Total Cost of Ownership Analysis of Fuel Cell Electric Bus with Different Hydrogen Supply Alternatives

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Abstract: In the transition to sustainable public transportation with zero-emission buses, hydrogen fuel cell electric buses have emerged as a promising alternative to traditional diesel buses. However, assessing their economic viability is crucial for widespread adoption. This study carries out a comprehensive examination, encompassing both sensitivity and probabilistic analyses, to assess the total cost of ownership (TCO) for the bus fleet and its corresponding infrastructure. It considers various hydrogen supply options, encompassing on-site electrolysis, on-site steam methane reforming, and off-site hydrogen procurement with both gaseous and liquid delivery methods. The analysis covers critical cost elements, encompassing bus acquisition costs, infrastructure capital expenses, and operational and maintenance costs for both buses and infrastructure. This paper conducted two distinct case studies: one involving a current small bus fleet of five buses and another focusing on a larger fleet set to launch in 2028. For the current small fleet, the off-site gray hydrogen purchase with a gaseous delivery option is the most cost-effective among hydrogen alternatives, but it still incurs a 26.97% higher TCO compared to diesel buses. However, in the case of the expanded 2028 fleet, the steam methane-reforming method without carbon capture emerges as the most likely option to attain the lowest TCO, with a high probability of 99.5%. Additionally, carbon emission costs were incorporated in response to the growing emphasis on environmental sustainability. The findings indicate that although diesel buses currently represent the most economical option in terms of TCO for the existing small fleet, steam methane reforming with carbon capture presents a 69.2% likelihood of being the most cost-effective solution, suggesting it is a strong candidate for cost efficiency for the expanded 2028 fleet. Notably, substantial investments are required to increase renewable energy integration in the power grid and to enhance electrolyzer efficiency. These improvements are essential to make the electrolyzer a more competitive alternative to steam methane reforming. Overall, the findings in this paper underscore the substantial impact of the hydrogen supply chain and carbon emission costs on the TCO of zero-emission buses.

Keywords: fuel cell electric buses; total cost of ownership (TCO); carbon emission; hydrogen supply alternatives; public transport

1. Introduction

Fuel cell electric buses (FCEBs) are a type of electric bus that uses a hydrogen fuel cell as its power source. This technology is increasingly seen as a promising sustainable alternative to conventional buses in the public transportation sector. Fuel cells generate electricity through a chemical reaction between hydrogen and oxygen, with the only by-products being water. This makes FCEBs a potential zero-emission mode of transportation, which could significantly reduce the carbon footprint. Although battery electric buses (BEBs) remain the most common form of zero-emission buses on the road in the U.S. as of 2022, with 211 active FCEBs nationwide, the FCEB fleet has grown by 64% compared
FCEBs offer several performance advantages over conventional buses. For instance, FCEBs have twice the fuel economy of conventional diesel and compressed natural gas (CNG) buses [2]. Additionally, they provide smoother acceleration and quieter operation. Furthermore, FCEBs offer longer ranges and quicker refueling times compared to battery electric buses, which benefits transit agencies in terms of bus scheduling. Recent research has transcended theoretical boundaries, showcasing an array of practical applications and experimental frameworks that signify considerable advancements in hydrogen’s application within the transportation sector. This encompasses an expansive range of hydrogen-powered conveyances, from FCEBs to personal vehicles and trains [3–6]. For instance, Ling-Chin et al. [3] spearhead the development of a comprehensive roadmap that charts the integration of hydrogen technology across the road, aviation, marine, and rail sectors, exemplified by the hydrogen refueling station in the UK. Caponi et al. [4] present an analysis of the operational performance of 5 hydrogen refueling stations and 34 FCEBs as part of the European 3Emotion project. These works underscore hydrogen’s potential in reducing carbon footprints and reliance on non-renewable energy sources.

However, studies also draw attention to the economic and infrastructural challenges inherent in wide-scale adoption [7–9]. For example, Genovese et al. [7] identify challenges in the hydrogen refueling process, particularly the inefficiency of various hydrogen refueling protocols due to their limited application scope and techniques. Advancements in fuel cell technology have painted a promising picture for the future, yet they come juxtaposed with concerns over hydrogen production and storage. The hydrogen refueling infrastructure is not as widespread as traditional fueling or electric charging stations, and the hydrogen supply chain can be complex, involving production, delivery, storage, and dispensing [10]. To operate a large FCEB fleet, refueling stations need to be built or upgraded to supply hydrogen. It is a costly endeavor that requires careful consideration of several factors such as location, economics, and safety. Additionally, for FCEBs’ application, many reports indicate that the initial purchase cost of FCEBs is currently higher than that of conventional buses and even BEBs [11–13].

Total cost of ownership (TCO) analysis can help address the economic concerns and provide a clearer picture of the viability of FCEBs, thereby aiding transit agencies in making informed decisions about transitioning to a FCEB fleet [14–23]. While BEBs have been widely analyzed, there are only a few studies in the literature focusing on the TCO analysis of FCEBs. The U.S. Department of Energy’s (DOE’s) National Renewable Energy Laboratory (NREL) published reports providing information about the operating performance of FCEBs [14,15]. However, these reports mainly focused on bus operation: a complete TCO analysis including both FCEBs and related hydrogen fueling infrastructures is rare. In the domain of TCO analysis for FCEBs, Kim et al. [16] conducted an analysis comparing the TCO of FCEBs, BEBs, and diesel buses based on European historical data and market price projections. Their results suggested that despite the higher upfront costs and fuel costs, FCEBs could become economically competitive in small to midsize cities as hydrogen costs decrease. However, their study only considered on-site hydrogen production through electrolysis and did not explore the implications of different hydrogen supply alternatives on the TCO. In fact, there are many hydrogen supply alternatives, and their TCO could exhibit significant differences.

In addition, a cost analysis of different supply-chain configurations for the delivery of hydrogen for light-duty and heavy-duty fuel cell electric vehicles (FCEVs) for the U.S. and China has been developed by Li et al. [17]. The analysis includes hydrogen production, transport, and station cost but it is for general FCEVs. Therefore, a comprehensive comparison of TCO for FCEBs and the associated infrastructures considering different hydrogen supply alternatives is lacking.

Furthermore, transit agencies are increasingly recognizing the significance of environmental factors, particularly carbon emissions, in their evaluations of buses with diverse fuel supply options. Khan and Onat [18] have devised a TCO framework that incorporates carbon emission costs for diesel, compressed natural gas (CNG), and electric buses. How-
ever, when it comes to FCEBs, despite some prior research on emission assessments and their economic implications, the inclusion of emission costs in the TCO analysis for various hydrogen supply alternatives remains relatively uncommon. Yan et al. [19] explored the economic value associated with reducing carbon emissions from hydrogen fuel cell commercial vehicles, encompassing various hydrogen production methods. On the other hand, Li and Taghizadeh-Hesary [20] concentrated on the carbon emission analysis of FCEVs using green hydrogen generated from renewable energy sources.

This study aims to bridge this existing gap by considering various hydrogen supply options and investigating how carbon emission costs impact TCO. Through a comparative analysis of the TCO for each alternative, this research will offer valuable insights into the most cost-effective hydrogen supply strategy in various scenarios. By integrating carbon emission costs into the TCO analysis, this study will recommend alternatives that are not only cost-effective but also environmentally friendly. Furthermore, this study will conduct TCO comparisons with the currently prevalent conventional diesel buses. This paper is structured into four sections. The first section outlines the overarching TCO analysis methodology, while the second section introduces the relevant cost input data and provides an explanation of cost components for different hydrogen supply alternatives. The third section presents detailed emission data for the bus fleet and infrastructure, and the final section summarizes all the TCO results and offers in-depth discussions.

2. Analysis Methodology

This study conducts a comprehensive TCO analysis to calculate the costs experienced during the entire bus life cycle. The TCO consists of bus purchase costs, infrastructure capital costs, operational and maintenance costs, and carbon emission costs. The TCO has been calculated based on data from available literature and online websites, and the flowchart of the TCO analysis framework is summarized in Figure 1. To begin, various hydrogen supply alternative scenarios were determined based on the specific case. This study then proceeds to assess cost components for both FCEBs and their associated infrastructures. The TCO results are derived by aggregating all these cost elements. As a point of reference, this study also conducts an analysis of the diesel bus scenario, serving as the baseline for comparative purposes. Additionally, sensitivity analysis is crucial for understanding how changes in important factors affect the TCO, while probabilistic analysis evaluates how the uncertainty of input parameters influences the results of the TCO.

![Figure 1. TCO analysis model framework of FCEB.](image-url)

The formula used to calculate the future value of TCO is shown in Equation (1). It takes into account the time value of money, which means that future costs are discounted to
their present value to account for inflation and other factors that affect the value of money over time.

$$\text{TCO} = \frac{\text{Initial capital costs}}{(1 + r)^n} + \frac{\text{Annual O and M costs}}{(1 + r)^t} + \sum \frac{\text{Carbon emission annual costs}}{(1 + r)^t}$$  (1)

where,

Annual O and M costs: operating and maintenance costs incurred over the life cycle of the system.

$r$: discount rate (3.9% in this study), which is the rate used to adjust future costs to their present value.

$t$: number of years from the present to each future year when the costs are incurred.

$n$: number of years over which the initial costs are depreciated or amortized.

Therefore, for the initial capital costs, if the initial capital cost is incurred at the beginning of the project, it is discounted to year 0 (the present). If we were discounting the initial capital costs to a future year, then $n$ would be equal to the number of years between the future year and the present year. On the other hand, the future operational and maintenance (O and M) costs and carbon emission costs are incurred each year after the initial capital cost, so they are discounted to different years into the future.

The options for supplying hydrogen fuel to FCEBs can be broadly categorized into two methods: on-site production and off-site purchase and delivery, each with unique process steps and cost implications.

- **On-site production with an electrolyzer:** In this scenario, the transit agency installs an on-site electrolyzer at the hydrogen refueling station to fulfill the daily hydrogen requirements. This process involves using electricity to split water into hydrogen and oxygen, and this reaction takes place within a unit known as an electrolyzer [24,25]. In this study, the electrolyzer is powered by electricity sourced from the grid. Among the various types of electrolyzers available, Alkaline electrolyzers, which employ a liquid alkaline sodium or potassium hydroxide solution as the electrolyte, have been commercially accessible for many years.

- **On-site production with steam methane reforming (SMR) (with or without carbon capture):** In this approach, alongside the hydrogen refueling station, the transit agency establishes a SMR plant to fulfill daily hydrogen demand using natural gas. This method involves the reaction of natural gas with high-temperature steam to produce hydrogen and carbon dioxide [26,27]. While SMR is typically more cost-effective than electrolysis, it results in the production of gray hydrogen with associated carbon emissions. However, if carbon capture processes are employed, it becomes possible to produce blue hydrogen, which significantly reduces emissions. The carbon capture process involves a sequence of steps, including the separation of CO₂ from energy-related industrial sources, its compression, and subsequent transport for long-term storage.

- **Off-site hydrogen purchases with gaseous hydrogen delivery:** Compressed hydrogen tube trailers are commonly employed in low-volume commercial applications or temporary demonstration projects [28]. In this approach, hydrogen is manufactured at an off-site facility and subsequently transported to the bus depot in gaseous form via tube trailers. These tube trailers provide a practical and mobile fueling solution but come with limitations such as limited storage capacity, necessitating frequent deliveries, and the delivery of hydrogen at lower pressure, requiring additional compression at the fueling station site. While this method eliminates the need for on-site production equipment, it does introduce costs and logistical challenges associated with hydrogen transportation. Regarding the hydrogen source, specifically, blue hydrogen is obtained from the off-site SMR plant with carbon capture, and gray hydrogen originates from the off-site SMR plant without carbon capture.

- **Off-site purchase with liquid hydrogen delivery:** This method also involves hydrogen production at an off-site facility, but here, the hydrogen is cooled to a liquid state for
transportation [28,29]. After liquefaction, the liquid hydrogen is loaded onto delivery trucks and transported to a refueling station, where it is vaporized into a high-pressure gaseous form for dispensing. Liquid hydrogen boasts a significantly higher energy density than compressed hydrogen, making it a generally more cost-effective solution for large-scale applications as fewer trips are needed to transport the same energy quantity. However, the process of hydrogen liquefaction and the maintenance of the necessary low temperatures do consume a significant amount of energy. In terms of potential boil-off during delivery, there are technological solutions in place to manage and minimize boil-off as much as possible [30,31].

3. Cost Components of FCEB and Diesel Bus
3.1. Hydrogen Production Costs
3.1.1. On-Site Production

Electrolyzers and steam methane reforming (SMR) are the most popular options to produce hydrogen nowadays. For the electrolyzer, apart from the electrolyzer stack, the plant also includes the cost of the balance of plant (BOP). The BOP is a range of system elements such as cooling, purifiers, thermal management, water treatment, etc. [32,33].

Many studies have looked into the potential cost decrease for increasing the module size and reaping the economy of scale [34–38]. Therefore, many cost estimation models, including technology development and electrolyzer plant size, have been developed based on the collected cost data. The cost of electrolyzer plants, including the cost of the BOP based on the plant capacity and a learning curve/technology development rate was developed [34] and used in this study. The cost of an electrolyzer plant in USD/kW is shown in Equation (2).

$$C = (k_0 + \frac{k}{Q} Q^\alpha)(\frac{V}{V_0})^\beta$$

where $C$ is the electrolyzer plant cost per kW, $k_0$ and $k$ are fitting constants, $Q$ is the electrolyzer plant capacity (decided based on daily hydrogen demand), and $V$ and $V_0$ are plant installation year and reference year, respectively. $\alpha$ and $\beta$ are fitting constants and are usually referred to as a scaling factor and learning factor, respectively. For example, if the electrolyzer is Alkaline, values of parameters $\alpha$, $\beta$, $k_0$, and $k$ are 0.649, $-27.33$, 301.04, and 11,603.

On the other hand, SMR is currently the most common method of hydrogen production. The integration of carbon capture facilities into the traditional SMR process significantly increases the total capital cost but decreases carbon emission costs a lot. According to Lewis et al. [39], adding carbon capture to SMR plants leads, on average, to a 54% increment in capital cost. The capital cost of a SMR plant without CC ranges from 500 USD/kW to 900 USD/kW and the capital cost of a SMR plant with carbon capture is 900–1600 USD/kW based on International Energy Agency (IEA) online data [40,41]. The size of the SMR plant is decided based on the daily hydrogen demand of the bus fleet.

3.1.2. Hydrogen Purchase and Delivery

Purchasing hydrogen from an off-site location is another fuel supply alternative for FCEBs. In this case, the hydrogen production cost is the hydrogen purchasing cost and delivery cost. However, hydrogen can be produced from diverse domestic resources, and their costs are different accordingly. Three common types of hydrogen are grey, blue, and green hydrogen [42]. According to S&P Global Commodity Insights [43,44], as of August 2022, green hydrogen costs roughly USD 5.5–9.5 per kilogram, depending on the technology and the location, while gray hydrogen costs roughly USD 1.8–2.4 per kilogram for steam methane reforming without carbon capture and storage, depending on the location, and blue hydrogen costs roughly USD 5–7 per kilogram in the U.S. These prices will only fall slightly by 2030 when the carbon capture system is scaled up. The green hydrogen will drop to 1.54 USD/kg by 2030 based on Rethink Energy’s prediction and blue hydrogen is expected to go as low as USD 1.25 [45,46].
As for hydrogen delivery, the cost can vary depending on factors such as the distance between the hydrogen production facility and the refueling station, the method of transportation (e.g., pipeline, truck, or other means), and any associated infrastructure costs. Delivery costs may also depend on the scale of hydrogen demand and the availability of local hydrogen production facilities. Overall, the cost is mostly dependent on the transport distance and trailer capacity and can be calculated as:

\[
\text{Delivery cost (Gas)} = \text{transport distance} \times \text{capacity} \times \text{operating cost} \tag{3}
\]

\[
\text{Delivery cost (liquid)} = \text{transport distance} \times \text{capacity} \times \text{operating cost} + \text{liquification cost} \tag{4}
\]

If the hydrogen is delivered in liquid, the liquification energy is 0.012 MWh/kg [47,48].

3.2. Hydrogen Refueling Station

The equipment required in a hydrogen refueling station depends on the type of station. Compressors, storage tanks, and dispensers are significant factors contributing to refueling station costs.

The capital cost of the hydrogen fueling station is estimated based on the model developed by Melaina and Perez [49], which differentiates the gaseous hydrogen fueling station from the liquid hydrogen fueling station. Therefore, capital cost for a large hydrogen refueling station scaled up from a small size can be calculated based on Equation (5).

\[
\text{Cost} = 1.3 \times \text{reference station cost} \times \text{station multiplier} \times \left( \frac{\text{target size}}{\text{reference size}} \right) \text{scaling factor} \tag{5}
\]

Table 1 provides the relevant information regarding the supply modes for the fueling station, using either liquid hydrogen (LH\(_2\)) or gaseous hydrogen (GH\(_2\)). The scaling factor and station multiplier differ depending on the chosen supply mode, the baseline station can dispense 210 kg per day, and the capital cost is EUR 600,000 (USD 648,000).

<table>
<thead>
<tr>
<th>Hydrogen</th>
<th>Station Multiplier</th>
<th>Scaling Factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>LH(_2)</td>
<td>0.9</td>
<td>0.6</td>
</tr>
<tr>
<td>GH(_2)</td>
<td>0.6</td>
<td>0.7</td>
</tr>
</tbody>
</table>

3.3. FCEB Related Cost

3.3.1. FCEB Purchase Cost

Normally, the cost of purchasing a FCEB (~USD 1,300,000) can be much higher than that of a conventional diesel bus (~USD 480,000) due to the technology and materials [12,13,51]. However, the cost of FCEBs is expected to decrease over time as technology becomes more mature and economies of scale are achieved. In fact, the industry’s 2029 cost target is USD 600,000 per bus, which can compete with diesel buses in the market [52].

3.3.2. Energy/Fuel Consumption Cost of FCEB

The fuel economy of a FCEB ranges from 5.42 to 8.67 miles per kilogram of hydrogen based on the reports [2,11–13,51]. Daily hydrogen demand can be determined by the daily mileage and fuel economy of a FCEB, as shown in Equation (6).

\[
\text{Daily hydrogen demand for one bus (kg)} = \frac{\text{Daily mileage (miles)}}{\text{Fuel economy (miles/kg)}} \tag{6}
\]
For example, in this case, the average daily mileage for each bus is 200 miles and if the average fuel economy is 7.05 miles/kg, then the daily hydrogen demand can be calculated as 28.4 kg for one bus. Hydrogen can be produced by an on-site SMR plant, an electrolyzer, or purchased from an off-site distribution center. Therefore, energy/fuel consumption costs are different based on different hydrogen supply alternatives.

For the on-site electrolyzer alternative, the cost is the electricity cost to produce the hydrogen. The efficiency of an electrolysis system can be calculated as the heating value of the hydrogen produced divided by the electrical energy input [53]. Therefore, the energy consumption of an electrolyzer can be calculated using Equation (7).

\[
\text{Electricity consumed} = \frac{\text{Hydrogen production (kg)} \times \text{Higher Heating Value (HHV) of H}_2 \text{ (kWh/kg)}}{\text{Electrolyser efficiency (HHV)}}
\]  (7)

For the on-site SMR plant, the cost is mainly the cost of natural gas consumption to produce the hydrogen. The quantity of consumed natural gas can be calculated using Equation (8)

\[
\text{Natural gas consumed} = \frac{\text{Hydrogen production (kg)} \times \text{Higher Heating Value (HHV) of H}_2 \text{ (kWh/kg)}}{\text{SMR efficiency (HHV) \times Higher Heating Value (HHV) of Natural gas (kWh/kg)}}
\]  (8)

3.3.3. FCEB Maintenance Cost

The maintenance costs of FCEBs can vary depending on several factors such as the age of the bus, the manufacturer, and the operating conditions. NREL collects all work orders for the evaluation buses to calculate the maintenance cost per mile. Costs for accident-related repairs, which are extremely variable from bus to bus, were eliminated from the analysis. Warranty costs are not included in the cost-per-mile calculations because those costs are covered in the capital cost of the buses. Cost per mile is calculated as follows:

\[
\text{Cost per mile} = \frac{[(\text{labor hours \times 50}) + \text{parts cost}]}{\text{mileage}}
\]  (9)

NREL calculates the total cost per mile, scheduled maintenance cost per mile, and unscheduled maintenance cost per mile. NREL also categorizes maintenance costs by the system to provide insight into which systems have the most costs for each technology. Under the warranty, the maintenance cost per mile is around 0.218–0.415 USD/mile. And without the warranty, the maintenance cost per mile is around 1.02–1.33 USD/mile. It is worth noting that NREL uses a constant USD 50 per hour for consistency [11–13,51]. In this study, the bus maintenance warranty length is assumed to be five years.

Overall, the general techno-economic assumptions of parameters for TCO calculation (except the carbon emission costs) of FCEBs and associated infrastructures are summarized in Table 2.

| Table 2. Average values of input parameters set for TCO calculation—FCEBs. |
|-----------------|-----------------|----------------|
| **Parameter**   | **Value**       | **Reference**  |
| Electrolyzer efficiency (2023) | 0.73            | [32–38]        |
| Electrolyzer efficiency (2028) | 0.82            | [32–38]        |
| SMR without carbon capture unit price | 910 USD/kW | [39–41]        |
| SMR with carbon capture unit price | 1583 USD/kW | [39–41]        |
| SMR without carbon capture efficiency (2023) | 0.76            | [32,40,41,54] |
| SMR without carbon capture efficiency (2028) | 0.82            | [32,40,41,54] |
| SMR with carbon capture efficiency (2023) | 0.69            | [32,40,41,54] |
| SMR with carbon capture efficiency (2028) | 0.73            | [32,40,41,54] |
Table 2. Cont.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
<th>Reference</th>
</tr>
</thead>
<tbody>
<tr>
<td>Electricity cost (2023)</td>
<td>126.8 USD/MWh</td>
<td>[55]</td>
</tr>
<tr>
<td>Electricity cost (2028)</td>
<td>106 USD/MWh</td>
<td>[56]</td>
</tr>
<tr>
<td>Natural gas cost (2028)</td>
<td>5.4 USD/MCF</td>
<td>[57,58]</td>
</tr>
<tr>
<td>Bus purchase cost per bus (2023)</td>
<td>USD 1,300,000</td>
<td>[2,11–13,51]</td>
</tr>
<tr>
<td>Bus purchase cost per bus (2028)</td>
<td>USD 600,000</td>
<td>[52]</td>
</tr>
<tr>
<td>Bus fuel economy</td>
<td>7.05 miles/kg H\textsubscript{2}</td>
<td>[2,11–13,51]</td>
</tr>
<tr>
<td>Gray hydrogen cost (2023)</td>
<td>USD 1.82/kg</td>
<td>[43,44,59,60]</td>
</tr>
<tr>
<td>Blue hydrogen cost (2023)</td>
<td>USD 4.15/kg</td>
<td>[44,59–63]</td>
</tr>
<tr>
<td>Electrolytic hydrogen cost (2023)</td>
<td>USD 8.75/kg</td>
<td>[43,44,46,60,61,63–65]</td>
</tr>
<tr>
<td>Truck capacity with gas tube trailer</td>
<td>200 kg</td>
<td>[17]</td>
</tr>
<tr>
<td>Truck capacity with liquid trailer</td>
<td>4000 kg</td>
<td>[17]</td>
</tr>
<tr>
<td>Hydrogen delivery operating cost (gas)</td>
<td>USD 2.43/mile</td>
<td>[17]</td>
</tr>
<tr>
<td>Hydrogen delivery operating cost (liquid)</td>
<td>USD 6.4/mile</td>
<td>[17]</td>
</tr>
<tr>
<td>Hydrogen liquefaction energy</td>
<td>0.012 MWh/kg H\textsubscript{2}</td>
<td>[47,48]</td>
</tr>
<tr>
<td>Bus maintenance cost under the warranty</td>
<td>USD 0.317/mile</td>
<td>[12,13]</td>
</tr>
<tr>
<td>Bus maintenance cost without warranty</td>
<td>USD 1.18/mile</td>
<td>[11,51]</td>
</tr>
</tbody>
</table>

3.4. Diesel Bus Implementation Cost

Parameters for diesel bus TCO calculation were also collected for comparison with the TCO of FCEBs, as shown in Table 3. For the capital cost, with existing fueling infrastructure, the transit agency only needs to consider the diesel bus purchase cost, which is much lower than the FCEB purchase cost in the market. Diesel costs can be different based on different locations. According to the Energy Information Administration (EIA), the diesel cost in 2023 in New Jersey, U.S., is 4.23 USD/gal [66], which is used in the case studies. Also, the diesel price increase rate is assumed to be 0.7%/year [67]. As for the bus maintenance costs, many reports by NREL show the average value is 1 USD/mile for each bus. It is important to note that all costs associated with infrastructures have not been included in the TCO analysis. This omission assumes that the existing infrastructures are capable of functioning without the need for additional expenditures.

Table 3. Average values of parameters set for TCO calculation—diesel buses.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
<th>Reference</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bus purchase cost</td>
<td>USD 480,000</td>
<td>[67]</td>
</tr>
<tr>
<td>Diesel cost (2023)</td>
<td>4.23 USD/gal</td>
<td>[66]</td>
</tr>
<tr>
<td>Diesel price increase</td>
<td>0.7%/year</td>
<td>[67]</td>
</tr>
<tr>
<td>Bus fuel economy</td>
<td>4.27 miles/gal</td>
<td>[11,67–69]</td>
</tr>
<tr>
<td>Bus maintenance cost</td>
<td>1 USD/mile</td>
<td>[67]</td>
</tr>
</tbody>
</table>

4. Carbon Emission Analysis

This section provides data on carbon emission costs as an integral part of the TCO assessment. As a baseline scenario, the diesel bus is subjected to both well-to-tank (WTT) and tank-to-wheel (TTW) assessments. The WTT analysis thoroughly examines the entire carbon footprint of the fuel, tracing it back to its origins, including the initial extraction, production, and distribution stages. Simultaneously, the TTW assessment scrutinizes the
bus’s emissions during its operational phase, quantifying the carbon emissions generated as it travels on the road. The relevant emission values are presented in Table 4.

Table 4. Carbon emission values of a diesel bus.

<table>
<thead>
<tr>
<th>Period</th>
<th>Carbon Emission</th>
<th>Reference</th>
</tr>
</thead>
<tbody>
<tr>
<td>WTT (Diesel production)</td>
<td>0.84 kg CO₂/kg diesel</td>
<td>[70]</td>
</tr>
<tr>
<td>TTW (Diesel consumption)</td>
<td>2.16 kg CO₂/mile</td>
<td>[71]</td>
</tr>
</tbody>
</table>

On the other hand, for FCEBs, the primary focus is on quantifying carbon emissions based on the CO₂ emissions generated during the WTT phases. The electricity used for all the FCEBs scenarios is sourced from the grid power, and Table 5 provides information on the electricity mix considered in New Jersey [72]. It is worth noting that New Jersey has enacted legislation mandating that 50% of electricity sold in the state must come from approved renewable sources by 2030 [73]. As shown in Table 5, the emission value for grid electricity is 0.26 kg CO₂/kWh in 2023, and this value decreases to 0.13 kg CO₂/kWh in 2028.

Table 5. New Jersey electricity mixes.

<table>
<thead>
<tr>
<th>Source of Power Generation</th>
<th>Year 2023 (%)</th>
<th>Year 2028 (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Natural gas</td>
<td>50.5</td>
<td>25</td>
</tr>
<tr>
<td>Nuclear</td>
<td>45.8</td>
<td>25</td>
</tr>
<tr>
<td>Renewable energy</td>
<td>3.7</td>
<td>50</td>
</tr>
</tbody>
</table>

The emission values for SMR, both with and without CO₂ capture, are detailed in Table 6. This assessment encompasses the entire lifecycle of the hydrogen production process, commencing from the extraction of raw materials (natural gas), and continuing through the subsequent stages of hydrogen production. It is important to note that while SMR with CO₂ capture has the potential to reduce emissions during the hydrogen production process, it requires additional energy for the carbon capture process. In this study, we assume an energy penalty percentage of 25% associated with this process [74].

Table 6. Carbon emissions generated during the SMR process [75].

<table>
<thead>
<tr>
<th>Natural Gas Production Emission</th>
<th>Hydrogen Production Emission</th>
</tr>
</thead>
<tbody>
<tr>
<td>SMR with CO₂ capture (blue hydrogen)</td>
<td>1.26 kg CO₂/kg Natural gas</td>
</tr>
<tr>
<td>SMR without CO₂ capture (grey hydrogen)</td>
<td>1.26 kg CO₂/kg Natural gas</td>
</tr>
</tbody>
</table>

When hydrogen is obtained from an external supplier and delivered, the carbon emissions associated with the delivery process are considered. If hydrogen is sourced from an external supplier and delivered in gaseous form, the major carbon emissions stem from the delivery process, particularly from the diesel truck used for transportation. However, in the case of liquid hydrogen, the emissions also encompass the electricity consumed during the hydrogen liquefaction process, in addition to the emissions from the transportation using a diesel truck.

In this study, the carbon emission cost is determined based on carbon offset prices. Carbon offset prices reflect the cost of procuring carbon offsets, which are essentially credits or certificates generated by projects designed to reduce, remove, or prevent greenhouse gas emissions [76]. By purchasing carbon offsets, individuals or organizations can compensate for their own emissions by supporting projects that contribute to greenhouse gas reduction efforts elsewhere. The price of these carbon offsets can vary depending on factors such as demand and supply, but generally falls within the range of USD 40 to USD 80 per metric
ton in 2023 [77,78]. According to the authors of [79], it is projected that carbon offset prices could potentially rise to as high as USD 224 per ton of CO₂ by 2030. Table 7 presents the average carbon emission price for the years 2023 and 2028, as derived from a variety of report sources.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
<th>Reference</th>
</tr>
</thead>
<tbody>
<tr>
<td>Carbon emission price per ton (2023)</td>
<td>USD 60</td>
<td>[77,78]</td>
</tr>
<tr>
<td>Carbon emission price per ton (2028)</td>
<td>USD 142.5</td>
<td>[79–82]</td>
</tr>
</tbody>
</table>

5. Case Study Analysis and Results

5.1. Analysis Scenarios

In the first TCO analysis case, the study assumes a fleet of 5 buses located at a site where the round-trip distance to the off-site hydrogen supplier is 150 miles if hydrogen is not produced on-site. The existing fleet is assumed to stay in operation from 2023 through 2032, providing a 10-year period for the TCO analysis. Given the relatively small hydrogen demand, the TCO assessment for this fleet considers four viable hydrogen supply alternatives. These alternatives encompass on-site hydrogen production using an electrolyzer and off-site purchases of electrolytic, blue, and gray hydrogen with gaseous hydrogen delivery. Consequently, five scenarios are analyzed, comprising four hydrogen supply options and a conventional diesel bus scenario used as a baseline for comparison:

- Scenario #1: On-site electrolyzer supplied by grid power.
- Scenario #2: Off-site electrolytic hydrogen purchase and gaseous delivery.
- Scenario #3: Off-site blue hydrogen purchase and gaseous delivery.
- Scenario #4: Off-site gray hydrogen purchase and gaseous delivery.
- Scenario #5: Conventional diesel bus.

In the second TCO case, the study involves a fleet of 100 FCEBs stationed at a location where the round-trip distance to the off-site hydrogen supplier is 390 miles if hydrogen is not produced on-site. The expansive future fleet is set to begin operations in 2028 and is expected to have an operational lifespan of 10 years for the purpose of calculating the TCO. The daily hydrogen demand in this case is significantly larger, leading to distinct hydrogen supply alternatives compared to the first case. In this case, six feasible hydrogen supply alternatives are considered: on-site hydrogen production with an electrolyzer; on-site hydrogen production with SMR with or without carbon capture; and off-site purchases of electrolytic, blue, and gray hydrogen with liquid hydrogen delivery. Consequently, seven scenarios are analyzed to comprehensively assess the TCO:

- Scenario #1: On-site electrolyzer supplied by grid power.
- Scenario #2: On-site SMR with carbon capture (blue hydrogen).
- Scenario #3: On-site SMR without carbon capture (gray hydrogen).
- Scenario #4: Off-site electrolytic hydrogen purchase and liquid delivery.
- Scenario #5: Off-site blue hydrogen purchase and liquid delivery.
- Scenario #6: Off-site grey hydrogen purchase and liquid delivery.
- Scenario #7: Conventional diesel bus.

In both cases considered, it is assumed that the average daily mileage for the buses is 200 miles, and the TCO analysis spans a 10-year lifespan. Consequently, there are no replacement costs accounted for in the cases of FCEBs or infrastructures. However, it is important to note that the bus maintenance warranty is assumed to cover a period of five years.

5.2. TCO Analysis without Carbon Emission Cost

Four major cost items are considered for both cases: bus purchase cost, infrastructure capital cost, total energy / fuel consumption cost, and operating and maintenance (O and
M) costs for buses and associated infrastructures. In the five-buses case, if hydrogen is produced by an on-site electrolyzer (Scenario #1), the infrastructure includes the electrolyzer and the refueling station. The energy/fuel consumption cost in the electrolyzer scenario reflects the electricity cost for the electrolyzer to produce the hydrogen. Besides the purchase cost, the energy/fuel consumption cost in Scenarios #2, #3, and #4 also accounts for the gaseous delivery cost. Additionally, the costs associated with hydrogen costs in Scenarios #2, #3, and #4 have been compiled using the latest available pricing data. The comparative TCO results for the five-buses case are illustrated in Figure 2.

Figure 2 shows that the bus purchase cost constitutes a large portion of the TCO in all hydrogen scenarios. For small fleets operating in 2023, diesel buses still have a TCO advantage over FCEBs. Despite the promising potential of FCEBs in terms of environmental benefits, the TCO analysis without the carbon emission cost suggests no clear break-even point favoring FCEBs over diesel buses within their lifespan. The initial capital costs and operational expenses of FCEBs currently outweigh the benefits. However, among the hydrogen alternatives considered in this case, the off-site gray hydrogen purchase with gaseous delivery (Scenario #4) emerges as the most cost-effective option for refueling FCEBs at present. The TCO for the diesel bus option is approximately 21.24% lower than that of the off-site gray hydrogen purchase and gaseous delivery option, which is the most cost-effective choice among all the hydrogen alternatives. This is mainly due to lower infrastructure capital costs (no hydrogen production infrastructure needed) and energy/fuel costs (cheaper gray hydrogen) compared to other hydrogen options. Its affordability makes it a competitive option for early FCEB adopters. On-site production with an electrolyzer (Scenario #1), however, still holds significant potential for smaller fleets when electricity prices are favorable. Although this option entails higher infrastructure capital costs due to the electrolyzer, these costs can be spread out and amortized over the operational lifespan. This explains why the TCO for the on-site electrolyzer scenario is 4.64% less than that of the off-site electrolytic hydrogen purchase and gaseous delivery scenario.

In the 100-buses case, the same as the five-bus case, if hydrogen is produced on-site with an electrolyzer (Scenario #1), the infrastructure includes the electrolyzer and refueling station. For scenarios using SMR (Scenarios #2 and #3), the infrastructure includes the SMR plant and refueling station. The energy/fuel consumption cost in Scenario #1 represents the cost of electricity to operate the electrolyzer and produce hydrogen. For Scenarios #2 and #3, the energy/fuel consumption cost is the cost of natural gas consumed to produce hydrogen. For Scenarios #4, #5, and #6, the energy/fuel consumption cost includes the hydrogen purchase cost, the energy cost for liquefaction, and the delivery cost of the liquid hydrogen purchase cost, the energy cost for liquefaction, and the delivery cost of the liquid
hydrogen. In these scenarios, the cost of hydrogen is determined based on the levelized cost of hydrogen (total costs of hydrogen production divided by the total amount of hydrogen produced over the lifespan) calculated in Scenarios #1, #2, and #3. Figure 3 shows the TCO breakdown for different hydrogen alternatives, while Figure 4 presents a trend analysis of TCO over time for each bus supply scenario, indicating cost projections up to the year 2037.

The average levelized costs of electrolytic, blue, and gray hydrogen in 2028, as calculated in Scenarios #1, #2, and #3, are 4.33 USD/kg, 2.12 USD/kg, and 1.48 USD/kg, respectively. These costs are subsequently applied as the hydrogen costs in Scenarios #4, #5, and #6. Figures 3 and 4 reveal a significant development in the analysis of large fleet scenarios in 2028: a clear breakeven point emerges for all hydrogen alternatives when compared to diesel buses. As hydrogen infrastructure and technologies mature, the TCO analysis suggests that FCEBs become a financially viable option for large fleets. In 2031, the TCO for all hydrogen scenarios is expected to be lower than the TCO for the diesel
bus scenario. Notably, on-site SMR without carbon capture (Scenario #3) proves to be the most cost-effective alternative for large bus fleets in 2028. Initially, procuring hydrogen and arranging for its delivery can present a cost-effective alternative, as it eliminates the need for constructing hydrogen production infrastructure. However, over time, on-site hydrogen production using SMR can become a more cost-effective option, leading to substantial savings in transportation expenses. For the on-site electrolyzer scenario, the TCO could still be high because of the high electricity cost to produce the hydrogen. However, with ongoing advancements in electrolyzer technologies and decreasing costs of electrolytic hydrogen production, it offers a feasible pathway for decarbonizing public transportation and achieving sustainability and cost-effectiveness goals.

Furthermore, sensitivity analysis was conducted specifically for the electrolytic hydrogen alternatives (Scenarios #1 and 4) projected for 2028. For Scenario #1, the analysis provides insight into how TCO results may vary as electrolyzer efficiency changes. Meanwhile, for Scenario #4, the variable parameter is the transport distance between the fueling station and the electrolytic hydrogen supplier. The outcomes of these analyses are presented in Figures 5 and 6. It demonstrates that as electrolyzer efficiency increases, the TCO value for Scenario #1 decreases greatly, and conversely, variations in transport distance in Scenario #5 do not significantly affect the TCO value.

Figure 5. Sensitivity analysis of electrolyzer efficiency for Scenario #1.

Figure 6. Sensitivity analysis of transport distance for Scenario #5.

5.3. TCO Analysis with Carbon Emission Cost

TCO analysis traditionally focuses on the financial costs associated with capital, operational, and maintenance costs. However, in recent years, there has been a growing recognition of the need to incorporate environmental factors, including carbon emissions, into TCO analyses. First, based on the emission data from Section 4, the carbon emission analysis results for both cases are presented in Figures 7 and 8.
For the 5-buses case, in Scenario #1, where hydrogen is produced on-site using an alkaline electrolyzer, carbon emissions are measured at 2.09 kg per mile, indicating a moderate environmental footprint, mainly from the grid electricity. Emissions in Scenarios #2, #3, and #4, which involve the off-site hydrogen purchase with gaseous delivery, are marked by both diesel truck delivery and hydrogen (electrolytic, blue, and gray) production emission. It is evident that the purchase and delivery of gray hydrogen (produced via SMR without carbon capture) to the fueling station could result in significant CO₂ emissions. This is primarily due to the fact that the SMR process without carbon capture produces a considerable amount of carbon. Scenario #5, representing a conventional diesel bus, presents a notably higher carbon emission rate of 2.84 kg per mile than most hydrogen scenarios, emphasizing the environmental advantages of transitioning to cleaner hydrogen-based transportation options. Overall, for a small bus fleet, purchasing blue hydrogen (SMR with carbon capture) and delivering to the refueling station is the most environmentally friendly alternative.

For the 100-bus case, in Scenario #1, which features on-site hydrogen production through an electrolyzer, carbon emissions stand at 0.95 kg per mile, and in Scenario #2, employing on-site SMR with CO₂ capture results in a commendably low emission rate of 1.14 kg per mile, both reflecting a relatively low environmental footprint. Conversely, Scenario #3 employs on-site SMR without CO₂ emissions reduction, resulting in a significantly higher emission rate of 2.30 kg per mile for gray hydrogen production. Off-site Scenarios...
#4, #5, and #6, involving the purchase of hydrogen with liquid delivery, result in carbon emission rates of 1.28, 1.47, and 2.64 kg per mile. In stark contrast, Scenario #7, representing a conventional diesel bus, exhibits the highest carbon emission rate at 2.84 kg per mile.

Along with emissions data, this study also calculates the TCO results while taking carbon emission costs into account for both cases. Figures 9 and 10 present a comparison of the TCO results for both cases. Figure 9 illustrates that carbon emission costs have a minor impact on the TCO for the current small bus fleet.

Figure 9. TCO comparison for the 5-buses case considering carbon cost.

Figure 10. TCO comparison for the 100-buses case considering carbon cost.

Figures 2 and 9 illustrate that, even when accounting for the carbon price, the diesel bus scenario maintains the lowest TCO, attributable to the fleet’s smaller size. However, the TCO for the off-site gray hydrogen purchase and gaseous delivery scenario (Scenario #4) has risen by 4.92%, primarily due to the substantial carbon emissions associated with it. In Figure 3, the scenario involving on-site SMR without carbon capture (Scenario #3) demonstrates its cost-effectiveness, especially when carbon emission costs are not considered. However, a closer examination of carbon emission analysis in Figure 10 reveals that...
SMR plants without carbon capture may lead to substantial emissions. On the contrary, Figure 10 shows that the implementation of on-site SMR with carbon capture presents a lower TCO when considering carbon emission costs, making it a more environmentally and economically favorable option.

5.4. Probabilistic Analysis of Total Cost Ownership

The results presented thus far have been derived from the average values of input parameters. To account for the impact of uncertain input variables on the TCO results, this study introduced variations in certain parameters across different alternatives and applied the Monte Carlo method (20,000 scenarios) for uncertainty quantification in the case of 100 buses.

For the analysis of capital costs, the efficiency of the hydrogen production infrastructure is factored in, specifically electrolyzers and SMR plants. The assumed ranges for these efficiencies are based on expert forecasts derived from various reports. The Beta distribution is employed for these parameters due to their values being constrained between 0 and 1. For instance, according to the IEA report [32], electrolyzers exhibit 10% variation in efficiency. Similarly in this study, both SMR plants with and without carbon capture are presumed to have a 10% efficiency variation, akin to that of electrolyzers.

For operating costs, primary considerations include energy prices and bus fuel economy. The normal distribution is assumed for these parameters, with the accessible range from the literature and reports accounting for 95% of the total variation. Consequently, the mean and standard deviation are calculated, adhering to the principle that 95% of the values fall within two standard deviations of the mean. However, it is important to note that the variation in hydrogen prices, specifically the levelized costs of hydrogen, is derived from the analysis results of Scenarios #1, #2, and #3 in the 100-bus case, ensuring comparability across all scenarios. Table 8 provides a comprehensive list of all uncertain parameters associated with each alternative.

Table 8. Uncertainty parameters for Monte Carlo simulation.

<table>
<thead>
<tr>
<th>Distributions</th>
<th>Uncertain Input Parameters</th>
<th>Distribution Parameters</th>
<th>Source</th>
</tr>
</thead>
<tbody>
<tr>
<td>Normal (PDF: (\frac{1}{\sigma\sqrt{2\pi}}e^{-\frac{1}{2}(\frac{x-\mu}{\sigma})^2}))</td>
<td>FCEB fuel economy (miles/kg H(_2))</td>
<td>7.05</td>
<td>0.81</td>
</tr>
<tr>
<td></td>
<td>Diesel bus fuel economy (miles/gal)</td>
<td>4.27</td>
<td>0.52</td>
</tr>
<tr>
<td></td>
<td>Retail electricity price (USD/MWh)</td>
<td>106</td>
<td>3.12</td>
</tr>
<tr>
<td></td>
<td>Natural gas price (USD/MCF)</td>
<td>5.40</td>
<td>0.72</td>
</tr>
<tr>
<td></td>
<td>Diesel cost (USD/gal)</td>
<td>4.23</td>
<td>0.27</td>
</tr>
<tr>
<td></td>
<td>Carbon emission price per ton (USD)</td>
<td>142.5</td>
<td>40.75</td>
</tr>
<tr>
<td>Beta (PDF: (\frac{1}{\beta(\alpha,\beta)}x^{\alpha-1}(1-x)^{\beta-1}))</td>
<td>Electrolyzer efficiency</td>
<td>17.18</td>
<td>3.77</td>
</tr>
<tr>
<td></td>
<td>SMR (with carbon capture) efficiency</td>
<td>26.27</td>
<td>9.72</td>
</tr>
<tr>
<td></td>
<td>SMR (without carbon capture) efficiency</td>
<td>17.18</td>
<td>3.77</td>
</tr>
</tbody>
</table>

Figures 11 and 12 depict the TCO distribution analysis, considering parameter uncertainty, both with and without the inclusion of carbon emission costs. Contrary to the earlier findings, Figures 11 and 12 illustrate the variability and distribution of TCO across various scenarios. Figure 12, incorporating carbon emission costs, leads to shifts in the distributions and adjustments to the TCO results for each scenario. For the on-site electrolyzer supplied by grid power scenario, a larger standard deviation of USD 7.3 million (excluding carbon emission costs) and USD 7.6 million (including carbon emission costs) is evident in comparison to other hydrogen supply alternatives. This heightened variability can be attributed to
the substantial impact of retail electricity prices on the TCO. This implies that a reduction in retail electricity prices could potentially result in a more cost-effective electrolyzer scenario, leading to lower TCO. Furthermore, as grid power increasingly incorporates renewable energy sources in the future, subsequently driving down retail electricity prices, the electrolyzer emerges as a compelling and competitive hydrogen supply alternative, particularly when considering carbon emission costs.

![TCO distribution analysis for the 100-buses case without carbon emission costs.](image-url)

**Figure 11.** TCO distribution analysis for the 100-buses case without carbon emission costs.
Conversely, Scenario #3, which entails on-site SMR without carbon capture, shows a lower standard deviation of USD 2.7 million, excluding the costs of carbon emissions. However, when the carbon price is factored in, the TCO variation for this scenario increases, making on-site SMR with carbon capture the most predictable and stable option, evidenced by its lowest standard deviation of USD 4.33 million. Regarding the diesel bus alternative, it boasts both the highest mean and standard deviation in TCO, both with and without factoring in carbon emission costs. This indicates that it is not only the costliest option but also the riskiest compared with hydrogen alternatives. The main factor contributing to the
high standard deviation is the fluctuation in diesel prices and carbon emission costs, which leads to variable TCOs.

However, as depicted in Figures 11 and 12, there is a noticeable overlap in some of the results. For instance, the TCO ranges for Scenarios #2 and #3 exhibit significant overlap when considering carbon emission costs. To advance the analysis, we conduct a detailed comparison of each scenario pair using statistical methods. Given that certain input parameters adhere to the beta distribution, the TCO outcomes depicted in Figures 11 and 12 diverge from the normal distribution, as confirmed by the Anderson–Darling test. Consequently, the rank-biserial correlation was examined as an effect size indicator, assessing the strength of association between two variables in the context of the Mann–Whitney U test (nonparametric test). The results of this test reveal notably small p-values for all scenario pairs, underscoring their statistically significant differences. Additionally, a probability ranking analysis is conducted to determine which alternative offers the lowest TCO more conclusively. Figure 13 illustrates the probability of each option having the lowest TCO.

![Figure 13. Probability of having the lowest TCO.](image)

Figure 13 reveals that, in the scenarios excluding carbon costs, SMR without carbon capture emerges as the most favorable alternative for the 100-bus case. It dominates other scenarios with the highest probability, at 99.5%, of achieving the lowest TCO. When carbon costs are considered, SMR with carbon capture and SMR without carbon capture present probabilities of 69.2% and 30.8%, respectively, for being the alternative with the lowest TCO. While both alternatives have the potential to be the most economical choice, SMR with carbon capture holds a higher probability.

### 5.5. Comparison with Previous Results

When comparing the TCO results with the existing literature on similar systems, variations in the results are found, primarily due to differing assumptions. In comparison to the study by Kim et al. [16], which analyzed a small fleet of 11 FCEBs supplied by an on-site electrolyzer, differences in average TCO are noted. In their 2020 findings, the fleet had an average TCO of 1.993 EUR/km (~3.63 USD/mile), decreasing to 1.414 EUR/km (~2.58 USD/mile) by 2030. In contrast, the results from this study for a 5-bus fleet supplied by an on-site electrolyzer without carbon emission costs in 2023 show an average TCO of 3.66 USD/mile, while for a 100-bus fleet in 2028, it is 1.82 USD/mile. While the TCO for small fleets is similar, variations arise in future projections due to differences in assumptions, including economies of scale and technological developments. For example, this study projects that capital costs for large-scale electrolysers will decrease in the future, resulting in a reduction of the TCO between 2028 and 2037.

While direct TCO analyses of hydrogen buses and their infrastructure are sparse in the literature, numerous reports and studies have conducted economic evaluations to calculate the levelized cost of hydrogen over its lifecycle. The levelized cost of hydrogen, which
encompasses the analysis of both capital and operating costs in the hydrogen production process, serves as a vital metric. In this study, the cost of hydrogen produced by an on-site electrolyzer in 2023 is calculated at 8.29 USD/kg, falling within the 2.5 USD/kg to 15 USD/kg range reported in various studies [43,44,60,61,63–65]. By 2028, the levelized cost of electrolytic hydrogen is projected to be 4.33 USD/kg in this study, which is above the average anticipated value of 2.5 USD/kg for green hydrogen. This discrepancy is primarily attributed to the energy source used for an electrolyzer. In our analysis, the grid power in 2028 is assumed to comprise only 50% renewable energy, impacting the overall cost of hydrogen production. For hydrogen produced via SMR both with and without carbon capture, the costs are estimated at 2.12 USD/kg and 1.48 USD/kg, respectively, aligning with ranges reported in various studies [43,44,59–63]. Specifically, the cost range for blue hydrogen (SMR with carbon capture) is between 1.3 USD/kg and 7 USD/kg, while for gray hydrogen (SMR without carbon capture), it falls within 0.7 USD/kg to 2.93 USD/kg.

The energy source powering the electrolyzer also has a significant impact on carbon emissions. In this study, the carbon emissions from a grid-connected electrolyzer are measured at 14.92 kg CO\(_2\)/kg H\(_2\) in 2023 and 6.70 kg CO\(_2\)/kg H\(_2\) in 2028, both figures falling below the global average emission value of 26 kg CO\(_2\)/kg H\(_2\). This reduction is attributable to the lower electricity emissions in this study, which are 0.26 kg CO\(_2\)/kWh in 2023 and 0.13 kg CO\(_2\)/kWh in 2028, compared to the global average of 0.48 kg CO\(_2\)/kWh [83]. In the case of the SMR scenario, the carbon emissions are calculated at 8.10 kg CO\(_2\)/kg H\(_2\) for the process with carbon capture and 16.22 kg CO\(_2\)/kg H\(_2\) for the process without carbon capture. Both values fall within the expected range [74,83–85].

6. Conclusions and Discussion

This paper presents a comprehensive total cost of ownership (TCO) analysis for fuel cell electric buses (FCEBs), with a focus on evaluating various hydrogen supply alternatives. This analysis aims to provide insights into the economic viability and environmental impact of different hydrogen production methods for FCEBs. These insights can facilitate informed decision making for transit agencies within the public transportation sector. The key results obtained from the research can be summarized as follows:

(1) The results suggest that, on average, diesel buses maintain a cost advantage in the smaller bus fleets for a 10-year operation period starting in 2023, even when accounting for carbon emission costs. Without factoring in carbon emission costs, the TCO for the diesel bus option is approximately 21.24% lower than that of the off-site gray hydrogen purchase and gaseous delivery option, which is the most cost-effective choice among all the hydrogen alternatives. However, hydrogen alternatives are projected to become economically competitive for a large bus fleet commencing in 2028. The findings indicate that in 2031, the TCO for all hydrogen scenarios is expected to be lower than the TCO for the diesel bus scenario. Hydrogen holds substantial promise as a sustainable and carbon-neutral solution, offering a viable path towards cleaner transportation in the future.

(2) The probabilistic analysis results underscore the significant impact of the selected hydrogen supply chain and carbon emission costs on the TCO. Looking forward to 2028, on-site Steam Methane Reforming (SMR) without carbon capture appears to be the most likely candidate to achieve the lowest TCO among all hydrogen supply options, excluding carbon emission costs. However, when carbon emission costs are considered, the TCO analysis suggests that choosing on-site SMR with carbon capture (69.2%) becomes a more probable cost-effective option for large bus fleets, compared to SMR without carbon capture (30.8%).

(3) Regarding the on-site electrolyzer, it is critical to note that its reliance on grid power initially leads to increased electricity costs and carbon emissions, resulting in a higher TCO that is 18.24% greater than that of on-site SMR with carbon capture for the 100-bus case in 2028, especially when including carbon emission costs. Moreover, the estimated levelized cost of hydrogen at 4.33 USD/kg from the electrolyzer in 2028...
remains higher than the levelized costs of blue and gray hydrogen from SMR, which are 2.12 USD/kg and 1.48 USD/kg, respectively. These results highlight the necessity for significant investments in enhancing renewable energy penetration within the power grid, thereby lowering electricity costs, to establish the electrolyzer as a more competitive alternative to SMR. Furthermore, as the sensitivity analysis suggests, improving the electrolyzer’s efficiency by 20% (from 0.73 to 0.88) could potentially decrease the TCO by 5.38%, indicating that future advancements in electrolyzer efficiency may lead to a more favorable TCO.

There are limitations that may affect the robustness of the findings. Firstly, this study does not account for certain costs, such as those associated with land acquisition, which could significantly impact the overall TCO of FCEBs. The costs of land acquisition for hydrogen refueling stations and other infrastructure components can vary widely, depending on the location and the chosen hydrogen supply alternatives. Moreover, the use of a scaling equation to estimate the capital cost of hydrogen refueling stations introduces some degree of uncertainty to the analysis. The accuracy of this scaling equation heavily depends on the assumption made about the reference cost, which may not accurately reflect the actual costs of individual components such as storage, dispensers, and other station equipment. A more robust approach might be to calculate these costs individually, tailored to each hydrogen supply alternative. Lastly, it is important to acknowledge that there are numerous other input parameters with variance beyond those considered in this study. Future research should aim to include more probabilistic parameters, based on comprehensive data collection, to enhance the study’s thoroughness and accuracy.

Despite these limitations, the study has successfully highlighted the comparative TCO of various hydrogen supply alternatives for FCEBs considering carbon emission costs. Further research and data collection efforts could enhance the accuracy and reliability of TCO analyses in future studies.

Author Contributions: Conceptualization, H.W.; Methodology, Z.C. and H.W.; Formal analysis, Z.C.; Data curation, Z.C.; Writing—original draft, Z.C.; Writing—review & editing, H.W.; Supervision, H.W. All authors have read and agreed to the published version of the manuscript.

Funding: This research received no external funding.

Institutional Review Board Statement: Not applicable.

Informed Consent Statement: Not applicable.

Data Availability Statement: Data are contained within the article.

Conflicts of Interest: The authors declare no conflict of interest.

References


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