RHODE ISLAND PUBLIC TRANSIT AUTHORITY

Sustainable Fleet Transition Plan

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Authorship and Uses

This report was prepared by the clean transportation and energy consulting firm of Gladstein, Neandross & Associates (GNA). This report was prepared on behalf of Rhode Island Public Transit Authority (RIPTA). The opinions, findings, conclusions, and recommendations are those of the authors and do not necessarily represent the views of RIPTA. RIPTA, its officers, employees, contractors, and subcontractors make no warranty, expressed or implied, and assume no legal liability for the information in this report.

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Executive Summary

The Rhode Island Public Transit Authority (RIPTA) is charged with meeting numerous interrelated federal, state and local requirements for congestion mitigation, air quality improvement, and transit service reliability. Converting its fleet to zero or near-zero emission vehicles has the potential to help RIPTA meet these obligations while supporting various state and local sustainability commitments. However, significant operational, infrastructure and cost constraints exist and must be addressed for long-term success while balancing environmental goals with important co-priorities of affordable service, reliability, equity, and operational flexibility. The introduction of new technologies into the fleet should be done in a manner that minimizes impacts to riders and provides continuity of service, while maximizing environmental benefits.

To fully assess the opportunities and implications of fleet conversion, and develop a strategy that is sustainable over the long term, a technical assessment of commercially-available technologies and their ability to meet RIPTA's operational needs was conducted. Battery-electric, fuel cell, and natural gas buses were evaluated for commercial readiness, fuel availability, performance, and capital, maintenance and infrastructure costs. These results informed eight fleet conversion scenarios to one or a combination of alternative technologies, and were evaluated against a baseline diesel scenario for cost and emissions over a 30-year timeframe. Although a helpful near-term step, a hybrid-electric vehicle scenario was not included because it did not meet the stated purpose to reach zero or near-zero emissions. These evaluations did not consider incentive programs due the inherent uncertainties of award amounts and timelines, although the report does describe these programs' potential to improve cost savings.

The analysis shows that while alternative fuel technologies offer higher capital costs and lower operational costs, the operational cost savings do not fully offset incremental costs over time in the absence of incentive funding. Of the alternative fuel scenarios, R/CNG and combination R/CNG+EV offer the most cost-competitive option at $2.61/mi and $2.66/mi, approximately $0.05/mi to $0.10/mi more than the current diesel scenario. All-battery electric scenario costs range from $2.82/mi to $3.33/mi, depending on the particular charging strategies assumed. In terms of emission reduction potential, conversion to 100% electric buses offers the greatest emissions reductions in the long term. Scenarios using natural gas buses fueled with Renewable Natural Gas (R/CNG) offer greater short-term NOx and GHG reductions because the electrical grid is initially powered in part by fossil fuels. Notably, the analysis shows that the additional long-term NOx and GHG emission reductions achieved by electric vehicles over the reductions achieved by R/CNG vehicles are relatively small. Both battery-electric buses and fuel cell buses provided the greatest particulate matter reductions over all timeframes.

Incorporating this research into an action plan requires RIPTA to balance environmental goals with co-priorities of affordable service, reliability, equity, and operational flexibility, all in a context of too few resources to meet current repair and service goals. Over the last few years there has been considerable excitement from the transport sector on the opportunity to electrify buses. Stakeholders at all levels have focused on the prioritization and uptake of electric vehicles. This provides the opportunity to mitigate the risk of the substantial capital and operational challenges associated with electric buses.

The results of this assessment suggest that RIPTA should adopt a graduated program that leverages equipment demonstrations to provide additional experience with zero-emission buses in RIPTA's operations while working toward a long-term transition to a fully zero-emission fleet. Additionally, RIPTA should initiate regular engagement with local utilities and state agencies to address infrastructure upgrades and financing needs as discovered through these processes.

Specifically, RIPTA proposes the following near-term steps over the next three years.

- Develop a zero-emission pilot program to demonstrate commercially available electric transit buses on a short-term basis in RIPTA's operations.
- Leverage available incentive funds at the state and federal level to subsidize the costs of the pilot program
- Develop an Electric Bus procurement specification
- Reassess the costs and challenges of zero-emission technologies over the course of the pilot program and update this Sustainable Fleet Transition Plan based on those reassessments
- Monitor R/CNG opportunities in the medium term in the event that zero emissions battery-electric bus technology proves insufficient to address statewide transit needs or is too costly
- Continue to work with state agencies and the local utility to:
    - Plan for a larger scale transition to zero-emissions that will likely require substantial electrical infrastructure upgrades and investments.
    - Develop policies to clarify rules, roles, and responsibilities for electricity use and management
    - Evaluate options to monetize these infrastructure investments through other mechanisms (energy/demand services, grid resiliency, etc.)

1.0 Introduction

The Rhode Island Public Transit Authority (RIPTA) is a quasi-public agency that runs Rhode Island's statewide public transit system. RIPTA's Mission is "to provide safe, reliable and cost-effective transit service with a skilled team of professionals responsive to our customers, the environment, and committed to transit excellence." Delivering on this objective involves managing a complex, inter-related mix of tough challenges that RIPTA must meet each day, to ensure that it provides excellent public transportation to the citizens of Rhode Island.

RIPTA provides public transportation to nearly every of Rhode Island's communities, covering an area of approximately 1,200 square miles with a population of 1.0 million. It provides fixed-route transit bus service, Flex services, and paratransit services throughout the state. RIPTA plays an especially important role in providing low-cost public transportation in the capital city of Providence, which has a population of about 180,000 people. Nearly 30 percent of Providence's citizens are in a lower income category. Providence has more RIPTA bus service (nearly 30 fixed routes and 770 stops) than any other city or town in the state, while also serving as a hub for bus service to all major regional cities. RIPTA works to meet all these public transportation needs, and is collaborating with the Rhode Island Department of Transportation (RIDOT) to create a strong multimodal transportation system in Providence.[1]

To cover Providence and its statewide service area, RIPTA operates nearly 2,800 daily transit trips on weekdays, and about 1,100 daily trips on weekends. Each year, RIPTA vehicles deliver passengers over nearly 10 million miles on fixed routes. It maintains a fleet of approximately 224 fixed-route buses, 95 paratransit vans, and 17 flex vans. In 2017, total ridership (person-trips) exceeded 16.6 million; about 96 percent was over fixed bus routes. However, this also included essential flex and senior ride services that totaled an annual ridership of about 600,000 trips.[2]

To meet core agency objectives codified in its mission statement, RIPTA has developed and implemented a variety of "green initiatives" that can reduce its overall environmental impact, while also cutting operating costs. This goes well beyond RIPTA's important role in reducing vehicle emissions by replacing automobile trips, reducing traffic congestion, and enabling compact development. RIPTA has also made important green investments in a variety of areas that include deployment of clean vehicles, implementation of building energy efficiency improvements (e.g., the Paratransit Operations Center), and installation of a solar rooftop on the Transportation Building in Providence. This facility now generates clean, renewable electricity while significantly reducing RIPTA's electricity costs.

While all of these initiatives are important, of particular relevance to this report are RIPTA's efforts over the last decade to purchase and deploy clean transit buses. In October 2010, RIPTA received ten new classic hybrid trolleys, as well as replacing a portion of the fixed-route fleet with 53 Gillig BRT Hybrid Buses. These hybrid diesel Gillig buses and trolleys are powered by clean diesel hybrid electrical propulsion systems that reduce emissions, save fuel and are smoother and quieter than conventional buses. This not only reduces air pollution, but noise pollution as well, thus improving the environment for Rhode Islanders.[3] However -- as this report describes in detail -- RIPTA now seeks to transition its fleet as rapidly

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[1] City of Providence, "Planning for the Smart Transit and Infrastructure System of the Future," Mayor Jorge O. Elorza, 2016, https://cms.dot.gov/sites/dot.gov/files/docs/RI%20Providence.pdf.

[2] Rhode Island Public Transit Authority, "About RIPTA," https://www.ripta.com/about.

[3] Rhode Island Public Transit Authority, "Green Initiatives," https://www.ripta.com/green-initiatives.

as possible to ultra-clean bus technology, by purchasing zero-emission public transportation technology wherever feasible, and near-zero-emission technology elsewhere.

RIPTA's current transit bus fleet consists of 224 fixed route buses, nearly all of which are powered by conventional heavy-duty diesel engine / transmission technology, complemented with diesel hybrid-electric buses. RIPTA also operates 93 paratransit vans and 16 Flex vans that are powered by diesel engines. During weekdays, it operates nearly 2800 daily trips, and approximately half as many daily trips on weekends. The agency's total fuel use exceeds 2.3 million gallons per year, most of which is diesel consumed by the fixed route bus fleet that is the focus of the current transition plan development.

1.1 Facilitating Transportation Policies

RIPTA's provision of public transportation in the city of Providence and throughout Rhode Island are essential to simultaneously meet numerous key, interrelated, federal, state and local requirements. These are to 1) mitigate congestion, 2) reduce emissions of harmful air pollutants (e.g., smog precursors like oxides of nitrogen, and toxic air contaminants like diesel particulate matter), 3) reduce GHG emissions, and 4) provide the general public with access to reliable, cost-effective transportation. As described below, numerous state and local policies have also been adopted that establish sustainability goals that can be advanced by RIPTA's transition to more sustainable transit technologies.

2014 Resilient Rhode Island Act of 2014 – This established Rhode Island's Executive Climate Change Coordinating Council (EC4), and set specific GHG reduction targets (25% below 1990 levels by 2025, 50% below 1990 levels by 2035, and 85% below 1990 levels by 2050). It also established a science and technical advisory board to assist the Council; and incorporated consideration of climate change impacts into the powers and duties of all state agencies.[4] The Resilient Act is one key driver for RIPTA's current efforts to transition toward a zero-emissions fleet.[5]

Rhode Island Greenhouse Gas Emissions Reduction Plan[6] - This Plan, also known as RIEC[4], was released by the State in December 2016. It includes strategies, programs, and actions to meet the targets for greenhouse gas (GHG) emissions reductions as established in the Resilient Rhode Island Act, in accordance with the provisions of Rhode Island General Laws §42-6.2-2(2). The Plan summarizes eight distinct existing state policies for reducing GHG emissions, including several that impact public transportation agencies such as RIPTA. Three of the GHG mitigation strategies that impact RIPTA's planning process are summarized in Table 1.

Table 1. Existing GHG mitigation strategies impacting RIPTA operations summarized in GHG Reduction Plan

GHG Mitigation Option / Approach	Applicable Major Policies for RIPTA	Existing or Potential New Mitigation Policy Considerations

[4] State of Rhode Island, "Resilient Rhode Island Act (2014)," http://www.energy.ri.gov/policies-programs/ri-energy-laws/resilient-rhode-island-act-2014.php.
[5] City of Providence, "Planning for the Smart Transit and Infrastructure System of the Future," Mayor Jorge O. Elorza, 2016, https://cms.dot.gov/sites/dot.gov/files/docs/RI%20Providence.pdf.
[6] State of Rhode Island, Rhode Island Greenhouse Gas Emissions Reduction Plan, December 2016, http://climatechange.ri.gov/documents/ec4-ghg-emissions-reduction-plan-final-draft-2016-12-29-clean.pdf.

Vehicle Miles Traveled (VMT) Reductions	Promote and invest in alternative modes of public transportation	• Reduce passenger car VMT by increasing public transit up to national average
Deployment of Electric Vehicles	Increase RIPTA deployment of electric and hybrid-electric buses	• Transition to 100% zero-emission bus fleet by 2050
Use of Biofuels	None existing	• Explore increased use of biofuels to power transit buses and support services

State Action Plan to Stand Up to Climate Change - On September 15, 2017, Governor Gina Raimondo issued Executive Order (EO) 17-10. This initiative largely focuses on avoiding the devastating economic impacts that climate change can impose on Rhode Island, given the State's 400 miles of low-lying coastline. The EO takes several key actions designed to help Rhode Island prepare for climate change while also reducing GHG emissions. This includes the establishment of a State Chief Resiliency Officer tasked with "driving climate resiliency efforts across the State, both in government and in collaboration with business, academic and nonprofit partners."

The Chief Resiliency Officer is charged with leading the development of a statewide "Action Plan to Stand Up to Climate Plan," for submittal to the Governor by July 1, 2018. The Plan must include recommended actions "to make Rhode Island's residents, economy, infrastructure, health system, and natural resources more resilient to the impacts of climate change."[7] Various specific types of potential actions must be "identified and prioritized" in the Plan, across all sectors of the State's economy. This includes potential actions relevant to RIPTA's sustainable fleet transition plan. Greater specifics will be identified as the Plan is developed, released and implemented.

Executive Order 15-17 ("Lead by Example") – in December 2015, Governor Raimondo issued a "Lead by Example" EO[8] that requires State agencies to reduce energy consumption, increase energy efficiency, and expand use of renewable energy sources. Many of the required action items or goals are relevant (directly or indirectly) to RIPTA's fleet transition plans. Examples include the following directives for State agencies like RIPTA:

- Seek to reduce the use of natural resources at State facilities, including a reduction in energy consumption derived from fossil fuels and emissions associated with such consumption
- Contribute to the State achieving a 10 percent reduction in energy consumption by 2019, and consume only renewable electricity by 2025
- Consider full life-cycle costs and savings in planning and implementing projects when making cost-effectiveness determinations about investments in capital assets and services
- Take steps to encourage state employees to commute by foot, bike, or public transit

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[7] State of Rhode Island, Executive Order 17-10: Action Plan to Stand Up to Climate Change, September 2017, http://www.governor.ri.gov/documents/orders/ExecOrder-17-10-09152017.pdf.

[8] State of Rhode Island, Executive Order 15-17: State Agencies to Lead by Example in Energy Efficiency and Clean Energy, December 2015, http://www.governor.ri.gov/documents/orders/ExecOrder15-17.pdf.

City of Providence Executive Order on Climate Action – In April 2016, Providence Mayor Jorge Elorza signed City Executive Order 2016-3 titled "Commitment to Eliminating City-Wide Carbon Emissions and Preparing for the Long-Term Impacts of Climate Change." This EO commits Rhode Island's largest city to become "carbon neutral" by 2050. Similar to State EO 17-10 (described above), the Providence EO establishes strategies to "prepare for the impacts of climate change" while simultaneously taking action to inventory – and aggressively reduce – the City's GHG emissions. As one example of how this does or will impact RIPTA's operations, the EO requires that the City must "consider climate impacts and greenhouse gas emissions in all planning and decision making processes."[9]

The Paris Agreement – The Paris climate conference (COP21) was held in December 2015. It resulted in the U.S. and 194 other countries jointly adopting the first universal, binding global climate action plan. The U.S. signed this "Paris Agreement" in April 2016,[10] and by the end of 2016 almost every country in the world has signed it also. The Agreement established a binding global action plan designed to systematically reduce worldwide GHG emissions, largely by focusing on major cities across the globe. The specific objective is to limit the rise in average global temperatures to below 2°C, which is believed to be the threshold that can avoid dangerous climate change. Because the transport of goods and people contributes roughly one quarter of the world's anthropogenic GHG emissions – with on-road transportation being by far the largest transportation-related source – a large part of the focus for the Paris Agreement centers on how the U.S. and other countries can stabilize, and then start decreasing, their mobility-generated GHG emissions.[11]

One key result from COP21 and the Paris Agreement was emergence of the "Compact of Mayors." This is the world's largest cooperative effort among mayors and city officials across the globe to reduce GHG emissions and climate risks in cities. Also formed was the Covenant of Mayors for Climate & Energy, which is oriented around European countries. In mid-2016, a new initiative titled "Global Covenant of Mayors for Climate & Energy" was announced, to join the two efforts. This is an international alliance of cities and local governments "with a shared long-term vision of promoting and supporting voluntary action to combat climate change and move to a low emission, resilient society." Both the Compact of Mayors and the Covenant emphasize the importance of climate change mitigation and adaptation, as well as increased use of clean, affordable energy. The focus is on reducing GHG emissions from city sectors with the greatest impact – especially transportation – to help ensure cost-effective targeting of localized GHG emission reductions.

Providence is one of nearly 125 U.S. cities – and 500 cities worldwide -- that have joined the Compact of Mayors. In conjunction with the Mayor's executive order described above (signed on the same day), Providence has agreed to implement the following specific strategies under the Covenant:

[9] City of Providence, Executive Order 2016-3: Commitment to Eliminating City-Wide Carbon Emissions and Preparing for the Long-Term Impacts of Climate Change, April 22, 2016, https://data.providenceri.gov/Reference/Executive-Order-on-Climate-Action/rnq7-avs3.

[10] In June 2017, President Trump announced that the U.S. was pulling out of the Paris climate agreement. He has since indicated that the U.S. might consider re-entering the agreement, if its terms can be renegotiated. Other nations in the agreement have rejected renegotiating. Notably, many U.S. cities (including Providence) are showing leadership to meet the goals and intent of the Paris agreement, without support of the federal government.

[11] United Nations, "Sustainable Development Goals," The Paris Agreement on Climate Change, accessed online at: http://www.un.org/sustainabledevelopment/climatechange/.

- Conduct an inventory of carbon / GHG emissions that meets standards set by the Compact of Mayors
- Track and disclose city carbon / GHG emissions
- Set targets for reductions in carbon / GHG emissions
- Implement a climate action plan that will integrate climate mitigation and resilience efforts in city and neighborhood planning

1.2 Transitioning to a Sustainable Fleet

RIPTA's transition to a sustainable fleet must balance environmental goals with important co-priorities of affordable service, reliability, equity, and operational flexibility. The introduction of new technologies into the fleet should be done in a manner that minimizes impacts to riders and provides continuity of service, while maximizing environmental benefits. Consequently, RIPTA is focusing the development of the current transition plan on the fixed route bus services that represent the majority of fleet emissions and ridership and where sustainable transit technology product offerings are greatest.

The transition plan is based on an analysis of zero-emission and near-zero emission technologies, including battery-electric, fuel cell, and natural gas powertrains. The remainder of this report describes RIPTA's current understanding of the state of these technologies, the numerous deployment scenarios analyzed, and the results of that analysis. It concludes with recommendations for next steps in the fleet transition.

Based on the assessments in this report, RIPTA believes that zero-emission technologies will be an important part of the future transit market. Further, zero-emission technologies most directly address the environmental and sustainability policy goals of the state. However, the technology landscape for zero-emission buses is in a state of rapid change. Battery-electric buses are generally more commercially mature and less costly than fuel cell buses, but both technologies remain more expensive options than RIPTA's current diesel fleet. And, while costs continue to decline for both technologies and operational capabilities such as range and refueling/recharging times continue to improve, neither technology yet represents a one-to-one replacement for diesel buses in all operations. Managing and deploying charging infrastructure at the scale necessary to fully transition RIPTA's fleet is also an unknown and daunting challenge. No transit agency in the U.S. has yet deployed the number of busses and charging/fueling infrastructure that RIPTA would require for a full transition to zero-emission buses.

No transit agency in the U.S. has yet deployed the number of busses and charging/fueling infrastructure that RIPTA would require for a full transition to a zero-emission fleet.

Given these considerations, RIPTA believes the that the next steps in a sustainable fleet transition should provide additional experience with zero-emission buses in RIPTA's operations while working toward a long-term transition to a fully zero-emission fleet. Specifically, RIPTA proposes the following near-term steps over the next three years.

- Develop a zero-emission pilot program to demonstrate commercially available electric transit buses on a short-term basis in RIPTA's operations.
- Leverage available incentive funds at the state and federal level to subsidize the costs of the pilot program
- Develop an Electric Bus procurement specification

- Reassess the costs and challenges of zero-emission technologies over the course of the pilot program and update this Sustainable Fleet Transition Plan based on those reassessments
- Monitor Renewable CNG (R/CNG) funding opportunities, particularly if battery-electric bus technology proves insufficient or too costly to address statewide transit needs
- Continue to work with state agencies and the local utility to:
    - Plan for a larger scale transition to zero-emissions that will likely require substantial electrical infrastructure upgrades and investments.
    - Develop policies to clarify rules, roles, and responsibilities for electricity use and management
    - Evaluate options to monetize these infrastructure investments through other mechanisms (energy/demand services, grid resiliency, etc)

2.0 Technology Review Summary

This report provides a comparative analysis of the costs, environmental benefits, and operational considerations of three categories of zero/near-zero emission transit bus technologies relative to RIPTA's current diesel fleet. Table 2 summarizes the technologies considered in the analysis, and any variants of the technologies considered. The variants listed are the result of considering different methods of supplying fuel/electricity to the bus as these different methods can have significant impacts on the costs, environmental benefits, and operational impacts of the technology. This is not an exhaustive list of every possible technology or variant that may exist for transit buses. Rather, this list represents a reasonable set of technologies that are believed to be the most viable near-term options for RIPTA's fleet.

Table 2. Included technologies

Technology	Variants
Battery-electric	Depot charging
	En-route charging
Fuel Cell	Liquid hydrogen delivery
	On-site electrolysis
	On-site steam-methane reformation
Near-zero Natural Gas	On-site CNG

For each of the technologies considered, and the subsequent deployment scenarios, certain common assumptions are made to better define the scope of the analysis and ensure comparability of the results between scenarios.

Emissions – The primary emissions of interest are oxides of nitrogen (NOx), fine particulate matter (PM2.5), and greenhouse gases. The analysis considers the direct "tailpipe" emissions of NOx and PM2.5 from the current diesel fleet and from the proposed technologies. GHG emissions are modeled on a full fuel cycle basis that considers GHG emissions from production to end use.

Electricity supply – All electricity is assumed to be supplied by the electrical grid. GHG emissions for supplied electricity in future years are dependent on the projected carbon intensity for the Rhode Island grid mix in future years. Additional details describing the assumed carbon intensity of the grid mix are described in Appendix D and track the carbon reduction goals for the electrical grid described in the RIEC[4] GHG reduction plan. Rhode Island is on track to meet its initial 2020 goal. Based on the goals in the RIEC[4] plan, the carbon intensity of the electrical grid is assumed to decline to zero by 2050.

2.1 RIPTA Fleet Profile

Facilities Overview

Transit operations and supporting administrative functions occur at RIPTA's two transit facilities located in Providence and Newport. The Providence facility consists of two maintenance facilities, administrative buildings, fueling infrastructure, wash bays, bus storage building, and bus storage yard. All transit buses (excluding paratransit) are parked at the storage building at 269 Melrose Street, and in the adjacent yard off of Cadillac Drive. The storage building and yard are constrained by limited parking for buses making any space claim for additional fueling/charging infrastructure an important consideration.

The Newport facility consists of a maintenance facility, administrative building, fueling infrastructure, wash bays, and a bus storage building. While the Newport facility is also space constrained, all transit buses are able to be parked in the storage building.

Fleet Overview

RIPTA operates a fleet of 224 35- and 40-foot urban transit buses, including 62 diesel-hybrid buses and 164 conventional diesel buses. Approximately 73% of the fleet is model year 2010 or newer buses. 190 buses operate out of the Providence facility and 36 buses operate out of the Newport facility. These numbers may fluctuate based on procurements, spare ratios, and annual service requirements but are representative of the current vehicle distributions between the two facilities.

Fueling and Fueling Infrastructure

The Providence bus storage facility has three fueling lanes supplying diesel fuel from three 20,000-gallon underground storage tanks. Buses are typically fueled over the course of an eight-hour evening shift. Fueling occurs over a typical 5-minute period while staff simultaneously sweep out the buses and record hubometer data. Once the clean out and fueling are complete, buses are returned to parking lanes. Fueling operations at the Newport facility are identical to Providence, except that the facility has only a single fueling lane and is supplied by a single 20,000-gallon underground storage tank.

Transit Operations

During peak service days which occur Monday through Friday, RIPTA operates approximately 150 buses in maximum service on 257 daily blocks out of the Providence facility and 30 buses on 50 daily blocks out of the Newport facility. The average distance of an assignment is 110 miles; however, individual assignments range from 6 miles up to 342 miles. Some transit buses receive more than one assignment during a peak day. Layovers occur at 83 unique locations. Some locations are owned by RIPTA, but many are not. Morning assignments begin at 4:45AM and occur throughout the day until 1:00AM.

2.2 Battery-Electric Buses

Commercial offerings

Electric transit buses are currently available from established transit bus manufacturers and from newer, EV-only bus manufacturers. Table 3 summarizes the current commercial offerings for new battery-electric buses. In addition, there are several companies offering EV retrofits of existing diesel buses, including Complete Coachworks and eBus. Product offerings continue to evolve as manufacturers deploy more BEBs, receive customer feedback, and improve their products with newer technologies. Consequently, the EV bus market is rapidly changing and new products are expected to enter the market over the next few years. For example, Gillig has announced a partnership with Cummins to integrate Cummins' newly developed electric powertrain into Gillig's next generation of electric buses. Other manufacturers, including New Flyer and Proterra, have announced significant improvements anticipated for the 2019 model year products that will increase efficiency and extend the range of the buses.

Table 3. BEB Commercial Offerings

Bus Manufacturer	New Flyer	Gillig	Nova	Proterra	BYD
35' bus	Yes	Expected 2019	No	Yes	Yes
40' bus	Yes		Yes	Yes	Yes
60' bus	Yes		No	No	Yes
Nominal Range* (miles per charge)	80-260		25	49-350	145-200
Battery Capacity (kWh)	150-885		76	79-660	270-591
En-route Charging Option	Yes		Yes	Yes	3rd party hardware

***Nominal range is based on manufacturer claims. Cabin HVAC loads, battery degradation, and other real-world impacts that may reduce actual range are not reflected in the nominal ranges stated.**

These improvements will be important to the long-term viability of a BEB strategy as this report considers the currently available range of BEB offerings for new purchases and includes projections of declining capital costs for BEBs over time. These assumptions are detailed in Appendix A. Additionally, the report considers a "full deployment" scenario for BEBs that implicitly assumes BEB range will increase over time to address blocks of work in RIPTA's current operations that cannot be met with current technology.

RIPTA-specific Requirements – Like other transit agencies, RIPTA has developed bus specifications based on their long operating experience. One particular requirement that was determined to limit the currently available bus options is the requirement of a stainless-steel chassis or other corrosion-resistant material. This requirement stems from the extreme corrosion of standard steel frames from road salt that RIPTA has experienced in the past. BYD does not currently offer a suitable corrosion-resistant chassis option that would meet RIPTA's requirements and was not considered as a technology option when developing the BEB deployment scenarios.

En-route vs Depot charging

Electric transit buses can broadly be divided into two groups, fast-charge and extended-range. Extended-range buses are equipped with large battery packs that provide long ranges, typically greater than 100 miles, and are charged over a period of several hours. Because of the long recharge times, these buses are charged at the transit agency's garage – or depot – and the practice is referred to as depot-charging.

Alternatively, buses may be charged using charging equipment placed at strategic locations along the bus route (en-route). En-route charging utilizes very high power (typically greater than 300 kW) fast chargers placed at locations where buses are expected to stop for an extended period of time, usually at the beginning or end of a route. These stops are known as layovers and provide an opportunity to recharge buses equipped with a specialized, overhead charging interface. Buses capable of en-route charging typically have smaller battery packs than extended range buses and the battery chemistry is specifically designed to improve high-power charging performance.

Operationally, depot-charged buses are similar to RIPTA's current diesel fleet in that the charging occurs at RIPTA's garage and the buses are intended to complete a full day of work before returning to the garage to recharge. By contrast, en-route charging requires frequent charging throughout the day. While en-route charging creates some operations restrictions compared to RIPTA's current diesel fleet, en-route charging has advantages compared to extended range buses in terms of maximum daily range and bus weights. These advantages and disadvantages are described in greater detail in the following sections.

Efficiency and Range

The feasibility of BEBs is highly dependent on the achievable daily range of the buses. When daily range is limited to less than the current daily mileages of the diesel fleet, transitioning to a fully battery-electric fleet could require replacing one diesel bus with more than one BEB. Replacement ratios of greater than one-to-one (EV-to-diesel) would be cost prohibitive, consequently, it is important to understand the practical range of BEBs in RIPTA's operations.

Bus manufacturers typically reference "nominal" ranges for BEBs in marketing literature. These nominal ranges, however, are based on testing conducted at the Altoona Bus Research and Testing Center. The tests used to generate these range estimates are useful for the purpose of comparing the energy efficiency amongst buses using the same technology (e.g. diesel to diesel comparisons). But the tests neglect important real-world impacts that significantly affect the reliable range for BEBs. Taken together, these real-world impacts can reduce the practical range to 45% to 90% of the nominal range for RIPTA's routes.

Battery Degradation – Current lithium-based battery technologies exhibit degradation of the battery capacity over time. The factors affecting the speed and extent of the degradation are complex and depend on both the specific battery chemistry and the use of the battery. In general, battery life decreases as the depth of discharge, frequency of discharges, peak power demand, and charging rate increase. Buses intended for en-route charging utilize a lithium titanite (LTO) battery chemistry that allows for very high charging rates and frequency of discharges while providing a long service life. However, LTO batteries achieve these improvements at the expense of reduced energy density and higher battery costs. Consequently, LTO batteries are used in en-route charging applications where the required range between recharging events is low and a smaller battery pack can be used. Extended range buses typically use lithium iron phosphate ($LiFePO_4$) or nickel manganese cobalt oxide (NMC) chemistries. NMC batteries have the highest energy density, allowing for maximum range with minimal incremental weight impacts. LiFePO4 chemistries have reduced energy densities compared to NMC, but excel in the area of safety and generally have longer cycle life at higher discharge rates than NMC chemistries.

Because battery degradation depends on so many complex factors, this report bases battery degradation assumptions on manufacturer claims of end-of-life capacity for warranty coverage. Warranty periods for the battery systems range from six to twelve years, depending on the manufacturer. End-of-life capacity estimates range from 70-80% of the original capacity. Since the objective of the analysis is to estimate total lifecycle costs and operational constraints of transit bus technologies, a conservative approach was taken with respect to the longevity of the battery system. As described in Appendix A, this analysis assumes a useful battery capacity of 80% of the original capacity with a replacement at the bus midlife.

Heating, Ventilation, and Cooling (HVAC) Loads – Air conditioning and heating loads can represent a significant energy demand on transit buses. For example, data reported by Worcester Regional Transit Authority indicates that per-mile energy consumption decreased by 50% between winter and spring operations, owing to decreased cabin heating demands.[12] These heating loads reduced the average energy consumption from 3.87 kWh/mi to 2.58 kWh/mi. Similarly, a study conducted by University of Minnesota researchers on air conditioning loads of a transit bus in Minneapolis during a two-week period in late summer indicated average air conditioning power demands of 6.1 kW.[13]

The impact of HVAC loads on per-mile energy consumption rates is greatest on low-speed routes where the average propulsion energy demand and daily mileage are low. Constant power demands from HVAC loads represent a larger portion of the total route energy requirements than for routes with higher average speeds and greater propulsion energy demands. This analysis assumes a fixed HVAC load of 6 kW for purposes of estimating energy requirements for each of RIPTA's blocks.

Route Design – Testing at Altoona demonstrates the effect of different drive cycles on the efficiency of BEBs. As shown in Table 4, the Altoona tests include energy consumption measured over the Central Business District (CBD), Arterial (ART), and Commuter cycles. Energy consumption is lowest in the Commuter cycle as this cycle includes no stops and is predominantly a constant cruise test at 55 mph. The next lowest energy consumption is seen in the CBD cycle, with low maximum speeds of 20 mph and frequent stops. The highest energy consumption rates are in the ART cycle, with its combination of higher peak speeds of 40 mph and several stops.

Table 4. Altoona energy consumption data for BEB buses

Bus Energy Consumption[14] (kWh/mi equivalent)	CBD	ART	Commuter
Avg Speed (MPH)	12.5	25.5	37
New Flyer XE40	*1.75*	*2.29*	*1.5*
Proterrra BE40	*1.56*	*2.1*	*1.41*
Proterra BE35	*1.83*	*2.23*	*1.34*
BYD K9	*1.99*	*2.54*	*1.43*
BYD K7	*1.18*	*1.84*	*1.15*
Average BEB Energy Consumption	1.67	2.20	1.37
New Flyer XD40 (diesel)	9.57	8.42	4.60

[12] Presentation by John Carney of Worcester Regional Transit Agency. 2016 Bus & Paratransit Conference. http://ad.apta.com/mc/bus/previous/2016bus/presentations/Presentations/Carney_John.pdf

[13] Campbell J, Kittleson D, Superbus Phase 1: Accesory Loads Onboard a Parallel Hybrid-Electric City Bus, 2009.

[14] Altoona test data. http://altoonabustest.psu.edu/buses

To estimate the effects of average route speeds on BEB energy efficiency, GNA compared reported energy consumption rates for several electric transit buses to a New Flyer XD40 diesel transit bus. The trends in Figure 1 are consistent for the range of BEBs tested. The relative efficiency of BEBs declines as average speeds increase. This occurs largely due to the reduced benefit of regenerative braking and idle reduction from BEBs at higher average cycle speeds with fewer stops.

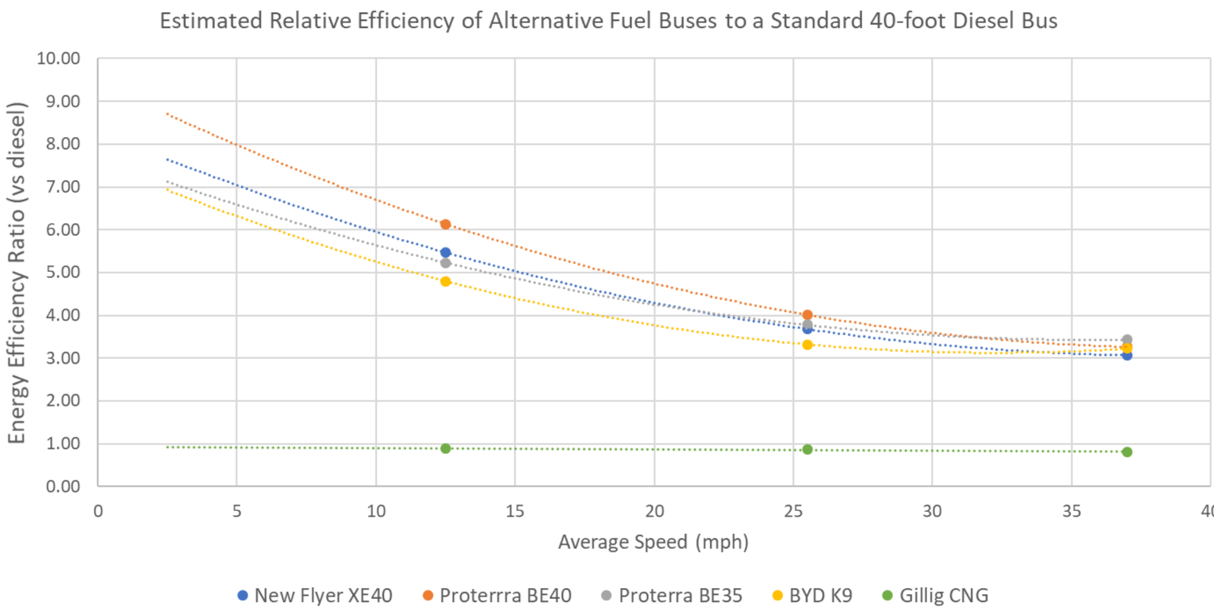

Figure 1. Relative efficiency of alternative fuel buses to a standard 40-foot diesel bus

RIPTA is currently engaged in an effort to equip the existing bus fleet with data collection equipment that will improve RIPTA's ability to track mileage and energy consumption on both a route-by-route basis as well as a vehicle-by-vehicle basis. Because those data were not available for the current analysis, an estimate of the fuel economy of a diesel bus at various average speeds was developed based on the Altoona test data for the XD40 transit bus. The resulting fuel economy curve is shown in Figure 2. At the average speed of 16.8 mph for the RIPTA fleet, the estimated average fuel economy using the curve in Figure 2 is 5.0 miles per gallon and compares well with the actual fleet average of 5.1 miles per gallon for RIPTA's fleet in 2016. Energy consumption rates for BEBs were then calculated using the Energy Efficiency Ratio (EER) curve for the New Flyer XE40 bus to calculate energy demand on a per-block basis.

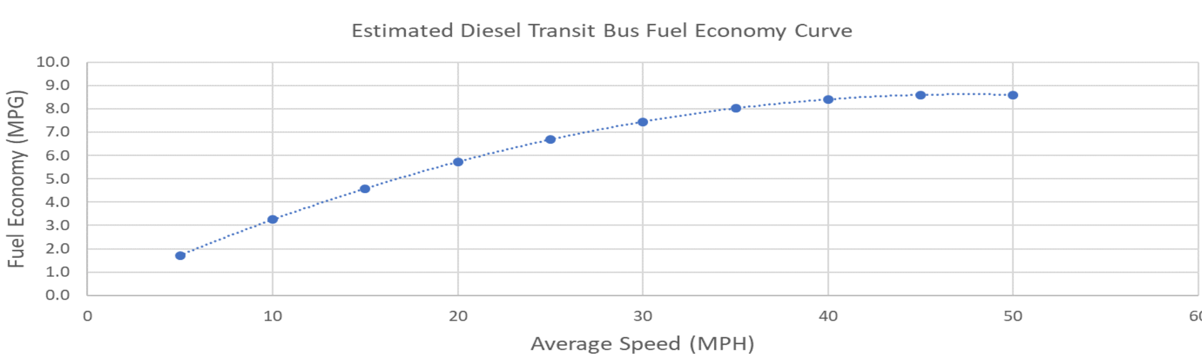

Figure 2. Estimated diesel transit bus fuel economy curve

En-Route Charging Assumptions – Range limitations of en-route charging buses are determined by the distance between charging opportunities. To avoid major disruptions in bus schedules, en-route charging is usually planned to occur during the normal "layover" time for a bus. These layovers usually occur at the beginning or end of a route and are used to make up for off-schedule arrivals and to relieve drivers in the field. By placing en-route charging infrastructure at these layover locations, it is possible to charge the bus while the bus would normally sit idle. However, to rely on en-route charging, the bus must be guaranteed a minimum amount of time at the charging stall to receive enough energy to reach the next en-route charging opportunity. This means that the charging portion of the layover time must be scheduled as if it is a stop and cannot be shortened to make up for off-schedule arrivals. For some routes, the energy requirements between layover locations are small enough to require only brief charging times of 5-10 minutes and can still allow time within the layover for schedule corrections. Other routes can require substantially longer charging periods, potentially requiring all of the layover time to be dedicated to charging or require schedule changes to increase layover time and reducing operational efficiency.

An analysis of RIPTA's current layover schedule indicates that all but five blocks could be served with en-route charging infrastructure using a BEB with a battery capacity of at least 105 kWh.[15] The remaining five blocks are constrained primarily by available recharging time at the layover location. Extending these layover times or deploying buses with additional battery capacity would allow all of RIPTA's current blocks to be served by en-route charging. However, 98 of the 444 modeled en-route charging events per weekday require the full layover time available. This indicates that a full-scale deployment with the current layover schedule and minimum battery capacity would be problematic for these 98 charging events as there is no flexibility in the duration of the layover to accommodate schedule corrections. RIPTA should anticipate the need to adjust layover schedules, utilize bus configurations with larger battery capacities, and/or provide for higher charging rates if en-route charging is to be used for any block that relies on one or more of these 98 charging events.

The above analysis relies on the same assumptions used for extended range BEBs related to useful battery capacity, HVAC loads, and route design impacts. As with the extended range BEB analysis, block-specific energy requirements are currently estimates. Collection of real-world route energy demands will improve the accuracy of the modeling estimates with respect to en-route charging requirements and scheduling burdens.

Bus Weight Impacts

The majority of battery-electric bus configurations currently available today result in incremental bus weight increases over a standard diesel bus. This has two significant implications for RIPTA's operations. First, the maximum weight to which a bus can safely be loaded is limited by the gross vehicle weight rating (GVWR). As the curb weight of the bus increases, the weight capacity available for passengers decreases. Under moderate passenger loadings, the incremental weight of EV buses generally does not pose a problem. For routes where there are a high number of standing passengers (standees), in addition to the seated passengers, the incremental weight of some battery-electric configurations could allow the bus to be loaded to unsafe conditions before the available space for passengers is filled. This problem is particularly prevalent for the largest battery configurations that exhibit the highest incremental weights. Table 5 summarizes the incremental weights for several battery-electric bus models and configurations at

[15] Proterra's FC+ 40' transit bus is equipped with a 105 kWh battery system. New Flyer also offers rapid charging buses with 150 and 200 kWh battery systems. Modeling of the layover charging opportunities assumes a 350 kW charge rate.

a standee ratio of 1.6 (all seats filled and an additional 60% of passengers standing) that is not atypical for some of RIPTA’s highest density routes. As highlighted, two bus configurations would exceed the bus GVWR at this passenger loading and were not considered as potential configurations in the plan development.

Incremental weight increases from the battery systems can be offset through other changes to reduce the bus weight. For example, Proterra’s use of fiberglass for much of its bus structure provides significant weight reductions. For the smallest battery configurations, Proterra’s battery-electric buses are lighter than a similar diesel bus. These lighter configurations come with significantly lower range and are generally best suited for use with en-route charging.

Table 5. Summary of electric bus weights

Make	Proterra							New Flyer			
Model	FC	FC+	XR	XR+	E2	E2+	E2 Max	XE40	XE40	XE40	XD40
Battery (kWh)	79	105	220	330	440	550	660	200	350	480	N/A
Nominal Range (miles)	25	34	70	106	141	176	211	64	112	154	
Curb Weight (lbs)	26,446	27,500	26,637	28,243	29,849	31,455	33,061	31,000	33,409	35,497	27,730
GVWR (lbs)	39,050	39,050	39,050	39,050	39,050	39,050*	39,050*	44,320	44,320	44,320	42,540
Seats	40	40	40	40	40	40	40	38	38	38	36
Design Load (passengers)	58	58	58	58	58	58	58	58	58	58	58
Weight at Design Load (lbs)	35,146	36,200	35,337	36,943	38,549	40,155	41,761	39,700	42,109	44,197	36,430
Exceeds GVWR	No	No	No	No	No	Yes	Yes	No	No	No	No
Weight (tons)	17.6	18.1	17.7	18.5	19.3	20.1	20.9	19.8	21.1	22.1	18.2
Incremental Weight vs Diesel (tons)	-0.6	-0.1	-0.5	0.3	1.1	1.9	2.7	1.6	2.8	3.9	0.0

*Note: Since the commencement of this study, Proterra has revised the GVWR for its new Catalyst bus models. The new models offer GVWRs of 43,650 lbs and would be capable of operating at the full design load without exceeding the GVWR.

The second significant implication incremental weight has for RIPTA's operations is tied to bridge weight limits. Rhode Island has over one hundred bridges with various weight limits. RIPTA traverses many of these bridges as part of regular service and can be at the posted weight limit for many bridges. Consequently, higher weight buses may be barred from certain routes by bridge weight limits even if the GVWR of the bus is not exceeded by passenger loading. A route-by-route analysis of bridge weight limits was not performed for the current planning effort, but could pose near-term restrictions on viable routes for battery-electric buses. Bus manufacturers are reporting weight reductions for their battery-electric bus platforms that will mitigate bridge weight issues, but these reductions may be offset by increasing battery capacities needed to serve some routes.

Costs

Battery-electric buses have significantly higher purchase prices than diesel buses, with the return on investment in the battery-electric platforms predicated on reduced operating and maintenance costs.

Bus Capital Costs – A transition to battery-electric buses includes upfront investments in both the incremental purchase price of battery-electric buses as well as the charging infrastructure needed to serve those buses. The incremental purchase price varies by model and is projected to decrease over time as battery costs decrease. These projections are detailed in Appendix A. However, current incremental costs for battery-electric buses are estimated at $168,000 to $415,000, depending on manufacturer and battery capacity. As shown in Table 6, RIPTA's current diesel bus purchase price is estimated at $539,000 and includes agency-specific equipment additions. Battery-electric bus purchase prices range from $707,000 to $954,000. Note that battery costs are a major driver, if not the major driver, of the incremental cost for BEBs. Battery costs are rapidly changing, leading to rapidly changing costs for BEBs. While this report incorporates battery cost reductions into the projected future price of BEBs, the exact cost of BEBs in any year and under any given procurement could be higher or lower than shown here.

Table 6. Purchase price assumptions for current battery-electric buses

Bus Type	Incremental vs Diesel	Base Vehicle	RIPTA Additions	Final Vehicle Cost
Baseline Diesel	$0	$481,200	$57,800	$539,000
Proterra FC+	$267,800	$749,000	$57,800	$806,800
Proterra XR	$187,800	$669,000	$57,800	$726,800
Proterra XR+	$267,800	$749,000	$57,800	$806,800
Proterra E2	$316,800	$798,000	$57,800	$855,800
Proterra E2+	$365,800	$847,000	$57,800	$904,800
Proterra E2max	$414,800	$896,000	$57,800	$953,800
BYD K9M	$268,800	$750,000	$57,800	$807,800
New Flyer XE40 (150 kWh)	$167,800	$649,000	$57,800	$706,800
New Flyer XE40 (480 kWh)	$357,550	$838,750	$57,800	$896,550

Bus O&M Costs – While BEBs have higher upfront purchase costs, their economic value proposition is based on their lower operating and maintenance costs. O&M costs were segmented into four categories; propulsion-related maintenance, non-propulsion related maintenance, mid-life overall, and fuel costs.

Fuel costs were calculated based on current and projected contract pricing for diesel fuel, utility energy and demand charges as described in National Grid tariffs, and estimated fuel economies. Table 7 summarizes the fuel cost assumptions for both depot-charged and en-route BEBs as compared to diesel buses. Note that RIPTA has very low costs for diesel fuel under their current contract. However, prices are expected to increase significantly in 2019. Based on contract futures for diesel fuel, RIPTA estimates that diesel prices could increase from $1.74/gallon to $2.20/gallon by 2019. This would raise the per-mile costs of diesel fuel to $0.37/mile. Additional details are provided in Appendix B.

Table 7. Fuel cost estimates for BEBs (2016 prices)

CY 2016 Values	Diesel	Depot-Charged BEB	En-route BEB
Fuel Costs	$1.74/gallon	$0.113/kWh	$0.258/kWh
Fuel Economy	5.95 mpg for MY2016+	2.01-2.26 kWh/mi	1.87-2.22 kWh/mi
Per-mile Fuel Costs	$0.29/mile	$0.23-0.26/mile	$0.48-0.57/mile

Maintenance costs are subdivided into propulsion and non-propulsion related costs to better differentiate costs attributable to differing powertrain technologies. Non-propulsion costs include chassis, interior, lighting, HVAC, and similar systems. It is assumed that these costs remain constant regardless of the powertrain technology utilized. Note that it is recognized these costs are highly dependent on the choice of manufacturer, which may be influenced by the choice of powertrain technology. Propulsion costs include engine, cooling, transmission, brakes and similar systems. RIPTA's current diesel fleet undergoes mid-life overhauls that include engine rebuilds and other substantial powertrain work. Buses are also subject to significant non-propulsion related work at mid-life. However, these costs are included in the non-propulsion related maintenance costs. Mid-life overhaul costs described in this analysis reflect only mid-life costs related to the propulsion system. Table 8 summarizes the estimated maintenance costs for BEBs and RIPTA's current diesel fleet. Additional details are provided below and in Appendix A.

Table 8. Maintenance cost estimates for BEBs

CY 2016 Values	Diesel	Depot-Charged BEB	En-route BEB
Non-propulsion Related Maintenance	$0.67	$0.67	$0.67
Propulsion-related Maintenance	$0.40	$0.04	$0.04
Mid-life Overhaul Costs	$0.07	$0.27 - $0.61	$0.11 – $0.18
Total Maintenance Costs	$1.14	$0.98 - $1.32	$0.82 - $0.89

RIPTA's current maintenance costs average $1.14/mile. Mid-life overhaul costs represent approximately $0.07/mile, while non-propulsion maintenance costs account for $0.67/mile and propulsion costs are $0.40/mile. The analysis eliminated maintenance costs associated with the diesel engine and its cooling systems. Additionally, battery electric powertrains include regenerative braking systems that significantly reduce the amount of brake repairs required. The analysis assumes that O&M costs for brake repairs to be 50% less than brake-related O&M costs for RIPTA's existing transit buses. These assumptions reduce the propulsion-related maintenance costs for BEBs to $0.04/mile.

As described earlier, a BEB's propulsion battery is anticipated to degrade sufficiently to require replacement at mid-life. The rate of degradation will depend substantially on the battery chemistry employed and the duty cycle the battery is subjected to over its lifetime. However, based on current warranty offerings from BEB manufacturers and lack of 12-year demonstrated battery life for current battery technology in transit applications, a conservative assumption of battery replacement at mid-life is made in this analysis. Consequently, mid-life overhaul costs for BEBs are strongly influenced by current and future battery price assumptions. The range of mid-life overhaul costs shown in Table 8 are based on current battery cost estimates and estimated costs in the 2030 timeframe. Additionally, midlife overhaul costs for BEBs include an allowance of $30,000 for reconditioning or replacement of the drive motor(s) and inverter.

Infrastructure Costs – In addition to the capital and O&M costs for BEBs, the cost of charging equipment must also be considered. There are broadly three categories of charging infrastructure costs; utility-side costs, facility improvements, and charging equipment/EVSE.

Utility-side costs are those costs associated with infrastructure upstream of the customer's utility meter. These costs are difficult to quantify or control as they are subject to the state of the grid infrastructure serving a particular location and the regulatory requirements for the associated utility company. Fortunately, fleets that charge BEBs overnight can generally avoid utility charges for on-peak power demand and can utilize the existing grid infrastructure when other demands are lower. Combined with substantial daily energy consumption for the bus fleet, utilities are often able to significantly discount or eliminate costs to customers for utility-side upgrades. By contrast, en-route charging strategies require high power delivery during on-peak periods and may require utility-side upgrades and those costs can be passed down to the transit agency. Assumptions for charging infrastructure costs are described in additional detail in Appendix C. These costs are based on prior projects and incorporate utility-side costs for en-route charging. The depot charging scenarios assume that utility-side costs could be fully offset by a customer credit from the utility based on the amount of energy consumed and the time of day that charging would occur.

Facility improvements include required upgrades to switch gear, conduit, electrical rooms, and other on-site modifications required to support the chargers/EVSE. These costs are differentiated from charger/EVSE costs because facility improvements generally have much longer service life than chargers/EVSE. Consequently, facility improvements are assumed to be one-time costs that do not reoccur with bus replacements. Based on an initial assessment of the RIPTA facilities in Providence and Newport, facility improvement costs are assumed to be $670,000 per 4,000 kW of capacity at Providence and $330,000 per 1,000 kW of capacity at Newport.

Charging equipment costs for depot-charging buses are incorporated into the bus purchase costs detailed in Appendix A and reflect an estimated $40,000 per charger for a 50-65 kW DC fast charger. Maintenance costs are estimated at $240/year per charger. The service life of these chargers remains unknown. Warranties for charging equipment are generally five years or less, but discussions with charging equipment manufacturers suggests that the expected lifetime of the charging equipment is ten years or more. In the current analysis, it is assumed that a single depot charger will last the life of a BEB and will be replaced when the bus is replaced.

En-route charging equipment costs are not incorporated into the purchase price of the bus as this infrastructure serves multiple buses. Costs are estimated at $500,000 per en-route charger and are assumed to be one-time costs that do not reoccur when buses are replaced. En-route chargers also require more significant maintenance than depot chargers, hence, a cost of $13,000 per year per charger is assumed based on contract maintenance prices provided by Proterra to Foothill Transit.

Other Facility Costs – RIPTA has noted that the placement of BEB depot chargers could have two operational impacts not otherwise accounted for in the cost modeling. First, if chargers are placed on pedestals between bus parking lanes, the additional space required for these chargers would require the elimination of at least one lane of bus parking in their indoor bus storage facilities. There is currently very limited space for additional outdoor bus parking at the Providence facility and no currently developed outdoor parking space for buses at the Newport facility. Consequently, pedestal chargers would pose a potentially significant challenge and cost to RIPTA as new parking space would need to be procured and/or developed. Overhead mounting of chargers could provide a solution for buses stored indoors at both the Providence and Newport facilities. However, buses stored outdoors at the Providence facility currently have no overhead structure on which to mount chargers. One possible solution would be to construct a canopy structure over the outdoor parking area. This would provide two benefits. First, it would create a structure that could support overhead chargers. Second, it would shield the outdoor parking area from heavy snowfall that, in the past, has required the buses to be relocated in the evening to allow clearing of snow from the lot and preventing buses from being snowed in. The costs associated with constructing such a structure are not included in the current cost analysis.

En-route charging scenarios avoid issues with charging infrastructure footprint at RIPTA's garages, but the costs of en-route charging are site-specific and can be highly variable between sites. This analysis assumes a site cost of $500,000 per en-route charger, based on examples of en-route charging infrastructure at other public access sites. While this cost assumption allows for approximately $150,000 in site-related costs (beyond the cost of the charger), it is recognized that costs could be substantially less or greater than assumed here. As such, these costs represent a significant unknown risk to RIPTA, particularly at sites where RIPTA does not own or control the property.

2.3 Hydrogen Fuel Cell Buses

Fuel cell buses operate by combining hydrogen with oxygen (taken from the air) to produce electricity in a fuel cell. The produced electricity is used to power an electric drivetrain in the same manner as a battery-electric bus. In fact, a fuel cell bus typically incorporates a small battery to buffer the fuel cell output from the instantaneous power demands of the drivetrain. Fuel cells are zero-emission vehicles, producing only water from the reaction in the fuel cell. Hydrogen is supplied through a high-pressure fueling station similar to those used for compressed natural gas buses.

Commercial offerings

Fuel cell transit buses are currently available from three established transit bus manufacturers. Table 3 summarizes the current commercial offerings for new fuel cell buses. The National Renewable Energy Laboratory characterizes fuel cell buses as being in development or early commercialization.[16] This is consistent with the current reported count of 29 active fuel cell buses and 45 planned bus deployments in the US.[17] Product offerings continue to evolve through a number of grant-funded demonstration programs and New Flyer recently announced an expansion of its FCB product line by offering a 60-foot articulated platform.

Table 9. FCB Commercial Offerings

Bus Manufacturer	New Flyer	ENC	Van Hool***
35' bus	No	Yes	No
40' bus	Yes	Yes	Yes
60' bus	Yes	No	No
Nominal Range* (miles per fill)	380-610	260	200**
Hydrogen Capacity (kg)	37.5-60	50	40
*Nominal range is based on manufacturer claims. Cabin HVAC loads and other real-world impacts that may reduce actual range are not reflected in the nominal ranges stated. **Based on average fuel economy in AC Transit demonstration program, as reported by the National Renewable Energy Laboratory in their 2017 Status Report for Fuel Cell Buses in US Transit Fleets. ***Van Hool buses do not currently meet FTA Buy America requirements.			

Compared to BEBs, fuel cell buses have greater range and shorter refueling times, enabling depot-based fueling strategies similar to diesel and natural gas buses today. Reductions in bus capital and maintenance costs, as well as fuel costs, will be critical to the long-term success of fuel cell buses based on the current state of technology assumed in this report. These assumptions are detailed in Appendix A.

Fuel Production and Delivery Pathways

While all fuel cell buses commercially available today store hydrogen on the bus as a compressed gas, there are several different pathways for the production, delivery, and on-site storage of the hydrogen prior to fueling buses. Each pathway has advantages and tradeoffs with respect to cost, space requirements, utility infrastructure requirements, and environmental footprint.

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[16] Eudy L, Post M, "Fuel Cell Buses in US Transit Fleets: Current Status 2017" Available at https://www.nrel.gov/docs/fy18osti/70075.pdf

[17] National Renewable Energy Laboratory, "US Fuel Cell Bus Project" Available at https://www.nrel.gov/hydrogen/fuel-cell-bus-evaluation.html

Steam-Methane Reformation – By far the most common method of producing hydrogen, steam-methane reformation (SMR) produces hydrogen by combining natural gas and steam in a high temperature reactor. The produced gas is primarily a mixture of hydrogen and carbon monoxide. This product gas must be purified to remove the carbon monoxide and any other impurities that could degrade the fuel cells that would ultimately use the fuel. This production method is used a large scale and is the most cost-effective method of hydrogen production today.

The most common method of producing hydrogen, steam-methane reformation (SMR) produces hydrogen by combining natural gas and steam in a high temperature reactor.

Electrolysis – Hydrogen can also be produced by splitting water using electricity. This process, known as electrolysis, has the advantage that it produces relatively clean hydrogen with reduced need for post-production purification. Produced costs of hydrogen can be substantially higher than SMR, depending on the cost of electricity, equipment, and infrastructure.

Both SMR and electrolysis can be used to produce hydrogen off-site, or on RIPTA's property. On-site production is appealing in that it eliminates the need to receive deliveries of hydrogen by tanker truck. While procuring hydrogen from suppliers that produce the hydrogen off site alleviates RIPTA of the space requirements of the production equipment, as well as the capital and O&M costs of the production equipment. Several manufacturers, including ITM Power, Hydrogenics, NEL, and Nuvera now offer integrated hydrogen production and fueling station solutions for transportation applications. Space requirements for on-site hydrogen production and fueling can be substantial. NEL estimates that a 2,000 kg per day electrolysis facility would require 7,500 square feet of space.[18] At full conversion to fuel cell buses, RIPTA's Providence facility is projected to require an average of 3,650 kg per day. This implies that the space requirements of an on-site electrolysis production and fueling station at the Providence facility would be approximately 15,000 square feet. This is approximately equal to the parking space for 28 buses.

While hydrogen produced onsite is stored as a compressed gas, hydrogen produced offsite may be delivered as a compressed gas or cryogenic liquid. When delivered as a compressed gas, the hydrogen is stored in tube trailers or gas transport modules. The most common gas transport modules used for light-duty vehicle hydrogen fueling stations have typical capacities of 100-200 kg. Using such modules to supply the Providence facility would be impractical as it would require the delivery and exchange of twenty or more fuel trailers per day. Larger tube trailers exist, from manufacturers such as Hexagon Lincoln, that can transport up to 1,000 kg of compressed hydrogen. Logistically, compressed gas deliveries using these larger tube trailers could be practical during the early transition to a fuel cell bus fleet but could only serve approximately one quarter of the daily fuel demand at the Providence facility before multiple deliveries per day would be required.

Transported as a cryogenic liquid, up to 4,000 kg of hydrogen can be delivered by cryogenic tanker truck., allowing for a single fuel delivery per day to meet the full fuel demand at the Providence facility. On-site

[18] Borup U, "Integrated Production and Fueling Solutions for Heavy Duty Vehicles". Presentation by NEL at H2FC Fair, 2017.

storage tanks can be sized to hold sufficient hydrogen to meet two or more days of fueling demand, providing a limited buffer to hydrogen supply interruptions.

Because of the logistical challenges and impracticality of receiving multiple fuel delivered each day, compressed gas delivery to the Providence facility was not considered a viable solution. This narrowed the hydrogen pathways considered in this report to:

- Off-site production by SMR and transport by cryogenic liquid tanker
- On-site production by SMR
- On-site production by electrolysis

The produced costs of hydrogen via these various pathways are summarized in Table 10. On-site SMR is the lowest cost pathway and is used for subsequent economic analysis and technology comparisons. Note that the high cost of on-site electrolysis is driven primarily by the high cost of electricity under RIPTA's current utility rates. Access to lower cost electricity, potentially by utilizing the electrolysis system to provide load management and avoid curtailment of renewable electricity production in the future, could significantly lower the cost of the on-site electrolysis pathway. Additional details on the infrastructure and fuel cost assumptions for hydrogen pathways are provided in Appendix B and Appendix C. Estimated emissions factors related to each production pathway are provided in Appendix D.

It should be noted that data on the current retail price for hydrogen dispensed into transportation applications is sparse and highly distorted by grants and other subsidies. California has the largest market in the US for hydrogen in on-road vehicles, with a network of 32 retail hydrogen stations serving over 4,000 light-duty fuel cell vehicles.[19] In this market, prices for hydrogen delivered at 350 bar (H35) are typically $11-$13/kg. The cost of fuel is heavily subsidized by vehicle manufacturers through incentives to customers, making the pump price an imperfect indication of fuel prices in an unsubsidized market. The California Energy Commission has developed financial assessments for various hydrogen station configurations using the US Department of Energy's Hydrogen Financial Analysis Scenario Tool (H2FAST).[20] In these assessments, a levelized cost of $6.60/kg is estimated for a 600 kg/day station with liquid hydrogen delivery; of similar magnitude to the levelized cost estimated for the liquid hydrogen pathway in this report.

Table 10. Produced Cost of Hydrogen

CY 2016 Values	Liquid Hydrogen	On-site SMR	On-site Electrolysis
Fueling Station Capital Cost at Full Build Out ($)	$8.5M	$5.7M	$5.7M
Produced cost ($/kg)	$4.49	$2.07	$9.00
Fueling Station O&M ($/kg)	$0.51	$0.24	$0.24
Levelized Cost through 2050	$5.07	$2.79	$11.19

[19] California Fuel Cell Partnership, March 2018

[20] California Energy Commission, California Air Resources Board "Joint Agency Staff Report on Assembly Bill 8: 2017 Annual Assessment of the Time and Cost Needed to Attain 100 Hydrogen Refueling Stations in California" December 2017.

Efficiency and Range

As noted previously, longer range is generally considered an advantage of fuel cell buses compared to BEBs. Manufacturer stated ranges for FCBs are up to 380 miles for a 40-foot bus and 610 miles for a 60-foot articulated bus. Actual ranges depend on the duty cycle of the bus, but NREL reports the current range of fuel economies in the US fuel cell bus fleet to be 5.12 to 6.87 miles/kg, with a fleet average fuel economy of 6.16 miles/kg and a fleet average range of 300 miles.[21] It is noted that these fuel economy values and average range estimates are based on data collected from transit buses in use. The values are, therefore, assumed to incorporate the real-world impacts of degradation, HVAC loads, and route design highlighted previously with regard to BEBs.

At a range of 300 miles, the average fuel cell bus would be able to meet the daily range requirements of 90-95% of RIPTA's current fleet. For purposes of this analysis, it is assumed that technology improvements would increase the fuel economy of FCBs to 7.03 mi/kg and the average range to 340 miles by 2025. A range of 340 miles would be sufficient to address 99% of RIPTA's current fleet operations.

Bus Weight Impacts

Fuel cell buses have historically exhibited higher curb weights than comparable diesel buses. The incremental weight comes largely from the high-pressure fuel tanks, rack systems, and fairings placed on top of the bus. This is the same basic configuration used for CNG buses. Additionally, fuel cell buses use a battery to buffer the transient road loads from the fuel cell system. The battery size varies between manufacturers, depending on the specific powertrain architecture, but contributes to the incremental weight of a fuel cell bus. Table 11 summarizes the incremental weights for several fuel cell bus models and configurations at a standee ratio of 1.6 (all seats filled and an additional 60% of passengers standing) that is not atypical for some of RIPTA's highest density routes.

As highlighted, one bus would exceed the bus GVWR at this passenger loading. This bus is also the oldest bus platform listed and does not meet FTA Buy America provisions. Consequently, it was not considered as a potential configuration in the plan development. The New Flyer platform, while promoted by New Flyer as a commercially available product, is still largely in limited demonstration as part of the American Fuel Cell Bus program. Consequently, details on the GVWR are not readily available. Given that the ENC configuration is able to support a passenger load of 56, equivalent to the baseline diesel bus with a standee ratio of 1.6 and can carry 50 kg of hydrogen in this configuration; it is assumed that fuel cell buses would be available in configurations to meet RIPTA's capacity requirements. It is noted that this configuration is substantially heavier than the baseline diesel bus, by approximately 3.6 tons. This higher weight may result in route restrictions depending on specific bridge weight limits.

[21] Eudy L, Post M, "Fuel Cell Buses in US Transit Fleets: Current Status 2017" Available at https://www.nrel.gov/docs/fy18osti/70075.pdf

Table 11. Summary of fuel cell bus weights

Make	ENC	Van Hool	New Flyer	
Model	Axess 40'	A300L	XHE40	XD40
Fuel Cell Power (kW)	150	120	85	N/A
Battery (kWh)	11	21	80	N/A
Fuel Capacity (kg)	50	40	38	
Nominal Range* (miles)	308	246	235	
Curb Weight (lbs)	34,800	31,400	31,500	27,730
GVWR (lbs)	44,300	39,350	?	42,540
Seats	37	33	38	36
Design Load (passengers)	58	58	58	58
Weight at Design Load (lbs)	43,500	40,100	44,197	36,430
Exceeds GVWR	No	Yes	?	No
Weight (tons)	21.8	20.1	?	18.2
Incremental Weight vs Diesel (tons)	3.6	1.9	?	0.0
*At 6.16 miles/kg				

Costs

Fuel cell buses have significantly higher purchase prices than diesel buses. Return on investment for fuel cell platforms is predicated on reduced operating and maintenance costs, however, the current cost of hydrogen is likely to preclude a return on investment.

Bus Capital Costs – Fuel cell buses are currently produced in very limited quantities in the US and are partially funded through grant programs focused on technology development, demonstration, and early deployments. Historical pricing of fuel cell buses reflects the high costs associated with low quantity orders of these vehicles and the evolving fuel cell systems that power these vehicles. NREL reports that the purchase price for buses currently under demonstration ranged from $2.1 to $2.5 million each, while OEMs report that buses ordered under recent FTA and California-funded programs average $1.356 million.[22] Further, New Flyer has stated that the cost of a fuel cell bus could be $900,000 (before agency-specific modifications) for orders of 40 or more buses. Clearly, purchase prices for fuel cell buses are trending down.

Despite these trends, the current and future purchase prices for fuel cell buses remains speculative. For purposes of this analysis, purchase price projections developed by the California Air Resources Board are used.[23] These projections are detailed in Appendix A and estimate current incremental costs for fuel cell buses at $655,000, declining to $162,000 by 2050. As shown in Table 12, RIPTA's current diesel bus purchase price is estimated at $539,000 and includes agency-specific equipment additions. Fuel cell bus purchase prices range from $1,119,400 today to $701,000 in 2050. Note that battery costs are a major driver, if not the major driver, of the incremental cost for BEBs.

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[22] Eudy L, Post M, "Fuel Cell Buses in US Transit Fleets: Current Status 2017" Available at https://www.nrel.gov/docs/fy18osti/70075.pdf
[23] California Air Resources Board, "Innovative Clean Transit - Cost Data and Sources - Update on 6/26/2017"

Table 12. Purchase price assumptions for fuel cell buses

Bus Type	Incremental vs Diesel	Base Vehicle	RIPTA Additions	Final Vehicle Cost
Baseline Diesel	$0	$481,200	$57,800	$539,000
Fuel Cell (2017)	$655,000	$481,200	$57,800	$1,119,400
Fuel Cell (2020)	$423,000	$481,200	$57,800	$962,000
Fuel Cell (2030)	$180,000	$481,200	$57,800	$719,000
Fuel Cell (2040)	$170,000	$481,200	$57,800	$709,000
Fuel Cell (2050)	$162,000	$481,200	$57,800	$701,000

Bus O&M Costs – As with BEBs, O&M costs for fuel cell buses were segmented into four categories; propulsion-related maintenance, non-propulsion related maintenance, mid-life overall, and fuel costs. Fuel costs are as summarized in Table 10.

Table 13 summarizes the estimated maintenance costs for fuel cell buses and RIPTA's current diesel fleet. Additional details are provided below and in Appendix A.

Table 13. Maintenance cost estimates for FCBs

CY 2016 Values	Diesel	Fuel Cell Bus
Non-propulsion Related Maintenance	$0.67	$0.67
Propulsion-related Maintenance	$0.40	$1.65
Mid-life Overhaul Costs	$0.07	$0.29 - $0.44
Total Maintenance Costs	$1.14	$0.98 - $1.32

The analysis eliminated maintenance costs associated with the diesel engine and its cooling systems. Additionally, fuel cell powertrains include regenerative braking systems that significantly reduce the amount of brake repairs required. The analysis assumes that O&M costs for brake repairs to be 50% less than brake-related O&M costs for RIPTA's existing transit buses. Other propulsion related costs, excluding mid-life overall, are based on AC Transit's reported maintenance costs under their fuel cell bus demonstration program, and include out-of-warranty costs that are not currently available for other demonstration programs. The total reported maintenance cost for AC Transit's fuel cell bus fleet was $2.11 including extended service support contracts with US Hybrid and EnerDel. Approximately $0.50 of the total was non-FC related cost, implying a propulsion-related cost of $1.61/mile associated with the fuel cell and supporting systems.[24] (Zero Emission Bay Area (ZEBA) Fuel Cell Bus Demonstration Results: Fifth Report). These assumptions result in a propulsion-related maintenance costs for FCBs of $1.65/mile. These costs are substantially higher than RIPTA's current maintenance costs and can be attributed to the developing maturing of the fuel cell technology and learning curve for bus manufacturers as relates to the integration of the fuel cell technology into robust transit bus platforms.

The ultimate performance target for durability of the fuel cell system set by the US DOE is 25,000 hours, or about six years for a transit bus operating 12 hours per day. According to NREL, at least 9 FCBs have accumulated 18,000 hours, with six reaching 20,000 hours and one bus exceeding 23,000 hours without repair or cell replacements. This suggests that it is reasonable to assume a fuel cell stack will reach the standard mid-life overhaul without a major failure. The analysis assumes that the fuel cell stack will be

[24] Eudy L, Post M. "Zero Emission Bay Area (ZEBA) Fuel Cell Bus Demonstration Results: Fifth Report", 2016

replaced at mid-life, but that the balance of the fuel cell system (pumps, air compressors, radiators, fuel injectors, etc.) would not need to be replaced. Additionally, the traction battery is assumed to be replaced at mid-life.

Mid-life overhaul costs for FCBs are strongly influenced by current and future fuel cell stack price assumptions and, to a lesser degree, battery price assumptions. The range of mid-life overhaul costs shown in Table 13 are based on fuel cell and battery cost estimates between now and 2030. Additionally, midlife overhaul costs for FCBs include an allowance of $30,000 for reconditioning or replacement of the drive motor(s) and inverter. This analysis assumes that the fuel cell bus is equipped with a 120 kW fuel cell stack and a 21 kWh battery, equivalent to the Van Hool bus specifications. Configurations with larger batteries and smaller fuel cell systems, like the New Flyer XHE40, would be projected to have slightly lower mid-life overhaul costs due to the substantially higher replacement cost for larger fuel cell stacks relative to larger batteries. The New Flyer configuration is projected to have a lower mid-life cost that translates to approximately $0.04/mile cost reduction relative to the modeled system.

Infrastructure Costs – Infrastructure costs for fuel cell buses are associated with the hydrogen fueling station required to provide fast-fill refueling of buses in the existing diesel fueling lanes. The infrastructure modeled varies by fuel pathway. On-site production pathways produce gaseous hydrogen that is stored and subsequently compressed to 350 bar for delivery to the bus. The liquid delivery pathway includes on-site storage of the liquefied hydrogen and utilizes pumps to pressurize the hydrogen to 350 bar before converting the liquid to gas in an ambient heat exchanger. Costs for these two station types were modeled in the US DOE's Hydrogen Refueling Station Analysis Model (HRSAM).[25] Fueling station construction costs were divided into phases based on daily fuel demand growth as the number of deployed FCBs increases. Phase 1 costs include site preparation work that will support later phases, resulting in higher Phase 1 costs on a per-kg/day basis than later phases. Table 14 summarizes the cost estimates for each of the three station build out phases and the associated total throughput at the completion of each phase at the Providence facility. Because of the much lower fuel demand at the Newport facility, only one construction phase is anticipated. This would provide up to 1,000 kg/day of dispensing capacity at the Newport facility at a cost of $3 million for the liquid hydrogen pathway or $2.3 million for the gaseous hydrogen pathways. Additional details for hydrogen fueling infrastructure cost assumptions are provided in Appendix C. It should be noted that the modeled station designs make allowances for additional compressors or pumps that provide approximately 20-30% redundancy, should some compressors/pumps be out of service for maintenance or other reasons.

Table 14. Hydrogen Station Cost and Throughput Assumptions for Providence Facility

Providence Hydrogen Station	Liquid Hydrogen	Gaseous Hydrogen
Phase 1 Cost	$6.1M	$3.7M
Phase 1 Total Capacity (kg/day)	1,000	1,000
Phase 2 Cost	$1.18M	$980,000
Phase 2 Total Capacity (kg/day)	2,000	2,000
Phase 3 Cost	$1.18M	$980,000
Phase 3 Total Capacity (kg/day)	4,000	4,000
Full Build Out Cost	$8.46M	$5.66M

[25] https://www.hydrogen.energy.gov/h2a_delivery.html

Table 15 summarizes the total capital and O&M costs for each facility at full build out. The levelized cost of O&M is based on total utility and maintenance costs and total delivered hydrogen projected through 2050.

Table 15. Summary of Capital and O&M Costs for Hydrogen Station Infrastructure

Hydrogen Station Cost Summary	Liquid Hydrogen	Gaseous Hydrogen
Providence Facility		
Full Buildout Cost	$8.46M	$5.66M
Levelized Station O&M ($/kg)	$0.51	$0.24
Newport Facility		
Full Buildout Cost	$3.00M	$2.30M
Levelized Station O&M ($/kg)	$0.33	$0.24

Utility-side infrastructure improvement costs are assumed to be negligible for hydrogen pathways. The total power demand for SMR and liquid delivery pathways are comparable to the current power demands at each facility until Phase 3. The fueling station pumps/compressors would operate for up to 8 hours per evening, providing substantial energy throughput. It is assumed that this throughput would be sufficient to justify customer credits from the utility sufficient to avoid upgrade costs to RIPTA.

Note that the costs of fuel production equipment for the on-site fuel pathways are incorporated into the delivered price of hydrogen given in Table 10.

Renewable Fuel Standard Credits – The US EPA's Renewable Fuel Standard (RFS) requires producers of traditional diesel and gasoline fuels to distribute a certain percentage of their total fuel volume as renewable fuels. This has historically been achieved in large part by blending corn-based ethanol into gasoline. Additionally, renewable fuel producers can generate credits through the production of alternative fuels including biodiesel, renewable diesel, renewable natural gas, and renewable hydrogen that can then be sold to traditional diesel and gasoline producers to offset their obligations under the RFS. The RFS program is complex and the value of credits depends on a range of factors that include annual changes to compliance obligations, renewable fuel feedstocks, average cost of gasoline, and credit market dynamics. Additionally, the long-term future of the RFS program is uncertain. The current statutes authorizing the RFS program mandate specific volumes of renewable fuel use through 2022. After 2022, volumes are to be set by the US EPA administrator. Further, the administrator may elect to reduce the total renewable fuel volume requirements before 2022. These factors make the long-term value of credits produced under the RFS uncertain.

In the absence of the Renewable Fuel Standard (RFS) program, the cost of renewable natural gas would be substantially higher than that of fossil gas. SMR pathways must use renewable natural gas to achieve the State's long-term GHG reduction goals.

Credit prices are currently $0.96 and $2.74 for D-5 and D-3 credits, respectively, averaged over the past 12 months. A credit is equivalent to the energy in one gallon of ethanol and 1 kg of hydrogen would generate 1.5 credits based on its energy content. D-3 credits are generated from fuels produced from cellulosic feedstocks, renewable natural gas produced from landfills and certain other cellulosic sources. D-5 credits are generated from low carbon sources that are not predominantly cellulosic.

With respect to the fuel production pathways considered in this analysis, hydrogen produced by SMR using landfill gas could generate D-3 credits while hydrogen produced from dairy waste or food waste could qualify for D-5 credits. Electrolysis pathways are not currently recognized under the RFS program While the SMR pathways generate substantially more valuable credits, much of the value of those credits is taken by the renewable natural gas producer to offset the higher production costs of renewable natural gas compared to fossil natural gas. In practice, renewable natural gas is typically available to a fleet at prices similar to, or slightly less than fossil natural gas and would not have a significant cost impact on the current cost analysis of SMR-based fuel pathways. However, in the absence of the RFS program, the cost of renewable natural gas would be substantially higher than that of fossil gas. This presents a price risk to SMR pathways because the SMR pathways must use renewable natural gas to achieve the State's long-term GHG reduction goals. This analysis presumes that renewable natural gas will be available at cost parity to fossil natural gas through 2050.

2.4 Compressed Natural Gas Buses

The most common alternative fuel technology in the US transit bus market, compressed natural gas (CNG) buses total over 12,200 units in active transit fleets in the US, or roughly 16% of the total active transit bus fleet.[26] CNG buses are powered by spark-ignited internal combustion engines connected to conventional mechanical drivetrains and have operating and maintenance characteristics similar to diesel buses. Natural gas is supplied through a high-pressure fueling station and stored on the bus in high pressure fuel tanks, providing an operating range that is slightly reduced compared to diesel buses but generally sufficient for most routes. In general, CNG transit buses are mature commercial products with well understood operational capabilities.

Commercial offerings

CNG buses are currently available from all four major transit bus manufacturers. Table 16 summarizes the current commercial offerings for new CNG buses. Additionally, many of these manufacturers offer CNG buses in a range of configurations including low floor, standard floor, and rapid transit. Fuel tank packages can be configured based on the transit agency's needs but can typically store 140 to 180 diesel gallons equivalent (DGE) of CNG.

Table 16. CNG Bus Commercial Offerings

Bus Manufacturer	New Flyer	Gillig	Nova	ENC
35' bus	Yes	Yes	No	Yes
40' bus	Yes	Yes	Yes	Yes
60' bus	Yes	No	No	No
Nominal Range* (miles per fill)	Varies by route. Typically, 300 to 800 miles			
CNG Capacity (DGE)	Varies by CNG tank configuration. Typical capacity is 18,000 to 23,000 standard cubic feet, or 140 to 180 DGE.			
*Average fuel economy for RIPTA buses estimated at 4.6 mpDGE, resulting in a typical range of 600 to 800 miles				

Compared to BEBs, CNG buses have greater range and shorter refueling times, enabling depot-based fueling strategies similar to diesel buses today. Incremental capital costs for CNG transit buses are modest relative to other alternative fuels, averaging about $50,000 over a diesel bus. However, infrastructure costs can be significant. Additionally, CNG buses are less fuel efficient than diesel buses due to their use of spark-ignited engines rather than more efficient compression ignition engines used in diesel buses. These assumptions are detailed in Appendix A.

The vast majority of the CNG transit bus market is supplied by a single engine manufacturer, Cummins Westport (CWI). CWI produces a range of natural gas engines, with the 8.9L ISL-G being the most commonly used in transit buses. The engine is similar in size and power to its diesel counterpart, the Cummins ISL9, and to diesel engines from other manufacturers. Beginning in 2016, CWI offered for sale a version of the ISL-G known as the ISL-G NZ. This engine is certified to California's Optional Low NOx standard, at a level of 0.02 gram/bhp-hr, or 90% lower than the current diesel standard. The exceptionally low NOx emissions from this engine are comparable to emissions from a modern, combined cycle natural

[26] Federal Transit Administration, "2016 National Transit Database"

gas power plant charging a battery-electric bus, leading to a compelling "near-zero" technology alternative to zero-emission buses. The CWI engine has since been rebranded as the L9N and a near-zero version of CWI's 12L engine is also available, the ISX12N. Beginning in 2018, CWI will only offer near-zero versions of its 8.9 and 12L engines for sale, discontinuing the versions certified to the higher 0.20 g/bhp-hr diesel emission standard.

Fuel Production Pathways and Renewable Natural Gas

While the majority of natural gas in the US is sourced from traditional fossil-based reservoirs, the availability of natural gas from renewable sources has grown substantially over the last several years. Much of this growth is attributable to credit programs like the EPA's RFS program and California's Low Carbon Fuel Standard. These programs allow RNG producers to generate significant value from the sale of renewably based, low carbon fuels into the transportation fuel market. As described in the hydrogen fuel cell bus overview above, RFS credits are available for RNG sold in Rhode Island (while California's LCFS credits do not apply to fuel sold outside of California) and are currently \$0.96 and \$2.74 for D-5 and D-3 credits, respectively. One diesel gallon equivalent of CNG would generate 1.7 credits under the RFS program, valuing D-3 RINs from RNG at as much as \$4.65/DGE. However, this revenue is assumed to be claimed by the fuel producer and is not passed down to RIPTA. Consequently, RIPTA is assumed to have access to RNG at cost parity with fossil natural gas but is not assumed to generate additional credit revenue from the use of the RNG. Estimated emissions factors related to the RNG production pathway are provided in Appendix D.

> This analysis assumes cost parity with fossil natural gas due to Renewable Fuel Standard credits. Availability is not anticipated to be a limiting factor because renewable gas injected elsewhere in the pipeline network and claimed by the buyer.
>
> In the absence of the Renewable Fuel Standard (SFS) credit program, the cost of renewable natural gas would be substantially higher than that of fossil gas. SMR pathways must use renewable natural gas to achieve the State's long-term GHG reduction goals.

Availability of RNG is not anticipated to be a limiting factor for RIPTA. RNG is typically supplied through a "book and claim" accounting methodology where RNG is injected into the national natural gas pipeline network and an equivalent volume of natural gas is used by a customer on their site. The physical RNG does not need to be transported to the customer site to claim benefits. This is similar to the accounting methodology for renewable electricity generation, where generation may occur far from a specific end user but can be claimed by the end user through contracting mechanisms.

Efficiency and Range

Currently available spark-ignited natural gas engines on the market today exhibit lower fuel efficiencies than their diesel counterparts. As described in Battery Electric Bus overview, and repeated here for convenience, fuel efficiency is significantly influenced by each route's characteristics. Testing at Altoona demonstrates the effect of different drive cycles on the efficiency of BEBs. As shown in Table 17, the Altoona tests include energy consumption measured over the Central Business District (CBD), Arterial (ART), and Commuter cycles. All bus technologies exhibit the lowest energy consumption in the Commuter cycle as this cycle includes no stops and is predominantly a constant cruise test at 55 mph. The next lowest energy consumption is seen in the CBD cycle, with low maximum speeds of 20 mph and frequent stops. The highest energy consumption rates are in the ART cycle, with its combination of higher peak speeds of 40 mph and several stops.

Table 17. Altoona energy consumption data for BEB, CNG, and diesel buses

Bus Energy Consumption[27] (kWh/mi equivalent)	CBD	ART	Commuter
Avg Speed (MPH)	12.5	25.5	37
New Flyer XE40	1.75	2.29	1.5
Proterrra BE40	1.56	2.1	1.41
Proterra BE35	1.83	2.23	1.34
BYD K9	1.99	2.54	1.43
BYD K7	1.18	1.84	1.15
Gillig CNG	10.86	9.70	5.68
New Flyer XD40 (diesel)	9.57	8.42	4.60

To estimate the effects of average route speeds on CNG energy efficiency, GNA compared reported fuel consumption rate of a Gillig CNG transit bus to a New Flyer XD40 diesel transit bus. The Gillig bus was selected for the CNG comparison as it was the most current 40-foot CNG bus tested. The trends in Figure 3 are consistent for the range of technologies analyzed, with the relative efficiency of each technology decreasing with increasing average speed as compared to the diesel baseline.

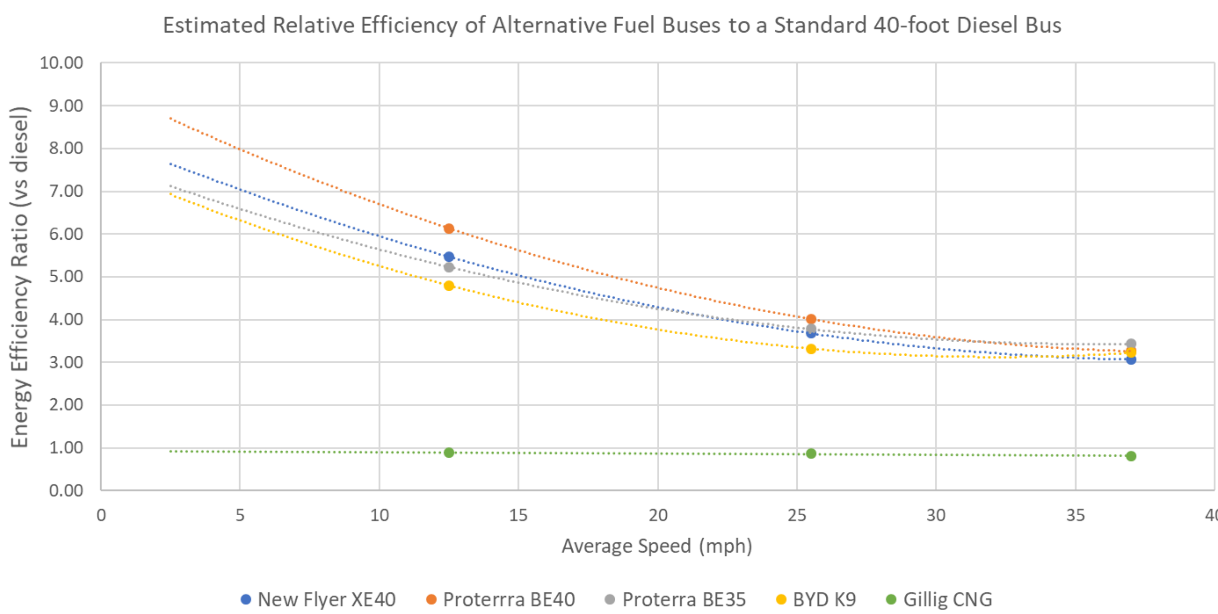

Figure 3. Relative efficiency of alternative fuel buses to a standard 40-foot diesel bus

RIPTA is currently engaged in an effort to equip the existing bus fleet with data collection equipment that will improve RIPTA's ability to track mileage and energy consumption on both a route-by-route basis as well as a vehicle-by-vehicle basis. Because those data were not available for the current analysis, an estimate of the fuel economy of a diesel bus at various average speeds was developed based on the Altoona test data for the XD40 transit bus. The resulting fuel economy curve is shown in Figure 4Figure 2. At the average speed of 16.8 mph for the RIPTA fleet, the estimated average fuel economy using the curve

[27] Altoona test data. http://altoonabustest.psu.edu/buses

in Figure 2 is 5.0 miles per gallon and compares well with the actual fleet average of 5.1 miles per gallon for RIPTA's fleet in 2016. Energy consumption rates for CNG buses were then calculated using the Energy Efficiency Ratio (EER) curve for the Gillig CNG bus to calculate energy demand on a per-block basis. This resulted in an average fuel efficiency of 4.52 miles/DGE, or approximately 26% fuel economy penalty relative to the baseline diesel bus.

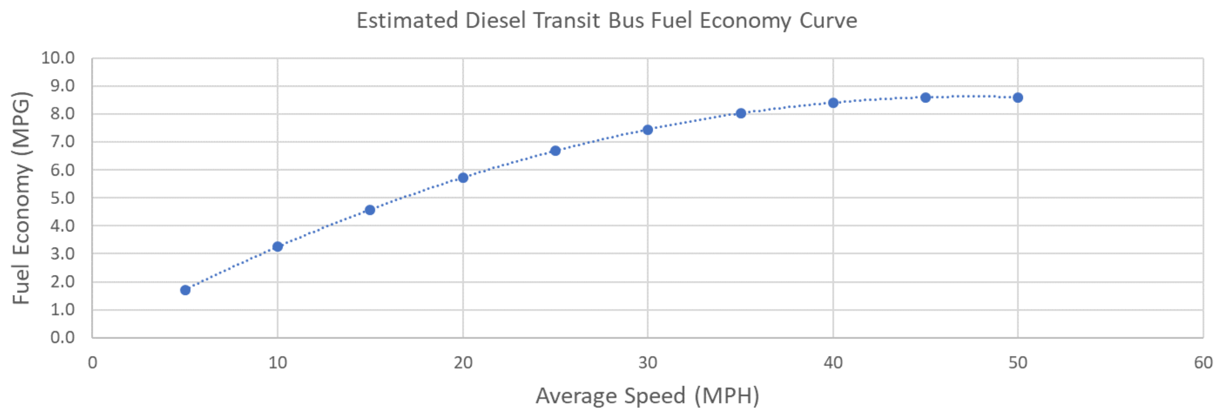

Figure 4. Estimated diesel transit bus fuel economy curve

Despite these efficiency penalties, CNG buses have nominal ranges of 300 to 800 miles, owing to their ability to carry up to 180 DGE in compressed gas fuel tanks. Based on these estimates of CNG bus range, it is assumed that CNG buses could serve all of RIPTA's current blocks.

Bus Weight Impacts

CNG buses exhibit higher curb weights than comparable diesel buses. The incremental weight comes largely from the high-pressure fuel tanks, rack systems, and fairings placed on top of the bus. Incremental weights vary based on the exact fuel tank package but can range up to 2,000 lbs over a comparable diesel bus. While this additional weight is not negligible, discussions with RIPTA staff indicate that a 2,000 lbs weight increase is unlikely to result in significant restrictions to bus operations due to bridge weight limits. Further, the Gillig CNG bus at a standee ratio of 1.6 has a loaded weight of 38,260 lbs, approximately 3,300 lbs below the 41,600 lbs GVWR for the bus. Therefore, passenger loading is not anticipated to be restricted by the incremental weight of the CNG fuel system.

Costs

CNG buses have modestly higher purchase prices than diesel buses but can generate a return on investment through reduced fuel costs, depending on the assumed price of diesel fuel.

Bus Capital Costs – CNG buses are currently available from all major transit bus manufacturers as standard product offerings. Typical incremental prices are approximately $50,000 over a comparable diesel bus[28], but will vary based on the specified fuel tank package. Additionally, CWI's near-zero variant of their 8.9L natural gas engine adds approximately $7,500 to the cost of the bus. Because this report focuses on technologies that provide the greatest emissions reductions possible, it is assumed that all CNG buses procured by RIPTA would be equipped with the near-zero variant of the engine and would include the additional $7,500 cost adder for the technology, bringing the assumed incremental cost for a CNG bus to

[28] California Air Resources Board, "Innovative Clean Transit - Cost Data and Sources - Update on 6/26/2017"

$57,500 over the diesel baseline. These assumptions are detailed in Appendix A. As shown in Table 18, RIPTA's current diesel bus purchase price is estimated at $539,000 and includes agency-specific equipment additions. The CNG bus purchase price is estimated at $595,500 and remains fixed throughout the analysis period.

Table 18. Purchase price assumptions for CNG buses

Bus Type	Incremental vs Diesel	Base Vehicle	RIPTA Additions	Final Vehicle Cost
Baseline Diesel	$0	$481,200	$57,800	$539,000
CNG	$57,500	$481,200	$57,800	$596,500

Bus O&M Costs – CNG bus maintenance costs are assumed to be the same as the diesel baseline in all three maintenance categories; propulsion-related maintenance, non-propulsion related maintenance, mid-life overall. Table 19 summarizes the estimated maintenance costs for fuel cell buses and RIPTA's current diesel fleet. Additional details are provided below and in Appendix A.

Table 19. Maintenance cost estimates for CNG buses

CY 2016 Values	Diesel	CNG Bus
Non-propulsion Related Maintenance	$0.67	$0.67
Propulsion-related Maintenance	$0.40	$0.40
Mid-life Overhaul Costs	$0.07	$0.07
Total Maintenance Costs	$1.14	$1.14

Fuel costs were calculated based on current and projected contract pricing for natural gas delivered under National Grid's Extra Large High Load tariff and escalated using the US EIA's 2017 Annual Energy Outlook projections for natural gas delivered to commercial customers in the New England region.

Using these assumptions, the cost of RNG supplied to a station is estimated at $0.87/DGE in 2016 and projected to grow at 1.2% year-over-year through 2050. Costs associated with station construction, operation, and maintenance are detailed separately in Appendix C.

Table 20 summarizes the fuel cost assumptions for CNG buses and diesel buses. Note that RIPTA has very low costs for diesel fuel under their current contract. However, prices are expected to increase significantly in 2019. Based on contract futures for diesel fuel, RIPTA estimates that diesel prices could increase from $1.74/gallon to $2.20/gallon by 2019[29]. This would raise the per-mile costs of diesel fuel to $0.37/mile. Additional details are provided in Appendix B.

Table 20. Fuel cost estimates for CNG buses (2016 prices)

CY 2016 Values	Diesel	CNG
Fuel Costs	$1.74/gallon	$0.87/DGE
Fuel Economy	5.95 mpg for MY2016+	4.52 mpDGE
Per-mile Fuel Costs	$0.29/mile	$0.19/mile

Infrastructure Costs – Infrastructure costs for CNG buses are associated with the CNG fueling station required to provide fast-fill refueling of buses in the existing diesel fueling lanes. Costs are based on GNA's

[29] RIPTA began soliciting quotes for its 2019 fuel supply contract in 2018. At the time of this report's publication, the lowest offered 6-month lock-in price was $2.5814/gallon diesel.

on-site assessments of the Providence and Newport facilities and assume a typical CNG station configuration supplied by utility pipeline. Fueling station construction costs were divided into phases based on daily fuel demand growth as the number of deployed CNG buses increases. Phase 1 costs include site preparation work that will support later phases, resulting in higher Phase 1 costs on a per-DGE/day basis than later phases. Table 21 summarizes the cost estimates for each of the three station build-out phases and the associated total throughput at the completion of each phase at the Providence facility. Because of the much lower fuel demand at the Newport facility, only one construction phase is anticipated. This would provide up to 1,800 DGE/day of dispensing capacity at the Newport facility at a cost of $1.9 million. Additional details for CNG fueling infrastructure cost assumptions are provided in Appendix C. It should be noted that the modeled station designs make allowances for additional compressors that provide 100% redundancy, should some compressors be out of service for maintenance or other reasons. This is a higher level of redundancy than offered by any other technology option.

Table 21. CNG Station Cost and Throughput Assumptions for Providence Facility

Providence CNG Station	CNG
Phase 1 Cost	$2.8M
Phase 1 Total Capacity (DGE/day)	2,900
Phase 2 Cost	$1.1M
Phase 2 Total Capacity (DGE/day)	5,800
Phase 3 Cost	$1.1M
Phase 3 Total Capacity (DGE/day)	8,800
Full Build Out Cost	$5.0M

Table 22 summarizes the total capital and O&M costs for each facility at full build out. The levelized cost of O&M is based on total utility and maintenance costs and total delivered CNG projected through 2050.

Table 22. Summary of Capital and O&M Costs for CNG Station Infrastructure

CNG Station Cost Summary	CNG
Providence Facility	
Full Buildout Cost	$5.0M
Levelized Station O&M ($/DGE)	$0.28
Newport Facility	
Full Buildout Cost	$1.9M
Levelized Station O&M ($/DGE)	$0.28

Utility-side infrastructure improvement costs are assumed to be negligible for the CNG pathway based on discussions with National Grid. While the utility would need to make some utility-side infrastructure improvements to serve the projected natural gas demand, this throughput is expected to be sufficient to justify customer credits from the utility sufficient to avoid upgrade costs to RIPTA.

3.0 Scenario Development

A total of nine technology deployment scenarios were considered that include a baseline diesel case, four of the six technology pathways described in the previous section, and four scenarios that are based on combinations of technologies. The mixed technology pathways arise principally because current depot-charged BEBs can only serve roughly half of RIPTA's current blocks. To serve all of RIPTA's blocks, either battery technology must improve significantly with respect to energy density, or other technologies must be relied upon to serve the longest blocks. Table 23 summarizes the nine deployment scenarios considered.

Table 23. Technology scenarios considered

Scenario	Technologies	Description
Baseline Diesel	Diesel Diesel hybrid	Business as usual case. All future purchases are 100% conventional diesel. Hybrid buses are largely phased out of the fleet.
100% Depot Charging	Battery-electric	Full transition of the fleet to depot-charged buses. Assumes battery capacity increases over time to meet longer block energy requirements.
Limited Depot Charging	Battery-electric Diesel	Transition to depot-charged buses for all blocks that can be serviced with current technology. Remainder of blocks continue to be served by diesel buses.
100% En-route Charging	Battery-electric	Full transition of the fleet to en-route charging of battery-electric buses.
Mixed En-route/ Depot Charging	Battery-electric	Transition to depot-charged buses for all blocks that can be serviced with current technology. Remainder of blocks are served by en-route charging.
Fuel Cell	Fuel cells + SMR	Full transition to fuel cell buses. Hydrogen supplied by on-site SMR of renewable methane as this is the lowest cost strategy analyzed.
Near-zero R/CNG	CNG	100% transition to CNG buses equipped with "near-zero" natural gas engines and fueled with renewable natural gas.
EV + R/CNG	Depot-charged BE CNG	Transition blocks that can be served by current depot-charged battery technology to battery-electric. Then transition remaining blocks to CNG.
R/CNG + EV	CNG Depot-charged BE	Transition longest blocks to CNG first, then transition blocks that can be served by current depot-charged battery technology to battery-electric.

Baseline Diesel Scenario

Under the baseline scenario, RIPTA continues to purchase primarily conventional diesel buses between 2019 and 2050. The fleet grows slightly, from 226 to 232 buses in the first year to restore spare ratios and remains fixed at 232 buses for the remainder of the analysis period. The majority of hybrid buses are phased out of the fleet by 2026, with a small contingent of six hybrid buses remaining a part of the fleet mix through 2050.

100% Depot Charging Scenario

In this scenario, RIPTA's current diesel fleet is transitioned to depot-charged battery-electric buses by 2032. By 2025, RIPTA has replaced enough buses to service all of its blocks that require battery-electric buses with a 480-kWh capacity or less. In 2026, RIPTA would require buses with a 537-kWh capacity. In subsequent years, battery capacity would need to grow to 593 kWh in 2027, 650 kWh in 2028, 763 kWh in 2029, 848 kWh in 2030, and 1,187 kWh in 2031. This scenario assumes that battery capacities increase at a sufficient rate to allow RIPTA to transition to a 100% depot-charged fleet by 2032. Potential weight impacts from increased battery capacity are not considered, making this 100% conversion scenario optimistic.

Given the rapid pace at which battery technology is evolving, a variant of the 100% Depot Charging scenario was considered. In this alternative, it is assumed that batteries do not require replacement over the life of the bus, or that the cost of their replacement is reflected in the initial purchase price assumptions for the bus.

Limited Depot Charging Scenario

The limited depot charging scenario assumes the replacement of existing diesel buses based on the fraction of the fleet that could ultimately be transitioned to depot-charged electric buses using the 480-kWh battery-electric bus configuration assumed to represent today's current technology. Based on the block analysis conducted for this study, approximately 55% of buses at the Providence facility and 44% of buses at the Newport facility could be transitioned to depot-charged buses. Consequently, in each year, 55% of purchases for the Providence facility and 44% of purchases for the Newport facility are assumed to be battery-electric buses and the balance of purchases are assumed to be conventional diesel buses.

100% En-route Charging Scenario

This scenario assumes that RIPTA's entire fleet is transitioned to battery-electric buses that charge en-route. An analysis of RIPTA's current block schedules and layover locations was conducted to estimate the number en-route chargers required under a full transition, as well as a partial transition to en-route charging. The analysis indicated that RIPTA would require 56 active chargers. Allowing for one spare charger at each layover location to provide redundancy, the total number of chargers required would be 97, installed across 41 separate locations. The model assumed the fast charge buses deployed are equipped with a 105-kWh battery pack and could support a charging rate of 350 kWh. The analysis did not attempt to optimize the charging infrastructure requirements by adjusting layover locations or modifying block schedules.

Mixed En-route/Depot Charging Scenario

Under this scenario, all initial bus replacements are depot-charged electric buses until deployments reach the fraction of the fleet that could ultimately be transitioned to depot-charged electric buses using the 480-kWh battery-electric bus configuration. Based on the block analysis conducted for this study, this is approximately 55% of buses at the Providence facility and 44% of buses at the Newport facility. The remainder of the fleet is then transitioned to en-route charging buses. This is similar to the Limited Depot Charging scenario with en-route buses serving the long blocks assumed to be served by diesel buses. The Mixed En-route/Depot Charging scenario also differs from the Limited Depot Charging scenario in that all depot-charged buses are deployed *before* deploying any en-route charging buses. Under the Limited Depot Charging scenario, the depot-charged buses are deployed *in parallel* with diesel buses. The purpose of deploying all depot-charged buses before deploying en-route charging buses under this scenario is to maximize the utilization of the en-route charging infrastructure. This helps minimize electricity costs for the en-route chargers as the delivered cost of electricity to the transit bus increases significantly with decreasing charger utilization.

An estimated 37 active en-route chargers would be required to support en-route charging buses under this scenario. Allowing for one spare charger at each location, a total of 67 chargers would be required across 30 separate locations.

Fuel Cell Scenario

The Fuel Cell scenario assumes a complete transition to fuel cell buses. Hydrogen is generated on-site from steam-methane reformation of natural gas. The natural gas supplied to the facility is assumed to be renewably based, providing substantial GHG reductions compared to a conventional natural gas supply. The potential range and refueling times possible for fuel cell buses allow for a one-to-one replacement of diesel buses, hence, the replacement schedule is identical to the Baseline Diesel scenario.

Near-zero R/CNG Scenario

This scenario assumes a complete transition to CNG buses equipped with near-zero emission natural gas engines. The natural gas supplied to the CNG station is assumed to be renewably based, providing substantial GHG reductions compared to a conventional natural gas supply. The potential range and refueling times possible for CNG buses allow for a one-to-one replacement of diesel buses, hence, the replacement schedule is identical to the Baseline Diesel scenario.

EV + R/CNG Scenario

Under this scenario, all initial bus replacements are depot-charged electric buses until deployments reach the fraction of the fleet that could ultimately be transitioned to depot-charged electric buses using the 480 kWh battery-electric bus configuration. Based on the block analysis conducted for this study, this is approximately 55% of buses at the Providence facility and 44% of buses at the Newport facility. The remainder of the fleet is then transitioned to near-zero R/CNG buses. The deployment schedule is identical to the Mixed En-Route/Depot Charging scenario, with R/CNG buses replacing the en-route charging electric buses.

R/CNG + EV Scenario

This scenario is identical to the EV + R/CNG scenario, with the only exception being the order of technology deployment. Under this scenario, all R/CNG bus deployments occur first and depot-charged EV bus deployments occur later. This scenario offers cost advantages over the EV + R/CNG scenario due to the projected decreases in battery costs in future years.

4.0 Results of Scenario Analysis

Cost analyses and emissions analyses were conducted to characterize the operational costs and emissions for each of the previously described scenarios over the 2018-2050 timeframe. The operational costs of each scenario are an aggregate of individual cost factors that include: bus capital, fuel, operations and maintenance (O&M), midlife overhaul, fueling infrastructure, and facility modification costs. For each scenario, costs were generated on a per-mile and lifecycle basis using fleet composition, operational data, procedural data, and assumptions where necessary to characterize the recently commercialized technologies. These assumptions are detailed in the prior sections of this report and in the attached appendices. The emissions analyses assess the environmental footprint of each scenario in terms of total GHGs, NOx, and PM. GHG emissions are evaluated on a lifecycle basis using the carbon intensity assumptions for each fuel as described in Appendix D, while NOx and PM emissions are evaluated based on direct vehicle emissions.

> Alternative fuel technology scenarios generally have lower operational costs than baseline diesel scenarios, but not sufficiently lower to fully offset anticipated capital costs at today's low diesel fuel prices.
>
> Future increases in diesel price could substantially change the cost of the Baseline Diesel scenario, making it more expensive than many of the mixed-technology scenarios.

Additionally, the diverse range of technologies and pathways available to RIPTA pose varying risks and operational implications. The following sections include a discussion of these risks and operational implications, many of which are likely to have reduced impact during early/limited deployments of alternative fueled buses but that grow in significance at higher deployment rates.

4.1 Capital and Operating Costs

Table 24 summarizes the results of the cost analysis. Costs are broken down into capital expenditures and operational expenditures. Capital expenditures include bus purchase costs and infrastructure installation/development costs. Operational costs include vehicle maintenance, fuel/electricity, and infrastructure maintenance. RIPTA's current diesel strategy offers the lowest capital cost and lowest total cost at $0.98/mi and $2.56/mi, respectively; but has the third highest operational cost, $1.57/mi, of the scenarios considered. Alternative fuel technology scenarios generally exhibit higher capital costs owing to the higher purchase price of the bus and requirements for new fueling infrastructure. Operational costs are generally lower for alternative fuel technology scenarios, but not sufficiently lower to fully offset their incremental capital costs, thus resulting in higher total costs than the baseline diesel scenario.

Table 24. Per-mile Scenario Costs through 2050

Combined Fleet through 2050	CapEx ($/mi)	OpEx ($/mi)	Total Cost ($/mi)
Baseline Diesel	**$0.98**	$1.57	**$2.56**
Near-zero R/CNG	$1.10	$1.51	$2.61
R/CNG+EV	$1.18	$1.48	$2.66
Limited Depot Charging	$1.21	$1.51	$2.73
EV+R/CNG	$1.29	$1.47	$2.76
100% Depot Charging, No Batt Replacement	*$1.62*	*$1.20*	*$2.82*
Mixed En-route/Depot Charging	$1.56	$1.54	$3.10
100% Depot Charging	$1.62	**$1.49**	$3.11
100% En-route Charging	$1.67	$1.65	$3.33
Fuel Cell	$1.38	$2.69	$4.07

A significant factor in the lower cost of operation for the Baseline Diesel scenario is the low diesel price in place at the time of the analysis. Future increases in diesel price could substantially change the cost of the Baseline Diesel scenario, making it more expensive than many of the mixed-technology scenarios.

Figure 5 differentiates the contributions of vehicle and infrastructure capital expenditures to the total CapEx for each scenario. Infrastructure costs represent a relatively small fraction of the overall CapEx in all scenarios except those using en-route charging. The high cost of the en-route charging equipment and installation contribute significantly to those scenarios' total CapEx. Note that the infrastructure costs referred to in Figure 5 include durable infrastructure such as fueling stations, electrical "make-ready" improvements, utility supply enhancements, and en-route chargers. Depot-charging equipment (from the conduit "stub" to the vehicle) is assumed to have a useful life comparable to the bus and is replaced with each bus purchase. Consequently, the cost of depot chargers is included in the Vehicle CapEx costs shown in Figure 5, while the make-ready costs for facility electrical infrastructure upgrades are included in the Infrastructure CapEx costs.

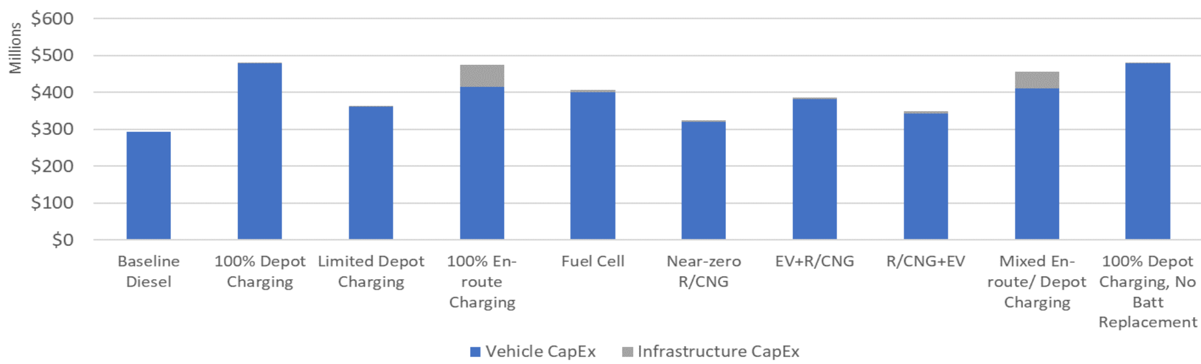

Figure 5. Components of Capital Costs by Scenario through 2050

Operating cost components are differentiated for each scenario in Figure 6. Vehicle maintenance costs are the largest OpEx cost component in each scenario, even for BEB scenarios with no battery replacement cost assumptions. This is driven by the fact that approximately 60% of RIPTA's current maintenance costs are attributed to non-propulsion systems. Note that the fuel cell bus scenario shows very high vehicle maintenance costs. These costs are currently elevated due to high maintenance costs documented in recent demonstrations. However, costs are likely to decline substantially in newer-generation FCBs currently under demonstration.

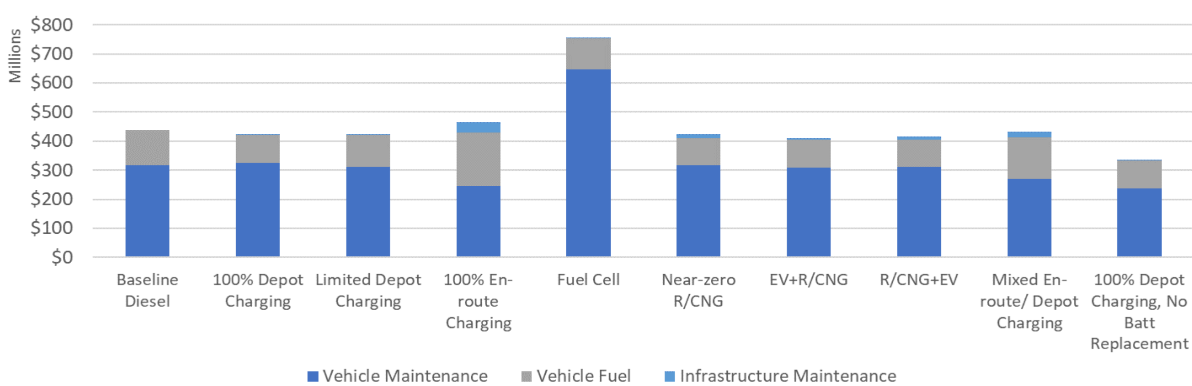

Figure 6. Components of Operating Costs by Scenario through 2050

RIPTA's current diesel fuel price contracts and US EIA projections of modest year-over-year increases in diesel fuel prices create a low fuel cost in the baseline scenario. Most alternative scenarios offer modest fuel cost savings over the baseline scenario, with the exception of en-route charging scenarios as they incur substantial demand-related electricity charges that increase the total "fuel" cost under these scenarios relative to the baseline case.[30]

Figure 7 summarizes the total costs of each scenario on 12-year (1 bus lifetime) and 24-year (2 bus lifetimes) basis, as well as total costs from 2018 to 2050. The relative ranking of each scenario changes little over time. Any investment in alternative fuels will result in additional outlay of funds. En-route charging scenarios improve their relative cost to other scenarios over time as increased utilization of the charging infrastructure drives down the high effective fuel costs during the first 12-year fleet transition period. The lowest cost alternative scenario to RIPTA's current diesel fleet is a transition to near-zero CNG transit buses with a $19 M incremental cost. The next-lowest cost scenarios are a mix of battery-electric and natural gas technology with a $36 M incremental cost. Within the two mix scenarios, the EV+R/CNG scenario exhibits higher total cost over the first 24 years than the R/CNG+EV scenario because the delayed deployment of the R/CNG+EV scenario allows RIPTA to take advantage of projected battery price declines before beginning purchases of BEBs.

Amongst the zero-emission scenarios, the 100% Depot Charging scenario is projected to be the least costly until the 2050 timeframe when the Mixed En-route/Depot Charging scenario becomes comparable in cost. If batteries in the 100% Depot Charging scenario can last the full useful life of the bus, while retaining sufficient capacity to meet daily range requirements, the cost of the 100% Depot Charging scenario decreases by approximately $100 million through 2050 and becomes much closer in total cost to the near-zero emission scenarios.

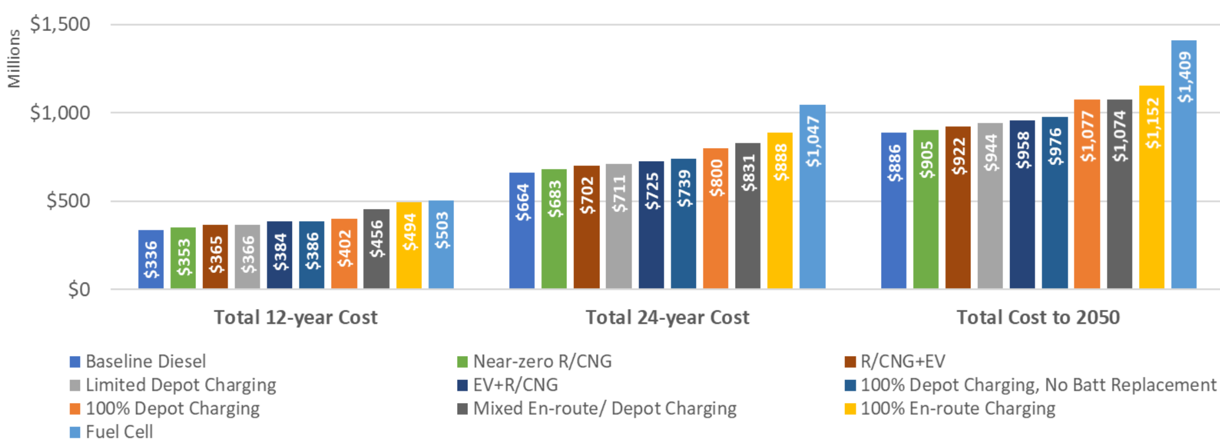

Figure 7. Projected Total Costs by Scenario

Effects of Incentive Programs

The cost analysis presented here does not include potential incentives available through various programs, including the FTA's LoNo program and the State's Volkswagen Settlement fund. These programs, along with others, can substantially buy down the capital cost of alternative fuel buses and associated fueling infrastructure. As these programs are currently structured, zero-emission technologies

[30] Note that this analysis does not include costs for operation or maintenance of diesel fueling infrastructure or maintenance equipment (DPF cleaning equipment). These cost sources should be revisited in future updates.

are most likely to be funded and could reduce incremental purchase costs by 80-100%. However, funding for these programs is limited, RIPTA is not guaranteed to receive funding under these programs, and the long-term availability of the funding is highly uncertain. Because of this uncertainty, the value of these incentives is not included in the current analysis.

Where incentive funding is available to buy down capital costs, these programs could allow RIPTA to lock in reduced operating costs that would result in a lower total cost. For example, the 100% Depot Charging scenarios have operating costs that are \$0.08-\$0.37/mile lower than the baseline diesel scenario. Buying down the full incremental capital cost of the depot-charging buses and infrastructure would allow RIPTA to receive the full value of the reduced operating costs of the BEBs.

Cost-related Risks

The cost analyses are predicated on a number of assumptions regarding future technology costs and fuel/energy pricing. The most significant assumptions and their potential risks are discussed here.

Fuel/Energy Supply Costs – The costs of diesel fuel, natural gas, and electricity are significant drivers of the total cost of ownership estimates for each scenario. Long-term forecasts of energy prices are imprecise and substantial volatility in pricing may occur at any time and for any energy supply. For example, the abundance of US reserves of natural gas has had a moderating effect on US natural gas commodity prices, but congestion of natural gas transmission pipelines (particularly in the northeastern US) has led to significant seasonal price variability. Additionally, after falling from post-recession highs in 2014 to a low in 2016, diesel fuel prices have increased steadily between 2016 and 2018, rising almost 45% over this period. Finally, electricity rates through RIPTA's utility, National Grid, are also currently in flux with an anticipated rate increase to be determined some time in 2018.

While forecasts remain imperfect tools, this analysis relies on the US EIA forecasted price trends for diesel fuel, natural gas, and electricity supplied to commercial customers in the New England region.[31] As shown in Figure 8, diesel prices are anticipated to trend upward through 2050. Natural gas prices are projected to remain relatively constant, with slight increases. Electricity prices, presented here as the energy component of the utility bill (excluding demand charges) are projected to increase substantially between 2018 and 2028, and then remaining flat through 2050. The total cost estimates for each scenario presented in this analysis are based on the US EIA projections shown in Figure 8.

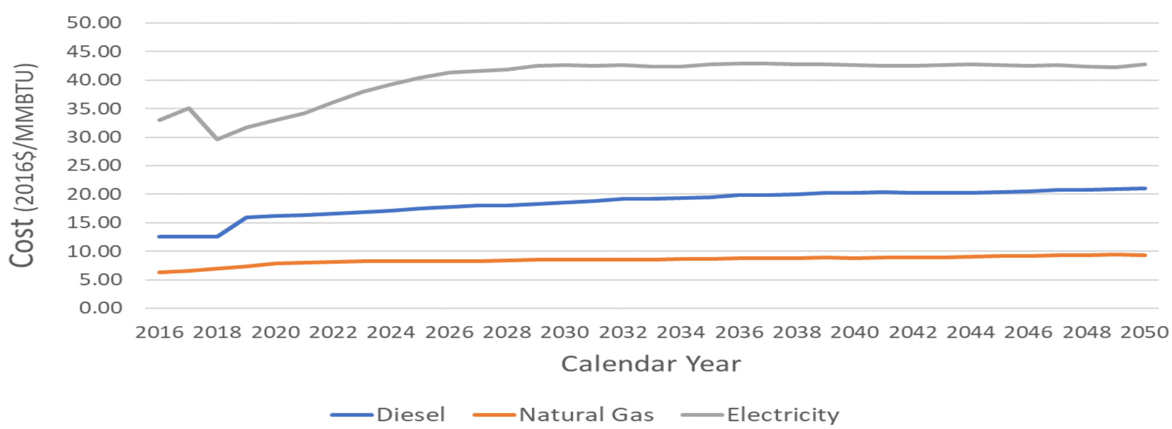

Figure 8. Energy Price Projections

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[31] US Energy Information Administration, 2017 Annual Energy Outlook.

Renewable Fuel Standard Credit Values – Scenarios utilizing CNG buses achieve substantial GHG reductions through the use of renewable natural gas. As described in Section 2.4, the cost to produce renewable natural gas is significantly greater than the cost of conventional natural gas. RNG is available at price parity relative to conventional natural gas due to the availability of credits under the RFS program that allow the RNG producer to offset their production costs. The values of these credits are highly variable, with D-5 RIN values currently down approximately 50% year-over-year. D-3 RINs have also exhibited volatility over the same timeframe but have been constrained to a 20% price swing.[32] While RNG could be purchased under terms that would mitigate near-term exposure to RIN price volatility, the long-term pricing of RNG remains dependent on the long-term value of RIN credits. Additionally, should the RFS program end, RNG pricing could increase substantially and would require RIPTA to absorb the increased costs or transition its natural gas supply to conventional natural gas.

Battery and Fuel Cell Technology Costs – Battery and fuel cell technologies are rapidly evolving. Costs for both technologies have declined significantly in recent years, driven in part by growing adoption of the technologies in the light duty space. Increased competition in the transit market, with more bus manufacturers offering electric drive platforms, has also placed downward pressure on costs. Both battery prices and fuel cell system costs are projected to decline significantly over the period of the cost analysis and cost reductions are incorporated into the models. Actual price reductions and the timing of these reductions may differ from the assumptions incorporated into this analysis. Because much of the incremental costs for battery-electric and fuel cell buses are attributable to battery pack costs and fuel cell system pricing, greater or lesser declines in these technology costs will have a substantial impact on the total cost of ownership for vehicles using these technologies.

4.2 Emissions Comparisons

As with the cost analysis, total emissions were calculated for each scenario on 12-year (1 bus lifetime) and 24-year (2 bus lifetimes) basis, as well as total emissions from 2018 to 2050. Pollutants included in the analysis are oxides of nitrogen (NOx), particulate matter less than 2.5 microns (PM2.5), and greenhouse gases.

NOx Emissions

Direct NOx emissions from transit buses under each scenario are summarized in Figure 9 and represent cumulative NOx emissions under each scenario, beginning in 2018. For all scenarios other than the Baseline Diesel and Limited Depot Charging scenarios, NOx emissions are similar across all timeframes. NOx emissions for the zero-emission scenarios come from diesel-fueled buses that are phased out during the first 12-year period. After the transition is complete, annual NOx emissions are reduced to zero. Note that the Newport facility finishes replacing its existing fleet one year later than the Providence facility and accounts for the small incremental NOx increase between the 12-year and 24-year totals for the zero-emission scenarios.

Under the Baseline Diesel and Limited Depot Charging scenarios, NOx emissions continue to accumulate through 2050. Annual emissions rates decrease significantly over the first 12-year period as the oldest diesel buses are phased out and replaced with new diesel engines meeting current emissions standards.

[32] Based on an analysis of OPIS credit price data collected by Gladstein, Neandross and Associates.

Additionally, the Limited Depot Charging scenario replaces approximately half of the diesel fleet with battery-electric buses, further reducing annual NOx emissions.

The scenarios incorporating near-zero CNG buses also show annual NOx emissions continuing through 2050, albeit at substantially reduced levels. For example, cumulative NOx emissions for the Near-zero R/CNG scenario grow only 15% between the end of the first twelve-year period and 2050, as compared to the 103% increase in cumulative NOx emissions under the Baseline Diesel scenario.

It is worth noting that the diesel emissions factors used in this report do not account for "off-cycle" emissions that are encountered in real-world driving. When vehicles are operated under conditions different from the test procedures used to certify the engine, emissions can be significantly different than measured under the certification procedures. Modern diesel engines are equipped with selective catalytic reduction (SCR) systems to control NOx emissions. When used in vehicle applications with substantial idling and low speed operation, low exhaust temperatures can cause the SCR system to become ineffective at controlling NOx emissions. Recent studies have indicated that real-world NOx emissions can be four to five times higher than certification levels in these applications. If the diesel emissions factors were adjusted to account for off-cycle NOx emissions, all scenarios utilizing diesel engines would show significantly higher total NOx emissions than indicated in Figure 9.

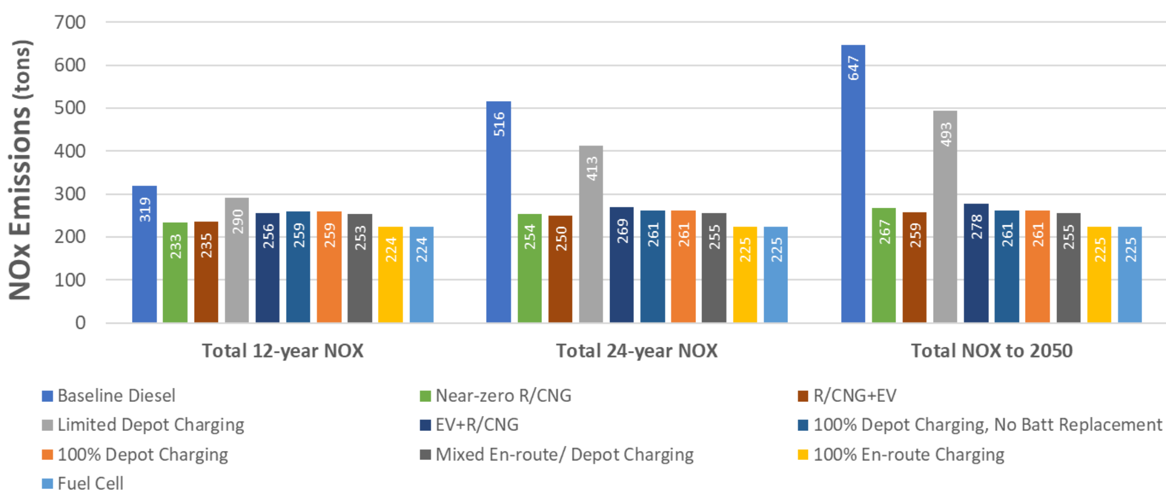


Figure 9. Projected NOx Emissions by Scenario

Amongst the zero-emission scenarios, differences in NOx emissions stem from assumptions in the way the technologies are initially deployed. Because of current range limitations and battery costs for depot-charged buses, it is assumed that these buses are first deployed to serve shorter blocks while longer blocks continue to be served by diesel buses. Consequently, depot-charged BEBs initially displace less diesel activity than the fleet average. By contrast, en-route charging and fuel cell buses are assumed to have no range restrictions and immediately begin displacing the fleet average bus activity as they are deployed.

$PM_{2.5}$ Emissions

Figure 10 summarizes the cumulative $PM_{2.5}$ emissions under each scenario. The trends for the zero-emission scenarios are similar to the trends for NOx emissions, wherein the total $PM_{2.5}$ emissions associated with each scenario are attributable to the phase out of the existing diesel vehicles during the first 12-year period.

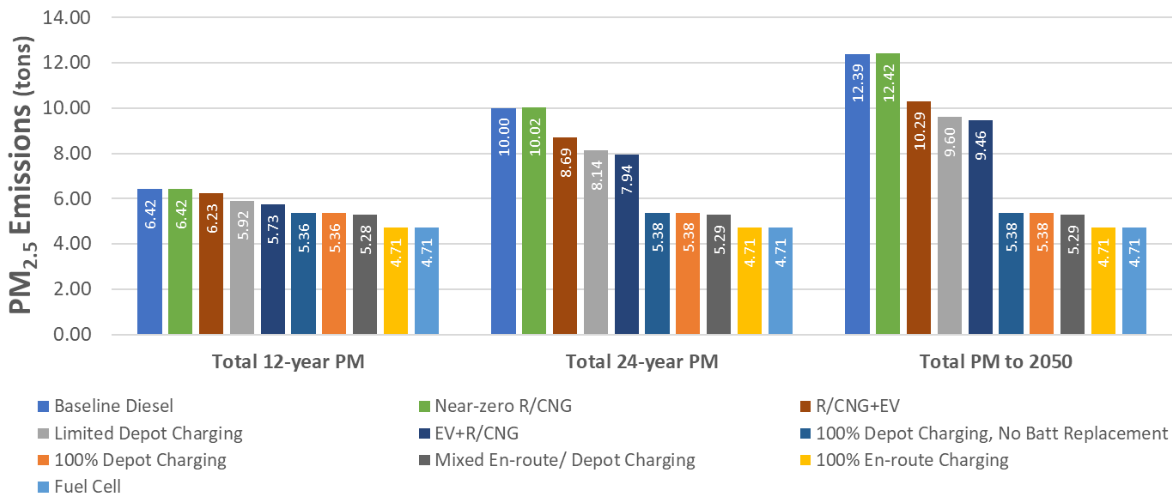


Figure 10. Projected PM2.5 Emissions by Scenario

Natural gas engines are assumed to emit $PM_{2.5}$ at the same rate as diesel engines, as both engine types are certified to the same PM emissions standard. It should be noted that, while $PM_{2.5}$ mass emissions are the same for both technologies, the composition of the particulate matter can be substantially different. Particulate matter produced by diesel engines (DPM), is recognized by the World Health Organization as a carcinogen due to the chemical composition of the DPM. Particulate matter produced from natural gas engines is regarded as less toxic than DPM as natural gas-derived PM typically has a lower organic carbon fraction that contains much of the carcinogenic risk associated with DPM. Therefore, while the total $PM_{2.5}$ mass emissions from diesel and natural gas engines are assumed to be the same, natural gas engines still represent a public health benefit over diesel engines with respect to particulate matter exposure.

GHG Emissions

In contrast to NOx and PM2.5 emissions, GHG emissions are assessed on a fuel cycle basis. Described in additional detail in Appendix D, carbon intensity factors are assigned to each fuel that represent the total "carbon dioxide-equivalent" emissions associated with producing, distributing, and utilizing the fuel in the vehicle. Table 25 summarizes the emissions rates of the three primary greenhouse gases (carbon dioxide, nitrous oxide, and methane) and the carbon dioxide-equivalent carbon intensity values for each fuel considered in the modeled scenarios. Note that all CNG buses are assumed to operate on renewable natural gas. Carbon intensity values are calculated using the 100-year global warming potentials in the International Panel on Climate Change (IPCC) Fifth Assessment.

Table 25. Carbon Intensity Values for Included Fuels

Fuel	CO_2 (g/MMBTU)	N_2O (g/MMBTU)	CH_4 (g/MMBTU)	CO_2e (g/MMBTU)
Diesel	93,215	0.43	199	99,305
RNG (from LFG)	2,262	0.54	415	14,843
Hydrogen (SMR of LFG)	18,935	-1.28	595	36,432
Grid Electricity (2014 mix)	80,687	2.52	221	88,282
Grid Electricity (Target 2050 mix)				0

Grid emissions are assumed to track the carbon reduction goals for the electrical grid described in the RIEC[4] GHG reduction plan. Based on the goals in the RIEC[4] plan, the carbon intensity of the electrical grid is assumed to decline to zero by 2050. GHG emissions for intervening years between 2014 and 2050 are linearly interpolated between the two end points.

Figure 11 summarizes the cumulative GHG emissions under each scenario. All alternative fuel scenarios offer substantial GHG reductions relative to the Baseline Diesel scenario. By 2050, all electric vehicle pathways are assumed to have zero GHG emissions as they are supplied by the Rhode Island grid. Other scenarios continue to have annual GHG emissions, albeit many at significantly reduced levels.

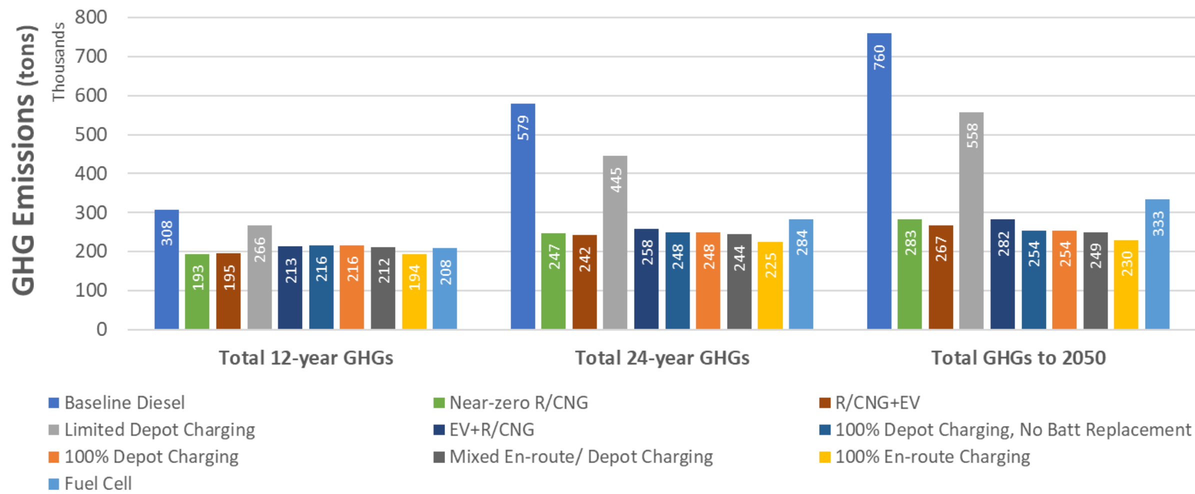


Figure 11. Projected GHG Emissions by Scenario

Table 26 summarizes the annual GHG emissions reductions that would be achieved by 2050 under each scenario. The baseline diesel pathway reduces annual GHG emissions by 11% in 2050 by replacing the older diesel buses currently in RIPTA's fleet with buses that achieve the higher fuel efficiency demonstrated by RIPTA's model year 2016 buses. Notably, the natural gas and fuel cell pathways using renewable CNG produce GHG reductions of 76-82%, independent of grid decarbonization efforts and provide GHG reductions that are comparable or greater than the electrification pathways over the mid-term (24-year scenario).

Table 26. Annual GHG Emissions Reductions by Scenario

Scenario	Annual GHG Reductions vs 2018 Baseline
Baseline Diesel	11%
Near-zero R/CNG	82%
R/CNG+EV	88%
Limited Depot Charging	46%
EV+R/CNG	89%
100% Depot Charging, No Batt Replacement	100%
Mixed En-route/Depot Charging	100%
100% Depot Charging	100%
100% En-route Charging	100%
Fuel Cell	76%

4.3 Cost and Emissions Analysis Summary

The combined costs and emissions results for each scenario are summarized in Table 26. A few consistent trends emerge from this analysis.

- All alternative fuels scenarios involve additional costs over baseline
- Scenarios that continue to rely on diesel vehicles – even partially, show substantially higher NOx and GHG emissions over the analysis period.
- Zero-emission technology pathways have lower total emissions through 2050 but are uniformly more expensive than scenarios with diesel and near-zero CNG vehicles.
- The incremental NOx and GHG emissions reductions from the zero-emission technology scenarios over the CNG scenarios are relatively small compared to the incremental costs of the zero-emission technology scenarios.
- The incremental PM emissions reductions from the zero-emission technology scenarios over the CNG scenarios are substantial and more consistent with the incremental costs of these scenarios.
- CNG-based scenarios offer greater near-term reductions in NOx and GHGs than zero-emission pathways. Zero-emission pathways offer greater reductions by 2050

The fuel cell pathway is an outlier in terms of costs and GHG emissions amongst the alterative scenarios. This is largely due to the status of technology. Fuel cell bus technology is earlier in its technical maturity and commercialization process than NGVs and BEBs. Consequently, costs are higher and vehicle efficiencies are lower than may ultimately be achieved. There is also less visibility to the rate at which costs may decline as current price estimates are based on very limited production of fuel cell buses. As newer generations of fuel cell buses are demonstrated in the next few years, the performance and costs of this technology may improve substantially.

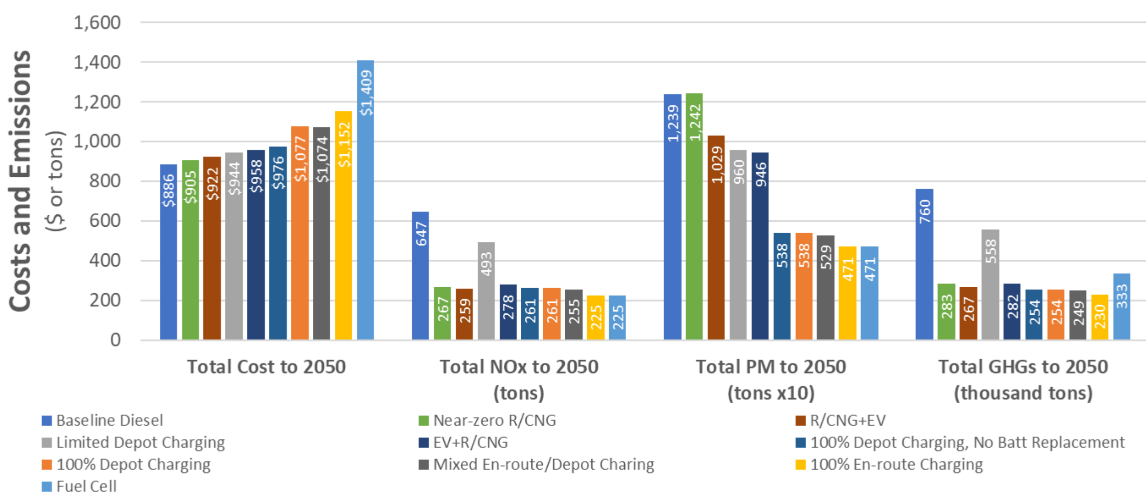


Figure 12. Projected Costs and Emissions by Scenario

4.4 Operational Implications to RIPTA

In addition to the costs and emissions implications of the various scenarios described in the preceding sections of this report, each scenario has unique operational implications to RIPTA that are difficult to quantify in terms of costs to RIPTA. These operational implications are discussed qualitatively to highlight some of the challenges that may be associated with particular technologies.

Infrastructure Footprint at RIPTA Facilities

RIPTA's current diesel fueling strategy requires relatively little space at the Providence and Newport facilities. Fuel is stored in underground tanks and dispensed in fueling lanes within each storage building. The electrical power required to operate the fuel pumps is modest and the noise associated with the operation of the pumps is negligible relative to other facility operations.

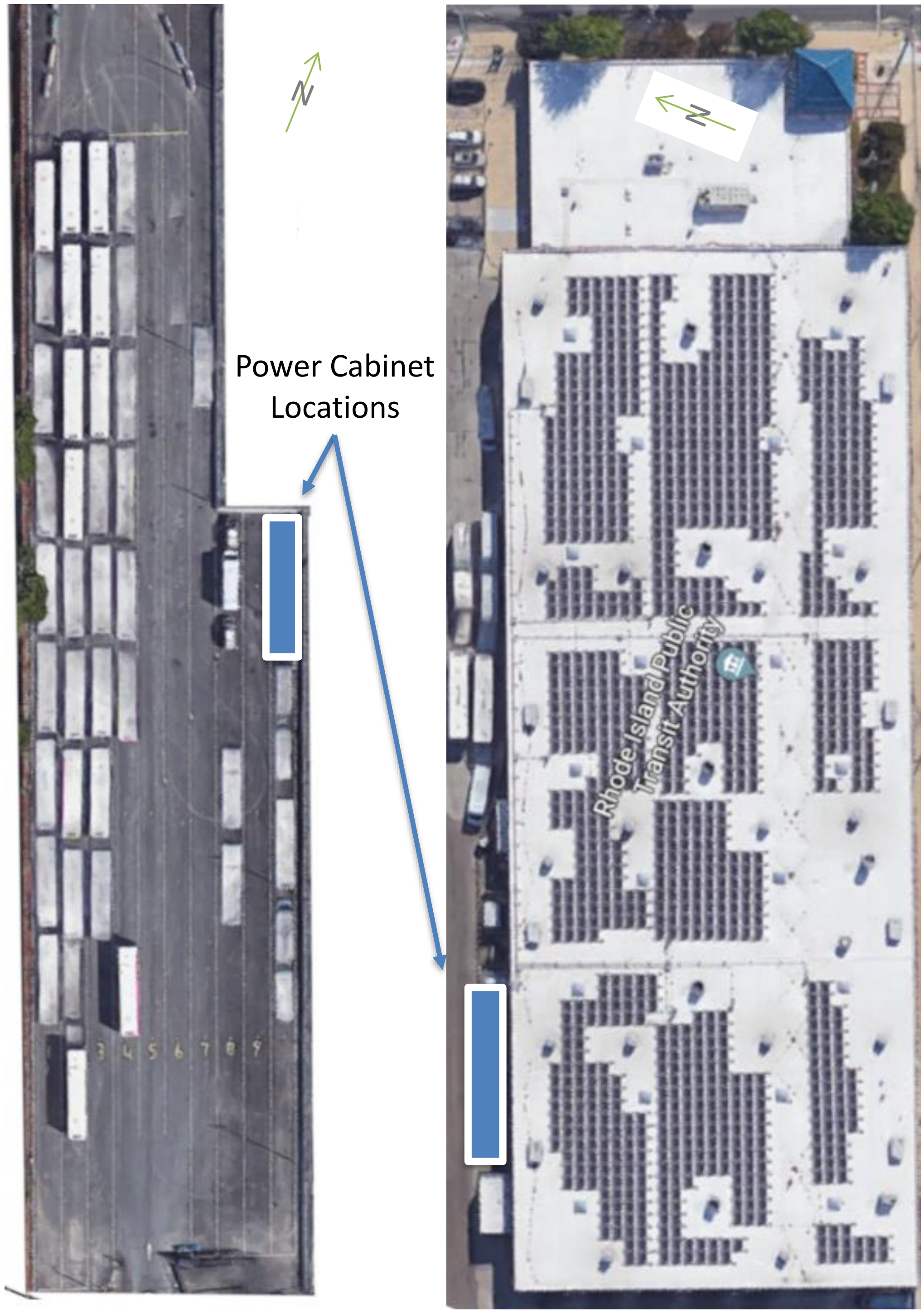
By contrast, the space requirements for depot charging infrastructure, CNG fueling stations, or hydrogen fueling stations will be non-trivial. The high density of buses at the Providence facility makes space requirements for alternative fueling infrastructure particularly significant at this facility. To assess these challenges, conceptual infrastructure layouts were developed for each fueling strategy at full build out at the Providence facility.

100% Depot Charging Scenario – Depot charging infrastructure for transit buses generally consists of two components; a "power cabinet" and a "dispenser." The power cabinet contains the high-power AC/DC electronics, controls, and connections to the facility electrical supply. The dispenser is typically a remote cabinet that includes the charging cable and certain safety components. The dispenser may be wall-mounted, pedestal-mounted, or mounted overhead. A typical power cabinet may be 7'x4'x2' (HxWxD) and capable of supplying 100 to 150 kW. A dispenser may be 2'x1.5'x0.8' (HxWxD).

Pedestal mounted dispensers pose specific challenges based on RIPTA's current parking configurations. It is assumed that the transitioned fleet will continue parking as currently organized and that travel lanes and directions within the facility will be maintained. The existing parking lanes are approximately 12 feet wide which accommodate transit buses that are approximately 8.5 feet wide with a mirror-to-mirror width of approximately 11 feet. For ground-mounted chargers installations, chargers and charging posts are most commonly installed between the parking lanes in order to minimize the amount of intrusion into each lane. Depending on the type of depot charger employed, the charging infrastructure would protrude 2-3 feet into each parking lane, when accounting for both the charging units and the concrete-filled bollards. Once the required number of chargers exceeds the number of chargers that can be placed along the outer lanes at each parking location, pedestals would need to be placed between lanes. The space required for the pedestals would result in the loss of at least one parking lane and require RIPTA to identify additional parking space at the property or procure additional real estate to house the displaced buses.

As an alternative, the dispensers may be mounted overhead. For buses stored indoors at the RIPTA facility, overhead mounting could likely be accommodated by the existing roof trusses. Buses stored outdoors would require the construction of a canopy structure to support the dispensers. The cost of such a structure is not included in the current Depot Charging scenarios.

To support charging of 196 buses at the Providence facility would require approximately 66 power cabinets, assuming that each cabinet could supply up to 150 kW of power and that the average power demand for a bus is 50 kW or less. These cabinets would require a combined footprint of approximately 10'x132', or roughly the parking space of three transit buses. It is anticipated that the cabinets would be divided between the two parking locations at the Providence facility, with roughly half the cabinets located along the north side of the bus storage facility and the remaining power cabinets located in the "Number 10" lane of the outdoor parking lot adjacent to Cadillac Drive (see Figure 13). Additionally, utility transformers and switchgear will be required to serve both parking areas. However, it is not anticipated that the power cabinets or other electrical supply infrastructure would pose a significant problem with respect to available space at the facility.



Cadillac Drive Yard **Melrose Storage Building**

Figure 13. Conceptual Footprint for Depot Charging Power Cabinets

Near-zero R/CNG Scenario – CNG fueling can largely replicate the diesel fueling experience through the use of fast-fill dispensers located on the fueling islands where the existing diesel dispensers are currently located. As such, the dispensers are not anticipated to require any incremental space beyond RIPTA's current operations. However, the full build out of the CNG station at the Providence facility will require up to six compressors and buffer storage vessels. In addition to the compressors, storage, and dispensers, other major equipment required includes a gas dryer and an emergency generator. The former is used to remove water vapor from the incoming gas stream that could condense possibly causing corrosion within the CNG equipment or the vehicles. A conceptual location for the compressor yard at Providence is shown in Figure 14. This location is advantageous as it is adjacent to the gas service in Thackeray Street. High pressure CNG will be routed through pipes located in a new utility trench between the compressor yard and the fueling/storage building. The piping can then be routed up the exterior wall of the building, across the roof, and down into the top-fed dispensers on the existing fueling islands. Based on discussions with RIPTA staff, the space requirements for the proposed location are not anticipated to pose significant problems. However, further study may identify a superior location.

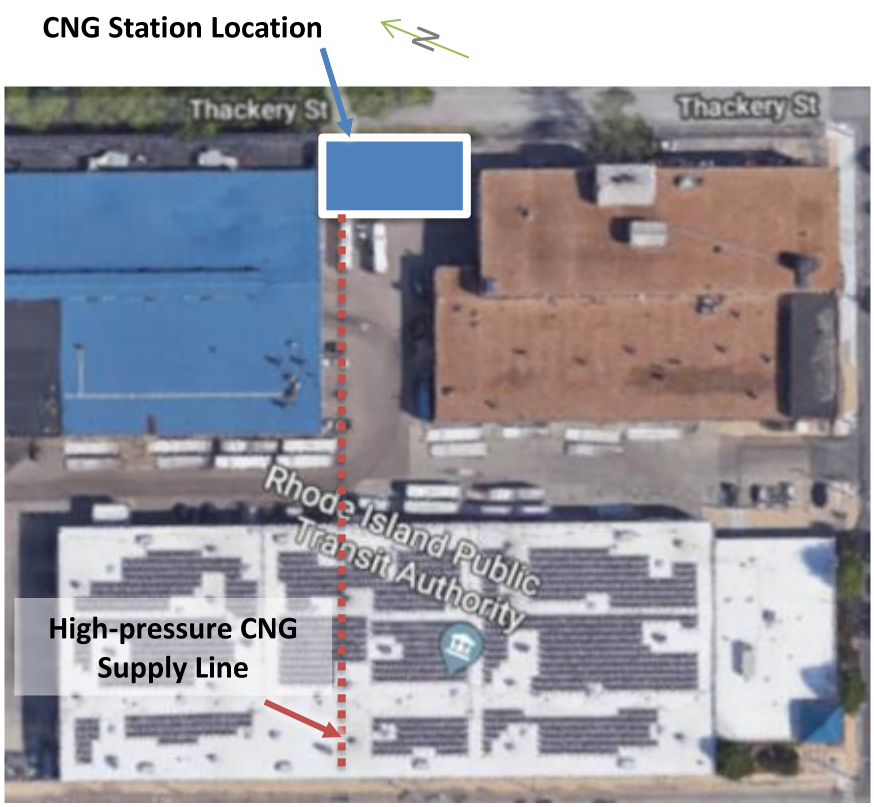


Figure 14. Conceptual Footprint for CNG Compression Equipment

Fuel Cell – As discussed in Section 2.3, the daily fuel demand of the Providence-based fleet dictates the use of liquid hydrogen delivered to the site, or the production of the hydrogen on-site. The cost and emissions analysis presented for the Fuel Cell scenario assumes that hydrogen is produced on-site from reformation of natural gas as this results in the lowest projected cost of fuel. However, on-site production substantially increases the footprint of the infrastructure to accommodate both the production equipment and the compression system. There are no known examples of transit agencies utilizing on-site SMR at the volumes that would be required by RIPTA at the Providence facility. Hence, the following estimates are speculative.

Fuel demand at the Providence facility is estimated to reach 3,650 kg/day at full conversion to fuel cell buses. Scaling equipment requirements from conceptual site layouts proposed by Linde Group, it is estimated that a 3,600 kg/day SMR site would require 9,000 to 11,000 square feet of space, including compression and storage systems. This is similar to space requirements for on-site electrolysis system layouts suggested by NEL. A liquid hydrogen station with this throughput capacity is estimated to require approximately 6,000 square feet of space, or slightly more than half the space requirement of the on-site production systems.

Site configurations are flexible as current designs are modular and higher capacities are achieved by the addition of compressors and storage from smaller functional blocks. However, given the typical "containerized" approach to these modular systems, the minimum characteristic length of the equipment is typically 40' to 50', setting the minimum length of any one side of the station layout to approximately 50' to 60' to allow for equipment spacing. Table 27 summarizes the assumed footprint for each of the stations configurations that would serve the Providence facility at full buildout.

Table 27. Assumed Infrastructure Footprint for Conceptual Hydrogen Station Configurations

Station Type	Footprint (square feet)	Length (feet)	Width (feet)
On-site SMR	10,000	60	167
On-site Electrolysis	10,000	60	167
Liquid Hydrogen	6,000	60	100

The larger footprint of a hydrogen station using on-site production is anticipated to pose significant impacts to RIPTA's current bus storage capacity. No space was identified on RIPTA property north of Longfellow Street that would accommodate the footprint of the hydrogen station options, leaving the Cadillac Drive yard as the most likely site. Figure 15 depicts the footprint required by a hydrogen station with on-site SMR or electrolysis located in the Cadillac Drive Yard. As shown, the station footprint would occupy space equivalent to approximately 18-20 bus parking spaces and may impact traffic flow that could preclude the use of additional parking space in "Lane 4" parallel to the station. Additionally, a high-pressure hydrogen supply line would be required to cross under Longfellow Street to reach the indoor fueling dispenser. Alternatively, the station could be located in space currently allocated for employee parking, just north of the Cadillac Drive yard. The station footprint would require reducing the employee parking to roughly one half of its current size and may require identifying alternative parking locations for RIPTA employees.

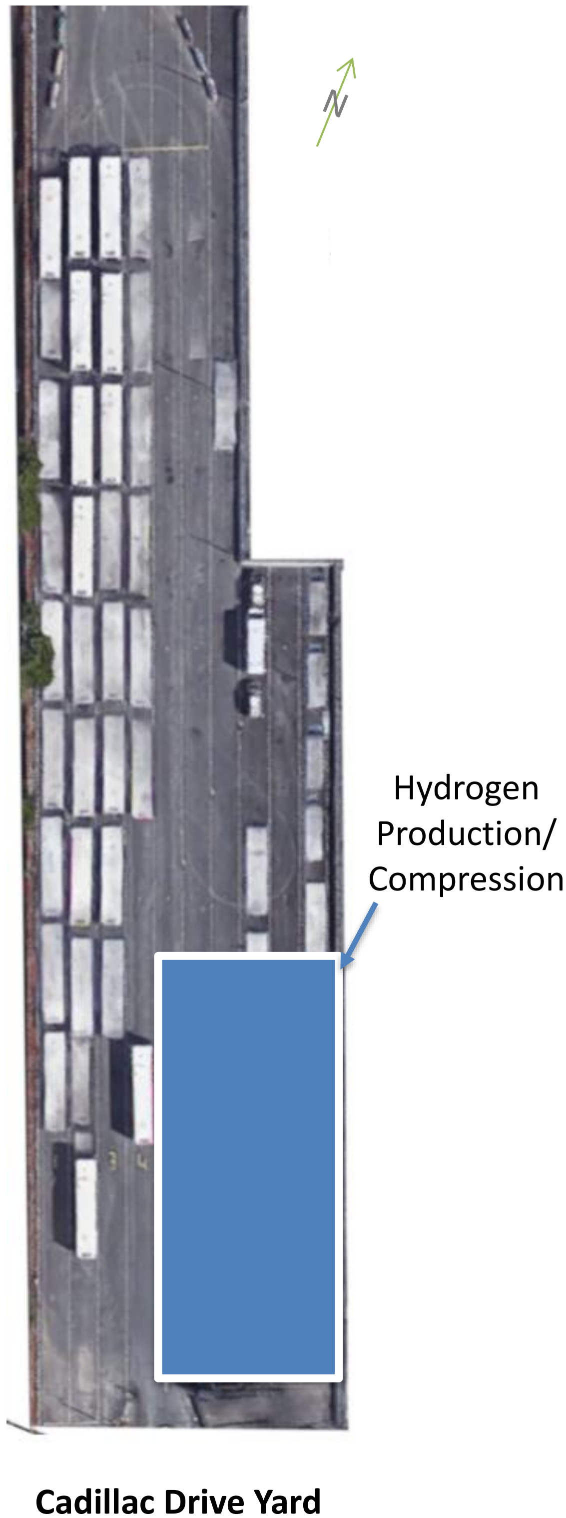


Figure 15. Conceptual Footprint for On-site Hydrogen Production and Compression Station

Range-restricted Bus Operations

The effective range of diesel buses in RIPTA's fleet is sufficient to service all of RIPTA's current blocks without requiring mid-day refueling. By contrast, the estimated range of depot-charged buses is currently sufficient to service only about half of RIPTA's current blocks on a single charge. En-route charging allows an electric bus to have essentially unlimited daily range, provided the bus stays within the en-route charging network and is able to recharge as needed. Both depot-charging and en-route charging strategies create operational constraints that RIPTA would be required to accommodate for at least a portion of the fleet if these technologies are adopted.

Route Pairing – RIPTA currently pairs a limited number of buses to specific routes/blocks. Specifically, buses branded for the R-Line and trolley-style buses dedicated to certain routes in the Newport region are routinely paired to their associated routes. For the remainder of the blocks, RIPTA does not explicitly pair buses. Instead, buses are dispatched based on availability, driver preference, and other factors.

Pairing buses to specific routes/blocks would be necessary for depot-charged buses and en-route charging buses. Depot-charging buses must be paired to daily block assignments that do not exceed the bus's range. En-route charging buses must be paired to routes equipped with the required charging infrastructure. Route pairing could be extended to all blocks but would require additional planning and dispatch management resources to implement. Once a transition to a 100% depot-charging fleet (with future improvements to range) or to a 100% en-route charging fleet is completed, route pairing would not be required. However, mixed technology scenarios (e.g. depot charging + en-route charging) would require continued route pairing.

Spares Management – Because BEBs may be restricted to specific routes during the transition or for mixed technology scenarios, RIPTA would likely need to maintain a spares fleet composed predominantly, or entirely, of diesel buses to ensure that a spare bus would be able to service any required block. This would limit RIPTA's ability to move the oldest BEBs into the spare fleet, as is typically done with the diesel fleet today, and may require RIPTA to procure diesel buses to serve as spares for a mixed BEB/en-route charging scenario.

Alternatively, RIPTA could structure the composition of the spares fleet to reflect the composition of the active fleet. Under this approach there is a risk that the number of buses of a given technology type coming out of service for maintenance might exceed the number of available spares of that technology type. In such a situation, RIPTA could be required to reduce transit service until the required mix of bus types was put back into service.

5.0 Recommendations

RIPTA's transition to a sustainable fleet must balance environmental goals with important co-priorities of affordable service, reliability, equity, and operational flexibility. The introduction of new technologies into the fleet should be done in a manner that minimizes impacts to riders and provides continuity of service, while maximizing environmental benefits. Consequently, RIPTA is focusing the development of the current transition plan on the fixed route bus services that represent the majority of fleet emissions and ridership and where sustainable transit technology product offerings are greatest.

RIPTA believes that zero-emission technologies will be an important part of the future transit market. Further, zero-emission technologies most directly address the environmental and sustainability policy goals of the state. This analysis of zero-emission and near-zero emission technologies indicates that battery-electric buses are generally more commercially mature and less costly than fuel cell buses, but both technologies remain more expensive options than RIPTA's current diesel fleet. And, while costs continue to decline for both technologies and operational capabilities such as range and refueling/recharging times continue to improve, neither technology yet represents a one-to-one replacement for diesel buses in all operations. Managing and deploying charging infrastructure at the scale necessary to fully transition RIPTA's fleet is also an unknown and daunting challenge. No transit agency in the US has yet deployed the charging/fueling infrastructure or number of transit buses that RIPTA would require for a full transition to zero-emission buses.

Given these considerations, prudent next steps in a sustainable fleet transition should provide additional experience with zero-emission buses in RIPTA's operations while working toward a long-term transition to a fully zero-emission fleet. Specifically, the following near-term steps over the next three years.

- Develop a zero-emission pilot program to demonstrate commercially available electric transit buses on a short-term basis in RIPTA's operations.
- Leverage available incentive funds at the state and federal level to subsidize the costs of the pilot program
- Develop an Electric Bus procurement specification
- Reassess the costs and challenges of zero-emission technologies over the course of the pilot program and update this Sustainable Fleet Transition Plan based on those reassessments
- Monitor Renewable CNG funding opportunities, particularly if battery-electric bus technology proves insufficient or too costly to address statewide transit needs.
- Continue to work with state agencies and the local utility to:
    - Plan for a larger scale transition to zero-emissions that will likely require substantial electrical infrastructure upgrades and investments.
    - Develop policies to clarify rules, roles, and responsibilities for electricity use and management
    - Evaluate options to monetize these infrastructure investments through other mechanisms (energy/demand services, grid resiliency, etc)

6.0 Appendix A – Vehicle Costs

<table>
<tr><th colspan="5">Near-Zero NO_x CNG Transit Bus</th></tr>
<tr><td rowspan="2">Fuel Economy</td><th>Year</th><th>Mile/DGE</th><th colspan="2">Source Description</th></tr>
<tr><td>All</td><td>4.52</td><td colspan="2">Fuel economy estimates were calculated based on a comparison of Altoona-reported fuel economies for a 2014 New Flyer XN40 CNG transit bus and a 2012 XD40 diesel transit bus. Fuel consumption rates were modeled as a function of average cycle speed for each fuel type. Energy consumption was then modeled for each route block based on its average speed and used to calculate an average fuel economy ratio for the CNG vs diesel bus. Based on this analysis, a 26% fuel economy penalty is assumed for CNG buses. This value is consistent with ARB's ICT working group document "Cost Data and Sources" dated June 26, 2017.</td></tr>
<tr><td rowspan="2">Capital Costs</td><th>Year</th><th>$/Bus
(constant 2016)</th><th colspan="2">Source Description</th></tr>
<tr><td>All</td><td>$596,500</td><td colspan="2">Based on an assumed $57,500 incremental cost over a baseline diesel vehicle. The capital costs were derived from information generated for ARB’s ICT working group meetings. Per ARB’s Bus Prices Analysis (Draft), the incremental cost of a 40-foot CNG transit bus is $50,000 over a baseline diesel bus. An additional $7,500 represents the incremental cost of a near-zero NOx certified CNG engine relative to a standard CNG engine.</td></tr>
<tr><td rowspan="4">O&M Costs</td><th>Year</th><th>Description</th><th>$/mile
(constant 2016)</th><th>Source Description</th></tr>
<tr><td rowspan="3">All</td><td>Propulsion</td><td>$0.40</td><td rowspan="3">Based on analysis of work order data for RIPTA transit buses and aggregate reported O&M costs in RIPTA's annual NTD report. Costs for CNG buses are assumed to be equivalent to diesel buses. Propulsion-related costs include engine/powertrain, brake, and transmission maintenance costs. Non-propulsion costs include all other maintenance costs except mid-life overall costs. Non-</td></tr>
<tr><td>Non-Propulsion</td><td>$0.67</td></tr>
<tr><td>Total O&M</td><td>$1.07</td></tr>
</table>

			propulsion costs are assumed to remain unchanged for all technologies considered.
Mid-Life Overhaul Costs	**Year**	**$/Bus (constant 2016)**	**Source Description**
	All	$32,000	Based on analysis of work order data for RIPTA transit buses and discussions with RIPTA maintenance personnel. Costs for CNG buses assumed to be equivalent to diesel buses.
Depot-Charged Battery-Electric Transit Bus			
Fuel Economy	**Year**	**kWh/mi**	**Source Description**
	All	2.01 - 2.26	Fuel economy estimates were calculated based on a comparison of Altoona-reported fuel economies for a 2012 XD40 diesel transit bus and a range of Proterra, New Flyer, and BYD 40-foot transit buses. Fuel consumption rates were modeled as a function of average cycle speed for each fuel type. An estimated 6 kW continuous load to meet HVAC requirements was added to the calculated energy requirements for EV buses. Energy consumption was then modeled for each route block based on its average speed. The range of energy consumption rates is based on the mix of blocks dispatched out of the Providence and Newport facilities and the blocks that can be addressed with current battery capacities. A bus dispatch model was run against the blocks for each facility assuming a 384 kWh/day battery capacity to estimate the average energy consumption for buses operating with this battery capacity. Providence - 2.26 kWh/mi Newport - 2.01 kWh/mi
Capital Costs	**Year**	**$/Bus (constant 2016)**	**Source Description**
	2017-2019 2020-2024 2025-2029	$936,550 $854,950 $809,350	Bus capital costs are based on the base price of a 40-foot extended range electric bus with a ~480 kWh energy storage system modeled off of the New Flyer XE40. The capital costs were derived from information generated for ARB's ICT working group meetings,

	2030+	$765,190	bus manufacturers, and information provided by RIPTA. Pre-tax base pricing of 40-foot buses provided by Proterra, BYD, and New Flyer are assumed to includes ADA and standard equipment but do not include fare boxes, transit management systems, telematics, or other agency-specific equipment. RIPTA estimates agency-specific equipment costs at $57,800 and this cost is added to the base price of the bus. The analysis also includes the costs associated with adding 330 kWh of battery capacity to the XE40 base capacity of 150 kWh for which pricing was available. Battery costs and projected reductions are based on ARB's Battery Cost for Heavy-Duty Electric Vehicles - (Discussion Draft). ARB estimate that the 2017 cost of $575/kWh will decline to $405/kWh (2020), $310/kWh (2025), and $218/kWh (2030). Using these projections, the capital cost of an extended range 40-foot electric bus with a ~480 kWh battery pack were estimated for buses procured in 2017-2019, 2020-2024, 2025-2029, and 2030+. Additionally, the cost of a DC fast charger was added to the purchase price of the bus at an estimated cost of $40,000. Based on expected life of the charger being between 10-15 years, a charger replacement would be required at approximately the same frequency as the bus service life. Consequently, the charger replacement is modeled as part of the capital cost of the bus. Site improvements and utility upgrades to supply the chargers are modeled separately and do not reoccur with each bus replacement. Below is the capital cost for a 2017 40-foot bus: Base Price 150 kWh : $649,000 Additional 330 kWh Battery Capacity: $189,750 RIPTA-specific additional equipment: $57,800 DC fast charger : $40,000 Total : $936,550 The incremental cost of the battery electric is $397,550/bus.

	Year	Description	$/mile (constant 2016)	Source Description
O&M Costs	2017	Propulsion	$0.04	O&M costs for battery electric transit buses are based on a combination of RIPTA's historical data and assumptions to account for the reduced O&M costs associated with the decreased complexity of the battery electric propulsion system. The analysis eliminates maintenance costs associated with the diesel engine and its cooling systems. Additionally, battery electric powertrains include regenerative braking systems that significantly reduce the amount of brake repairs required. The analysis assumes that O&M costs for brake repairs to be 50% less than brake-related O&M costs
		Non-Propulsion	$0.67	
		Total O&M	**$0.71**	

				for RIPTA's existing transit buses. The assumed brake-related O&M cost reductions are based on ARB's Literature Review on Transit Bus Maintenance Cost (Discussion Draft) - August 2016. Propulsion-related costs include engine/powertrain, brake, and transmission maintenance costs. Non-propulsion costs include all other maintenance costs except mid-life overall costs. Non-propulsion costs are assumed to remain unchanged for all technologies considered.
Mid-Life Overhaul Costs	**Year**	**$/Bus (constant 2016)**	**Source Description**	
	2017-2019 2020-2024 2025-2029 2030+	$306,000 $224,400 $178,800 $134,640	Battery electric transit bus midlife costs are estimated from information provided by bus OEMs to ARB, Altoona test results, and assumptions to account for specific components of a battery electric powertrains that may require replacement or reconditioning as part of the midlife overhaul. The total cost includes repairs to the drive motors, inverter, and energy storage system. Battery replacement costs are based on a ~480 kWh battery pack and account for projected battery cost reductions. Battery cost reductions are based on ARB's Battery Cost for Heavy-Duty Electric Vehicles - (Discussion Draft). ARB estimate that the 2017 cost of $575/kWh will decline to $405/kWh (2020), $310/kWh (2025), and $218/kWh (2030). Using these projections, the cost of replacing a ~480 kWh battery pack are assumed to be $276,000 (2017-2019), $194,400 (2020-2024), $148,800 (2025-2029), $104,640 (2030+). It is assumed that battery costs beyond 2030 will remain constant. In addition, replacement or reconditioning of a battery electric transit bus's drive motor and inverter may be required as part of the midlife overhaul at a cost of $30,000. The model assumes that the cost for a midlife overhaul are the costs that will be incurred 6 years from the date the bus was initially purchased; a 2020 model year bus will be overhauled in 2026 at a cost of $178,800.	
En-route Charged Battery-Electric Transit Bus				
Fuel Economy	**Year**	**Mile/DGE**	**Source Description**	
	All	1.87 - 2.22	Fuel economy estimates were calculated based on a comparison of Altoona-reported fuel economies for a 2012 XD40 diesel transit bus and a range of Proterra, New Flyer, and BYD 40-foot transit buses. Fuel consumption rates were modeled as a function of average cycle speed for each fuel type. An estimated 6 kW continuous load to meet HVAC requirements was added to the calculated energy requirements for EV buses. Energy consumption was then modeled for each route block based on its average speed.	

			The range of energy consumption rates is based on the mix of blocks dispatched out of the Providence and Newport facilities. A bus dispatch model was run against the blocks for each facility. All blocks are assumed to be servicable by en-route charging buses, consequently, the energy consumption rates represent the average of all blocks dispatched from each facility. Providence - 2.22 kWh/mi Newport - 1.87 kWh/mi
	Year	**$/Bus (constant 2016)**	**Source Description**
Capital Costs	2017-2019 2020-2024 2025-2029 2030+	$806,800 $788,950 $778,975 $769,315	Bus capital costs are based on the base price of a 40-foot en-route fast charge electric bus with a ~105 kWh energy storage system modeled off of the Proterra FC+. The capital costs were derived from information generated for ARB's ICT working group meetings, bus manufacturers, and information provided by RIPTA. Pre-tax base pricing of 40-foot buses provided by Proterra, BYD, and New Flyer are assumed to includes ADA and standard equipment but do not include fare boxes, transit management systems, telematics, or other agency-specific equipment. RIPTA estimates agency-specific equipment costs at $57,800 and this cost is added to the base price of the bus. Battery costs and projected reductions are based on ARB's Battery Cost for Heavy-Duty Electric Vehicles - (Discussion Draft). ARB estimate that the 2017 cost of $575/kWh will decline to $405/kWh (2020), $310/kWh (2025), and $218/kWh (2030). Using these projections, the capital cost of an en-route charging 40-foot electric bus with a ~105 kWh battery pack were estimated for buses procured in 2017-2019, 2020-2024, 2025-2029, and 2030+. Note that Proterra's fast charge buses use a lithium titanate (LTO) battery chemistry. The cost per kWh for LTO batteries is currently significantly higher than the cost for the battery types used in extended range buses. However, because of the very limited available data for LTO battery cost projections, battery cost projections for extended range batteries are used. This likely underestimates capital cost reductions for fast charge buses while overestimating mid-life battery replacement cost reductions. Below is the capital cost for a 2017 40-foot bus: Base Price 105 kWh : $749,000 RIPTA-specific additional equipment: $57,800 Total : $806,800 The incremental cost of the battery electric is $267,800/bus.

	Year	Description	$/mile (constant 2016)	Source Description
O&M Costs	2017	Propulsion	$0.04	O&M costs for battery electric transit buses are based on a combination of RIPTA's historical data and assumptions to account for the reduced O&M costs associated with the decreased complexity of the battery electric propulsion system. The analysis eliminates maintenance costs associated with the diesel engine and its cooling systems. Additionally, battery electric powertrains include regenerative braking systems that significantly reduce the amount of brake repairs required. The analysis assumes that O&M costs for brake repairs to be 50% less than brake-related O&M costs for RIPTA's existing transit buses. The assumed brake-related O&M cost reductions are based on ARB's Literature Review on Transit Bus Maintenance Cost (Discussion Draft) - August 2016. Propulsion-related costs include engine/powertrain, brake, and transmission maintenance costs. Non-propulsion costs include all other maintenance costs except mid-life overall costs. Non-propulsion costs are assumed to remain unchanged for all technologies considered.
		Non-Propulsion	$0.67	
		Total O&M	**$0.71**	

	Year	$/Bus (constant 2016)	Source Description
Mid-Life Overhaul Costs	2017-2019 2020-2024 2025-2029 2030+	$90,375 $72,525 $62,550 $52,890	Battery electric transit bus midlife costs are estimated from information provided by bus OEMs to ARB, Altoona test results, and assumptions to account for specific components of a battery electric powertrains that may require replacement or reconditioning as part of the midlife overhaul. The total cost includes repairs to the drive motors, inverter, and energy storage system. Battery replacement costs are based on a ~105 kWh battery pack and account for projected battery cost reductions. Battery cost reductions are based on ARB's Battery Cost for Heavy-Duty Electric Vehicles - (Discussion Draft). ARB estimate that the 2017 cost of $575/kWh will decline to $405/kWh (2020), $310/kWh (2025), and $218/kWh (2030). Using these projections, the cost of replacing a ~105 kWh battery pack are assumed to be $60,375 (2017-2019), $42,525 (2020-2024), $32,550 (2025-2029), $22,890 (2030+). It is assumed that battery costs beyond 2030 will remain constant. In addition, replacement or reconditioning of a battery electric transit bus's drive motor and inverter may be required as part of the midlife overhaul at a cost of $30,000. The model assumes that the cost for a midlife overhaul are the costs that will be incurred 6

			years from the date the bus was initially purchased; a 2020 model year bus will be overhauled in 2026 at a cost of $62,550. Note that Proterra's fast charge buses use a lithium titanate (LTO) battery chemistry. The cost per kWh for LTO batteries is currently significantly higher than the cost for the battery types used in extended range buses. However, because of the very limited available data for LTO battery cost projections, battery cost projections for extended range batteries are used. This likely underestimates capital cost reductions for fast charge buses while overestimating mid-life battery replacement cost reductions.

Fuel Cell Electric Transit Bus

	Year	Miles/kg H2	Source Description
Fuel Economy	2017 - 2024 2025 +	6.16 7.03	Fuel economy estimates are based on the current fleet average performance of "second generation" fuel cell buses as reported by NREL in their report, "Fuel Cell Buses in US Transit Fleets: Current Status 2017." Current average fuel economy for these buses is reported as 7.01 mi/DGE or approximately 6.16 mi/kg H2. The US DOE has established an ultimate target of 8 mi/DGE or approximately 7.03 mi/kg for fuel cell bus fuel economy. The fuel economy of second generation FC buses is used for the MY2017-2024 time frame, at which point it is assumed that newer generation buses achieve the US DOE target.

	Year	$/Bus (constant 2016)	Source Description
Capital Costs	2017 2020 2030 2040 2050	$1,119,400 $962,000 $719,000 $709,000 $701,000	Purchase costs are based on the calculated incremental cost of a fuel cell bus relative to a diesel bus as reported by ARB in there ICT working group document "Innovative Clean Transit - Cost Data and Sources - Update on 6/26/2017." ARB notes that the initial price declines between 2017 and 2020 are based on a letter from New Flyer indicating that a baseline bus sales price of $900,000 (before agency specific modifications) would be possible for orders of 40 or more buses. Below is the capital cost for a 2017 40-foot bus: Base Price : $1,136,200 RIPTA-specific additional equipment: $57,800 Total : $1,194,000 The incremental cost of the battery electric is $655,000/bus.

	Year	Description	$/mile (constant 2016)	Source Description
O&M Costs	All	Propulsion	$1.65	O&M costs for fuel cell transit buses are based on a combination of RIPTA's historical data, maintenance cost data reported by NREL for AC Transit's fuel cell bus demonstration program, and assumptions
		Non-Propulsion	$0.67	
		Total O&M	**$2.32**	

				to account for the reduced O&M costs associated with the decreased complexity of the electric propulsion system. The analysis assumes that brake and transmission related O&M costs for fuel cell transit buses to be 50% less than O&M costs for RIPTA's existing transit buses. These assumptions are consistent with the assumptions made for battery-electric buses. Other propulsion related costs, excluding mid-life overall, are based on AC Transit's reported maintenance costs and include out-of-warranty costs that are not currently available for other demonstration programs. The total reported maintenance cost for AC Transit's fuel cell bus fleet was $2.11 including extended service support contracts with US Hybrid and EnerDel. Approximately $0.50 of the total was non-FC related cost, implying a propulsion-related cost of $1.61/mile associated with the fuel cell and supporting systems. (Zero Emission Bay Area (ZEBA) Fuel Cell Bus Demonstration Results: Fifth Report) Propulsion-related costs include engine/powertrain, brake, and transmission maintenance costs. Non-propulsion costs include all other maintenance costs except mid-life overall costs. Non-propulsion costs are assumed to remain unchanged for all technologies considered.

	Year	$/Bus (constant 2016)	Source Description
Mid-Life Overhaul Costs	2017-2019 2020-2024 2025-2029 2030+	$222,075 $183,530 $150,028 $142,970	Fuel cell transit bus midlife costs are estimated from information provided by ARB, data from NREL's annual fuel cell transit bus industry status reports, and assumptions to account for specific components of fuel cell electric powertrains that may require replacement or reconditioning as part of the midlife overhaul. The total cost includes repairs to the drive motors, inverter, fuel cell stack, and energy storage system. Battery replacement costs are based on a 21 kWh battery pack and account for projected battery cost reductions. Battery cost reductions are based on ARB's Battery Cost for Heavy-Duty Electric Vehicles - (Discussion Draft). ARB estimate that the 2017 cost of $575/kWh will decline to $405/kWh (2020), $310/kWh (2025), and $218/kWh (2030). Using these projections, the cost of replacing a 21 kWh battery pack are assumed to be $60,375 (2017-2019), $42,525 (2020-2024), $32,550 (2025-2029), $22,890 (2030+). It is assumed that battery costs beyond 2030 will remain constant.

			It is also assumed that the fuel cell stack will require replacement at mid-life. Based on ARB's Literature Review on Transit Bus Maintenance Cost (Discussion Draft) - August 2016, the cost of the fuel cell stack is estimated to be 75% of the cost of the fuel cell system. Fuel cell system costs are projected to decline sustantially from current costs estimated at $2,000/kW. Costs are assumed to decrease based on the projected cost reduction for a complete fuel cell bus. Fuel cell stack costs are assumed to be $1,500/kW (2017-2019), $1,209/kW (2020-2024), $946/kW (2025-2029), and $903/kW (2030+) and are applied to a 120 kW average system size. In addition, replacement or reconditioning of a fuel cell electric transit bus's drive motor and inverter may be required as part of the midlife overhaul at a cost of $30,000. The model assumes that the cost for a midlife overhaul are the costs that will be incurred 6 years from the date the bus was initially purchased; a 2020 model year bus will be overhauled in 2026 at a cost of $150,000.
Diesel Transit Bus			
	Year	**Mile/DGE**	**Source Description**
Fuel Economy	2004	4.09	Based on analysis of fuel economy data provided by RIPTA for FY 2016.
	2005	5.41	
	2009	4.73	
	2010	4.11	
	2013	4.99	
	2016+	5.95	
	Year	**$/Bus (constant 2016)**	**Source Description**
Capital Costs	All	$539,000	Based on RIPTA's analysis of recent procurements and anticipated future pricing.

	Year	Description	$/mile (constant 2016)	Source Description
O&M Costs	All	Propulsion	$0.40	Based on an analysis of RIPTA's fleet-wide average maintenance cost of $1.14/mile. Mid-life costs were deducted based on the assumed mid-life overhaul cost and an assumed average lifetime mileage of 500,000 miles. Costs were then apportioned to propulsion and non-propulsion categories based on an analysis of job orders for a subset of RIPTA's fleet.
		Non-Propulsion	$0.67	
		Total O&M	**$1.07**	

	Year	$/Bus (constant 2016)	Source Description
Mid-Life Overhaul Costs	All	$32,000	Based on current estimates of RIPTA's estimates to perform mid-life engine rebuilds. Other non-propulsion related mid-life costs are reflected in the non-propulsion O&M costs reported above.

Diesel Hybrid Transit Bus

	Year	Mile/DGE	Source Description
Fuel Economy	2010	5.65	Model year 2010 fuel economy estimate is based on fuel economy data provided by RIPTA. Future year fuel economy data are based on an estimated 20% fuel economy improvement. RIPTA reports fuel economy improvements of 13-19% for 2009 diesel vs 2010 hybrid and 2013 diesel vs 2010 hybrid buses. Additionally, Altoona test data for New Flyer XD (diesel) and the XDE (diesel hybrid) buses report average fuel economies of 4.82 and 5.84 mpg, respectively; a 17% reduction in fuel consumption. See Altoona test reports 1211 and 1015.
	2017+	7.14	

	Year	$/Bus (constant 2016)	Source Description
Capital Costs	All	$739,000	Based on RIPTA's analysis of recent procurements and anticipated future pricing.

O&M Costs	**Year**	**Description**	**$/mile (constant 2016)**	**Source Description**
	All	Propulsion	$0.36	Costs are based on RIPTA's current diesel fleet O&M costs and assumes a 50% reduction in brake and transmission maintenance costs.
		Non-Propulsion	$0.67	
		Total O&M	**$1.03**	
Mid-Life Overhaul Costs	**Year**	**$/Bus (constant 2016)**	**Source Description**	
	2017-2019 2020-2024 2025-2029 2030+	$87,500 $72,717 $64,457 $56,457	Hybrid diesel transit bus midlife costs are estimated from information provided by RIPTA, and assumptions to account for specific components of hybrid electric powertrains that may require replacement or reconditioning as part of the midlife overhaul. The total cost includes repairs to the drive motors, power electronics, engine, and energy storage system. Battery replacement costs are based on a current battery pack replacement of $50,000 and account for projected battery cost reductions. Battery cost reductions are based on ARB's Battery Cost for Heavy-Duty Electric Vehicles - (Discussion Draft). ARB estimate that the 2017 cost of $575/kWh will decline to $405/kWh (2020), $310/kWh (2025), and $218/kWh (2030). Using these projections, the cost of replacing a battery pack are assumed to be $50,000 (2017-2019), $35,217 (2020-2024), $26,957 (2025-2029), $18,957 (2030+). It is assumed that battery costs beyond 2030 will remain constant. It is also assumed that a fraction of hybrid buses will require replacement of power electronics at mid-life. Based on RIPTA's current experience, the cost to replace the power electronics module is $55,000 per bus with an estimated 10% failure rate, resulting in a prorated cost of $5,500 per bus, averaged over the fleet. Hybrid buses also require midlife overhaul of the diesel engine at a cost of $32,000 (assumed to be equal to standard diesel engine overhaul costs). The model assumes that the cost for a midlife overhaul are the costs that will be incurred 6 years from the date the bus was initially purchased; a 2020 model year bus will be overhauled in 2026 at a cost of $64,457.	

7.0 Appendix B – Fuel Costs

Fuel Costs			
RNG	**Year**	**$/unit (constant 2016)**	**Source Description**
	2016 Future Years	$0.87/DGE 1.2% average Year-over-Year growth	Fuel price is based on cost of natural gas delivered by National Grid under the "Extra Large High Load" tariff at $6.32/MMBTU in 2016. Future prices are escalated based on year-over-year price changes projected by US EIA in the 2017 Annual Energy Outlook for Commercial customers in the New England Region. RNG is assumed to be available at price equivalency with traditional natural gas based on the availability and value of credits through the US EPA Renewable Fuel Standard. Costs do not include fueling infrastructure capital or O&M costs as these are calculated separately.
Electricity - Depot Charging	**Year**	**$/unit (constant 2016)**	**Source Description**
	2016 Future Years	$0.113/kWh 0.8% average Year-over-Year growth	Fuel price is based on cost of electricity delivered by National Grid under the "Large Demand (G-32)" tariff at $0.113/kWh. Charging is assumed to occur during non-peak periods, thereby avoiding demand charges. Future prices are escalated based on year-over-year price changes projected by US EIA in the 2017 Annual Energy Outlook for Transportation customers in the New England Region. Costs do not include fueling infrastructure capital or O&M costs as these are calculated separately.
Electricity - En-route Charging	**Year**	**$/unit (constant 2016)**	**Source Description**
	2016 Future Years	$0.258/kWh 0.8% average Year-over-Year growth	Fuel price is based on cost of electricity delivered by National Grid under the "Large Demand (G-32)" tariff at $0.258/kWh. These costs include demand charges based on $4.066/kW demand charge, 350 kW charge rate, 330 operational days per year. Future prices are escalated based on year-over-year price changes projected by US EIA in the 2017 Annual Energy Outlook for Transportation customers in the New England Region.

			Costs do not include fueling infrastructure capital or O&M costs as these are calculated separately.
Hydrogen - LH2	**Year**	**$/unit (constant 2016)**	**Source Description**
	2016	$4.49/kg	Fuel price represents delivered cost of LH2 to station, assuming 4,600 kg/day peak station capacity and 9,600 kg/day liquefier supplying facility. Analysis based on modeling using US DOE's HDSAM 3.0 hydrogen cost model. Costs do not include fueling infrastructure capital or O&M costs as these are calculated separately.
	Future Years	Assumed fixed	
Hydrogen - On-site Electrolysis	**Year**	**$/unit (constant 2016)**	**Source Description**
	2016	$9.00/kg	Fuel price represents on-site produced costs by PEM electrolysis. Analysis based on modeling performed by US DOE for a 1,500 kg/day facility. https://www.hydrogen.energy.gov/pdfs/14004_h2_production_cost_pem_electrolysis.pdf Costs include electricity supply costs, capital costs, and O&M costs for the fuel production equipment. Fueling infrastructure (compression and dispensing) capital are O&M costs are calculated separately. Future prices are escalated based on year-over-year price changes projected by US EIA in the 2017 Annual Energy Outlook for electricity to customers in the New England Region.
	Future Years	0.7% average Year-over-Year growth	
Hydrogen - On-site SMR	**Year**	**$/unit (constant 2016)**	**Source Description**
	2016	$2.07/kg	Fuel price represents on-site produced costs by SMR. Analysis based on modeling performed by US DOE for a 1,500 kg/day facility. https://www.hydrogen.energy.gov/h2a_prod_studies.html Costs include electricity and natural gas supply costs, capital costs, and O&M costs for the

	Future Years	0.7% average Year-over-Year growth	fuel production equipment. Fueling infrastructure (compression and dispensing) capital are O&M costs are calculated separately. Future prices are escalated based on year-over-year price changes projected by US EIA in the 2017 Annual Energy Outlook for electricity and natural gas to customers in the New England Region.
Diesel	**Year**	**$/unit (constant 2016)**	**Source Description**
	2016 2019	$1.74/gallon $2.20/gallon	2016-2018 fuel price is based on current RIPTA diesel contract pricing. 2019 fuel price is based on cost of diesel new contract pricing for 2019 at $2.20/gallon. Future prices are escalated based on year-over-year price changes projected by US EIA in the 2017 Annual Energy Outlook for Transportation customers in the New England Region. Costs do not include fueling infrastructure capital or O&M costs as these are calculated separately.
	Future Years	1.6% average Year-over-Year growth	

8.0 Appendix C – Infrastructure Costs

Fueling Infrastructure			
	Cost	**$ (constant 2016)**	**Source Description**
RNG	Capital	Providence: Phase 1 - $2,800,000 Phase 2/3 - $1,100,000 Newport: $1,900,000	Capital costs are estimated by GNA based on site assessments of Providence and Newport facilities, and GNA experience with typical installed costs of CNG fueling stations for transit facilities. Providence: Phase 1 costs include a 2x 800 SCFM compressors, providing 100% redundancy. Phase 2 and phase 3 costs include an additional 2x 800 SCFM compressors per phase, providing 100% redundancy in each phase. Newport: Costs in 2x 500 SCFM compressors, providing 100% redundancy.
	O&M	Providence: $0.49/DGE Newport: $0.52/DGE	O&M costs: Include station maintenance contract pricing at $0.20/therm and electricity costs based on 1.16 kWh/DGE of produced CNG. Energy consumption values are based on Argonne National Laboratory's GREET 2017 values for CNG compression. Natural gas utility upgrade costs assumed to be zero based on preliminary discussions with National Grid.
	Year	**$ (constant 2016)**	**Source Description**
Electricity - Depot Charging	Capital	Providence: $670,000 per 4,000 kW of capacity Newport: $330,000 for 1,000 kW of capacity	Providence: Capital costs of $670,000 per 4,000 kW of capacity and include transformers, switch gear, site work, and distribution of power to chargers. Based on GNA assessment of typical infrastructure costs and site designs for DC fast-charging stations with average loads of 40-50 kW/vehicle. Newport: Capital costs of $330,000 for 1,000 kW of capacity and include transformers, switch gear, site work, and distribution of power to chargers. Based on GNA assessment of typical infrastructure costs and site designs for DC fast-charging stations with average loads of 40-50 kW/vehicle. Capital costs do not include required utility distribution infrastructure improvements upstream of the customer meter. It is assumed that these costs would be offset by customer credits offered by the utility based on the customer's energy use. Costs for DC fast chargers are included in the Vehicle Capital Cost for depot-charged electric buses.
	O&M	$240/year per charger	O&M costs: ARB ICT Cost data, June 2017. Only includes inspection costs. Assume cord set replacements are covered by 12-year replacement cycle of chargers.

	Year	$ (constant 2016)	Source Description
Electricity - En-route Charging	Capital	$500,000/charger	Capital costs are based on estimates from ARB ICT Cost Data, June 2017 and discussions with Proterra. Cost of charging equipment is approximately $350,000. Additional site work and ancillary equipment (utility transformer, site work, security/monitoring systems) is estimated at $150,000 per charger. Maintenance costs are based on contract maintenance prices provided by Proterra to Foothill Transit.
	O&M	$13,000/year per charger	
Hydrogen - LH2	**Year**	**$ (constant 2016)**	**Source Description**
	Capital	Providence: Phase 1 - $6,100,000 Phase 2/3 - $1,180,000 Newport: $3,000,000	Capital and maintenance costs for dispensing are based on estimates from the Department of Energy's H2A hydrogen station cost model (HRSAM v 1.1) for 1,000, 2,000, and 4,000 kg/day forecourts dispensing hydrogen at 350 bar using liquid pressurization and subsequent vaporization. Providence: Phase 1 capital costs include 2,000 kg/day forecourt with 20% redundancy for LH2 pumps. Phase 2 and Phase 3 capital costs provide an incremental 2,000 kg/day of dispensing capacity per phase and maintain LH2 pump redundancies of 20-30%. O&M costs are $0.13/kg for maintenance and $0.38/kg for utility costs Newport: Capital costs include a 1,000 kg/day forecourt with 33% redundancy for LH2 pumps. O&M costs are $0.19/kg for maintenance and $0.14/kg for utility costs.
	O&M	Providence: $0.51/kg Newport: $0.33/kg	
Hydrogen - On-site Electrolysis	**Year**	**$ (constant 2016)**	**Source Description**
	Capital	Providence: Phase 1 - $3,700,000 Phase 2/3 - $980,000 Newport: $2,300,000	Capital and maintenance costs for dispensing are based on estimates from the Department of Energy's H2A hydrogen station cost model (HRSAM v 1.1) for 1,000, 2,000, and 4,000 kg/day forecourts dispensing hydrogen at 350 bar using gas compression. On-site electrolysis system costs are based on a DOE scenario analysis for a 1,500 kg/day PEM electroyzer system. (https://www.hydrogen.energy.gov/pdfs/14004_h2_production_cost_pem_electrolysis.pdf). Production costs are calculated on a $/kg basis and scaled to match demand in each phase of
	O&M	Providence: $0.24/kg Newport: $0.24/kg	

			construction. Providence: Phase 1 capital costs include 2,000 kg/day forecourt with 33% redundancy for compressors. Phase 2 and Phase 3 capital costs provide an incremental 2,000 kg/day of dispensing capacity per phase and maintain compressor redundancies of 20-30%. O&M costs are $0.09/kg for maintenance and $0.15/kg for utility costs. Newport: Capital costs include a 1,000 kg/day forecourt with 33% redundancy for compressors. O&M costs are $0.12/kg for maintenance and $0.12/kg for utility costs.
Hydrogen - On-site SMR	**Year**	**$ (constant 2016)**	**Source Description**
	Capital	Providence: Phase 1 - $3,700,000 Phase 2/3 - $980,000 Newport: $2,300,000	Capital and maintenance costs for dispensing are based on estimates from the Department of Energy's H2A hydrogen station cost model (HRSAM v 1.1) for 1,000, 2,000, and 4,000 kg/day forecourts dispensing hydrogen at 350 bar using gas compression. On-site SMR system costs are based on a DOE scenario analysis for a 1,500 kg/day SMR system. (https://www.hydrogen.energy.gov/h2a_prod_studies.html). Production costs are calculated on a $/kg basis and scaled to match demand in each phase of construction. Providence: Phase 1 capital costs include 2,000 kg/day forecourt with 33% redundancy for compressors. Phase 2 and Phase 3 capital costs provide an incremental 2,000 kg/day of dispensing capacity per phase and maintain compressor redundancies of 20-30%. O&M costs are $0.09/kg for maintenance and $0.15/kg for utility costs. Newport: Capital costs include a 1,000 kg/day forecourt with 33% redundancy for compressors. O&M costs are $0.12/kg for maintenance and $0.12/kg for utility costs.
	O&M	Providence: $0.24/kg Newport: $0.24/kg	
Diesel	**Year**	**$ (constant 2016)**	**Source Description**
	Capital	$0	Assumes costs for fuel station maintenance and operation are negligible and that no new fueling infrastructure will be required over the analysis period.
	O&M	$0	

9.0 Appendix D – Emissions Factors

Well-to-Wheels GHG Emissions Factors (g/MMBTU delivered to vehicle)					
Fuel	**CO2**	**N2O**	**CH4**	**CO2e**	**Description**
RNG	2,262	0.54	415	14,843	GREET 2017 estimates for CNG derived from landfill gas. To convert emissions values to CO2e, global warming potentials (GWPs) for CH4 (30) and N2O (265) are used by GREET 2017 and reflect values from IPCC's 5th Assessment Report.
Hydrogen - LH2	60,128	-0.41	678	80,348	Greet 2017 estimates for liquid hydrogen delivered by tanker and dispensed to the vehicle as compressed hydrogen at 700 bar. To convert emissions values to CO2e, global warming potentials (GWPs) for CH4 (30) and N2O (265) are used by GREET 2017 and reflect values from IPCC's 5th Assessment Report.
Hydrogen - On-site SMR	18,935	-1.28	595	36,432	GREET 2017 estimates for compressed hydrogen produced from landfill gas by steam methane reformation at the station and delivered to the vehicle at 700 bar. To convert emissions values to CO2e, global warming potentials (GWPs) for CH4 (30) and N2O (265) are used by GREET 2017 and reflect values from IPCC's 5th Assessment Report.
Diesel	93,215	0.43	199	99,305	GREET 2017 estimate for national average low sulfur diesel. To convert emissions values to CO2e, global warming potentials (GWPs) for CH4 (30) and N2O (265) are used by GREET 2017 and reflect values from IPCC's 5th Assessment Report.

Well-to-Wheels GHG Emissions Factors (g/MMBTU delivered to vehicle)					
Fuel	**CO2**	**N2O**	**CH4**	**CO2e**	**Description**
Electricity (2014 grid)	80,687	2.52	221	88,282	Calendar year 2014 emissions are based on NPCC New England grid mix reported in EPA's eGRID 2014 database and incorporated into GREET 2017. Future year GHG emissions are projected using a linear decrease to a zero GHG emission rate. These reductions are consistent with the reduction trend identified in the Rhode Island Greenhouse Gas Emission Reduction Plan (2016) to achieve 80% statewide GHG reductions by 2050. To convert emissions values to CO2e, global warming potentials (GWPs) for CH4 (30) and N2O (265) are used by GREET 2017 and reflect values from IPCC's 5th Assessment Report.
2015				85,830	
2016				83,378	
2017				80,925	
2018				78,473	
2019				76,021	
2020				73,569	
2021				71,116	
2022				68,664	
2023				66,212	
2024				63,759	
2025				61,307	
2026				58,855	
2027				56,403	
2028				53,950	
2029				51,498	
2030				49,046	
2031				46,593	
2032				44,141	
2033				41,689	
2034				39,237	
2035				36,784	
2036				34,332	
2037				31,880	
2038				29,427	
2039				26,975	
2040				24,523	
2041				22,071	
2042				19,618	
2043				17,166	
2044				14,714	

Well-to-Wheels GHG Emissions Factors (g/MMBTU delivered to vehicle)					
Fuel	**CO2**	**N2O**	**CH4**	**CO2e**	**Description**
2045				12,261	
2046				9,809	
2047				7,357	
2048				4,905	
2049				2,452	
2050				0	
Hydrogen - On-site Electrolysis (2014)	129,596	4.03	354	141,294	2014 emissions are based on GREET 2017 estimates using the NPCC New England grid mix for compressed hydrogen produced on-site by electrolysis and delivered to the vehicle at 700 bar. Because electrolysis is assumed to rely on grid-supplied electricity, future year GHG emissions rates for hydrogen production are scaled down from 2014 emissions rates based on the relative reduction in the grid emissions rates projected above. To convert emissions values to CO2e, global warming potentials (GWPs) for CH4 (30) and N2O (265) are used by GREET 2017 and reflect values from IPCC's 5th Assessment Report.
2015				137,370	
2016				133,445	
2017				129,520	
2018				125,595	
2019				121,670	
2020				117,745	
2021				113,821	
2022				109,896	
2023				105,971	
2024				102,046	
2025				98,121	
2026				94,196	
2027				90,271	
2028				86,347	
2029				82,422	
2030				78,497	
2031				74,572	
2032				70,647	
2033				66,722	
2034				62,798	
2035				58,873	
2036				54,948	
2037				51,023	
2038				47,098	

Well-to-Wheels GHG Emissions Factors (g/MMBTU delivered to vehicle)					
Fuel	**CO2**	**N2O**	**CH4**	**CO2e**	**Description**
2039				43,173	
2040				39,248	
2041				35,324	
2042				31,399	
2043				27,474	
2044				23,549	
2045				19,624	
2046				15,699	
2047				11,775	
2048				7,850	
2049				3,925	
2050				0	

AFV Control Factors - Tailpipe Emissions					
Technology	**NOx**	**PM2.5**	**CO**	**THCs**	**Description**
CNG	90%	0%	0%	0%	NOx emissions reductions are based on the Optional Low NOx standard certification level of 0.02 g/bhp-hr, and is 90% lower than the US EPA 2010 standard of 0.20 g/bhp-hr for diesel engines.
EV	100%	100%	100%	100%	EVs are assumed to produce no measurable emissions from the vehicle. Note that tire and brake PM are not considered in this emissions analysis for any technology.
FCV	100%	100%	100%	100%	FCVs are assumed to produce no measurable emissions from the vehicle. Note that tire and brake PM are not considered in this emissions analysis for any technology.
Diesel Hybrid	20%	20%	20%	20%	Diesel hybrid emissions reductions are assumed to follow the estimated fuel consumption reductions relative to traditional diesel buses. RIPTA reports fuel economy improvements of 13-19% for 2009 diesel vs 2010 hybrid and 2013 diesel vs 2010 hybrid buses. Additionally, Altoona test data for New Flyer XD (diesel) and the XDE (diesel hybrid) buses report average fuel economies of 4.82 and 5.84 mpg, respectively; a 17% reduction in fuel consumption. See Altoona test reports 1211 and 1015.

CY2017 Diesel Vehicle Emissions Factors (g/mile)					
Vehicle Model Year	**NOx**	**PM2.5**	**CO**	**THCs**	**Description**
1987	34.69	2.311	8.52	1.33	Emissions rates are based on EPA MOVES2014a default emissions and activity data for transit buses in Rhode Island. Future calendar year emissions rates include deterioration of vehicle emissions performance as the vehicles age.
1988	34.69	0.881	8.51	1.33	
1989	34.69	0.881	8.49	1.33	
1990	26.79	0.881	8.48	1.33	
1991	25.19	0.374	8.46	1.33	
1992	25.19	0.374	8.45	1.33	
1993	25.19	0.374	8.44	1.33	
1994	25.19	0.660	8.42	1.33	
1995	25.19	0.660	8.41	1.32	
1996	25.19	0.472	8.40	1.32	
1997	25.19	0.472	8.39	1.32	
1998	21.47	0.345	8.38	1.32	
1999	16.61	0.345	8.37	1.32	
2000	16.61	0.344	8.36	1.32	
2001	16.61	0.344	8.35	1.32	
2002	16.61	0.344	8.34	1.32	
2003	9.25	0.311	3.39	0.86	
2004	9.25	0.311	3.38	0.86	
2005	9.25	0.311	3.37	0.86	
2006	9.25	0.311	3.36	0.86	
2007	4.60	0.032	0.89	0.22	
2008	4.60	0.029	0.81	0.20	
2009	4.60	0.029	0.80	0.20	
2010	1.32	0.024	0.54	0.14	
2011	1.32	0.024	0.53	0.14	
2012	1.14	0.021	0.50	0.13	
2013	1.09	0.020	0.49	0.13	
2014	0.93	0.017	0.47	0.12	
2015	0.93	0.017	0.46	0.12	
2016	0.93	0.017	0.45	0.12	
2017	0.93	0.017	0.45	0.12	

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