. The model inputs that can lead to significant changes in the resulting analysis are listed below.

(A). Selection of buses

Currently the selection of buses for Phase I and Phase II is based on the annual miles driven for each route. However, the set of buses selected could change as per the requirements of HTA, the availability of new buses in the future, and/or based on other constraints that could be considered. A change to the set of buses selected would result in changes to the cost in both phases. As mentioned in Section 2.3, a total of 21 buses are operated in Humboldt County, out of which only 20 are functioning currently. This analysis considered that all 21 buses will function in the near future, but the results would change if the fleet included a different number of buses. In addition, the results can also change if the routes used in this study are altered.

(B) LCFS credits

As discussed above, the LCFS credits are function of miles covered by the ZEBs. The mileage of the buses depends on the year of implementation and the bus route. For example, a bus commissioned in 2022 operating on a long route will generate more credits than a bus commissioned in 2023 with a shorter route. The change of implementation year and the selection of buses can change the results. In addition, a change in the value of the LCFS credits would also change the revenue generated by these buses, which in turn would impact the net cost per mile and the net overall cost. This study considers a sensitivity analysis around the LCFS credit value for BEBs and HFCBs and identified, for example, that a 1% increase in the LCFS credit value generates

approximately $0.45 million in additional revenue for BEBs, as shown in Figure 31. Therefore, it is recommended to begin the conversion to either BEBs or HFCBs promptly to maximize the generation of these credits. The buses qualify to begin accruing LCFS credits as soon as HTA starts the service by these buses. As the CARB ICT regulation would require HTA to convert its fleet to zero emission fleet by 2040, an early conversion of buses can lead to accrual of more LCFS credits and, therefore, less total cost. These credits have potential to increase over time, which would significantly increase the projected revenue (CARB, 2018a).

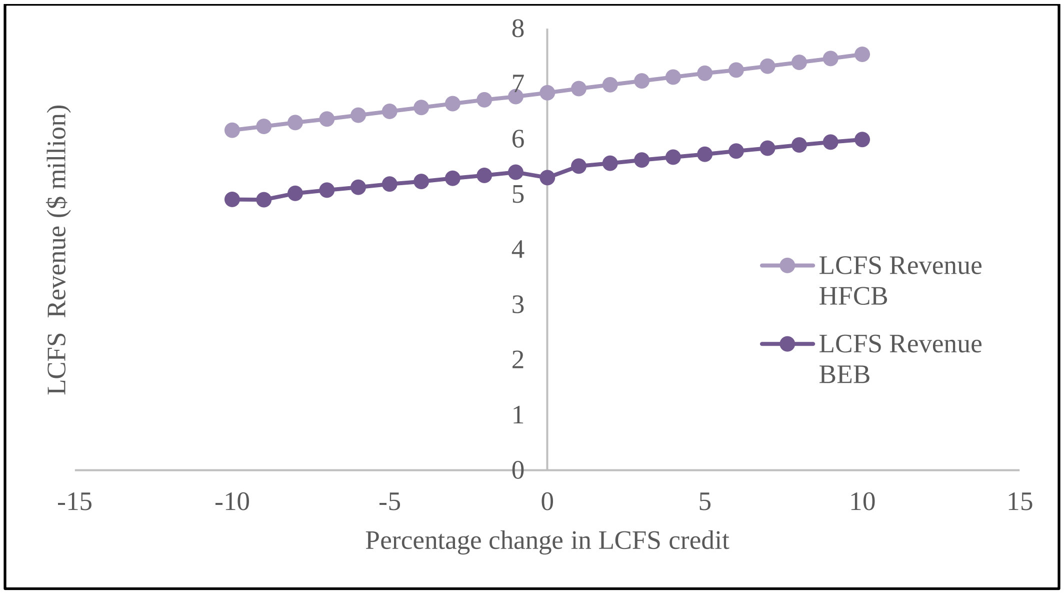

Figure 31. **Impact of change in LCFS credit value on revenue generation for BEBs and HFCBs**.

(c) Electricity Rate Structure

A change in electricity cost and demand charges will also affect the overall cost of converting HTA’s conventional fleet to HFCBs or BEBs, which could be possible in two scenarios. The change could occur through a revision of electricity rates by PG&E or by increase in demand on the part of HTA. For example, adding additional buses will

increase the demand, and removing buses would do the opposite. An increase in the number of buses could result in HTA surpassing the maximum hourly demand limit defining eligibility for the BEV-2-P rate. Currently, PG&E does not have a BEV rate schedule for demand that exceeds 1MW. Research conducted for this study indicates that the E-19 rate structure could be worth analyzing and adopting for the above case, but detailed examination of this issue was outside of the scope of this analysis. The energy charges change seasonally in the E-19 rate structure, while there are no seasonal changes in the BEV-2-P rate schedule. Under the E-19 rate, the peak demand charge rates are three times the amounts given under the BEV-2-P rate, and the energy charges are also higher under the E-19 rate compared to the BEV-2-P rate.

In addition to possible changes in the rate structure, HTA would also need to increase the use of on-route charging to support the charging of buses. Currently, all the buses are charged primarily during the off-peak or super off-peak hours by adjusting the charging cycle, which means that most charging occurs during off-peak periods. Some of the on-route charging occurs during peak periods, but this is limited to charging at a rate of 500 kW for a maximum of 20 minutes per bus. In the current analysis, a single on-route charger is required to enable completion of the routes. If new buses are added to the fleet, they may also need support from on-route charging depending on their routes and daily energy consumption.

For HFCBs, a change in electricity rates would also have a substantial impact on the total cost of conversion if hydrogen is generated onsite. This study does not capture

this as the electricity costs are calculated using the HDRSAM model, and it does not allow for adjustment of the assumed electricity rates.

As mentioned in Section 3.2, the model utilizes HDRSAM cost factors to identify the cost of the refueling station for the HFCB conversion case (see Table B-5, Appendix B). These cost factors include the cost of electricity consumed in hydrogen production with electrolysis. HDRSAM uses a rate structure for electricity costs that is different from the rates available through PG&E. The energy and demand charges used in the HDRSAM model are ($0.102/ kWh and $12.4/ kW), respectively. As shown in Table B-5, Appendix B, these values are different that the energy and demand charges in the BEV-2-P rate structure that is utilized to calculate the cost of electricity consumed to charge the BEBs. This is a limitation of the HDRSAM model. The difference in the energy and demand charges rates used to calculate the costs for operation of the HFCBs and BEBs could lead to some variance in the results. To characterize this variance, the analysis for BEB conversion was repeated using the energy and demand charge rates used in the HDRSAM model ($0.102/ kWh and $12.4/kW) instead of the corresponding rates in the BEV-2-P rate structure. The results of this analysis indicate that the total cost of converting the buses to BEBs increased from $27.33 million in the base case (using the BEV-2-P rate) to $28.53 million when using the HDRSAM model rates, an increase of about $1.2 million (~4%). The increase in the cost when using the HDRSAM rates is primarily due to high demand charges. It is worth noting that the overall cost of the BEB conversion for the HTA fleet remains considerably lower than cost of converting the buses to HFCBs regardless of which electricity rates are used.

D) Change in Fleet Size

Fleet size is also one of the significant factors that influences which technology is more economically feasible for Humboldt County. Studies report a correlation between fleet size and total cost for both HFCBs and BEBs. A study from Sunline Transit indicates that the total cost of conversion to HFCBs decreases with economies of scale, whereas total cost of conversion to BEBs increases as the fleet size goes up. See Figure 32. This indicates that if HTA decides to increase its fleet size, HFCBs may become economy preferable. If HTA anticipates increasing its bus fleet substantially beyond the current size of 21 buses, additional analysis would be warranted regarding selection of BEBs or HFCBs. However, a small increase in the number of buses is unlikely to result in a different conclusion. Determining how much larger the fleet would need to be to change the result with respect to the cost effectiveness of the two technology options is beyond the scope of this analysis.

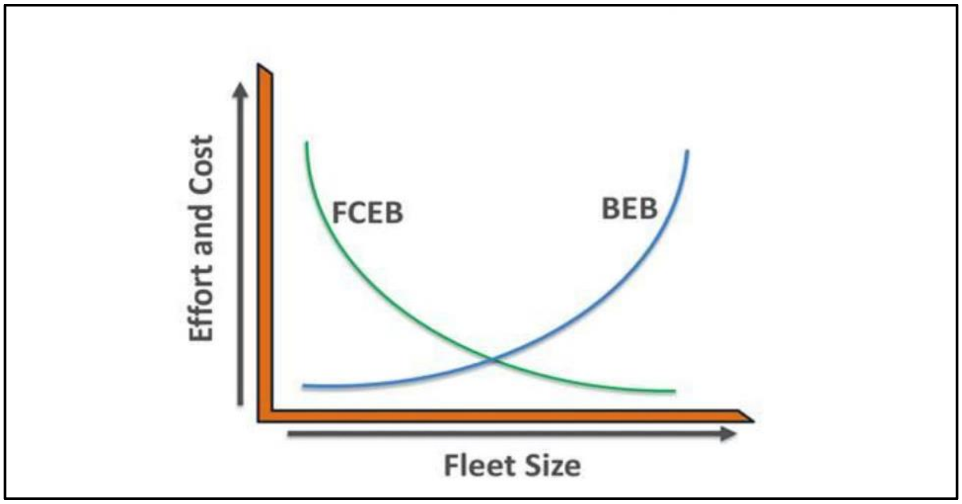

Figure 32. Sunline Transit study on correlation between infrastructure and scalability for HFCBs and BEBs. Source: (California Transit Association, 2019)

E) GHG reduction

The expected GHG emission reductions can also change based on variations in the model assumptions and inputs. For example, if the longest bus routes are not converted to ZEVs earlier in the implementation phases, the amount of GHG emissions reduction decline in Phase I, and it would increase in Phase II. In addition, if energy for bus charging and hydrogen production is obtained from non-renewable sources of energy, this will shift the emissions from transport sector to the power sector, thereby reducing the net gain in GHG emissions reductions.

Human error can also introduce some level of uncertainty. The results of this analysis are based on data gathering and spreadsheet model management, and there is always some chance of human error in this process.

CHAPTER 5: CONCLUSION AND RECOMMENDATION

This study concludes that HTA should consider converting their conventional fleet to a battery-electric fleet, as this route is a more economically feasible alternative in the current situation. As mentioned in Section 2.3, both technologies are feasible from a technological perspective, and both offer significant potential for reducing GHG emissions. However, converting to a battery-electric bus fleet is more economically feasible for HTA, considering its current routes and fleet size.

As shown in Table 21 in Chapter 4 (Results and Discussion), the total cost of converting conventional buses to HFCBs is estimated to be $61.8 million (Phase I: $45 million; Phase II: $16.8 million). In comparison, the cost of conversion to BEBs is estimated to be approximately $27.5 million (Phase I: $18.5 million; Phase II: $9 million). In other words, converting conventional buses to HFCBs is 225% more expensive than converting them to BEBs. This cost includes the operating costs through 2040 from the year of implementation for both bus types. This conclusion is made by comparing the total cost that HTA will incur in converting buses to HFCBs or BEBs in Phase I and Phase II. The analysis is aligned with CARB’s ICT plan, and the economics for both cases are supported using LCFS credits.

This study calculates the total cost for both on-site and off-site hydrogen production techniques; however, for comparison purposes, only on-site production of hydrogen is considered. The cost of converting the full fleet to HFCBs with the help of

off-site and on-site production would come around $60 and $62 million, respectively. Both production techniques are more expensive than BEB-based conversion.

The overall cost per mile of BEBs and HFCBs are $0.14/mile and $0.32/mile, respectively, for operation from 2021-2040. In addition, adopting ZEBs can mitigate approximately 1.8 $MTCO_2$ of GHG emissions until 2040.

Based on the results of this study, it can be concluded that the BEB route is economically more feasible for HTA. However, additional analysis is recommended to determine the cost of converting the current HTA fleet to BEBs if HTA decides to source its electricity from 100% renewable sources. The LCFS calculator referred in this study does not provide provision to select 100% renewable electricity in its current version, and additional analysis is required to identify accurate revenue generated from the LCFS credit for a 100% renewable energy scenario. This study suggests that BEBs are more cost effective for HTA considering the current fleet size, but if HTA decides to adopt HFCBs, an additional analysis can be performed to identify the fleet size at which HFCBs can become more cost effective.

Additionally, it is recommended that HTA should considered utilizing 100% renewable energy sources as it could completely remove emissions associated with HTA’s bus operation. Finally, with this conversion, HTA can fulfill the required mandates by CARB ICT by the end of 2030 with the help of LCFS credits.

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APPENDIX-A HTA BUSES AND ELECTRIC RATE STRUCTURE

The miles considered in this study are recorded from HTA. As of December 2020, 21 buses are running in Humboldt County under various transit systems. The miles considered in this study are recorded from HTA. Most of these buses are operated by HTA, but one transit system (BLRTS) operates independently. The active routes, schedule, and miles covered by these buses in a week are listed in the Table A-1 and Figure A-1, below. The annual miles covered are used to calculated the life cycle cost. The BEV-2-P electric rate structure is shown in Table A-2. All the major terms and condition associated with the BEV-2-P rate structure are shown in Figures A-2, A-3, and A-4, below.

Table A-1. Miles covered and daily routes of HTA.

Bus number	Routes under HTA	Annual Distance	Miles in week
25500	AMRTS	34,299	555
2552150	AMRTS	42,411	711
428	BLRTS	47,586	770
66	ETS	37,385	620
67	ETS	37,015	611
68	ETS	33,362	553
69	ETS	32,136	520
100 & 101	RTS	99,614	1665
102 & 116	RTS	87,566	1471
104 & 105	RTS	110,734	1811
106 & 107	RTS	110,107	1798
108	RTS	55,929	905
110 & 123	RTS	68,598	1110
112 & 115	RTS	100,116	1620
118 & 119	RTS	64,272	1040
120	RTS	35,844	580
410	SHT	107,939	1794
512	SHT	55,594	924
714	WC	98,657	1640

Source: (Humboldt Transit Authority, 2021)

RTS MONDAY - FRIDAY

RUN	Revenue TIME	TOTAL MILES	NON-REV	Non Rev Miles
100 & 101	11:25	266	37	229
102 & 116	10:25	226	41	185
104 & 105	14:14	338	43	295
106 & 107	14:00	339	40	299
108	7:12	181	43	138
110 & 123	8:55	222	44	178
112 & 115	12:39	324	56	268
118 & 119	9:43	208	30	178
120	4:32	116	33	83
	93:05	***2,220***	***367***	***1,853***

RTS SATURDAY

RUN	Revenue TIME	TOTAL MILES	NON-REV	Non Rev Miles
601 & 602	12:50	335	46	289
604 & 604	12:57	341	56	285
605	6:36	121	20	101
606	4:16	103	24	79
	36:39	***900***	***146***	***754***

ETS MONDAY - FRIDAY

RUN	Revenue TIME	TOTAL MILES	NON-REV	Non-Rev Miles
201 & 251	9:00	105	2	47
203 & 253	9:00	107	2	105
204 & 254	9:00	94	2	92
205 & 255	9:00	104	2	102
	36:00	***410***	***8***	***346***

ETS SATURDAY

RUN	Revenue TIME	TOTAL MILES	NON-REV	Non-Rev Miles
200	7:00	95	1	94
206	7:00	76	1	75
207	7:00	83	1	82
	21:00	***254***	***3***	***251***

WCREEK MONDAY - FRIDAY

RUN	Revenue TIME	TOTAL MILES	NON-REV	Non-Rev Miles
701 & 702	5:28	273	71	202
	5:28	***273***	***71***	***202***

W/CREEK SATURDAY

RUN	TIME	TOTAL MILES	NON-REV	Non-Rev Miles
750 & 751	6:26	275	16	259
	6:26	***275***	***16***	***259***

SOHUM MONDAY - FRIDAY

RUN	Revenue TIME	TOTAL MILES	NON-REV	Non-Rev Miles
501	6:24	299	72	227
503	4:00	154	2	152
	10:24	***453***	***74***	***379***

SOHUM LOCAL SAT & SUN

RUN	Revenue TIME	TOTAL MILES	NON-REV	Non-Rev Miles
551	6:16	299	72	227
553	4:00	154	2	152
	10:16	***453***	***74***	***379***

Figure A-1. HTA details route information. Source: (Humboldt Transit Authority, 2021)

Table A-2. BEV-2-P Electric Rate Structure, Energy cost, Demand charges, and ToU period. Source: (PG&E, 2020)

Times	Hours	BEV	Energy Charges	Demand Charges
9:00:00 AM	0	Super Off Peak	0.10041 ($/kWh)	1.72 ($/kW)
10:00:00 AM	1	Super Off Peak	0.10041 ($/kWh)	1.72 ($/kW)
11:00:00 AM	2	Super Off Peak	0.10041 ($/kWh)	1.72 ($/kW)
12:00:00 PM	3	Super Off Peak	0.10041 ($/kWh)	1.72 ($/kW)
1:00:00 PM	4	Super Off Peak	0.10041 ($/kWh)	1.72 ($/kW)
2:00:00 PM	5	Off Peak	0.12307 ($/kWh)	1.72 ($/kW)
3:00:00 PM	6	Off Peak	0.12307 ($/kWh)	1.72 ($/kW)
4:00:00 PM	7	Peak	0.33195 ($/kWh)	1.72 ($/kW)
5:00:00 PM	8	Peak	0.33195 ($/kWh)	1.72 ($/kW)
6:00:00 PM	9	Peak	0.33195 ($/kWh)	1.72 ($/kW)
7:00:00 PM	10	Peak	0.33195 ($/kWh)	1.72 ($/kW)
8:00:00 PM	11	Peak	0.33195 ($/kWh)	1.72 ($/kW)
9:00:00 PM	12	Off Peak	0.12307 ($/kWh)	1.72 ($/kW)
10:00:00 PM	13	Off Peak	0.12307 ($/kWh)	1.72 ($/kW)
11:00:00 PM	14	Off Peak	0.12307 ($/kWh)	1.72 ($/kW)
12:00:00 AM	15	Off Peak	0.12307 ($/kWh)	1.72 ($/kW)
12:00:00 AM	16	Off Peak	0.12307 ($/kWh)	1.72 ($/kW)
1:00:00 AM	17	Off Peak	0.12307 ($/kWh)	1.72 ($/kW)
2:00:00 AM	18	Off Peak	0.12307 ($/kWh)	1.72 ($/kW)
3:00:00 AM	19	Off Peak	0.12307 ($/kWh)	1.72 ($/kW)
4:00:00 AM	20	Off Peak	0.12307 ($/kWh)	1.72 ($/kW)
5:00:00 AM	21	Off Peak	0.12307 ($/kWh)	1.72 ($/kW)
6:00:00 AM	22	Off Peak	0.12307 ($/kWh)	1.72 ($/kW)
7:00:00 AM	23	Off Peak	0.12307 ($/kWh)	1.72 ($/kW)
8:00:00 AM	24	Off Peak	$0.12307	$1.72

ELECTRIC SCHEDULE BEV Sheet 1
BUSINESS ELECTRIC VEHICLES

APPLICABILITY: Except as noted below, Electric Schedule Business Electric Vehicle (hereafter BEV) is an optional schedule that applies to commercial EV charging purposes where the non-EV commercial usage and the EV charging usage is metered separately. The designation "EV" includes battery electric vehicle or plug-in hybrid electric vehicle as well as low speed electric vehicles and electrically powered motorcycles or bicycles. This schedule is not available to residential or agricultural service for customers for which a residential or agricultural schedule is applicable with the exception of Multi-Family Accommodations as defined in Electric Rule 1[1], which qualify as commercial premises for purposes of BEV rate applicability.

Service under this schedule is provided at the sole option of PG&E and based upon the availability of metering equipment and customer infrastructure improvements necessary for charging (see "Special Conditions" section, item 10). Beginning October 1, 2020 Net Energy Metering (NEM) customers will be eligible for the BEV rate as long as customers meet the BEV eligibility requirements of being commercial customers with separate meters for EV charging. For more information on which NEM Schedules are eligible, see the "Special Conditions" section, item 12.

The BEV rate has two distinct rate options: BEV-1 and BEV-2. The BEV-1 rate option is applicable to customers with kW usage at or below 100 kW. The BEV-2 is applicable to customers with kW usage at or above 100 kW. Note that customers may be on the BEV-1 or BEV-2 at usage of 100 kW based on the customer's preference. BEV-1 is for Secondary Voltage service, and BEV-2 was designed with a Primary and Secondary Voltage option. Transmission Voltage customers are eligible for enrollment on the BEV-2 Primary rate.

The BEV rate replaces the customer charge and traditional maximum kW demand charge with a subscription-based model for monthly kW allocation. Customers taking service on this rate schedule can use any amount of kW and kWh but will incur an "overage" fee if the kW usage exceeds a customer's self-designated subscription level. The specific mechanics of the subscription model and overage fee are described in more detail in the "Special Conditions" section item 6 and item 8..

TERRITORY: This rate schedule applies everywhere PG&E provides electric service.

RATES: Total bundled service charges are calculated using the total rates below. Direct Access (DA) and Community Choice Aggregation (CCA) charges shall be calculated in accordance with the paragraph in this rate schedule titled Billing.

ELECTRIC SCHEDULE BEV Sheet 2
BUSINESS ELECTRIC VEHICLES

RATES:(Cont'd.)

TOTAL RATE

Total Energy Rates ($ per kWh)	**BEV-1**		**BEV-2-S (Secondary)**		**BEV-2-P (Primary / Transmission)**	
Peak	$0.32455	(R)	$0.33974	(R)	$0.33195	(R)
Off-Peak	$0.13254	(R)	$0.12651	(R)	$0.12307	(R)
Super Off-Peak	$0.10588	(R)	$0.10324	(R)	$0.10041	(R)
Block Size (kW)	10		50		50	
Subscription Charge (per block)	$12.41		$95.56		$85.98	
Subscription Charge ($ per kW)*	$1.24		$1.91		$1.72	
Overage Fee ($ per kW)	$2.48		$3.82		$3.44	

Total bundled service charges shown on a customer's bills are unbundled according to the component rates shown below.

UNBUNDLING OF TOTAL RATES

Energy Rates by Component ($ per kWh)	**BEV-1**		**BEV-2-S (Secondary)**		**BEV-2-P (Primary / Transmission)**	
Generation:						
Peak	$0.25786	(I)	$0.27713	(I)	$0.26675	(I)
Off-Peak	$0.07530	(I)	$0.07377	(I)	$0.07077	(I)
Super Off-Peak	$0.04991	(I)	$0.04837	(I)	$0.04657	(I)
Distribution*:**						
Peak	$0.01487		$0.01261		$0.01573	
Off-Peak	$0.00542		$0.00274		$0.00283	
Super Off-Peak	$0.00415		$0.00487		$0.00437	
Transmission** (all usage)	$0.02784		$0.02784		$0.02784	
Transmission Rate Adjustments** (all usage)	($0.00248)	(R)	($0.00248)	(R)	($0.00248)	(R)
Reliability Services* (all usage)	$0.00013		$0.00013		$0.00013	
Public Purpose Programs (all usage)	$0.01607	(I)	$0.01453	(I)	$0.01400	(I)
Nuclear Decommissioning (all usage)	$0.00093		$0.00093		$0.00093	
Competition Transition Charges (all usage)	$0.00003		$0.00003		$0.00003	
Energy Cost Recovery Amount (all usage)	$0.00032		$0.00032		$0.00032	
Wildfire Fund Charge (all usage)	$0.00580		$0.00580		$0.00580	
New System Generation Charge (all usage)***	$0.00318		$0.00290		$0.00290	

Figure A-2. Detailed BEV-2-P Electric Rate Structure (Part-2) Source: (PG&E, 2020)

ELECTRIC SCHEDULE BEV Sheet 3
BUSINESS ELECTRIC VEHICLES

1. TIME PERIODS: Times of the year and times of the day are defined as follows:

TOU Period	Times	Days
Peak	4:00 p.m. to 9:00 p.m.	Every day including weekends and holidays, all year
Off-Peak	9:00 p.m. to 9:00 a.m. and 2:00 p.m. to 4:00 p.m.	Every day including weekends and holidays, all year.
Super Off-Peak	9:00 a.m. to 2:00 p.m.	Every day including weekends and holidays, all year/

2. SEASONAL CHANGES: Schedule BEV has no seasonal variation.

3. BILLING: A customer's bill is calculated based on the option applicable to the customer as follows.

Bundled Service Customers receive supply and delivery services solely from PG&E. The customer's bill is based on the Total Rates set forth above.

Transitional Bundled Service Customers take transitional bundled service as prescribed in Rules 22.1 and 23.1, or take bundled service prior to the end of the six (6) month advance notice period required to elect bundled portfolio service as prescribed in Rules 22.1 and 23.1. These customers shall pay charges for distribution, transmission, transmission rate adjustments, reliability services, nuclear decommissioning, public purpose programs, the new system generation charge, the applicable Cost Responsibility Surcharge (CRS) pursuant to Schedule DA CRS or Schedule CCA CRS, and short-term commodity prices as set forth in Schedule TBCC.

ELECTRIC SCHEDULE BEV Sheet 5
BUSINESS ELECTRIC VEHICLES

5. WILDFIRE FUND CHARGE: The Wildfire Fund Charge was imposed by California Public Utilities Commission Decisions 19-10-056, 20-07-014, 20-09-005, and 20-09-023 and is property of Department of Water Resources (DWR) for all purposes under California law. The Charge became effective October 1, 2020, and applies to all retail sales, excluding CARE and Medical Baseline sales. The Wildfire Fund Charge (where applicable) is included in customers' total billed amounts. The Wildfire Fund Charge replaces the DWR Bond Charge imposed by California Public Utilities Commission Decisions 02-10-063 and 02-12-082.

6. SUBSCRIPTION: The kW subscription component of the BEV replaces a kW demand charge. The BEV rate does not include demand or customer charges and instead uses a monthly subscription for customer's kW demand. The subscription comes in blocks of 10 kW for the BEV-1 rate and in blocks of 50 kW or the BEV-2 rate. A customer determines their estimated maximum kW demand and then selects a subscription level to suit their need.

7. GRACE PERIOD: A grace period is a period of three (3) billing cycles in which a BEV customer is not subject to overage fees (see "Special Conditions" section, item 8) associated with exceeding the customer's monthly pre-defined kW subscription. A grace period is triggered under either or both of the following two conditions: (1) a BEV customer first enrolls in a BEV rate, and/or (2) the BEV customer adds additional charging infrastructure that increases the customer's load and the customer informs PG&E of these changes. These events are described in more detail below.

   a. **Customer Enrollment**: A grace period is triggered when a customer enrolls in a BEV rate.

      i. A PG&E customer is eligible for a grace period when they enroll into a BEV rate. The grace period only applies to separate meters dedicated to electrical vehicle infrastructure and service equipment (EVSE).

      ii. This means that customers who change from BEV-1 to BEV-2 (or vice versa) are eligible for a grace period upon enrollment in the new rate. For example, a customer that has been enrolled in the BEV-1 (<=100 kW) version of the rate and changes to BEV-2 (=>100 kW) - or vice versa - is eligible for a grace period.

   b. **Addition of Electrical Vehicle Service Equipment (EVSE):** After a customer is enrolled in BEV rate, a second qualifying event for grace periods is if an existing customer enrolled on the BEV rate (BEV-1 or BEV-2) adds load supporting EVSE. In this case a customer must notify PG&E that they have increased the amount of EVSE infrastructure behind the meter, which will then trigger a grace period.

      i. The main contributor to incremental increase in a customer's EV load is due to the addition of electrical vehicle chargers.

Figure A-3. Detailed BEV-2-P Electric Rate Structure (Part-2) Source: (PG&E, 2020)

ELECTRIC SCHEDULE BEV
BUSINESS ELECTRIC VEHICLES

Sheet 6

7. GRACE PERIOD (Cont'd): (N)

Note that an automatic adjustment of a customer's subscription level may occur at the end of a grace period for the following billing cycle. This would only occur if the customer had exceeded their subscription level on the third (and last) billing cycle of the grace period, in which case their subscription level for subsequent billing cycles would be automatically set to the overage amount from the third billing cycle of the grace period rounded up to the nearest kW block of subscription. The customer would be eligible to modify the subscription level again after three consecutive billing cycles following the end of the grace period.

Note that overage fees and grace periods will not be introduced to the rate until October 1, 2020. Customers who enroll on the BEV rate before October 1, 2020, will have a grace period introduced to their rates on or after October 1, 2020 depending on the start date of their billing period. These customers will not receive overage fees until three billing cycles have been completed after October 1, 2020.

8. OVERAGE/OVERAGE FEE: An overage is incurred when a customer surpasses the kW allotment of their pre-determined subscription level outside of a grace period. Note that the customer's subscription level is determined by the customer and can be increased or decreased as the customer sees fit. The only exception to this is the case of a "lock out" when PG&E auto adjusts the customer on the fourth month of billing following a customer overage in the third billing period within the grace period.

Overage will be based on 15-minute intervals readings of the average kW usage. For example, a customer with a 50 kW subscription whose average demand exceeds 50 kW in a given 15-minute interval of the billing cycle is considered to have incurred an overage.

If a customer exceeds their subscription after the grace period, PG&E will bill them for their subscription amount and any overages in increments of 1 kW. Although a customer may exceed their pre-determined kW subscription level multiple times per billing period, a customer can only incur one (1) financial penalty associated with overage for each billing period. Overage fees are based on the maximum kW demand in a given billing period. For example, if a customer with a 60 kW subscription uses 61 kW of demand in a 15-minute window followed by a 65 kW of demand in another 15-minute window, the customer will only incur an overage fee for the 5 kW overage for that billing period. Note: In some cases, such as rate version changes or seasonal cross overs, more than one billing period may be included in a general PG&E billing cycle.

Figure A-4. Detailed BEV-2-P Electric Rate Structure (Part-3) Source: (PG&E, 2020)

As mentioned above, the BEV-2-P rate structure is used to determine the electricity costs while charging BEBs. The demand charges are determined based on a pre-defined block sized by the customer. The pre-define block sizes are on the order of 50kW, 100kW, 150 kW, and so on, up to 1MW. As per the current condition (the recommended block size for HTA is calculated to be 750 kW). The above-mentioned demand charge is the rate for each 50kW size block. Further, it comes with three time of use (ToU) tariffs, including super off-peak, off-peak, and peak, for different time intervals, as shown in Table A-2, above. The overall cost of electricity conversion is shown in Table A-4, below.

For HFCBs, the detailed cost of full fleet conversion to hydrogen for each transit system under HTA is shown in Table A-4. The daily hydrogen requirement per route of each bus is also shown in TableA-4. The overall discounted and non-discounted cost comparison of all the considered transit systems is shown in Figures A-5 and A-6 below. As per the outcomes of the model, the daily hydrogen requirement is considered to be 580 kg. However, the cost is calculated based on 600 kg per day. It is worth noting that the size of the hydrogen infrastructure would need to be reconsidered in the future in the case of an increase in the bus fleet and/or route lengths. For the current size, it was determined that only one hydrogen dispenser is needed.

Table A-3. Cost Components of HFCBs ($/mile for full fleet conversion)

Bus number	Transit System	Year	Life	Refueling cost	O&M Cost of Station	Midlife Maintenance Cost ($)	Fuel cost ($/mile)	Refueling - O&M ($/mile)	Midlife ($/mile)	LCFS ($/mile)
25500	AMRTS	2029	15	$566,003	$149,431	$200,000	0.114	0.030	0.075	-0.049
2552150	AMRTS	2027	15	$725,096	$191,434	$400,000	0.106	0.028	0.045	-0.045
428	BLRTS	2026	14	$879,497	$232,198	$400,000	0.117	0.031	0.070	-0.050
66	ETS	2027	14	$590,139	$155,804	$200,000	0.105	0.028	0.051	-0.045
67	ETS	2028	13	$540,031	$142,575	$200,000	0.110	0.029	0.059	-0.047
68	ETS	2029	13	$488,768	$129,041	$200,000	0.117	0.031	0.077	-0.050
69	ETS	2030	12	$424,247	$112,006	$200,000	0.122	0.032	0.094	-0.052
100 & 101	RTS	2023	20	$2,264,012	$597,726	$1,200,000	0.089	0.023	0.059	-0.038
102 & 116	RTS	2024	20	$2,000,217	$528,081	$1,000,000	0.093	0.024	0.060	-0.040
104 & 105	RTS	2021	20	$2,339,411	$617,632	$1,400,000	0.081	0.021	0.060	-0.035
106 & 107	RTS	2021	20	$2,322,617	$613,198	$1,200,000	0.081	0.021	0.061	-0.035
108	RTS	2026	20	$738,353	$194,934	$400,000	0.097	0.026	0.060	-0.042
110 & 123	RTS	2024	20	$1,358,407	$358,635	$800,000	0.089	0.024	0.057	-0.038
112 & 115	RTS	2022	20	$1,982,540	$523,414	$1,200,000	0.083	0.022	0.063	-0.036
118 & 119	RTS	2025	20	$1,202,034	$317,351	$400,000	0.093	0.025	0.046	-0.040
120	RTS	2028	20	$433,766	$114,519	$200,000	0.108	0.028	0.061	-0.046
410	SHT	2022	17	$2,073,508	$547,431	$1,200,000	0.085	0.022	0.059	-0.036
512	SHT	2025	16	$1,005,140	$265,369	$400,000	0.096	0.025	0.053	-0.041
714	WC	2023	16	$1,784,014	$471,001	$1,000,000	0.088	0.023	0.059	-0.038

Table A-4. Cost Components of BEBs $/Mile Break Up of Each Transit System Under HTA.

Bus number	Transit System	Year	Useful Life	Electricity Cost ($)	Midlife Maintenance Cost ($)	LCFS ($)	Electric Cost ($/Mile)	Midlife. ($/Mile)	LCFS ($/Mile)
25500	AMRTS	2029	15	145,506	73,548	177,993	0.19	0.11	0.26
2552150	AMRTS	2027	15	178,827	70,597	212,034	0.20	0.08	0.26
428	BLRTS	2026	14	225,265	73,548	276,578	0.24	0.07	0.32
66	ETS	2027	14	145,757	73,548	185,583	0.19	0.09	0.27
67	ETS	2028	13	154,983	79,904	197,226	0.22	0.11	0.31
68	ETS	2029	13	126,105	73,548	153,705	0.20	0.11	0.26
69	ETS	2030	12	116,405	73,548	133,414	0.20	0.13	0.25
100 & 101	RTS	2023	20	648,754	306,450	698,807	0.24	0.11	0.29
102 & 116	RTS	2024	20	416,149	306,450	617,384	0.17	0.13	0.28
104 & 105	RTS	2021	19	576,371	306,450	722,079	0.21	0.10	0.29
106 & 107	RTS	2021	19	573,616	306,450	716,896	0.21	0.10	0.29
108	RTS	2026	12	169,719	88,076	221,020	0.18	0.07	0.26
110 & 123	RTS	2024	18	334,549	306,450	419,284	0.20	0.17	0.27
112 & 115	RTS	2022	18	442,391	306,450	611,928	0.19	0.11	0.28
118 & 119	RTS	2025	17	353,727	211,564	374,533	0.23	0.07	0.27
120	RTS	2028	11	106,704	73,548	136,408	0.19	0.10	0.26
410	SHT	2022	17	454,170	306,450	640,006	0.19	0.10	0.29
512	SHT	2025	16	239,798	105,782	313,184	0.19	0.08	0.28
714	WC	2023	16	425,894	153,225	550,651	0.20	0.11	0.00

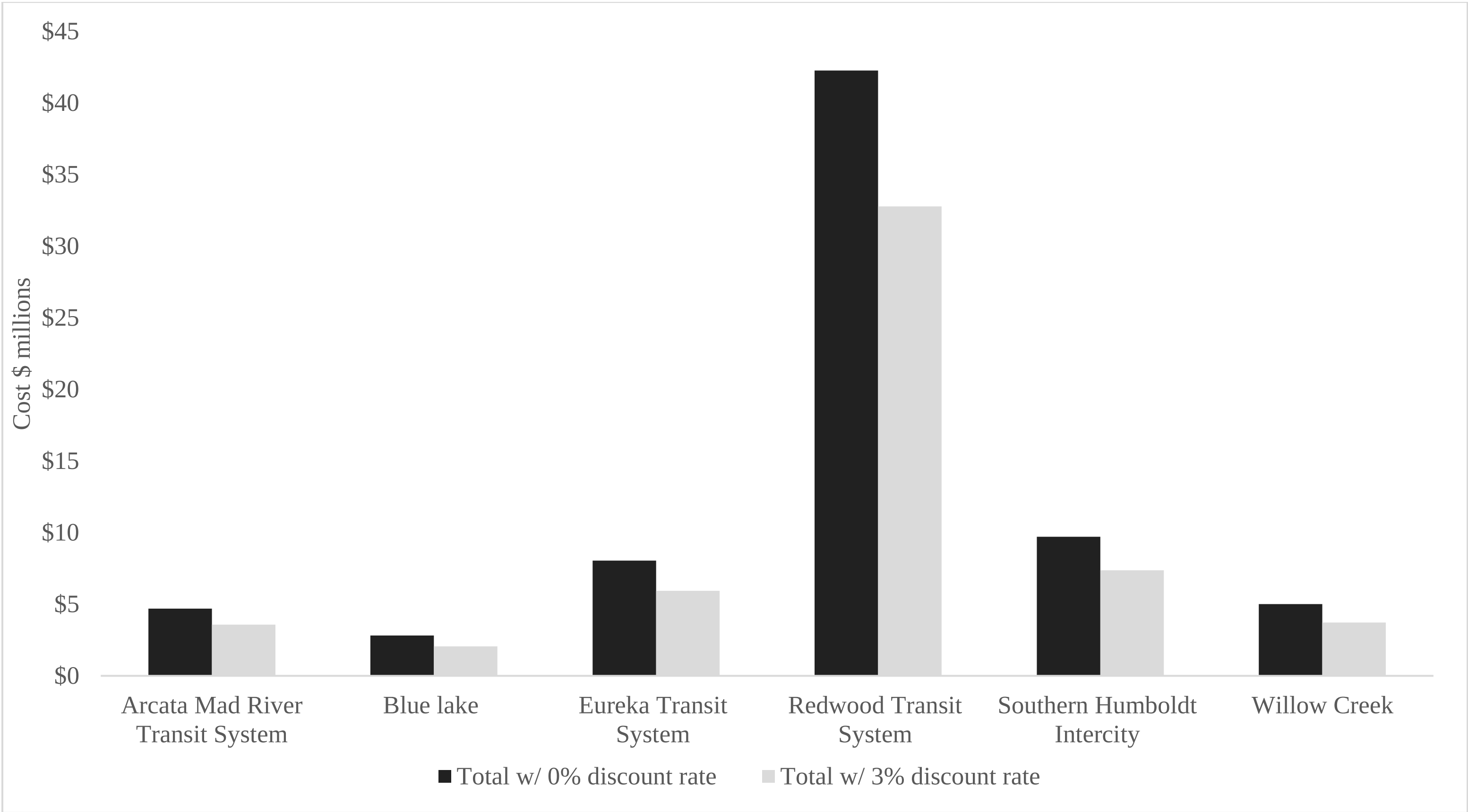

Figure A-5. Discounted cost comparison of all the considered transit systems in this study for HFCBs

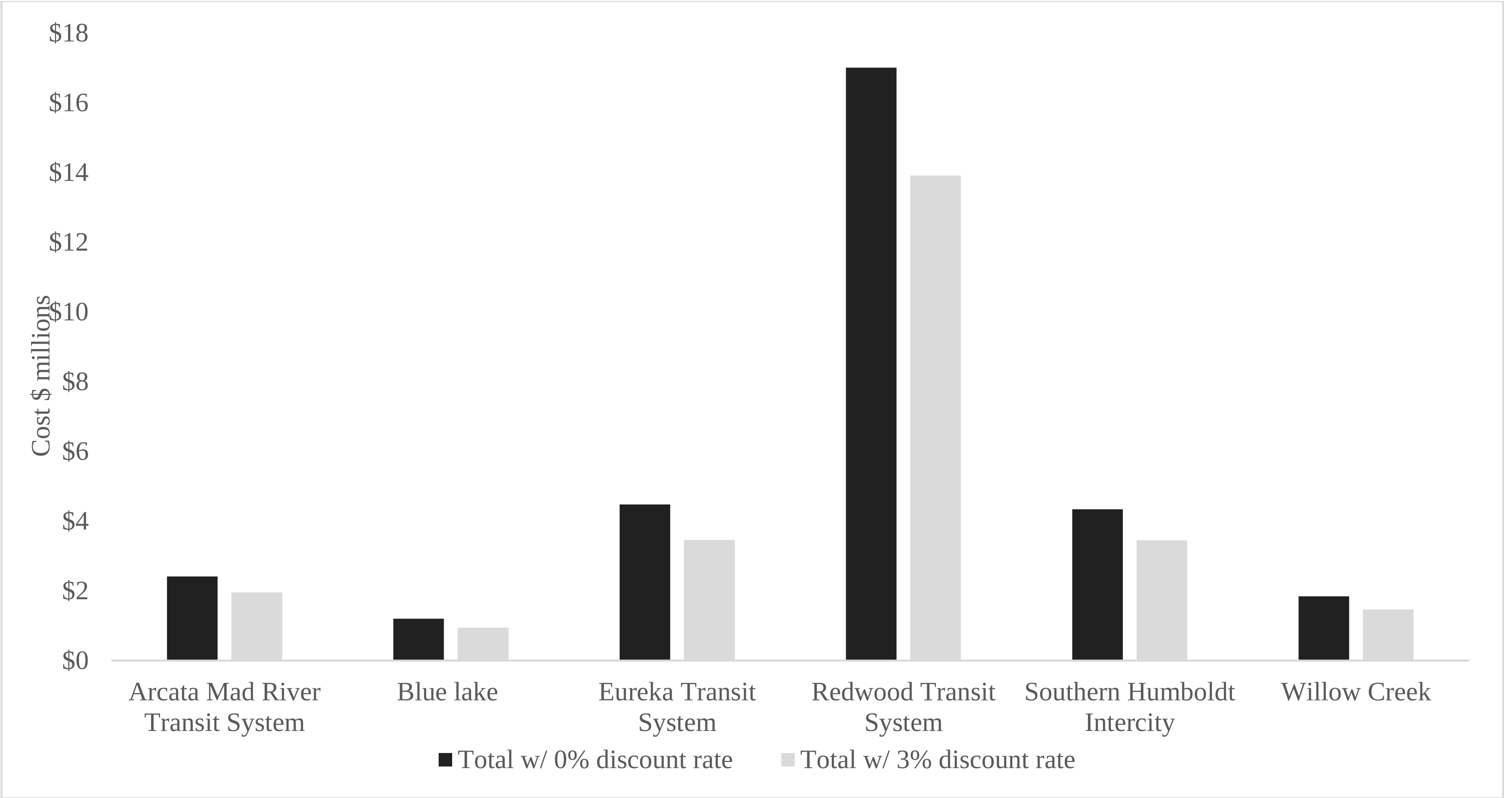

Figure A-6. Discounted cost comparison of all the considered transit systems in this study for BEBs

APPENDIX-B PLUG-IN CHARGING REGIME

As mentioned in Section 3.3.2.A.1, this study developed an optimization tool to design a plug-in charging regime to reduce the overall utility cost associated with charging. The result of the optimization tool is shown in Tables B-1 and B-2. The optimization is based on the energy required by BEBs to complete their daily routes and available time slots to complete plug-in charging. The available time slots for HTA's buses are shown in Table B-3, with number of working days in Table B-4. All inputs and useful values for the HDRSAM model are listed in Table B-5. The values for energy consumption for hydrogen production considered are the HDRSAM model are also listed in Table B-5.

Table B-1. Plug-In Charging Schedule for BEBs of HTA (Part-1)

Route	**å[12]**	**Ç[13]**	**∂[14]**	**66**	**67**	**68**	**69**	**100 & 101**	**102 & 116**	**104 & 105**	**106 & 107**	**108**	**110 & 123**	**112 & 115**	**118 & 119**	**120**	**410**	**512**	**514**	**714**	**Hourly demand (kW)**
Selected bus	A[15]	B[16]	A	A	C[17]	A	A	D[18]	D	D	D	B	D	D	D	A	D	D	A	D	
Daily Depot charging need (kWh)	193	230	259	216	247	193	181	540	503	540	540	300	380	540	359	202	540	319	0	540	
On board Capacity (kWh)	259	249	259	259	282	259	259	540	540	540	540	310	540	540	373	259	540	373	259	540	
Daily require charge (kWh)	193	230	322	216	247	193	181	569	503	619	615	300	380	554	359	202	613	319	0	561	
9 to 10 pm	1		1					1		1		1	1			1		1		1	750
10 to 11 pm	1		1					1		1		1	1			1		1		1	750
11 to 12 pm	1		1					1		1		1	1			1		1		1	750

(Note: "1" stand for charging "0" stand for not charging during allotted hr.)

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12 å =Bus ID 25500
13 Ç =Bus ID 2552150
14 ∂=428
15 A = BYDK9
16 B= New Flyer Xcelsior
17 C=BYD K9 S
18 D= Proterra 40"

Table B-2. Plug-In Charging Schedule for BEBs of HTA (Part-2)

Route	**å**	**Ç**	**428**	**66**	**67**	**68**	**69**	**100 & 101**	**102 & 116**	**104 & 105**	**106 & 107**	**108**	**110 & 123**	**112 & 115**	**118 & 119**	**120**	**410**	**512**	**514**	**714**	**Hourly demand (kW)**
Selected bus	A	B	A	A	C	A	A	D	D	D	D	B	D"	D"	D	A	D	D	A	D	
12 to 1 am	1		1					1		1		1	1			1		1		1	750
1 to 2 am			1						1		1	1	1					1			500
2 to 3 am		1			1	1			1		1	1	1					1			600
3 to 4 am		1		1	1	1			1		1		1					1			600
4 to 5 am		1		1	1	1	1				1		1	1							600
5 to 6 am		1		1	1	1	1							1	1		1				700
6 to 7 am		1		1	1		1							1	1		1				650
7 to 8 am				1			1								1		1				400
Total hours (hr.)	4	5	5	4.32	5	4	4	4	3	4	4	6	8	3	3	4	3	6.38		3.6	
Energy Charge ($)	24.6	30.7	30.7	26.5	30.7	24.6	24.6	73.8	55.3	73.8	73.8	36.9	49.2	55.3	55.3	24.6	55.3	39.2	0	66.4	
Charger Type (kW)	50	50	50	50	50	50	50	150	150	150	150	50	50	150	150	50	150	50	0	150	
Total energy	200	250	250	216	250	200	200	600	450	600	600	300	400	450	450	200	450	319	0	540	

(Note “1” stand for charging “0” stand for not charging during allotted hr.)

Table B-3. Available Time-slots for BEBs charging.

Route	Available charging Weekday	Available charging Weekends	Weekdays start	Weekdays end	Weekend start	Weekend end
Arcata Mad River Transit System	6:00 PM	6:00 PM	7:00 AM	11:59 AM	-	-
Blue Lake Rancheria Transit System	6:30 PM	6:30 PM	7:00 AM	6:00 PM	-	-
Eureka Transit System	5:30 PM	5:30 PM	8:00 AM	5:00 PM	10:00 AM	5:00 PM
Redwood Transit System	9:00 PM	10:00 PM	6:30 AM	8:46 PM	8:30 AM	9:20 PM
Southern Humboldt Intercity	8:00 PM	7:30 PM	6:50 AM	7:16 PM	8:30 AM	7:02 PM
Willow Creek	6:00 PM	8:30 PM	7:00 AM	5:30 PM	8:25 AM	7:45 PM

(Note: These are the slots considered in the study for plug-in charging of BEBs at depot.)

Table B-4. HTA Operational Days

Name	Qty	Units
No. of normal working days trips (Consider weekend and 11 holidays)	309	Days
No of weekend trips with less capacity	52	Days

Table B-5. Key Inputs for HFCBs Calculation

H_2 Fuel Cost Onsite Distributed Electrolysis	Units	Dollars
Baseline installed cost	($)	$279,443
Fixed operating cost	($/year)	$159,711
Total system electrical usage/kg of H_2	(kWh/kg)	54.6
H_2 production	(kg/year)	329,466
Electrolyzer system input power (peak)	(kW)	2,388
Refueling station system peak input power	(kW)	1,706
Main compressors electricity consumption	(kWh/year)	2,642,222
Refrigeration electricity consumption	(kWh/year)	33,901
Energy (electricity) cost	($/kWh)	0.102
Demand charges	($/kW)	12.95
Demand charges	($/kg)	1.68
Hydrogen production cost contribution	($/kg)	$6.78
Production + delivery cost	($/kg)	$6.91
Refueling station system peak input power	(kW)	2,204
Refrigeration electricity consumption	(kWh/year)	65,814

Source: (Argonne National Lab, 2017)

A comparison of the different transit systems in Humboldt County based on the number of buses and distances travelled by these buses is shown in Figure B-1, below.

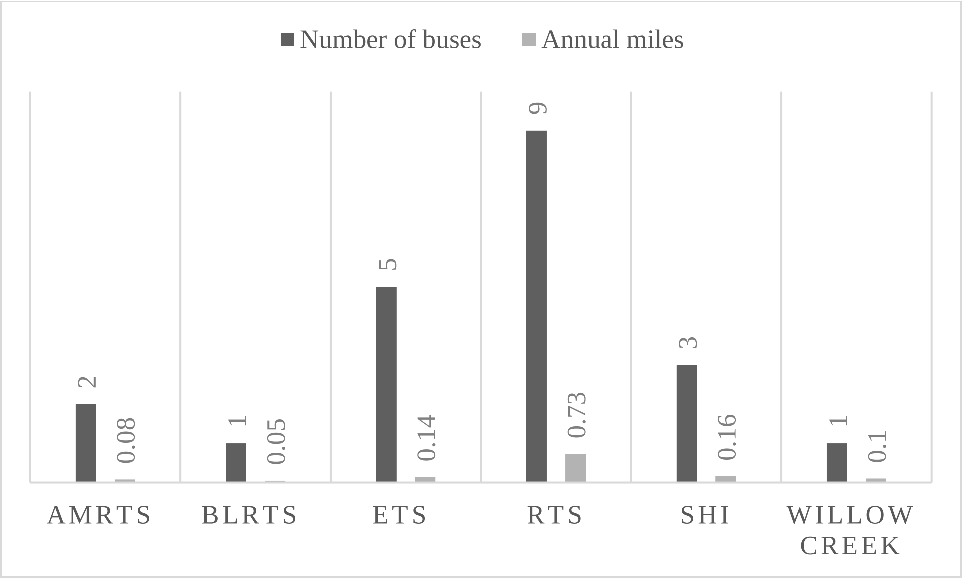

Figure B-1. Buses and distance traveled for transit systems in Humboldt county. Source HTA