Feasibility Study of DCFC + BESS in Colorado:

A technical, economic and environmental review of integrating battery energy storage systems with DC fast charging

Final Report

Prepared by E9 Insight and Optony Inc on behalf of Colorado Energy Office

Executive Summary

Overview of Goals and Approach

This report contains the Technical, Economic, Regulatory and Environmental Feasibility Study of Battery Energy Storage Systems (BESS) paired with Electric Vehicle Direct Current Fast Chargers (EV DCFC) for the state of Colorado Energy Office (CEO). The goal of this report is to enable stakeholders to better understand the costs and benefits of deploying BESS alongside DCFC, and to provide programmatic and funding allocation recommendations for future CEO programs. This includes analysis of factors regarding technologies available, potential use cases, ownership structures, the impact of rate design on DCFC and the economic viability of a BESS coupled system, as well as exploration of potential enabling policies.

The Project Team conducted a statewide utility survey to analyze the existing market for BESS+DCFC systems and fast charging in general, customer demand for access to fast charging, and barriers preventing accelerated buildout of charging infrastructure. Responses were received from 31 of Colorado's 53 utilities, representing 89% of the state's retail electricity market. Topics discussed included:

- Existing or planned DCFC deployments, with and without BESS
- Existing or planned standalone BESS deployments
- Details of existing rate structures applicable to charging stations
- Barriers and other limiting factors to the viability of BESS + DCFC
- How EV adoption and DCFC expansion aligns with long-term and strategic goals
- Infrastructure upgrade and interconnection costs associated with BESS and DCFC

Preliminary market research indicated that there are two primary economic use cases for BESS: Demand charge management (DCM), and project cost reductions that enable access to fast charging at the grid edge as a result of avoided distribution system upgrades. Additionally, there are 3 distinct geographies in Colorado categorized by charging station load characteristics:

Rural: DCFC deployments in areas of Colorado with low population density, likely used by a combination of local drivers and potentially drivers traveling long distances. When compared to other geographical use cases, rural deployments are also more likely to be in areas with minimal grid infrastructure. In general, rural areas tend to have lower charger utilization rates.

Corridor: DCFC deployments along major travel corridors in Colorado, likely used primarily by drivers traveling long distances. Charging in corridor locations occurs more sporadically compared to metropolitan areas, where there are more EVs and drivers have adopted more regular charging schedules, but generally more often than rural locations.[1] This category also includes areas that may be less densely populated or located further from metropolitan areas, where the majority of utilization is likely driven by recreation and tourism. This resulted in entities that service popular mountain destinations and areas in proximity to national and state parks. Corridor areas have moderate utilization rates.

Denver-Metro & North Front Range: DCFC deployments in densely populated areas, used by a wide range of vehicles including local drivers running errands and commuting, municipal and commercial vehicles (e.g. delivery vehicles). Urban/suburban areas also include electrified fleet

[1] See station utilization rates in Table 2, Section 2.3.2

vehicles, including buses and utility-owned service trucks. The highest utilization rates are found in urban and suburban areas

In addition to the aforementioned utility survey,, E9 Insight and Optony Inc. (Project Team) conducted analysis across a total of 55 rates collected from 23 Colorado utilities that would be applicable to a commercially owned DCFC charging station, informed by the geographic segmentation above.Project team then calculated optimal BESS sizing for a range of load profiles and identified a “break-even” demand charge for each BESS size in order to identify rate structures that are most conducive to and maximize the utility of BESS implementation. Additionally, the Project Team applied the actual Colorado utility rates to the range of load profiles considered and calculated an estimated “break-even” BESS cost for each rate. Based on the results of the rate survey, BESS performance modeling and insights from market research, the Project Team provides recommendations for utilities/utility territories that CEO should prioritize for deployment of a BESS + DCFC pilot program.

Throughout the report, modeling results and market research is supported by nationwide policy and regulatory review, as well as an in-depth literature review of EVSE technology, grid services, interconnection processes, and infrastructure costs.

Role of the Utility/Project Selection

The retail electricity market in Colorado is segmented into 29 municipal, 22 rural cooperative (co-op), and 2 Investor Owned Electric Utilities (IOUs). Rural Cooperatives act on behalf of their members and are motivated to keep rates as low as possible while being responsive to shifting demand from consumers. These cooperatives encompass 32% of the market and a vast majority of Colorado’s geographic footprint. The latter point is particularly relevant for discussions surrounding the buildout of EV charging infrastructure because of the need to limit range anxiety and allow intrastate travel.

Municipal Utilities are most focused on local control to serve long-term community needs as a public service. While they encompass the lowest percentage market share in Colorado, the largest municipal utilities arise in concentrated population centers outside of the Denver metropolitan area, such as Fort Collins, Longmont, and Colorado Springs. Given their community focused agenda and accountability to voter demands, some of the most progressive EV infrastructure policies come from these entities.

At first glance, Colorado’s IOUs are good candidates for a capital intensive BESS+DCFC program given that they are incentivised to deploy infrastructure by earning a return on capital expenditures. PSCo and Black Hills Energy also service the largest percentage of Colorado customers, with a combined share of about 54% of the retail electricity market. However, not only do these entities require PUC approval to develop and rate base new projects, both PSCo and Black Hills Energy have active transportation electrification plans that include rebates, EV charging specific rates, and make ready infrastructure programs which may negate the economic justification of implementing BESS. Therefore, **CEO funding would likely be of better use to address gaps in other areas of the state, where potential charging station sites located in the state’s rural or corridor situated cooperatives and municipal utilities are most likely to require state support.**

Project Options and Findings

Gradually trickle charging the battery system can smooth the level of electricity consumption by the charging station, lowering the maximum kilowatts required from the grid.[2] This results in two primary economic use cases for the pairing of BESS with DCFC:

Demand Charge Management: Research has shown that the demand charge feature of utility electricity rates creates a cost prohibitive environment for DCFC station operators. This is because high periods of maximum kilowatt draw from the grid result in high demand charge costs that cannot be recovered through revenue from overall charging volume in early stages of EV adoption (and low station utilization rates). Unlike home charging, public DCFC charging needs are less elastic as drivers depend on charging to be available so that they are able to get back on the road. Batteries can allow time-of-use energy arbitrage to lower operating costs and create a more attractive business case for DCFC station operators. The critical questions related to Demand Charge Management are:

- What is the optimal battery sizing required to provide demand charge management across a range of load profiles?
- What is the battery break-even cost below which a BESS will be cost-positive when providing demand charge management across utility rates in Colorado?

Using data from 72 existing charging stations in Colorado, Optony's proprietary battery simulation model (MDOCs) was used to examine a wide range of load profiles and charging scenarios across the three geographic use cases (Rural, Corridor, Denver-metro/North Front Range). These scenarios were then applied to a sample of rate structures representative of said geographic use cases, resulting in a total of 157 model simulations. Simulations identified the optimally sized battery system to maximize savings from demand charge management across each load profile scenario, as well as the break-even battery costs and demand charge amount required to make the optimally sized systems economically feasible.

Results from this analysis demonstrate an encouraging economic case for BESS implementation. Break even demand charges for many scenarios were lower than the actual utility demand charges applicable to their respective charging station plaza size (Table 1). This implies that despite the high capital costs associated with BESS, demand charges can be relatively low in order to achieve savings by implementing a battery. The break-even demand charges showcase the outsized effect that demand charges have on the economic viability of fast charging.

[2] Trickle charging in this context refers to gradually charging a battery at lower power levels such that the rate of charge is minimized while providing a discharge rate that is sufficient to meet fast charging load

Table ES-1: Break-even Demand Charges Compared to Actual Demand Charges.

<table>
<tr><th rowspan="3">Geographic Use Case</th><th colspan="3">Break-Even Demand Charges Low Utilization Scenario</th><th colspan="3">Break-Even Demand Charges High Utilization Scenario</th><th rowspan="3">Range of Actual Utility Demand Charges</th></tr>
<tr><th colspan="3">Plaza Size[3]</th><th colspan="3">Plaza Size</th></tr>
<tr><th>Small</th><th>Medium</th><th>Large</th><th>Small</th><th>Medium</th><th>Large</th></tr>
<tr><td>**Rural**</td><td>$8.50</td><td>$2.50</td><td>$2.50</td><td>$5.50</td><td>$4.00</td><td>$3.00</td><td>$3.00 - $28.50</td></tr>
<tr><td>**Corridor**</td><td>$3.50</td><td>$3.00</td><td>$3.00</td><td>$6.00</td><td>$4.00</td><td>$4.00</td><td>$8.00 - $17.00</td></tr>
<tr><td>**Urban**</td><td>$5.50</td><td>$4.50</td><td>$5.00</td><td>$5.00</td><td>$4.00</td><td>$3.50</td><td>$4.40 - $14.91</td></tr>
</table>

To identify utility territories that would benefit the most from deploying DCFC with BESS designed to reduce operating costs, an alternative approach was needed. Rather than focusing on break-even demand charges, priority utilities can be identified by reviewing results of the break-even system cost analysis with respect to the specific rate structure of that utility. Table 2 provides the minimum, maximum and average break-even system costs for various utilities. Based on prior market research, BESS costs can vary from $469/kWh to $2,167/kWh, with shorter duration systems likely to fall toward the high end of this range. High average break-even system costs indicate utility territories where BESS are likely to be financially feasible when deployed to reduce operating costs of DCFC.

Table ES-2: Summary of Break-even BESS System Costs by Utility

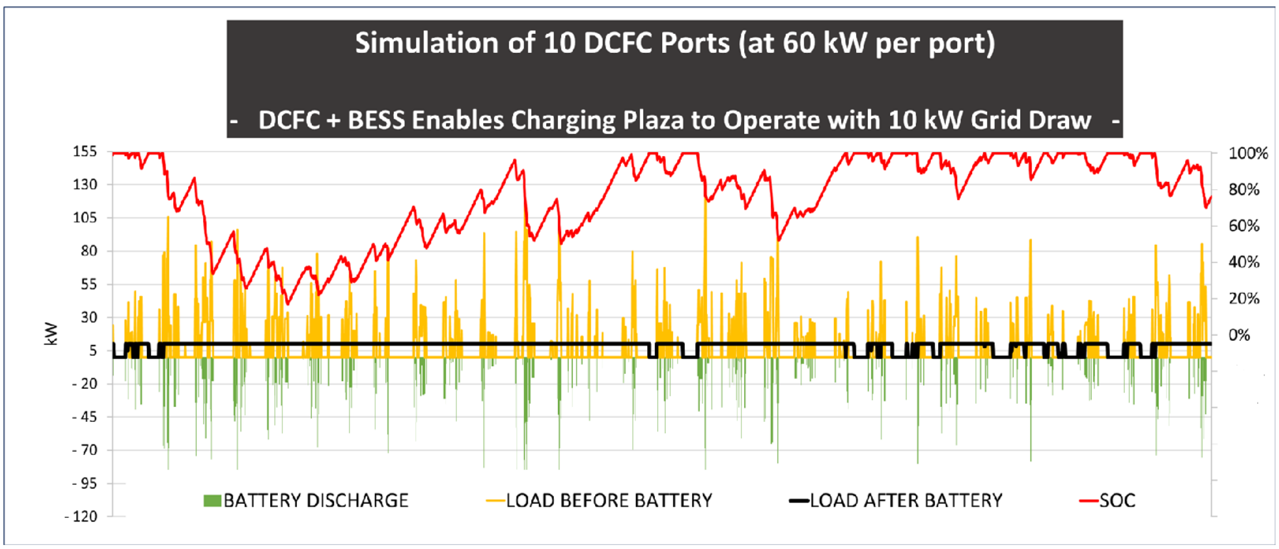
Utility	Break-even BESS System Cost ($/kWh)		
	Minimum	Maximum	Average
White River	$ 7,200	$ 13,000	$ 10,600.00
Poudre Valley	$ 2,100	$ 8,700	$ 5,650.00
Estes Park	$ 1,100	$ 8,100	$ 4,783.33
Highline Electric	$ 1,600	$ 7,600	$ 4,466.67
Intermountain Rural	$ 1,300	$ 7,700	$ 3,788.89
Mountain Parks	$ 800	$ 7,300	$ 3,335.71
City of Fort Collins	$ 800	$ 8,600	$ 2,922.22

[3] All plazas utilize 62.5 kW ports - small stations consist of one port, medium plazas ten ports (625 kW total), and large plazas consist of twenty ports (1250 kW total).

PSCo	$ 1,600	$ 3,600	$ 2,516.67
City of Longmont	$ 900	$ 5,400	$ 2,155.56

Enabling DC Fast Charging at the Grid Edge or in Grid Constrained Scenarios: Given that DCFC requires a 480V transformer and three phase line compared to the 240V transformer and single phase line requirement of L2 chargers, DCFC are more likely to induce significant infrastructure costs in the event that they require a service upgrade. Among surveyed utilities, several mentioned that the most expensive aspect of DCFC development is additional 3-phase wiring and transformers. Battery technology can lower the maximum kW draw from the grid in order to provide fast charging service using single phase lines, lowering infrastructure costs.

Figure ES-1: DCFC charging station load before and after implementing BESS, highlighting its ability to smooth grid draw dramatically. SOC = state of charge.



The Project Team conducted further analysis in order to determine the minimum battery size (and therefore minimum cost) required to maintain fast charging service. In a grid constrained scenario in which a BESS+DCFC is connected via a single phase line, the required battery size in a **rural use case** is relatively small in all utilization scenarios. A single Freewire Boost battery integrated DCFC would be sufficient to serve load in all scenarios. For a grid constrained, single phase **corridor use case**, required battery sizes are larger. Under a high utilization scenario, a single station DCFCrequires a 90-150 kWh battery, a 10 station plaza requires a 420-700 kWh battery and a 20 station plaza could not feasibly be served by a single phase line regardless of battery size.

As battery costs continue to decrease, rate arbitrage through demand charge management is primarily a commercially motivated use case for BESS implementation, and is more likely to be adopted by private markets in service areas with prohibitive demand charges. There are examples nationally of commercially owned and EV manufacturer owned DCFC stations that have already deployed BESS for this purpose,[4] and Colorado's first battery integrated DCFC was recently installed in a well developed, highly

[4] https://media.electrifyamerica.com/en-us/releases/48

trafficked Estes Park location.[5] On the other hand, significant portions of the state are served by rural cooperatives with grid constraints. Remotely located but high-impact corridor charging stations in these territories are much less likely to be served by the market in the near future, therefore the Project Team recommends that CEO funding be directed primarily towards filling this gap.

Summary of Results

The ability of BESS to enable fast charging at the grid edge is technically feasible, and sites may capture economic value through avoided distribution infrastructure costs. The fast charging electricity demand of all Corridor and Rural load profiles can be met with reasonable battery sizes, all under 160 kWh except the largest corridor plaza size modeled (thirteen 150 kW Ports), under a high utilization scenario. However, overall project costs are highly site specific and difficult to monetize, and identifying sites best fit for this application is another challenge that must be addressed.

The majority of rates studied are conducive to BESS demand charge management at any reasonable hardware cost ($/kWh), but unquantified soft costs are an important factor in determining overall economic feasibility of a project.

Additional modeling demonstrated that there is no inherent emissions benefit of adding BESS for demand charge management as periods of charging do not always align with periods of low carbon intensity on the grid. However, BESS could facilitate emissions reductions if charging is actively managed to avoid carbon intensive hours.

Program Design Recommendations

The Project Team recommends two separate funding programs depending on BESS use case. For a grid edge charging use case, the Project Team recommends an “RFP” based funding approach for a pilot program in the near-term. Grid edge BESS+DCFC are a priority for funding as they are less likely to be undertaken by the market, however there are challenges to creating a programmatic funding approach. Further research is needed to determine which sites require BESS when compared to other solutions; moving sites closer to existing infrastructure for example. More data on overall project costs including soft costs and interconnection or engineering studies may also be required in order to inform a full BESS program.

These challenges can be addressed in part through a pilot program with the goal of deploying BESS+DCFC in real-world grid-edge sites, and determining the exact information and processes needed to calculate the cost-effectiveness compared to line extensions. An effective pilot would also help determine if there are any site characteristics that can be generalized in order to identify other sites that are likely to be cost-effective.

---

[5]https://freewiretech.com/national-park-village-brings-battery-integrated-ultrafast-ev-charging-to-the-gateway-of-colorado-rocky-mountain-national-park/

Table ES-3: Descriptions of key solicitation features to be included in a grid edge BESS+DCFC program

Key Solicitation Features	Description
Variable Funding Requests	● Variable based on characteristics of specific project, guided by expected funding levels ● CEO can accept asks for higher funding if cost-effectiveness argument is strong
Eligible Costs	● Eligible BESS costs should align with categories cost listed in Charging Plazas program ● Specifically call out interconnection costs as eligible ● Limit total award to 80% of project costs
Funding Levels for BESS	● $40,000 – $60,000 per DCFC port (additional to any charger incentives) ● Range encompasses estimated BESS cost and marginal cost of BESS-integrated DCFC compared to standalone DCFC of same nameplate
Prioritize projects that address existing DCFC gaps	● Maximizes impact of project on statewide project needs
Prioritize teams including utilities/cooperatives	● Inclusion of load serving entities (LSE) enable pre-project cost-effectiveness calculations to be completed because LSEs can provide necessary data to determine whether the addition of a BESS defers is less costly then expansion of the distribution system ● Fosters collaboration between DCFC developers & utilities in relation to site selection, which hasn't existed in rural areas ● Streamline interconnection
Require Cost-Benefit Analysis (Pre & Post Project)	● Pre Project: Estimate cost-effectiveness of BESS+DCFC vs. line extension, used to vet projects and evaluate funding requests ● Post Project: Confirm pre-project estimates and determine lessons learned for other sites

A BESS funding program focused on Demand Charge Management would be more suited as an adder to existing CEO funding programs. Such a program should be second in priority behind a grid edge program due to the likelihood of the private market adopting BESS technology in the future, however CEO could add BESS to chargers in targeted utility service territories. Analysis provided in section 2 of this report provides utility rates that are best fit for BESS by geographic use case, and details break-even system cost results for every rate across varying utilization scenarios.

Table of Contents

Tasks Completed (for reference throughout report)

Task 1: Overview of BESS and BESS + DCFC Market in Colorado
Task 2: BESS + DCFC Technology and Hardware Considerations
Task 3: Colorado Rate Structure Analysis and the Effect of Rate Design on BESS + DCFC Viability
Task 4: Costs and Benefits of BESS + DCFC Deployment
Task 5: Project Considerations
Task 6: Additional Considerations

Section 1: Overview of BESS + DCFC: Market Overview, Hardware Options, and Potential Use Cases

Section 1 provides context for the Direct Current Fast Charging (DCFC), the Battery Energy Storage System (BESS) market, as well as the market for coupling these technologies for use in Colorado. E9 Insight and Optony Inc (Project Team) conducted a targeted outreach campaign and stakeholder interview process to survey the state's electric utilities for relevant project activity to date, supported by a literature review of DCFC + BESS project considerations and a nationwide project of note.

1.1: Market Overview

1.1.1: Outreach Methodology

The Project Team identified 53 total utility entities across the state of Colorado: including two investor-owned utilities, 29 municipal utilities, 22 rural cooperatives, as well as several public power and wholesale generation providers.[6] The Project Team conducted a targeted outreach campaign and survey to provide a snapshot of relevant project infrastructure deployed, or in the pipeline, across utility service territories. In addition, as part of CEO's Beneficial Electrification Working Group (BEWG), the outreach effort was flagged by CEO staff for participant participation and follow-up.

Outreach efforts yielded survey results from 31 of Colorado's 53 utility entities, with a total of 52 utilities contacted. Data was collected via email exchanges and phone conversations with key stakeholders and utility representatives. The focus of these conversations was centered on, but not limited to, the following set of questions:

1. Existing or planned DCFC deployments
2. Existing or planned BESS paired with DCFC deployments
3. Existing or planned standalone BESS and project motivations
4. Details of existing rate structures, including applicable Dynamic TOD or Commercial Demand Charges
5. Barriers, pain points and other limiting factors to the viability of BESS + DCFC
6. Interconnection processes, streamlined permitting and any applicable thresholds for various levels of project sizes (e.g., > 500 KW BESS),
7. How does EV adoption and DCFC expansion align with long-term and strategic goals?

---

[6] 2019. EIA Form 861: Utility Data contains information on the types of activities each utility engages in, the North American Electric Reliability (NERC) regions of operation, whether the utility generates power, whether it operates alternative-fueled vehicles, and, beginning in 2010, the Independent System Operator (ISO) or Regional Transmission Organization (RTO) region in which the entity conducts operations.

Table 1: E9 received survey responses from the following list of Colorado Utility Entities

Utility Respondents		
Arkansas River Power Authority	Grand Valley Power	San Isabel Electric Assn. Inc
City of Center	Gunnison County Electric Assn.	San Luis Valley REC, Inc
City of Colorado Springs	Highline Electric Assn.	Town of Flemming
City of Fort Collins	Holy Cross Electric Assn.	Town of Frederick
City of Julesburg	Intermountain Rural Electric Assn.	Town of Granada
City of Lamar	La Plata Electric Assn. Inc	United Power, Inc
City of Las Animas	Moon Lake Electric Assn. Inc	Western Area Power Administration
City of Longmont	Mountain View Electric Assn. Inc	White River Electric Assn. Inc
City of Loveland	Platte River Power Authority	Y-W Electric Assn.
City of Loveland	Poudre Valley REA, Inc	Yampa Valley Electric Assn. Inc
Delta Montrose Electric Assn.	Public Service Company Colorado (PSCo)	

The Project Team established a set of evaluation criteria to create a shortlist of organizations that encompass a diverse and representative sample of electricity rates, utilization, goal alignment, and loads across the state. This shortlist excluded utilities whose rates are most conducive to the current environment of Electric Vehicle (EV) charging, and therefore the least likely to fully benefit from the implementation of BESS. The goal of this evaluation is to create a list of priority utility territories based on a set of factors important to the feasibility of deploying DCFC + BESS and to creating a successful state funding program. Each evaluation question, listed above, was established to address a specific factor, summarized below:

- **Utility Stakeholder Support:** The deployment of DCFC + BESS projects benefit from significant utility participation, potentially requiring utility funding of make-ready infrastructure and interconnection support. Stakeholders from within the profiled utilities were identified as a key aspect of ensuring a successful funding program. Therefore, utilities that have deployed DCFC or are planning additional buildout of charging programs, are interested in advancing the adoption of EVs in their service territory, and have dedicated staff working on transportation electrification projects, were tagged for further engagement.

- **High demand charges:** Given that stations face a low average utilization rate followed by intermittent periods of high demand, demand charges are likely to be a large portion of a station's operating costs. BESS provides an opportunity to smooth consumption and mitigate the effect of these charges, significantly lowering costs. The evaluation criteria enables identification of utility territories with commercial rates featuring high demand charges in which BESS deployment could be used to achieve reductions in operating costs in the absence of conducive rate structures. Therefore, utilities whose rates do not include demand charges nor coincident peak demand charges are not considered.

- **Lack of EV charging specific rates:** While utility territories with EV specific rates may be conducive to DCFC deployment, EV specific rates can eliminate the economic feasibility of a BESS system providing demand charge management. Four utilities (including PSCo) have developed rates that are more reflective of the cost of service for DCFC load. While the effectiveness of these rates is contested and varies across the state, in general these rates either lower or offer rate alternatives that reduce DCFC station exposure to demand charges. In these cases, it is less likely that DCFC stations would require BESS to enable commercial viability, as EV-specific rates are designed to mitigate demand charge exposure.[7]

- **Interconnection Timelines and Costs**: Discussions with utility and 3rd party stakeholders, as well as Project Team experience assisting in procurement and development of DCFC + BESS, have indicated that interconnection timelines and costs can significantly reduce BESS feasibility even if utility rates create an economic opportunity for storage. Without the time and budget required to evaluate the BESS interconnection processes of every utility in Colorado, presence of vehicle electrification in a strategic plan and staff dedicated to EV integration were chosen as criteria to indicate the likelihood of reduced, or manageable, interconnection barriers.

- **Geographic diversity:** Utilization rates and the time distribution of charging load profiles will impact the cost-effectiveness of BESS deployed to mitigate operating costs of DCFC. Maintaining a geographically diverse sample while balancing the other evaluation criteria was deemed necessary for a successful study. Additionally, limited grid infrastructure will determine the relevance/value of deploying BESS to enable DCFC on single-phase power lines. Shortlisted utilities are categorized according to their fit with the three geographical use cases identified for DCFC deployment: Urban/Suburban, Rural, and Corridor charging.

Table 2: Priority Utilities by Geographic Charging Use Case

Urban/Suburban	Rural	Corridor
PSCo City of Fort Collins City of Longmont	Grand Valley Power Highline Electric Assn Poudre Valley REA White River Electric Assn	Estes Park Intermountain Rural Elec Assn Mountain Parks Elec Assn

The goal of filtering utilities by the evaluation criteria was not to identify a list of utilities that are a perfect match for each feasibility factor, but rather to identify a list of representative utilities that narrows the focus of the ensuing analysis while still addressing all relevant study areas. Analysis was not conducted on data from charging stations that exist in these utilities' service territories, however their electricity rates were used as an input. As described below in section 2.3, a representative sample of load profiles were selected separately.

1.2: Context for Charging Station Deployment and Role of BESS

1.2.1: Inclusion of EV Adoption in Utility Organizational Goals

Due to the wide variety of geographies and demographics that make up Colorado, EV adoption and charging station utilization rates vary widely across the state. Organizational goal alignment surrounding investment in charging infrastructure, interest in exploring technologies such as BESS, and acceleration of

[7] Mountain Park Electric Association's EV charging specific rate was included in the shortlist because it contains a very high ($19.34/kW) demand charge component

EV adoption in general is heavily influenced by these factors. The results of this survey provide evidence that DCFC expansion aligns with the long-term strategic goals of some state utility entities more than others. The below utilities represent examples of those which have developed EV charging infrastructure plans, EV charging specific rates, or have otherwise displayed interest in increasing charging infrastructure and EV adoption in their service territories.

- **Holy Cross Electric Association:** Offers "make-ready" investments and line extensions to "community partners," exhibits high EV charging station utilization rates, and interest in BESS as part of future resource planning.
- **La Plata Electric Association:** Owns and operates one corridor DCFC with another 2 planned, and has developed an EV charging specific rate.
- **San Isabel Electric Association:** Owns and operates 1 DCFC, plans for an ultrafast DCFC.
- **Yampa Valley Electric Association:** Owns and operates 1 DCFC, has also developed an EV charging specific rate
- **Intermountain Rural Electric Association:** Owns and operates 2 DCFC, and is planning a corridor charging program along its major highways.

1.2.2: State of Market for BESS Coupled with Charging Stations

Results from Colorado utility outreach indicate that the market for the coupling of BESS with DCFC is in the exploratory stages. Multiple organizations expressed interest in utilizing BESS to mitigate the effect of demand charges, and potentially piloting a system. Such organizations include Longmont, Highline Electric Association, and La Plata Electric Association. The first example of a BESS + charging station coupled deployment in the state as of 2021 is a FreeWire Boost battery integrated DCFC charger in Estes Park, located at a retail grocery store and gift shop near the entrance to Rocky Mountain National Park. The owner of the charger cited avoided infrastructure costs and demand charges as the primary driver of choosing this technology, as well as the ability to provide exceptional fast charging service near one of the state's most popular tourist destinations.[8] Highline Electric Association is reported to be considering a proposal for such a system, but the status of this project is unclear and appears to be in its proposal phase. Utilization rates in their service territory are also very low, currently only charging approximately 10 vehicles each month.

It is likely that private Electric Vehicle Station Companies (EVSCs) and developers are conducting early stage pilot programs for these technologies elsewhere in the state, however among publicly available data sources there are few examples of DCFC + BESS deployments in the state. Atlas Policy's EValuateCO tool lists 166 active DCFC charging locations in the state.[9] BESS + DCFC appears to only be seriously included in the long term goals of a select few utilities, and those that have considered it cite a few common barriers:

1. High upfront capital cost
2. Limited data on the use of these systems, best practices
3. Uncertainty around how to effectively utilize BESS systems
4. Complications surrounding BESS in their agreements with wholesale partners[10]

[8] "Ultrafast EV Charging at National Park Village with Jim Sloan," video. IPOWER Alliance. https://www.ipoweralliance.com/
9 Atlas Public Policy. Charging Deep Dive "EvaluteCO" https://atlaspolicy.com/evaluateco

[10] See section 1.4.3: "BESS Limitations in Wholesale PPAs"

1.2.3: Rate Structures

Rate structures, and specifically high demand charges, remain the primary driver in determining the commercial viability of any BESS + DCFC paired project.[11,12] As mentioned, DCFC stations face a low average utilization rate followed by intermittent periods of high demand, thus demand charges are likely to be a large portion of a station's operating costs. Demand charges are common in typical commercial retail electricity rates offered by utilities. Demand charges are a per kilowatt (kW) charge that evaluates the highest level of demand during any 15-minute interval experienced throughout the month. Among surveyed utilities, these charges vary from $3-28 per kW, with an average of $12.3 per kW in the summer and $11.8 per kW non-summer. Three utilities (not including Public Service Company Colorado (PSCo)) have developed EV specific rate structures to provide rate relief to better accommodate load profiles of DCFC: La Plata Electric Association, Yampa Valley Electric Association, and Delta Montrose Electric Association, with EV charging falling under a dynamic TOD rate in Holy Cross Electric Association. For all other utilities surveyed, 3rd party charging falls under typical commercial tariffs, of which rates vary widely based on required capacity and other factors. No utilities mentioned EV charging specific rates offered to them by their wholesale partners, putting them largely at the mercy of standard wholesale demand charges and making it difficult to develop charging specific rates that still allow them to recoup costs. EV specific charging rates are designed to mitigate the effect of demand charges, which increase operating costs for charging stations and, particularly when spread out over a limited amount of energy (kWh) dispensed, can hinder a station owner's ability to recover costs from EV drivers.

1.2.4: Battery and Charging Economics

There are several challenges to deploying additional fast charging infrastructure, including high operating costs that reduce the economic viability of commercially owned stations and a lack of sufficient grid infrastructure to support required power levels. The challenge of high operating costs for DCFC is well-documented in multiple studies.[13,14,15] In lieu of EV specific rates designed to mitigate costs for operating a station, BESS can be a technical solution that can provide similar results for station owners.[16] In addition, BESS can provide fast charging capability when only single-phase power is available.[17] DCFC charging typically places a large load on the grid and requires higher capacity three-phase lines in order to charge vehicles at high speeds. BESS can smooth the rate at which electricity is drawn from the grid over time, lowering the instantaneous power required from the grid while allowing vehicles to charge using the battery at high speeds.

---

[11] Great Plains Institute, "Analytical White Paper: Overcoming Barriers to Expanding Fast Charging Infrastructure in the Midcontinent Region." July 2019.

[12] Levy, Isabelle Riu, Cathy Zoi, "The Costs of EV Fast Charging Infrastructure and Economic Benefits to Rapid Scale-Up," May 2020.

[13] R. J. Flores, B. P. Shaffer, and J. Brouwer, "Electricity costs for an electric vehicle fueling station with Level 3 charging," Appl Energy, Vol. 169, May 2016, pp. 813–30.

[14] M. Muratori, E. Kontou, and J. Eichman, "Understanding Electricity Rates for Electric Vehicle DC Fast Charging,".

[15] Fitzgerald, Garrett, and Chris Nelder. DCFC Rate Design Study. Rocky Mountain Institute, 2019. http://www.rmi.org/insight/DCFC-rate-designstudy

[16] M. Muratori et al., "Technology Solutions to Mitigate Electricity Cost for Electric Vehicle DC Fast Charging"

[17] Md Ahsanul Hoque Rafi., "A Comprehensive Review of DC Fast-Charging Stations With Energy Storage: Architectures, Power Converters, and Analysis"

1.2.5: Review of EV Enabling Policies in Colorado

Governor Jared Polis signed Senate Bill 19-077 in 2019, requiring the state's investor-owned utilities to file programs to support widespread transportation electrification (TE) within their service territories.[18] In May 2019, PSCo filed an adjustment to its tariff schedule, including a new Time-of-Use (TOU) based rate for EV fleet charging and public DCFC.[19] In support of its proposed rate design, PSCo asserted its desire to better study the interaction of EVs and residential rate designs and the various benefits of EVs. The rate, Secondary Voltage Time-of-Use (TOU Electric Vehicle Service tariff (Schedule S-EV)), claims to have eliminated as much as 72% of demand charges. Schedule S-EV was designed for non-residential EV charging and included standard monthly service and facility, TOU Energy, Distribution Demand, and Critical Peak Pricing (CPP) Energy charges.

Settlement discussions in the development of said rate, focused on the "critical peak" (CPP) adder charge for energy, defined as a four-hour period occurring between noon and 8:00 pm, which PSCo would call on based on the day-ahead generation to load forecast. CPP periods were set to occur as many as 15 days during a calendar year. The demand charge was also calculated based on the highest amount of demand during a 15-minute interval each month.

In September 2019, a comprehensive, unopposed Settlement Agreement was reached where the parties agreed that PSCo would file a new EV rate by August 2021.[20] The new EV rate proposal will be designed to alleviate and address concerns of parties that the demand charge components of the rates were too high to effectively promote widespread transportation electrification and commercial viability of commercial DCFC charging. As of the publishing of this report, the rate has not yet been filed.

Table 3: Existing Commercial Charging Rate Options for PSCo

Current Commercial Charging Rate Options[21]	
Small Commercial (Schedule C) ● 250kW Maximum Load ● Simple kWh charges ● Proposed TOU Structure in 2020 Rate Case	Standard Commercial Rate (Schedule SG) ● Based on Demand Charges ● Could be good option for fleets with high load factors
Low Load Factor (SGL) ● Eliminates most demand charges ● Simple summer/winter energy charges	Schedule S-EV ● Eliminates most demand charges ● TOU energy charges

[18] May 2019. SB 19-077: https://leg.colorado.gov/bills/sb19-077
[19] May 2019. 19AL-0290E: http://www.dora.state.co.us/pls/efi/EFI.Show_Docket?p_session_id=&p_docket_id=19AL-0290E
[20] October 2019. Settlement Agreement: http://www.dora.state.co.us/pls/efi/EFI_Search_UI.Show_Decision?p_dec=26837&p_session_id=
[21] From PSCo correspondence with E9

1.3: BESS Technology & Hardware Options

1.3.1 Hardware Considerations

BESS are available in a wide range of power and duration combinations. Power capacities range from a few kWs for residential applications up to multiple megawatts (MW) for grid connected applications. Given the presence of lithium-ion as the dominant battery chemistry in the market (see below) and its cost characteristics, system durations usually do not exceed 4-hour systems.

Lithium-ion batteries dominate current stationary battery deployment and are expected to continue to be the largest share of the market over the next ten years.[22] While other battery energy storage types, such as flow batteries, may have useful applications in relation to fast charging, especially for long duration systems (greater than 4-hour) in support of off-grid charging, these technologies are not currently widely deployed. As such, the Operational Constraints section of this market review focuses on lithium-ion as the dominant battery type in the market currently. The term "Lithium Ion," while often treated as a single type of battery, refers to a family of battery chemistries that all use Li+ ions to transport charge across an electrolyte. The key differentiator between them is the material used as the cathode. Different chemistries yield different energy, power, and safety characteristics, which is why a "Li-ion" battery in a power tool will be very different from that in a BESS container. Of most relevance to commercial and grid-scale energy storage systems are:

- Lithium Nickel Manganese Cobalt (NMC) batteries, which will often vary the ratio of Ni to Mn to Co in order to tune the batteries' performance.
- Lithium Iron Phosphate (LFP) batteries, which eschew the use of cobalt, an expensive and highly toxic material, leading to higher cycle lives, greater protection from thermal runaway, slightly greater depth of discharge, and somewhat higher power density at the expense of lower energy density.

1.3.2: System Architecture

While BESS paired with DCFC has the potential to provide a range of economic and environmental benefits, the exact system architecture has implications on tradeoffs between capital cost, ability to integrate renewables, resilience and reliability. Three common system architectures have been defined.[23] Table 1 summarizes the tradeoffs of each architecture with respect to the categories listed above.

- **Collocated DCFC + Battery (AC Coupled):** DCFC and BESS systems collocated at the same site and interconnected behind the same electricity meter. Each DCFC in the configuration, as well as the BESS, connects to a common AC bus. Separate power electronics are required to connect the DCFC and the BESS to the main AC bus.
- **Collocated DCFC + Battery (DC Coupled):** As with an AC coupled system, DCFC and BESS systems are collocated behind the same electrical meter. In a DC-coupled system all EV chargers and the BESS are connected to a common DC bus, removing the need for power electronics to provide multiple points of AC to DC conversion throughout the system.

[22] Energy Storage Grand Challenge Energy Storage Market Report, U.S. Department of Energy, 2020.

[23] The generalized system configurations were used throughout the study to inform modeling assumptions.

- **Battery-integrated DCFC:** A BESS is integrated directly into the DCFC, located between the power input and the DC charging port(s). A DC coupled configuration is used internally to the equipment between the BESS and DCFC port(s).

A summary of these common system configurations and associated tradeoffs related to cost, integration of renewables, resilience and reliability is provided in Appendix A.

1.3.3: Operating Constraints of BESS & DCFC

When considering a paired BESS and DCFC system, whether the technologies are co-located or fully integrated, the BESS is going to be the limiting factor of operations in relation to extreme temperatures, not the DCFC hardware. Colorado's environment may pose challenges to BESS deployment without proper thermal management. Operating ambient temperature ranges are dependent on HVAC systems. Without HVAC systems, Li-ion BESS have a common operating range from -4 F to ~140 F.[24] With HVAC, systems can operate at more extreme temperatures. For example, the ABB PowerStore system can tolerate temperatures down to -58F with proper HVAC. Operating altitudes for BESS are commonly under 6,500 feet. DCFC hardware has larger ranges across both environmental factors; with operating temperatures ranging from -40 F to 131 F and maximum altitude reaching 9,800 feet for some ChargePoint hardware (due to a use of liquid cooling).

An additional factor to consider is that temperature and elevation are not independent variables. As air density decreases with higher elevations, air's ability to transfer heat will decrease. This diminishes the ability of an HVAC system to control ambient temperature in an enclosed system, leading to greater negative impacts of extreme temperatures on efficiency. Thus, deploying systems at high elevation will limit the ability of HVAC to control temperature within the ideal operating range. Tables 3 and 4 summarize operating temperature ranges and elevation limits for a selection of common BESS and DCFC hardware.

Table 4: Operating Temperature & Altitude Limit of Common DCFC[25]

Manufacturer & Model	Operating Temperature Range (without HVAC)	ElevationLimit (feet above Sea Level)
ChargePoint CPE250	-40 to 122 F	9,800
Tritium PK350	-31 to 122 F	6,560
ABB Terra	-31 and 131 F	6,650 – 8,200 *(depending on model)*
BTC Power HPCT	-22 and 122 F	6,000
Freewire Boost[26]	-4 to 131 F	Not yet rated, however integrated Li-ion battery likely means under ~6,500 feet.

[24] Ma, et al. Temperature effect and thermal impact in lithium-ion batteries: A review., 2018.

[25] Gathered from hardware specification sheets provided by OEMs on June 25th, 2021.

[26] While not commonly deployed, this model is included for reference as it is the currently the only UL certified DCFC with a fully integrated battery.

Table 5: Operating Temperature & Altitude Limit of Common Li-ion BESS Packs[27]

Manufacture & Model	Chemistry	Operating Temperature Range (without HVAC)	Operating Temperature Range (with HVAC)	Elevation Limit (feet above Sea Level)
ABB PowerStore	NMC	-4F to 131F (temps >113F degrade battery)	-4F to 104F (down to -58F w/ cold weather package) without derating	TBD
SUNSYS HES L	LFP	-4F to 140F (temps >113F degrade battery)	-4F to 140F without derating	3,200, higher for special applications
Energport S Series	LFP	-4F to 140F (temps >113F degrade battery)	-4F to 131F (temps >113F degrade battery)	TBD
Powin Stack750E	LFP	-4F to 140F (temps >113F degrade battery)	14F to 122F	TBD
Tesla Powerpack	LFP	-4F to 140F (temps >113F degrade battery)	-22F to 122F	TBD
LG Chem Custom Energy Containers	NMC	-4F to 131F (temps >113F degrade battery)	-4F to 122F	~6,500

1.4: BESS Benefits, Use Cases & Ownership Structures

This section describes potential benefits and services provided by BESS paired with DCFC (use cases), provides an overview of potential ownership structures and provides a matrix of which use cases are most applicable to which ownership structures.

1.4.1: Environmental, Economic and Grid Benefits

The range of use cases (benefits) a BESS can provide when paired with a DCFC are summarized below, organized into three categories: economic, environmental and grid benefits. These are distinct from the *geographic* charging use cases discussed elsewhere in this report.

The techno-economic analysis performed during this study (Section 2), assessing optimal BESS sizing and savings potential, focused on two benefits defined above in the Economic category; namely demand charge management and distribution system upgrade deferral. In the case of distribution upgrade deferral, the analysis focused only on the optimal size of a BESS system required to provide fast charging in a grid-constrained scenario.

[27] Gathered from hardware specification sheets provided by OEMs on June 29th, 2021.

Table 6: Summary of BESS Benefits

	Use Case/Benefit	Description	Mitigating Risks
Economic	**Demand charge management**	During the early stage of EV adoption, given that stations face a low average utilization rate while requiring intermittent periods of high electricity draw from the grid, demand charges can amount to a majority of a station's operating costs, threatening commercial viability. BESS provides an opportunity to smooth consumption and mitigate the effect of these charges, significantly lowering costs.	The financial upside of demand charge management is a product of rate design. BESS can result in significant savings where there are high demand charges. Thus, rate changes that eliminate or reduce demand charges could negate the need for BESS, and the justification for its capital costs.[28]
	Distribution system or make-ready infrastructure upgrade deferral	The power requirements to support installation of DCFC can trigger significant upgrades to the grid and/or other "make-ready" infrastructure requirements. This can occur in many scenarios from large plazas installed in densely populated areas to single fast chargers installed in rural settings without three-phase power. BESS can charge at lower power rates and discharge at higher rates to enable fast charging without performing costly grid upgrades.[29]Additionally, at a grid level, BESS can absorb unexpected load growth at substations and help avoid larger capacity upgrades of utility infrastructure.[30] Depending on what party is required to bear the cost of such upgrades, BESS deployment can provide a benefit for a range of system owners, or even be passed through to ratepayers.	Lack of grid-storage interconnectivity and coordination leading to underutilization of BESS' full potential
	Reliable, low cost charging for drivers	Reserves of capacity held at charging stations ensure the availability of low cost charging during peak hours or periods where multiple users are charging at once. Costs as a result of demand charges are less likely to be passed on to drivers.	High charging volume and EV adoption rates in the future may reduce the need for demand charge management, while increasing scale reduces costs. While this improves the business case for DCFC generally, this could threaten the long term financial case for BESS. However, demand charges only become a non-binding constraint at utilization rates of around 30%.

[28] Regulatory Risks associated with Demand Charge Rate alternatives are further discussed later.
[29] Rafi et al. 2021
[30] L. Garcia-Garcia, E. A. Paaso and M. Avendano-Mora, "Assessment of battery energy storage for distribution capacity upgrade deferral," *2017 IEEE Power & Energy Society Innovative Smart Grid Technologies Conference (ISGT)*, 2017, pp. 1-5, doi: 10.1109/ISGT.2017.8086030.

Environmental	**Unlocks additional DCFC development**	To the extent that storage can be leveraged to cost-effectively install DCFC, both at the grid-edge and in densely developed areas, it increases overall EV infrastructure in Colorado to support the state's electric vehicle and emissions reduction goals	
	Reduces real-time emissions	The BESS can be used to absorb excess renewable energy generated on-site, or charge from the grid at low-emissions times, and discharge to vehicles to reduce the carbon intensity of the electricity being used.	More sophisticated BESS controls systems are needed to optimize for maximum real-time emissions reductions while preserving the financial benefit provided by the system. In the absence of controls, storage systems can cause increased real-time emissions due to efficiency losses and risk of charging during periods of higher emissions.
Grid	**Resilience**	BESS increases grid resilience by creating a system capable of islanding and operating independently from the grid during outages [31]	Development of software infrastructure and technology implementation may slow down the ability to use BESS effectively for resilience. In addition, BESS would need a significant enough capacity to replace grid service for charging, which may be cost prohibitive at current BESS costs.
	System peak shaving	If a utility wants to reduce DCFC loads during system peaks, a BESS is likely needed. This cannot be done with load flexibility or curtailment, as might be possible with home charging, because fast charging is serving a community need (i.e. supporting mobility).	Adoption of BESS may not be widespread enough to make a significant impact on overall system demand. Additionally, regulations can limit station owners' ability to actively manage charging and shave peak demand: In some areas, utilities are limited to certain levels of self-generation, and BESS is often defined as generation. This is primarily a risk in the utility owned charging model.[32]
	Wholesale Power Arbitrage	Purchasing power during off-peak periods and discharging power during peak periods by a utility in order to reduce costs or make a profit.	Regulatory limitations as a result of PPAs and relations between wholesale/G&T providers, utilities, and customers
	Access in remote locations	With the implementation of renewables, chargers can be implemented off-grid at locations far away from distribution lines. This can be especially useful for rural and corridor use cases, given that distribution line extensions can make up a significant portion of interconnection costs.	Construction costs in mountainous corridor areas can be prohibitive regardless of grid interconnection

[31] Valuing the Resilience Provided by Solar and Battery Energy Storage Systems, NREL https://www.nrel.gov/docs/fy18osti/70679.pdf
[32] See "BESS Limitations in Wholesale PPAs" below

1.4.2: Ownership Structures

When considering the wide range of use cases and benefits that a combined DCFC + BESS system can provide to utilities, 3rd parties, drivers and ratepayers, the ownership structure of the system is a key variable that determines which specific benefits are applicable. A variety of ownership models will experience different costs, advantages, and considerations when implementing BESS + DCFC. Below are descriptions of various possible ownership scenarios:

- **Utility/Cooperative Owned:** Ownership model in which the local electric service provider owns and operates both the BESS and DCFC.

- **Municipality Owned:** Local municipal utility owns and operates BESS and DCFC.

- **Private Business or Automaker Owned:** Model where DCFC and BESS are the owned by the site host who may or may not be involved in EV charging (business with a parking lot, sufficient land), a 3rd party investor or EV charging developer, or an automaker who is building charging stations to extend the range of their cars and incentivize adoption of their brand.

- **DCFC Manufacturer/Provider Owned:** Model where the manufacturer of the physical DCFC system owns and operates the station as well as BESS (Chargepoint, Electrify America, etc.).

- **Utility and various 3rd Party Hybrid Ownership:** This model encompasses an array of possible agreements between 3 different entities: The station's site host, the utility, and DCFC manufacturer. While the site host will most likely pay the bill at the meter, either the site host, DCFC manufacturer or the utility can own the BESS.

- **Utility and DCFC Manufacturer Hybrid Ownership:** Model where a DCFC manufacturer owns, operates, and pays the bill for the DCFC station, while the local utility owns the BESS.

1.4.3: BESS Limitations in Wholesale PPAs

The utility-owned BESS+DCFC model is complicated in some rural cooperatives' territories due to clauses in their wholesale electricity power purchase agreements. Many co-ops are subject to self generation caps of 1-5% of the energy distributed to customers, and batteries are often included in definitions of self generation within these agreements. For utilities that have already reached their allotted self generation, implementation of BESS may not be feasible. Other co-ops have clauses in their PPAs that prohibit utility owned batteries from conducting demand charge management; any avoided charges that result from system peak shaving will be added back to the utility's costs. However, there are only two utilities in Colorado that have expressed such concerns.

While these complications discourage a utility ownership model, this should not influence privately owned BESS for Demand Charge Management (DCM). It is not clear that these clauses would apply in any way to a commercially operated DCFC charger, nor any device behind the meter. A private 3rd party or hybrid ownership model is also more likely as it allows stakeholder to share costs, and is already the primary model for DCFC stations across the state. The following matrix summarizes which benefits are applicable under which ownership structure.

Table 7: Summary of DCFC+BESS Ownership Structures

Ownership Model	Drawbacks & Limitations	Benefits
Utility/Cooperative	While many utilities interviewed were interested in owning DCFC, the use case of a utility-owned BESS paired with DCFC is not clear. While the use of a battery to avoid system upgrades may be applicable, this is likely most beneficial for municipal utilities and cooperatives who are interested in passing savings to ratepayers. Roughly one third of Colorado energy consumers receive service from member-owned cooperatives.[33] These coops must be more conservative with their investments in new infrastructure due to the regulatory processes that dictate how they recover costs. Among those utilities that are considering BESS, the primary barrier to development of these systems is upfront capital costs. BESS may be too risky for wide scale adoption by utilities in the future. The current market for utility owned DCFC is limited compared to other ownership models. Wholesale demand charge management for utilities and cooperatives is restricted for Tri-State, PSCo, and Platte River Power Authority members.	Utilities and cooperatives have a high degree of knowledge of rate structures, interconnection processes, and service areas to inform siting. Commercial rate structures are not relevant, so there may be a slight cost reduction compared with private 3rd party owned stations. The utility ownership model may be more applicable in the long term, given that the usefulness of batteries may decline at higher charger utilization rates in the future[34,35], which could limit private investment in the market.
Municipality	With the exception of Colorado's larger cities (Longmont, Fort Collins, and Colorado Springs), municipal utilities often have fewer staff dedicated to advancing adoption of renewables/electric vehicles and lack organizational goal alignment with investing in charging and battery storage. May also be subject to limitations from wholesalers.	Municipalities also face barriers with upfront capital costs. Use of BESS to avoid distribution upgrade costs may enable more widespread deployment of DCFC by municipal utilities and capture savings for customers. Municipalities are attractive DCFC owners because they may have access to, or already own, potential DCFC sites that are centrally located and accessible to more drivers and have no incentive to profit from fees for charging. For example, post offices, city halls and community centers.

[33] See Feasibility Study of BESS + DCFC In Colorado: Task 1. Member owned cooperatives are responsible for 32% of retail sales in Colorado.

[34] How battery storage can help charge the electric vehicle market, McKinsey, 2018 https://www.mckinsey.com/business-functions/sustainability/our-insights/how-battery-storage-can-help-charge-the-electric-vehicle-market

[35] Muratori, et. Al. Technology solutions to mitigate electricity cost for electric vehicle DC fast changing "Applied Energy Vol 242. 2019. Pp 415-23.

Private Business or Automaker	Private businesses and automakers have less visibility into the rates and regulations involved with building a DCFC+BESS station than a utility would if they owned it themselves. In addition, 3rd parties will often face standard commercial rates, which subject them to demand charges and interconnection costs.	More realistic case for widespread adoption in the short term; private businesses have more capital mobility and vested interest in providing cost effective charging for their car consumers. Commercial 3rd parties are not restricted by demand response limitations from generation and transmission partners.
DCFC Manufacturer/ Provider	DCFC manufacturers or service providers face many of the same drawbacks as private businesses and automakers. However, it is not typical for manufacturers of chargers to own and operate the stations themselves, rather it is the site location and/or equipment owners. Thus, this may not fit into DCFC manufacturers' expertise or business models.	DCFC manufacturers are uniquely familiar with technological capabilities and limitations of chargers, have teams that are highly specialized, and access to large amounts of data.
Hybrid (Utility + 3rd party)	Requires complicated agreements and regulatory arrangements that do not seem to exist yet, as well as communication and coordination of various moving parts. As detailed above, utility owned assets may not be used for demand charge management.	All parties are designated to their areas of expertise, allowing for greater efficiency and overall effectiveness of the system. For example, site hosts do not have to operate and maintain DCFC+BESS, while utilities have access to infrastructure and data enabling demand charge management, and DCFC manufacturers have the best understanding of integrating batteries with their system.
Hybrid (Utility + Manufacturer)	There are additional costs associated with a DCFC manufacturer acquiring land for a station and installing a new meter, rather than building with the cooperation of an existing site host. As discussed above, utility owned assets may not be useful for demand charge management.	Removes the site host as a player, therefore charging rates and revenues can be negotiated more flexibly when the utility is working directly with the DCFC manufacturer.

Table 8: BESS Benefit & Ownership Structure Matrix

	Economic			Environmental		Grid		
	Demand charge management	Reliable, low cost charging for drivers	Distribution system upgrade deferral	Unlocks Additional DCFC Development	Potential for real-time emissions reductions	Resilience	System peak shaving	Wholesale Power Arbitrage
Utility/Cooperative		×	×	×	×	×	×	×
Municipality		×	×	×	×	×		×
Private business or automaker	×	×	×	×	×	×		
DCFC manufacturer or service provider	×	×	×	×	×	×		
Hybrid (Utility + 3rd party)	×	×	×	×	×	×	×	
Hybrid (Utility + Manufacturer)	×	×	×	×	×	×	×	

Section 2: Techno-economic Analysis of BESS+DCFC in Colorado

The following section details a techno-economic analysis of BESS+DCFC systems using data from sources in Colorado. Section 2 includes subsections that detail an analysis of rate structures from Colorado utilities to examine the economic feasibility of pairing BESS and DCFC stations, considerations pertaining to BESS technology, optimal battery sizing, and as well as the costs and benefits associated with BESS+DCFC.

2.1: Modeling Methodology

Optimal sizing for BESS systems paired with DCFC will vary when considering the range of potential use cases and grid locations that such a system could be deployed. For example, the power and duration required for a BESS system deployed close to high-capacity transformers will likely be different than the specifications desired for a system deployed at the grid-edge, as BESS systems deployed at various locations are likely to have different primary use cases and be providing different benefits. Accordingly, and in order to explore tradeoffs between BESS sizing, this study treated the primary BESS use case as a proxy for grid location. To align with the primary BESS benefits assessed in this study, BESS primarily providing demand charge management were considered as a proxy for systems located near high-capacity transformers and other system load, while BESS primarily enabling fast charging on single-phase lines and providing distribution system upgrade deferral were considered deployed at the grid-edge away from other system loads.

To enable a techno-economic analysis of BESS use cases across a variety of potential project contexts, a total of 27 charging scenarios were analyzed across a combination of variables, including: utilization rate (charges per day) and charging plaza size across three distinct geographic use cases. Additionally, information was collected from 55 rate schedules for small use,[36] commercial and small industrial customers from 23 of the Colorado utilities. The Project Team offers a comparative analysis of these rate structures and scenarios to provide the Colorado Energy Office (CEO) with an understanding of which rate structures and use cases would most benefit from BESS + DCFC pairing.

2.1.1: Defining Geographical Use Cases

This study provides a detailed comparative assessment of two specific benefits provided by BESS when paired with a DCFC; demand charge management and distribution system upgrade deferral. The applicability of deploying a BESS system to either of these benefits, as well as the optimal capacity and duration of the deployed system, will vary depending on multiple factors. Station utilization rates and the time distribution of charging load profiles will impact the cost-effectiveness of BESS deployed to mitigate operating costs of DCFC through demand charge management. Limited grid infrastructure will determine the relevance/value of deploying BESS to enable fast charging on single-phase power lines. Since station utilization, time distribution of charging and existing grid infrastructure vary throughout Colorado geographies, three geographical use cases were defined to guide modeling scenarios (in Tasks 2 and 3) and utility rate prioritization, as follows:

- **Rural:** DCFC deployments in areas of Colorado with low population density, likely used by a combination of local drivers and potentially drivers traveling long distances. When compared to

[36] While defined differently across utilities, small use or small commercial rates typically encompass systems requiring less than 50 kW of power

other geographical use cases, rural deployments are also more likely to be in areas with minimal grid infrastructure. In general, rural areas tend to have lower charger utilization rates.

- **Corridor:** DCFC deployments along major travel corridors in Colorado, likely used primarily by drivers traveling long distances. Charging in corridor locations occurs more sporadically compared to metropolitan areas, where there are more EVs and drivers have adopted more regular charging schedules, but generally more often than rural locations.[37] This category also includes areas that may be less densely populated or located further from metropolitan areas, where the majority of utilization is likely driven by recreation and tourism. This resulted in entities that service popular mountain destinations and areas in proximity to national and state parks. Corridor areas have moderate utilization rates.

- **Denver-Metro & North Front Range:** DCFC deployments in densely populated areas, used by a wide range of vehicles including local drivers running errands and commuting, municipal and commercial vehicles (e.g. delivery vehicles). Urban/suburban areas also include electrified fleet vehicles, including buses and utility-owned service trucks. The highest utilization rates are found in urban and suburban areas.

Table 9: Summary of BESS Grid Location & Primary Value Stream Assumptions

Geographic Use Case	Primary Challenge	BESS Value Stream(s)
Rural	• Lack of grid infrastructure required to support fast charging	• Enablement of service & distribution system upgrade deferral
Corridor	• High operating costs OR lack of grid infrastructure	• Multiple
Metro	• Low utilization & unfavorable rate structures lead to high operating costs	• Demand Charge Management

2.1.2: Load Profile Scenarios

In order to study the value and suitability of DCFC paired with BESS in Colorado, a basis of data was needed which was specific to the patterns of DCFC utilization in the state. CEO provided charging event records for 72 existing DCFC stations from a diverse set of geographies within Colorado, including more than 12,000 charging event records from between 2019 and 2021. A filtering process was applied across all events to remove any false events, such as plug-ins that were ended immediately, or events that did not deliver any consequential quantity of energy. For the events remaining after filtering, all events were segmented by the charging location and specific EV supply equipment (EVSE) serial number. For each event at each station, the event was tagged by its representative power level (in kW), and then allocated to the closest 15-minute intervals on the day (calendar date) in which the event occurred. The result was a time series of representative electric power loads for each individual station. A key element of this study was to identify differences in suitability for DCFC+BESS in diverse charging use cases across Colorado, under varying utilizations and varying charging plaza sizes. Accordingly, 24 load scenarios were identified for modeling optimal BESS sizing under the primary BESS services considered.

[37] See station utilization rates in Table 9.

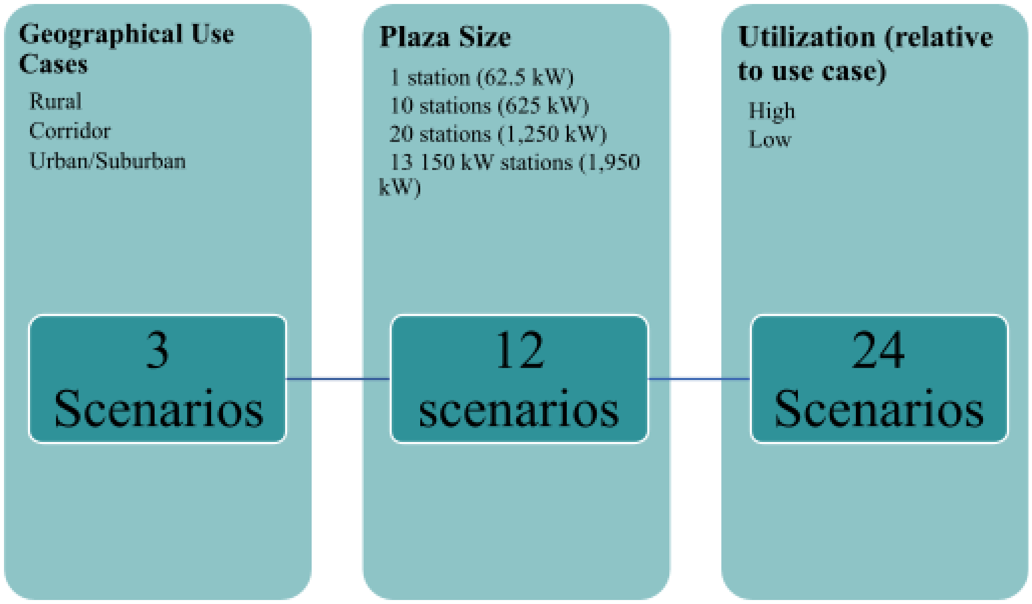


Figure 2: Summary of Load Profile Scenarios

Given the need to simulate different plaza total power levels for the three geographical use cases (rural, corridor, and metro), an assumed load profile for each use case and plaza level was required. The first step to create these profiles was to locate EV station load profiles from the existing data that appeared to be mostly complete, since significant data gaps can occur due to lapses in EV station network connectivity.[38] Next, stations were ranked by the total utilization, defined as the percent of charging intervals in which the station was dispensing electricity as compared to the total possible charging intervals since the date when the station became active. All existing charging plazas for which data was provided are summarized below. Utilizations reported are for an entire plaza.

Table 10: Existing DCFC Charging Plazas - Source Data

	Plaza Location	Utility	Utilization (Active Weeks)	Utilization (6 Months)
Metro Area	Fort Collins *(two ports)*	City of Fort Collins	0.57%	0.85%
	Denver A	PSCo	5.14%	9.88%
	Longmont[39]	**Longmont Power**	**11.92%**	**15.59%**
	Thornton	PSCo	1.40%	1.68%
	Pueblo West	Black Hills Energy	0.41%	0.34%

[38] For example, one DCFC located in the Denver area shows no charging data in the most recent 6-month period, but previously had a utilization of 3.35%. See Table 9.

[39] This charging plaza is located at the Greeley Nissan Dealer in Longmont. The extremely high utilization rate, compared to other plazas, may be due to Nissan's "No Charge to Charge" program which provided two years of free charging to drivers at participating locations (https://www.greeleynissan.com/blogs/1612/no-charge-to-charge-ending/)

	Greeley	PSCo	1.86%	2.11%
	Colorado Springs	Colorado Springs Utilities	2.03%	2.03%
	Denver B	**PSCo**	**3.35%**	**0.00%**
	Golden	PSCo	0.15%	0.18%
	Brighton	United Power	0.51%	0.78%
Corridor	Estes Park	Estes Park Light & Power	1.16%	1.24%
	Steamboat Springs *(two ports)*	Yampa Valley Electric Association	1.70%	1.70%
	Vail	Holy Cross Energy	3.88%	3.86%
	Salida	Sangre De Cristo	2.06%	2.02%
	Pagosa Springs	La Plata Elec Assoc.	2.00%	1.95%
	Basalt	**Holy Cross**	**2.94%**	**2.88%**
	Aspen	Aspen Municipal	1.56%	3.01%
	Grand Junction	Grand Valley Power	0.73%	0.69%
	Carbondale	Holy Cross	0.69%	0.72%
	Buena Vista	Sangre de Cristo	0.33%	0.23%
	Gypsum	**Holy Cross**	**0.48%**	**0.46%**
	Avon	Holy Cross	0.76%	0.81%
	Eagle	Holy Cross	1.46%	0.94%
	Keenesburg	United Power	0.30%	0.30%
	Gypsum	Holy Cross	0.35%	0.35%
	Minturn	PSCo	0.12%	0.12%
	Vail	Holy Cross	0.01%	0.01%
	PSCo	PSCo	1.81%	1.86%
	Montrose	Delta-Montrose Electric Association	1.45%	1.64%
	Rifle (*two ports*)	*PSCo*	0.68%	0.39%
	Dinosaur	Moon Lake	0.58%	0.59%
	Edwards	Holy Cross	0.57%	0.79%
	Fraser	Mountain Parks Electric	1.39%	1.39%
Rural	Yampa	Yampa Valley Electric Association	0.03%	0.02%
	Lake City	Gunnison County Electric	0.03%	0.00%
	Crested Butte	**Gunnison County Electric Assoc**	**0.19%**	**0.15%**
	Meeker	White River Electric	0.17%	0.10%
	Del Norte	**San Luis Valley Rural**	**0.22%**	**0.22%**
	Northwood (*two ports*)	San Miguel Power Assoc.	0.026%	0.26%

Load profiles from six existing stations were chosen as being representative of the three geographical (marked in bold above), with one lower utilization tier profile and one higher utilization profile for each. All chosen profiles were from stations with a 62.5 kW nameplate capacity. Understanding that rural stations may never be as highly utilized as urban/suburban stations, the choice was made not to define low and high utilization as a specific percent value, but rather to identify low and high utilization profiles relative to each geographic use case. Additionally, the presumption was made that choosing the existing station with the absolute highest utilization for each geographic use case as the representative high utilization profile for that use case would provide insight into load profile changes under near-term (3-5 years) growth of EV adoption. Generally, the low utilizations observed in the existing charging plazas in Colorado align with low utilizations nationally.[40] The highest utilizations observed (Longmont) approach the highest DCFC utilization observed nationally in California.[41]

The six selected load profiles were then manipulated to reflect the load profile of a charging plazas with a total of ten and twenty stations. The recombination of load profiles to simulate larger charging plazas based on field data from previous use of existing chargers is not a trivial exercise. Care must be taken specifically to address the fact that simply doubling the usage in each interval – for example, by combining two identical profiles ¬ creates artificial (and unrealistic) spikes in load. The random variability of DCFC station usage, which is shown from any given week to the subsequent week of event data, was measured and determined not to have a sufficient correlation coefficient (i.e. average correlation below 0.3). The usage of individual stations within a plaza is likely to remain uncorrelated and therefore, it is not unreasonable to combine each load interval power from ten random distinct weeks from the existing load profile usage patterns from the selected appropriate station use case in order to simulate the load increase by a factor of ten. Thus, the electricity power profile of a future DCFC plaza with ten stations (625 kW total plaza nameplate power rating) was considered to be generally approximated by combining ten distinct weeks from the existing load profile in the appropriate use case (not accounting for electricity load from controls, network equipment, or efficiency losses within each DCFC). Likewise, a hypothetical twenty station plaza (1,250 kW total plaza nameplate power rating) was created with a utilization simulated by combining twenty random distinct weeks from the existing load profile usage patterns selected from the existing load profile in the appropriate use case.

Finally, in order to study the impacts of increased per port power output on load profiles and BESS sizing, load profiles for a fourth plaza configuration were constructed. This plaza was modeled as consisting of thirteen 150 kW ports (1,950 kW). Since many currently available electric vehicles are not capable of charging at rates above 100 kW, the majority of this study focused on load profiles consisting of ports under the 100 kW threshold.[42] However, there are multiple 150 kW and 350 kW ports being planned for construction in Colorado.[43] As such, this final plaza configuration was created to begin exploration of the impact of higher capacity fast chargers being developed for future vehicle capabilities.[44] This plaza configuration was not modeled under a rural geographic use case because of the unlikelihood of such a plaza being developed in such a use case in Colorado. This was assumed to be unlikely because of the lack of expected demand for that number of fast chargers exceeding 100 kW in one place.[45]

---

[40] Electric Vehicle Charging Implications for Utility Ratemaking in Colorado, NREL
[41] Electric Vehicle Charging Implications for Utility Ratemaking in Colorado, NREL
[42] Evaluating Multi-Unit Resident Charging Behavior at Direct Current Fast Chargers, UCLA Luskin Center for Innovation
[43] Discussions with CEO staff indicated that such stations are being submitted under various state funding programs.
[44] Further exploration of the implications of higher powered charging stations is noted under Areas for Further Study.
[45] The “Colorado charging infrastructure needs to reach electric vehicle goals” study completed by ICCT in 2021 showed many rural counties around the state needing under 10 DCFC by 2035. Additionally, it was assumed that the power of those stations would range between 26.4 kW to 130 kW.

Table 11: Summary of Plaza Sizes Analyzed

Small Plaza	Medium Plaza	Large Plaza	Large Plaza (150 kW Ports)
One port (62.5 kW)	Ten ports (625 kW)	Twenty Ports (1,250 kW)	Thirteen ports (1,950 kW)

2.1.3: Rate Survey

Based on the market survey, the Project Team identified 21 Colorado utilities to be considered during the rate and technical analysis. The criteria these utilities held in common align with the segmentation methodology. The Project Team completed a rate survey of utilities in Colorado to:

1. Provide a comprehensive review of relevant commercial and EV-specific rate structures, including demand charges and energy costs,
2. Identify the average demand and energy charges across Colorado in order to inform the BESS sizing modeling required prior to identifying "break-even" demand charges, and
3. Create a database of specific rates to inform additional modeling to identify specific opportunities for priority project deployments.

Three additional organizations were included (Fort Collins Municipal, Estes Park, and Mountain Parks Electric) because they represented geographical use cases that could yield insightful results from cost modeling and analysis, utilization, and load data from current charging stations in their service area was readily available (Mountain Parks & Estes Park), or they encompassed a sufficiently large urban/suburban population (Fort Collins). Various rates from the Public Service Company of Colorado were also analyzed due to their majority share of the Colorado electricity market. The Town of Frederick, City of Center, and City of Lamar were excluded due to low utilization rates and the inclusion of other entities that represent more salient examples of similar use cases.

Rate data was collected from a combination of publicly available tariff documents and stakeholder interviews. The rates recorded encompass a range of possible DCFC station capacities, from individual or dual port systems of less than 25 kW to entire stations or plazas of over 5000 kW total.

2.1.4: BESS Sizing & "Break-Even" Demand Charge Calculation

Optony's proprietary battery simulation model (MDOCs) was used to identify the optimally sized battery system to maximize savings from demand charge management across each load profile scenario. Initial sizing was modeled assuming a demand charge of 13 $/kW and an energy charge of 0.08 $/kWh, the average demand charge and energy charge observed through the survey of utility rates of the priority Colorado utilities.[46] Once an initial optimal sizing was determined, that sizing was held constant and demand charges were varied to determine the break-even demand charge for each scenario. The break-even demand charge is defined as the minimum demand charge required to provide breakeven savings when compared to the total amortized costs of the battery over the lifetime of the system (10 years).

[46] Coincident demand charges were not included in this average. Coincident demand charges are additional demand charges applied to peak demand of a load occurring coincidently with a given utility's system peak. Generally, they apply to loads with a peak of 750 kW and are calculated at the end of each month. Given the unpredictability of the monthly cost of coincident demand charges to a utility customer, they were excluded from consideration when determining BESS sizing. The potential impacts of coincident demand charges are discussed under Findings.

2.1.5: "Break-Even" Battery Cost Estimation

To complement the break-even demand charge analysis, the Project Team also used Optony's proprietary battery simulation model (MDOCs) to perform the inverse analysis and determine a break-even BESS cost ($/kWh) for actual Colorado utility rates. Each rate identified through the Rate Survey was categorized by the geographic use case assigned to its utility. Applicable rates for each of the 24 load profiles were identified based on matching geographical use case and the peak demand observed in the profile. Then, simulations were completed for each of the 24 load profiles and the applicable rates, resulting in a total of 157 simulations. Each simulation provided a break-even battery system cost in $/kWh, under which a BESS deployed for demand charge management on the load profile in question is likely to make economic sense.

2.1.6: Battery Cost Assumptions

In order to inform the techno-economic analysis, several assumptions related to battery costs were necessary. Cost estimates for BESS are rather varied. The economics of BESS vary greatly depending on battery chemistry, rated energy capacity, power capacity, AC vs DC coupling configuration, any special environmental factors at the project site, and more. In general, larger BESS installations will benefit from economies of scale and have a lower $/kWh or $/kW levelized cost. While many studies propose single value $/kWh estimates for BESS cost, these numbers often miss the importance of economies of scale, leading to both over- and underestimates for the levelized cost of storage depending on what sizing assumptions were used. For this reason, we consider both the model outlined in NREL's US Solar Photovoltaic System and Energy Storage Cost Benchmark (Jan 2021), and the empirical data discussed in the DOE's Energy Storage Technology and Cost Characterization Report (Jul 2019). The DOE report presents average cost data from California's SGIP program in 2017; the resulting average for these systems is $932/kWh, with a range from $722-$1,383/kWh.[47],[48] The NREL report's model is in some agreement with these figures, but instead presents cost estimates based on system kW/kWh sizing. Below is a table for their "Commercial Li-ion ESS" scenario, which assumes 600 kW of power capacity.

Table 12: Summary of NREL Modeled BESS Costs

	600 kW; 2,400 kWh (4 hrs)	600 kW; 1,200 kWh (2 hrs)	600 kW; 600 kWh (1 hr)	600 kW; 300 kWh (0.5 hrs)
EPC Costs ($/kWh)	353	587	993	1,772
Developer Costs ($/kWh)	76	121	214	396
Total Estimate ($/kWh)	469	708	1,207	2,167

[47] National Renewable Energy Laboratory, US Solar Photovoltaic System and Energy Storage Cost Benchmark, 2021 https://www.nrel.gov/docs/fy21osti/77324.pdf

[48] Pacific Northwest National Laboratory, Energy Storage Technology and Cost Characterization Report, 2019 https://www.energy.gov/sites/default/files/2019/07/f65/Storage%20Cost%20and%20Performance%20Characterization%20Report_Final.pdf

To complete our calculations of break-even demand charges, a cost of 900 $/kWh was used. In later tasks, system cost will be varied to determine BESS feasibility across actual utility rates in Colorado.

2.1.7: System Configuration Assumptions

Assumptions of BESS+DCFC system configurations differed depending on the BESS use case being modeled. For the BESS sizing analysis for fast charging at the grid-edge, the BESS+DCFC system configuration assumed for modeling was a Battery-integrated DCFC. In all scenarios considered during the demand charge management and rate analysis, an AC-coupled BESS and DCFC system was assumed, as this is the most common system architecture of similar projects currently deployed. The other system architectures reviewed in Section 1, DC-coupled BESS and DCFC and Battery-integrated DCFC are less commonly deployed to date.

2.2: Results of Load Profile Simulation

The load profiles created for each scenario range in peak demand from 20 kW and 51 kW for the low and high utilization rural single-station plaza up to 205 kW and 317 kW for the low and high utilization urban twenty-station plaza.[49] Importantly, and in all cases, peak demand seen by the electric grid never approaches the nameplate capacity of the plaza size. This is primarily due to the assumption that the larger plaza sizes are made up of multiple 62.5 kW ports and relatively low load factors, even on high utilization stations. It is uncommon for more than a few ports in a plaza to be used coincidentally, keeping peak demand low. The maximum charging rates of electric vehicles currently on the road may be another factor deflating peak loads. Existing charging data revealed that it was uncommon for a single charging port to reach maximum output, with peak demands never exceeding 50 kW, indicating that the vehicle is likely the bottleneck controlling the power demand seen at the meter.

Looking forward, higher nameplate charging stations (e.g., 350 kW) and an increased penetration of vehicles capable of high direct current charging rates may impact these results and cause peak demands to approach plaza nameplate ratings. However, as port ratings increase, the duration of each charging event is expected to decrease, reducing the likelihood of coincident charging sessions across ports causing increased peak grid draw. As such, utilization (load factor) of a plaza and an increased penetration of medium- and heavy-duty vehicles with larger batteries are likely to have an equal, or potentially higher, impact on peak grid draw compared to port ratings.

2.3: Results: BESS Sizing for Fast Charging at the Grid-edge

DCFC deployed at the grid-edge were considered likely in the Rural and Corridor geographic use cases described above. Table 6, below, summarizes optimal battery sizing results for systems enabling fast charging at the grid-edge and providing distribution system upgrade deferral across a range of utilization scenarios and charging plaza ratings.

In the grid-constrained charging scenario, each geography was assumed to not only have different representative charging profiles (see Task 3, Methodology), but also different ability to provide power to the station without requiring significant infrastructure upgrades to the local distribution system. The assumed maximum power draw for a Rural geography at the grid-edge was 10 kW. Generally, the smallest service provided by the grid will be single-phase power at 120/240V. Assuming a standard 100

[49] A complete summary of peak and average demands for each profile can be found in the Appendix under Table A-1.

amp service panel, this service is capable of providing 12 kW. Thus, an assumed maximum grid power of 10 kW is conservative.

Under the assumed system configuration of a battery-integrated DCFC, grid output is assumed to be the charge rate of the BESS. Each site's battery was then sized such that it could provide the prescribed charging plaza size (1 station, 10 stations, or 20 stations, by scenario) with sufficient power to provide fast charging to all drivers while only charging at the assumed grid limit. The goal is to identify the minimum amount of storage required to maintain service (charging output at the nameplate station power) without dropping to 0% state of charge in the BESS.

Table 13: Energy Ratings to Provide Fast Charging at Grid-constrained Rural DCFC Plazas

	Minimum Battery kWh Required to Maintain Level of Service		
Rural Plaza Capacity	**1 Station (62.5kW)**	**10 Stations (625 kW)**	**20 Stations (1,250 kW)**
Low Utilization	15 - 25 kWh	24 – 40 kWh	24 – 40 kWh
High Utilization	36 – 60 kWh	72 – 120 kWh	78 – 130 kWh

Due to the relatively low utilization of Rural DCFC (when compared to the Corridor and Urban geographic use cases), even in a high utilization scenario, the minimum energy rating (kWh) required of a BESS to provide fast charging services to all drivers remains low across all plaza sizes. This means that the BESS system cost required to provide fast charging at locations in Colorado with single-phase grid service is likely to be low. The Boost Charger manufactured by Freewire Technologies, the only BESS-integrated DCFC currently available, features a 160 kWh battery. While it may be useful to provide multiple charging ports when developing a charging plaza, all scenarios summarized in Table 6 could be served by the battery duration in a single Boost Charger unit.

Initial results indicated that, when assuming a grid service level of 100kW to charge the BESS, there was limited need for a battery to provide fast charging capability for load profiles in the Corridor use case. Accordingly, battery size modeling for all Corridor load profiles was repeated under an assumption of 10 kW grid service, matching the initial assumption for the Rural use case. This modeling also considered the fourth plaza size consisting of thirteen 150 kW charging stations.

Table 14: Energy Ratings to Provide Fast Charging at Grid-constrained Corridor DCFC Plazas

	Minimum Battery kWh Required to Maintain Level of Service			
Corridor Plaza Capacity	**1 Station (62.5kW)**	**10 Stations (625 kW)**	**20 Stations (1,250 kW)**	**13 Stations (150 kW ports)**
Low Utilization	18 – 30 kWh	42 – 70 kWh	48 – 80 kWh	54 – 108 kWh
High Utilization	90 – 150 kWh	420 – 700 kWh	*Infeasible*	3,000 – 5,000 kWh

When compared to the Rural charging use case, battery capacities are higher in all cases under a Corridor charging use case. Importantly, when considering a 20 station DCFC plaza under high utilization, no realistic battery capacity could enable fast charging on single-phase power.

2.4: Results: Demand Charge Management & Rate Analysis

In order to assess the value that BESS can provide to DCFC operators across varying utility rates, DCFC utilization, use case and plaza sizes in Colorado, the Project Team sought to identify a "break-even" demand charge for BESS across the range scenarios of defined through the creation of varying load profiles. The break-even demand charge is defined as the minimum demand charge required to provide breakeven savings when compared to the total amortized costs of the battery over the lifetime of the system. Additionally, the Project Team applied the actual Colorado utility rates to the range of load profiles considered and calculated an estimated "break-even" BESS cost for each rate.

2.4.1: Rate Analysis

This section provides a rate structure analysis of which types of utility rate structures would benefit from deployment of BESS paired with DCFC. Specifically considering BESS systems providing demand charge management (DCM) to reduce DCFC operating costs. Findings from the rate survey suggest that for all utilities, all commercial DCFC charging falls under either traditional commercial business rates, or EV specific charging rates. Rate structures among Colorado utilities encompass a wide variety of designs, which are tiered by the capacity required of a given system. The exact system demand and therefore rate tier that is given to a particular system is evaluated on a case-by-case basis, and therefore may be difficult to establish prior to submitting an application for interconnection. The breakdown of rate designs observed across all utilities is as follows:

- **Standard Commercial:** A majority of the rates examined among shortlisted utilities (29 of 35) are standard commercial rates with a monthly fixed charge, a per kWh energy charge, and demand charges. Five commercial rates include system coincident peak charges, which are only on the highest capacity tiers of the utilities that have them (750-2000+ kW rates).

- **Time of Day (TOD):** Four shortlisted utilities developed TOD rates, typically optional for a given capacity tier, which offer the customer the ability to pay different rates at different hours of the day. Rates in this category include both on and off-peak energy and demand charges, and critical peak charges. Peak hours for all TOD rates are detailed below:

- **EV Charging specific:** Utilities with these rates other than PSCo and Mountain Parks Electric Association (Yampa Valley Electric Association, Delta Montrose Electric Association, and La Plata Electric Association) are not shortlisted because they either lack demand charges or offered very low demand charges and would be conducive to EV charging without BESS. Given the high capital costs, lack of best practice data, and lack of expertise on how to fully utilize BESS, it is likely not a worthwhile investment in lieu of a highly prohibitive rate structure.

Values are organized into summer and non-summer rates, further categorized by rate design (Standard commercial, time of day, and EV charging specific), as well as by component (Energy, demand, critical peak, coincident peak, monthly fixed, off-peak and on-peak). The range of months defined as summer months is listed for utilities in which summer and non-summer rates are different. Below are descriptions of the various elements that make up Colorado rate designs:

Table 15: Elements of Colorado Rate Design

Monthly service	Charges that are evaluated monthly and do not change with the amount of kWh pulled from the grid. In rates indicated by comments in the CO Utilities Rates tables, monthly service charges scale up slightly with the amount of kW capacity of a system.
Volumetric Energy	Charges that are evaluated per kWh that pass through a meter. Average volumetric charge per kWh among shortlisted utilities was $0.0707 during summer months, and $0.0674 during non-summer months. Energy charges are negatively correlated with the size of the system; customers save $0.0127 per kWh on average for every increase in the tier.
Demand	Demand charges are a per kW charge that evaluates the highest level of demand during any 15-minute interval experienced throughout the month. Among shortlisted utilities, these charges vary from $3-28 per kW, with an average of $12.3 per kW in the summer and $11.8 non-summer. All demand charges are evaluated on a monthly basis unless otherwise noted.
Coincident Peak	System coincident peak charges are evaluated separately from and added in addition to standard demand charges. Coincident peak periods occur during the 1 hour of each month where system demand is highest. Coincident peak timing is evaluated at the end of the month and cannot be predetermined. Coincident peak policies vary across utilities, and are detailed in the comments of CO Utilities Rates tables. All coincident peak demand charges are evaluated on a monthly basis unless otherwise noted.
Critical Peak	Critical Peak pricing is unique to PSCo. These can occur up to 15 times a year, be up to four hours in duration, are called between 12 p.m. and 8 p.m. on non-holiday weekdays and cannot be called more than once per day. Customers will receive day-ahead notification when critical peak days are called.
Multi Tiered Rates	Multi Tiered rates (denoted by asterisks on the Colorado Utility Rates supplemental spreadsheet are rates in which within a given capacity tier, there are progressive rates for increasing levels of kWh. For example, all commercial customers larger than 50 kW in Highline Electric Association's service area pay $0.0982 per kWh for the first 1600 kWh used. All kWh metered in addition to that first 1600 is charged at a rate of $0.0838 per kWh.

2.4.2: Optimal Battery Sizes

Optimal battery sizes identified range from a 10 kW battery with a 1.75 hour duration up to a 130 kW battery with a ~40 minute duration. Port sizes are modeled as 62.5 kW, with Small plazas encompassing 1 port, Medium plazas with ten ports (625 kW), and Large plazas with twenty ports (1,250 kW). Also included in modeling were Large plazas with thirteen higher powered 150 kW ports (1,950 kW).

Table 16: Optimized Battery Sizes Across Load Scenarios

	Low Utilization				High Utilization			
Plaza Size	*Small*	*Medium*	*Large*	*Large (150 kW Port)*	*Small*	*Medium*	*Large*	*Large (150 kW Port)*
Rural	10 kw, 1.76 hrs	25 kW, 0.48 hrs	25 kW, 0.48 hrs	N/A	25 kW, 0.96 hrs	30 kW, 0.8 hrs	45 kW, 0.64 hrs	N/A
Corridor	25 kW, 0.64 hrs	25 kW, 0.64 hrs	30 kW, 0.43 hrs	55 kW, 0.32 hrs	25 kW, 1.28 hrs	60 kW, 0.96 hrs	80 kW, 0.64 hrs	125 kW, 0.48 hrs
Urban	15 kW, 0.96 hrs	55 kW, 0.8 hrs	90 kW, 0.8 hrs	95 kW, 0.32 hrs	25 kW, 0.8 hrs	90 kW, 0.8 hrs	130 kW, 0.64 hrs	160 kW, 0.32 hrs

As plaza size and utilization increase, the peak power (kW) of the recommended batteries also increases. However, as peak power increases the required duration (kWh) decreases. This is likely because systems with higher peak power can charge faster, therefore requiring a smaller duration and enabling minimization of system costs. Load factors across all load profiles remain low enough to provide time to recharge a short duration battery.

2.4.3: “Break-Even” Demand Charges

Break-even demand charges range from 2.5 $/kW (rural, low utilization ten port and twenty port plazas) up to 8.50 $/kW (rural, low utilization single-port plaza). Break-even demand charges are lower for low utilization loads, which aligns with previous research demonstrating that the marginal benefit of BESS providing DCM fell as utilization increased.[50] Across all scenarios, the break-even demand charges were lower than expected and are unlikely to significantly limit which Colorado rate schedules are a good fit for pairing a BESS with DCFC to provide demand charge management. The break-even demand charges identified hold for all reasonable (under 0.85$/kWh) energy charges.

[50] M. Muratori et al., “Technology Solutions to Mitigate Electricity Cost for Electric Vehicle DC Fast Charging”

Table 17: Break-Even Demand Charges Across Load Scenarios.

	Low Utilization				**High Utilization**			
Plaza Size	*Small*	*Medium*	*Large*	*Large (150 kW Port)*	*Small*	*Medium*	*Large*	*Large (150 kW Port)*
Rural	$ 8.50	$ 2.50	$ 2.50	N/A	$ 5.50	$ 4.00	$ 3.00	N/A
Corridor	$ 3.50	$ 3.00	$ 3.00	$ 1.50	$ 5.50	$ 4.50	$ 5.00	$ 3.00
Urban	$ 6.00	$ 4.00	$ 4.00	$ 2.00	$ 5.00	$ 4.00	$ 3.50	$ 2.00

2.4.3: "Break-Even" System Costs

157 model runs were completed to determine the breakeven BESS cost ($/kWh) for each load profile across each applicable Colorado utility rate identified. As expected, due to the dependency of demand charge management savings on rate schedule and load profile, break-even costs ranged considerably from 800 $/kWh to 13,000 $/kWh. 93% of scenarios had break even system costs greater than 900 $/kWh, the system cost assumed in the breakeven demand charge analysis. Table 17 provides a summary of breakeven system costs by load profile.

Table 18: Summary of Break-even BESS System Costs

Plaza Size	Utilization	Rural	Corridor	Urban
		Min – Avg – Max System Cost ($/kWh)	Min – Avg – Max System Cost ($/kWh)	Min – Avg – Max System Cost ($/kWh)
Small	**Low Utilization**	1,600 – 1,900 – 2,100	1,500 – 3,800 – 5,700	700 – 1,514 – 2,600
	High Utilization	2,500 – 2975 – 3,300	800 – 2,100 – 3,200	900 – 2,114 – 3,700
Medium	**Low Utilization**	1,400 – 7,100 – 12,900	1,800 – 4,688 – 7,100	900 – 2,114 – 3,700
	High Utilization	800 – 3,957 – 7,200	1,200 – 3,075 – 4,600	1,100 – 2,543 – 4,400
Large	**Low Utilization**	1,400 – 7,257 – 13,000	2,200 – 5,700 – 8,600	900 – 2,057 – 3,600
	High Utilization	1,000 – 5,143 – 9,300	1,100 – 8,738 – 13,200	1,400 – 3,071 – 5,400
Large (150 kW ports)	**Low Utilization**	N/A	3,500 – 8,738 – 13,200	2,700 – 6,300 – 10,900
	High Utilization		2,300 – 5,825 – 8,800	2,700 – 6,443 – 11,100

2.4.4: Priority Utility Territories

The analysis was designed to identify optimal battery sizes to provide DCM across a range of potential DCFC load profiles unique to Colorado and identify the break-even demand charge amount required to make the optimally sized systems economically feasible. This analysis was completed with the goal of identifying a list of recommended utilities for CEO to target for engagement. Table 19 reports the estimated break-even charge level for each geographical use case and range of plaza sizes. Results are also separated by the utilization scenarios considered, which were defined as "low" and "high" with the actual utilization percentage being determined relative to the range of utilizations for existing stations observed in each use case.

Table 19: Break-even Demand Charges Compared to Actual Demand Charges

Geographic Use Case	Break-Even Demand Charges - Low Utilization (Small, Medium, Large, Large [150 kW Ports])	Break-Even Demand Charges - High Utilization (Small, Medium, Large, Large [150 kW Ports])	Range of Applicable Utility Demand Charges
Rural	$8.50 - $2.50 - $2.50	$5.50 - $4.00 - $3.00	$3.00 - $28.50
Corridor	$3.50 - $3.00 - $3.00 - $1.50	$6.00 - $4.00 - $4.00 - $2.00	$8.00 - $17.00
Urban	$5.50 - $4.50 - $5.00 - $2.00	$5.00 - $4.00 - $3.50 - $2.00	$4.40 - $14.91

However, results indicated that, under the load profile scenarios examined, **demand charges are unlikely to be a limiting factor in determining BESS feasibility.** Only utilities with rates at the low end of the demand charge range, such as Grand Valley Power and City of Longmont, may pose challenges to the economic feasibility of BESS and not require deployment of technology to control DCFC operating costs depending on the capacity of the system. Even for these utilities, however, some commercial rates have higher demand charges that well exceed the break-even amounts.[51]

To identify priority utilities territories for deploying DCFC with BESS designed to reduce operating costs, an alternative approach was needed. Instead of focusing on break-even demand charges, priority utilities can be identified by reviewing results of the break-even system cost analysis. Table 12 provides the minimum, maximum and average break-even system costs by utility. Complete results for each scenario and utility rate can be found in Appendix B.

[51] Longmont has the highest urban demand charge ($14.91) for systems with capacity between 50 and 800kW, but low demand charges in the smallest and largest capacity tiers. Grand Valley's demand charges decrease with capacity; 50kW+, 500kW+, and 1000kw+ capacity tiers have demand charges of $16, $9, and $3 respectively.

Table 20: Summary of Break-even BESS System Costs by Utility

Utility	Minimum Break-even System Cost ($/kWh)	Maximum Break-even System Cost ($/kWh)	Average Break-even System Cost ($/kWh)
White River	$ 7,200	$ 13,000	$ 10,600.00
Poudre Valley	$ 2,100	$ 8,700	$ 5,650.00
Estes Park	$ 1,100	$ 12,500	$ 6,012.50
Highline Electric	$ 1,600	$ 7,600	$ 4,466.67
Intermountain Rural	$ 1,300	$ 11,700	$ 4,662.50
Grand Valley Power	$ 800	$ 7,300	$ 3,335.71
Mountain Parks	$ 800	$ 13,200	$ 3,608.33
City of Fort Collins	$ 1,600	$ 7,700	$ 3,700
PSCo.	$ 900	$ 11,100	$ 3,141.67
City of Longmont	$ 700	$ 9,200	$ 3,031.25

Based on market research summarized in the "Methodology" section, an expected range of actual BESS costs is 469 $/kWh to 2,167 $/kWh, with shorter duration systems likely to fall toward the high end of this range.[52] High average break-even system costs indicate utility territories where BESS are likely to be financially feasible when deployed to reduce operating costs of DCFC. White River stands out as a utility territory where all commercial rates applicable to DCFC support deployment of BESS. Poudre Valley and Estes Park Municipal are also appealing, given high average break-even system costs. Overall, every utility included in the analysis has rates that are conducive to BESS deployment for demand charge management. However, the wide range of system costs within utilities demonstrates the significant impact of specific utility rates on project feasibility.

This analysis focused primarily on hardware costs for BESS. However, soft costs are likely to have a large impact on the feasibility of a given project and represent a variable cost that incentive dollars provided by CEO could address. Given the small BESS sizes identified for each load profile scenario, soft costs, such as interconnection studies, can have a large impact on the unit cost of the system even if the absolute value of the soft costs is low. As an illustrative example, $20,000 in soft costs applied to a 25 kW, 1-hour battery equates to an increase in unit cost of 800 $/kWh. **Focusing funding efforts on utility territories where average break-even cost is close to the high end of expected hardware costs and soft costs may push BESS cost above the break-even threshold, such as Intermountain Rural, Mountain Parks, City of Fort Collins, and even PSCo. This is likely the most effective use of incentive dollars to enable BESS and DCFC deployment.**

[52] See Table 20 and the preceding paragraph.

When considering territories where CEO should focus funding efforts on BESS to reduce operating costs, the territories mentioned above, that have rates very conducive to BESS deployment, are not recommended. BESS deployment alongside DCFC's in these territories is likely to be market driven since the savings opportunities are significant and appealing to system developers. Instead, it is recommended that CEO focus funding programs on utility territories, such as those listed above, where rates may or may not support BESS deployment, depending on the scale of soft costs.

Section 3: Detailed Costs and Benefits of BESS + DCFC

This section contains an analysis of the costs and benefits of deploying BESS with DCFC in regards to a variety of key stakeholders and market participants, defined as market segments.

The economic viability of public DCFC is challenged by a combination of factors, including high upfront capital costs, infrastructure costs associated with line extensions and service upgrades, operating costs that are dominated by high demand charges, and soft costs that are associated with interconnection processes and project implementation. While there are likely to be unique costs and considerations regarding BESS+DCFC systems, there is evidence that some of these costs can be mitigated through implementation of BESS. Benefits of BESS also include (limited) ancillary benefits, resiliency, renewable integration, distribution upgrade and infrastructure investment deferral, as well as the advancement of state EV adoption goals. While it could be inferred that BESS can also allow for shifting load to accommodate more renewables, the direct impact of BESS implementation alone on GHG emissions requires further discussion. These costs and benefits could manifest in various ways for utilities, ratepayers, and DCFC developers.

In order to summarize how various costs and benefits of combined DCFC and BESS systems apply to the Colorado market, four relevant market segments were identified. Each segment is defined below.

Colorado Ratepayers: Households and businesses that pay electricity bills to investor-owned, municipal and cooperative utilities in Colorado. Benefits that accrue to all of Colorado, such as emissions reductions, should be considered as accruing to this market segment.

DCFC Owners & Operators: Entities that own and operate DCFC and BESS systems. This market segment is inclusive of system developers and long-term owner/operators, which may or may not be the same entity. This market segment is mostly 3rd party entities but may also include site owners.

DCFC Site Hosts: Entities that own the site where the DCFC and BESS system is deployed, but do *not* own the system. Cases where the site owner also owns the system are included in the DCFC Owners & Operators market segment.

Utilities: Investor-owned, municipal and member-owned cooperative utilities in Colorado. These entities may or may not own the DCFC and BESS systems. Costs and benefits applicable to this market segment in both ownership scenarios are considered in this document.

Table 21: Summary of Costs and Benefits by Market Segment

Market Segment	Costs	Benefits
Colorado Ratepayers	• Utility Owned DCFC Infrastructure, including BESS, would be added to the rate base and recovered through customers rates. • Make Ready Incentives and other rebates are ratebased in the cost of service and recovered in rates.	• Increased access to DCFC infrastructure • Emissions reductions from enabling EV adoption through greater access to charging • Economic benefits (cheaper charging) from reduced DCFC operational costs • Deferred distribution system upgrades that would normally be rate based • May improve equitable access to areas not served by the market (disadvantaged communities)
DCFC Owners & Operators (3rd Party or Site Host)	• Increased hardware costs compared to DCFC only project (varies by utilization rate due to changes in optimal battery size) • Soft costs of development (e.g. interconnection, permitting) • Possibility for easier permitting process	• Reduced operating costs • Decreased project costs if battery can be used to avoid electrical upgrades • Increased uptime • Demand charge management
DCFC Site Hosts	• If site host is system owner, see above • Depending on arrangement, could be reduction in site access (e.g. easements or leases) • Possibility for easier permitting process	• If site host is system owner, see above • Amenity to customers or visitors
Investor-owned, Municipal and Member-owned Cooperative Utilities	• Increased hardware costs, compared to DCFC-only installations • Increased soft costs from staff time, either related to project management or interconnection staffing • Increased uncertainty and engineering considerations, depending on BESS technology	• Wholesale power arbitrage • System peak shaving • Other ancillary services such as load flexibility to integrate renewables and meet renewable energy goals

3.1: Costs

In this analysis, BESS + DCFC costs are categorized into charging and BESS hardware and equipment, utility interconnection and make-ready infrastructure, project development and soft costs, and operating costs, including electricity costs and maintenance costs.

3.1.1: DCFC, BESS Charging Hardware and Equipment

DCFC and BESS equipment and hardware includes the costs of charging hardware, management software, communications hardware, weatherization and safety components. Given the increasing growth in development of public DCFC charging hardware, these costs are well documented for DCFC systems alone, but can still vary considerably based on a number of factors and are relatively uncertain for a BESS coupling. According to the U.S. DOE, the costs of DCFC units alone can range anywhere from $10,000-$40,000, depending on the power level and additional features.[53] An RMI analysis on DCFC project costs states that DCFC hardware ranges from $20,000-$35,800 for a 50 kW system, $75,600-$100,000 for a 150kW system, and $128,000-$150,000 for a 350 kW system.[54] 50 kW DCFC charging units outlined in Aspen Colorado's EV infrastructure plan estimated costs of approximately $45,116.[55] In Gunnison County, the total project costs of DCFC charging station materials totaled $62,000.[56]

Section 2.5 includes a summary of recent research on unit cost of battery storage, expressed in $/kWh. The National Renewable Energy Laboratory's (NREL) most recent US Solar Photovoltaic System and Energy Storage Cost Benchmark, published in January 2021, included a range of $469 to $2,167 $/kWh for commercial lithium-ion battery storage sized at 600 kW with various durations. DOE's Energy Storage Technology and Cost Characterization Report includes data from deployed systems in California's Self-Generation Incentive Program (SGIP) and provides a range of $722-$1,383/kWh.

In order to determine the overall hardware costs of a DCFC + BESS system, we can combine the costs of the two individually. Applying the unit cost of battery hardware discussed above to the optimal battery sizes identified in analysis conducted on battery sizing and cost optimization in Tasks 2 and 3 will provide a range of estimated BESS hardware costs that can be expected. BESS sized for demand charge management ranged from $10,800 to $25,000 for the rural use case, $11,000 to $52,000 for the corridor use case and $12,800 to $75,000 for the urban use case. BESS sized to provide fast charging at a grid-constrained site ranged from $18,000 to $94,000 for the rural use case and $21,000 to $504,000 for the corridor use case. Across all use cases considered, for the same plaza sizes, estimated battery costs are always higher in a high utilization charging scenario. The difference in battery cost between a high utilization scenario and low utilization scenario is greater for BESS designed to provide fast charging at a grid-constrained site than for systems designed to provide demand charge management.

3.1.2: Infrastructure costs

While charging hardware is responsible for a significant portion of total project budget, grid infrastructure may be both the greatest source of costs, variability, as well as opportunity for BESS to play a role in cost reduction. In this section, we analyze details primarily surrounding the interconnection and infrastructure costs associated with traditional DCFC, in order to better understand the aspects that can be reduced by implementation of BESS, or to the extent that BESS can substitute for infrastructure upgrades. The Idaho National Lab reports the main cost drivers for charging station infrastructure installations include electrical service upgrades, the condition of the ground surface under which the

[53] United States Department of Energy, Alternative Fuels Datacenter. https://afdc.energy.gov/case/2832
[54] Chris Nelder and Emily Rogers, Reducing EV Charging Infrastructure Costs, Rocky Mountain Institute, 2019, https://rmi.org/ev-charging-costs
[55] City of Aspen, Electric Vehicle Public Charging Infrastructure Masterplan
[56] It was not specified whether or not "materials" included additional hardware or infrastructure outside of the charging unit itself.

electrical conduits were installed, the length of the conduits from the power source to the service transformer and from the transformer to the fast charger, material costs, permits, and administration.[57] The previously cited RMI analysis on DCFC project costs states the elements of a charging site including charging hardware, management software and communication contracts typically only make up 10%-30% of total project costs.[58] DCFC projects outlined in Aspen's Electric Vehicle Public Charging Infrastructure Masterplan detailed installation and permitting costs of $15,050, or roughly 20% - 24% of total project cost.

Given that DCFC requires a 480V transformer and three phase line compared to the 240V transformer and single phase line requirement of L2 chargers, DCFC are more likely to induce significant infrastructure costs in the event that they require a service upgrade. Among surveyed utilities, several mentioned that the most expensive aspect of DCFC development is additional 3-phase wiring and transformers. PSCo estimates that for one 50 kW DCFC, infrastructure upgrade costs typically range to as high as $50,000 (multiple DCFC at one site could be more).[59] This poses a risk for remote and corridor locations that are far away from existing lines. For example, a 150kV rated transformer can cost $39,200, whereas smaller overhead transformers can cost between approximately $4,000-$10,000. In California, a 480 volt transformer and 100 feet of lines can cost $58,000.[60] New 15 kV service extensions can cost $47.7 per foot,[61] or $251,856 per mile of additional lines. However, this figure can also vary widely by region: A rural Kansas cooperative prices single phase lines at $20,592 per mile, versus $45,144 per mile for three phase lines.[62] A 2020 NARUC EV Working Group estimates that upsizing distribution transformers and digging trenches can be as much as 20% of total DCFC project costs.[63] Based on examples of existing DCFC projects in Ottawa Ontario, increasing the capacity of DCFC from 150 kW to 400 kW increased overall project costs by approximately 400-600% compared with only marginal cost increases from 50 kW to 100 kW systems, and 100 kW to 150 kW systems. Much of this increase is a result of the triggering of more extensive infrastructure upgrades.[64]

To emphasize the uncertainty surrounding a generalized reduction in infrastructure costs, a New Jersey energy storage analysis found that "the impact on the distribution networks requires more granular, specific neighborhood/network understanding that could help project when this added energy load will trigger T&D upgrades."[65] NREL studied the proximity of electrical substations and interstate exits, in order to determine the length of line extensions required for corridor DCFC. Results show that the average distance between an interstate exit and the nearest electrical substation is 2.9 miles across the country. Only 3% are farther than 10 miles from the nearest substation, 16% farther than 5 miles, and 35% farther than 3 miles.[66] For Colorado, this number appears to be lower, especially along the I-70 corridor west of Denver. This analysis is limited to the interstate highways system, so these figures are likely to increase when averaged across all of Colorado's mountainous corridor highways.

---

[57] PEV and Infrastructure Analysis. Idaho National Laboratory: https://avt.inl.gov/sites/default/files/pdf/arra/ARRAPEVnInfrastructureFinalReportHqltySept2015.pdf
[58] Nelder and Rogers, RMI
[59] Xcel Energy, New Service for EV Guide: https://www.xcelenergy.com/staticfiles/xe-responsive/Energy%20Portfolio/EV-Charging-Station-Guide.pdf
[60] PG&E Unit Cost Guide, updated April 2021
[61] NREL Distribution Grid Integration Unit Cost Database, Version 2, 2019. These are high level estimates for Massachusetts, and do not include other costs, such as land rights, removal costs, taxes, etc.
[62] Pioneer Electric Cooperative Inc. Line Extension Costs https://pioneerelectric.coop/my-account/help/line-extension-cost/
[63] NARUC EV Working Group Webinar. https://pubs.naruc.org/pub/21568D54-155D-0A36-31C0-2F57C64A153A
[64] Michael Nicholas and Dale Hall, Lessons Learned on Early Electric Vehicle Fast Charging Deployments, ICCT 2018, p.33
[65] New Jersey Energy Storage Analysis (ESA) Final Report, Responses to the ESA Elements of the Clean Energy Act of 2018, The State University of New Jersey, pg. 52
[66] Wood et al., "National Plug-In Electric Vehicle Infrastructure Analysis," US Department of Energy, 2017

Additional infrastructure costs related to BESS deployment are limited; additional infrastructure may only include additional pad construction for the base of the BESS. Therefore, BESS can offer a significant opportunity to reduce costs through avoided infrastructure upgrades.

In order to incentivize investment in EV charging infrastructure, larger utilities across the country have begun offering make-ready infrastructure investments. Make-Ready Infrastructure includes the requisite electrical infrastructure from the grid to the panel at the site of the EVSE and includes distribution lines, transformers, and meters. The costs associated with these make-ready investments are often included in the utility's rate base, recovered through increases in distribution rates as part of the cost of service ratemaking. Make-ready infrastructure takes the form of rebates and other incentives to cover the upfront costs of the line extensions or other distribution infrastructure necessary to serve DCFC. Colorado Revised Statute (CRS) 40-5-107(1)(b)(I)[67], requires the state's IOUs, as part of the Transportation Electrification Plans to, "seek to minimize overall costs and maximize overall benefits, including make-ready infrastructure and associated electric equipment that supports transportation electrification." While PSCo has adopted conforming make-ready policy as a part of their 2021-2023 Transportation Electrification Plan, no other investor-owned or member-owned utilities has included such policies. While Black Hills Energy has included a multitude of EV related rebates and charging rates in their transportation electrification plan, there is no mention of make-ready infrastructure for charging.[68,69] PSCo will own, operate, and maintain new service connections and EV supply infrastructure for participants in the program. Equipment coverage includes:

- Transformer upgrades
- Pads
- Poles
- New service conductors
- Metering equipment for EV charging
- New panels
- Conduit
- Wiring up to the charger
- Any necessary civil construction work in compliance with state and local codes

In utility service territories that offer make-ready infrastructure for DCFC, DCFC + BESS can likely be implemented using the same hardware. PSCo will offer a list of prequalified charging equipment that can be included in their commercial charging infrastructure program, and while it is unclear whether or not the addition of BESS will be included in this list, batteries do not require any additional capacity from the grid relative to DCFC. In addition, existing battery-integrated DCFC systems can be installed using single phase or Level 2 charging equipment, and require only a marginally larger footprint than traditional chargers. To the extent that funding for make-ready infrastructure is rate based by utilities, Colorado ratepayers could potentially see savings as a result of BESS integration through avoided infrastructure upgrades (savings would be very small on a marginal basis and would require large scale implementation).

[67] Colorado Revised Statute 40-5-107.
https://casetext.com/statute/colorado-revised-statutes/title-40-utilities/public-utilities/general-and-administrative/article-5-new-construction-extension/section-40-5-107-electric-vehicle-programs-definitions-repeal
[68] Public Service Company of Colorado Transportation Electrification Plan
[69] Black Hills Colorado Electric Transportation Electrification Plan,
https://www.dora.state.co.us/pls/efi/EFI.Show_Docket?p_session_id=&p_docket_id=20A-0195E

While the consensus among surveyed Colorado utilities is that it is somewhat unclear how the implementation of battery systems would affect specific infrastructure requirements, BESS offers the possibility of reducing major infrastructure upgrades by providing fast charging capability when only single-phase power is available.[70] This is because DCFC charging typically places a large load on the grid and requires higher capacity three phase lines in order to charge vehicles at high speeds. BESS can smooth the rate at which electricity is drawn from the grid over time, lowering the instantaneous power required from the grid while allowing vehicles to charge using the battery at high speeds.

3.1.3: Project Development and Soft Costs

Installation, siting, and other soft costs related to overall project costs of DCFC and BESS development are among the most problematic and uncertain, "and there is no consensus among industry stakeholders about the direction of future installation costs."[71] Soft costs include location siting, permitting, inspections, and communication between utilities and developers. The latter three have the potential to increase the overall project time, which decreases efficiency and increases labor costs. Additionally, without transparency on distribution system capacity, interconnection costs are largely unknown until a study is complete, creating a significant risk for any project. Therefore, according to existing literature and industry stakeholders, streamlining interconnection processes in order to mitigate soft costs will be vital to the widespread development of DCFC. Soft costs also vary by utility territory and respective policies.

Surveyed Colorado utilities are largely uncertain of the specific permitting and inspection processes that would apply to DCFC coupled BESS because there are virtually no examples of said projects in the state. Therefore, given their lack of familiarity with BESS + DCFC, utility representatives believed that it is likely their engineering teams would need to carefully inspect aspects of any charging station battery in order to assess its capacity requirements and interactions with the grid. This process is likely to be simpler with batteries that do not feed electricity back to the grid, however there is still no standardized process. A study conducted by EVgo suggests that delayed permit approvals from jurisdictions can be a much larger factor on project implementation than interconnection.[72]

Location siting factors into soft costs in multiple ways and is interconnected with other soft costs. Location can determine the level of infrastructure upgrades required by a DCFC+BESS, the difficulty of construction and overall project time, and permitting. In the initial utility survey conducted by E9 Insight, approximately 20% of utility respondents mentioned siting considerations as a primary barrier to DCFC and DCFC+BESS deployment.[73] In addition, industry stakeholders suggest that streamlining siting processes may be the best opportunity for reducing future hurdles and soft costs. Determining the best site can be one of the most challenging and time-consuming aspects of a BESS+DCFC project, however some stakeholders are creating processes that quantify location considerations and allow for easier analysis. A collaboration of stakeholders from Holy Cross Energy and The City of Aspen developed a weighted scoring system of various site considerations and assigned scores to various sites. City GIS staff then created a heatmap which displays suitability of various sites.[74]

[70] Md Ahsanul Hoque Rafi., "A Comprehensive Review of DC Fast-Charging Stations with Energy Storage: Architectures, Power Converters, and Analysis"
[71] Nelder and Rogers, RMI
[72] Jonathan Levy, Isabelle Riu, and Cathy Zoi, The Costs of EV Fast Charging Infrastructure and Economic Benefits to Rapid Scale-Up, EVgo, 2020
[73] Feasibility Study of BESS + DCFC in Colorado: Task 1
[74] City of Aspen Electric Vehicle Public Charging Infrastructure Masterplan, Charging Station Citing Criteria, p.25-26

The impact of BESS on soft costs is uncertain among Colorado utilities and existing studies. To quote an IREC report on energy storage, "it is highly likely that interconnection issues could emerge as a significant blockade to the success of storage programs if they are not addressed prior to the launch of any incentive, procurement mandate, or other storage-centric program."[75] While the BESS market is largely uncharted territory, the closest proxy to the BESS + DCFC interconnection process is solar power. Reports from the solar industry have indicated that in the most extreme cases, soft costs can represent up to 60% of total project costs.[76]

Excluding make-ready infrastructure, a select number of utilities across the state offer rebates that can lower the overall project costs of battery storage systems. Holy Cross Energy offers a rebate for distributed energy storage resources of $500 per kW for systems sizes of 0-25 kW. This rebate only applies to customers who are classified under their optional Distribution Flexibility Program tariff (DFT). This program also requires that HCE maintain operational control over the consumer's approved system. [77] For customers who are not enrolled in the DFT program, there is a rebate of $250 per kW for 0-25 kW systems. These customers must instead be enrolled in a TOD tariff.[78] While not specific to battery coupled DCFC, utilities also offer significant rebates to lower the overall costs of DCFC in general. For example, Black Hills Energy offers a rebate of $35,000 per DCFC station.[79]

3.2: Benefits

The range of benefits that *could* be provided by combined BESS and DCFC projects are described and summarized below. The first two benefits, reduced DCFC operating costs and increased access to fast charging, have been explored in depth in previous Tasks.

3.2.1: Reduced DCFC Operating Costs

As described in detail throughout Tasks 2 and 3, high operating costs, stemming primarily from demand charges, can have significant negative impacts on the business case for standalone DCFC. This is particularly prevalent during the early stage of EV adoption when DCFCs tend to have low overall utilization and the cost of demand charges is not amortized over a large amount of energy sold at a station. Electrify America asserts that demand charges are presently the largest operating cost barrier to public EV infrastructure deployment, representing up to 80 percent of project operating costs.[80] BESS provides an opportunity to smooth consumption and mitigate the effect of demand charges, significantly lowering operating costs.

The amount of savings that a BESS can provide varies widely based on the nuances of the applicable utility rate and load profile. Table 1 summarizes estimated gross annual savings from the optimal battery size providing demand charge management across a range of utility rates in Colorado. Gross annual savings estimates were determined based on charging load profile, optimal battery size and battery operation for each unique combination of geographical use case, charging plaza size and utility rate

[75] Sky Stanfield, Joseph "Seph" Petta, and Sara Baldwin Auck, IREC Charging Ahead: An Energy Storage Guide For State Policymakers, 2017.
[76] Nelder and Rogers, RMI
[77] Holy Cross Distribution Flexibility Program Tariff https://www.holycross.com/wp-content/uploads/2019/06/Electric-Service-Tariffs-Rules-and-Regulations-amended-14May2019-CLEAN_a.pdf#page=38
[78] Holy Cross Energy, Renewable Energy Incentives page, https://www.holycross.com/renewable-energy-incentives/
[79] Black Hills Colorado Electric, Transportation Electrification Plan,
[80] Electrify America Press Release: https://media.electrifyamerica.com/en-us/releases/89

analyzed in Task 3 (157 total combinations). The annual savings ranges by utility territory represent variability across load profiles from varying plaza sizes, utilizations and utility rates.

Table 22: Annual Savings Ranges from Demand Charge Management

Rural	
Utility Rate	*Estimated Annual Gross Savings*
Grand Valley Power >50kW	$1,500 - $7,500
Grand Valley Power >500kW	$2,400 - $4,200
Grand Valley Power >1000kW	$800 - $1,400
Highline Electric Association >50kVA	$1,300 - $6,900
Poudre Valley REA 37.5 - 5000 kW	$1,800 - $9,000
Poudre Valley REA 37.5 - 5000 kW TOU	$1,800 - $9,000
White River Electric Association 50-1000kW	No demand charges.
White River Electric Association 1000-5000kW	$7,800 - $13,400
Corridor	
Estes Park Municipal >35kW	$3,700 - $10,300
Estes Park Municipal >35kW TOU	$4,300 - $12,500
Intermountain Rural >50 kVA	$3,000 - $9,000
Intermountain Rural >500 kVA	$4,800 - $11,800
Intermountain Rural >2000 kVA	$2,200 - $5,100
Mountain Parks Electric Association >50 kW	$1,200 - $3,500
Mountain Parks Electric Association >500 kW	$1,400 - $3,400
Mountain Parks Electric Association EV Rate	$4,500 - $12,600
Urban	
City of Longmont >800 kW	$1,900 - $5,300
City of Longmont >50 kW	$1,400 - $18,009
City of Fort Collins >750 kW	$5,400 - $14,900
City of Fort Collins 50-749 kW	$1,100 - $13,600
PSCo S-EV TOU	$500 - $7,100

PsCO Secondary General (Low Load Factor)	$500 - $7,100
PsCO Secondary General Service	$1,800 - $22,300

3.2.2: Increased Access to Fast Charging

In previous tasks, we examined the statewide market for DCFC and BESS + DCFC, modeled general geographic use cases and technologies for BESS + DCFC, and analyzed the overarching costs and benefits of coupling batteries with fast charging stations. Before refining a project implementation plan, it is crucial to consider the state's climate strategy and approach to decarbonizing the transportation sector, and how CEO might best utilize BESS technology to advance these priorities. As outlined in the Colorado GHG Pollution Reduction Roadmap, the state is targeting 940,000 EVs or 70% of passenger vehicle sales in service by 2030 to reduce emissions from the transportation sector, which is now the leading source of emissions in the state.[81] This is an increase of roughly 900,000 EVs over the next nine years.[82] An additional goal is to build a statewide network of charging infrastructure: "Particular emphasis must be placed on filling gaps on the state highway network to allow for longer-distance travel."[83] Expanding fast charging infrastructure particularly on highways and transportation corridors can reduce two barriers to EV adoption. First, well-placed stations can reduce range anxiety of prospective EV drivers. Second, according to modeling of the Seattle area by Wei Wei et al., adding highway fast charging in addition to home and work-place charging increased the vehicle electrification potential of the area by 27%,[84] highlighting the outsized effect that increasing the effective range of EVs can have on transportation electrification.

We can examine the relative marginal impact of each additional DCFC in a given area in Colorado by analyzing the charging infrastructure gap analysis completed by the International Council on Clean Transportation (ICCT). The gap analysis shows which highway corridors in Colorado will likely require the most DCFC ports per mile by comparing the total vehicle miles traveled on a given highway and comparing that to the projected growth in adoption of EVs according to state goals.[85] Figure 3 displays the number of DCFC ports needed per mile as the thickness of the red lines that trace major highways. The red numbers indicate the total number of DCFC required in a county. This gap analysis compares the amount of existing infrastructure with the amount needed in the state. Figure 4 shows that red counties are those with the lowest number of public charging ports as a percentage of what is required by 2030.

[81] Colorado Greenhouse Gas Pollution Reduction Roadmap, 2021
[82] https://energyoffice.colorado.gov/zero-emission-vehicles/evs-in-colorado-dashboard
[83] Colorado Greenhouse Gas Pollution Reduction Roadmap, 2021
[84] Wei Wei, Sankaran Ramakrishnan, Zachary A. Needell, and Jessika E. Trancik, Personal vehicle electrification and charging solutions for high-energy days, Nature Energy, 2021 https://www.nature.com/articles/s41560-020-00752-y.pdf
[85] Chih-Wei Hsu, Peter Slowik, and Nic Lutsey, Colorado charging infrastructure needs to reach electric vehicle goals, ICCT, 2021 https://theicct.org/sites/default/files/publications/colorado-charging-infra-feb2021.pdf

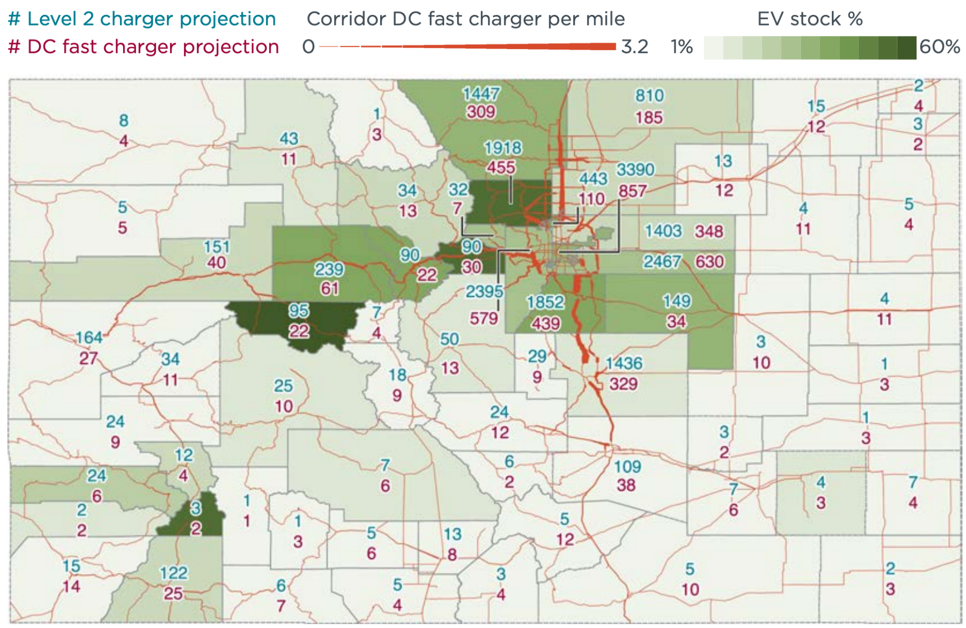


Figure 3: 2030 county-level public Level 2 (blue numbers) and DC fast (red numbers) chargers needed and share of EV stock, based on a high-growth EV adoption scenario. Chart source: ICCT Gap Analysis, 2021.

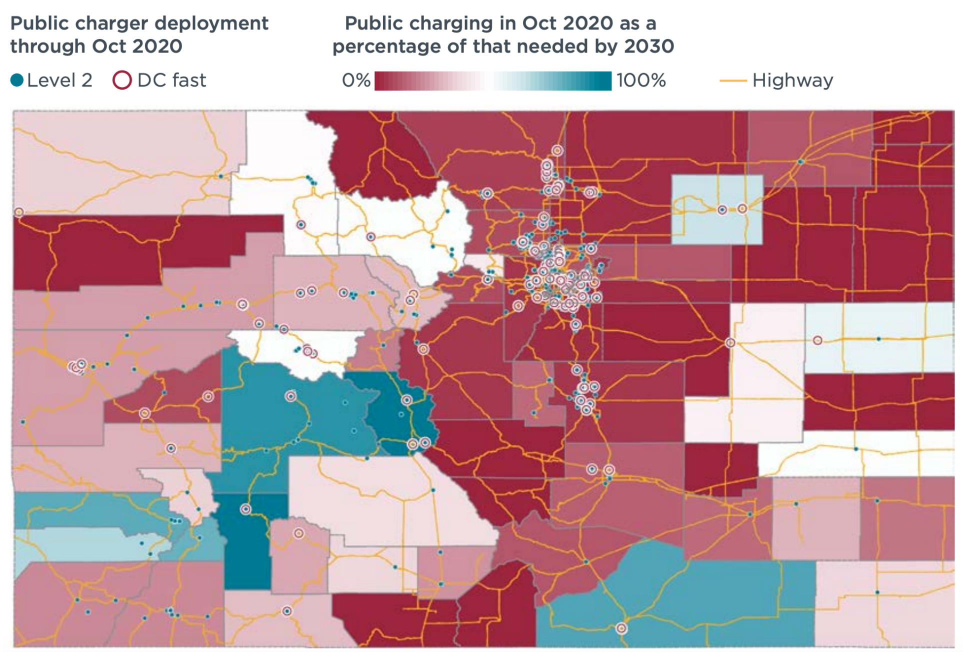


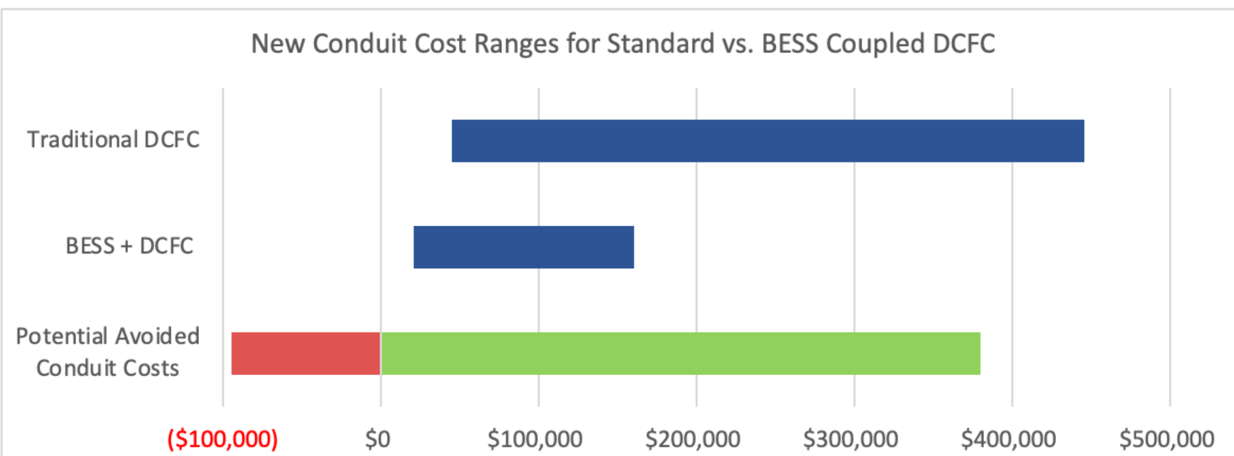
Figure 4. County-level public charging in place as a percentage of infrastructure needed by 2030. Charging infrastructure data are from PlugShare, chart source: ICCT Gap Analysis, 2021

In order to have the greatest impact per additional DCFC station, CEO should consider corridor areas that will require the largest total amount of DCFC ports per mile, and that require the greatest increase in charging ports relative to current infrastructure levels. Pairing battery storage with DCFC, either as a battery-integrated charger or a co-located system, has the potential to increase access to fast charging throughout Colorado by enabling cost-effective deployment of DCFC at sites where installation would be otherwise difficult due to lack of sufficient power. Examples of such sites are rural locations or locations along travel corridors that have single-phase power.

3.3.3: Avoided Distribution Upgrade and Infrastructure Costs

As an extension of the benefit discussed immediately above, when batteries are deployed to enable fast charging at the grid-edge there may be additional benefits in the form of avoided distribution upgrades. Detailed information on utility distribution systems is needed to accurately determine the cost that would be incurred if a given line was upgraded to support DCFC and compare those avoided costs to the cost of the BESS added to the DCFC project. Therefore, while a precise quantification on the possible avoided upgrade costs at different site locations based on a bottom-up engineering analysis of existing infrastructure is out of the scope of this study, estimates gathered from existing literature and primary research can provide insights into the range of costs that can be avoided.

A combination of figures gathered from literature review and primary research (utility surveys) detailed in Task 4, reveal that the primary infrastructure cost drivers for DCFC occur when a given site does not have necessary hosting capacity to support the high level of load, and additional high capacity 3 phase lines and 480-volt transformers are required.



Figures 5: Estimated costs of required transformers and for DCFC vs. BESS + DCFC, and the potential avoided infrastructure costs as a result of using batteries at the grid edge.[86] Infrastructure required for BESS + DCFC for grid edge scenarios is low voltage, single phase hardware.

[86] Maximum bound for savings is calculated by subtracting lowest bound of cost range for BESS + DCFC from the highest bound of traditional DCFC infrastructure, and vice versa for minimum bound.

The above figure demonstrates both the potential for BESS to allow for significant savings from reduced infrastructure costs, as well as the high level of variation in costs realized by different stakeholders. Geography is among the largest factors that influence new line extension costs, and the mountainous terrain surrounding Colorado's westward corridors could prove to be a significant barrier. Due to the wide range of potential costs for constructing new lines, it is possible that single phase lines built in mountainous, forested terrain could cost more than 3-phase lines constructed on flatter, rural landscapes.[87]

While the modeling in previous tasks focused on leveraging BESS to accelerate DCFC deployment at the grid-edge, likely in rural contexts, larger battery systems may be used to defer distribution upgrade costs in urban contexts as well, potentially resulting in greater financial benefits. Upgrading and expanding undergrounded distribution systems is more expensive than overhead lines.[88,89] This suggests that the potential avoided costs of avoided distribution system upgrades in urban contexts is larger than in rural contexts on a per unit basis. BESS + DCFC can potentially operate on single phase lines rather than three phase lines, whereas traditional DCFC requires a three phase connection. Based on the discussion in the *Infrastructure Costs* section, conservative estimates from a rural cooperative indicate that the savings from building single phase lines vs. three phase lines could be $24,552 per mile, while data from a cooperative utility in a mountainous region of Colorado suggest potential savings of up to $260,000 per mile. Therefore, while the prospect of a remote corridor station which is not near existing distribution lines is still costly, BESS implementation poses significant savings. Additional work is needed to quantify the total project savings, and there are a significant number of unknowns and site specific cost considerations.

While savings on avoided infrastructure can benefit DCFC developers with reduced project times, these avoided cost values are not easily captured by commercial 3rd parties. Low utilization rates for remote corridor charging locations make the profitability of this use case challenging regardless of technology implementation and access to make ready infrastructure. This presents an opportunity for state funding to fill a gap where the commercial charging market might not, while simultaneously having the greatest impact on infrastructure expansion goals and EV adoption and minimize the cost of doing so. In addition, these savings will benefit ratepayers. Both IOUs and electric cooperatives in Colorado fund their infrastructure investments using their rate base. While their business models differ, in either case lower infrastructure costs result in lower rates passed on to the public.

Findings indicate that utility ownership may not be conducive to conducting demand charge management; one of two key value propositions for implementing BESS, due to limitations with existing power purchase agreements, self-generation regulations, and the overall applicability of demand charges. For this use case, BESS + DCFC is more feasible in a case where the system(s) are owned by a 3rd party or a site host operating on a commercial meter under standard commercial rates. However, cooperative or municipal utility ownership may be more beneficial in a grid-edge application. In the context of this study, grid-edge locations are defined as those at which there is not adequate grid hosting capacity to service a traditional DCFC load. Specifically, areas serviced by single phase lines or transformers with a voltage lower than 480V. Responses from surveyed utilities suggest that the ability for commercial customers to recover costs may be difficult in a remote corridor location. However, BESS

[87] Upper bound figure for cost of single-phase lines came from estimates given by a rural Colorado electric cooperative, the majority of whose service area lies in mountainous areas and portions of the front range. The lowest figures for 3 phase lines represented costs for a rural Kansas cooperative.
[88] "Underground Electric Transmission Lines," Public Service Commission of Wisconsin
[89] https://www.pgecurrents.com/2017/10/31/facts-about-undergrounding-electric-lines/

can provide a cheaper alternative to a standard DCFC station by mitigating otherwise requisite infrastructure costs. And grant funds can be spread across a larger total number of chargers, and result in a more successful program in accelerating EV adoption. While developers siting locations in a PSCo service territory would benefit from the utility's make ready program outlined in the 2021-2023 TEP, much of the state's geographical area is serviced by member owned cooperatives and municipal utilities. Given that many crucial grid edge corridor locations will lie in these territories, BESS for a grid edge application will be more effective for cooperatives and municipal utilities.

Section 4: Program Considerations & Funding Recommendations

Section 4 provides an overview of additional project considerations for future program development, implementation and management, as well as an overview of associated project costs to inform potential future program funding levels. Specifically, this report summarizes and builds on analysis conducted in previous tasks in regard to costs and benefits, siting considerations, GHG emissions benefits, ownership models, and considerations for grid-edge versus demand charge management use cases. This section describes recommended funding program designs and funding levels to inform future CEO funding programs supporting BESS deployed in the two primary use cases assessed in this study; demand charge management and enablement of fast charging at the grid-edge. Recommendations are based on market research, stakeholder feedback and technical modeling completed in prior tasks. Due primarily to the variability in the required funding amounts and deployment challenges across the two primary BESS use cases considered in this study, two distinct funding program designs are proposed.

4.1: Critical Considerations for Program Implementation: Grid-edge

4.1.1 Implications of Infrastructure Avoidance: Cost Mitigation, not Commercial Viability

BESS implementation in a grid-edge scenario could unlock large benefits in the form of avoided distribution costs. While limited real world examples of BESS + DCFC projects exist for this particular use case, we can examine project costs of traditional DCFC deployment to determine which aspects of infrastructure can be avoided by substituting a BESS. A combination of figures gathered from literature review and primary research (utility surveys) detailed in section 2, reveal that the primary infrastructure cost drivers for DCFC occur when a given site does not have necessary hosting capacity to support the high level of load, and additional high capacity 3 phase lines and 480 volt transformers are required. Estimating the specific project costs that could be avoided however, is difficult, as any distribution upgrades required are endemic to the particular site, determined by a utility survey. **Regardless of the wide variability of total infrastructure costs as a result of many different factors, savings from batteries as a result of avoiding higher capacity infrastructure is likely to be significant**.[90]

[90] Feasibility Study of BESS + DCFC in Colorado: Section 3.3.3.

Table 23: Estimated Costs of Required Infrastructure for DCFC vs. BESS + DCFC

	Traditional DCFC	Battery coupled DCFC
Transformer costs	$13,000 - $39,000	$3,500 - $10,000
Costs of new lines	$45,144 - $400,000 per mile	$20,592 - $140,000 per mile

Many utilities do not have the capacity to conduct service area wide GIS mapping and site host capacity studies without a consultant and an outside funding source.[91] In order to streamline future charging infrastructure projects, funding allocated towards incentivizing a systemwide hosting capacity database could greatly reduce project timelines and provide a starting point for charging and DER developers.[92] Mapping of highway corridors as well as existing parking lots, commercial vendors, and distribution infrastructure along said corridors may also be considered for future CEO program success.

4.1.2: Future-proofing Battery Sizes

As EV adoption and load factors for fast charging increase, the relatively small battery sizes considered to optimize cost to charging ratio, and which support early market growth and remote corridor charging conditions, may no longer provide sufficient fast charging capacity for EVs. Based on current load profiles, corridor charging stations in Colorado experienced an average utilization rate of 1.17% - given the high capital cost of the hardware, smaller battery sizes maximize savings while still providing the necessary level of service at lower utilization rates. However, if utilization rates were to increase to 5% or 10% over the next decade, battery capacities would need to be upgraded. This further complicates the commercial viability of such a system, as 3rd party developers will likely want to ensure adequate return on investment over the lifespan of the battery. This creates an additional consideration for CEO when allocating grant funds to BESS projects; developers may want to invest in larger batteries than what is currently necessary in order to ensure the assets don't become obsolete or stranded given a high EV adoption growth scenario.

4.1.3: Program Design & Funding Levels

An RFP-based funding program where the CEO issues a solicitation for pilot projects designed to demonstrate fast charging enabled by BESS on single-phase, or otherwise capacity limited distribution lines, is the recommended funding program structure for the grid-edge use case. This program could also target funding for a pilot off-grid charging program, if of interest to the CEO. With an expected program budget of $500,000 and assuming that CEO provides funding for BESS cost, DCFC hardware cost and each project as at least two DCFC ports, it is estimated that CEO could fund no more than three (3) projects, and likely fewer. Per project funding is expected to be significantly higher than funding in a DCM program because, unlike DCM, the benefits provided by the BESS are not easily monetizable by the system owner.[93] Thus, the state must focus on funding levels closer to the entire BESS cost rather than funding levels designed to push marginal projects into economic feasibility. Key features of the

[91] E9 Insight, correspondence with utility stakeholders
[92] An August 2021 CO PUC Order, 20R-0516E, adopted rules for the state's IOU's Distribution System Plans and required the IOUs to provide expanded demand flexibility data to bolster EV charging availability while minimizing grid impact.
[93] See Section 1

solicitation, as well as project requirements recommended for inclusion in the solicitation, are described below.

- **Funding Requests & Eligible Costs:** Under the proposed pilot project, it is recommended that awarded funding amounts be variable based on the characteristics of the specific solicitation responses. Funding requests should be guided by the expected funding levels discussed below, but CEO should be empowered to accept requests for additional funding based on the cost-effectiveness argument of the proposed project. Eligible costs should include BESS hardware, power electronics and associated equipment, software management costs, warranties (at least 5 years), other hard costs such as conduit, wire, concrete pads etc., as well as non-labor soft costs including design, engineering, permitting and interconnection studies. DCFC hardware and associated equipment can be included as well (see below). Funding awards should be limited to 80% of total project costs.

- **Technical Specifications:** In addition to complying with the minimum specifications CEO has established in Section 3a of the Plazas Grant Program RFA, CEO should also require that systems are capable of providing the rated DCFC output with only single-phase power input. Additionally, based on the review of available technology, it is recommended that CEO require a minimum of 70 kW in charger output (a reduction from the minimum requirements in the Plazas Grant Program). This minimum would also apply to instances of power sharing.
    - Finally, eligible system types should include the three system architectures reviewed in this report; battery-integrated DCFC and AC- or DC-coupled, colocated DCFC and BESS.

- **Expected BESS Funding Levels:** Based on modeling completed in Tasks 2 and 3, the cost of battery hardware for a grid-edge application is likely to be $18,000 - $45,000 per DCFC port. It is estimated that the marginal cost of a 150 kW battery-integrated DCFC unit and a traditional 150 kW DCFC is $50,000 - $60,000. Systems deployed through the grid-edge solicitation could be battery-integrated DCFC or DCFC backed-up by a separate battery (AC or DC-coupled), thus a recommended blanket funding range for BESS hardware per fully-powered DCFC port is $40,000 - $60,000.[94] Given the uncertainty in battery sizing that will be proposed by applicants and the potential pressure to oversize batteries in order to future-proof systems, a fixed per port funding regime is recommended (as opposed to a variable per kWh scheme) to encourage applicants to size battery systems appropriately. Minimum charger outputs are established above to avoid applicants undersizing batteries.
    - CEO can include these expected per port funding levels for BESS in the solicitation but should provide the ability for proposing teams to ask for a higher per port cost and provide a justification for CEO consideration. Requests for additional funding can be evaluated relative to the cost-effectiveness of the project presented in the solicitation response (see below). At its discretion, CEO can increase funding awards to support projects that provide higher savings when compared to the alternative of expanding the distribution system.

---

[94] If an installed system is capable of power sharing and features multiple ports that split power when multiple vehicles are plugged in, that would count as a single port and receive funding as such. For example, a system capable of providing 150 kW to a single port or 75 kW to two ports would be treated as a single port when considering the expected funding amount.

- **DCFC Funding Levels:** In addition to BESS funding, CEO could also provide funding for the DCFC hardware at the same level as in the rural category of the Charging Plazas program, if deemed appropriate. To avoid situations where funding provided is higher than project costs, it is recommended that a funding cap of 80% of project costs be instituted on each project, applied to all eligible costs, as discussed above.[95]

- **Prioritize Projects Addressing Existing DCFC Gaps:** CEO should prioritize solicitation responses that propose DCFC deployments in counties lacking the required infrastructure. CEO can reference the gap analysis completed by ICCT to determine which areas in the state should be given priority.

- **Prioritize Teams Including Utilities/Cooperatives:** Proposing teams are expected to consist of a load-serving entity (e.g., electrical cooperatives, municipal utility), a site host and a 3rd party (developer). Teams including an electrical cooperative or municipal utility should be prioritized. Stakeholder feedback indicated that utilities, particularly rural cooperatives, have not had active engagement with 3rd-party DCFC developers around siting. Rewarding this collaboration will help facilitate future efforts to strategically site DCFC in Colorado to serve customer needs. Additionally, inclusion of load serving entities will streamline interconnection and enable auditing of the value of the distribution system upgrade deferral. CEO can facilitate connections between potential team members through existing working groups prior to solicitation release and by creating a list of parties indicating interest after solicitation release.

- **Require Cost-Benefit Analysis of Deferred Distribution System Upgrades (Pre & Post Project):** As part of the solicitation response, teams seeking funding should be required to complete a cost-benefit analysis, with documented assumptions, estimating what the avoided costs are of deploying a BESS at their proposed location instead of upgrading the distribution system. After completion of the project, teams receiving funding should be required to validate the cost-benefit analysis submitted in their solicitation response and, if costs were higher than expected, share insights on what caused cost increases. These post-project audits, or surveys if a detailed audit is deemed too burdensome, can be analyzed by CEO or a consultant to determine lessons learned for program expansion and deployment at additional sites.
    - Ensuring utility participation in the awarded teams enables this analysis to be completed. If appropriate, CEO could also hire a 3rd party to complete updated cost-effectiveness audits after project completion and awarded teams would be required to provide the necessary data and support as a condition of funding.

A programmatic funding approach with fixed incentives and a state-wide reach is not recommended for two primary reasons, summarized below. The primary goal of running a pilot program is to address the cost-effectiveness challenge. By deploying BESS to enable fast charging at the grid-edge at a couple real-world sites, the exact information and process required to calculate the cost-effectiveness of BESS compared to a line extension can be determined. From there, CEO can determine if any characteristics that made the pilot sites cost-effective can be generalized to identify other sites throughout the site

[95] For example, if funding was provided for DCFC ports at the amounts proposed in the Charging Plaza program, the sum of DCFC plus BESS hardware incentives could exceed the MSRP of a battery integrated DCFC system (~$135,000 plus install costs).

where BESS are likely to be cost-effective. The siting challenge discussed below is proposed to be addressed via the “**Siting Survey for Grid-Edge DCFC”** proposed in the **Areas for Further Study**.

- **Siting & Demand:** Stakeholder feedback from rural load serving entities indicated that demand for fast charging in areas served by single-phase lines is still minimal. Siting of DCFC at the grid-edge is likely to be strategic, with sites chosen based on where key nodes in the statewide DCFC network overlap with single-phase power supplies.[96] This technology is not likely to be a technology deployed at hundreds of sites throughout the state. 3rd party development of DCFC is currently targeting higher traffic areas and sites with existing three-phase power. Thus, it is not evident that there is sufficient demand to support a statewide programmatic funding approach for BESS + DCFC at the grid-edge.

- **Cost-effectiveness:** With current data, the cost-effectiveness of deploying a BESS+DCFC system instead of extending or upgrading distribution lines to support a traditional DCFC is difficult to generalize as justification of a statewide funding program. Results summarized in Tasks 4 and 5 indicated that construction of three-phase lines is on the order of $100,000 per mile, but this figure can vary greatly depending on terrain, whether the line is underground or overhead and other factors. If the estimated difference in cost between a 150 kW DCFC and a 150 kW battery-integrated DCFC is ~$60,000, then a useful rule of thumb is that for any site requiring line upgrades over .6 miles a BESS+DCFC system would prove cost-effective. However, there is significant uncertainty in this figure which underscores the importance of piloting such technologies with the intent to study cost effectiveness.

In the future, particularly as priority sites are identified throughout the state, a technology agnostic “grid-edge” funding program could be considered by CEO. BESS is not the only technology capable of enabling fast charging on single phase lines. If it is determined that there is widespread demand for fast charging on single-phase lines, CEO could drive down costs of deployment by opening funding to any technology that can meet the use case

4.2 Critical Considerations for Program Implementation: Demand Charge Management

4.2.1 Tailor Funding to “Tipping Point” Projects

Based on the analysis completed in Task 3, the business case for deploying BESS to provide Demand Charge Management (DCM) for DCFC installations is clear and likely to be viable in many parts of Colorado. However, the exact utility rate that applies to a given project will impact feasibility on a site-by-site basis. The break-even system costs identified in Task 3 varied greatly by utility and by utility-rate within a single territory. The maximum break-even system cost identified was over 16 times greater than the minimum. In a single territory (Mountain Parks Electric), the biggest spread was also a 16 times difference between the minimum and maximum break-even system costs. Four out of the ten utility territories considered in detail in Task 3 had a spread greater than 10 times between the minimum and maximum break-even system costs. CEO should consider this range of system break-even costs and focus funding on utility rates and territories where BESS break-even costs fall in the middle of the range. These are rates and territories where the market, depending on the specific load profile of the given charging plaza or the soft costs (see below), may or may not support BESS deployment for DCM and CEO

[96] See “Areas of Future Study” below for suggestions on avenues to further address site identification.

dollars could be spent efficiently to push projects over the "tipping-point" into feasibility, resulting in additional build of DCFC stations.[97]

Table 24: Colorado utility service territories with highest break-even BESS costs per kWh for a system performing DCM

	Break Even BESS Costs ($/kWh)			
Utility	**Min**	**Max**	**Average**	**Ratio of Max to Min**
White River Electric Assn, Inc	7,200	13,000	**10,600.00**	1.805555556
Poudre Valley R E A, Inc	2,100	8,700	**5,650.00**	4.142857143
Estes Park	1,100	12,500	**6,012.50**	11.36363636
Highline Electric Ass.	1,600	7,600	**4,466.67**	4.75
Intermountain Rural Elec Assn	1,300	11,700	**4,662.50**	9
Grand Valley Power	800	7,300	**3,335.71**	9.125
Mountain Parks Elec Assn	800	13,200	**3,608.33**	16.5
City of Fort Collins	1,600	7,700	**3,700.00**	4.8125
Public Service Company of Colorado (PSCo)	900	11,100	**3,141.67**	12.33333333
City of Longmont	700	9,200	**3,031.25**	13.14285714

Soft costs related to battery deployment, including requisite interconnection studies and permitting (staff time and project delays), are difficult to quantify and can have a significant impact on the unit cost of the battery ($/kWh), particularly for the relatively small system sizes required for the DCM application. For example, if soft costs total $25,000 more than expected on a 60 kW, 1-hour duration battery, that increases the system's unit cost by approximately 416 $/kWh, a 46% increase when compared to the $/kWh unit cost assumed in the initial analyses completed in Task 3. This change could push the BESS out of economic viability. Thus, if CEO wants to fund BESS for DCM, it should focus on covering soft costs in addition to hardware costs. .

4.2.2: Program Design & Funding Levels: BESS for DCM

If CEO pursues a funding program targeting BESS performing demand charge management, it is recommended that this program be designed as an add-on to the state's existing DCFC Charging Plaza program. The Charging Plaza program is a well-established and successful incentive program entering its third round of funding. Since any projects funded under a program designed for BESS that will manage

[97] Complete results of the BESS system break-even cost analysis including every utility rate analyzed will be provided to CEO as a reference to identify target utility territories and rates during program implementation.

demand charges incurred by DCFC will also require installation of DCFC hardware, expanding the existing Charging Plaza program with dedicated BESS funding instead of creating an entirely new program eases implementation. Additionally, solar and storage equipment dedicated to the charging equipment is already an eligible cost under the current program.

Table 25 summarizes recommended funding levels ($/kWh) and estimates of total incremental program cost required if BESS funding is added to the next round of the Charging Plaza program. Funding levels and estimated incremental budgets required to implement a BESS adder within the Charging Plaza program are provided by geographic categories aligning with those defined by CEO to guide Charging Plaza program funding. Incremental budget estimates are calculated as a function of the per kWh rebate, average battery size, soft cost rebate and number of sites deployed. Average battery sizes per site are informed by the optimal system sizing modeling completed in Task 3. Rebate funding levels are based on the break-even system costs calculated in Task 3 and an analysis of funding required for "tipping point" projects (described further below).

Table 25: Summary of Potential Funding Levels for Demand Charge Management Program (Low & High Estimates by Region) .

	Denver Metro Area		Front Range Urban		Rural	
	Low Station Est.	High Station Est.	Low Station Est.	High Station Est.	Low Station Est.	High Station Est.
Estimated Current Program Funding	$516,129		$677,419		$806,452	
Target For DCFC+BESS Plazas deployed	4	4	4	4	4	4
Target For DCFC Stations Deployed	8	16	8	16	8	16
Average Chargers per Plaza	2	4	2	4	2	4
DCFC Rebates per Station	$80,000		$105,000		$125,000	
Per kWh Battery Rebate	$214	$258	$214	$258	$214	$258
Average Battery per Site (kWh)	39	68	22	78	20	39
Study / Soft Cost Rebate Per Site (e.g. covers incremental interconnection cost caused by BESS)	$25,000	$50,000	$25,000	$50,000	$25,000	$50,000
Incremental Funding Required	**$133,384**	**$269,763**	**$118,918**	**$280,496**	**$116,692**	**$240,248**
Estimated % of Costs Covered	**40%**	**46%**	**62%**	**41%**	**67%**	**71%**
Total Program Funding	$649,513	$785,892	$796,337	$957,915	$923,144	$1,046,700

The high-end estimates of incremental cost by region total approximately $790,000. It is expected that, once a BESS adder is offered through the Charging Plaza program, developers will determine appropriate sites from their pipelines and apply for funding. However, the forthcoming funding round of the Charging Plaza program targets further expansion into rural plaza development, increasing the number of utility territories that will see installations and range of utility rates that will apply to said installations. To further guide CEO on targeting utility territories and utility rates in the state that are a good fit for funding BESS projects, Table 25 provides a list of utility rate, geographic use case, plaza size and utilization combinations where the addition of BESS is likely to be at a financial "tipping point." As discussed in Task 5, these tipping point projects are projects where the state incentive is likely to push the addition of a BESS into financial viability, thereby catalyzing development of marginal DCFC projects.

The rate and use case scenarios in Table 3 were selected from the 127 scenarios modeled by the Project Team, summarized in Task 3. Target scenarios were identified by making an assumption on actual battery cost and then finding the difference between actual costs and the BESS break-even cost previously calculated for each scenario. To account for the significant potential impacts of soft costs on BESS unit price, described in Task 5, a conservative range of actual battery costs of 2,167 $/kWh - 2,817 $/kWh was used.[98] To identify rate and use case scenarios that are considered "tipping point" projects, a required incentive range of 0 $/kWh to 500 $/kWh was used. Some rate and use case scenarios result in a required incentive rate higher than this range and some result in required incentives lower than this range (i.e. negative, meaning the BESS project should pencil out without an incentive). A result of "None" does not indicate that BESS will not be feasible in the given scenario, rather that for all applicable rates BESS is economically feasible without incentives or would require an unrealistic incentive amount to become economically feasible.

Table 26: Target Utility Rates for Demand Charge Management

Geographic Use Case	Plaza Size	Utilization	Target Utility Rates
Metro	Small	Low Utilization	City of Longmont >50 kW, Public Service Company of Colorado (PSCo), Secondary Generation
		High Utilization	City of Longmont >50 kW, Fort Collins 50 - 749 kW
	Medium	Low Utilization	City of Longmont >50 kW, Fort Collins >750 kW, Fort Collins 50 - 749 kW
		High Utilization	Fort Collins >750 kW, Fort Collins 50 - 749 kW
	Large	Low Utilization	City of Longmont >50 kW, Fort Collins >750 kW, Fort Collins 50 - 749 kW
		High Utilization	None
	Large (150 kW ports)	Low Utilization	City of Longmont >800 kW
		High Utilization	City of Longmont >800 kW
Corridor	Small	Low Utilization	None
		High Utilization	Estes Park >35 kW, Estes Park >35 kW TOU, IREA >50 kVA
	Medium	Low Utilization	Mountain Parks Rural Elec. >50 kW
		High Utilization	None
	Large	Low Utilization	Mountain Parks Rural Elec. >50 kW, Mountain Parks Rural Elec. >500 kW TOU

[98] This range represents the highest end of battery costs observed through market research. Hardware costs are likely to be between 800-1000 $/kWh but all-in costs fluctuate greatly based on site-specific soft costs.

		High Utilization	IREA >2000 kW
	Large (150 kW ports)	Low Utilization	None
		High Utilization	Mountain Parks Rural Elec. >50 kW, Mountain Parks Rural Elec. >500 kW TOU
Rural	Small	Low Utilization	Poudre Valley REA 37.5 - 5000 kW, Poudre Valley REA 37.5 - 5000 kW TOU
		High Utilization	Grand Valley Power >50 kW, Highline Electric Association >50 kVA
	Medium	Low Utilization	None
		High Utilization	Grand Valley Power >500 kW
	Large	Low Utilization	None
		High Utilization	Grand Valley Power >500 kW

4.3: Areas for Future Study

There are several areas for future study that CEO can consider for further exploration of DCFC+BESS in order to accelerate deployment of fast charging in Colorado. This section contains future areas of study that fall into two categories. The first category includes additional areas of study that are direct extensions of this report. The second category includes study areas designed to complement and expand on lessons learned from the potential grid-edge funding pilot, provide additional information needed to establish a statewide funding program for grid-edge charging and further explore the value of BESS in relation to the impacts of vehicle electrification on rural cooperatives.

4.3.1: Siting Survey for Grid-Edge DCFC and Hosting Capacity Mapping

Compare locations of single-phase lines with projected geographic DCFC needs to identify sites, or granular areas of the state, that require grid-edge fast charging in order to support electric vehicles deployment in Colorado. Stakeholder engagement revealed that some utilities may not know the exact locations of their single-phase lines, or have them mapped in a digital format, which may pose challenges to completing this study. Further utility engagement around this issue is recommended in advance of such a study.

Some utilities will have 3 phase feeders running along major highways as rights of way and existing clearances make it easier to construct lines. The availability of GIS data and ability of utilities to accurately and efficiently determine specific hosting capacities of various locations is a key consideration for overall project implementation. Utility interviewees mentioned that projects will be more efficient if CEO has specific corridors, locations, and required capacities in mind:

> "...an easier option could be to communicate desired charger intervals and capacity along a specific route to the utility with territory of interest. Time allowing, their planning/engineering groups are best positioned to perform some

> quick screens on conductor size, pole height & strength, existing loading and if a potential host business could be identified in the vicinity."[99]

If site location to alleviate range anxiety is among the most important factors for CEO, identifying high impact corridor routes - screened by utilities that have distribution lines running in parallel - could be an effective method of engaging with utilities.

Many cooperative and municipal utilities in Colorado do not have easily accessible data discerning the hosting capacity of their grid in various locations. For each utility, the process of collecting and aggregating this data would be far too costly and time consuming. With the presence of outside funding and regulatory drivers, the availability of such data would be beneficial for a number of state clean energy efforts, including facilitating the buildout of DERs and accelerated interconnection processes.

4.3.2: Evaluation Matrix for Grid-edge Pilot

Prior to the release of a funding pilot for grid-edge fast charging, it is recommended that an evaluation matrix be created to assess solicitation responses and requests for funding. This matrix will build on the key program considerations outlined in this report.

4.3.3: Impacts of Medium & Heavy-Duty Vehicles on BESS Sizing

As discussed in Section 2, the impacts that an increased penetration of medium- and heavy-duty vehicles, along with increases in charger nameplate, may have on the BESS sizing discussed in this study was not fully explored. Modeling that included adjusted assumptions of vehicle mixes using charging plazas, beyond the current or near-term mix, could be completed to explore this further.

4.3.4: Emissions Signal

DCFC and BESS have the potential to reduce the carbon intensity of the electricity provided to vehicles by using the battery to limit charging directly from the grid when the electricity supply has the highest carbon intensity. The ability of BESS to reduce the real-time emissions intensity of fast charging is not inherent to simply deploying a battery, however. In Colorado, it is likely that BESS will only reduce real-time emissions if battery operation is optimized in response to a marginal emissions signal. Without such a signal, if BESS operations are only operated to minimize demand charges, BESS is unlikely to provide emissions benefits. However, the extent to which co-optimizing BESS operations to minimize carbon intensity and provide demand charge management reduces the potential economic value of demand charge management is unknown. A study completed in California indicated that this co-optimization does not negatively impact BESS economics but it is recommended that a similar study be completed for Colorado.[100]

4.3.5: Market Review of Grid-edge Charging Technologies

A market review to identify non-BESS grid-edge charging technologies (e.g. https://edgeenergyev.com/) is warranted to understand if CEO should expand the proposed pilot to be technology agnostic or pursue a technology agnostic grid-edge charging program in the future.

[99] E9 Insight. Correspondence with utility stakeholders

[100] SGIP GHG Signal Working Group Final Report, AESC Inc. for California Public Utilities Commission Rulemaking 12-11-005, September 6th, 2018.

4.3.6: Value of Distribution System Upgrades in Urban Areas

This study thoroughly explored the value that BESS can provide through deferral of distribution system upgrades related to rural fast charging. Additional work could be done to explore this value in an urban context. While line extensions or other upgrades may be less necessary in areas with significant existing grid capacity, when upgrades are needed they may be more expensive due to additional costs related to trenching in developed areas and other construction complications.

4.3.7: Valuation of Utility Peak Shaving for Electric Cooperatives

Additional study and collaboration with electric cooperatives is needed to determine what business models, ownership structures and policy changes (e.g. PPA limitations) would be needed to enable BESS paired with DCFC to provide meaningful peak shaving and benefit capture.

Appendix A: Detailed Results of Load Profile Simulations

Table A-1: Peak and Average Demand of Load Profile Scenarios

Peak Demand (kW)			Rural			Corridor				Metro			
		Plaza Size	Small	Medium	Large	Small	Medium	Large	Large (150 kW Ports)	Small	Medium	Large	Large (150 kW Ports)
	Utilization	Low	20	49	49	52	67	67	158	40	136	205	250
		High	51	96	113	84	156	207	297	47	191	317	417

Average Demand (kW)			Rural			Corridor				Metro			
		Plaza Size	Small	Medium	Large	Small	Medium	Large	Large (150 kW Ports)	Small	Medium	Large	Large (150 kW Ports)
	Utilization	Low	0.04287	0.17757	0.39676	0.06282	0.46191	0.97497	0.59093	0.84840	11.59263	22.44020	4.36283
		High	0.05567	0.62642	1.33611	0.66803	7.45560	14.85533	9.48322	1.93186	19.02050	37.68279	24.94203

Ratio of Peak Demand to Average Demand (kW)			Rural			Corridor				Metro			
		Plaza Size	Small	Medium	Large	Small	Medium	Large	Large (150 kW Ports)	Small	Medium	Large	Large (150 kW Ports)
	Utilization	Low	466.48	275.95	123.50	827.77	145.05	68.72	267.38	47.15	11.73	9.14	57.30
		High	916.11	153.25	84.57	125.74	20.92	13.93	31.32	24.33	10.04	8.41	16.72

Appendix B: System Configuration Comparison

Table B-1: Summary of Common DCFC+BESS System Architectures & Associated Characteristics

	System Cost	Renewable Integration	Resilience	Reliability
Collocated DCFC + Battery (AC Coupled)	• Due to required Power Conversion Systems (PCS) and controls, hardware in AC-coupled systems tend to be more expensive than DC-coupled.[101] However, additional costs related to inverters and converters may not be hugely significant, as costs range from 0.07 $/watt - 0.14 $/watt.[102] • Evidence from the solar industry demonstrates that familiarity with AC-coupled systems can drive down install costs. In both the Commercial- and Utility-scale solar projects, AC-coupled systems end up costing slightly less than DC-coupled systems due to savings on labor and other soft costs, even though hardware and power electronics are more expensive.[103] • AC-coupled systems have reduced soft costs because installers are	• Modular additions and retrofits of on-site renewables are easier than on DC-coupled systems since there is no need to replace the entire PCS, and the majority of power electronic hardware for distributed solar is already designed for an AC system • AC-coupled systems with on-site renewables will experience lower round-trip efficiency than DC-coupled systems because there are more power conversion steps. Each step is under 100% efficiency. Typical grid-tied inverters are around 95% efficient, while lower efficiency inverters can drop to 70% efficient.[104,105]	• In an AC-coupled configuration batteries can charge from both on-site renewables and the grid, increasing the ability to charge in expectation of blackouts, while also recharging during grid outages and potentially providing other grid services	• While limited data on the reliability of AC-coupled DCFC + BESS systems exists, a related study which looked at 1500 V PV + Storage found that AC-coupled is more reliable and longer lasting than a DC-coupled system because the high voltage takes a higher toll on the DC-DC Converters.[106] Lower voltage systems, such as residential PV + Storage, were shown to be more reliable than DC-coupled configurations

[101] Rafi et al. 2021
[102] "US PV Plus Storage Benchmark 2020," p. 7
[103] Ibid.
[104] https://pvpmc.sandia.gov/modeling-steps/dc-to-ac-conversion/cec-inverter-test-protocol/
[105] https://www.e-education.psu.edu/eme812/node/738
[106] He, Yang, & Vinnikov

	more used to such systems, there are more standards for AC-coupled, they are safer to install/interact with and location of BESS can be easier to reach. ● AC systems can also save on battery racking costs because they need less HVAC and smaller racks			
Collocated DCFC + Battery (DC Coupled)	● As detailed above, DC-coupled systems have lower hardware costs but may suffer from higher install costs due to lack of familiarity from contractors ● DC-coupled systems have efficiency benefits since power goes through fewer conversion steps.[107] DC to DC converters have efficiencies around 95% under good conditions.[108] ● More costly to retrofit or add to a DC-bussed system, since it essentially requires a re-design of the PCS	● DC-coupled systems are more power efficient over lifetime if on-site renewables are integrated during initial construction. ● AC-coupled system PV production may be clipped during peak output by an undersized inverter ● Retrofitting a DC-coupled system, such as would be required to integrate on-site PV after construction, is much more costly than in an AC-coupled system	● In a DC-coupled configuration batteries can only charge from PV, limiting resilience because ability to reach necessary state-of-charge to survive a grid outage may be constrained by PV output	● Due to the higher voltages taking a toll on DC-DC converters, DC-coupled systems are less reliable and durable than AC-coupled ● Decreased system reliability of DC-coupled systems can be addressed through proper redundancy in design, but this requires higher hardware and labor costs
BESS-integrated DCFC	● Battery-integrated DCFC are most suited to situations where few chargers are needed. If a higher number of chargers, and thus a BESS with more capacity, are needed, it may be more	● Battery-integrated DCFC use internal DC-coupling with external AC-bussed configuration, enabling flexible renewable	● Battery-integrated DCFC have some resilience potential as the battery enables off-grid charging, albeit	● Independent testing performed by the Electric Power Research Institute (EPRI) was not able to test the battery's thermal management system.

[107] US PV Plus Storage Benchmark 2020, p 77
[108] https://www.maximintegrated.com/en/design/technical-documents/app-notes/3/3166.html

	cost-effective to design large systems since economies of scale cannot be achieved on the battery cells with many, lower capacity, systems	integration similar to a AC-coupled system	likely for relatively few vehicles.[109]	Battery-integrated systems are a new market entrant and additional data collection on system reliability is required, although early deployments have not revealed any concerns. ● While reliability of providing fast charging service is dependent on the battery, if the battery fails or the charge runs out, battery-integrated DCFC can default to Level 2 charging enabling continued use at a lower level of service

[109] Using the Freewire Boost Charger's standard battery capacity of 165kWh and an average battery capacity of a light-duty EV of 60kWh indicates that, during a grid outage with no ability to recharge, only 3.4 vehicles can be charged to an 80% state-of-charge.