Culver City Battery Electric Bus Transportation Facility Electrification Transition Plan

Culver CityBus Electrification Master Plan

Prepared by Culver CityBus and the Center for Transportation and the Environment

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Executive Summary

Culver CityBus (CCB) engaged the Center for Transportation and the Environment (CTE) to perform a zero-emission bus (ZEB) transition study. The study's goal is to create a plan to implement a 100% zero-emission fleet by 2028 to meet Culver City's commitment to the Transportation Electrification Partnership (TEP) and to comply with the Innovative Clean Transit (ICT) regulation enacted by the California Air Resources Board (CARB). The results of the study will inform the City of Culver City's City Council and CCB staff of the estimated costs, benefits, constraints, and risks of the transition to a zero-emission fleet and will guide future planning and decision-making.

On December 14, 2018, CARB enacted the ICT regulation, setting a goal for California public transit agencies to have 100% zero-emission fleets by 2040. The ruling specifies the percentage of new bus procurements that must be zero-emission for each year of the transition period (2023 – 2040). Those annual percentages for Small Transit agencies are outlined in **Table ES-1** below.

Table ES 1 - ICT ZEB Percentage Requirements

Starting January 1	ZEB Percentage of Total New Bus Purchases for Small Transit Agencies
2026	25%
2027	25%
2028	25%
2029+	100%

This schedule lays out a pathway to reaching 100% zero-emission fleets in 2040 based on a 12-year projected lifespan for a transit bus. There is the opportunity to request waivers, however, that allow purchase deferrals in the event of economic hardship or if zero-emission technology has not matured enough to meet the service requirements of a given route. These concessions recognize that zero-emission technologies may cost more than current internal combustion engine (ICE) technologies on a lifecycle basis and that zero-emission technology may not currently be able to meet all service requirements. Although the ICT requires 100% of bus purchases to be zero-emission by 2029, Culver City joined the TEP and has committed to exceed this requirement by switching to exclusively BEB purchases from 2021 onward and will have a fully zero-emission fleet by 2028.

Zero-emission technology considered in this study was limited to battery-electric buses (BEB) given the relatively short blocks seen at CCB and the significant increase in BEB battery capacity and range that has been observed in recent years. Additionally, CTE determined that depot-charged BEBs would be sufficient for CCB's needs based on an engineering analysis conducted as part of the study.

CTE worked closely with CCB staff throughout the project to develop an approach for the study, define assumptions, and confirm the results. The approach for the study is to determine if depot charged battery-electric buses can adequately complete all of the agency's blocks and, in the event that a service gap is identified, to investigate alternatives to fill that gap. In the case of CCB, depot-charged BEBs were found to be sufficient to meet the service demands assuming that the technology continues to improve over the transition period. As a result, no other alternative zero-emission technologies were pursued.

To accurately project service feasibility for zero-emission technologies, CTE assessed the block achievability of CCB's current service schedules. Block achievability is determined by comparing the estimated energy required to operate a BEB under loaded conditions on a given block to the usable onboard energy storage capacity of the bus. If the block energy requirement exceeds the onboard storage capacity, the block is considered unachievable. If the block energy requirement does not exceed the usable onboard storage capacity, the block is considered to be achievable.

The BEB Only scenario was developed to model a fleet consisting entirely of battery electric buses that can meet existing service range requirements. A uniform technology throughout the fleet allows for the installation of a single fueling technology at the depot. The underlying basis for the assessment is CTE's ZEB Transition Planning Methodology, a complete set of analyses used to inform agencies planning the conversion of their fleets to zero-emission technologies.

The methodology consists of data collection, analysis, and evaluation stages; these stages are sequential and build upon findings in previous steps. In the evaluation stage, CTE assesses energy efficiency and energy use by the buses to calculate the distance that a bus will be able to travel on a single charge. Then, using generic BEB battery capacity specifications for given bus lengths, CTE estimated range and energy consumption on all CCB routes and blocks under varying environmental and passenger load conditions.

Once this information was established, CTE completed the following assessments to develop cost estimates for fleet, fuel, maintenance and facilities costs.

Battery Electric Bus Investment and Total Cost of Ownership

As a result of the analysis described above, CCB proposes to convert their current CNG fleet to a 100% Battery Electric fleet by 2028. To achieve this goal, it will be necessary to invest an additional $30 million in capital for BEBs and $21 million for charging infrastructure as compared to what CCB may have invested in CNG buses over the same time period.

Table ES 2: CCB Capital Investment to transition to a 100% BEB fleet by 2028

	CNG Baseline	BEB Incremental Costs	Total Investment
Initial Buses	$35,310,000	$30,301,000	$65,611,000
Fueling Infrastructure	$0	$20,507,000*	$20,507,000
Total	$35,310,000	$50,808,000	$86,118,000

*Does not include SCE Charge Ready contribution

To understand the total impact of CCBs investment into transit electrification, CTE analyzed the total cost of ownership (TCO) over a 20-year period. This includes not only the initial investment to transition to 100% BEBs by 2028, but also additional bus replacement capital and (electricity to recharge the buses) and maintenance operating costs over the 20-year period. The TCO also includes an estimate of potential credits available through CARB's Low Carbon Fuel Standards program.

Table ES 3: CCB BEB Total Cost of Ownership

	CNG Baseline	BEB Incremental Costs	**Total Cost of Ownership**
Initial Buses	$35,310,000	$30,301,000	**$65,611,000**
Fueling Infrastructure	$0	$20,537,000	**$20,537,000**
Bus Replacements	$42,217,000	$79,056,000	**$144,666,000**
Fuel	$20,639,000	-$3,823,000	**$16,816,000**
Maintenance	$52,670,000	-$10,525,000	**$42,144,000**
LCFS Credit Value	(Inc. in RCNG price)	-$12,583,000	**-$12,583,000**
Total	**$150,836,000**	**$67,061,000**	**$217,897,000**

Other Considerations

For ZEBs procured prior to 2023, CCB is eligible for credits that could be used to count toward CARB's ZEB procurement requirements. However, since the agency is already committed to purchasing only BEBs going forward, these credits will not be used. If CCB chooses to participate in a joint group for submitting their Rollout Plan to CARB, CCB could potentially give these credits to other agencies in the group that need more credits to offset their ZEB purchases. It is not possible to buy or sell credits.

In addition to the uncertainty of technology improvements, there are other risks in trying to estimate costs over the 20-year transition period to consider. Although current BEB range limitations may be improved over time as a result of advancements in battery energy density and more efficient components, battery degradation may re-introduce range limitations, which is a cost and performance risk to an all-BEB fleet over time.

Redundancy, Resilience, and Emergency Response are elements that require serious consideration with an all-electric fleet. In emergency scenarios that require use of BEBs, agencies may face challenges supporting long-range evacuations and providing temporary shelters in support of fire and police operations. Furthermore, fleetwide energy service requirements, power redundancy, and resilience may require additional infrastructure investment at any given depot in an all-BEB scenario.

The project team considers this transition plan to be a living document. Transit service requirements, assumptions, technology development and costs should be re-evaluated periodically to determine if any changes are required to the transition plan. Key assumptions have been **bolded** throughout this document so that CCB can return to this assessment and adjust these assumptions as needed.

Introduction

CARB's Innovative Clean Transit Regulation

On December 14, 2018, the California Air Resources Board (CARB) enacted the Innovative Clean Transit (ICT) regulation, requiring all California public transit agencies to purchase only zero-emission buses (ZEB) from the years 2029–2040 with percentage requirements for ZEB purchasing beginning in the year 2023. The goal of the ICT regulation is to transition agencies to fully ZEB fleets.

Project Overview

Culver City Goals and Alignment with Electrification

Widespread adoption of zero-emission bus technology has the potential to significantly reduce greenhouse gas (GHG) emissions resulting from the transportation sector. Culver City is wholeheartedly committed to implementing environmentally-friendly policies and reducing its carbon footprint; therefore, the City has committed to full CityBus fleet electrification by the year 2028. With this goal in mind, Culver City has worked diligently with the State of California to piggyback off of the statewide Department of General Services (DGS) contract and execute a purchase order with New Flyer of America for the purchase of 10 battery electric buses (BEBs) and associated charging infrastructure. The first four buses are scheduled to be delivered in Fall 2021 and the next six in end of Calendar Year 2022.

The Culver City Department of Transportation will collaborate with New Flyer, Southern California Edison (SCE) and the Center for Transportation and the Environment (CTE) to plan the deployment of these ten buses and, in addition, will prepare a transition study to plan for a full fleet conversion to battery electric buses by 2028. The first phase of this project is the deployment of four buses, a temporary charger and the transition study. The second phase of this project is the deployment of the remaining six buses, charging for the ten buses and the phased design of the facilities required for full electrification.

Funding

The first two phases of this project is funded through a mix of federal funding through 5307 funds and local funding provided through CA Transportation Development Act (TDA), SCE infrastructure programs, and other state electrification programs such as Hybrid and Zero-Emission Truck and Bus Voucher Incentive Project (HVIP). This project will help Culver City enter the BEB market and begin to evaluate the technology and the operation of an electric bus within agency's service area. Furthermore, the final project report will determine the impact on operations and capital programs as the agency transitions to an all-electric fleet by 2028.

Project Partners

Culver City has executed a contract with CTE to prepare a ZEB Transition Plan and a Smart Deployment for the pilot deployment of ten buses in 2021 and 2022. CTE is the national leader in providing technical assistance for ZEB deployments, guiding transit agencies through battery electric and fuel cell electric bus deployment projects while minimizing project risks. CTE understands both the technical and administrative challenges associated with the procurement, deployment, and operation of zero-emission vehicles.

Joining CTE in its work will be two subcontractors: AECOM and Sage Energy Consulting, Inc (Sage). Working closely with CTE, AECOM has assembled a design team from offices in Northern and Southern California and will have primary responsibility for the facilities and infrastructure analysis and the design and construction management for the project. AECOM has teamed with CTE on several ZEB transition studies for transit agencies in California over the past few years. AECOM has helped CTE develop roadmaps for clients' transitions from existing CNG fleets to 100% BEBs, in compliance with the CARB ICT regulation. AECOM has also been the lead engineer on several transit and heavy-duty vehicle electrification projects.

Culver City has engaged New Flyer to provide the ten pilot buses and coordinate charging infrastructure. Culver City will also work with the local electrical utility, SCE, which will provide charger and power upgrade installation through its charge ready program. This program covers costs for "make ready" infrastructure enhancements, providing full-service design and construction of the electrical and site upgrades needed to add electric vehicle charging to a site. This includes installing a new panel, meter, conduit and wires leading up to the concrete pads to support EV charging stations owned and operated by Culver City. The costs associated with these enhancements are estimated to be approximately $500,000.

Project Management

CTE is providing project management services in conjunction with the Culver City Electrification Steering Committee, led by the Chief Transportation Officer, Rolando Cruz. See Methodology section and Figure 1 below for further details.

Pilot Deployment

Phase I: First Delivery of 4 buses & Temporary Charging

The first delivery will consist of four 40-foot, heavy-duty New Flyer Xcelsior CHARGE™ battery electric transit buses with a 439 kWh capacity battery. This delivery should be completed by the end of October 2021.

Culver City Bus has selected to install a single ABB Terra HVC 150C 150 kW charger to power the initial four New Flyer 40' pilot buses to be delivered in 2021. Additional charging will be added for the second delivery of six buses in 2022.

Phase II: Second Delivery of 6 buses and Charging for up to 10 buses

The second delivery will consist of six 40-foot, heavy-duty New Flyer Xcelsior CHARGE™ battery electric transit buses with approximately 527 kWh battery capacity. This delivery is currently planned to be completed in December 2022.

Transition Planning

Methodology

This study uses CTE's ZEB Transition Planning Methodology, which is a complete set of analyses used to inform agencies converting their fleets to zero-emission technology. The methodology consists of data collection and analysis and assessment stages; these stages are sequential and build upon findings in previous steps. The work steps specific to this study are outlined below:

1. Planning and Initiation
2. Requirements & Data Collection
3. Service Assessment
4. Fleet Assessment
5. Fuel Assessment
6. Facilities Assessment
7. Maintenance Assessment
8. Total Cost of Ownership Assessment

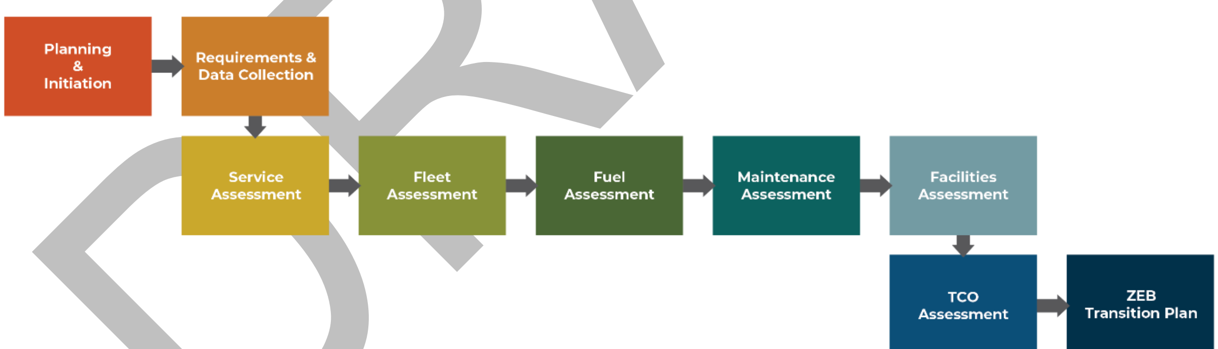


Figure 1 - CTE's ZEB Transition Study Methodology

The **Planning and Initiation** phase builds the administrative framework for the transition study. During this phase, the project team drafted the scope, approach, tasks, assignments, and timeline for the project. CTE worked with Culver City staff to plan the overall project scope and all deliverables throughout study timeline.

For the **Requirements Analysis & Data Collection,** CTE collects data on the agency's fleet, routes and blocks, operational data, like mileage and fuel consumption, and maintenance costs. Using this data, CTE establishes requirements for the planned zero-emission fleet to drive analyses in the later assessments.

The **Service Assessment** phase initiates the technical analysis of the study. Using information collected in the Data Collection phase, CTE evaluates the feasibility of a zero-emission fleet over the study timeframe. Results from the Service Assessment are used to guide ZEB procurements in the Fleet Assessment and to determine energy requirements in the Fuel Assessment.

The **Fleet Assessment** develops a projected timeline for replacement of current buses with ZEBs that is consistent with the agency's fleet replacement plan. This assessment also includes a projection of fleet capital cost over the transition timeframe and is optimized with regard to state mandates, like CARB's ICT regulation, or agency goals, such as minimizing cost or maximizing service levels.

The **Fuel Assessment** merges the results of the Service Assessment and Fleet Assessment to determine annual fuel requirements and associated costs. The Fuel Assessment calculates energy costs through the transition timeframe, including the agency's current fossil fuel buses, and considers applicable low-carbon fuel standard (LCFS) credits. To more accurately estimate BEB charging costs, a focused Charging Analysis is performed to simulate daily system-wide charging use. As current technologies are phased out in later years of the transition, the Fuel Assessment calculates the increasing energy requirements for ZEBs. The Fuel Assessment also provides a total energy cost over the transition lifetime.

The **Facilities Assessment** determines the necessary infrastructure to support the projected zero-emission fleet based on results from the Fleet Assessment and Fuel Assessment. This assessment provides quantities of charging infrastructure and calculates associated costs sequenced over the transition timeframe.

The **Maintenance Assessment** calculates all projected fleet maintenance costs over the transition timeframe. This includes costs related to existing fossil fuel buses remaining in the fleet, as well as new BEBs.

The **Total Cost of Ownership Assessment** compiles results from the previous assessments and provides a comprehensive view of all associated costs over the transition timeframe.

Planning and Initiation

Project Charter

The project charter outlines the scope, timeline, budget, and risks of the project. This document ensures quality by defining the success of the project in advance. The project charter provides clarity on roles and responsibilities and serves to bring everyone into alignment and as the foundation of the project.

Scope

Table 1 below provides a summary of the scope agreed upon between stakeholders in the Project Charter.

Table 1 - Project Scope

Project Deliverable	Responsibility	Summary
BEB Procurement and Commissioning	Culver City / New Flyer	Deliver and accept four 40’ battery electric buses starting in August 2021 and six 40’ battery electric buses in 2022
Route Modeling	CTE	Use real-world efficiency data to estimate the performance of the New Flyer BEB on Culver City routes.
Charging Equipment	CTE / New Flyer	Develop charging model to assess options for charging equipment, evaluating charger power and quantities to meet service requirements.
Rate Modeling	CTE	Use route model results combined with charge modeling to assess the operational cost of the pilot service.
Training	New Flyer	Provide training to all operators and maintenance technicians prior to deployment of buses into revenue service.
Diagnostic Equipment, Software & Data Access Tools	New Flyer / ViriCiti	Provide diagnostic equipment, software, and data access tools to be used by maintenance technicians to identify vehicle issues. ViriCiti will be used for data access and performance reporting.
Charging Infrastructure	SCE	Draft plans for constructing the infrastructure necessary to charge 10 buses at the Culver City Transportation facility, and the supporting vaults & transformer for the entire fleet.
Facility Electrification Plan	CTE / AECOM	Develop a battery electric bus deployment plan that complies with all California Air Resources Board (CARB) Innovative Clean Transit (ICT) regulations.
Analysis of Infrastructure Needs	CTE / AECOM	Evaluate capacity of current grid infrastructure to determine if it will be sufficient for the City’s needs as its electric fleet grows. Determine the capacity constraints, possible problems, and identify when capacity is reached. Assess scale of required charging and electricity upgrades.
Analysis of Yard Layout and Charger Location	CTE / AECOM	Identify different charger layouts that can be implemented for an all-electric fleet, and how each layout will impact parking and operations.
EVSE Market Survey	CTE	Analyze the types of charging equipment that is available or under development, including plug-in, overhead, and in-ground technology. This

		analysis includes operational limitations, construction challenges, and cost.
Assess and Incorporate New Flyer Charging Options for Pilot Project	CTE / New Flyer	Assess charging options that are readily available for use by Culver City for the 10-bus pilot deployment using findings from the EVSE Market Survey.
Yard Layout Analysis	AECOM	Analyze and present multiple options for a 100% BEB yard layout, including impacts on traffic flow and turn radius, along with the reduction in parking and mitigation strategies.
Renewable Energy Analysis	Sage	Evaluate current electricity consumption and incorporate projections of future load from the BEB rollout plan. Identify strategies for using renewable power and provide costs and benefits of each. Outline key steps and strategies for implementing renewables in an optimal way.
BEB Transition Plan	CTE	Perform Total Cost of Ownership assessment for transitioning Culver City's fleet to 100% BEB by 2028. The TCO will calculate Culver City's total capital and operational costs from 2021-2040.

Timeline

ID	Task Name	Start	Finish
1	**Objective 1: Facility Analysis and BEB Transition Plan**	**10/8/20**	**9/14/21**
2	Work Plan and Schedule	10/8/20	11/5/20
8	Analysis of Battery Electric Bus Market	10/9/20	11/5/20
9	Analysis of Battery Electric Bus Performance and Cost	10/8/20	12/31/20
22	Analysis of Infrastructure Needs	10/9/20	6/8/21
35	Renewable Energy Analysis	12/24/20	3/24/21
38	BEB Transition Plan	6/9/21	9/14/21
44			
45	**Objective 2: Pilot Project Phase 1: 4 BEBs**	**10/1/20**	**12/1/22**
46	Pilot Project Phase 1 Management & Reporting	10/1/20	7/1/21
52	Bus Design & Build	10/1/20	8/20/21
103	Infrastructure Design, Procurement & Build: Temporary Charging S	3/2/21	8/4/21
113	Bus Deployment	5/1/21	9/24/21
141	KPI Analysis & Reporting	8/26/21	12/1/22
150			
151	**Objective 3: Pilot Project Infrastructure Design**	**4/1/21**	**9/26/22**
152	Infrastructure Design Management & Reporting	4/2/21	9/26/22
158	Alternative 1: Ground-based plug-in pedestal charging	4/1/21	6/30/21
163	Alternative 2: Overhead pantograph charging system	4/1/21	9/28/21
171	Alternative 3: Parking Structure charging system	4/1/21	8/4/22
179			
180	**Objective 4: Pilot Project Infrastructure Build**	**6/30/21**	**5/31/23**
181	Infrastructure Build Management & Reporting	7/1/21	4/26/22
187	Alternative 1: Ground-based plug-in pedestal charging	6/30/21	3/9/22
192	Alternative 2: Overhead pantograph charging system	12/9/21	8/6/22
196	Alternative 3: Design-Build Documents for Parking Structure	8/4/22	5/31/23
199			
200	**Objective 5: Pilot Project Phase 2: 6 BEBs**	**12/20/21**	**8/29/24**
201	Bus Design & Build	12/20/21	5/20/22
213	Bus Deployment	4/29/22	7/31/23
241	KPI Analysis & Reporting	8/1/23	8/29/24
244			
245	**Objective 6: Secure Funding**	**10/1/20**	**10/1/20**

Requirements Analysis

It is essential to understand the key elements of Culver City's current service to evaluate the costs of a full zero-emission transition. Culver City staff provided key data elements of the current service as inputs to the analysis, which included the following:

- Fleet composition
- Routes and blocks
- Mileage and fuel consumption
- Maintenance costs

Fleet

Culver City's fleet is comprised of fifty-four (54) 40-foot New Flyer Renewable Compressed Natural Gas (RCNG) buses of varying ages. All buses are housed at a single depot, located at 4343 Duquesne Avenue, Culver City, CA. Buses range in age from model year 2001 to 2017; the average age is 9.7 years. Assumption is that the fleet will remain the same size, yet flexibility will be built into the plan to accommodate CityBus' current movement to add smaller electric mini-buses and shuttles to the fleet.

Routes and Blocks

Culver City's service is all fixed-route, operating on eight routes centered in downtown Culver City and serving Marina del Ray and the bordering Los Angeles neighborhoods. Routes 1 through 7 operate as local, frequent weekday and weekend service; in addition, route 6 runs as a separately-branded rapid service on weekdays. Culver City's service is organized into 105 unique blocks comprised of these eight routes. Blocks range in length from about 1 hour to 18 hours long, and in mileage from 7 miles to just over 200 miles. There are 68 weekday blocks, 20 Saturday blocks and 17 Sunday blocks. Buses pull out from the depot as early as 4:45 in the morning and can return after midnight. Assumption is that the amount of service hours will remain the same.

Mileage and Fuel Consumption

Culver City operates an exclusively RCNG fleet. The annual fleet mileage of the 54 buses is 1.7 million miles and annual fuel consumption is approximately 1 million gasoline gallons equivalent (GGE) of CNG. Fleet average efficiency is 1.76 mpg. It cost Culver City $1.1 million in 2019 to fuel its fleet at an average cost of $1.10 per GGE of CNG and $0.62 per mile. Assumption is that the amount of service miles will remain the same.

Maintenance Costs

In 2019, Culver City spent approximately $1.7 million on scheduled and unscheduled maintenance, including both parts and labor, for its entire fleet. This results in an average maintenance cost of $0.94 per mile. Buses also undergo a one-time engine and transmission overhaul during their lifetime at an average cost of $10,700 and $7,500, respectively.

Service Assessment

Assessment Overview

The Service Assessment phase initiates the data collection and technical analysis of the study. CTE met with Culver CityBus (CCB) to define assumptions and requirements used throughout the study and to collect operational data. The results from the Service Assessment are used to guide ZEB procurement projections in the Fleet Assessment and to determine energy requirements in the Fuel Assessment.

This assessment analyzes the feasibility of maintaining CCB's current level of service with BEBs and does not plan for any fleet expansions. The main focus of the Service Assessment is the block analysis, which determines if BEBs could meet the service requirements of the blocks throughout the transition period based on bus endurance, range limitations, weather conditions, levels of battery degradation and route specific requirements. The energy needed to complete a block is compared to the available energy for the respective bus type that is planned for the block to determine if a BEB can successfully operate on that block. This assessment also determines a timeline for when blocks become eligible for zero-emission buses as technology improves. This information is then used to inform BEB procurements in the Fleet Assessment.

The analysis assumes a 5% improvement in battery capacity every other year and a starting battery capacity of 660 kWh, which is used to determine the timeline for when blocks become achievable for BEBs to replace fossil-fuel buses in a one-for-one ratio. The results from the analysis are used to determine when, or if, a full transition to BEBs may be feasible. Results from this analysis are also used to determine the specific energy requirements for the agency and develop the estimated costs to operate the BEBs in the Fuel Assessment. This modeling analysis also assumes blocks will maintain a similar distribution of distance, relative speeds, and elevation changes as exists at the time of the study since bus service will continue to serve similar locations within the city and use similar roads to reach these destinations even if specific routes and schedules change. This core assumption affects energy use estimates and block achievability in each year.

Bus efficiency and range are primarily driven by bus specifications; however, both metrics can be impacted by a number of variables including the route profile (i.e. distance, dwell time, acceleration, sustained top speed over distance, average speed, and traffic conditions), topography (i.e. grades), climate (i.e. temperature), driver behavior, and operational conditions such as passenger loads and auxiliary loads. As such, BEB efficiency and range can vary dramatically from one agency to another. Therefore, it is critical to determine efficiency and range estimates that are based on an accurate representation of CCB's operating conditions.

CTE's route modeling models the impact of varying passenger load, accessory load, and battery degradation on real-world bus performance, fuel efficiency, and range. CTE ran models with varying loads to represent "nominal" and "strenuous" loading conditions. Nominal loading conditions assume average passenger loads and moderate temperature over the course of the day, which places marginal demands on the motor and heating, ventilation, and air conditioning (HVAC) system. Strenuous loading conditions assume high or maximum passenger loading and near maximum output of the HVAC system. This nominal/strenuous approach offers a range of operating efficiencies to use for estimating average annual energy use (nominal) or planning minimum service demands (strenuous). Route modeling ultimately provides an average energy use per mile (kilowatt-hour/mile [kWh/mi]) associated with each route, bus size, and load case. System-wide energy use is estimated in subsequent assessments.

As noted previously, CTE models the impact of battery degradation. BEB range is negatively impacted by battery degradation over time. A BEB may be placed in service on a given block with beginning-of-life batteries; however, it may not be able to complete the entire block at some point in the future before the batteries reach end-of-life (typically considered 80% of available service energy). Conceptually, older buses can be moved to shorter, less demanding blocks and newer buses can be assigned to longer, more demanding blocks. **CCB can rotate the fleet to meet demand, assuming there is a steady procurement of BEBs each year to match service requirements so that older buses with reduced range are continually moved to shorter blocks, while new buses are placed on longer blocks.**

Key Results

Figure 2 shows that by 2028 nearly all CCB blocks can be completed by BEBs. It is likely that battery capacity will improve more quickly than by 5% every two years, which means that it is possible that all of CCB's blocks will be achievable by that time. **If batteries do not improve at the modeled rate, the range gap can be remedied through re-blocking.** Re-blocking is the process by which blocks that are too long to be achieved by a single BEB are reworked to be completed by two BEBs. Re-blocking takes advantage of the buses that will return to the depot with significant charge remaining after morning operations and would therefore be available to go out and relieve BEBs on longer blocks. Based on this analysis, re-blocking is a viable option for CCB and would not require expanding their fleet even if 100% of their blocks are not achievable by 2028.

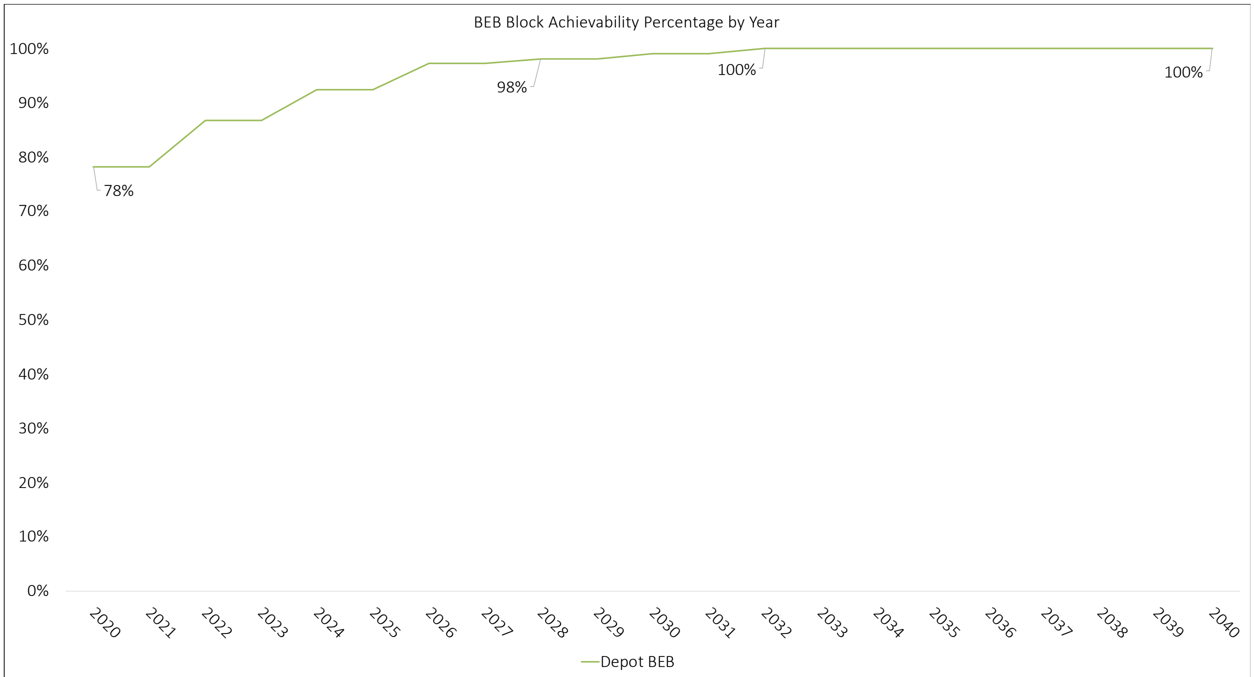


Figure 2 – BEB Block Achievability Percentage by Year

Culver CityBus's Current Plan for Pilot Deployment

CCB's transition will begin with a pilot deployment of ten buses that will take part in two phases. In Phase I, CCB will receive four BEBs with a 439kWh battery capacity and in Phase II, the agency will receive six buses with 527 kWh batteries. CTE has assessed CCB's blocks and determined that these battery capacities will be sufficient for many of the agency's blocks and that putting a higher capacity bus on these blocks would not be necessary and would only incur increased cost and weight. By beginning with lower capacity battery BEBs, CCB is also familiarizing themselves with the technology while allowing the industry time to develop before committing to higher capacity battery buses. CTE anticipates that batteries will continue to increase in energy density, while maintaining, or even decreasing, in battery weight, which means that when CCB is ready to transition the remainder of the fleet beyond the pilot, the buses will not be heavier than the buses in the pilot deployment, but will be able to travel further on a single overnight depot charge.

Conclusion

Assuming a 5% improvement in battery capacity every other year and a starting battery capacity of 660kWh, CTE concludes that Culver City will be able to achieve a full battery electric fleet by 2028, which is in line with the agency's zero-emission goals. These results will be used to inform the following Fleet, Fuel, Maintenance and Facilities Assessments, which will produce an estimate of the total cost of this full fleet transition to depot charged BEBs. Because all blocks will be achievable with battery electric technology, no other ZEB transition scenarios will be explored further.

Fleet Assessment

Assessment Overview

The Fleet Assessment develops a projected timeline for the replacement of existing buses with BEBs that is consistent with CCB's fleet replacement plan. This assessment also includes a projection of fleet capital costs over the transition timeline. The assessment can be optimized with regard to any state mandates such as CARB's ICT regulation or agency goals such as minimizing cost or maximizing service levels.

Cost Assumptions

CTE and CCB developed cost assumptions for future bus purchases. Key assumptions for bus costs for the CCB Transition Study are as follows:

- Bus costs are based on CCB's most recent procurement price and the State of California statewide procurement contract base bus price for 40' BEBs executed in 2019 with Producer Price Index (PPI) inflationary rates used to adjust to current pricing
- Bus costs are inclusive of estimates for configurable options and taxes
- Future bus costs are estimated using PPI inflationary rates from 2019 state contract pricing
- The battery capacity will continue to increase, but the cost will not increase or decrease. The technology will improve, but the cost will remain stable due to economies of scale.

Table 2 provides estimated bus costs used in the analysis.

Table 2 – Fleet Assessment Cost Assumptions

	Pilot Deployment	Deployments from 2023 On
Bus Cost (CA State Contract Average)	$742,000	$764,000
Taxable Options Pricing (New Flyer Contract)	$164,000	$164,000
Non-Taxable Options Pricing (ADA, Delivery) (New Flyer Contract)	$42,000	$42,000
Extended Battery Warranty (State Contract)	$30,326	$30,326
Tax	*6.31%*	*10.25%*
Inflation (PPI Commodity Data - WPU141301)	*1.5%*	*1.5%*
Total	**$960,422**	**$1,056,577**

Note: Based on California State Contract, Inclusive of Options and Extended Battery Warranty

Key Results

As previously discussed in the Service Assessment, depot-charged BEBs will be sufficient to meet CCB's range demands. The fleet transition strategy is to replace each RCNG series with BEBs as they reach the end of their useful life at the end of 12-years of service. **Figure 3** provides the number of each bus type that is purchased each year through 2040 with this replacement strategy.

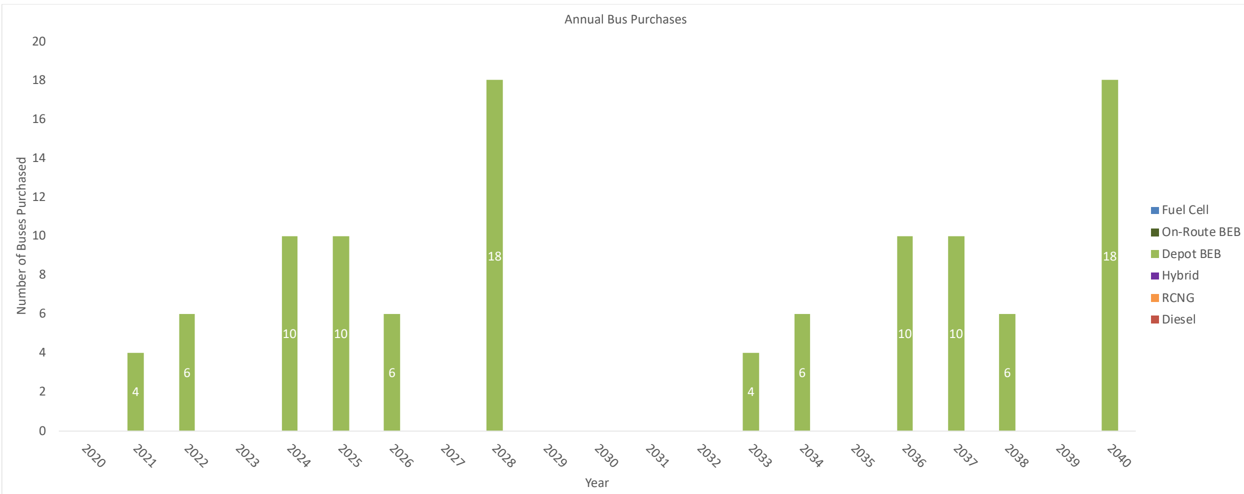


Figure 3 – Projected Bus Purchases, BEB with Depot Only Charging Scenario

Figure 4 depicts the annual fleet composition through 2040. CCB phases out their RCNG buses for BEBs. By 2028, CCB's fleet consists entirely of BEBs. The fleet is able to transition to 100% ZEB using depot-charged BEBs without the addition of any buses.

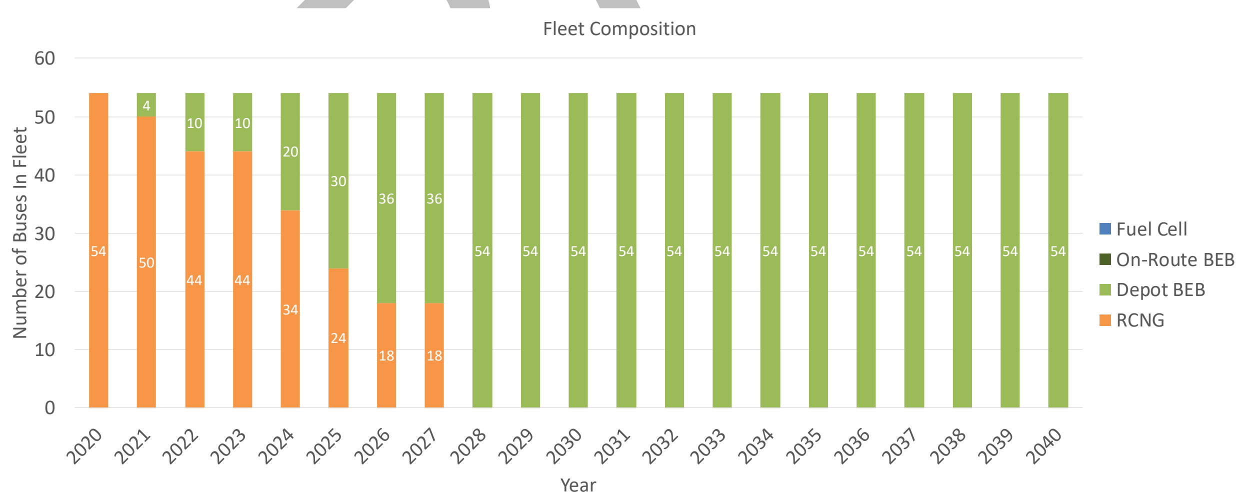


Figure 4 – Annual Fleet Composition, BEB with Depot Only Charging Scenario

Figure 5 shows the annual total bus capital costs for BEBs purchased in a given year through 2040. The expected total cost over the entire transition period is around $145 million. As noted in **Table 2**, these cost estimates include a PPI inflationary rate of 1.5% per year and an extended battery warranty that will cover the cost of a mid-life battery replacement.

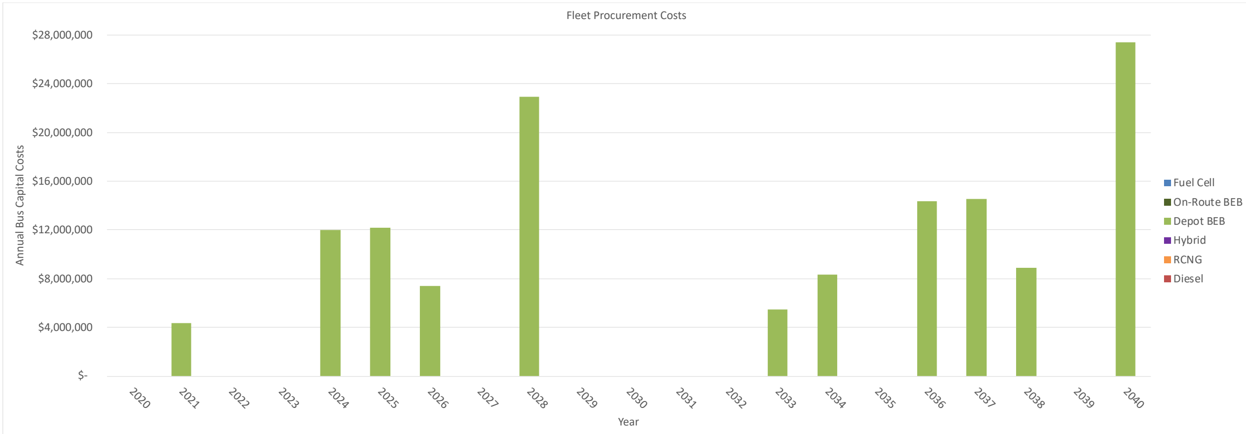


Figure 5 – Annual Capital Costs, BEB with Depot Only Charging Scenario

Table 3 – CCB Bus Capital Investment to transition to a 100% BEB fleet by 2028

	CNG Baseline	BEB Incremental Costs	Total Investment
Initial Buses	$35,310,000	$30,301,000	$65,611,000

As seen in **Table 3** – CCB Bus Capital Investment to transition to a 100% BEB fleet by 2028, the capital investment in purchasing BEBs is significantly higher than for CNG buses. **This highlights the importance of staying vigilant in the search for funding opportunities to help fill this gap.**

Conclusion

The Service Assessment concludes that it will be possible for CCB to transition to an entirely BEB fleet without the need for on-route charging. The expected total bus capital cost of the transition to a BEB fleet is estimated at $145 million. **The years with highest costs will be 2028 and 2040, which are years when the agency is expecting to replace 18 buses in a single year. It may be possible to split those purchases into two years to avoid incurring such a high expense in a single year.** This is a decision that will need to be made down the road.

Fuel Assessment

Assessment Overview

The Fuel Assessment estimates fuel consumption and cost for each of the fuel technologies—Renewable Compressed Natural Gas (RCNG) and electricity—studied in the relevant scenario.

Using ZEB performance data from the Service Assessment, CTE analyzed expected bus performance on each block in Culver CityBus' (CCB) service catalog to calculate daily fuel required to complete respective blocks. CTE completed this analysis for depot-charged BEBs on all of CCB's blocks to estimate the fuel costs unique to the respective transition scenarios throughout the transition period.

The Fuel Assessment includes operation and maintenance costs for fueling infrastructure for BEBs. Fuel cost estimates are based on the assumptions shown in

Table 4 **below.**

Table 4 – Fuel Cost Assumptions

Fuel	Cost	Source
RCNG	$1.10/GGE	CCB-contracted rate
Electricity	Varies	CPA Generation with SCE Commercial EV Tariff Schedule

The primary source of energy for a BEB comes from the local electrical grid. Utility companies typically charge separate rates for total electrical energy used [kilowatt-hours (kWh) or megawatt-hours (MWh)] and for peak power demand [kilowatts (kW) or megawatts (MW)] on a monthly basis. Peak power demand is defined as the maximum amount of power that a customer pulls from the grid for any 15-minute window within a month. Demand charges are then applied on a per kW basis to that maximum demand in addition to per kWh costs for energy consumption. In addition to Energy and Demand charges, utilities typically have other standard monthly service fees.

CCB is also dedicated to only purchasing the greenest electricity possible, which is why they have contracted with Clean Power Alliance (CPA), a community choice aggregator, to ensure that the agency only uses 100% renewable, California sourced energy.

As a transit agency adds more BEBs and chargers, the agency's energy consumption increases. With more BEBs in the fleet, more buses are being charged simultaneously, resulting in an increase in the peak power demand and related costs. Rates may vary with time of day, day of the week, and with the changes of seasons. As a result, the time to charge and the number of chargers operating concurrently must be effectively managed to keep energy costs to a minimum. Charge management strategies include limiting charging buses to times of day at which energy rates are lower and spreading out the number of buses charging concurrently to minimize peak power demand. **Ideally, buses would charge exclusively in the least expensive Super Off-Peak and Off-Peak times, currently between 9pm and 9am, to minimize overall cost.**

Table 5 – CCB Utility Rate Schedule

Per meter charge	$571.13					
	Summer (4 Months)		Winter (8 Months)		Annual Avg	
	Delivery (SCE)	Generation (CPA)	Delivery (SCE)	Generation (CPA)	Delivery (SCE)	Generation (CPA)
	$0.069	$0.044	$0.069	$0.048	$0.069	$0.047
Off Peak Total	$0.113		$0.117		$0.116	
Depot Rate	$0.116					
Depot Demand Charge	$14.97					
Power factor adjustment - $/kVAR	$0.60					

Table 5 shows a summary of the rate schedule used in the Fuel Assessment to estimate electrical costs for BEBs. The CCB Utility Rate Schedule is an amalgamation of SCE and CCB energy and demand rates that we assume to representative of the effective utility rate schedule for CCB. The local utility, SCE, calculates total energy costs, measured per kWh, using a time-of-use rate (TOU), as shown in **Table 5**. This rate is inclusive of generation, delivery, and demand charges. SCE has contracted Clean Power Alliance (CPA) to provide the generation portion of their energy costs in order to ensure that they are paying for 100% renewable electricity. **CTE used the SCE TOU-EV-9 published in 2021 to calculate delivery charges and CPA's TOU-EV-9 SUB rates published in July of 2021 to calculate generation charges.**

SCE's current TOU-EV-9 rate schedule currently excludes demand charges through 2024 as an incentive to induce customers to transition to electric vehicles. SCE has stated that "commencing on March 1, 2024, demand charge shall be phased-in unless otherwise authorized by the Commission." As a result, we conservatively assume that demand charges are gradually reintroduced over a five-year period beginning in 2024. SCE's TOU-EV-8 rate schedule was used as the basis to estimate demand charges assumed to be introduced gradually between 2024 and 2028 for the "CCB Utility Rate Schedule" used in this assessment. **CCB should reassess the expected cost of fuel on an annual basis to account for changes in SCE and CPA's rates.** CTE escalated pricing in the Fuel Assessment from the base rates shown in this table using EIA Annual Energy Outlook 2021 for future electricity cost.

Charging Analysis Methodology

To accurately estimate energy consumption, peak power demand, and resulting costs, CTE conducted simulations of charging at the depot for each year of the transition. The Fuel Assessment estimated energy consumption and peak power demand based on current block schedules and projections of BEB utilization each year of the transition period. CTE then used SCE tariff schedules to calculate the annual cost of charging. This annual cost is evaluated for each year of the study (2020–2040) to obtain a total charging cost of BEBs with depot charging for the transition period. CTE uses this estimate of total charging cost as the total fuel cost for the BEB Only scenario and other fleet scenarios.

Charge Management

As the fleet grows, charging will require additional planning to ensure all buses are charged to meet service requirements, to minimize utility costs, and to minimize required infrastructure. Charge management software can automate fleet charging and is an important tool for managing charging schedules and costs. It minimizes electricity costs by limiting the number of chargers running simultaneously, thereby limiting the overall power demand. This software can turn individual dispensers on and off, limit the power of an individual charger, and also be used to schedule charging to avoid on-peak costs. Currently there is no standard charge management software available in the market. **Culver City will seek grant funding opportunities with the goal of partnering with a company to develop a software system that meets the aforementioned requirements. If no funding is secured, Culver City will continue to assess the market until a standard software solution emerges and is cost feasible. (Note: as of the publication of this report – Culver CityBus received notice of award of a California Energy Commission grant of $5 Million that includes a partnership with MOEV software for a charge management program.)**

The charging simulations described previously were performed assuming two scenarios: one without any charge management and a second with a simulated charge management program. **Figure 6** shows how charge management can delay charging to avoid on-peak times and minimize the number of required chargers (maximum 18 required chargers using charge management versus 22 without). **Figure 7** shows how charge management avoids on-peak periods and reduces the overall demand of the charging system by spreading charging over a longer period (maximum 2,250 kW peak demand with charge management versus 2,984 kW without).

Because of the cost savings and reduced infrastructure requirements attributable to charge management, this assessment assumes that CCB's fleet uses software-managed charging when calculating all future BEB fuel costs shown in this report.

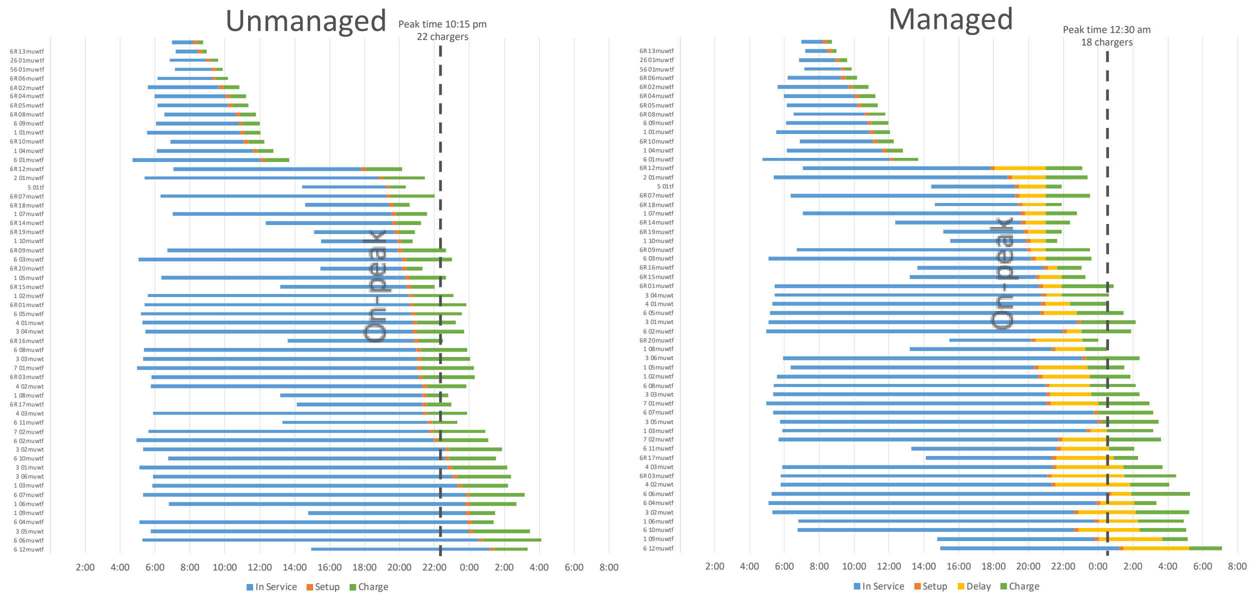


Figure 6 – Bus blocks without (left) and with (right) charge management

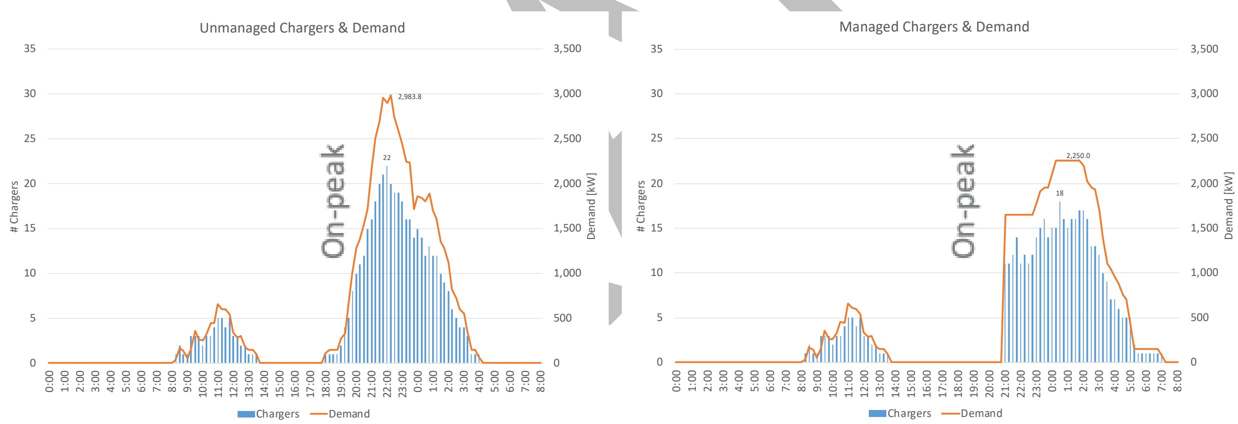


Figure 7 – Peak demand without (left) and with (right) charge management

Fuel Assessment Results

The BEB Only scenario models a transition to an all-BEB fleet that employs depot-charging only. The fuel costs for the BEB Only scenario is based on the assumption that the fleet will not change in size or service level.

Figure 8 depicts energy consumption for each fuel type over the transition period, assuming the RCNG buses in the fleet run until the end of their 12-year useful life at which point they are replaced with BEBs. Legacy fuels are phased out as the number of BEBs in the fleet, and the resulting electricity consumption, increases. Fleet energy use is reduced from about 1.1 million diesel-gallon-equivalent (DGE) in 2020 to just over 92,000 DGE in 2040, an approximately 90% decrease.

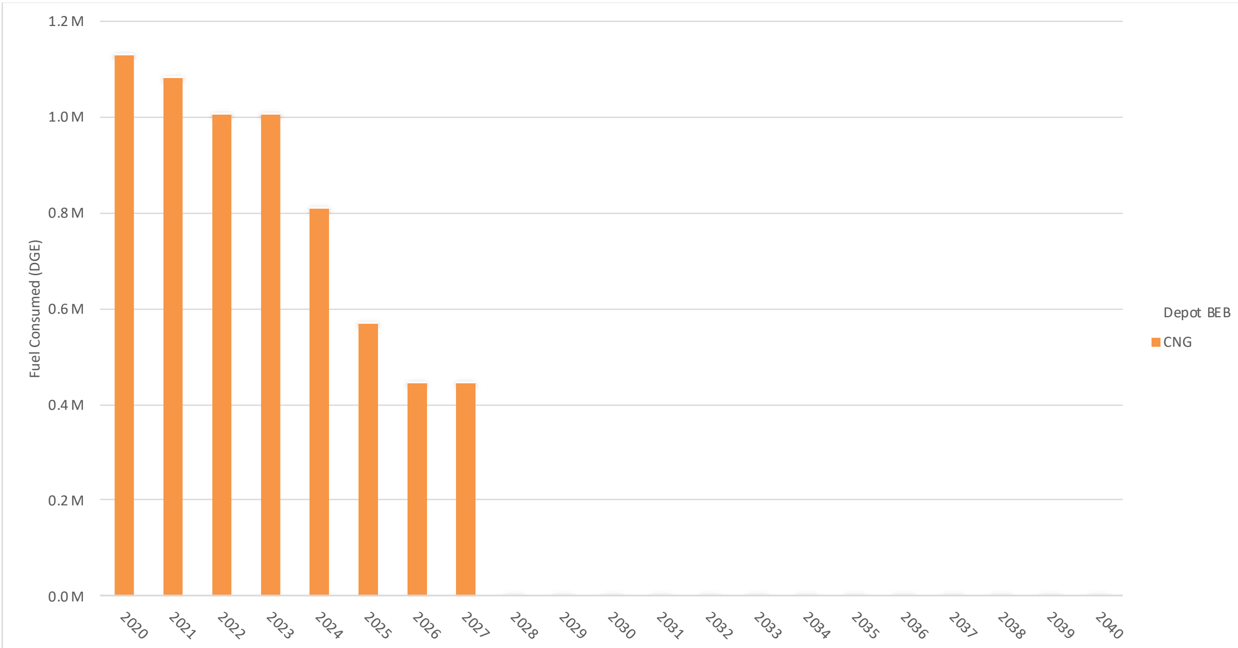


Figure 8 – Annual Fuel Consumption, BEB Only Scenario

Figure 9 shows the annual costs for each fuel type based on the quantities in **Figure 8**. Total estimated fuel costs in 2040 are approximately $1.6 million. Comparatively, if the fleet remained entirely RCNG, the 2040 annual costs would be $1.2 million including inflation. This price difference is largely the result of the introduction of demand charges. In 2025, before inflation is introduced, the costs drop below the RCNG costs, but as the demand costs are introduced, the electricity pricing exceeds the cost of the RCNG.

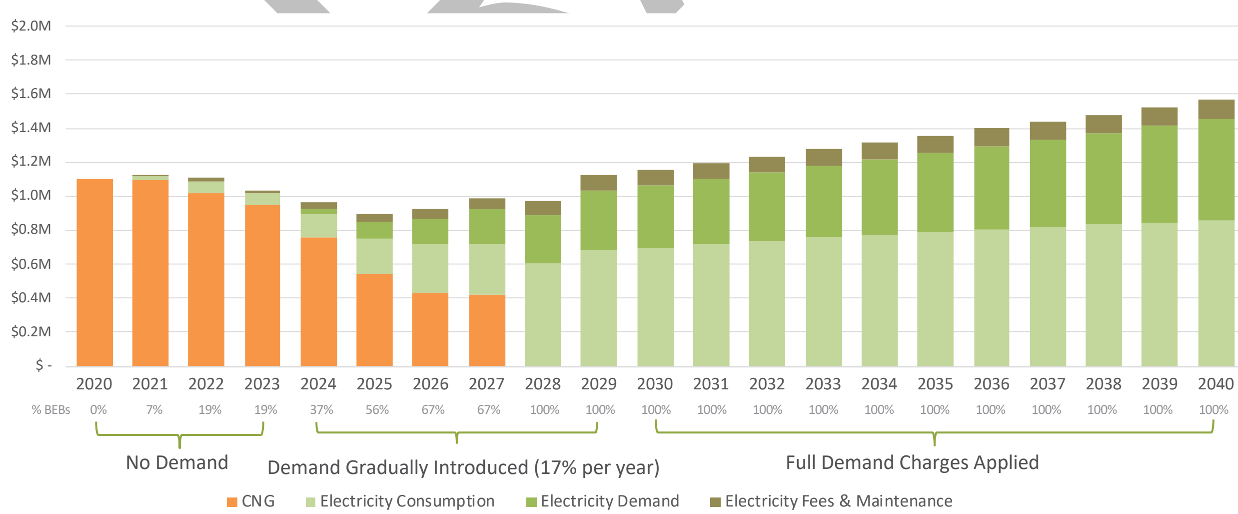


Figure 9 – Annual Fuel Costs, BEB Only Scenario

Low Carbon Fuel Standard Credits

CTE, with assistance from Sage Clean Energy, estimated the fuel cost reductions that CCB would receive if it engages in CARB's Low Carbon Fuel Standard (LCFS) credit program. The LCFS program aims to reduce carbon emissions by setting carbon emissions intensity goals for the transportation sector and then reducing that limit over time. Under this program, fuels that have a lower carbon intensity than diesel generate credits that are dispensed by CARB. The number of credits that are generated by the fuel depend on the pathway for the fuel's production with the least polluting pathways generating the most credits. Each credit has the same value, but since some pathways generate more credits that others, low-carbon pathways have the most credit revenue generation potential. **The current program extends through 2030 but is expected to be renewed within the next few years.** In the LCFS program, one credit is equivalent to one metric ton of carbon dioxide reduction. Although this program is optional, these credits would allow CCB to greatly reduce their expected fuel costs. **CPA is currently developing an LCFS program and CCB intends to consider participation when it is developed.**

Owning the charging equipment necessary to operate BEBs would also make CCB eligible for LCFS credits. Although using standard grid electricity would generate credits, procuring 100% renewable energy would generate the most credits for CCB. Since CCB purchases electricity through CPA, the electricity purchased by the agency would qualify for the maximum number of credits. **As mentioned above, CPA has not yet formalized their LCFS program, so the estimates included here assume that CCB would be the managers of their own credits and that CPA would be retiring Renewable Energy Credits (RECs) on their behalf.** Since all energy taken from the grid has the same renewable energy content, RECs are used to offset carbon emissions in order to qualify for 100% renewable energy while still receiving energy through the grid. RECs are generated through clean energy production, but need to be retired in order to "cash them in." If CPA does not retire their RECs on CCB's behalf, CCB would not qualify for 100% renewable credits.

Another option for qualifying for 100% renewable credits without securing clean energy through CPA would be purchasing RECs directly. RECs could enable CCB to qualify for LCFS credits for 100% renewable energy while still receiving its electricity from SCE with standard generation, but purchasing the RECs would reduce the profit margin slightly since the cost of those RECs and their processing fee would detract from the credit revenue. **On-site generation through solar panels would also quality for 100% renewable credits, though likely not enough to fully offset CCB's energy consumption.** *Table* 6 – *LCFS Credit Revenue Estimates Through CPA Generation* below illustrates the credit revenue estimates through 2030 with CPA generation and **Table 7** shows the credit revenue estimates for the same period with SCE standard generation and REC purchases to achieve 100% renewable energy.

Table 6 – LCFS Credit Revenue Estimates Through CPA Generation

Year	Year	Charging Load, kWh	LCFS Credits	LCFS Credit Value, $/Credit	Gross LCFS Value, $	Gross LCFS Value, $/kWh	LCFS Processing Fee, $	Net LCFS Value, $	Net LCFS Value, $/kWh
1	2021	171,615	283	$195	$55,200	$0.32	$5,500	$49,700	$0.29
2	2022	621,785	1,012	$189	$191,400	$0.31	$19,100	$172,300	$0.28
3	2023	621,785	998	$183	$183,100	$0.29	$18,300	$164,800	$0.27
4	2024	1,281,627	2,028	$178	$360,800	$0.28	$36,100	$324,700	$0.25
5	2025	1,915,744	2,988	$173	$515,800	$0.27	$51,600	$464,200	$0.24
6	2026	2,538,433	3,901	$167	$653,300	$0.26	$65,300	$588,000	$0.23
7	2027	2,538,433	3,844	$162	$624,400	$0.25	$62,400	$562,000	$0.22
8	2028	4,870,480	7,265	$158	$1,144,700	$0.24	$114,500	$1,030,200	$0.21
9	2029	4,870,480	7,156	$153	$1,093,600	$0.22	$109,400	$984,200	$0.20
10	2030	4,870,480	7,045	$148	$1,044,400	$0.21	$104,400	$940,000	$0.19
					$5,866,700	**$0.24**	**$586,600**	**$5,280,100**	**$0.22**

Table 7 - LCFS Credit Revenue Estimates Through SCE Standard Generation and REC Purchases

Year	Charging Load, kWh	LCFS Credits	LCFS Credit Value, $/Credit	Gross LCFS Value, $	Gross LCFS Value, $/kWh	REC Purchase Cost, $	LCFS Processing Fee, $	REC Processing Fee, $	Net LCFS Value, $	Net LCFS Value, $/kWh
2021	171,615	283	$195	$55,200	$0.32	$2,600	$5,500	$300	$46,800	$0.27
2022	621,785	1,012	$189	$191,400	$0.31	$9,300	$19,100	$900	$162,100	$0.26
2023	621,785	998	$183	$183,100	$0.29	$9,300	$18,300	$900	$154,600	$0.25
2024	1,281,627	2,028	$178	$360,800	$0.28	$19,200	$36,100	$1,900	$303,600	$0.24
2025	1,915,744	2,988	$173	$515,800	$0.27	$28,700	$51,600	$2,900	$432,600	$0.23
2026	2,538,433	3,901	$167	$653,300	$0.26	$38,100	$65,300	$3,800	$546,100	$0.22
2027	2,538,433	3,844	$162	$624,400	$0.25	$38,100	$62,400	$3,800	$520,100	$0.20
2028	4,870,480	7,265	$158	$1,144,700	$0.24	$73,100	$114,500	$7,300	$949,800	$0.20
2029	4,870,480	7,156	$153	$1,093,600	$0.22	$73,100	$109,400	$7,300	$903,800	$0.19
2030	4,870,480	7,045	$148	$1,044,400	$0.21	$73,100	$104,400	$7,300	$859,600	$0.18
				$5,866,700	**$0.24**	**$364,600**	**$586,600**	**$36,400**	**$4,879,100**	**$0.20**

In these tables, the LCFS credit value is calculated at an estimated 2% per year reduction rate from current credit pricing. The gross value increases, however, as more BEBs are added to the fleet. **Within this model, a broker service fee of 10% was subtracted from the gross credit value in both cases and the SCE only case also incurred a REC processing fee, as well as the cost of the RECs themselves.** Finally, although the current LCFS credit program only extends through 2030, speculating on how the pricing will trend after the program renewal is challenging. **Therefore, in Figure *10* and Figure 11 below, the per-bus LCFS credit revenue remains at 2030 values for years beyond 2030.**

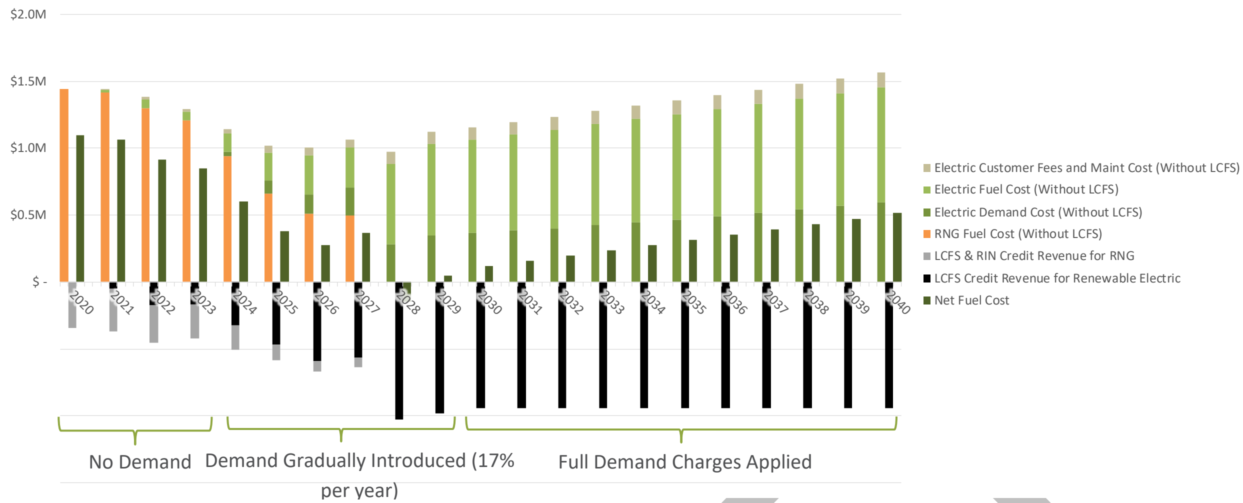


Figure 10 - Potential LCFS Credit Revenue for 100% Renewable Electric, CPA Generation

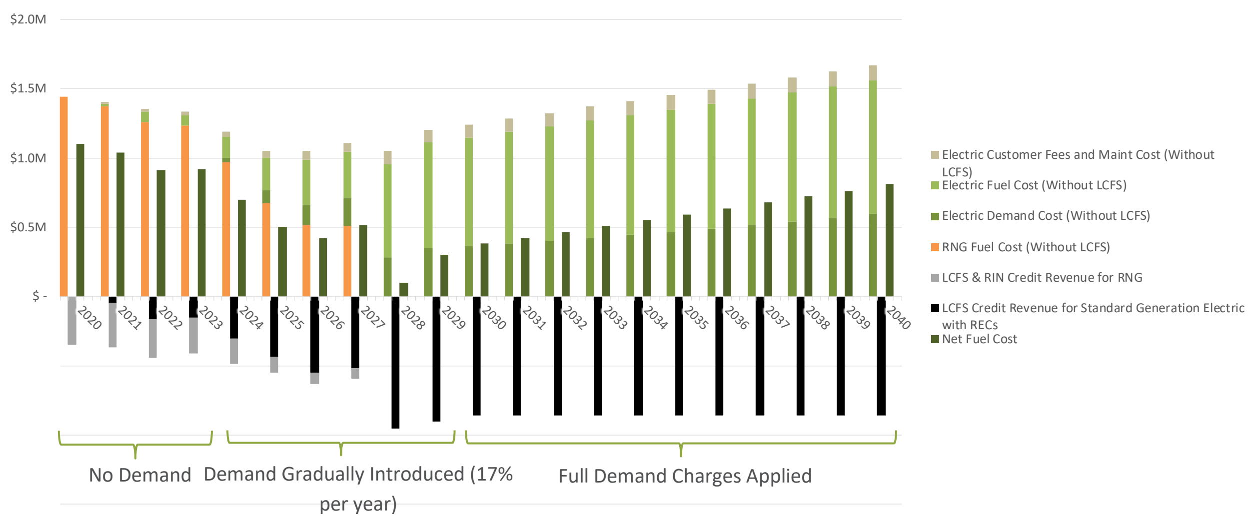


Figure 11 - Potential LCFS Credit Revenue for 100% Renewable Electric, SCE Generation with RECs

The expected total fuel cost over this entire 20-year ZEB transition period is estimated to be $26.5 million, exclusive of LCFS credits. The costs may be reduced to $10.5 million with LCFS credits.

Table 8 – Fuel Cost Comparison

Current Annual Net Fuel Expense (RCNG)	Projected 2040 Fuel Expense if Fleet Remained RCNG	Projected 2040 Electric Expense without LCFS	Projected 2040 Electric Expense with LCFS
$1.1 million	$1.2 million	$1.5 million	$0.67 million

Conclusion

Understanding how electricity costs are incurred and how to best structure charging to avoid unnecessary expense is essential for managing fuel costs. This is a substantially different process and skill from what is required with today's consumption of RCNG. Due to the assumed gradual increase in demand charges, and complex rate schedules, CCB should consider charge management software and procedures to ensure the most efficient and cost-effective path forward. Secondly, participating in CARB's LCFS program would allow CCB to offset fuel costs. CCB could receive credits for 100% renewable electricity by working with CPA or by purchasing RECs while receiving standard SCE electricity.

Maintenance Assessment

Assessment Overview

One of the anticipated benefits of operating a BEB fleet, compared to an internal combustion engine (ICE) fleet, is a reduction in maintenance costs. Early adopters of ZEB technologies have reported that a transit agency may save 30% to 50% in maintenance costs for a BEB compared to an ICE vehicle. Battery electric buses have fewer fluids to replace (no engine oil or transmission fluid), fewer brake changes due to regenerative braking, and far fewer moving parts than internal combustion engine vehicles. The savings in traditional maintenance costs may be offset by the cost of battery or fuel cell replacements over the life of the buses. These costs, however, may be covered by extended warranties.

CCB provided data on CNG bus labor and maintenance costs for their current fleet. CTE estimated that BEB labor and maintenance costs would be 17% lower than the CNG cost, which was based on industry expectations and labor and maintenance costs from Long Beach Transit as reported by the U.S. DOE National Renewable Energy Laboratory (NREL). [1] **CCB should update this projection to reflect the BEB maintenance costs seen once these BEBs have been in service for a few years.** **Table 9** shows the assumed costs of scheduled and unscheduled labor and maintenance used in this analysis.

Table 9 – Labor and Materials Cost Assumptions

Type	Estimate (Per Mile)	Source
40’ CNG	$ 0.94	CCB
40’ BEB	$ 0.78	U.S. DOE & NREL

In addition to labor and materials, this study also estimates the cost impact of midlife overhauls for major components of each bus type. **Table 10** shows the assumptions used to estimate midlife overhaul costs**.** Cost assumptions for engine and transmission overhauls on CNG buses are based on CCB data. For BEBs, the analysis uses an extended battery warranty cost in place of a midlife battery overhaul cost. Although incurring the additional $51,000 for the extended battery warranty as part of the bus capital costs is a significant expense, paying for the extended warranty in place of incurring midlife battery replacement was found to actually save the agency more than $15 million over the transition period, or $330,000 per bus.

OEMs provided the extended warranty cost information. In the analysis, this warranty cost was added to the bus capital costs in the year of purchase.

[1] Eudy, Leslie and Matthew Jeffers. 2020. Zero-Emission Bus Evaluation Results: Long Beach Transit Battery Electric Buses. U.S. Department of Transportation Federal Transit Administration. FTA Report No. 0163. https://www.transit.dot.gov/sites/fta.dot.gov/files/2020-05/FTA-Report-No.-0163.pdf

Table 10 - Midlife Overhaul Cost Assumptions

Type	Overhaul Scope	Estimate	Source
CNG	Engine/Transmission Overhaul	$50k per bus	CCB
BEB	Warranty Cost	$51k per bus	Bus OEM

Maintenance Assessment for Battery Electric Bus Results

Figure 12 shows the combined labor, materials, and midlife overhaul costs for the BEB Only scenario for each year of the transition, including inflation at a rate of 3% per year based on labor inflation rates. The projected cost of maintaining a fully RCNG fleet is shown behind the BEB maintenance costs to illustrate how much higher the costs would be for a RCNG fleet. The cost spike seen in 2022 is caused by mid-life overhauls for the CNG buses in the fleet. Such cost spikes phase out as the fleet transitions to BEBs because CCB's fleet replaces overhaul costs with battery warranty costs. Comparing 2020 to 2040, inflation is the cause of the higher annual maintenance cost.

Figure 12 - Annual Fleet Maintenance Costs, BEB Only Scenario

Conclusion

As CCB transitions to a fully electric fleet, per-mile maintenance costs are expected to fall by 19% in the absence of inflation. Adding the extended battery warranty cost to the bus purchase price will also save the agency more than $10 million over the transition period.

Facilities Assessment

Assessment Overview

Scaling to a fleetwide BEB deployment requires substantial infrastructure upgrades and a significantly different approach to charging compared to smaller pilot deployments. With pilot deployments, charging requirements are met relatively easily with a handful of plug-in pedestal chargers and minimal infrastructure investment.

Full fleet BEB deployments, however, require installation of charging stations and improvements to existing electrical infrastructure. These improvements may include upgrades to switchgear or service connections. Planning and design work, including development of detailed electrical and construction drawings required for permitting, is also necessary once specific charging equipment has been selected.

To determine the installation timeline and costs for charging equipment, this assessment breaks the infrastructure scope of work into four key project types: planning, structural, power upgrades, and charger installation - sized and scheduled to meet near-term charging requirements rather than immediately building out all necessary infrastructure for a full fleet transition.

CCB, CTE, and AECOM worked together to create four charging infrastructure scenarios (plug-in pedestal, plug-in pedestal with suspended dispensers, inductive charging, and gantry with pantograph) and three different layouts (current yard, garage over current yard, and building a taller structure on the current garage's footprint). Each charging infrastructure scenario was iterated for each garage scenario, so that a total of 12 infrastructure scenarios were examined. See **Table 11** for a summary of these scenarios.

Table 11 - Infrastructure Scenario Summary

	A. Pedestal with plug-in	B. Pedestal with suspended dispenser	C. Inductive	D. Gantry with Pantograph
1. Existing Yard	1A	1B	1C	1D
2. New Garage Over Yard	2A	2B	2C	2D
3. Garage Replacing Existing Footprint	3A	3B	3C	3D

Through discussions with CCB and AECOM, the *existing yard* (1A through 1D) and the *garage over yard* (2A through 2D) options were found to be non-viable. The *existing yard* option was eliminated because space constraints determined that the maximum number of buses and support vehicles could not be accommodated. The *garage over yard* option was eliminated because of insufficient spacing for the maximum quantity of buses, the inconvenience to other activity in the yard, the awkwardness of the structure design, and the close proximity to the main facility.

The third scenario considered is to replace the existing garage using the current footprint, but going higher. The benefits of raising the first floor to 20 feet, would accommodate parking for up to 9 40' buses – providing access from the yard and exit through Duquesne Avenue. The second floor entry and exit would come from Duquesne and be xx feet high to accommodate electric mini-buses, shuttles and city vehicles. A third and fourth floor would be added to expand parking for our city employees, expanding the capacity from xx to xxx vehicles.

Scenarios 3C and 3D were additionally ruled out due to the cost of inductive chargers and pantographs respectively. The remaining options, 3A and 3B only differed in cost by 7.5%, so the final selection came down to the convenience that the light gantry structure in 3B would be able to provide over the 3A option. Therefore, the following discussion focuses on scenario 3B. The existing yard (option 1) option will be included in the cost summary table, **Table 18,** but option 2 was not included as there was physically no solution to make it functional.

CTE and AECOM developed estimates for the components of each project type to build up a total cost estimate by project type. **Table 12** shows the assumptions used for BEB infrastructure costs. Conceptual layouts for the BEB Only scenario, prepared by AECOM, are provided in **Appendix** A2. Site Plans Produced by AECOM**.** AECOM also supplied a report including the power requirements, equipment and raceway routing, gantry/island build, and phasing at the depot for the BEB Only infrastructure scenarios.

Infrastructure Project Phasing

The infrastructure deployment was broken into 5 phases. Although these phases are expected to occur in designated years, they are modular, which means that they can be adjusted as units as needed.

Pilot Phase: Involves the deployment of a single 150 kW ABB charger that will be used to charge the first four buses that will be delivered. Nominal demand for this charger is 198A at 480V, three-phase power with a maximum power dissipation of 170 kVA. SCE's analysis of the electrical demand data shows that the single charger load can be added on to the facility's main building transformer via a small, separately metered service panel installed by SCE as part of the Charge Ready program.Phase 1a: All the major trenching and electrical work should be completed to avoid needing to repeatedly disrupt the yard as the ZEB transition moves forward. The transformer should be upgraded, trenching and boring to install conduit from distribution panel to charging island should be completed, and the charger stub out should be accomplished. Additionally, the existing 4' CNG fuel island should be expanded into a 6' island to accommodate the chargers and gantry structure that will be built out in the coming years. This is expected to occur in 2021/2022.

Phase 1b: Five chargers (600kW total) will be needed to charge the first 10 buses delivered by 2022. These chargers have a maximum demand of 120kW each, with two gantry mounted dispensers per charging cabinet. Given that the current transformer is already reaching capacity, a 1500 kVA transformer will be needed to serve the existing building and the 10 buses, if the loads are combined as recommended by SCE. This upgrade is expected to be done by SCE as part of the Charge Ready program. **SCE has yet to confirm what portion of the total project costs they will be willing to cover at this stage, but CCB expects to cover the difference. This cost**

assumption should be updated when the terms are finalized. The first 5 gantries are also expected to be installed this year.

Phase 2: Expected in 2024, 10 buses are expected to be delivered, which will require an additional 5 chargers and 10 gantry mounted dispensers to be added to the existing gantry structure

Phase 3: The scheduling on this modular phase could be easily adjusted but due to funding opportunities and the need for expanded vehicle space, we expect to start immediately planning this phase in late 2022 and building in 2024. This phase is largely the garage phase, which involves tearing down the existing garage and constructing a new one in its place, 1 ½ stories higher. In the garage, 5 chargers will also be installed on the first floor with 10 ceiling mounted dispensers. The second floor would be devoted to electric charging of mini-buses, shuttles and City Vehicles – for a total of 2x vehicles.

Phase 4: Expected in 2026, Phase 3 sees the next and last stage of gantry construction with 5 more gantries being built out. 3 more chargers and 6 gantry mounted dispensers will also be added.

Phase 5: Expected in early 2028, to accommodate the final 18 buses. The remaining 6 chargers and 18 gantry mounted dispensers are expected to be built.

Once a plan gets approved, AECOM would be contracted to immediately design a full phased gantry to be built over five years 2022 – 2028 and then commence design of the garage in 2022 to be built in 2024 in alignment with the 40' bus replacement schedule. See below for a timeline.

	CY2020	CY 2021				CY 2022				CY 2023				CY 2024				CY 2025				CY 2026				CY 2027				CY 2028			
		Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
BEB 40' Buses				4	4	4	4	4	10	10	10	10	10	10	10	20	20	20	20	30	30	30	30	30	36	36	36	36	36	36	36	36	54
LT Plan	Planning																																
Yard Gantry																																	
Design																																	
Procurement																																	
Build							Phase 1								Ph 2							Phase 4								Ph 5			
Garage																																	
Design																																	
Procurement																																	
Build															Phase 3																		

Theoretically, at the time of the final bus deployment, the existing CNG facility would be partially or completely decommissioned, as on-site CNG fueling would no longer be needed by the battery-electric fleet. **The removal of CNG infrastructure would enable CCB to use the existing service location for the addition of a larger transformer and switchboard to serve the additional bus chargers. This decision would be dependent on CCB, as some CNG vehicles may remain in the non-transit fleet.**

Table 12 – BEB Infrastructure Project Cost Assumptions

Project	Cost Estimate Metrics	Source
Infrastructure Planning	$200k per project	Engineer's estimate

Structural Projects (Gantries/Islands, Conduit, duct banks, etc.)	Design/Construction: variable by scenario	Engineer's estimate, includes 20% contingency
Power Upgrade Projects	Design, Construction, & Equip: $96k per MW	Engineer's estimate, includes 20% contingency
Charging Projects	Charging Equipment & Installation: variable by scenario	Quotes and estimates, includes 20% contingency

Key assumptions applied in CCB's Facilities Assessment are as follows:

- One plug-in reel per bus;
- Two buses per 150 kW charger (with the exception of the inductive charger scenarios);
- Two charge windows, i.e., no more than half the buses charge at any given moment;
- Off-peak, overnight charging with automated charge management software; and
- Dispenser capacity to serve up to 80% of the fleet at a time; no movement of buses overnight.

Facilities Assessment Projects

The following section will introduce the timeline and cost estimates for the Project Planning, Structural Projects, Power Upgrade Projects, Charger Installation Projects, and Garage Construction/Deconstruction costs associated with the four infrastructure scenarios being explored.

BEB Only Depot Planning Projects

A&E Planning at the depot is estimated to cost $200,000 before each Power Upgrade project. Three $200,000 projects are therefore planned for CCB over the transition period.

BEB Only Depot Structural Projects

Structural projects include (1) trenching and building out duct banks from the switchgear to the charger pads, (2) construction of charger pads (i.e., foundation for charging equipment), (3) construction of gantry foundations and overhead gantry structures that hold the dispensers (for applicable scenarios), and (4) installation of conduit from switchgear to charger pads. **Table 13** shows the detailed cost assumptions for structural projects. These cost assumptions also apply to other projection scenarios. Duct bank cost is incurred only once per depot, other costs are on a per gantry basis.

Table 13 – Scenario 3B: Structural Project Cost Assumptions

Item	Cost	Unit
Initial Duct/Bank	$ 300,000	per Division

Island	$ 45	per square foot
Gantry & Foundation	$ 150,000	per gantry (light load)
Incremental Duct Bank/Conduit	$ 300	per Lineal Foot
Charger Pads	$ 50	per square foot
Contingency	20%	on project costs
Design Engineering	6%	on project costs and contingency

BEB Only Power Upgrade Projects

Power upgrade projects include construction of transformer foundations and installation of transformers. This study assumes that transformers are modular and that incremental power requirements are met over time. **Table 14** shows the estimated costs for depot power upgrade projects.

Table 14 – Depot Power Upgrade Cost Assumptions, BEB Only Scenario

Transformer/Switchback Pad	Cost	Unit
Transformer	350,000	Per Division
Trench and Duct bank	$ 300	per lineal foot
Construction, Equipment (1 MW)	$ 200,000	per project
Construction, Equipment (2 MW)	$ 300,000	per project
Contingency	20%	on project costs
Design Engineering	6%	on project costs and contingency

Figure 13 shows total required electrical demand, in megawatts, for each depot over time. Each entry indicates the minimum amount of power that must be added in a given year to meet the growing demand at a given facility as more BEBs are purchased.

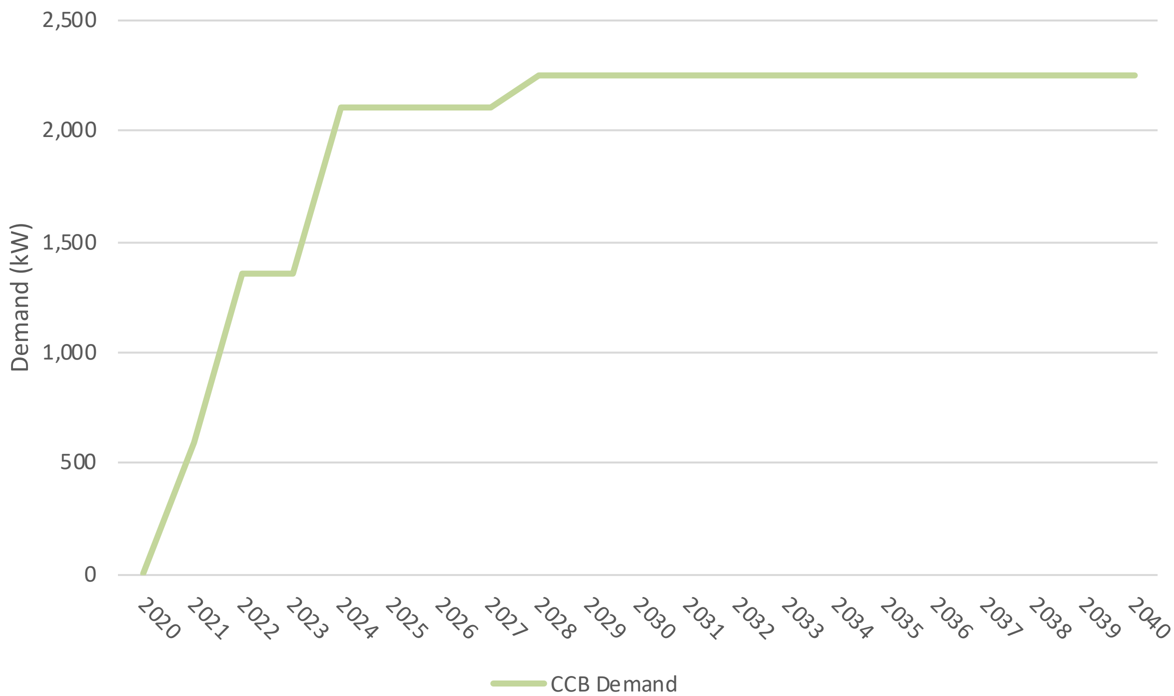


Figure 13 – Incremental Depot Electrical Demand, BEB Only Scenario (MW)

Power upgrades are consolidated to occur in selected years, in accordance with the required demand in **Figure 13.** These recommended upgrades are expected to occur in the years outlined in **Table 15** below.

Table 15 - Depot Recommended Power Upgrade Projects, BEB Only Scenario (MW)

Year	Upgrade Required (MW)
2022	2
2024	1
2028	1

Total estimated power upgrade costs over the project life are approximately $1.3 million, although around $700,000 would likely be covered by SCE as part of the ChargeReady Program.

BEB Only Depot Charger Installation Projects

Charging projects include purchase and installation of 150 kW chargers and dispensers. Each bus will require one dispenser. Every two buses will require one charger, with the exception of the inductive scenario, which would require one charger per bus. The dispenser type depends on the scenario, with 3B requiring plug-in dispensers. provides the costs assumed for charger and dispenser installs.

Table 16 – 3B Dispenser and Charger Project Cost Assumptions

Item	Cost	Unit
Charger	$ 100,000	per 150 kW charger
Charger Installation	$ 10,000	per 150 kW charger
Dispenser/Pantograph	$ 10,000	per dispenser
Dispenser Installation	$ 5,000	per dispenser
Contingency	20%	on project costs

Garage Construction Costs

In scenarios 3B, the current light-duty parking structure on CCB's property would be torn down and replaced with a new, taller garage that would allow for additional bus parking on the ground level and would increase the light-duty parking availability in the structure by 50%. The garage deconstruction and construction are both part of Phase 5, which is shown in 2028, but the timing of this construction project may be adjusted as needed. The cost of removing the existing structure is estimated at $1.8 million, and the cost of reconstruction is estimated at $9.5 million. Upon approval of the plan, a full site survey and independent costing would be done as this is a high cost infrastructure item. The CCB team is concerned that these costs could be much higher and thus have asked for a $5M contingency for the garage replacement.

Additionally, there are height restrictions that need to be worked through with the City, as this garage is xx' ….

BEB Only Infrastructure Cost Summary

Figure 14 summarizes all costs for charging infrastructure for all of the BEB Only Infrastructure Scenarios. The estimated total infrastructure costs are approximately $20 million. This total cost includes all gantry projects (including the duct, bank, charger pad etc. costs required to support the chargers that will be installed along with the gantry), all power upgrade projects, all charger and dispenser installations, all planning projects, design engineering costs, the added 20% contingency on all costs, and 1.5% annual inflation.

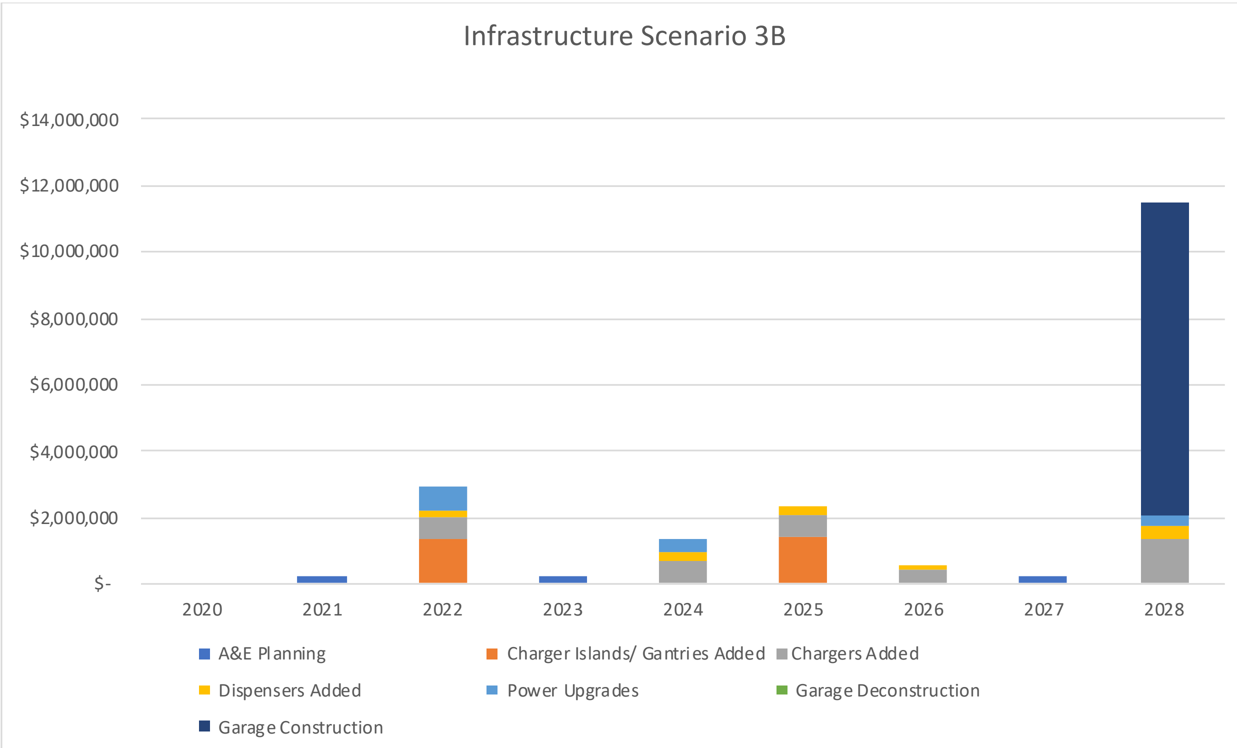


Figure 14 - Depot Only Cumulative Costs, Infrastructure Scenario 3B

The sum cost of all of these annual expenses can be seen in **Table 18**, which also includes an overview of the scenarios that were determined to be non-viable.

Table 17: CCB Infrastructure Capital Investment to transition to a 100% BEB fleet by 2028

	CNG Baseline	BEB Incremental Costs	Total Investment
Fueling Infrastructure	$0	$20,507,000*	$20,507,000

*Does not include SCE Charge Ready contribution

Looking at Table 17: CCB Infrastructure Capital Investment to transition to a 100% BEB fleet by 2028 **Table 17**, the infrastructure required for this transition to a fully zero-emission fleet has a significant expense that would not be incurred by maintaining a CNG fleet. **There is, however, funding available to help fill this gap, and CCB should be able to meet the financial need through additional grant funding.**

Resiliency and Redundancy

With a growing BEB fleet, CCB will need to incorporate resiliency and redundancy to their fueling and infrastructure plans. The loss of electrical power to CCB's facility could be the result of various causes including utility equipment or line faults, transformer failure, severe weather events, mandatory wildfire safety shutoffs, or high-demand load shedding (brown-outs).

CCB's emergency plan should be an ongoing discussion as the BEB fleet grows, as local policies change, and as new technologies emerge. To lay a solid foundation for an evolving energy resiliency plan, CCB should consider the following actions when creating an energy resiliency plan. These tasks are not an exhaustive list, and there may be other considerations that are specific to Culver City.

1. Identify the frequency and duration of outages.
2. Determine a mitigation strategy proportional to the risk.
3. Obtain *essential service* designation to avoid being affected by rolling blackouts.
4. Create and assess infrastructure solutions to mitigate identified risks.

The strategies below are aimed at mitigating the impacts of utility outages and are all infrastructure-based solutions. Each strategy can be used as a standalone solution or in conjunction with one another. These are not one-size-fits-all solutions, and they have not yet been widely used in transit operations.

Dual Utility Feeders

CCB could work with SCE to install a second utility circuit at the depot. If SCE determines this is feasible, this secondary circuit can continue to provide power to the site in the event the substation or distribution line becomes de-energized. Both feeders would meet at a main switchboard and be able to switch sources via automatic or manual means. This solution would provide redundancy should a problem occur upstream on one of the feeders, but it would not address the risk of wildfire safety shutoffs. To mitigate weather-related shutoffs, this would need to be coupled with one of the solutions below.

Battery Energy Storage (BES) Systems

Battery energy storage (BES) systems can provide immediate backup power to a facility in the event of a complete utility outage. The size and rating of the BES along with the amount of backed-up load will determine how much time the BES will provide power without need for recharging. BES systems can be designed for both maximum power outputs and for power outputs for certain lengths of time, depending on the intended use of the system.

Standby Generator

A common option for backup power is providing one or more sockets at load centers for the connection of portable generators. Since it is unlikely that all chargers will be operating at the same time, a smaller generator could provide adequate backup power during an outage (assuming no substantial auxiliary loads are operating simultaneously). CCB already operates a stationary generator on-site that could be incorporated into any future on-site generation plans.

Microgrid

A microgrid is a small, on-site, independent power system that integrates generation, energy storage, and control devices at or near the bus depot.[2] Microgrids may also employ renewable generation from wind or solar, which can help meet net-zero emissions goals while saving on utility

[2] Li, Fusheng, et al. *Microgrid Technology and Engineering Application*. 1st ed., Academic Press, 2015.

costs. In tandem with managed depot charging, a smart microgrid can manage the demands on the BES while utilizing on-site generation through multiple sources. In addition, a microgrid can supplement grid power to reduce peak-demand and energy costs from the utility.

Renewables Analysis

CCB also worked with Sage Energy Consulting to develop a preliminary Renewable Assessment Study, which looked at adding photovoltaic (PV) solar panels on the CCB facilities. The results of the assessment are included as **Appendix A1. Culver CityBus BEB Electrification Plan: Renewables Assessment Study**.

Conclusion

The chosen infrastructure pathway will significantly impact the cost of transitioning to a zero-emission fleet. CCB has already weighted the pros and cons of 12 different infrastructure scenarios and has found that option 3B would be the best option for the agency based on cost and convenience. In addition to the presented infrastructure options, CCB will need to incorporate energy resiliency and redundancy in their battery electric operations as the fleet grows.

Table 18 - Annual Cost of Infrastructure, All Scenarios

CCB ZEB Study								
BEB Infrastructure Conceptual Cost Estimates*			Goal is to accommodate 54 40' buses					
	Current Yard				Existing Garage Footprint Structure			
Design Options	1A	1B	1C	1D	3A	3B	3C	3D
Description	Plug-In Chargers	Plug-In Chargers and Light Gantry to Suspend Dispensers	Inductive Chargers**	Gantries & Pantographs**	Plug-In Chargers	Plug-In Chargers and Light Gantry to Suspend Dispensers	Inductive Chargers**	Gantries & Pantographs**
Total Number of Buses Accomodated	39	43	50	45	54+	54+	54+	54+
Number of Buses in Yard	*39*	*43*	*50*	*46*	47	47	47	47
Number of Buses in Garage					10	10	10	10
Level of Disruption in Yard	Minimal Yard Disruption	Minimal Yard Disruption	Minimal Yard Disruption	Minimal Yard Disruption	Minimal Yard Disruption	Minimal Yard Disruption	Minimal Yard Disruption	Minimal Yard Disruption
Is This a Viable Scenario	X	X	X	X	✓	✓	✓	✓
A&E Planning	*$ 684,000*	*$ 684,000*	*$ 684,000*	*$ 684,000*	*$ 684,000*	*$ 684,000*	*$ 684,000*	*$ 684,000*
Charger Islands/ Gantries Added	*$ 1,074,000*	*$ 2,641,000*	*$ 633,000*	*$ 6,562,000*	*$ 1,242,000*	*$ 2,713,000*	*$ 668,000*	*$ 12,164,000*
Chargers Added	*$ 2,822,000*	*$ 2,971,000*	*$ 352,000*	*$ 5,794,000*	*$ 3,863,000*	*$ 3,120,000*	*$ 352,000*	*$ 6,848,000*
Dispensers Added	*$ 770,000*	*$ 973,000*	*$ 25,635,000*	*$ 4,635,000*	*$ 1,054,000*	*$ 1,046,000*	*$ 25,635,000*	*$ 5,479,000*
Power Upgrades	*$ 1,159,000*	*$ 1,159,000*	*$ 1,481,000*	*$ 1,481,000*	*$ 1,480,310*	*$ 1,490,000*	*$ 1,481,000*	*$ 1,481,000*
Garage Deconstruction	*$ -*	*$ -*	*$ -*	*$ -*	*$ 1,780,000*	*$ 1,780,000*	*$ 1,780,000*	*$ 1,780,000*
Garage Construction	*$ -*	*$ -*	*$ -*	*$ -*	*$ 9,466,000*	*$ 9,466,000*	*$ 9,466,000*	*$ 9,466,000*
Savings from ChargeReady Program*	*$ (759,000)*	*$ (759,000)*	*$ (759,000)*	*$ (759,000)*	*$ (759,000)*	*$ (759,000)*	*$ (759,000)*	*$ (759,000)*
TOTAL INFRASTRUCTURE COST	*$ 5,750,000*	*$ 7,669,000*	*$ 28,026,000*	*$ 18,397,000*	*$ 18,810,310*	*$ 19,540,000*	*$ 39,307,000*	*$ 37,143,000*
Additional Bus Costs			*$ 5,130,000*	*$ 1,575,000*			*$ 5,130,000*	*$ 1,890,000*
Total Infrastructure and Added Bus Costs	***$ 5,750,000***	***$ 7,669,000***	***$ 33,156,000***	***$ 19,972,000***	***$ 18,810,310***	***$ 19,540,000***	***$ 44,437,000***	***$ 39,033,000***
	*Costs in this assessment are conceptual and would need to be refined as selection is narrowed, Inflation applied at 1.5% annually							
	**Buses in these scenarios would also incur additional costs due to additional charging equipment installation See Additional Bus Cost Row)							
	***Includes Initial Duct work ($300,000) and first MW upgrade							

Total Cost of Ownership

Assessment Overview

The Total Cost of Ownership Assessment compiles the results from the Fleet, Fuel, Facilities, and Maintenance Assessments to show cumulative and annual costs throughout the transition period for each scenario. It includes selected capital and operating costs of each fleet scenario over the transition timeline. Other costs may be incurred (e.g., incremental operator and maintenance training) during a fleet transition; however, these four assessment categories are the key drivers in ZEB transition decision-making.

Future changes to CCB's service level, depot locations, route alignments, block scheduling, or other operations are unknown. The analyses below provide best estimates using the information currently available and the assumptions detailed throughout this report.

Total Cost of Ownership Assessment Results

Figure 15 shows the combined fleet, fuel, facilities, and maintenance costs including inflation for infrastructure scenario 3B, which equals a total combined cost of $218 million over the length of the transition (2021–2040). Only 3B (garage/pedestal with suspended dispenser), were brought forward into the TCO Assessment. The TCO Assessment, consistent with the previous assessments, assumes a total of 54 total BEBs in service by 2028. Infrastructure costs are incurred toward the beginning of the project when the infrastructure is purchased to support the transition. Maintenance and fueling costs remain relatively stable from year to year. Fleet costs are the main source of variability in costs from year to year, depending on the agency's bus procurement schedule.

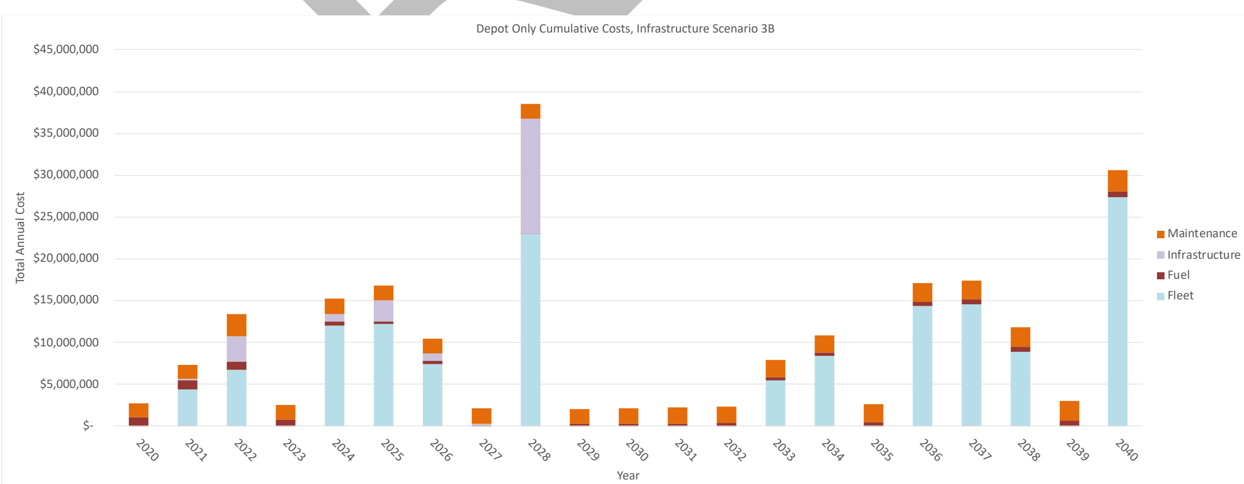


Figure 15 - Depot Only Cumulative Costs, Infrastructure Scenario 3B

Table 19 - Total Cost of Ownership

Assessment Type	Total Cost of Ownership
Fleet	$ 144,666,000
Fuel*	$ 10,550,000
Infrastructure**	$ 20,537,000
Maintenance	$ 42,144,000
Total	**$ 217,897,000**
% ZEB in 2040	**100%**

*Excludes any potential LCFS credit revenue

**Does not include SCE Charge Ready contribution

Table 20 – BEB Incremental Total Cost of Ownership

	CNG Baseline	BEB Incremental Costs	Total Cost of Ownership
Initial Buses	$35,310,000	$30,301,000	**$65,611,000**
Fueling Infrastructure	$0	$20,537,000*	**$20,537,000**
Bus Replacements	$42,217,000	$79,056,000	**$144,666,000**
Fuel	$20,639,000	-$3,823,000	**$16,816,000**
Maintenance	$52,670,000	-$10,525,000	**$42,144,000**
LCFS Credit Value	(Inc. in RCNG price)	-$12,583,000	**-$12,583,000**
Total	**$150,836,000**	**$67,061,000**	**$217,897,000**

*Does not include SCE Charge Ready contribution

It is also important to consider that there was already a significant amount of cost that would be incurred over that time even without switching to zero-emission technology. As seen in **Table 20** – BEB Incremental Total Cost of Ownership $67 million of the expected $218 million is the incremental cost for the BEB transition.

Conclusion

CCB has explored all of its options at each step of this assessment to determine the most practical and cost-effective transition pathway to a fully battery electric bus fleet. The plan that CCB has set forth exceeds the expectations of CARB's Innovative Clean Transit Regulation and provides a blueprint for the transition to zero emissions. Because this plan includes several assumptions about cost and improvements in battery technology, this plan should be updated regularly to account for the actualization of technology improvements and costs.

Conclusions and Recommendations

ZEB technologies are in a period of rapid development and change. While the technologies have been proven in many pilot deployments, they are not yet matured to the point where they can easily replace current fossil-fuel technologies on a large scale. BEBs require significant investment in facilities and infrastructure and may require changes to service and operations to manage their constraints.

CARB's ICT regulation is an achievement toward addressing the challenges of climate change and improving local air quality with a goal of 100% zero-emission transit fleets by 2040. However, as demonstrated in this analysis, there will be substantial costs and technical challenges to overcome. Transit agencies may be challenged to meet this goal while maintaining the same level of passenger service.

In an all-BEB strategy, total ZEB transitional costs are likely to be around $217 million not including LCFS credit revenue to offset fuel costs. By adding on-route charging, CCB could achieve a transition to a 100% battery-electric fleet without increasing fleet size or sacrificing block achievability. The difference in cost between this scenario and the current fleet configuration is largely the result of the price difference between CNG buses and BEBs.

Given these considerations, the recommendations for CCB are as follows:

1. **Remain proactive with ZEB deployments:** For successful fleetwide deployment, BEBs will require charge management software, hardware, and standards to manage the fleetwide transition. CCB should move forward thoughtfully, taking advantage of various grant and incentive programs to offset the incremental cost for ZEB deployment. Incentive programs may be eliminated in future years as ZEB procurements are required instead of being optional.
2. **Target specific routes and blocks for early ZEB deployments:** CCB should consider the strengths of ZEB technologies and focus those technologies on routes and blocks that take advantage of their efficiencies and minimize the impact of the constraints related to the respective technologies. These technologies cannot follow a one-size-fits-all approach from either a performance or cost perspective. Matching the technology to the service will be a critical best practice. Results from the ZEB Pilot Program will help to inform these decisions.

The transition to ZEB technologies represents a paradigm shift in bus procurement, operation, maintenance, and infrastructure. It is only through a continual process of deployment with specific goals for advancement that the industry can achieve the goal of economically sustainable, zero-emission public transit.

Appendix

A1. Culver CityBus BEB Electrification Plan: Renewables Assessment Study

Subject:	Renewables Assessment to Support BEB Electrification – Culver CityBus
Client:	Center for Transportation and the Environment (CTE)
Prepared by:	Sage Energy Consulting
Date:	July 16, 2021

1. Introduction

Sage Energy Consulting (Sage) was contracted by The Center for Transportation and the Environment (CTE) in January 2021 to provide technical expertise and modeling for on-site renewables and battery storage to support Battery Electric Bus (BEB) electrification for Culver CityBus (CCB). The objective of this memo is to review the physical and financial viability of solar photovoltaic (PV) and stationary battery storage integrated with BEB charging at the City's Transportation Facility. The financial analysis also includes a review of Low Carbon Fuel Standard Credits (LCFS), Renewable Identification Number (RINs) credits, the Renewable Energy Credits (RECs) generated with onsite renewables, and the LCFS Zero Carbon Intensity (CI) pathways to enhance the LCFS credits.

Sage's findings from the renewables assessment are presented in this memo. The key objectives and results of the assessment are summarized in Table 1-1.

Table 1-1. Renewables Assessment Objectives and Results

Objectives	Value	
1. Evaluate Historical Electrical Consumption and Cost (CY2019) at Transportation Facility	Consumption: 1,255,000 kWh (main service and CNG service) Cost: $262,000 ($0.21/kWh)	
2. Estimate Future Electrical Consumption and Cost with Fleet Electrification (Facility + BEB Load)	2022 (10 BEB's)	2028 Full Buildout (54 BEB's)
	Consumption: 1,877,000 kWh Cost: $364,000 ($0.19/kWh)	Consumption: 5,656,000 kWh Cost: $1,349,000 ($0.24/kWh)
3. Conceptualize PV system size based on space constraints	Rooftop PV Only: 195 kW_p (313,000 kWh in Yr-1) Rooftop + Canopy PV: 750 kW_p (1,198,000 kWh in Yr-1) See Attachment B for conceptual solar PV system options.	
4. Conduct utility tariff analysis and lifecycle financial analysis	See Table 2-2 for financial analysis summary.	
5. Review Battery Energy Storage System (BESS) applicability and financial viability	BESS could be utilized for load shaping, grid services and/or resiliency. Financial analysis indicates poor financial performance. See Section 6 for further detail.	

1. Utility cost based does not include LCFS credits.

2. Summary

2.1 Quantitative Results Summary

Based on the utility tariff analysis and lifecycle financial modeling, Table 2-1, and Table 2-2 summarize the key metrics of the solar PV financial evaluation.

Table 2-1. Summary of Solar PV Project Evaluated

Metric	Rooftop PV Only	Rooftop + Canopy PV
Targeted Number of Sites	1 Site, Transportation Facility	
Electrical Utility Services Reviewed	3 SCE services (Main, CNG and Future EV)	
Approx. PV System Size	195 kW_p	750 kW_p
Financing Options Analyzed	Cash Purchase, Power Purchase Agreement (PPA)	
Energy Consumption Offset w PV, Annual Avg. 2022	17%	64%
Energy Consumption Offset w PV, Annual Avg. 2028	5%	18%
Energy Cost Offset w PV, Annual Avg. 2022 (Cash)	9%	37%
Energy Cost Offset w PV, Annual Avg. 2022 (PPA)	(1%)	(9%)
CO_2 Eqv. Offset (Metric Tons), 25-Year[1]	700 MT CO_2	2,700 MT CO_2
Shade Created by Canopies (SF)	-	33,000 SF

1. The carbon offset value accounts for reducing carbon intensity of grid supplied electricity to align with the state goal of 100% carbon-free electricity by 2045.

Table 2-2. 25-Year Solar PV Project Financial Summary

Metric	Rooftop PV Only		Rooftop + Canopy PV	
	Cash	PPA	Cash	PPA
Solar PV System Capital Cost | PPA Rate[1]	$588,000	$0.14/kWh	$3,375,000	$0.165/kWh
Project Development Soft Costs[2]	$76,000	$76,000	$439,000	$439,000
Annual Operating Costs (Year-1)[3]	$7,000	$42,000	$36,000	$198,000
Total Project Capital and Soft Cost Combined	$665,000	$0.15/kWh	$3,814,000	$0.18/kWh
Year-1 Gross Savings[4]	$33,000	($2,000)	$131,000	($31,000)
25-Year Gross Nominal Savings	$970,000	$298,000	$4,129,000	$720,000
25-Year Net Nominal Savings[5]	$305,000	$219,000	$317,000	$278,000
25-Year Net NPV Savings (2.5% discount rate)	$40,000	$117,000	($819,000)	($14,000)
Simple Payback	17.5 Yrs.	13.5 Yrs.	23 Yrs.	20 Years

1. Capital Cost for solar PV (in 2021 dollars) has been estimated using recent procurements in CA and adjusted higher to account for recent increases in steel, copper, and electrical component costs.

2. Project development soft costs are set at 13% of build cost, and include contingency, consultant fees, inspection fees, CCB legal and administrative expenses (see Appendix A for detailed breakdown).
3. Annual Operating Costs for under cash purchase include O&M cost, insurance, asset management fees, inverter replacement annual sinking fund and end-of-life decommissioning annual sinking fund. Under a PPA, the annual operating costs include PPA payments made by CCB for consumed electricity from the PV system.
4. Gross Nominal Savings includes electrical savings minus operating costs and assumes NEM 2.0 tariff.
5. Net Nominal savings are inclusive of capital and project development soft costs.

2.2 Key Findings

The following are key qualitative findings from the analysis:

1. Two solar PV options were conceptualized for this study based on site constraints and discussions with the City. The first option is a 195 kW_p Rooftop PV Only system. The second option is a 750 kW_p rooftop + canopy system; conceptual layouts are provided in Attachment B.
2. A solar PV project is physically viable at the Transportation Facility and the cash purchase and PPA scenarios result in positive gross and net nominal savings for both PV options. Option 1, the rooftop system, provides Net Present Value (NPV) savings, assuming a 2.5% discount rate, over the 25-year life of the system. However, Option 2, the larger PV system, results in negative NPV savings over 25-years due to the higher cost associated with constructing canopy structures. A summary of the solar PV savings analysis is provided in Section 5.4.
3. The financial modeling in this study assumes the Net Energy Metering (NEM) Successor Tariff, typically referred to as NEM 2.0, with 20-year grandfathering. The current NEM 2.0 regime will be transitioned to NEM 3.0 sometime in 2022. NEM 3.0 is expected to significantly reduce the value of PV generated energy. <u>If CCB intends to pursue a solar project, the City should finalize an interconnection application for the PV system by Q4 2021 to ensure grandfathering under NEM 2.0.</u>
4. The Low Carbon Fuel Standard (LCFS) program and Renewable Identification Number (RINs) credits are estimated to provide substantial subsidies to CCB, with approximately $395,000 in the first year and a total of ~$5M through 2030 (based on conservative estimates but can vary significantly based on actual price movement of LCFS and RINs credit prices over time). An analysis of the LCFS and RINs credits can be found in Section 4.
5. CCB could utilize a combination of Renewable Energy Certificates (RECs) from the onsite solar and RECs purchased from the market to pursue the higher value LCFS Zero-CI pathway. However, the local Community Choice Aggregation (CCA) entity, Clean Power Alliance (CPA), is developing a LCFS program where it may be possible for CCB to leverage the higher value Zero-CI pathway with CPA retiring RECs from the 100% renewable electricity tariff in favor of the LCFS program.
6. A conceptual BESS system was sized to provide onsite load shaping to provide cost savings on the utility tariff. Lifecycle modeling of a BESS (10-year) showed that the additional savings from a BESS paired with the PV system is not sufficient to overcome the installation cost, inclusive of current California Self Generation Incentive Program (SGIP) incentives. A summary of the BESS analysis along with resiliency considerations can be found in Section 6.

7. If the CCB does pursue a solar PV project, we recommend including provisions for a future BESS, as financial drivers are likely to improve in the future. This can include spare conduits, reserving footprint, and making provisions in any electrical upgrades for a future BESS.

3. Energy Consumption Review

This section reviews current and future energy consumption and cost at the Transportation Facility for electricity and natural gas.

3.1 Historical Annual Energy Usage and Cost

The current baseline electricity usage was tabulated from 15-minute interval data provided by CCB; and the natural gas usage and cost data was provided by CCB and CTE, respectively. Table 3-1 summarizes baseline energy consumption and cost at CCB's Transportation Facility. The electricity consumption and cost is based on CY2019, while the CNG fuel consumption and cost is based on CY2020.

Table 3-1: Current Energy Consumption and Cost, Transportation Facility

Metric	Usage (unit/yr.)	Cost ($)	Unit Cost ($/unit)
Electricity, Main Service (kWh), CY2019	641,000	$116,000	$0.19/kWh
Electricity, CNG Service (kWh), CY2019	613,000	$146,000	$0.24/kWh
Electricity, Total (kWh), CY2019	**1,255,000**	**$262,000**	**$0.21/kWh**
CNG, Total (Therms), CY2020	832,500	$1,099,000	$1.32/Therm
Total Energy Cost, Electricity & Gas, $	**-**	**$1,361,000**	**-**

3.2 Future Expected Annual Energy Usage

Figure 3-1 and Table 3-2 summarize the energy usage over time with increased adoption of BEBs. The energy consumption in Figure 3-1 is disaggregated between CNG Fuel (therms), and electricity use on the existing Main and CNG meters, and future EV meter.

CTE provided Sage with 15-minute interval weekly charge profiles for the BEBs from 2022 to full build-out in 2028. These weekly charge profiles were utilized by Sage to generate annual profiles to estimate total annual electricity usage on the future EV meter.

The CNG meter electricity consumption and fleet related CNG fuel consumption is assumed to be phased-out, with significant new load from future BEB charging. A small portion of electricity use at the CNG meter is shown at full fleet electrification to account for usage from the remaining fuel stations (diesel, unleaded) and bus vacuum/bus wash; based on information provided by CCB.

Figure 3-1: Future Expected Energy Usage, Transportation Facility

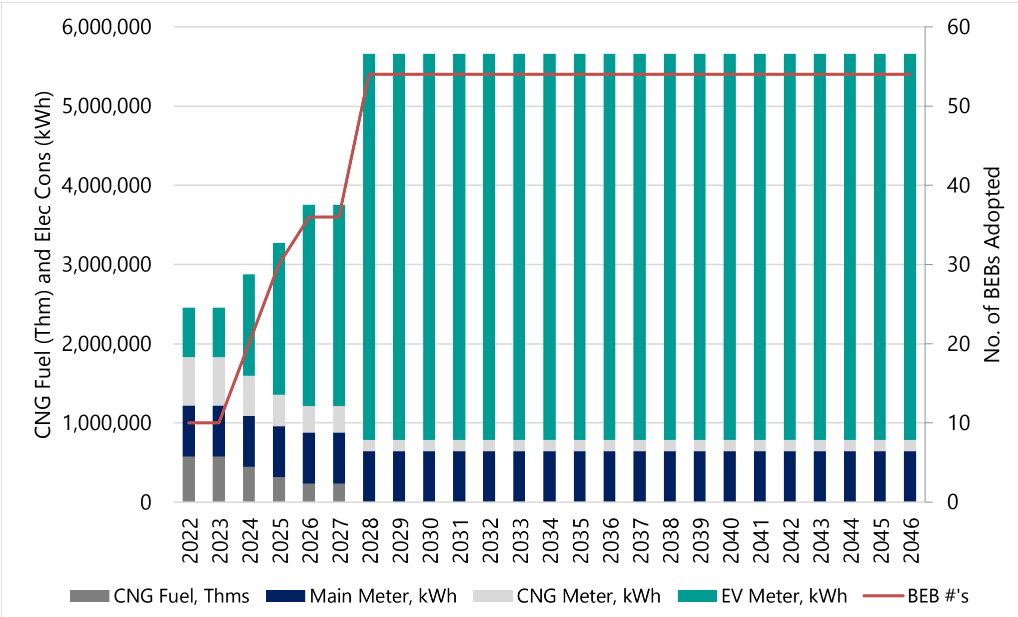


Table 3-2: Future Energy Usage Impact Summary, Transportation Facility

	Baseline, 2019	First BEBs Adopted, 2022	Full Buildout, 2028-2046
No. of BEBs Adopted	0	10	54
Electricity Total, kWh[1]	1,255,000	1,877,000	5,656,000
Delta from Baseline, %		+50%	+351%
CNG Fuel Total, therms[2]	708,000	577,000	0
Delta from Baseline, %		-19%	-100%

1. Electricity Total is a combination of the existing Main and CNG meters, and future EV meter.
2. CNG Fuel consumption over time has been linearly scaled based on the CNG bus phase-out plan provided by CTE.

3.3 Future Expected Annual Energy Cost without Solar PV, LCFS or RINS credits

Figure 3-2 and Table 3-4 shows the changes in energy cost over time with added electricity from the BEBs and elimination of CNG fuel consumption. The costs shown do not include LCFS-RINS credits and savings from onsite solar PV. CNG fuel costs are based on estimates provided by CTE, while the utility energy costs have been escalated at 3% per year. See Attachment A for a detailed summary of the cost escalation assumptions.

The utility energy cost of BEB charging on the EV meter has been modeled using Clean power Alliance's (CPA) TOU-9-EV Tariff supplied with 100% renewable electricity. This tariff does not currently have demand charges through February 2024. Beginning in March 2024, the demand charges will be phased in over 5 years. While CPA has not published the expected demand charges that will be phased-in, Sage utilized publicly available information to approximate the demand charges; sources of the information and the demand charge assumptions can be found in Attachment A. Given that the demand charges assumed are approximated, the utility cost modeling for the EV service is sensitive to these assumptions.

Figure 3-2: Future Expected Energy Cost without Solar PV, LCFS and RINs Credits

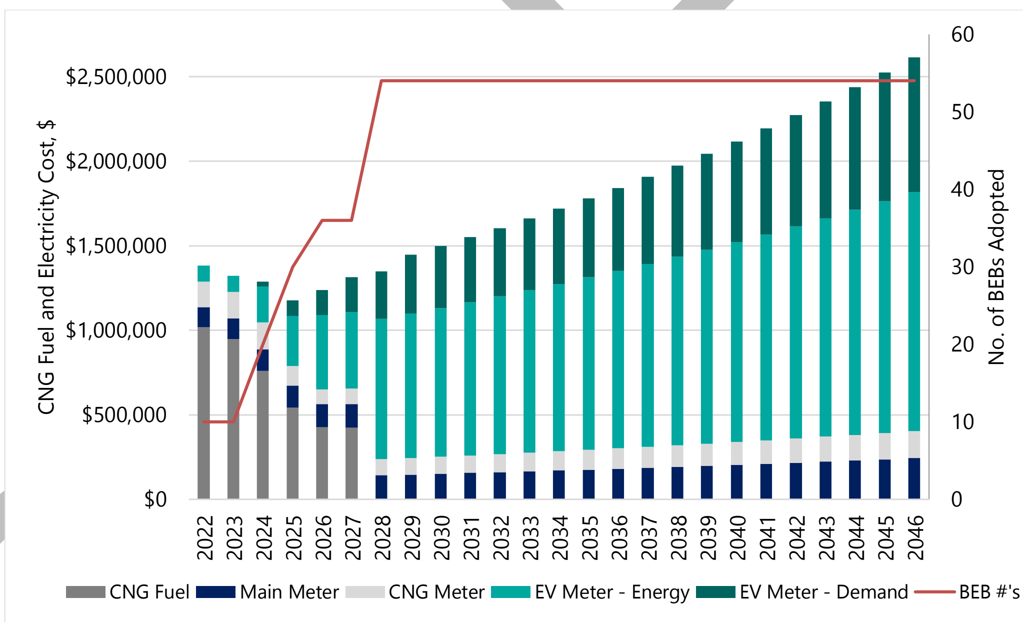


Table 3-3: Future Energy Cost without Solar PV, LCFS and RINs Credits

	Baseline, 2019	First BEBs Adopted, 2022	Full Buildout, 2028	Full Buildout, 2046
No. of BEBs Adopted	0	10	54	54
Total Energy Cost, $[1]	$1,361,000	$1,382,000	$1,349,000	$2,615,000
Delta from Baseline, $		$21,000	($12,000)	$1,254,000
Delta from Baseline, %		2%	-2%	92%

1. Total fuel cost is inclusive of CNG fuel and cost of electricity on the Main, CNG and EV meters.

3.4 Future Expected Annual Energy Cost with Solar PV, LCFS and RINs Credits

Figures 3-3 and 3-4 show the changes in energy cost (CNG fuel and cost of electricity on the Main, CNG and EV meters) over time inclusive of savings from LCFS-RINs credits and savings from onsite solar PV. The assumptions detailing how the cost of electricity is escalating over time is detailed in Attachment A. Some key takeaways:

- CCB would save approximately ~$556,000 on average per year from LCFS and RINs credits between 2022-2030, while onsite solar PV would generate an average of ~$40,000-$165,000 in savings per year (not including capital cost and annual operating costs) depending on whether CCB elects to implement a smaller rooftop PV system or larger rooftop + canopy solar PV system. The two solar PV implementation options with associated financial analysis is detailed in Section 5. The LCFS and RINs credits analysis is detailed in Section 4.
- Under Rooftop PV only scenario, CCB would save a total of ~6M from PV, LFCS and RINs (~$5M in LCFS/RINs credits, ~$1M in PV savings not including capital and soft costs), which represents savings of approximately 13% of the total cumulative fuel cost of $44.6M between 2022 and 2046.
- Under the Rooftop + Canopy PV scenario, CCB would save a total of ~9M from PV, LFCS and RINs (~$5M in LCFS/RINs credits, ~$4M in PV savings not including capital and soft costs), which represents savings of approximately 20% of the total cumulative fuel cost of $44.6M between 2022 and 2046.

Figure 3-3: Future Energy Cost with Rooftop PV, LCFS and RINs Credits

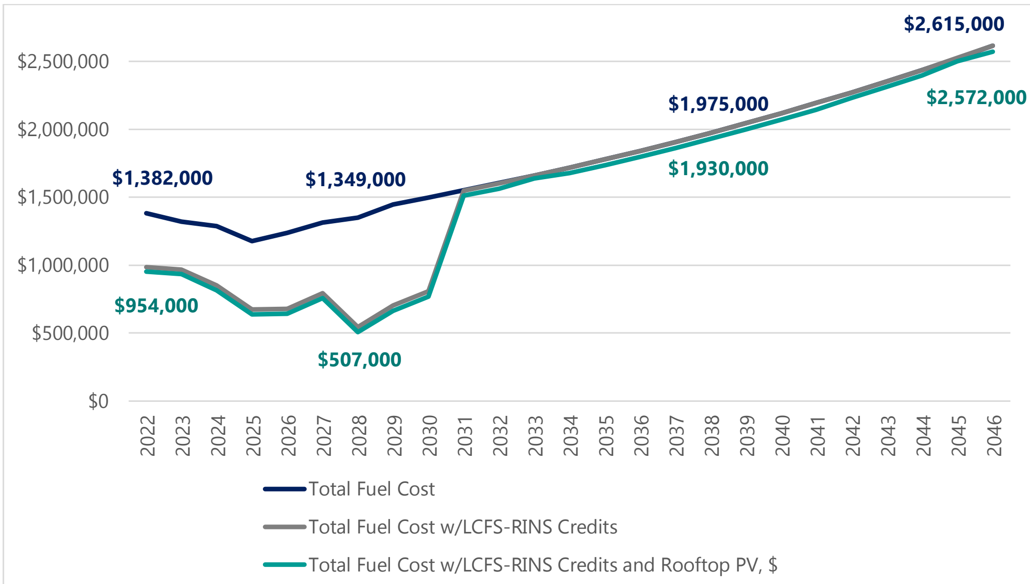
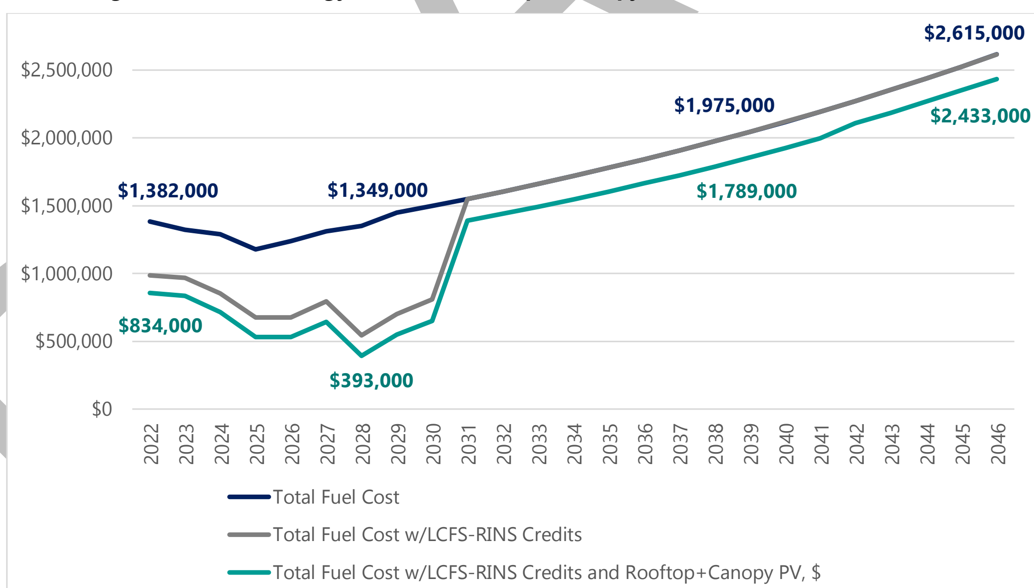


Figure 3-4: Future Energy Cost with Rooftop + Canopy PV, LCFS and RINs Credits



4. LCFS and RINs Credits Analysis

4.1 LCFS Credits

Sage estimated the annual Low-Carbon Fuel Standard (LCFS) credits generated by displacing fossil fuel consumption with clean electricity powered BEBs. The LCFS program is aimed at reducing carbon emissions in the transportation sector by increasing the use of low-carbon transportation fuels and reducing the use of fossil-based fuels. This is achieved by providing cash incentives for units of fossil fuel replaced by a low-carbon fuel.

The magnitude of the cash incentives depends on the selected low-carbon fuel and fossil fuel being replaced. These credits were estimated with input from SREC Trade and Clean Energy (current LCFS manager for CCB). Specifically, the LCFS credits were calculated for:

1. Current CNG Fleet consuming RNG against a baseline of Diesel fuel.
2. Future BEB fleet consuming electricity against a baseline of Diesel fuel.

Sage assumed this project would utilize the Zero-CI Electricity pathway from the LCFS pathway options. This pathway is available when replacing fossil fuel with electricity from zero-emission sources such as solar PV and wind. This pathway allows the use of Renewable Energy Certificates (RECs) generated from an onsite PV system, RECs purchased from the market, or through a 100% green utility tariff to meet the Zero-CI pathway requirements. RECs used for the Zero-CI pathway must be registered with WREGIS (Western Renewable Energy Generation Information System) and must be retired in WREGIS on behalf of the LCFS program on a quarterly basis. The number of RECs that are retired needs to be equivalent to the electricity consumed by the BEBs.

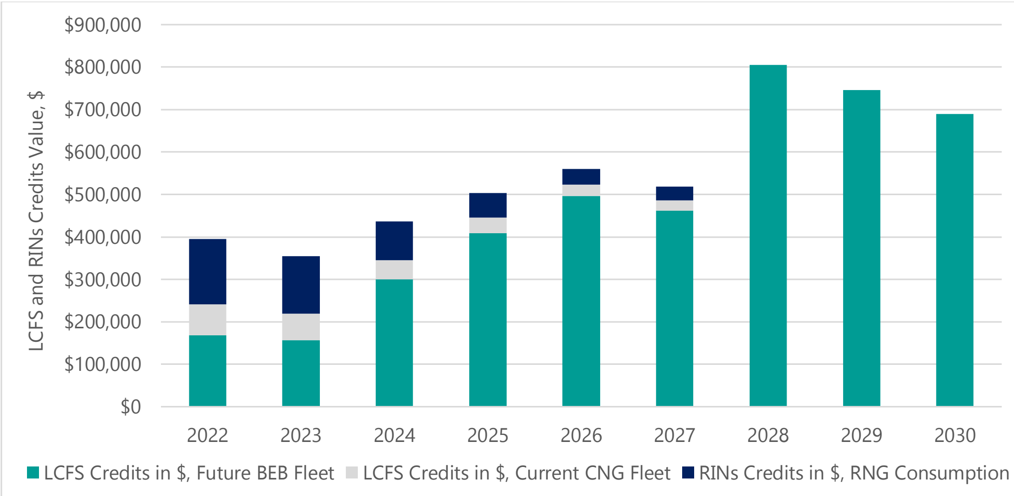
The value of LCFS credits estimated and shown in Figure 4-1 are conservative and assumes that CCB would retire RECs generated from the PV system in favor of the LCFS program; and cover any additional REC requirements through purchase in the open market. In reality, it is likely that CCB would be able to utilize RECs generated from the purchase of 100% renewable electricity from CPA; but CPA support would be needed to retire RECs in favor of the LCFS program. At the time of writing this report, CPA is still in the process of developing their LCFS support program and no details are available. Economics of the CPA program should be compared against a CCB-managed effort once CPA finalizes their program.

As shown in Figure 4-1, the LCFS program is currently slated to end in 2030, although it is likely that the program could be extended. The LCFS and RINs credits generated from the current CNG fleet would end in 2027 when all CNG buses are replaced with BEBs. The assumptions used in estimating the LCFS credits are detailed in Attachment D.

4.2 RINs Credits

RINs are generated when renewable fuel such as RNG or ethanol is made and is purchased by refiners and fuel importers when blending these renewable fuels with fossil fuel. The RINs are then released and usable as credits for generators and users of the renewable fuels. These credits are utilized by Environmental Protection Agency (EPA) to mandate and track the use of renewable fuels in the US. CCB would generate RINs credits through the use of RNG until full fleet replacement with BEBs by 2028, as shown in Figure 4-1. The assumptions used in estimating the RINs credits are detailed in Attachment D.

Figure 4-1: Estimated Annual LCFS and RINs Credit Value (2022-2030)



It is important to note that while conservative assumptions have been used to estimate the value of LCFS and RINs credits, these can significantly vary depending on how the LCFS and RINs credit prices vary over time.

5. Onsite Generation with Solar Photovoltaic (PV) Systems

Conceptual solar PV system designs were prepared with the following overarching goals:

- Maximize production in available area with cost-effective design options.
- Maximize offset of onsite consumption with renewable generation from solar PV.

5.1 PV System Sizing

The PV system designs were developed using HelioScope solar design software. The two following preliminary layouts were prepared and sought to maximize production within the available area using cost efficient layouts:

1. Rooftop PV on the main building.
2. Rooftop PV on the main building + Canopies on the existing parking garage and new parking garage structure being considered by CCB within the Facility Yard.

Updated PV siting and sizing can be provided for proposed changes in Facility layout as the planning process progresses. The Helioscope modeling assumptions and solar PV layout concepts can be found in Attachments A and B, respectively. Attachment B also contains pictures and design considerations for the canopy structures. Table 5-1 summarizes the main metrics from the modeling below.

Table 5-1: PV System Sizing and Expected Production

PV Option	System Size (kW_p)	Yr-1 Yield (kWh/kWp)	Yr-1 Production (kWh)[1]	Yr-1 Carbon Offset (Metric Tons CO_2)[2]
Rooftop PV Only	195	1,605	313,000	60
Rooftop + Canopy PV	750	1,600	1,198,000	230

1. PV system output declines over time, conservatively assumed ~0.75%/year.

5.2 Consumption Offset Over Time

Figures 5-1 and 5-2 show the increase in electricity usage over time, alongside PV production from Rooftop PV Only and Rooftop + Canopy PV alternatives, respectively. The electricity usage over time is an aggregate of:

1. Site consumption from building.
2. New load from phased adoption of BEB (from charge analysis conducted by CTE).
3. Declining usage on CNG meter, based on phased replacement of CNG buses.

Under the Rooftop PV only scenario, the PV system offsets ~17% of the total site load in 2022 and declines to 5% by 2046 with increasing BEB loads and declining PV output. In comparison, the Rooftop + Canopy PV alternative offsets ~64% of the total site load in 2022 and declines to 18% by 2046.

Figure 5-1: Rooftop PV Only, Annual Electricity Consumption and PV Production (kWh)

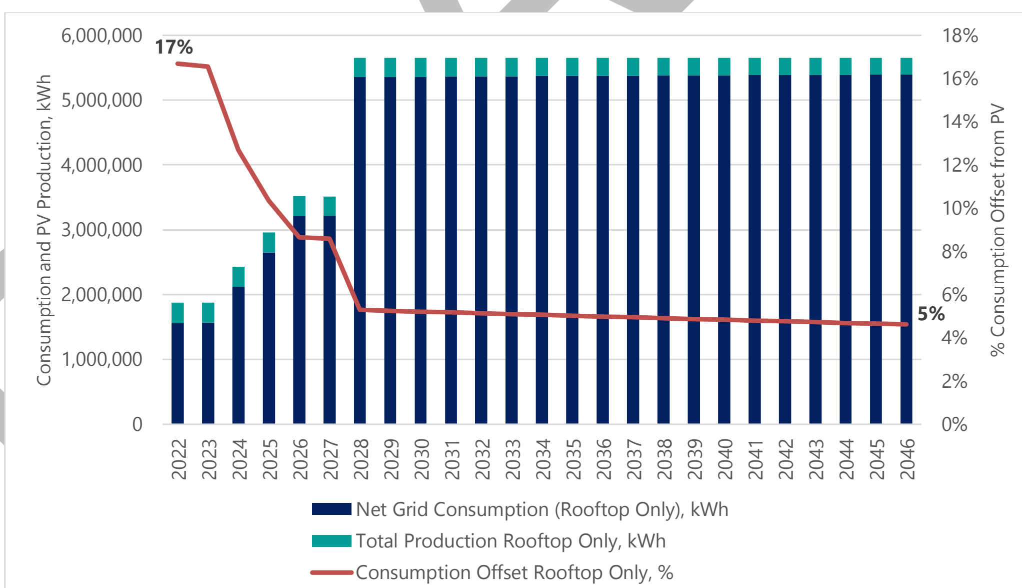
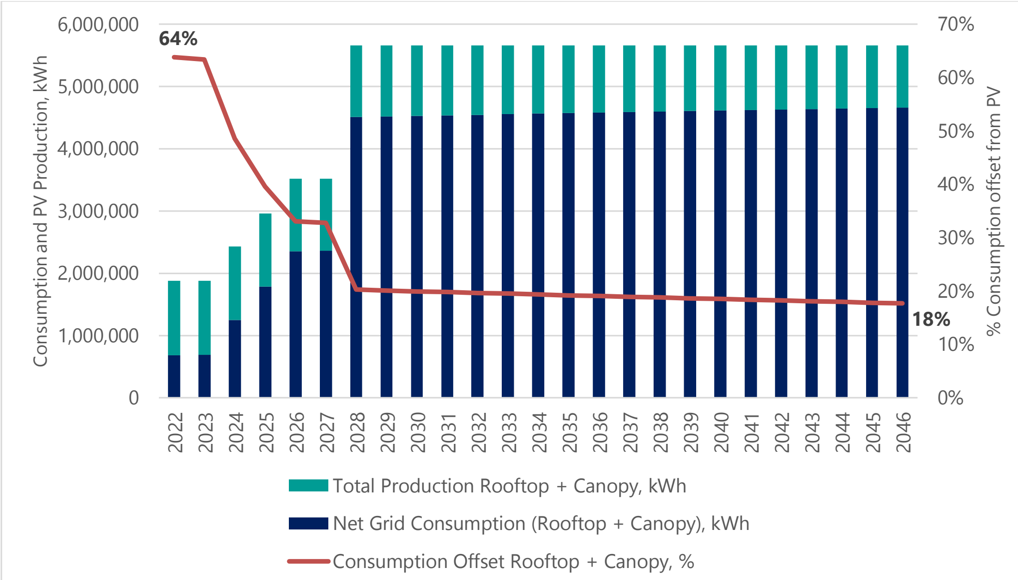


Figure 5-2: Rooftop + Canopy PV, Annual Electricity Consumption and PV Production (kWh)



5.3 Utility Tariff Analysis Results

Sage conducted tariff modeling using actual building consumption data from SCE, simulated BEB consumption data from CTE and simulated Helioscope PV production data. Table 5-2 shows the Year-1 gross savings, bill offset, and value of PV energy.

The proposed PV system would interconnect to the grid under a Net Energy Metering Aggregation (NEMA) arrangement. Under NEMA, a single site with multiple meters on the same property, or on the customer's adjacent or contiguous property, can use renewable energy generation to serve their aggregated load behind all eligible meters through a single point of interconnection. This arrangement is typically considered for sites with multiple meters on same parcel or adjacent parcels.

At the Transportation Facility, solar PV would interconnect on the existing main meter (generating account), offsetting electricity consumed at that service as well as the adjacent CNG and EV meters (load or benefitting accounts). Energy not consumed directly on the main meter would be exported to the grid and would be virtually allocated to all accounts in the NEMA arrangement based on the proportion of the most recent year's usage for each meter.

The analysis assumed the proposed solar project would be interconnected under the NEM 2.0 Guidelines. NEM 2.0 is grandfathered for 20 years from the date of initial operation of the additional solar PV system, after which point, exported energy is expected to have significantly lower value under NEM 3.0 or future NEM program iterations. See Section 8 for additional details about NEM 3.0.

Table 5-2. Utility Tariff Analysis Results (Yr-1)

PV Option	Cash Purchase			Power Purchase Agreement (PPA)		
	Yr-1 Gross Savings[1]	Bill Offset, %	Value of Energy, $/kWh	Yr-1 Gross Savings	Bill Offset, %	Value of Energy, $/kWh
Rooftop PV Only	$33,000	9%	$0.105	($2,000)	(1%)	($0.01)
Rooftop + Canopy PV	$131,000	37%	$0.110	($31,000)	(9%)	($0.03)

1. Gross Nominal Savings includes electrical savings minus operating costs and assumes NEM 2.0 tariff.

While gross savings under a PPA is negative in Year-1, CCB is likely to generate savings over the PPA term by hedging against rising utility rates using a flat $/kWh PPA price (0% annual escalator).

5.4 25-Year Lifecyle Modeling

Sage performed financial modeling to determine the anticipated financial performance of the two PV system options over a 25-year system lifetime. The analysis includes initial capital costs as well as ongoing operating costs, equipment replacement and system degradation over time. While 25 years is considered a typical life for a PV system for modeling purposes, the system can continue to operate well past this period with ongoing maintenance.

The financial analysis evaluated financing the system via cash purchase or third-party financed Power Purchase Agreement (PPA). The cash purchase does not include any incentives or grants since there are no current programs California or federal programs for public entities. The PPA analysis assumes the private system owner would leverage federal tax incentives for renewable energy projects. Financial performance of the project would improve markedly if any additional incentives or grants could be secured for the project. A comparison of these two financing mechanisms can be found in Section 7.

Table 5-3. 25-Year Solar Nominal and NPV Savings

Site Name	Cash Purchase			Power Purchase Agreement (PPA)		
	Gross Nominal Savings, $	Net Nominal Savings, $	NPV Savings, $	Gross Nominal Savings, $	Net Nominal Savings, $	NPV Savings, $
Rooftop PV Only	$970,000	$305,000	$40,000	$298,000	$219,000	$117,000
Rooftop + Canopy PV	$4,129,000	$317,000	($819,000)	$720,000	$278,000	($14,000)

A summary of the financial analysis is shown in Table 5-3; and charts showing Net Nominal Savings over time for the two PV system options are shown in Figures 5-3 and 5-4. The modeling methodology and key financing assumptions have been detailed in Attachment A, and Attachment C provides the 25-year cash flow tables.

Figure 5-3: 25-Year Savings Rooftop PV Only, Net Nominal $

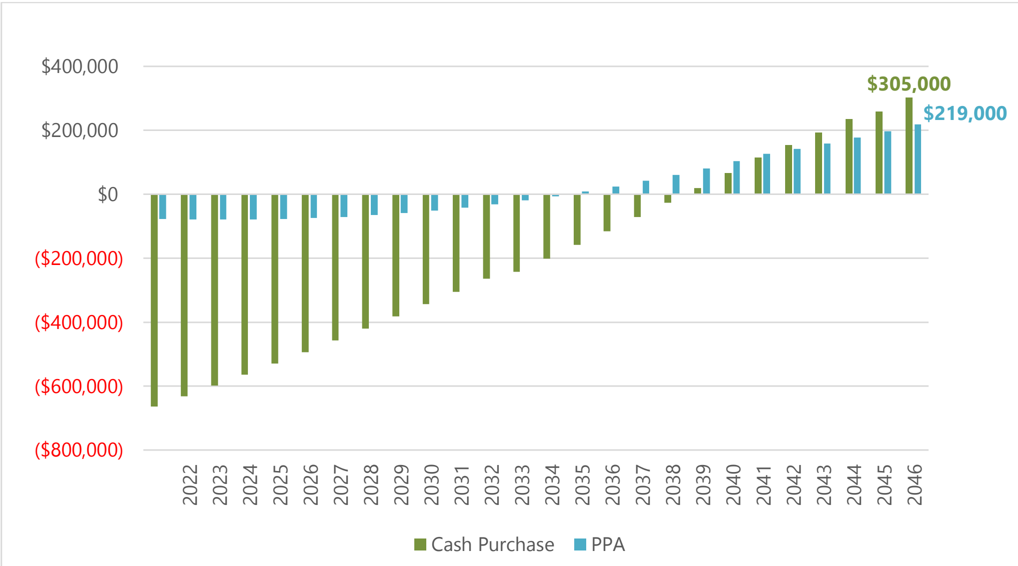
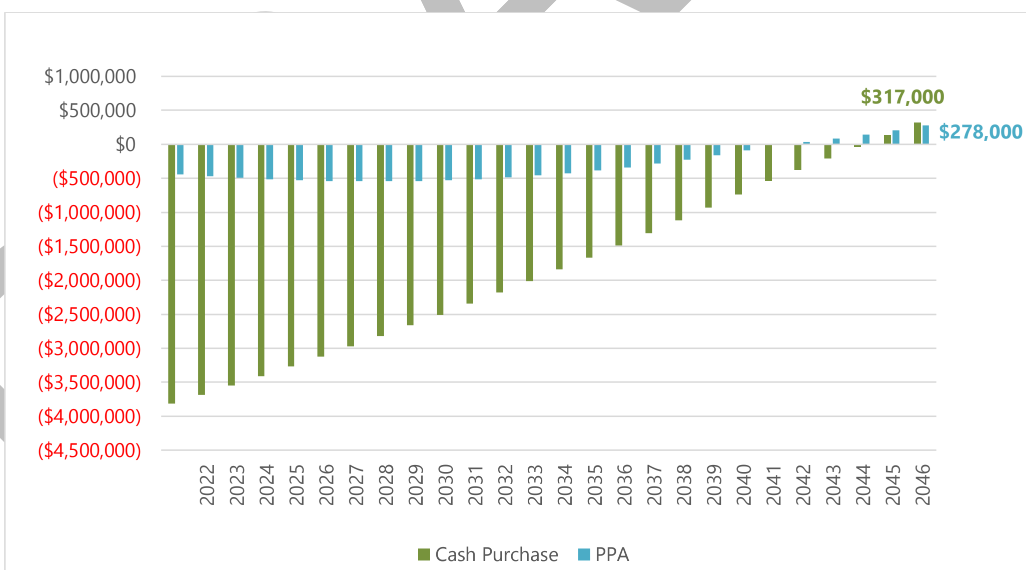


Figure 5-4: 25-Year Savings Rooftop + Canopy PV, Net Nominal $



6. Stationary Battery Energy Storage System (BESS)

6.1 BESS Analysis Summary

The inclusion of BESS at the Transportation Facility was considered in two ways:

1. Paired BESS with Solar PV on the Main Service. The BESS sizing and performance was determined using industry-standard design software, Energy Toolbase. The performance for a range of system sizes and durations was simulated to assess utility cost savings vs. size/duration curves for each site. The savings curves were used to determine optimum BESS size beyond which the incremental savings are negligible compared to the increased capital cost. This optimum BESS size was then aligned to commonly available BESS size increments in the market. Based on this analysis, a 125 kW/500 kWh BESS was modeled. A 10-year lifecycle modeling of the BESS showed that the additional savings from the paired system are not sufficient to overcome the cost of installing the BESS through cash purchase, even with Self Generation Incentive Program (SGIP) incentives.
2. Stand-alone BESS on the EV Service. This is not a viable option because a distributed energy resource like BESS cannot be connected to a meter/service that is already part of a NEMA arrangement. Additionally, a combined PV and BESS system could not be connected to the EV meter due to current SCE rules for a service utilizing the commercial TOU-EV tariffs. A further limitation is that a stand-alone BESS charging from the grid cannot export to the grid according to current SCE interconnection rules. This limits a key value stream, Energy Arbitrage through which savings are derived by charging the battery during times of low-cost electricity and discharging during times of high-cost electricity.

The financial analysis focused on current available utility tariffs and does not forecast future benefits or attempt to quantify indirect benefits. Additional potential benefits not quantified include:

- Additional value streams besides the behind-the-meter retail tariff management (demand management and arbitrage) are beginning to emerge, such as grid services (e.g. resource adequacy, demand response, frequency regulation, etc.). These new value streams have the potential to increase the value of BESS systems in the future. For example, CCAs, such as CPA, are utilizing and incentivizing distributed energy storage for grid services.
- While the savings analysis applies current retail tariffs to the proposed systems, new tariffs in the future could improve savings. For instance, in PG&E territory, the utility recently released an Option S tariff that adds considerably more value to BESS systems. A similar tariff may be introduced in SCE territory in the future, however, is not currently available.
- The BESS also helps in carbon emissions reduction by shaping site demand to align with the grid needs i.e. consume during times of excess renewables in the grid during midday and discharge during high carbon intensity periods in the evening.
- Resiliency has not been quantified in this study, however public entities are increasingly placing a value on the ability to operate during grid outages and avoid the cost of diesel gensets. See Section 6.2 for further discussion of BESS in resiliency applications.

6.2 BESS Resiliency Application

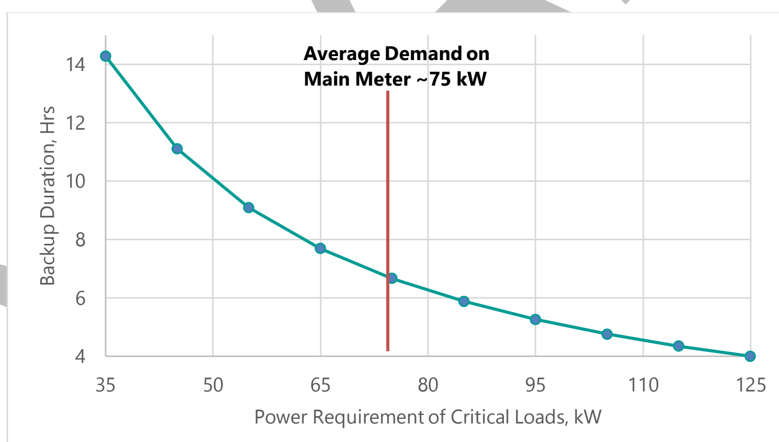
As discussed in Section 6.1, there is no financial driver for installing a BESS at the Transportation Facility for retail tariff management. However, a BESS can offer backup capabilities in the event of a grid outage that could aid CCB in powering critical building or BEB loads. Table 6-1 compares the backup capability of two BESS sizes with associated cost and footprint requirements.

Table 6-1: BESS Resiliency Application Options

Metric	Small BESS on Main Service 125 kW/500 kWh	Larger BESS for EV Charging 750 kW/3 MWh
Est. Capital Cost, $[1]	$700,000	$3,000,000
Backup Capability	Critical Load Dependent (see Figure 6-1)	~5 x 450 kWh charges
BESS Footprint	375 SF (<2 standard parking spaces)	~900 SF (~5 standard parking spaces)

1. The Small BESS would be eligible for the Self Generation Incentive Program (SGIP) incentive of $350/kWh ($175,000).
2. The Larger BESS (e.g. a Tesla Megapack) would not be eligible for SGIP incentives because the kW size would exceed the previous 12-month max demand on the main meter (beyond SGIP limit). If SCE changes rules for a BESS system connected on an EV service, the BESS could interconnect on that service and the SGIP incentive could be applied.

Figure 6-1: Backup Duration by Power Requirement of Critical Loads (125 kW/500 kWh BESS)



This analysis assumes liquid lithium chemistry since this is the dominant technology in the market and the most space-efficient. A 4-hour battery has been assumed where the BESS can discharge at maximum rated power for 4 hours continuously. Commercial lithium batteries typically range from 1-hour to 4-hour. As shown in Figure 6-1, the 125 kW/500 kWh BESS can discharge at full power for 4 hours or at a lower power for longer. CCB's resiliency requirements require further study to inform a preference or mix of higher power rating-longer duration BESS or lower power rating-shorter duration BESS. Available area for a BESS at the facility is also an important consideration given the limited available footprint at the Transportation Facility and various code constraints on BESS siting.

7. Solar PV Financing Options

Two financing mechanisms have been discussed in this study:

1. **Cash Purchase**: In a Cash Purchase Agreement, CCB finances the projects and owns the PV system, accruing all the financial savings. Cash purchase also encompasses grant funding and would be part of the capital stack used to finance the project. CCB would be responsible for the cost of ownership, including O&M, equipment replacement, etc.
2. **Power Purchase Agreement (PPA):** Financing through a Power Purchase Agreement (PPA) is a Public Private Partnership where a private third-party funds, owns, and operates the systems, and CCB purchases power at a fixed price for a contracted period of 20-25 years from the third party. CCB can also choose to buy out the system at certain time intervals negotiated in the PPA contract. Buyout options typically become available in year 7, year 12-15, and year 20. A buyout is an indirect way of taking advantage of federal tax incentives while still achieving ownership after a period of time.

The pros and cons of each financing option are detailed in Table 7-1.

Table 7-1: Financing Options, Pros and Cons

Financing Type	Pros	Cons
Cash Purchase	• Highest energy savings. • No privately owned assets on City property or long-term agreement with a private entity.	• Large upfront investment. • CCB responsible for O&M. • Federal Investment Tax Credit (ITC) and MACRS (Modified Accelerated Cost Recovery System) not available.
Power Purchase Agreement (PPA)	• No large upfront investment. • No O&M burden. • Predictable electricity rate. • ITC and MACRS apply to developer such that CCB benefits with lower prices. • PV system performance guarantee from vendor.	• Net savings less than those available via cash purchase. • Long term (20-25 year) contracts with private entity and City hosting privately owned assets.

8. Key Considerations

8.1 EV Tariff

The energy cost of BEB consumption on the EV meter was modeled on the TOU-EV-9 tariff. This tariff encourages off-peak (9 pm-8 am) and super-off-peak charging (8am-4 pm). And for early adopters of EVs, there are no demand charges currently through February 2024. Demand charges will be phased in incrementally to hit full demand charges by 2029. There are currently no published values for these demand charges, nor any indication of how the energy charges would change with demand charge phase-in. Sage utilized publicly available information to approximate demand charge increase over time; sources of this information and approximated demand charge assumptions can be found in Attachment A.

8.2 Third Party Financing and Federal ITC

For third-party financed projects such as a PPA, The ITC is a federal tax credit that allows renewable energy customers and developers that are taxable entities to deduct 26% of the system installed cost from their federal taxes. The ITC level is scheduled to drop to 22% in 2023 and set at 10% for commercial customers after 2025. Any project commencing after 2022 would likely see increasingly higher PPA prices corresponding to the ITC stepdown.

8.3 Net Energy Metering (NEM) 2.0 Grandfathering

Per the NEM rules, a PV system is grandfathered on the active NEM version for 20 years from the date the system is interconnected. The transition to NEM 3.0, the successor to NEM 2.0, is expected to occur in Q2/Q3 2022 in Investor-Owned Utility (IOU) territories. NEM 3.0 is expected to reduce the value of solar PV generated energy by up to ~20-25% based on conservative assumptions. We recommend that CCB grandfather the proposed PV system under NEM 2.0 by finalizing an interconnection application with SCE prior to the end of Q4 2021.

The analysis presented in this memo assumed the planned project will be grandfathered under NEM 2.0 regulations for 20 years which govern the value of energy exported to the utility grid when PV production exceeds onsite consumption.

8.4 Plan for Future BESS

Cost efficiencies can be gained by planning for future BESS implementation during any work on energy infrastructure. This includes adding spare conduits during PV system installation, including future BESS capacity in any service panel upgrades, and by reserving footprint (as indicated in Section 6.2) for the BESS as close to the main service as possible. Spare conduits should be provided from the main service to the nearby reserved BESS area.

The BESS would ideally be connected to the load-side of the main switchgear via breaker. If the main service is being modified for the solar PV project, accommodation should be made for a load-side breaker to accommodate BESS. A supply-side tap is also feasible for BESS implementation, should load-side capacity be insufficient.

8.5 EVSE and Solar PV

Ground-Mounted EVSE - "Ground-mounted" EVSE can be co-located with solar canopies. Solar canopy columns can be used for mounting of EVSE equipment; however, columns are typically not spaced close enough to provide a mounting location for all stations. Additional pedestal-mounted EVSE would be required for the gaps between columns (columns are typically spaced 25–30-ft apart) if the intent is to provide charging for each parking bay. Charging pedestals would typically be sited in alignment with the columns and bollards would be required to protect the equipment. Unique canopy installations, such as trellises or other non- "T"-shaped canopies would require site-specific review to determine if columns are conveniently located to charging ports on the vehicles.

Underground duct banks typically route the conductors to each charging station. Electrical switchboards, inverters, and any other ancillary equipment (often packaged and referred to as "power packs" or power control systems) for the chargers would be pad-mounted and require additional footprint, however, this equipment does not necessarily need to be local to the charging station. Pad mounted footprint can be substantial for a large bank of Level 3 chargers, with size varying with the number of chargers and the power supplied to each charger. For example, the Proterra power control cabinet for a 125kW charger occupies a footprint of 8.3 SF and the 60kW occupies a footprint of 5.2 SF. 2 to 3 times this area should be reserved per charger installation to achieve clearance requirements, install bollards, and to site ancillary equipment.

Overhead EVSE - Overhead Level 3 cable chargers are possible and can be adapted to typical "T"-shaped solar canopies. The weight and location of the chargers would have to be considered in the structural design of the canopy; however, this should not require excess modification to the structure's design, assuming the large power control equipment is ground-mounted.

Pantograph-style chargers would require custom canopy design. Siting pantographs on solar canopies would likely require trellis-style canopies or more substantial and custom structures for cantilevered canopies. Clear-heights would need to increase considerably and more structural steel components would be required. Canopy costs for pantograph style charging would be considerably more expensive than the standard "T"-shaped solar canopies envisioned in this study.

Attachment A

Solar PV Production, BESS, and Financial Modeling Assumptions

PV Solar Production and BESS Modeling Assumptions

A.1 PV and BESS Modeling Assumptions

Solar PV and BESS model assumptions are detailed in Table A-1 and A-2, respectively.

Table A-1. PV Model Assumptions

Solar Production Modeling	
Solar Insolation Data	Santa Monica, NSRDB (TMY3, II)
Shading Assumption	Minimal based on siting
Soiling Assumption	~3% monthly soiling loss assumed
PV Modules used in Helioscope	LG Electronics, 420N2W-V5, 420 Watt
Inverters used in Helioscope	SMA Sunny Tripower (50-60 kW) String Inverters
Installation type	Carport Canopy, Rooftop
PV System Lifetime	25 years
Annual Degradation	0.75%

Table A-2. BESS Model Assumptions

BESS Modeling	
Batteries Power/Capacity	125 kW/500 kWh
Max Depth of Discharge	100%
Charge/Discharge Efficiency	89%/100%
Peak Shaving Efficiency	85%
BESS Lifetime	10 years
Annual Battery Degradation %	2%

A.2 Tariff Modeling

Sage performed tariff modeling using the Energy Toolbase solar analytics program, Sage's proprietary modeling, and SCE's currently active tariff schedules to determine cost offset for the Rooftop PV Only and Rooftop + Canopy PV options. As previously described, the financial modeling utilized building electricity consumption data from SCE, simulated BEB electricity consumption from CTE, and simulated production data modeled using industry-standard solar design software, HelioScope.

The analysis was conducted using currently active SCE tariffs, most recently revised in Feb 2021. Table A-3 summarizes the tariff assumptions used in the tariff analysis model.

Table A-3. Tariff Modeling Assumptions

Meter Name	Meter Number	Current Tariff	Tariff w/PV
Main Meter	259000-006983	TOU-GS-2D	TOU-GS-2E
CNG Meter	V349N-019045	TOU-GS-2E	TOU-GS-2E
EV Meter	New	TOU-EV-9	TOU-EV-9

A.3 Lifecycle Financial Modeling (25-Year)

Utilizing the results from the tariff modeling, 25-year lifecycle savings analysis was performed. Sage assumed the project would be grandfathered under NEM 2.0 regulations for 20 years, which currently govern the value of energy exported to the utility grid when PV production exceeds onsite consumption.

The solar PV and BESS financial models are greatly influenced by the assumptions. Modeling assumptions consider risks associated with changes in utility TOU schedules, rates, and conditions. Sage uses conservative assumptions across the board. System pricing assumptions are based on market knowledge from other similar projects and current industry trends. Utility escalation rates are based on historical averages over the past thirty years. If utility rates increase more over time in the future due to increased regulations, demand, and finite resources, the financial performance of the systems will be affected positively. Conversely, if rates increase slower than historical averages, the financial performance will be negatively affected.

Key financial assumptions, project capital cost and soft cost assumptions in Sage's financial modeling are shown in Tables A-4, A-5, and A-6, respectively.

Table A-4. Key Financial Modeling Assumptions

Metric	Value
Annual Utility Escalation	3%
Utility Tariff Degradation Risk	-0.50%
NEM 2.0 Export Energy Rate	Full retail rate, minus non-bypassable charges, for 20 years
NEM 2.0 Loss % (2042)	-15%
Discount Rate (for NPV calculations)	2.5%

Table A-5. EV Tariff Demand Charge Assumptions

Based on publicly available information sources, Demand Charges on the EV tariff are expected to be phased in ~17%/year between 2024-2029, with the demand charges in 2029 being ~60% of the facilities relate demand charge of a comparable non-EV tariff[1,2]. Sage utilized this information and current facilities related demand charges (on TOU-8 tariff effective February 2021) to approximate and escalate the EV tariff demand charges.

Yr.	Demand Charge, $/kW
2022	$0
2023	$0
2024	$2
2025	$4
2026	$6
2027	$9
2028	$11
2029	$14
2030	$14
2031	$15
2032	$16
2033	$17
2034	$17
2035	$18
2036	$19
2037	$20
2038	$21
2039	$22
2040	$23
2041	$24
2042	$26
2043	$27
2044	$28
2045	$30
2046	$31

[1] "SCE's new C&I rate plan, to be implemented March 1, offers a five-year demand charge holiday, SCE Director of Pricing Design and Research Russ Garwacki told Utility Dive. It will be followed by a five-year demand charge phase-in to a new demand charge 40% below the current charge".

[2] "Demand charges for customers on TOU-EV-7, TOU-EV-8, and TOU-EV-9 are scheduled to phase-in starting in 2024 and are projected to be 60% of the facilities related demand charge by 2029".

Table A-6. Project Pricing Assumptions

		Rooftop PV Only	Rooftop + Canopy PV
Design-Build Turnkey Project Cost[1]		$588,000	$3,375,000
PPA Rate, $/kWh		$0.14/kWh	$0.165/kWh
Project Development Soft Costs	~% of Build Cost	~Capital Cost Equivalent, $	~Capital Cost Equivalent, $
Contingency	5.0%	$29,000	$169,000
Consultant Fees	5.0%	$29,000	$169,000
Testing and Inspection Fees	1.0%	$6,000	$34,000
CCB Legal and Administration Fees	2.0%	$12,000	$68,000
Project Soft Cost Subtotal	**13.0%**	**$76,000**	**$439,000**
Total Project Cost		**$665,000**	**$3,814,000**

The build prices shown in Table A-6 are for standard, double cantilevered PV canopies. Facility reconfiguration, increased space constraints, overhead mounting of pantograph type chargers or a desire to increase onsite generation may require non-standard canopies, such as trellises, which could significantly increase these build costs.

Attachment B

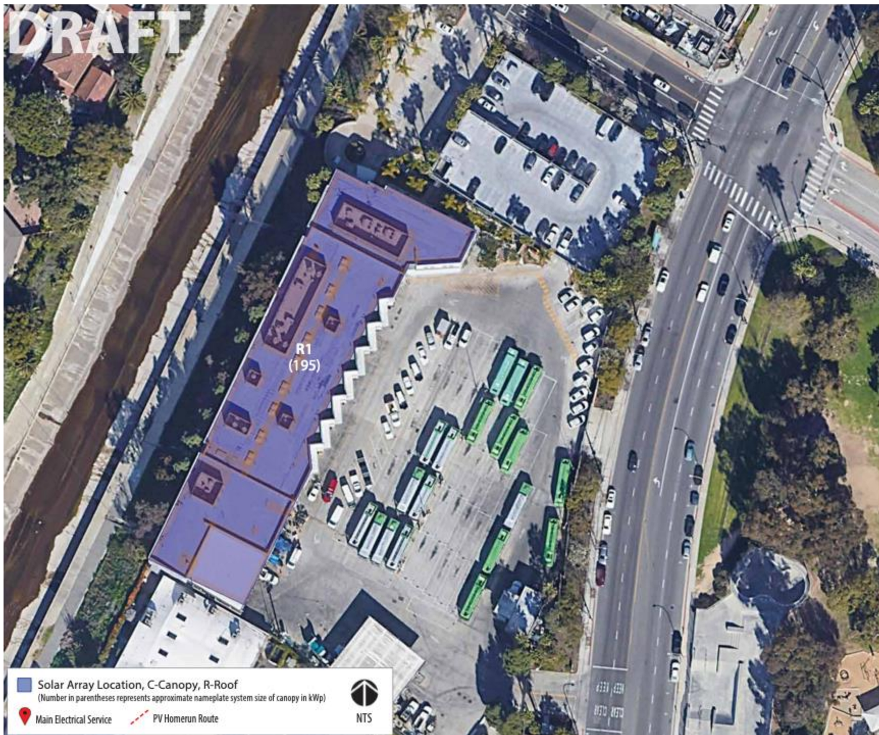
Solar PV Conceptual Layouts

Solar PV Conceptual Layouts

The PV concepts and analysis in this memo are based on solar canopy structures mounted on a standard double cantilevered canopy in a "T" configuration. Examples of a "T" configuration canopy are shown below. Key points about the canopy structures and electrical equipment discussed below:

- Canopy structures shown have a minimum clear height on 13' 6".
- Columns are spaced apart 25-30 ft along the center row.
- String inverters and panel boards are mounted on support structure columns.
- There is minimal need for ground space to locate other electrical equipment such as combiner panels.

CCB could also consider long span trellis-style PV structures, either flat and louvered or shallow slope, as shown in the pictures below. These structures would have columns along the perimeter, although columns may be required within the structure depending on span length. These structures are however ~50% more expensive than standard canopies due to their custom nature.



Culver City Bus Yard

4343 Duquesne Ave, Culver City, CA 90232

PV Shown

Group	Nameplate (kWp)	Year-1 Production (kWh)	Array Area (SF, Approx.)
R1	195	313,000	15,000

Notes

Culver City Solar, Preliminary Siting
7/16/2021

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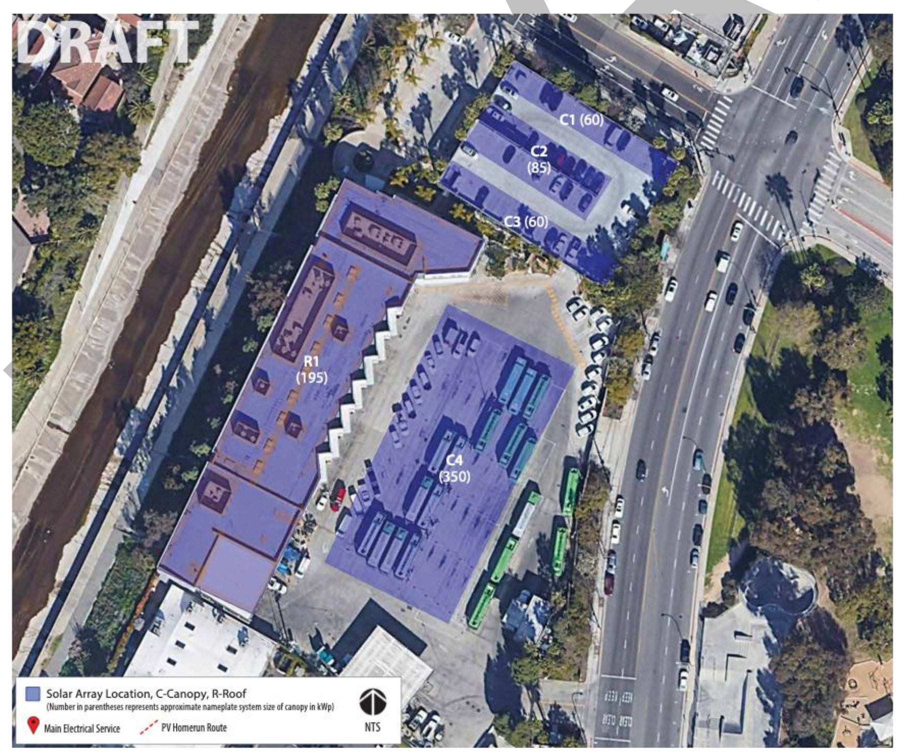

Culver City Bus Yard

4343 Duquesne Ave, Culver City, CA 90232

PV Shown

Group	Nameplate (kWp)	Year-1 Production (kWh)	Array Area (SF, Approx.)
R1	195	313,000	15,000
C1-C3	205	327,000	12,000
C4	350	558,000	21,000
Total	**750**	**1,198,000**	**48,000**

Notes

Culver City Solar, Preliminary Siting
7/16/2021

SAGE ENERGY CONSULTING

Attachment C

Detailed 25-Year Cash Flow

25-Year Solar PV Financial Analysis Cash Flows (Cash Purchase, PPA)

Table C-1. 25-Year Cashflow, Rooftop Solar PV (Cash Purchase)

Yr.	Est. Utility Cons. (kWh)	Annual Estimated Utility Cost w/o PV	Utility Energy Cost w/PV	Annual Savings w/o Operating Costs	PV Operating Costs	Gross Annual Savings	Cumulative Project Cash Flow
0							($665,000)
1	1,876,000	$364,000	$324,000	$40,000	$7,000	$33,000	($632,000)
2	1,876,000	$375,000	$334,000	$41,000	$8,000	$33,000	($599,000)
3	2,429,000	$529,000	$487,000	$42,000	$8,000	$34,000	($565,000)
4	2,957,000	$635,000	$592,000	$43,000	$8,000	$35,000	($530,000)
5	3,516,000	$810,000	$766,000	$44,000	$8,000	$36,000	($494,000)
6	3,516,000	$887,000	$842,000	$45,000	$8,000	$37,000	($457,000)
7	5,656,000	$1,349,000	$1,303,000	$46,000	$9,000	$37,000	($420,000)
8	5,656,000	$1,448,000	$1,401,000	$47,000	$9,000	$38,000	($382,000)
9	5,656,000	$1,498,000	$1,450,000	$48,000	$9,000	$39,000	($343,000)
10	5,656,000	$1,550,000	$1,501,000	$49,000	$9,000	$40,000	($303,000)
11	5,656,000	$1,604,000	$1,554,000	$50,000	$10,000	$40,000	($263,000)
12	5,656,000	$1,661,000	$1,610,000	$51,000	$29,000	$22,000	($241,000)
13	5,656,000	$1,719,000	$1,667,000	$52,000	$10,000	$42,000	($199,000)
14	5,656,000	$1,779,000	$1,726,000	$53,000	$10,000	$43,000	($156,000)
15	5,656,000	$1,842,000	$1,788,000	$54,000	$11,000	$43,000	($113,000)
16	5,656,000	$1,907,000	$1,852,000	$55,000	$11,000	$44,000	($69,000)
17	5,656,000	$1,975,000	$1,919,000	$56,000	$11,000	$45,000	($24,000)
18	5,656,000	$2,045,000	$1,987,000	$58,000	$12,000	$46,000	$22,000
19	5,656,000	$2,117,000	$2,058,000	$59,000	$12,000	$47,000	$69,000
20	5,656,000	$2,193,000	$2,133,000	$60,000	$12,000	$48,000	$117,000
21	5,656,000	$2,271,000	$2,219,000	$52,000	$13,000	$39,000	$156,000
22	5,656,000	$2,352,000	$2,299,000	$53,000	$13,000	$40,000	$196,000
23	5,656,000	$2,437,000	$2,383,000	$54,000	$13,000	$41,000	$237,000
24	5,656,000	$2,524,000	$2,468,000	$56,000	$31,000	$25,000	$262,000
25	5,656,000	$2,615,000	$2,558,000	$57,000	$14,000	$43,000	$305,000

Table C-2. 25-Year Cashflow, Rooftop + Canopy Solar PV (Cash Purchase)

Yr.	Est. Utility Cons. (kWh)	Annual Estimated Utility Cost w/o PV	Utility Energy Cost w/PV	Annual Savings w/o Operating Costs	PV Operating Costs	Gross Annual Savings	Cumulative Project Cash Flow
0							($3,814,000)
1	1,876,000	$364,000	$197,000	$167,000	$36,000	$131,000	($3,683,000)
2	1,876,000	$375,000	$204,000	$171,000	$36,000	$134,000	($3,549,000)
3	2,429,000	$529,000	$355,000	$174,000	$37,000	$137,000	($3,412,000)
4	2,957,000	$635,000	$453,000	$182,000	$38,000	$144,000	($3,268,000)
5	3,516,000	$810,000	$624,000	$186,000	$39,000	$147,000	($3,121,000)
6	3,516,000	$887,000	$697,000	$190,000	$40,000	$150,000	($2,971,000)
7	5,656,000	$1,349,000	$1,157,000	$192,000	$41,000	$151,000	($2,820,000)
8	5,656,000	$1,448,000	$1,252,000	$196,000	$42,000	$154,000	($2,666,000)
9	5,656,000	$1,498,000	$1,298,000	$200,000	$43,000	$158,000	($2,508,000)
10	5,656,000	$1,550,000	$1,345,000	$205,000	$44,000	$161,000	($2,347,000)
11	5,656,000	$1,604,000	$1,395,000	$209,000	$45,000	$164,000	($2,183,000)
12	5,656,000	$1,661,000	$1,448,000	$213,000	$46,000	$168,000	($2,015,000)
13	5,656,000	$1,719,000	$1,501,000	$218,000	$46,000	$172,000	($1,843,000)
14	5,656,000	$1,779,000	$1,557,000	$222,000	$47,000	$175,000	($1,668,000)
15	5,656,000	$1,842,000	$1,615,000	$227,000	$48,000	$179,000	($1,489,000)
16	5,656,000	$1,907,000	$1,675,000	$232,000	$49,000	$183,000	($1,306,000)
17	5,656,000	$1,975,000	$1,738,000	$237,000	$51,000	$186,000	($1,120,000)
18	5,656,000	$2,045,000	$1,803,000	$242,000	$52,000	$190,000	($930,000)
19	5,656,000	$2,117,000	$1,870,000	$247,000	$53,000	$194,000	($736,000)
20	5,656,000	$2,193,000	$1,941,000	$252,000	$54,000	$198,000	($538,000)
21	5,656,000	$2,271,000	$2,052,000	$219,000	$56,000	$163,000	($375,000)
22	5,656,000	$2,352,000	$2,128,000	$224,000	$57,000	$167,000	($208,000)
23	5,656,000	$2,437,000	$2,209,000	$228,000	$59,000	$170,000	($38,000)
24	5,656,000	$2,524,000	$2,291,000	$233,000	$60,000	$173,000	$135,000
25	5,656,000	$2,615,000	$2,377,000	$238,000	$56,000	$182,000	$317,000

Table C-3. 25-Year Cashflow, Rooftop Solar PV (PPA)

Yr.	Est. Utility Cons. (kWh)	Annual Estimated Utility Cost w/o PV	Utility Energy Cost w/PV	Annual Savings w/o PPA Payments	PPA Payments	Gross Annual Savings	Cumulative Project Cash Flow
0							($76,000)
1	1,876,000	$364,000	$324,000	$40,000	$42,000	($2,000)	($78,000)
2	1,876,000	$375,000	$334,000	$41,000	$42,000	($1,000)	($79,000)
3	2,429,000	$529,000	$487,000	$42,000	$42,000	$0	($79,000)
4	2,957,000	$635,000	$592,000	$43,000	$41,000	$2,000	($77,000)
5	3,516,000	$810,000	$766,000	$44,000	$41,000	$3,000	($74,000)
6	3,516,000	$887,000	$842,000	$45,000	$41,000	$4,000	($70,000)
7	5,656,000	$1,349,000	$1,303,000	$46,000	$40,000	$5,000	($65,000)
8	5,656,000	$1,448,000	$1,401,000	$47,000	$40,000	$7,000	($58,000)
9	5,656,000	$1,498,000	$1,450,000	$48,000	$40,000	$8,000	($50,000)
10	5,656,000	$1,550,000	$1,501,000	$49,000	$40,000	$9,000	($41,000)
11	5,656,000	$1,604,000	$1,554,000	$50,000	$39,000	$10,000	($31,000)
12	5,656,000	$1,661,000	$1,610,000	$51,000	$39,000	$12,000	($19,000)
13	5,656,000	$1,719,000	$1,667,000	$52,000	$39,000	$13,000	($6,000)
14	5,656,000	$1,779,000	$1,726,000	$53,000	$38,000	$15,000	$9,000
15	5,656,000	$1,842,000	$1,788,000	$54,000	$38,000	$16,000	$25,000
16	5,656,000	$1,907,000	$1,852,000	$55,000	$38,000	$17,000	$42,000
17	5,656,000	$1,975,000	$1,919,000	$56,000	$37,000	$19,000	$61,000
18	5,656,000	$2,045,000	$1,987,000	$58,000	$37,000	$20,000	$81,000
19	5,656,000	$2,117,000	$2,058,000	$59,000	$37,000	$22,000	$103,000
20	5,656,000	$2,193,000	$2,133,000	$60,000	$37,000	$23,000	$126,000
21	5,656,000	$2,271,000	$2,219,000	$52,000	$36,000	$16,000	$142,000
22	5,656,000	$2,352,000	$2,299,000	$53,000	$36,000	$17,000	$159,000
23	5,656,000	$2,437,000	$2,383,000	$54,000	$36,000	$19,000	$178,000
24	5,656,000	$2,524,000	$2,468,000	$56,000	$36,000	$20,000	$198,000
25	5,656,000	$2,615,000	$2,558,000	$57,000	$35,000	$21,000	$219,000

Table C-4. 25-Year Cashflow, Rooftop + Canopy Solar PV (PPA)

Yr.	Est. Utility Cons. (kWh)	Annual Estimated Utility Cost w/o PV	Utility Energy Cost w/PV	Annual Savings w/o PPA Payments	PPA Payments	Gross Annual Savings	Cumulative Project Cash Flow
0							($439,000)
1	1,876,000	$364,000	$197,000	$167,000	$198,000	($31,000)	($470,000)
2	1,876,000	$375,000	$204,000	$171,000	$196,000	($26,000)	($496,000)
3	2,429,000	$386,000	$212,000	$174,000	$195,000	($20,000)	($516,000)
4	2,957,000	$397,000	$219,000	$178,000	$193,000	($15,000)	($531,000)
5	3,516,000	$409,000	$227,000	$182,000	$192,000	($10,000)	($541,000)
6	3,516,000	$422,000	$236,000	$186,000	$190,000	($5,000)	($546,000)
7	5,656,000	$434,000	$244,000	$190,000	$189,000	$1,000	($545,000)
8	5,656,000	$447,000	$253,000	$194,000	$187,000	$6,000	($539,000)
9	5,656,000	$461,000	$263,000	$198,000	$186,000	$12,000	($527,000)
10	5,656,000	$474,000	$272,000	$202,000	$185,000	$17,000	($510,000)
11	5,656,000	$489,000	$283,000	$206,000	$183,000	$23,000	($487,000)
12	5,656,000	$503,000	$292,000	$211,000	$182,000	$29,000	($458,000)
13	5,656,000	$518,000	$303,000	$215,000	$181,000	$34,000	($424,000)
14	5,656,000	$534,000	$314,000	$220,000	$179,000	$40,000	($384,000)
15	5,656,000	$550,000	$326,000	$224,000	$178,000	$46,000	($338,000)
16	5,656,000	$567,000	$338,000	$229,000	$177,000	$53,000	($285,000)
17	5,656,000	$584,000	$350,000	$234,000	$175,000	$59,000	($226,000)
18	5,656,000	$601,000	$362,000	$239,000	$174,000	$65,000	($161,000)
19	5,656,000	$619,000	$375,000	$244,000	$173,000	$71,000	($90,000)
20	5,656,000	$638,000	$389,000	$249,000	$171,000	$78,000	($12,000)
21	5,656,000	$657,000	$441,000	$216,000	$170,000	$46,000	$34,000
22	5,656,000	$677,000	$456,000	$221,000	$169,000	$52,000	$86,000
23	5,656,000	$697,000	$471,000	$226,000	$167,000	$58,000	$144,000
24	5,656,000	$718,000	$488,000	$230,000	$166,000	$64,000	$208,000
25	5,656,000	$739,000	$504,000	$235,000	$165,000	$70,000	$278,000

Attachment D

LCFS and RINS Credits Analysis Assumptions

LCFS and RINs Credits Analysis Assumptions

Table D-1 summarizes the approximate LCFS and RINs credits CCB is likely to generate between 2022 and 2030, based on input from Clean Energy and SRECTrade. Tables D-2 and D-3 show the key assumptions used to estimate the credit values.

Table D-1. LCFS and RINs Credits Summary

Year	LCFS Credits in $, Future BEB Fleet	LCFS Credits in $, Current CNG Fleet	RINs Credits for RNG in $, Current CNG Fleet
2022	$168,500	$72,000	$154,300
2023	$157,100	$62,000	$135,300
2024	$300,300	$45,100	$91,800
2025	$408,700	$36,600	$56,800
2026	$497,400	$25,600	$37,400
2027	$461,800	$23,900	$32,800
2028	$805,200	$0	$0
2029	$745,900	$0	$0
2030	$690,300	$0	$0
Totals	**$4,235,200**	**$265,200**	**$508,400**

Table D-2. LCFS Credits Analysis Assumptions

Metric	Value
LCFS Credit Value, 2022	$185
LCFS Credit Annual Change	-5%/year
REC Purchase Value	$0.015/kWh
REC Value Annual Change	0%/year
REC Processing Fee	10%/year
LCFS Processing Fee	10%/year

Table D-3. RINs Credits Analysis Assumptions

Metric	Value
RINs Credit Value, 2022	$2.85
RINs Credit Annual Change	-12%/year
RNG RIN Revenue to Customer (from RNG Producer)	8%
RNG LCFS Incremental Credit Revenue to Customer	10%

A2. Site Plans Produced by AECOM