DCFC Electricity Rate Design Document

Prepared for:

Énergie NB Power

New Brunswick Power

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Submitted to:

Énergie NB Power

New Brunswick Power

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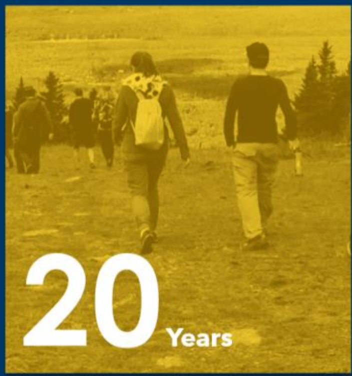
About Dunsky



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EXECUTIVE SUMMARY

New Brunswick Power (NB Power) has defined a need within its 2021 *Beneficial Electrification of Transportation Strategy* and its 2022 Rate Design Application for a rate design that improves the business case for third-party-owned publicly accessible direct current fast charging (DCFC) providers to increase fast charging access and, therefore, electric vehicle (EV) adoption and associated emission reduction and utility revenue benefits. As part of this effort, the New Brunswick Energy & Utilities Board (NBEUB) directed the utility to evaluate material barriers to third-party development of public EV charging and rate design and policy changes to address these issues.

This design document provides evidence of a material barrier to public fast charging and a proposed rate design to address this issue. A **load-factor-based demand and energy charge with an energy time-of-use component** is an appropriate design to mitigate an important barrier to third-party-owned public DCFC deployment.

The Value of Public Charging and EV Adoption

Publicly accessible fast charging is a **key catalyst** of EV adoption among consumers. Public charging is an important option for EV drivers who do not have access to charging at home or require additional charging when away from home, and a key consideration for current and prospective EV drivers.

Supporting EV adoption through a strong DCFC network provides **broader ratepayer benefits**. While public charging is an important component of the charging landscape, the majority of EV drivers will charge at home. If residential charging occurs overnight when the grid has excess capacity, the revenue associated with increased electricity sales can far outweigh any costs associated with supporting that load growth thereby putting downward pressure on electricity rates for the benefit of all ratepayers.

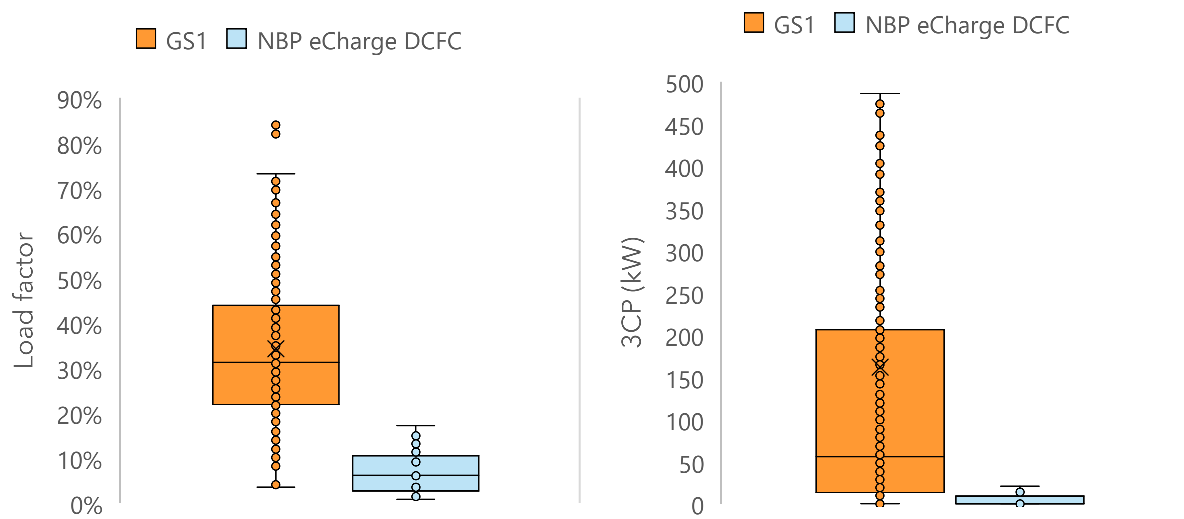
Addressing a Key Barrier to Expanded Charging Access

The province's fast-charging network will **require significant growth** by 2035 to meet the forecasted demand. The current pace of third-party deployment may not meet these needs. One important barrier identified by public DCFC operators during an engagement process is the **high operational cost of the electricity bill** and a challenging business case, driven by **demand charges** under General Service I (GSI).

This challenge is not unique to New Brunswick nor NB Power's GSI rate. This challenge is unique to the consumption profile of DCFC sites with low utilization. The challenge for fast-charging stations is that their demand has high, brief and often infrequent peaks. The fast-charging operator incurs the demand charge under GSI for the momentary peak demand, even if that same level of demand is not reached again in the month. Low-utilization sites have a challenge in reaching a positive business case because the limited user fee revenue from infrequent use does not cover the high monthly demand charge.

The variability of DCFC sites can be expressed in terms of **load factor**: the average load divided by the peak load in a specified period. DCFC profiles, based on NB Power's eCharge sites, are distinct from other General Service customers because they have low load factors, highlighting this variable demand. At these lower load factors, DCFC profiles generally

contribute less to system peak demand, as represented by 3CP,[1] compared to other GSI customers and less than the DCFC site's theoretical (nameplate) maximum. The differences between GSI and DCFC customers are summarized in Figures ES-1 and ES-2.



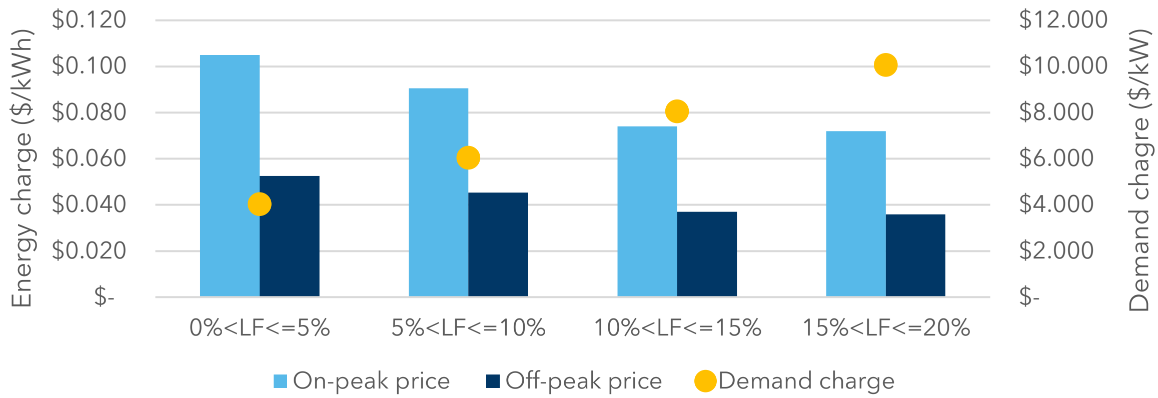
Figures ES-1 and ES-2: Box plots showing variation in load factor and peak demand (3CP), respectively, across GS1 customers and eCharge fast-charging stations

The business case barrier can be mitigated by a rate design solution that is tailored to the unique DCFC challenge and profile.

Proposed Design

The proposed design includes demand and energy charges in four tranches or increments based on a site's annual load factor (LF), up to and including 20%, as shown in Figure ES-3. The energy charge also varies by two year-round time-of-use periods: an on-peak period from 7 am to 10 pm and an off-peak period of all other hours. The ratio between on-peak and off-peak costs is 2:1.

[1] 3CP refers to the multiple coincident peak and average demand classification as defined in NB Power's Class Cost Allocation Study methodology (Matter 554, filing NBP02.05). This approach calculates the average coincident peak demands of the three high demand months. The system peak times included in this study are 12/6/2023 at 8am, 1/24/2024 at 8am, and 2/21/2024 at 7am.



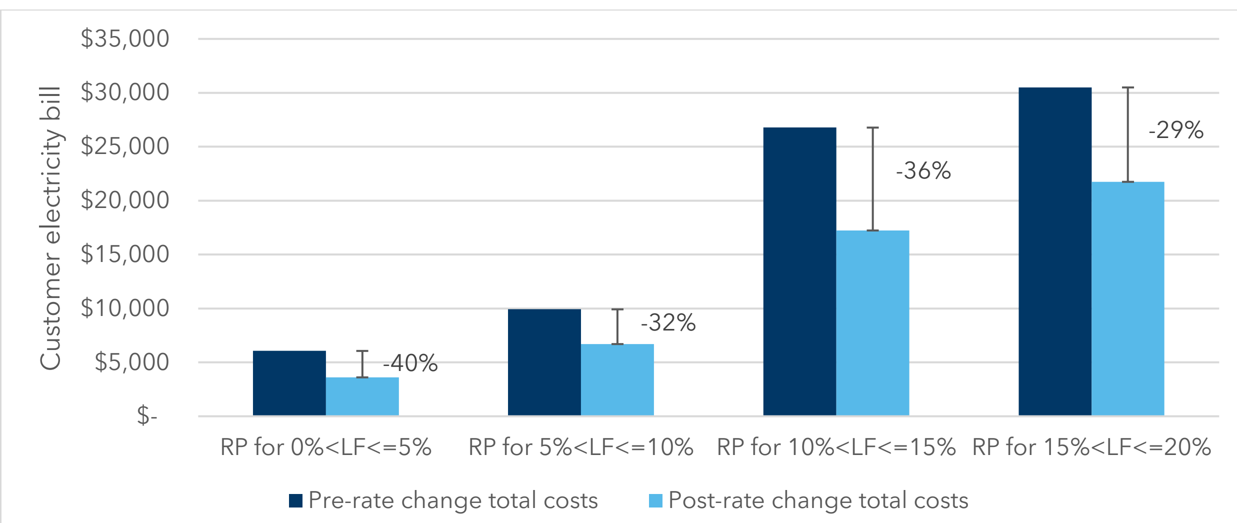
Figures ES-3: Proposed rate billing determinants across four load factor tranches

This rate is intended for new and existing publicly accessible EV fast-charging stations with at least one DCFC port with a minimum nameplate capacity of 50 kW.

Dunsky developed the proposed design in two steps. First, we completed a qualitative review process of a range of potential rate structure options to determine the leading structure. Second, we undertook a quantitative analysis to establish specific parameters (i.e. thresholds and billing determinants) within the preferred structure that both meet the revenue recovery requirements of NB Power while also reducing DCFC operator electricity bills and their business case barrier. The parameters were developed using representative profiles across a range of load factors based on the NB Power eCharge network data set.

An Effective Solution

The proposed rate design **mitigates a real barrier** of high electricity bill costs by aligning the demand and energy charges with the fast-charging station load factor and the cost of service of representative DCFC sites. The design reduces operational costs driven by demand charges compared to the status quo (shown in Figure ES-4) and improves the overall business case.



Figures ES-4: Customer electricity bill pre-rate change (under General Service I) and post-rate change (under the proposed rate)

We selected the proposed design from a range of potential solutions based on a qualitative evaluation of rate-making and implementation considerations, as well as leading trends from other jurisdictions. The proposed design considers the changing EV adoption and fast-charging market. The design aligns cost mitigation with utilization levels, cost recovery based on the DCFC customer profile, and a stress test considers a range of potential site sizes and consumption.

Conclusion

The proposed rate **responds to NBEUB's direction and a market need**: to mitigate demand charges to reduce the barrier to public DCFC deployment. The proposed rate provides relief to low load factor stations by shifting cost recovery from demand to energy charges, while also more appropriately collecting costs based on the cost to serve these unique customers. The load factor-based approach is an emerging approach across jurisdictions with strong EV adoption policy contexts and will remain relevant in an evolving EV market. The proposed rate reduces electricity bill costs to DCFC operators while ensuring appropriate cost recovery and assessing risk. Therefore, the proposed rate is a strong option to mitigate this important barrier.

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List of Acronyms

Acronym	Definition
AMI	Advanced Metering Infrastructure
CP	Coincident Peak
3CP	Three Month Average Coincident Peak
DCFC	Direct Current Fast Charging
EV	Electric Vehicle
GS	General Service
NCP	Non-coincident peak
RCR	Revenue-to-cost ratio
RP	Representative Profile

1. Context & Need for Rate Design

1.1 New Brunswick Power's Role in Transportation Electrification

New Brunswick Power (NB Power) has recognized that the utility will have an important role to play in transportation electrification. To determine the most appropriate roles, the utility completed significant internal engagement, research, and decision-making which resulted in the *2021 Beneficial Electrification of Transportation Strategy*[2]. The Strategy defines the utility's two primary roles as driving vehicle-grid integration and accelerating electric vehicle (EV) adoption and NB Power outlines several initiatives to support those roles. In each role, the utility defined priority levers. Under the accelerating EV adoption role, NB Power defines public direct current fast charging (DCFC) as a priority market intervention.

1.2 Regulatory Context

NB Power operates its eCharge network, providing publicly accessible Level 2 and direct current fast charging (DCFC) across the Province. NB Power received direction from the New Brunswick Energy and Utilities Board (the NBEUB) not to expand its public charging network using ratepayer funds in Matter 375 stating that "charging stations are not within the core business and are already provided by the private sector, without any ratepayer investment."[3] While the eCharge network expansion has been completed using external funding sources, this direction emphasizes the key role of the private sector in provisioning public charging in the province.

NB Power's role in transportation electrification is linked to its current rate modernization efforts. In the utility's 2022 Rate Design Application Evidence, the utility identified several mid-term rate design proposals, including the mitigation of unnecessary or unjustified barriers in rate design to public charging and fleet charging, because the development of charging stations is "somewhat impeded by up-front and ongoing costs that, in the early years, are high relative to the usage of the charging service."[4] Specifically, NB Power outlined its plan to explore and where applicable, to file Business EV Charging Rates in the Rate Modernization Phase 2a submission in Fiscal Year (FY) 2025.[5]

In this application, NB Power asked for direction from the NBEUB to resolve the following issue: "Enhancements such as declining discounts on demand charges for commercial customers upon the introduction of electric vehicle charging for fleets or public charging." In response, the NBEUB, in the decision for Matter 529, directed NB Power to submit as evidence in Phase 2a:

[2] New Brunswick Power. 2021. *Beneficial Electrification of Transportation: Strategy and Roadmap (2021-2026)*. (Matter 529, Filing NBP04.21)
[3] New Brunswick Energy and Utilities Board. 2018. Decision. Matter No. 375.
[4] New Brunswick Power. 2022. 2022 Rate Design Application – Evidence. (Matter 529, Filing NBP01.03)
[5] New Brunswick Power. 2023. Undertaking Response #01. (Matter 529, filing 14.01)

- "an evaluation of any material barriers to third-party development of EV stations in NB Power's eCharge Network and other public and fleet EV stations"
- "any proposed rate design and policy changes to address these issues"

This design document has been developed to support the evidence of the material barriers to public EV stations and a proposed rate design to address this issue.

1.3 Market Need

1.3.1 Public Fast-Charging is an Important Enabler of EV Adoption and Broader Ratepayer Benefits

Publicly accessible EV fast charging is a key catalyst of EV adoption among consumers. Public charging, including fast charging, is an important option for EV drivers who do not have access to charging at home or require additional charging when away from home, and a key consideration for current and prospective EV drivers. In a 2023 Canada-wide survey, 89% of current EV drivers, use fast charging for at least a portion of their charging needs.[6] According to a 2023 survey of NB Power customers, limited access to charging is the second biggest concern when it comes to buying or leasing an EV, second only to the upfront cost of an EV relative to gas-powered vehicles.[7] Public charging, including DCFC, will see higher demand as more drivers without access to home charging adopt EVs[8], and if efforts to increase access in existing homes are not achieved.[9] A strong network of fast-charging stations across New Brunswick is important to enable broader EV adoption.

Supporting EV adoption through a strong DCFC network provides broader ratepayer benefits. While public charging is an important component of the charging landscape, the majority of EV drivers will charge at home. If residential EV charging occurs overnight when the grid has excess capacity, the revenue associated with increased electricity sales can far outweigh any costs associated with supporting that load growth, including support to public fast charging, thereby putting downward pressure on electricity rates for the benefit of all ratepayers. Further exploration of the case for utility supports to enable EV investment to enable EV adoption for new beneficial load growth is covered in the Rate Structures for EV Charging memo included in the Appendix. This memo was prepared in 2022 and therefore, some of the case studies and jurisdictional scan information may no longer be current. For example, a key study referenced in that memo - the Synapse 2020 study - was updated in 2024. The Synapse study of US EV adoption across 50 states compared the revenues generated by charging to the utility marginal cost to serve those EVs.[10] The study estimates that, over 11 years, EV drivers contributed a cumulative US$3.12 billion more in revenues than associated costs. The study also explored the EV-related program costs, and the revenues still

[6] Pollution Probe. 2024. *2023 Canadian Electric Vehicle Owner Charging Experience Survey.*
[7] Narrative Research. 2023. NB Power Quarterly Survey Q3 2023.
[8] ICCT. 2023. Assessment of U.S. electric vehicle charging needs and announced deployments through 2032.
[9] Dunsky Energy + Climate Advisors. 2024. *Updated forecasts of vehicle charging needs, grid impacts and costs for all vehicle segments.* Natural Resources Canada.
[10] Synapse Energy Economics, Inc. 2024. Electric Vehicles Are Driving Rates Down for All Customers. National Update.

outweighed costs by US$2.44 billion. These additional revenues put downward pressure on rates by driving revenue and efficient system use by this flexible load. The study noted the importance of the utility role in encouraging off-peak charging, and the potential for utilities to invest in the deployment of charging infrastructure to accelerate the EV market and these associated benefits.

1.3.2 Increasing Near-Term Demand for Fast Charging

In 2024, there are 151 public DCFC ports across 69 sites in New Brunswick.[11] NB Power operates 48 ports, which are part of the broader eCharge network, with government, institutional, and private sector partners operating an additional 20 ports for a total of 68 ports in the network. The eCharge network is the second largest network in the province after Tesla, which operates 54 ports.

In a Canada-wide study with Natural Resources Canada, Dunsky forecast the public charging demand, including for fast charging from 2025 to 2035. For New Brunswick, we found that the demand for fast-charging ports will be 98 ports in 2025, 318 in 2030 and 671 in 2035.[12]

The number of fast-charging ports over time and the forecast demand are shown in Figure 1. Currently, the 2025 demand for public charging is met with the ports available today. However, the fast-charging network will require significant growth by 2030 (~2.5x today's ports) and 2035 (~5x) to continue to meet the charging demand, and the actual demand could be higher if there are lower levels of multi-family home retrofits than included in the forecast scenario.

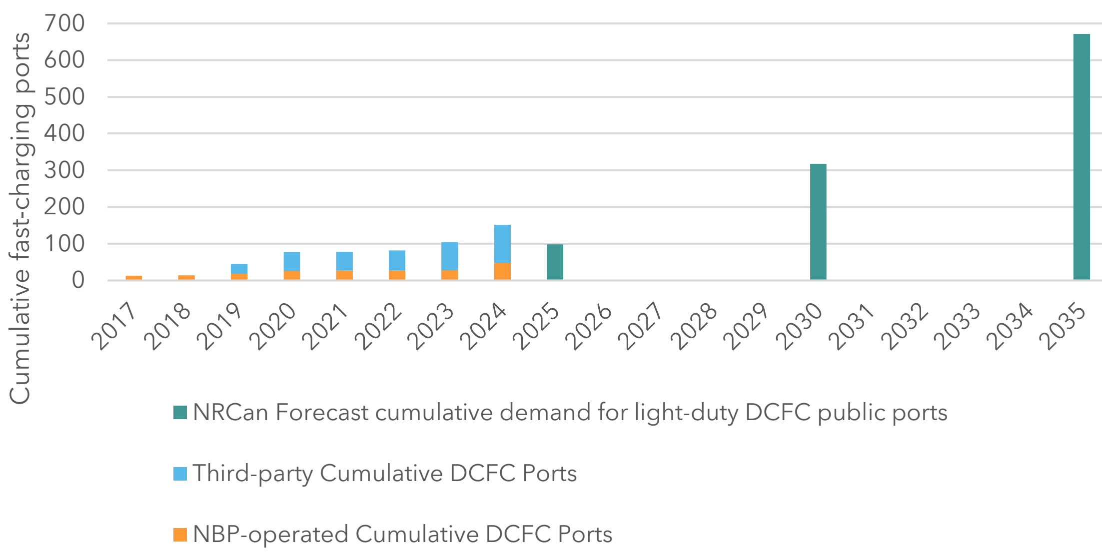

Figure 1 Cumulative number of DCFC ports in New Brunswick, operated by NB Power and others, and forecast 2025-2035 demand

[11] Port values based on a) NB Power-operated eCharge data and b) Natural Resources Canada. 2024. Electric Charging and Alternative Fuelling Stations Locator. Accessed September 11, 2024.
[12] Dunsky Energy + Climate Advisors. 2024. *Updated forecasts of vehicle charging needs, grid impacts and costs for all vehicle segments.* Natural Resources Canada.

1.3.3 High Electricity Costs are One Barrier to Private Sector Deployment

As seen in the figure above, private networks have expanded in New Brunswick since 2019, however, the current pace of deployment may not meet the forecast public fast-charging needs for 2030 and 2035. Further, the deployment would likely focus on areas with high utilization where sites have a stronger business case under the current electricity rate. This could leave gaps in provincial coverage where sites are critical for connectivity or equitable access but have challenging business cases. Through this study, we completed an engagement process to respond to the NBEUB direction to assess whether there are material barriers to the pace of third-party development of EV stations. As explored further in section 3.1, there are multiple barriers to deployment at the current levels of EV adoption.

One important barrier that was identified by all stakeholders is the high operational cost of the electricity bill, which is driven by demand charges. This challenge is not unique to New Brunswick nor NB Power's commercial rate. This challenge is unique to the consumption profile of DCFC sites with low utilization.[13]

Currently, private-sector fast-charger operators are charged under the General Service I (GSI) rate. This rate includes a charge for energy consumption ($ per kilowatt-hour [kWh]) and demand ($ per kilowatt [kW]). The demand charge is billed based on the highest averaged 15-minute period of demand in the monthly billing period. The challenge for fast-charging stations is that their usage can be highly intermittent, characterized by brief periods of high demand. For sites that see relatively infrequent use (e.g., in areas with low EV adoption or along highway corridors with highly seasonal traffic), the demand charge can represent a very significant portion of the electricity bill. For example, a site with a single 100 kW charger would be subject to close to $1000 per month in demand charges, whether the charger is used once per month or multiple times per day. For sites with infrequent usage, it can be challenging to reach a positive business case because the limited user fee revenue from infrequent use does not cover the high monthly demand charge.

To review this trend in New Brunswick, we leveraged NB Power's data set of the utility-operated eCharge DCFC sites for one year (FY2023-2024), which includes a total of 28 DCFC stations (26 of which are 50 kW stations and 2 are 100 kW). Figure 2 highlights the consistency of the demand, represented by the annual non-coincident peak (NCP) demand for all 50 kW ports is roughly 50 kW and roughly 90 kW for the two 100 kW ports. However, the total annual energy consumption varies, with the same demand, and demand charge, for sites that have low energy consumption.

[13] Matteo Muratori, Eleftheria Kontou, Joshua Eichman. 2019. Electricity rates for electric vehicle direct current fast charging in the United States. *Renewable and Sustainable Energy Reviews*, Volume 113.

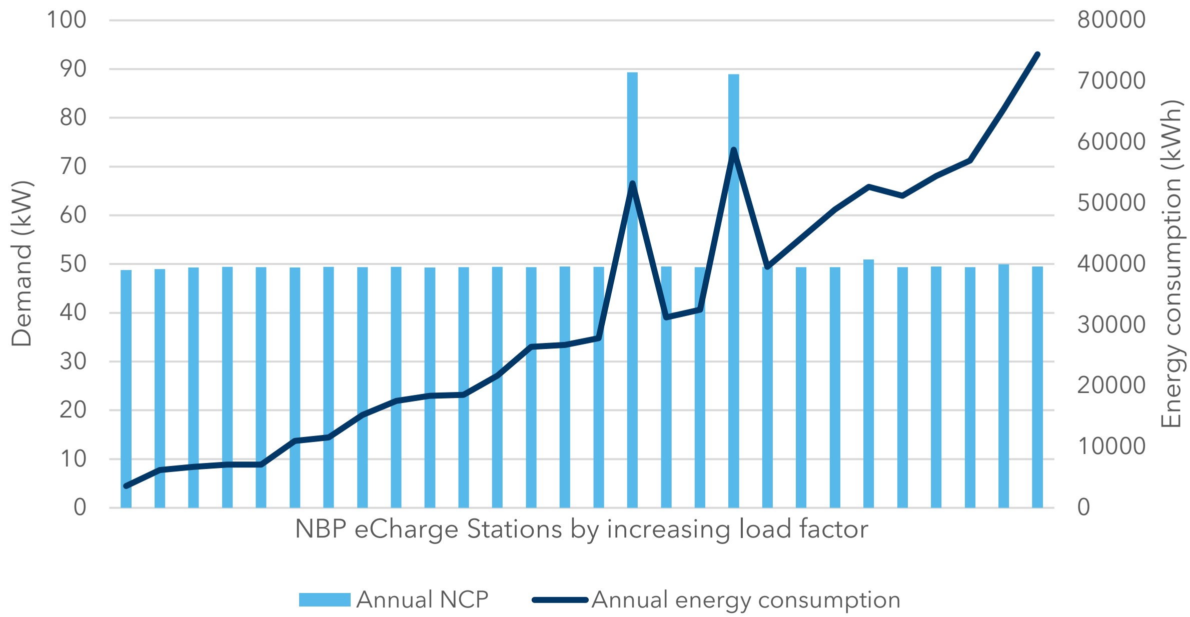

Figure 2: Annual non-coincident peak (NCP) and annual energy consumption of NBP eCharge Stations

1.3.4 Understanding DCFC Operator's Unique Profile and Load Factor

As DCFC site demand has variable peaks, there is the potential that a site's demand does not align with the system peak. Currently, in New Brunswick, the three months with peak demand contributing to the system peak or, more specifically, coincident peaks are December, January and February, which is referred to as 3CP. [14] In Figure 3, we compare the non-coincident peak (NCP) demand, as the potential contribution to system peak based on the site capacity, to the 3CP, as the actual contribution to system demand.

There is variability in the 3CP demand, but it is significantly lower than the NCP. Figure 3 highlights that DCFC sites have high demand, but their contribution to system peak (represented as 3CP), is significantly less than the site's total potential contribution based on the port capacity.

[14] 3CP refers to the multiple coincident peak and average demand classification as defined in NB Power's Class Cost Allocation Study methodology (Matter 554, filing NBP02.05). This approach calculates the average coincident peak demands of the three high demand months. The system peak times included in this study are 12/6/2023 at 8am, 1/24/2024 at 8am, and 2/21/2024 at 7am.

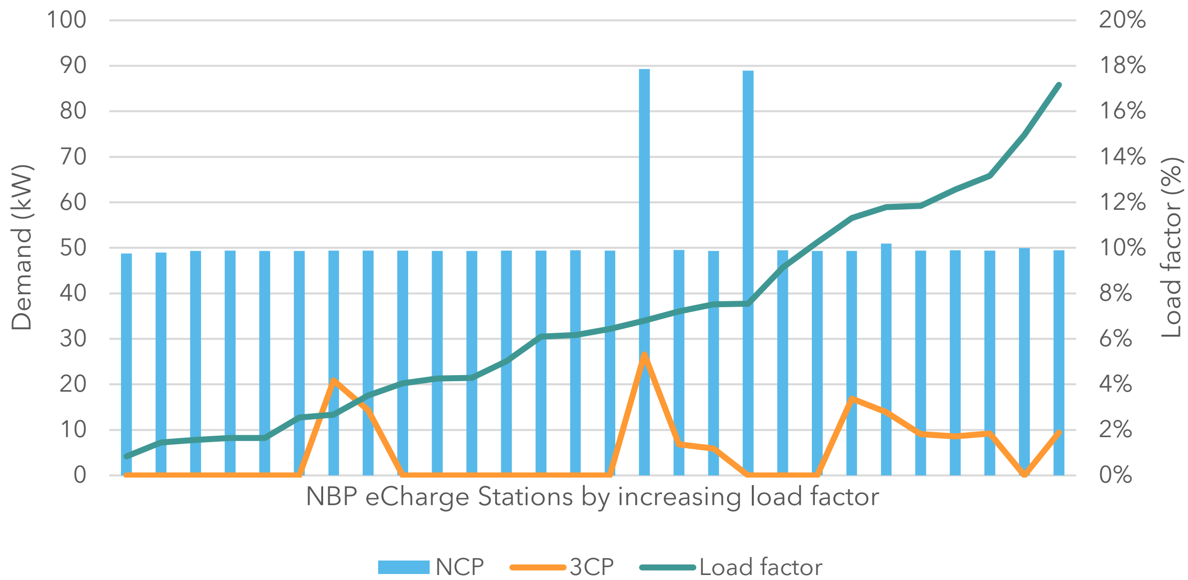

Figure 3: Peak demand and 3CP of NB Power eCharge stations

Figure 4 compares the 3CP between 356 GS (General Service) customers and 28 NB Power-operated eCharge network DCFC sites and highlights that DCFC stations do not contribute significantly to the system peak. The 3CP of DCFC stations is significantly lower than GS customers, with the GS dataset having a median 3CP of 56 kW, and the eCharge DCFC stations having a median 3CP of 0 kW.

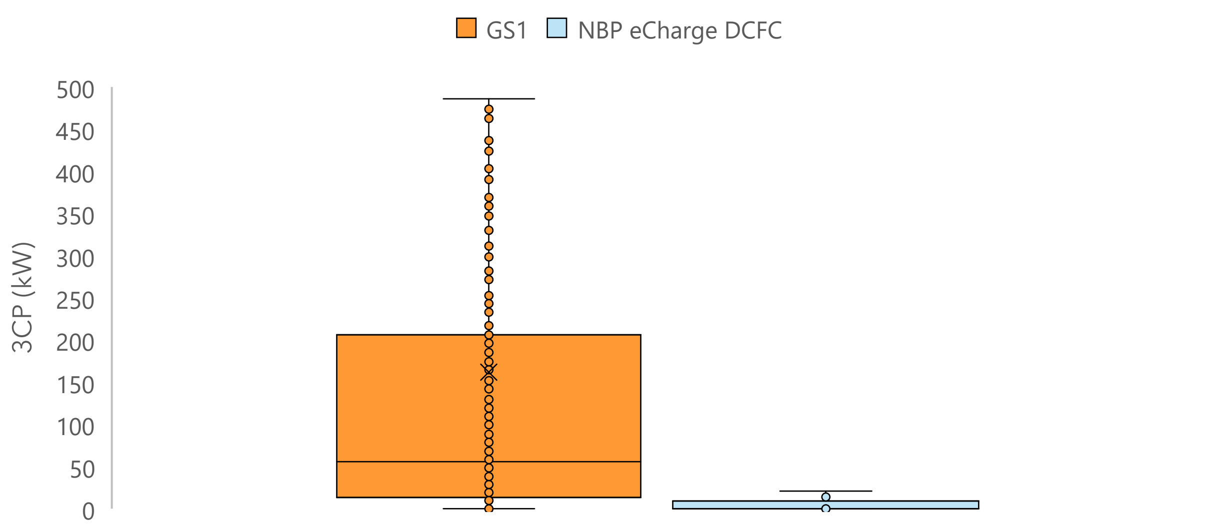

Figure 4: Box plot showing variation in 3CP across GS1 customers and eCharge fast-charging stations

When comparing the 3CP coincidence factor of the GS population to eCharge DCFC stations, a similar contrast can be observed, as seen in Table 1. Collectively, eCharge DCFC sites have a 3CP coincidence factor of 10%, which is significantly lower than GS sites, which have a 3CP coincidence factor of 86%. This emphasizes that DCFC stations draw only a small portion of their demand during system peaks, whereas GS stations contribute a much larger share of their demand during these peak periods.

Table 1: 3CP Coincidence Factor for GS sites versus eCharge DCFC stations

	Total 3CP (kW)	1NCP[15] (kW)	3CP Coincidence Factor[16]
GS sites[17]	504,524	587,112	86%
eCharge DCFC Stations	142	1,447	10%

A similar disparity is evident when comparing the NCP of GS customers to DCFC stations, with the median NCP being 94 kW for GS customers and 49 kW for DCFC sites.

This unique profile of DCFC operators can be understood in terms of its load factor - a useful metric which integrates peak load (or NCP) and stability. Load factor is the average load divided by the peak load in a specified period.

$$Load\ factor = \frac{total\ kWh\ consumed\ in\ a\ period}{kW_{max} \times number\ of\ hours\ in\ a\ period}$$

For sites with a constant demand, the load factor approaches 100%. With these high load factor sites, NB Power needs to design its system to accommodate the expected, constant load. For fast-charging sites with varying demand, the load factor is low, and for sites with very low usage, it can approach 0%. The load factor of the eCharge sites is shown in Figure 3, ranging from ~1% to 17%. In the eCharge site data set, there is no clear correlation between an increase in load factor and a corresponding increase in contribution to the system peak (3CP). However, as shown in Table 1, the 3CP coincidence factor for eCharge sites is very low, and they collectively contribute minimally to the system peak.

To further explore the difference between GS customers and fast-charging operators, we compared the load factors of GS to eCharge DCFC customers. Figure 5 highlights the large contrast in load factors between GS and fast-charging stations. The GS customers have a median load factor of 31%, whereas the fast-charging stations have a significantly lower load factor of 6%. The fast-charging stations have a lower load factor due to their distinct usage profiles characterized by intermittent usage and variability in demand, compared to GS. This difference between profiles explains why the demand charges are more significant for DCFC operators.

[15] 1NCP is defined as the maximum of the total NCP for the months of December, January, and February

[16] 3CP Coincidence Factor is defined as the ratio of the total 3CP to 1NCP, expressed as a percentage

[17] Collective 3CP Coincidence Factor of GSI and GSII sites calculated from actual FY22-23 values from NB Power-provided file “Load Research for FY25_FY26 Budget CCAS”.

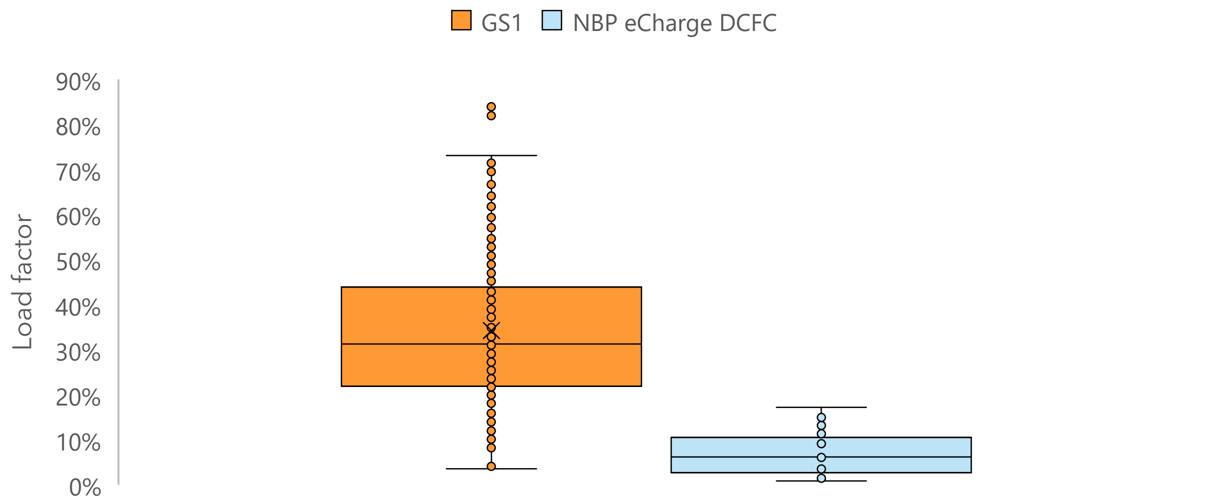

Figure 5: Box plot showing variation in load factor across GS1 customers and eCharge fast-charging stations

Figure 6 further highlights that the majority of NB Power eCharge stations have low load factors, with 20 stations (or 71% of total stations assessed) being within a load factor of 0% to 10%, and the average load factor being 6.7%.

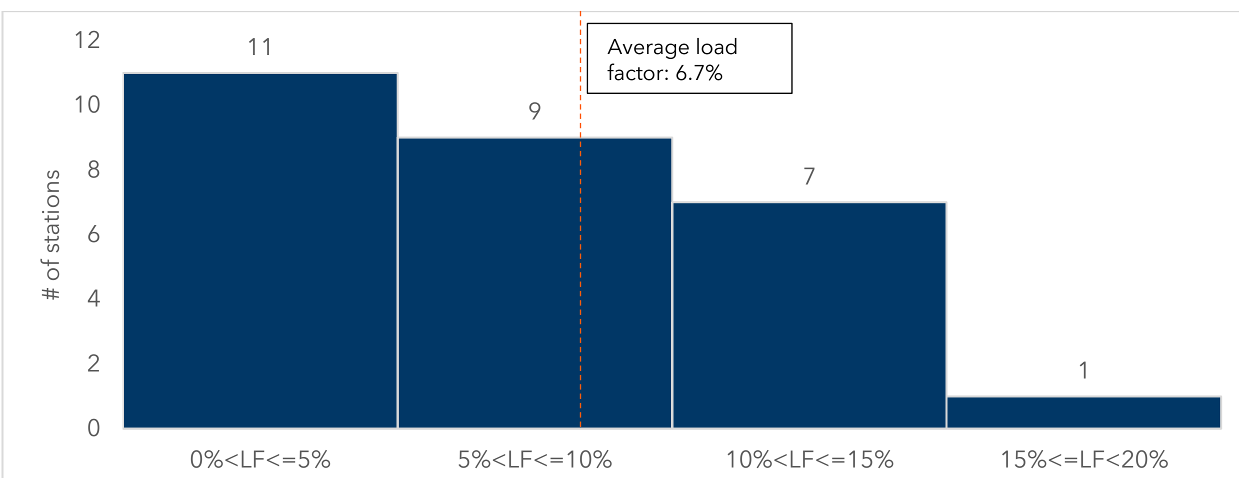

Figure 6: Distribution of load factors in NB Power eCharge stations

Load factor aligns with another key metric in the EV charging space: time-based utilization. Load factor defines the proportion of the maximum peak (kW) in a time period whereas time-based utilization defines the proportion of time a port is in use in a period. Time-based utilization is a common metric in EV charging to highlight the level of use, and therefore, the potential for improved revenue and profitability for a site.

$$Time\ based\ utilization = \frac{total\ hours\ of\ EV\ charging\ in\ a\ period}{total\ available\ hours\ for\ potential\ charging\ in\ a\ period}$$

Generally, as time-based utilization increases, load factor increases. This trend can be found in the selection of eCharge network sites, as shown in Figure 7.

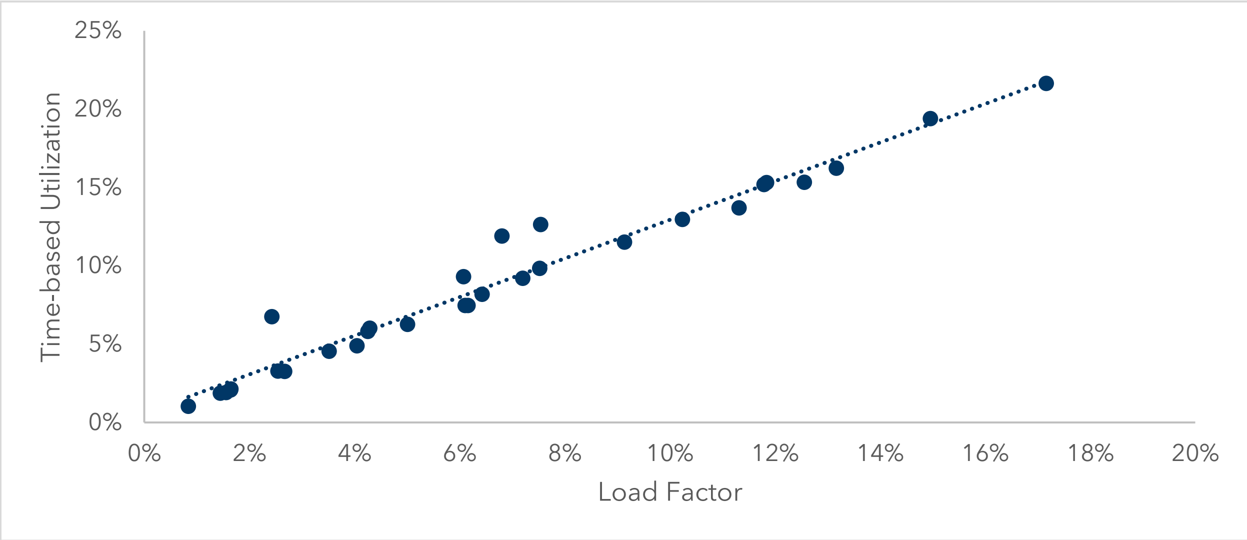

Figure 7: Load factor & time-based utilization for eCharge sites

1.4 Proposed Solution

An important barrier to public fast-charging deployment is the challenging business case, driven by high operational electricity bills. The proposed rate design mitigates the high operational costs by aligning the demand and energy charges with the fast-charging station load factor and the cost of service of representative DCFC sites.

2. Design Development Approach

Dunsky developed the proposed design through two steps: first, a qualitative review process of a range of potential rate structure options to determine the leading structure, and then a quantitative analysis to establish specific parameters (i.e. thresholds and rates) within the preferred structure that both meet the revenue recovery requirements of NB Power while also reducing DCFC operator electricity bills and their business case barrier.

2.1 Rate Structure Selection

The rate structure selection process involved a multi-step qualitative assessment of potential options. We developed a long list of potential options based on a jurisdictional scan of Canadian and US EV fast-charging rates both in-market and in regulatory review. We reviewed a total of 15 in-market or in-review rates from 12 provinces and states, with the full list of rates included in Appendix Table 8.

From this scan, we deconstructed the rate designs into their energy and demand components to evaluate the components separately prior to making assumptions regarding potential combinations. We used the range of energy and design components, summarized in Table 2, as the long list of potential design component options. Additional descriptions and examples of these options are included in the Appendix Table 9.

Table 2 Long list of energy and demand components options considered, with short-listed options in bold

Energy component options	Demand component options
• Declining Block (currently in GSI) • **Energy-Only** • **Energy Time-of-Use (TOU)** • Energy TOU + Critical Peak Pricing (CPP) • Energy Real-Time Pricing (RTP)	• Demand Charge (currently in GSI) • Transformer Demand Charge • Demand Charge Holiday • **Load-Factor-Based Demand** • **Demand TOU** • **Coincident Peak (CP) Demand Charge**

We evaluated the long list of component options based on six evaluation criteria, which incorporated rate design principles and beneficial electrification objectives. The criteria are detailed in section 4.2.1. The energy and design options that ranked highest (bolded in Table 2) were incorporated into a short list for further assessment. We assessed the short list of options for effectiveness and viability in implementation based on a qualitative framework of four key considerations (section 4.2.2). The energy option and demand option that ranked the highest among these considerations were selected as the rate structure for the proposed design: energy time-of-use and load-factor-based demand charge.

Exploring Fleet and Residential EV Rates

NB Power engaged Dunsky to explore potential EV rate design options for residential, fleet and public charging markets. This *DCFC Electricity Rate Design Document* is the primary outcome. However, the **rate structure selection process** described in this section was also applied to fleets and residential EV rates. We developed initial recommendations for future potential designs. Full designs were not pursued at this stage for either market due to current regulatory or market considerations.

Fleet Operators

We recommended an **energy time of use (TOU) and transformer demand charge rate concept** for fleets based on the qualitative rate structure selection process. We also identified a potential opportunity to offer the public DCFC rate to fleets (as one General Service EV rate offered to both markets). This option would offer a similar demand charge as the status quo for most fleets with mitigation for very early-stage, low-load factor fleets and could achieve efficiencies in administration and outreach. These benefits may outweigh the less optimized rate for fleets.

NB Power decided not to pursue a fleet rate at this time for two main reasons. Firstly, electricity rates and costs were not raised as a major barrier for fleets in our stakeholder engagement. Currently, electricity costs are expected to be a valuable savings relative to fuel costs, and most fleets are in the early stages of the electrification process. However, fleets expect rapid EV adoption in the coming years, and they will be monitoring electricity costs and rates. Secondly, NB Power is in the process of completing a customer reclassification process as Advanced Metering Infrastructure is being rolled out. Therefore, fleets under General Service I may fall under a new rate in the near future. Therefore, a fleet rate design and comparison to the new status quo should be completed after the reclassification.

Residential Customers

We recommended an **energy time of use (TOU) rate concept** for residential customers based on the qualitative rate structure selection process. We did not complete a design analysis, but through the evaluation process, we determined that a TOU concept would likely be most appropriate as a whole-home rate with TOU periods that vary by daily periods (not seasonally).

We also recommended engagement with customers before finalizing a new rate design. While residential customer engagement was not within Dunsky's scope of work for this project, it is generally best practice. NB Power made progress on this recommendation with a residential focus group in May 2024.

NB Power decided not to pursue a residential rate at this time because the utility is exploring how an EV-oriented rate would integrate with the net-metering rate to offer one new residential rate option. Further, NB Power is considering offering residential TOU in its rate sandbox, if approved by the EUB, offering additional exploration of residential TOU prior to a rate design submission.

2.2 Billing Determinants Development

The billing determinants were defined through a two-step process:

1. Calculate revenue recovery requirement for the unique DCFC site characteristics.
2. Defining billing determinants values by shifting demand charges to energy charges and adjusting by load factor tranche characteristics.

2.2.1 DCFC-Specific Revenue Recovery

To base the billing determinants on the revenue recovery for the DCFC site characteristics, we completed an assessment of the revenue recovery requirements for public DCFC sites in New Brunswick.

We leveraged the NB Power eCharge data set to select and develop representative profiles because the data included local usage patterns and was readily available. As seen in Figure 8, although the quantity of energy consumed across the eCharge profiles differs, they generally have a similar shape – with the majority of charging happening during the daytime hours.

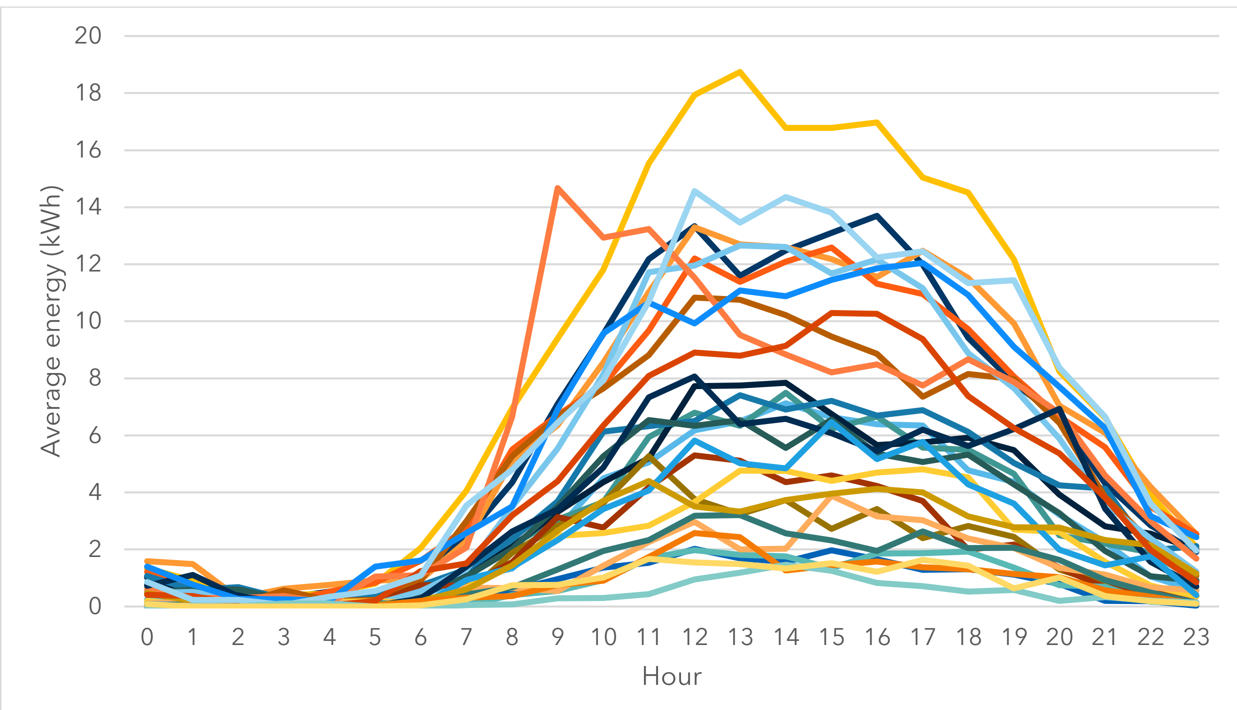

Figure 8: Average energy consumption over a day for NBP-operated DCFC sites in the eCharge data set

We aimed to have the representative profiles represent a range of load factors. The profile covers an increment of load factors, which we define as a tranche.

We developed and selected four representative profiles based on the following factors:

- Load factors within the middle of tranches
- Increasing energy consumption with an increasing load factor
- Increasing NCP with increasing load factor
- Increasing 3CP with increasing load factor

The energy consumption over a day in the summer and winter are summarized in Figure 9 and Figure 10, respectively, and the key characteristics of the profiles are summarized in Table 3. The profile development and selection process are further detailed in the Appendix.

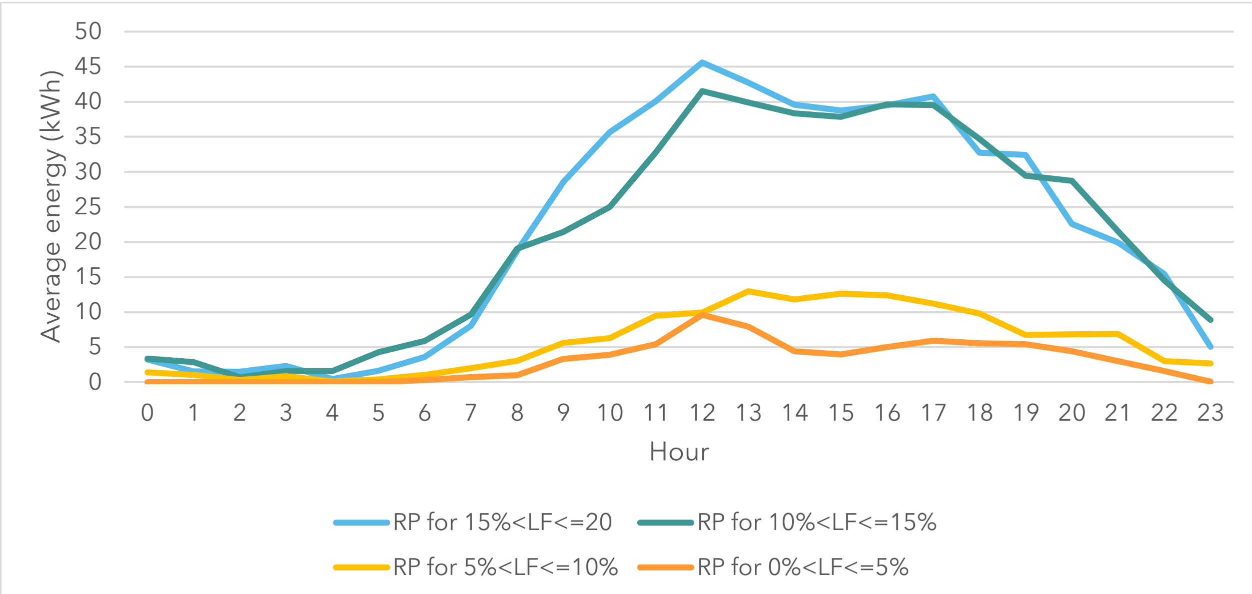

Figure 9: Summer (July and August) average energy consumption over a day for representative profiles

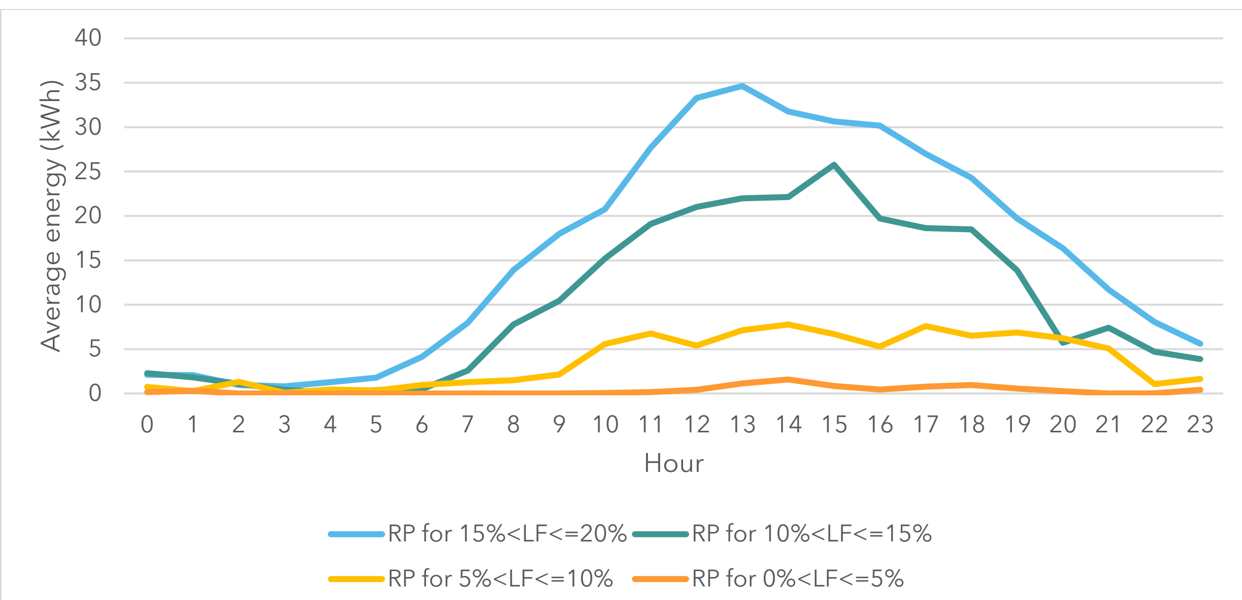

Figure 10: Winter (December, January, February) average energy consumption over a day for representative profiles

Table 3: Summary of representative profiles selected

Load factor tranche	Number & Size of Ports	Load factor	Time-based utilization	Annual energy (MWh)	Annual NCP (MW)	3CP (MW)
RP for 0%<LF<=5%	1x50 kW	2.5%	3.3%	12	0.05	0.000
RP for 5%<LF<=10%	1x50 kW	7.5%	9.8%	34	0.05	0.005
RP for 10%<LF<=15%	2x50 kW	12.7%	15.7%	116	0.10	0.016
RP for 15%<LF<=20%	2x50 kW	16.2%	20.5%	148	0.10	*0.025 (adjusted)*

To note, these four profiles are representative examples of current DCFC patterns in New Brunswick but do not denote all possible DCFC site profiles.

For each representative profile, we determined the overall generation, NCP, and 3CP. As the DCFC profiles are based on demand at the customer point, we included the impact of the following losses: primary losses, distribution substation losses, and transmission losses.

The levelized costs were then applied for each representative profile's impacts (generation, NCP, and 3CP). NB Power provided the levelized costs, based on NB Power's Class Cost Allocation Study (Appendix Table 7). A Revenue-Cost Ratio (RCR) was applied to the cost of service value to determine the applicable total revenue that should be collected from the representative profiles. A comparison of the revenue recovered under GSI compared to the calculated revenue requirement is in Figure 11, highlighting that the cost to serve these customers is lower than the revenue currently recovered under GSI (i.e., the DCFC customer electricity bill).

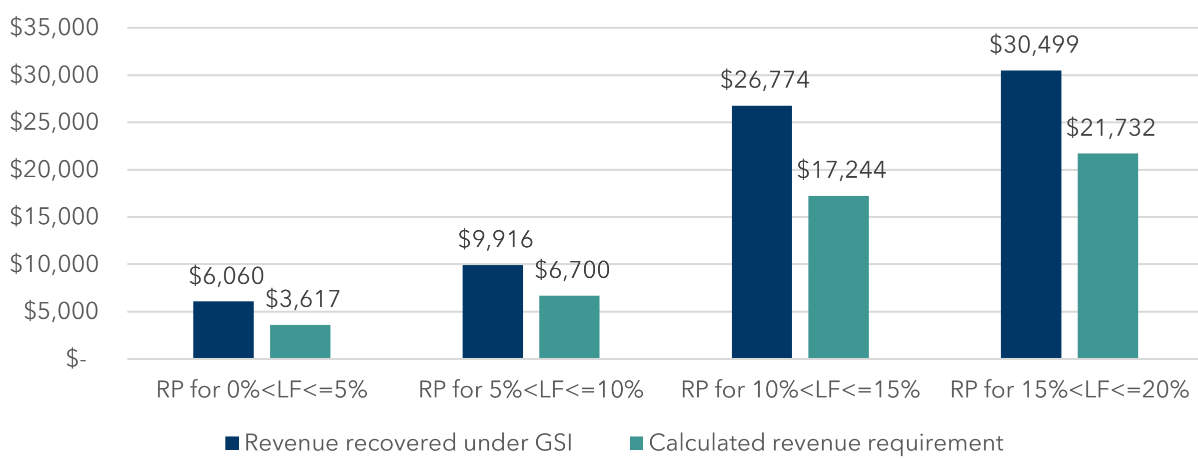

Figure 11 **Revenue recovery for DCFC profiles under General Service I and as calculated for DCFC profiles**

2.2.2 Adjusting Billing Determinants

Once the revenue requirement was determined for each representative profile, we varied the billing determinants through an iterative process (while keeping the revenue recovery constant) to assess the impact on the customer electricity bill and the DCFC site business case.

We first defined the demand charge by using the GSI equivalent demand charge ($/kW). To reduce the influence of the demand charge on the electricity bill, we applied a percentage reduction to the GSI-equivalent demand charge to shift a portion of revenue recovered by demand charges to be recovered by volumetric energy charges. This percentage could vary by load factor tranche, with the general trend that lower load factors had a higher percentage of the recovery shifting to energy.

We explored various options for the load factor tranche characteristics included in the structure. We varied the following elements:

- Load factor tranche size (e.g., 0-5% vs. 0-10%)
- Load factor maximum value (e.g., 10% vs. 20%)

We also explored options for time-of-use periods in the rate with various on-peak: off-peak ratios. We selected the billing determinants based on the values that produced the most improvement in customer bill and site business case across all representative profiles.

3. Proposed Rate Design

3.1 Rate Design Structure

The rate design is defined by two broad components:

1. A demand charge that increases based on site load factor
2. An energy charge that decreases based on the site load factor and varies by time-of-use periods.

The rate includes sites with an annual load factor of up to and including 20%, with the variation by load factor separated into tranches (i.e., increments) of 5%.

The time-of-use period includes two daily periods year-round: an on-peak period from 7 am to 10 pm and an off-peak period of all other hours. The ratio between on-peak and off-peak costs is 2:1.

3.2 Billing Determinants

The billing determinants based on load factor tranche are summarized in Table 4 and Figure 12.

Table 4 Proposed rate billing determinants

Load Factor Tranche	**Off-peak energy** ($/kWh) All other hours	**On-peak energy** ($/kWh) 7 am to 10 pm	**Demand** ($/kW)	**Customer Charge** ($/billing period)
0%<LF<=5%	$0.053	$0.105	$4.025	$27.57
5%<LF<=10%	$0.045	$0.091	$6.037	$27.57
10%<LF<=15%	$0.037	$0.074	$8.050	$27.57
15%<LF<=20%	$0.036	$0.072	$10.062	$27.57
General Service I[18]	*First 5,000 kWh:* *Balance of kWh:*	*$0.1587* *$0.1124*	*First 20 kW: $0* *Balance kW: $12.69*	*$27.57*

[18] NB Power 2024-2025 rate schedule. Does not include Variance Account Charge of +0.37cents/kWh

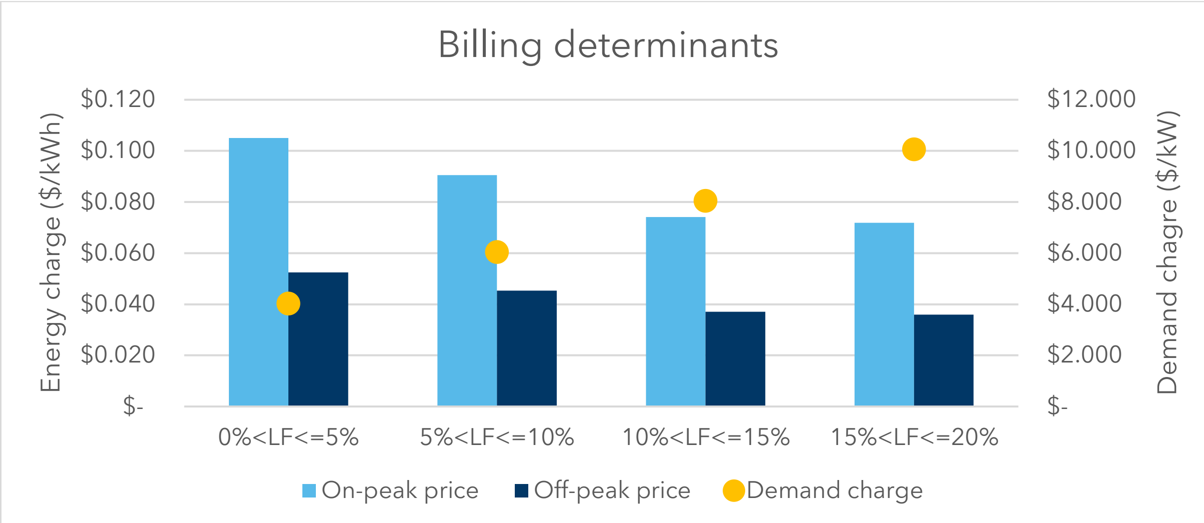

Figure 12 Proposed rate billing determinants

3.3 Eligibility

3.3.1 Site Eligibility

This rate is intended for publicly accessible fast-charging stations. Sites can be new or established (i.e., an existing NB Power customer under another rate class). Sites should have at least one direct current fast-charging port with a minimum nameplate capacity of 50 kW.

Sites are eligible if publicly accessible, meaning the site should be fully or partially publicly accessible. The following locations with fast-charging ports should be considered public-accessible:

- Corridor (highway) or curbside
- Retail establishments
- Public institutions (i.e., schools, hospitals, municipal facilities)
- Workplaces, including public and employee-only/semi-public

Other low load factor sites would not be eligible. Fast-charging sites for fleets or other non-publicly accessible use would not be eligible.

3.3.2 Average Load Factor

Sites are eligible for the rate if they have an annual average load factor less than or equal to 20%. The annual load factor is calculated based on the annual load factor equation below. The site will be assigned to the appropriate load factor tranche based on the previous twelve months of site data of site consumption.

$$Annual\ load\ factor = \frac{total\ kWh\ consumed\ in\ a\ year}{kW_{max}\ x\ number\ of\ hours\ in\ a\ year}$$

If the site is new and, therefore, does not have previous data, the site can be assigned to the lowest tranche (0%<=LF<5%) or another more appropriate tranche based on the expected site utilization, as deemed appropriate by NB Power.

The site should be assessed on an annual basis to determine if the site should transition to a different tranche in the rate or, if the annual load factor exceeds 20%, if the site should transition to a different rate (i.e., GSI).

Alternative approaches can be used to assess site load factor tranches, such as monthly load factor, or rolling average annual load factor.

Transitioning from the DCFC rate to General Service

If load factors exceed 20%, a transition to the GSI rate structure is recommended. Currently, the demand charge for GSI and the highest load factor tranche (15%<LF<=20%) is equivalent, ensuring a reasonable transition from the proposed rate to GSI. We calculated the actual GSI demand charge of the representative profile for the highest tranche by dividing the total annual demand charges by the sum of NCPs, resulting in a demand charge of $10.04/kW.

As can be seen in Figure 13, the difference between pre- and post-rate change values narrows as load factors increase. Moreover, Figure 15 highlights that DCFC operators in the highest two load factor tranches experience positive gross operating and net profit under both the pre- and post-rate change scenarios. Therefore, although DCFC operators can expect an increase in their electricity bills (specifically in their energy charges) when transitioning from the highest load factor tranche in our rate design to GSI, they should still achieve positive net and gross operating profit, minimizing any significant financial impact.

Given the majority of eCharge stations currently have an average load factor of 6.7%, as observed in Figure 6, we do not anticipate many eCharge stations switching from the proposed rate design to GSI in the near to medium term. However, if load factors begin to increase significantly as more data is available from other third-party network operators and many customers are moving to GSI, we recommend revisiting the rate design and tranches to ensure the new distribution of customers is accounted for.

3.3.3 Metering Requirement

Sites are eligible if the fast-charging ports are separately metered from other, non-fast-charging loads.

We recommend allowing a small portion (i.e., 10% of total consumption) of auxiliary load to be allowable on the rate-eligible submetering (i.e., site lighting, site communications equipment, etc.).

3.4 Implementation Considerations

We recommend providing the rate for a 10-year period to provide a reliable rate for current and potential DCFC operators to develop business and deployment plans. The rate may continue to be offered after the 10-year period if determined to be valuable to continue supporting expanded DCFC deployment and low utilization sites.

We recommend updating the billing determinants during the 10-year period, in alignment with updates to other rate billing determinants, or every two to five years following implementation. Billing determinants can be updated by selecting current representative profiles from the eCharge or other private-sector networks, where available. The revenue requirements and the billing determinant adjustments can be made according to the updated profiles.

In addition, we recommend assessing the load profiles (NCP and 3CP) of customers under the proposed rate to identify outliers relative to the representative profile on an annual basis.

4. Rationale for Proposed Rate

4.1 An Effective Solution to a Real Barrier

The proposed design provides an effective solution to a real barrier to increased public DCFC deployment. By reducing operational costs driven by demand charges, a key barrier to DCFC deployment is mitigated.

4.1.1 Barrier Confirmed Through Engagement

To understand the barriers to third-party-owned public DCFC deployment in New Brunswick, we completed a stakeholder engagement process. We completed interviews with five publicly accessible DCFC network operators in Fall 2023:

DCFC Operator	Interviewee Title
ChargePoint	Director, Public Policy – Canada Senior Manager, Regulatory Policy
Flo	Senior Product Line Manager
NB Power eCharge	Product Management Specialist, E-Mobility
Petro Canada/Suncor	Category Manager, EV Charging Manager, Energy Marketing
Tesla	Regional Manager, Canada Senior Advisor, Public Policy and Business Development Senior Advisor, North America Charging Policy

Through these interviews, operators highlighted that low utilization, driven by the early stage of EV adoption in the province, is the primary barrier to network expansion in New Brunswick. The four private-sector operators flagged that electricity costs greatly impact the underlying business case. Operators identified demand charges as a significant barrier given low utilization across many sites, making the electricity bill, and specifically the demand, a significant portion of fast-charging network operational costs. These high costs at low utilization sites create a challenging or unreasonable return on investment, limiting network expansion. NB Power noted that it is in a unique position as a utility-owned network, but that it had received feedback that demand charges are a significant portion of electricity bills and operator costs at some sites. Tesla indicated that its expansion plans are based on having a broad network where a challenging business case in one region with lower EV adoption and DCFC utilization is balanced by regions with stronger utilization. However, ChargePoint, Flo and Petro Canada highlighted that the low EV adoption in New Brunswick means that it is challenging to find a clear return on investment. This low EV adoption translates to low utilization and revenue, which makes it difficult to balance out the capital and operational costs. At low utilization, the demand charges make up a significant portion of the effective cost. One operator provided the example that at 2.5% utilization, which is typical for some chargers in New Brunswick, the effective electricity cost can be $1/kWh. An operator noted that the business case will only get more challenging under the current rate design as sites transition to higher power charging, including ultra-fast charging (i.e., ports with >200 kW power). Extension and connection fees are another significant cost and barrier to network expansion.

When asked about solutions for the rate design challenge, operators identified that certainty for the solution is important. Offering long-term (i.e., 10-year) solutions are needed to enable providers to develop their network development plans, as rates define key operational costs. Operators noted that interim solutions are helpful if the rate will take a long time to come into effect, but that demand charge mitigation solutions should not be short-lived.

Operators also flagged that effective solutions exist, particularly in the United States, where demand charge solutions have been explored and implemented. There is no need to reinvent the wheel with a new, unique, or overly tailored solution.

Regarding eligibility, operators requested that the rate be available to new and existing sites, and that minimizing metering requirements further improves the business case.

4.1.2 Barrier is Reduced Under Proposed Rate Design

The proposed design and its billing determinants led to an improved business case for public DCFC operators in our analysis compared to the status quo (i.e., under GSI).

We developed the proposed rate by assessing the business case barrier mitigation and revenue recovery requirements for representative profiles (RP) for each load factor tranche. The customer bill and site business case were assessed for each profile. In each case, the annual electricity bill is lower for the tranches under the proposed design, as summarized in Figure 13. The reduction ranges from a reduction of $2,400 or 40% compared to GSI under the lowest tranche for 0% to 5% load factor, and $8,800 or 29% under the highest tranche for 15% to 20% load factor. This reduction is driven by the cost of service assessment that found a lower revenue recovery requirement for DCFC profiles compared to the revenue recovered under GS1, and the balancing of costs between demand and energy charges to mitigate high demand charges, especially for lower load factor stations.

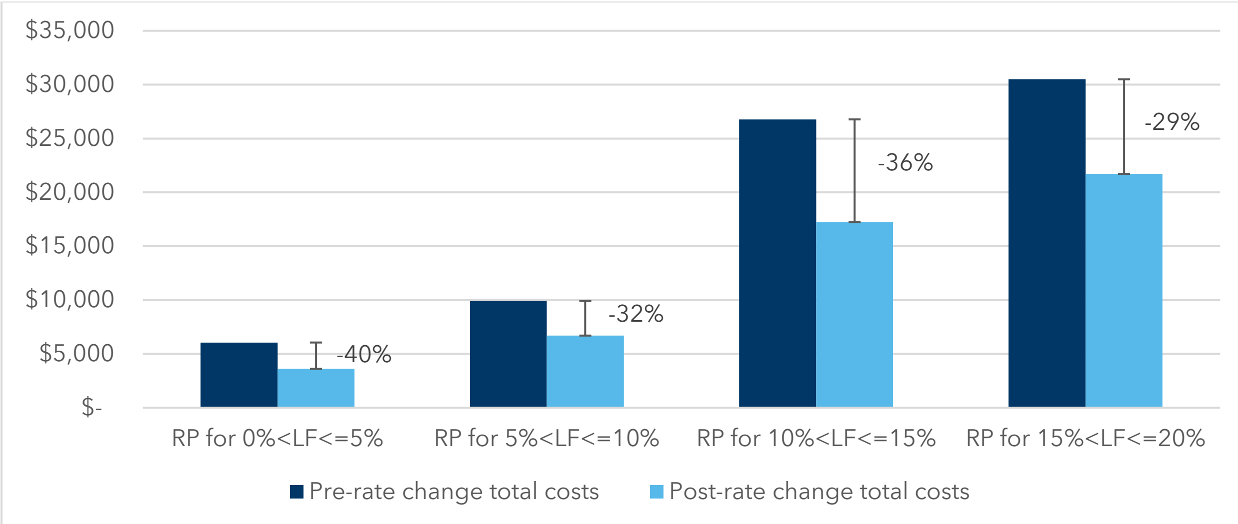

Figure 13 Change in DCFC operator annual electricity bill, with percent difference indicated

Electricity bill reduction is a key metric to determine if the operational challenge of high demand charges has been addressed. The effectiveness of demand charge mitigation rate design is ultimately to reduce the barrier to a positive business case in order to have higher levels of third-party operating fast-charging sites available in New Brunswick. This bill reduction can be put into the larger context of the overall DCFC operator business case.

We evaluated the business case based on the capital and operational costs, and revenue based on user fees and federal low-carbon fuel credits. For each profile, the only value to change between the proposed design and the status quo was the operational electricity costs. The business case improved across all four profiles, shown as the gross operating and net profits on a $ per kWh in Figure 14 and a dollar basis in Figure 15.

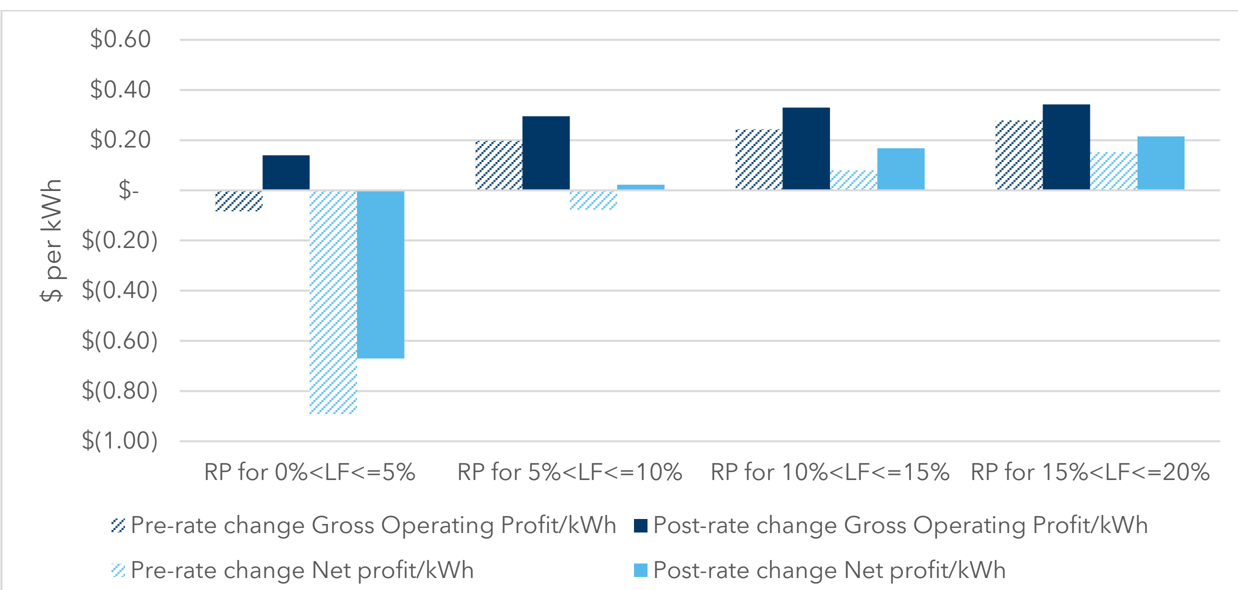

Figure 14 Change in DCFC operator gross operational and net profitability ($ per kWh)

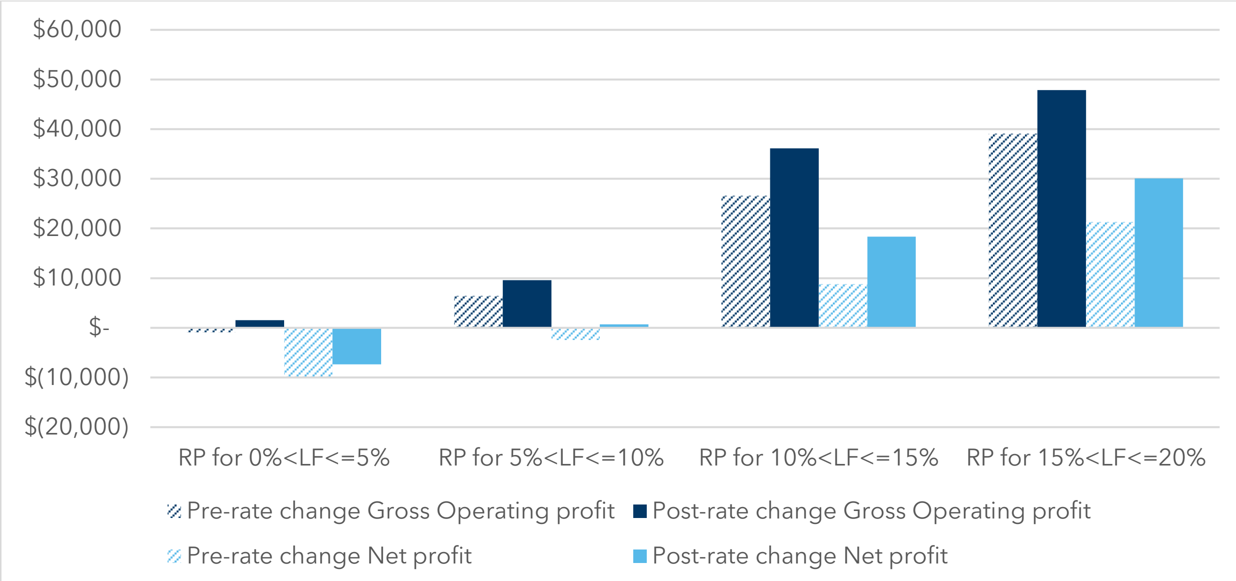

Figure 15 Change in DCFC operator gross operational and net profitability ($)

All four representative profiles reach operational profitability, meaning that the revenue offsets the operational costs, compared to three under GSI. The three higher load factor profiles reach net profitability, meaning that the site achieves profitability considering operational and capital costs under the proposed rate. Under the status quo, only two higher load factor representative profiles achieve profitability. This shift highlights the impact of the rate design by removing a key business case barrier.

The decision to develop or expand a DCFC site will consider the business case and the overall network's approach to risk and growth. While it is difficult to quantify whether this change will impact go/no-go decisions for new sites, the proposed rate provides an improvement on two important factors that relate to DCFC operator business decisions. The rate provides an improvement related to operational costs and the overall business case. The rate also provides certainty for the operator to forecast a return on investment, based on the utilization level (and associated load factor).

DCFC User Fee Structure

To determine the user fee revenue, we applied a time-based user fee ($/hour) based on an aggregation of time-based user fees across multiple networks in New Brunswick. This choice reflects the current market conditions and typical revenue.

User fee structures in New Brunswick are evolving. Energy-based fees ($/kWh) are now offered, and hybrid time and energy structures are also viable. It is important to clarify that the choice of user fee structure would not shift the business case. Changes in user fee structure can provide different indicators to the consumer. However, the pricing within the structure will define the profitability – higher $/hr or $/kWh fees will increase revenue and vice versa. Therefore, our selection of time-based user fees reflects the current market offering, and we expect similar outcomes if an energy-based user fee at current pricing is used instead.

4.2 Leading Design Option Among Alternatives

We selected the proposed design from a range of potential solutions based on a qualitative evaluation of rate-making and implementation considerations, as well as leading trends across jurisdictions.

4.2.1 Design Aligns with Key Rate-Making Principles

To assess the long list of component options, we developed six key criteria based on leading factors identified in a review of transportation electrification rate design literature, key Rate Design Principles[19] and electrification objectives for an EV-focused design. The criteria were refined in consultation with NB Power. The six criteria are:

1. The rate should align with cost causation and provide economic signals that correspond to NB Power costs.
2. The rate should consider social impacts and the economic situations of customers.
3. The rate should be adaptable to future market and technology changes and new customer types.
4. The rate should be reasonable to administer by NB Power.
5. The rate should complement parallel NB Power electrification programs.
6. The rate should enable higher EV adoption than the current state.

Time-of-use ranked the highest among all energy components assessed and load factor-based demand charge ranked highest among the demand components assessed. The results of the evaluation process are summarized in the Appendix Table 10.

Notably, the time-of-use energy component and load-factor-based demand components ranked highly in two key rate-making principle-related evaluation criteria:

- The rate ranked highly to improve cost causation (evaluation criteria #1 above) for public DCFC providers and sends a more accurate economic signal based on NB Power costs compared to alternatives. The time-of-use energy component can provide a signal to customers regarding the higher cost periods to the system. The load-factor-based demand charge increases the demand charge with increasing load factor, which provides better alignment of costs with impact on the system.
- The rate ranked highly as adaptable to future market and technology changes (evaluation criteria #3 above) compared to alternatives. The time-of-use energy charge provides a signal towards the peak periods, which can be adjusted to align with evolving system needs and peak periods. The load-factor-based demand charge aligns demand with the individual site load factor. The load factor of sites across the province should increase with increasing utilization, but there will be significant variability between sites. The load factor-based demand charge provides a flexible charge that varies by site and broader market evolution.

4.2.2 Design is a Strong Option for Effective Implementation

For publicly accessible DCFC operators, demand charge mitigation to reduce the business case barrier is the key factor. Therefore, demand components were evaluated to select the

[19] As outlined in NB Power Rates Modernization Principles and Objectives, Jan 25, 2022.

leading option before finalizing the energy component. The shortlist of options evaluated is summarized in Table 10.

The short-list of design components was assessed for their effectiveness and viability in implementation based on a qualitative framework of four key considerations:

Key Consideration	Qualitative Assessment
Impact and future-proof	Impact refers to how well the rate provides cost causation and appropriate price signals. Future-proof refers to whether the rate structure is compatible with increasing load flexibility and distributed energy resources.
Market opportunity	How well the rate aligns with intrinsic customer needs and likely ability to persuade customers to opt-in to the rate.
Regulatory alignment	Alignment with previous regulatory decisions and direction.
NB Power implementation	Cost and effort needed to implement the rate relative to the status quo.

Together, the load-factor-based demand and energy time-of-use rate design was selected because it recognizes the long-term variability of station utilization (i.e., some rural stations will never reach high utilization) while remaining reflective of cost causation (i.e., reflecting the significantly lower coincidence factor of DCFC public charging compared to GS customers more broadly). From the DCFC operator perspective, it provides predictability on station cost and improves the business case for low utilization in the early adoption period. This option provides regulatory alignment by responding to the direction in Matter 529 to assess the challenge of demand charges and respond to the feedback received during stakeholder engagement. Finally, for implementation by NB Power, this design requires AMI and new billing structures (including assessment of customer load factor) which is significant but feasible.

4.2.3 Design is Similar to Rates in Jurisdictions with Strong EV Policy Contexts

In a scan of publicly accessible DCFC rate designs in Canada and the United States, we found an 'evolution' in public DCFC approaches in recent years. A diversity of solutions exists today and there is no one 'right way' to design a rate at this early stage in EV adoption and charging load management. Generally, there was a trend of early approaches that included time-limited demand charge holiday designs, evolving to energy-only (i.e., no demand charge) rates and demand charges aligned with DCFC use (e.g., load factors).

A load-factor-based demand component is a structure that is coming to market in jurisdictions where there is policy direction from State governments or regulators to resolve barriers to DCFC deployment. The policy direction is explicitly directed to mitigate the impact of demand charges, and in New York, with direction to develop a load factor-based demand charge solution. While the Government of NB has not, as of yet, provided similarly explicit policy direction on mitigating the impact of demand charges, the Province has set strong targets for EV adoption and emphasized the importance of sufficient public charging to support this transition. The Province defined EV adoption targets of 6% of light-duty vehicles by 2025 and 50% by 2030 through purchase incentives and charging infrastructure in its current climate change action plan.[20] The Province further emphasized the role of charging infrastructure as an enabler of EV adoption by including the development of charging infrastructure and necessary infrastructure upgrades as a key action in its 2035 energy strategy.[21]

The three utilities and jurisdictions with similar rates are Connecticut, Massachusetts and New York. The rates are summarized in Table 5.

[20] Government of New Brunswick. 2022. *Our Pathway Towards Decarbonization and Climate Resilience – New Brunswick's Climate Change Action Plan 2022 – 2027.*
[21] Government of New Brunswick. 2023. *Powering our Economy and the World with Clean Energy – Our Path Forward to 2035.*

Table 5 Summary of rates and EV policy contexts similar to the proposed design

Utility & Rate (Jurisdiction)	Description	Status	EV Policy Context
Eversource EV Charging Service: EV-S, EV-M, EV-L **(CT)**	Tiered pricing based on load factor for small (<100 kW), medium (100 to 350 kW), and large (>350 kW) public and select fleet charging. Demand charge increases with load factor while energy charge decreases across 7 tranches, up to 35% load factor. Medium and large EV charging service energy charges include weekday (12-8 pm) and weekend (1-9 pm) TOU periods.	In-market	CT's *An Act Concerning Climate Change Planning and Resiliency* (2018) establishes a mandatory GHG emissions reduction target of 45% below 2001 levels by 2030, with wide-scale EV deployment as a primary GHG reduction strategy to meet the 2030 and 2050 targets. ZEV targets are also set under a 2013 MOU. The Public Utilities Regulatory Authority (PURA) developed the EV Charging Program to support the GHG and ZEV targets. In the Program, PURA directed "EDCs shall also offer a tariff for separately metered DCFCs designed to mitigate the impact of demand charges" because a "robust DCFC network is a key component to achieving Connecticut's ZEV and GHG emissions reductions goals."
Eversource General Service Optional Electric Vehicle Charging EV-2 **(MA)**	Tiered pricing based on load factor for public charging with >100 kW. Demand charge increases with load factor while energy charge decreases across 4 tranches, up to 15% load factor.	In-market	In amendments to regulation 310 CMR 7.00: Air Pollution Control (2023), Massachusetts adopted the requirements in the California Air Resources Board Advanced Clean Cars II regulation, requiring 100% of new passenger vehicles sold must be ZEVs by 2035. *An Act Authorizing and Accelerating Transportation Investment* (2021) requires each electric distribution company to file at least one tariff or program using alternatives to traditional demand-based rate structures to facilitate faster charging for EVs. The Department of Public

			Utilities (PPU) provided further guidance on the alternatives to consider energy-only charges, off-peak charging demand charge discounts, demand charges based on the load factor.
ConEdison Rider AD (NY)	Tiered pricing based on load factor for sites with at least 50% of demand as EV charging. Demand charge increases with load factor while energy charge decreases across 4 tranches, up to 25% load factor. Energy charges include three daily (on or super-peak 8 am – 10 pm) and two seasonal TOU periods.	Awaiting regulatory decision	Under the Advanced Clean Car II regulations (2022), New York State will require all new passenger cars and light-duty trucks sold in the State be zero emission by 2035. A major investment in the State's EV charging infrastructure followed with legislative direction to the Public Service Commission (Commission) to commence a proceeding to establish a commercial tariff utilizing alternatives to traditional demand-based rate structures, other operating cost relief mechanisms, or a combination thereof to facilitate faster charging for eligible light duty, heavy-duty, and fleet vehicles. The Commission's *Order Establishing Framework for Alternatives to the Traditional Demand-Based Rate Structures* (2023) required multiple immediate and near-term operating cost relief solutions for commercial EV charging. The Near-term Solution includes temporary EV Phase-In Rates as an alternative to traditional demand rates, including direction to develop rates based on load factors, as outlined in a Commission staff white paper.

Notably, two Canadian jurisdictions incorporate load factor into their current or proposed rates. In Ontario, the Ontario Energy Board has recently wrapped the stakeholder feedback on a proposal for a new Retail Transmission Service Rate (RTSR) for low load factor public EV charging stations, also known as the EV Charger Discount Electricity Rate. The opt-in rate would provide discounts to the RTSR with three potential variations: a single-tier reduced demand charge, a stepped multi-tier reduced demand charge, and an energy-based recovery rate. In Quebec, Hydro-Quebec offers an opt-in rate BR, an energy-only tariff for public fast-charging sites, with three tiers of energy charges. The first tier per kWh charge is on energy associated with 50 kW of demand, the second tier is for energy associated with more than 50 kW of demand, up to a 3% load factor on the demand above 50 kW, and the third tier for the remainder of the energy consumed.

In recent regulatory direction and decisions, load factor-based demand charge, often paired with a time-of-use energy charge, is a strong option to mitigate electricity rate-related public charging deployment barriers.

4.3 Durable Option for Near-Term Market Evolution

The proposed design was developed to consider the changing EV adoption and fast-charging market. The design aligns mitigation with utilization, cost recovery based on the customer profile, and the range of potential site sizes and consumption.

4.3.1 Design Will Evolve with the Fast-Charging Market

New Brunswick is in the early but advancing stages of EV adoption, reaching 6% of new light-duty vehicle registrations in the first quarter of 2024.[22] At this stage of adoption, the utilization of charging stations, and therefore load factor, is low. However, as EV adoption increases, we can expect load factors to increase across the network. Stations that continue to have low load factors will benefit from continued demand charge mitigation, while those with a higher utilization and load factor will have less mitigation (as shown in Figure 13).

In a comprehensive network of fast charging across the province, there will be a diversity of load factors. Many sites will see higher utilization with higher numbers of EVs on the roads. These sites will move up through the load factor tranches and can reach the standard General Service rate when the load factor better aligns with typical General Service customers. However, many sites will remain at low utilization and therefore low load factors. Rural fast-charging sites are critical to ensure equitable access to charging infrastructure and travel connectivity but may never see significant levels of usage. These stations can benefit from the proposed rate by having more accessible operational costs while providing an important service.

The time-varying component of the energy charge provides a signal to DCFC operators of how the cost to supply electricity varies with time (see Time-of-Use Period & Ratio Selection text box below). Public charging is a less flexible load, and therefore, there may be limited opportunity to shift public charging. Currently, most of the public charging takes place in the on-peak period, as shown in Figure 16 and Figure 17 below. However, by providing a signal

[22] Transport Canda. 2024. ZEV Council Dashboard. Accessed September 5, 2024.

to these customers, the DCFC operators have the option to respond, or at a minimum, have a predictable structure and pay the appropriate costs. The DCFC operator could pass along the signal to their customers (i.e. EV drivers) to encourage off-peak use or introduce technologies to shift consumption (i.e., on-site storage).

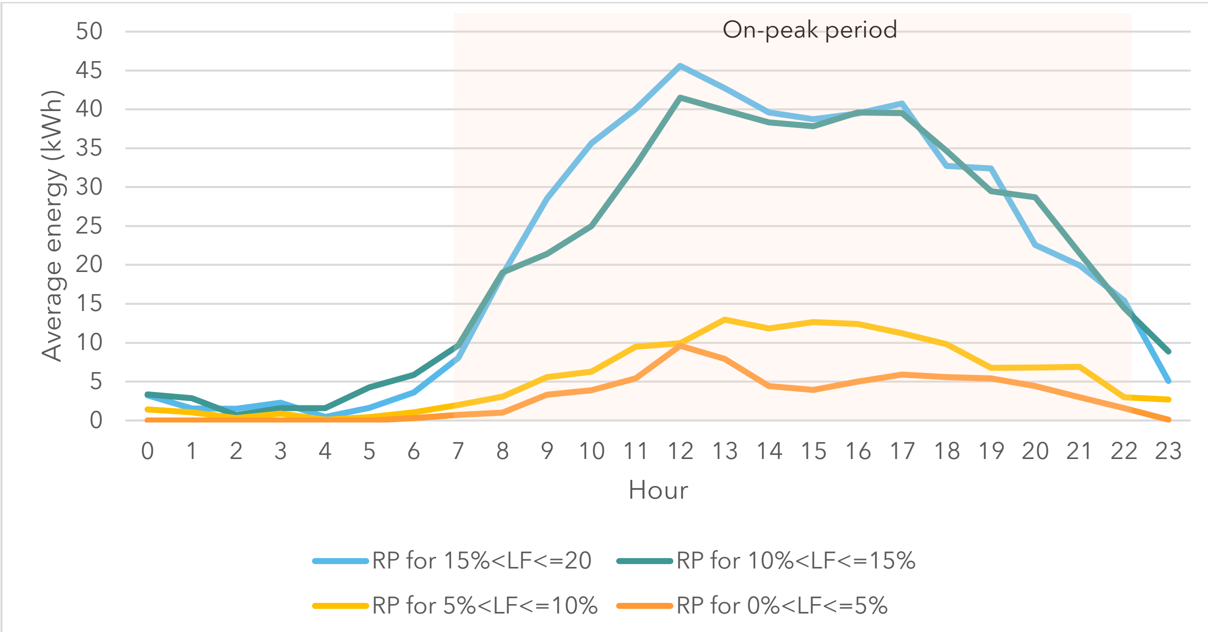

Figure 16: Summer (July and August) average daily energy consumption by hour for representative profiles

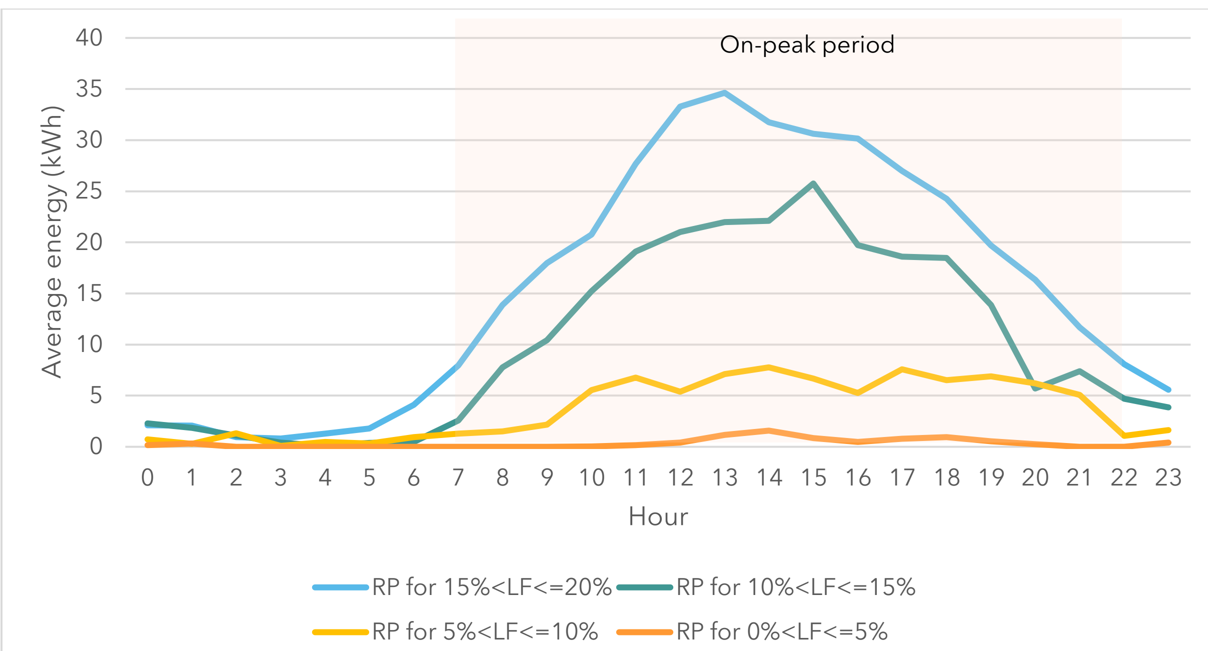

Figure 17: Winter (December, January, February) average daily energy consumption by hour for representative profiles

Time-of-Use Period & Ratio Selection

New Brunswick Power provided the on-peak period definition of 7 am to 10 pm, year-round. The period was developed through an internal assessment of the hourly generation and hourly marginal costs throughout the year.

The on-peak: off-peak pricing ratio of 2:1 was defined in the billing determinant adjustment process and in collaboration with New Brunswick Power. The 2:1 ratio was determined to be the minimum pricing differential to affect change based on a meta-analysis of 80 residential time-varying rate pilots which indicated that customers respond to increasing peak: off-peak ratios although at a declining rate.[23] The 2:1 ratio also generally aligns with the on-peak: off-peak cost differential determined by NB Power.

The time-of-use periods can evolve as NB Power further explores time-varying rates. For example, the current on-peak period could be refined to include off- or mid-peak periods that align with lower-cost periods that align with potential DCFC charging windows at the edges of the high-cost period, such as late evening or lunchtime.

4.3.2 Design Provides Appropriate Revenue Recovery

We calculated the cost of service and corresponding revenue requirement for NB Power for each load factor tranche to ensure NB Power is appropriately recovering costs through the demand and energy charges to the DCFC operator.

Using the representative profiles, we then determined the cost of service based on levelized embedded costs for GSI customers (see Appendix Table 7 for details) and then calculated the corresponding revenue requirement, assuming an RCR of 1.05.

As seen in Figure 18, the calculated revenue requirement, and therefore the proposed rate customer electricity bill cost, for each representative profile is lower than under GSI. The GSI collection amount indicates that the current rate is over-collecting costs from the fast-charging profiles compared to the cost to serve those customers, across all load factors. Under the proposed rate, the calculated revenue requirement better aligns with the cost to serve this customer.

[23] Ahmad Faruqui and Ziyi Tang. 2023. Time Varying Rates (TVRs) are moving from the periphery to the mainstream of electricity pricing for residential customers in the United States. Draft of forthcoming chapter *Handbook on Electricity Regulation*.

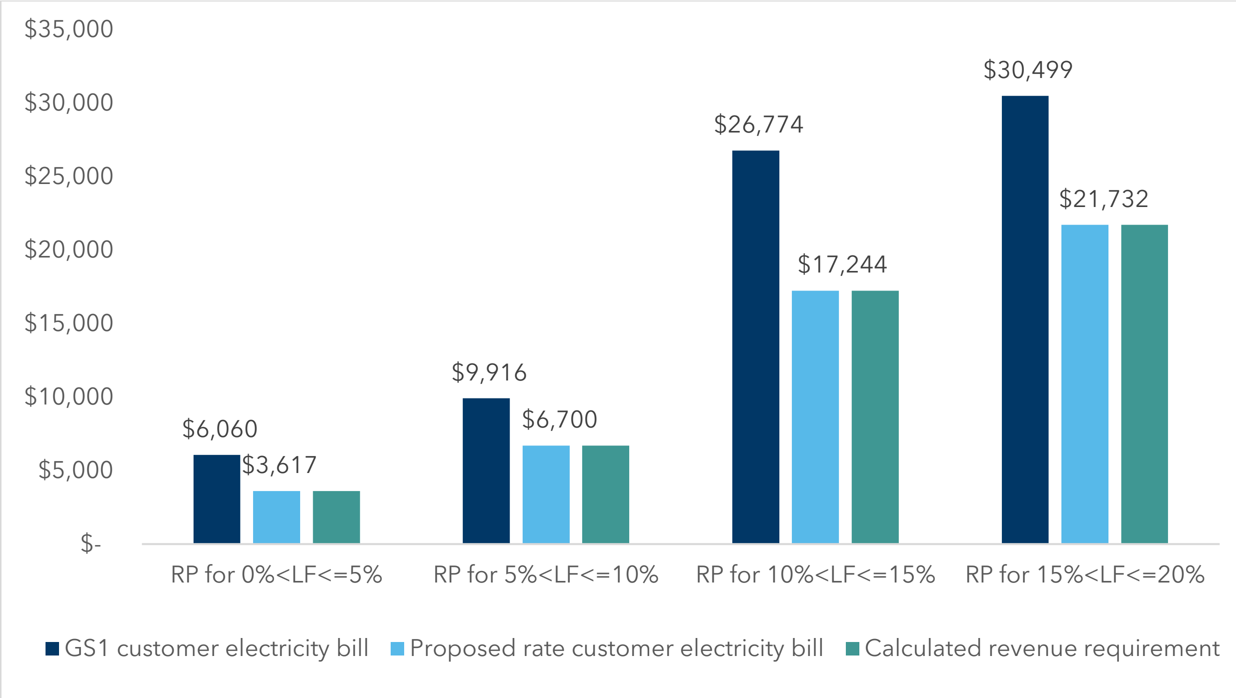

Figure 18: Comparison of revenue collected and revenue required

4.3.3 Design Considers Range of Potential Customers

To ensure the rate design considers a range of potential customers, we conducted a stress test to explore the impact of varying energy consumption, NCP, and 3CP values on the DCFC operator electricity bill and NB Power revenue recovery. To pass the stress test, the rate design needs to achieve the following:

- Objective 1: The electricity bill for DCFC operates under the new rate structure must be reduced compared to their bill under the current rate structure
- Objective 2: The average revenue recovered must exceed the estimated revenue requirement (revenue recovery rate[24] is greater than 0% on average). If there is any under-collection, it should be less than 20%.

As the NB Power eCharge data was used which was composed primarily of 50 kW DCFC stations, we aimed to test a range of station sizes to ensure the rate is robust. For each station size, a minimum and maximum scenario was created to test extreme cases. A summary of the assumptions and scenarios tested can be found in Appendix A.

Table 6 summarizes the results of the stress test and shows that both objectives were passed

[24] Revenue recovery rate is the percentage by which revenue recovered from electricity bills exceeds or falls below the NB Power revenue requirement. A positive revenue recovery rate indicates over recovery, while a negative rate indicates under recovery.

with the proposed rates. The results show a wide range of revenue recovery, but overall, under-recovery at some stations should be balanced out by over-recovery at others, and since we tested extreme scenarios, we expect most stations within NB Power's network to fall between the minimum and maximum results shown.

Passing our stress test indicates that rates are sufficiently robust to accommodate variations in usage patterns across the load factor tranches. It also helps reduce the risk that NB Power needs to do rate calibration, as it is more capable of ensuring stable revenue across diverse conditions, especially as DCFC charging stations expand with larger sizes.

Table 6: Summary of stress test results

Objective	4 x 50 kW results	4 x 350 kW results
Reduced electricity bill vs. status quo	Yes, all tranches have reduced electricity bill	Yes, all tranches have reduced electricity bill
Revenue recovery rate is on average positive and under collection is less than 20% if it occurs	Yes Average: 0.5% Min: -15% Max: 14%	Yes Average: 4% Min: -14% Max: 22%

Although our stress test covers the range of possibilities, we recommend NB Power to continue to monitor energy consumption and demand (both NCP and CP) within each tranche where possible, to identify outliers and stations that are under-collecting. An example of an outlier could be very high CP values, which can drive up the cost of service but not be reflected within the DCFC operator bills. This challenge was also observed in the highest scenario of the CP stress test in the Appendix (see Table 13 results).

5. Conclusion

The proposed rate responds to NBEUB direction and a market need: to mitigate demand charges to reduce the barrier to public DCFC deployment. The proposed rate provides relief to low load factor stations by shifting cost recovery from demand to energy charges, while also more appropriately collecting costs based on the cost to serve these unique customers. The load factor-based approach is an emerging approach across jurisdictions with strong EV adoption policy contexts and will remain relevant in an evolving EV market. The proposed rate reduces electricity bill costs to DCFC operators while ensuring appropriate cost recovery and assessing risk. Therefore, the proposed rate is a strong option to mitigate this important barrier.

Appendix

Representative Profile Development and Selection Process

To assess cost recovery, as well as the business case barrier reduction outlined in section 4.1, we developed profiles that represented typical DCFC site profiles in New Brunswick. To develop the profiles, we explored potential data sets for DCFC sites. We determined that using NB Power's eCharge network was the most readily available and NB-specific data set to use as it represented real data from a major network with operational fast-charging sites in operation in the province. The challenge for this data set is that the network has limited fast-charging capacity ports (i.e. 50kW and 100 kW ports only) and few sites contain more than one charging port with at least one full year of data. Other considered data sets were modelled data or were not located in New Brunswick and, therefore, were deemed less representative.

The eCharge network data set has limitations in terms of the number of fast-charging ports per site and the range of load factor sites available. Therefore, we made the following adjustments to the selected profiles:

- To include sites with multiple fast-charging ports as it is becoming more common in New Brunswick, we combined two 50 kW NB Power eCharge stations from separate sites to develop a profile that includes two 50 kW ports as if they were co-located at the same site. This was completed for the two profiles with 2x50 kW.
- To ensure that the profiles align with expected market behaviour (i.e., that there is increasing CP with increasing load factor), we made a minor adjustment to the 3CP value for the 15% to 20% load factor representative profile. This adjustment was necessary due to the limited availability of stations with higher load factors within the eCharge data set.

The characteristics of each representative profile are summarized in Table 3.

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Levelized Embedded Costs for GS1 Customers

The following levelized costs were provided to us by the NB Power team and used to calculate the corresponding cost of service for the representative profiles.

Table 7: GS1 Levelized Embedded Costs

Type of levelized cost	$/MWh (Energy)	$/MW (NCP)	$/MW (CP)	Customer ($/#)
Generation	$77	-	$134,904	-
Transmission	-	-	$54,268	-
Distribution	-	$38,198	-	$210
Customer	-		-	$411

Qualitative Evaluation of Energy and Demand Components

Table 8 outlines the range of jurisdictions and rate designs reviewed to inform the design and the long list of potential energy and demand components.

Table 8 Summary of rate and jurisdictions reviewed

	Utility/Organization (Jurisdiction)	Rate Design Name	Rate Category
Rates Designated for Public DCFC Operators	ATCO Alberta (AB)	Electric Vehicle Fast Charging Services Price Schedule D23	Energy only
	Fortis Alberta (AB)	Rate 62 (pilot)	Energy only
	Hydro Quebec (QC)	Rate BR	Energy only
	OEB (ON)	Proposed Load Factor Rate for Public DCFCs	Load Factor Demand Charge
	Duke Energy (IN)	RATE LLF - OPTIONAL TIME-OF-USE SERVICE	Energy TOU + Demand TOU
	Eversource (CT)	Rates EV-S, EV-M, EV-L: Small, Med, Large Electric Vehicle Charging Service	Energy TOU + Load Factor Based Demand
	Eversource (MA)	General Service Rate EV-2: Optional Electric Vehicle Charging	Volumetric Energy + Load Factor Demand Charge
	Georgia Power (GA)	Charge It - Electric Vehicle Charger Rider Schedule: “CIEV-1”	Declining Block Energy + Demand charge holiday
	NYS PUC/All utilities (NY)	Interim Solution and EV Phase-In Rate Design based on *Order Establishing Framework For Alternatives To Traditional Demand-based Rate Structures*	Demand Holiday; future: Load Factor Demand Charge
	Pacific Power (OR)	Public DC Fast Charger Optional Transitional Rate	Energy TOU + Demand charge holiday

Rates Designated for both Public DCFC and Fleet Customers	Duke Energy (NC)	Small General Service: Time of Use with Critical Peak Pricing	Energy TOU + CPP + Demand TOU
	Georgia Power (GA)	Real Time Pricing - Day Ahead Schedule	Real Time Pricing
	Georgia Power (GA)	Time of Use – Electric Vehicle Charging Schedule: "TOU-EVC-2"	Energy TOU + Demand Charge
	PG&E (CA)	Business Low and High Use EV Rate - BEV 1 and BEV2	Energy TOU + Demand Block
	Xcel Energy (CO)	Secondary Voltage Time-of-use – Electric Vehicle Service Schedules S-EV And S-EV-CPP	Energy TOU + CPP + Demand Charge

To review the diversity of options and understand potential combinations of energy and demand charges, we reviewed and rated the following potential energy and demand separately. The range of options with descriptions and examples is presented in Table 9.

Table 9 Summary of energy and demand component options evaluated

Energy Component Option	Description	Example
Declining Block (current)	$/kWh declines with increasing consumption	-
Energy-Only	Flat or varying $/kWh based on kW usage	Rate BR, Hydro Quebec, QC
Energy TOU	Different $/kWh rate per daily and/or seasonal period	Secondary Voltage Time-of-use – Electric Vehicle Service (S-EV), Xcel Energy, CO
Energy TOU + CPP	TOU $/kWh and CPP rates applicable based on announcement. CPP events typically announced day-ahead.	Small General Service: Time of Use with Critical Peak Pricing, Duke Energy, NC

Energy Real-Time Pricing (RTP)	No fixed rate periods; Hourly (or other period) $/kWh based on real-time system conditions	Power Real Time Pricing (RTP) – Day Ahead Schedule, Georgia Power, GA
Demand Component Option	**Description**	**Example**
Demand Charge (current)	$/kW for all or a portion of peak kW in billing period	-
Transformer Demand Charge	$/kW reflecting average cost to serve final line transformers	Non-Residential Rate Design Best Practice, Illustrative, Regulatory Assistance Project
Demand Charge Holiday	No/low but increasing $/kW charge for a defined period	Public DC Fast Charger Optional Transitional Rate, Pacific Power, OR
Load-Factor-Based Demand	$/kW increases with increasing load factor, which typically is combined with decreasing energy costs	Electric Vehicle Charging Service – Medium, Large (EV-M, EV-L), Eversource, CT
Demand TOU	Different rate $/kW per daily and/or seasonal period	Rate LLF – Schedule for Low Load Factor, Duke Energy, IN
Coincident Peak (CP) Demand Charge	Ex-post calculation of demand charge. Could be based demand in a period of 15 to 60 min of CP each month.	Coincident Peak Distribution Service (CPD), CORE Electric Cooperative, CO

Each component was qualitatively assessed based on the key six criteria as to whether it ranked as needs improvement, better, or best, as outlined in Table 10.

Table 10 Qualitative ranking of energy and demand rate design components for publicly-accessible DCFC operators and short list selection

Rate Design Options	Evaluation (Qualitative Ranking)						Short Listed
	Cost Causation	Social & Economic	Admin.	EV Adoption	Adapt to Future	Complement Electrification	
General Service (current)	Needs Improvement	Better	Best	Needs Improvement	Needs Improvement	Needs Improvement	
Energy-Only	Needs Improvement	Best	Best	Best	Better	Better	Yes
Energy TOU	Better	Best	Better	Better	Better	Best	Yes
Energy TOU + CPP	Better	Best	Needs Improvement	Better	Better	Best	
Energy Real-Time Pricing (RTP)	Best	Best	Needs Improvement	Better	Best	Best	
Transformer Demand Charge	Better	Better	Best	Better	Better	Best	
Demand Charge Holiday	Needs Improvement	Better	Better	Best	Needs Improvement	Better	
Load-Factor-Based Demand	Better	Best	Better	Best	Better	Best	Yes
Demand TOU	Better	Best	Better	Best	Better	Best	Yes
Coincident Peak (CP) Demand Charge	Best	Best	Needs Improvement	Better	Best	Best	Yes

Ranking: Needs Improvement Better Best

Stress Test Assumptions

Table 11: Stress test assumptions

		On-peak energy (MWh)		Off-peak energy (MWh)		NCP (kW)		CP (kW)	
Station size	LF	Min	Max	Min	Max	Min	Max	Min	Max
4 x 50 kW	RP for 0%<LF<=5%	4.8	60.9	0.4	3.5	75	147	5	15
	RP for 5%<LF<=10%	36.1	121.9	3.3	6.9	90	147	8	23
	RP for 10%<LF<=15%	84.3	182.8	7.7	10.4	105	147	13	38
	RP for 15%<LF<=20%	144.5	243.7	13.2	13.8	120	147	26	77
4 x 350 kW	RP for 0%<LF<=5%	9.9	191.5	0.9	10.9	154	462	6	47
	RP for 5%<LF<=10%	61.8	383.0	5.6	21.7	154	462	9	71
	RP for 10%<LF<=15%	123.6	574.5	11.3	32.5	154	462	16	118
	RP for 15%<LF<=20%	185.4	766.0	16.9	43.4	154	462	31	236

Additional Stress Test Results

We conducted an additional stress test under the condition that total energy and NCP remains the same, but CP increases. The revenue recovery rate was then assessed with the same requirements for passing as the main stress test (average revenue recovery rate must be greater than 0%, and minimum revenue recovery rate must be no lower than -20%). Assumptions are displayed in Table 12 below and results are shown in Table 13.

Table 12: Varying CP stress test assumptions

Station size	*LF*	*On-peak energy (MWh)*	*Off-peak energy (MWh)*	*NCP (kW)*	*CP (kW)*	*CP*2 (kW)*	*CP*3 (kW)*
4 x 350 kW	0%<LF<=5%	9.9	0.9	154	6	13	19
	5%<LF<=10%	61.8	5.6	154	9	19	28
	10%<LF<=15%	123.6	11.3	154	16	31	47
	15%<LF<=20%	185.4	16.9	154	31	63	94

As seen in Table 13, increasing CP is a large driver of a decrease in revenue recovery rate. The last scenario where the CP values are tripled from the baseline does not pass the stress test, as the average revenue recovery rate is negative, and the minimum rate is -23%.

Table 13: Results of varying CP stress test

Scenario	Revenue recovery rate	Pass?
CP (no sensitivity)	Average: 13% Minimum: -1% Maximum: 22%	Yes
CP*2	Average: 0% Minimum: -13% Maximum: 8%	Yes
CP*3	Average: -14% Minimum: -23% Maximum: -3%	No

2022 Memo: Rate Structures for Electric Vehicle Charging

To: Das, Shantanu, NB Power

From: Jeff Turner, Paige Hahmann, Dunsky

Date: 2022-07-21

Re: Rate Structures for Electric Vehicle Charging

Introduction

Electric Vehicles (EVs) are an essential step towards tackling greenhouse gas (GHG) emissions from the transportation sector. EVs have seen significant growth in the past ten years, thanks to both supportive policies from governments and utilities, and an increasingly competitive and diverse array of EV models on the market.

While the relatively limited range and long charging times of EVs persist as perceived barriers to EV adoption, new EV models typically have a range of over 400 km, and fast charging capabilities allow vehicles to receive an 80% charge in 20 to 40 minutes. That said, the DC fast charging (DCFC) infrastructure that enables this kind of recharging time is expensive to deploy and operate, and the business models to support this critical infrastructure are unclear, particularly due to high demand charges.

This memo explores opportunities for utilities to improve the business case for private investment in DCFC infrastructure through alternate rate structures with reduced demand charges. The memo includes two sections:

1. The critical role of DCFC infrastructure in enabling EV uptake despite a challenging business case to support deployment.
2. Opportunities to improve this business case, including case studies of utilities that have offered reduced demand charges or similar incentives.

This memo is intended to set the stage for more detailed quantitative analysis that would follow later in 2022, including identification of specific rate structures and an assessment of their impacts and benefits.

DCFC Infrastructure: Critical to Enable EV Uptake but Challenging Economics

Adoption of electric vehicles (EVs) has been accelerating, driven by federal and provincial transportation electrification targets, increasing consumer concern over fuel prices, and desire to reduce carbon emissions. For example, the Canadian federal, Quebec and British Columbia governments have all committed to phase out new sales of combustion-powered light-duty vehicles by 2035. Not only does the rollout of additional electric vehicles benefit the environment and meet government targets, EVs can also help utilities by providing load growth opportunities while potentially offering flexibility to minimize peak load impacts.

For the majority of EV drivers, most charging is likely to happen at home or at work. A study by Idaho National Laboratory evaluated the charging habits of people driving 8,300 EVs over three years and found that typical EV drivers charged at home 84 – 87% of the time, while drivers with access to charging at their workplace charged at work between 32 – 39% of the time[1]. Given the long dwell times of vehicles parked at home or at work, charging in these locations would be well suited to managed charging. Managed charging (such as time-of-use rates or direct control options) are generally low cost to implement and reduce the impact of EVs on the grid.

The Importance of Reliable and Fast Public Charging

Although the majority of charging will occur at home or at the workplace, access to fast and reliable public charging infrastructure is essential to enable longer trips, provide charging for those without access to home or workplace charging, and serve as a marketing piece to encourage and enable higher rates of EV adoption. A Canada-wide survey conducted in 2021 found that after high cost, limited driving range and a lack of charging infrastructure were the second and third most cited reasons to not buy an EV[2]. Similarly, recent studies in the United States have found that ongoing investment in public charging infrastructure is needed to support the transition to EVs[3].

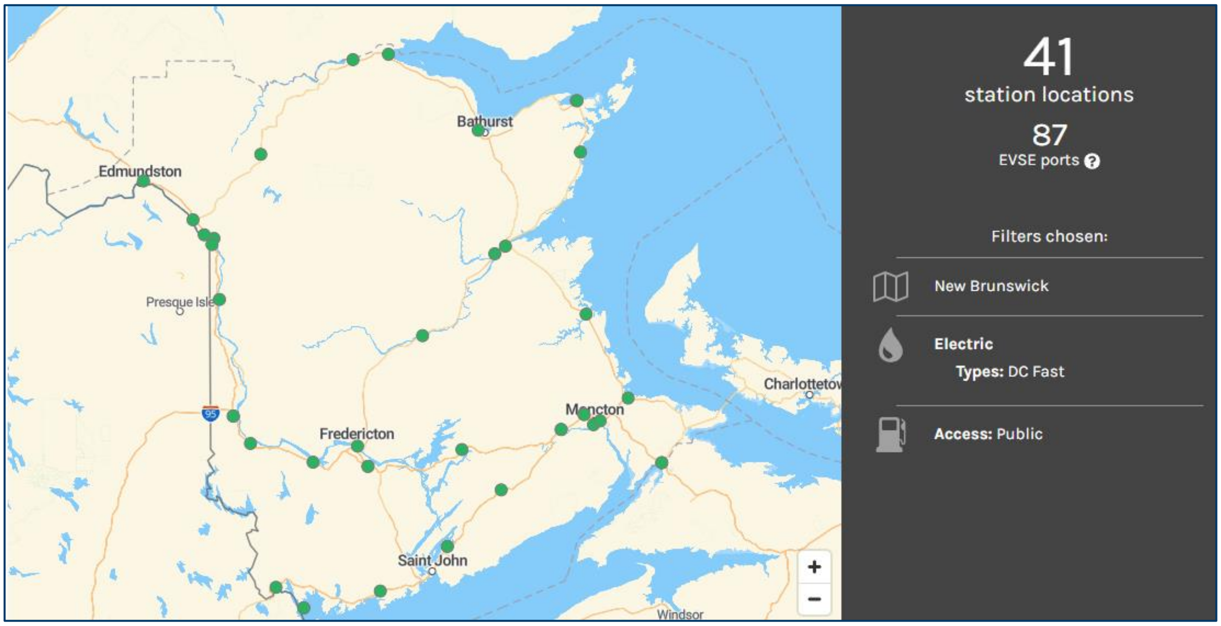
Access to charging infrastructure in New Brunswick is fair, with 41 fast charging sites across the province, of which 28 have been deployed by NB Power. Of the remainder:

- 3 sites deployed by Petro-Canada
- 6 sites deployed by Tesla
- 4 sites deployed by other private entities including car dealerships, malls, and supermarkets.

Of these sites, 31 can only charge one vehicle at a time, four sites can charge two vehicles at a time, while all six Tesla charging sites can charge eight vehicles at a time, although only Tesla vehicles are compatible with Tesla's chargers.

[1] https://avt.inl.gov/sites/default/files/pdf/arra/ARRAPEVnInfrastructureFinalReportLqltySept2015.pdf
[2] https://home.kpmg/ca/en/home/media/press-releases/2021/02/electric-vehicles-to-make-up-majority-of-new-car-purchases.html
[3] https://theicct.org/sites/default/files/publications/charging-up-america-jul2021.pdf

Figure 1: Public Fast Charging Stations Currently Deployed in New Brunswick[4]



While the existing fast charging infrastructure in New Brunswick provides good geographic coverage, additional investment is needed in New Brunswick to ensure the infrastructure can keep pace with growing EV adoption without experiencing lineups. Further expansion in terms of geographic coverage can also be helpful to maximize convenience for drivers and minimize detours required to charge.

Another important factor for EV adoption and fast chargers is maintaining station reliability. According to a study conducted by the University of California Berkely, only 72.5% of fast chargers were functional out of the 657 individual connectors on 181 open, public DCFC in the Greater Bay Area[5]. Ongoing maintenance is critical to ensure all chargers are functional, and both existing and future EV drivers are confident they can charge when and where they need to. Ideally, reliability would be as high as it is for traditional gas stations or higher to ensure EV drivers have the confidence that they will be able to fuel up on the road.

Challenging Economics of DCFC Deployment

One major component of DCFC operating costs is utility demand charges. DCFCs deliver high power (typically 50 kW to 350 kW) and trigger high demand charges, even if a charger is used only once in a given billing period. This means that it can be hard to cover operating costs based on charger usage fees, let alone earn a return on investment on the initial cost of deployment. Fleet electrification faces similar challenges, with high peak loads driving demand charges that can worsen the business case for a given fleet to electrify.

[4] NRCan Electric Charging and Alternative Fuelling Stations Locator, https://www.nrcan.gc.ca/energy-efficiency/transportation-alternative-fuels/electric-charging-alternative-fuelling-stationslocator-map/20487#/analyze?region=CA-NB&fuel=ELEC&ev_levels=dc_fast&show_map=true
[5] https://gmauthority.com/blog/2022/06/ev-fast-charging-stations-arent-very-reliable-new-study-indicates/

Demand charges account for the impact that heavy electric demand from large commercial and industrial customers can have on utility operations and infrastructure. This price on power capacity can help encourage more efficient and consistent electric consumption, which can help utilities right-size their system and manage operations effectively. However, with the grid serving new types of load and new technologies to monitor and control supply and demand at more granular time intervals, some researchers have questioned if demand charges are still the best way to price electricity[6]. Demand charges send a price signal to lower a customer's noncoincident peaks and to level a customer's load over time, which is a different price signal than reducing usage at the time of coincident peaks, which may be better addressed through time-varying energy rates.

These demand charges also make it difficult to develop a profitable business case for fast chargers, especially during the early stages of EV adoption, when utilization rates of the infrastructure may be low. With the majority of EV drivers doing most of their charging at home or at work, the relatively infrequent usage of public fast chargers means that the potential revenue from charger usage fees may be insufficient to fully offset demand charges and other ongoing operating costs such as maintenance. This may limit the business case for private investment, which can reduce critical investments in EV charging infrastructure. While utilization should increase over time as the EV population grows, this growing demand also drives a need for more chargers to support peak travel periods without excessive lineups. Meanwhile, some DCFC charging locations in more remote areas may never see utilization at rates high enough to make these charging stations profitable.

Demand Charges in New Brunswick

To better understand how these demand charges impact New Brunswick, Dunsky conducted an initial analysis of demand charges and energy costs in New Brunswick today assuming NB Power, General Service 1 rates, detailed in the table below[7].

Table 0-1: NB Power General Service 1 Rate

Service Charge	$24.27
Demand Charge	$0 per kW for the first 20 kW of demand $11.17 per kW after 20 kW
Energy Charge	$0.14 for the first 5,000 kWh $0.10 per kWh after

This analysis assessed two charger types (50 kW and 150 kW) under three scenarios, described below. For reference, utilization rate is the total time a charger is actively charging during the billing month.

Table 0-2: Scenario Assumptions

Scenario	Charging Station Assumptions	Utilization Assumptions

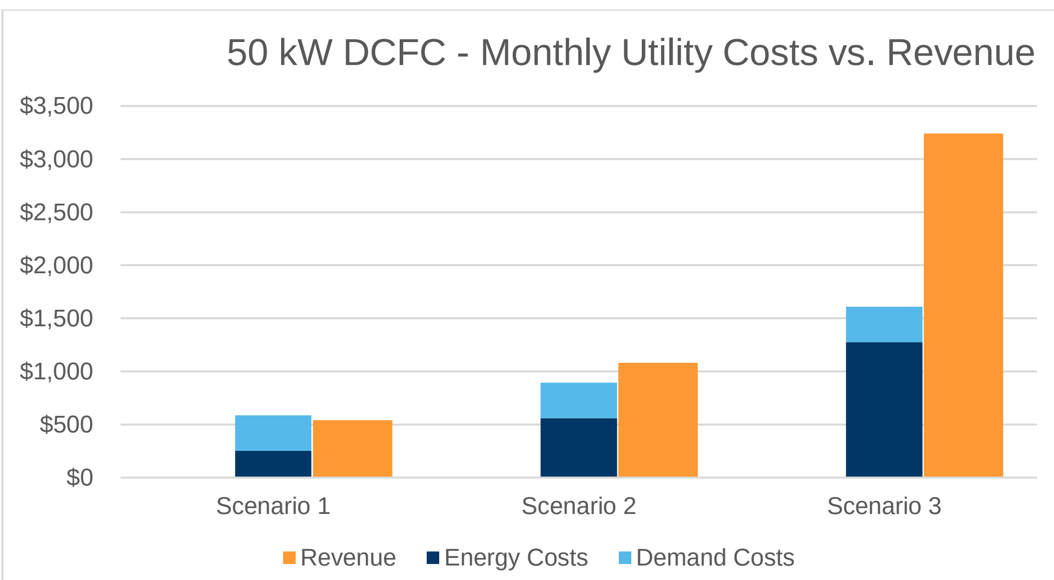
[6] https://www.raponline.org/wp-content/uploads/2020/11/rap-lebel-weston-sandoval-demand-charges-what-are-they-good-for-2020-november.pdf
[7] https://www.nbpower.com/en/products-services/business/rates

1	Assuming one charger Assuming costs $15/hr to charge for 50 kW, $20/hr for 150 kW	5% - representative of many public DCFC chargers today.
2		10% - representative of the utilization rates that a public DCFC might experience in a maturing EV market within 5 years or so
3		30% - representative of the utilization rates that a public DCFC might experience in a very mature EV market.

It should be noted that based on Dunsky's work focused on charging infrastructure in leading jurisdictions like British Columbia and California, the average utilization of fast chargers in these relatively mature markets today tends to fall within the 10-15% range. As such, the 30% utilization assumed in Scenario 3 is very optimistic, and may be more representative of higher utilization locations in densely populated areas in a mature EV market, rather than a network-wide average. In all cases, increases in utilization are limited by potential congestion at charging sites, and utilization rates significantly above 30% are rare. Even regions with network-wide averages of 5% utilization or lower experience lineups at charging sites on peak travel days.

The assumption on usage fees for 50 kW chargers was based on current fast charger rates in New Brunswick. It was found that the average cost to charge for 50 kW fast chargers was $15.00/hour[8]. Based on this usage fee, a charging site with one 50 kW DCFC chargers could recover energy and demand costs at a 10% utilization rate. However, this excludes other operating costs, such as network fees, insurance, and maintenance costs, let along the capital cost of the infrastructure.

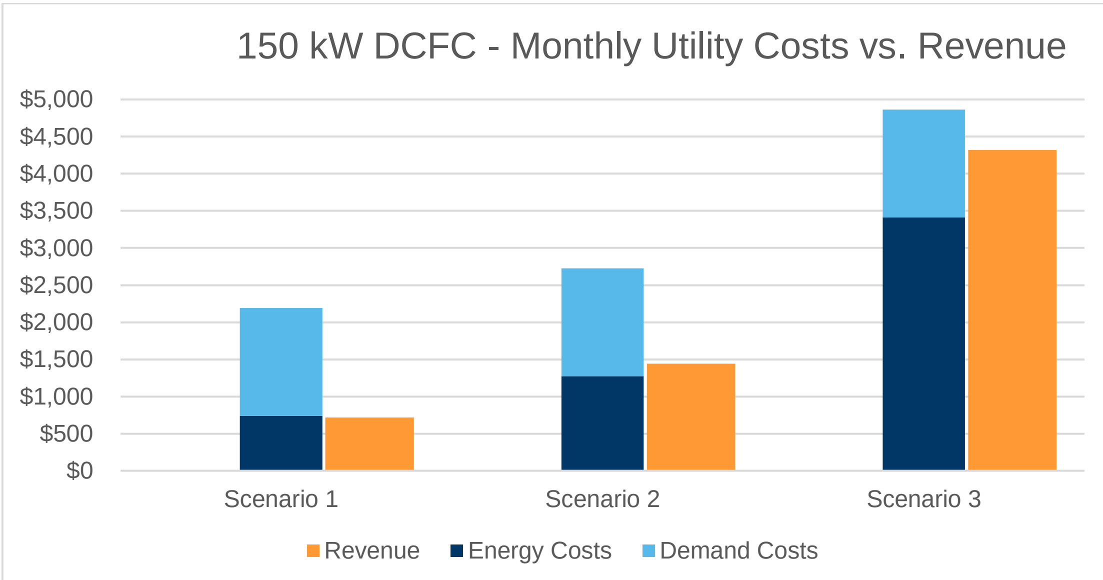
Figure 2: Potential Utility Costs and Revenues for a 50 kW Charger in New Brunswick



[8] https://chargehub.com/en/charging-stations-map.html

Higher power DCFC chargers have a harder time breaking even due to higher demand charges. While the higher power chargers currently available in New Brunswick currently employ a similar $15 per hour usage fee, we have assumed a higher usage fee of $20 per hour for 150 kW chargers given trends in other jurisdictions. Nevertheless, none of the scenarios for a 150 kW DCFC charger broke even under the different utilization scenarios, even before considering additional costs beyond the utility costs.

Figure 3: Potential Utility Costs and Revenues for a 150 kW Charger in New Brunswick



While even higher usage fees could improve the business case for DCFC stations, there is a risk that fees that are too high could discourage EV adoption, especially if charging costs begin to approach the equivalent cost of fueling a conventional vehicle. Especially during this early stage of EV adoption, when utilization is likely to most closely resemble Scenario 1, the tripling of usage fees that would be required to fully recover utility costs would likely dampen enthusiasm for EV adoption, thereby slowing the progression towards higher utilization and more favourable economics for DCFC site hosts. A reduction of demand charges would provide a more favourable business case for DCFC charging stations and enable greater investment from the private sector.

Encouraging Private Investment in New Brunswick’s DCFC Infrastructure

Deployment of fast charging infrastructure is a critical enabler of EV adoption in New Brunswick. While NB Power has installed a network of DCFC chargers, NB Power is also encouraging third party deployment of DCFC infrastructure over ongoing expansion of NB Power’s own DCFC network. That said, the business case for private investment in DCFC deployment is challenging. While a given EV population requires a DCFC network of sufficient capacity to support peak travel times while minimizing lineups, most EV drivers ultimately do the vast majority of their charging at home. This means that the utilization of public DCFC infrastructure and the revenue from usage fees is limited, leading to a weak return on investment when considering the cost of operating and installing the infrastructure.

To help support private investment, some utilities are offering specific rate structures that reduce or temporarily eliminate the demand charges for fast charging infrastructure. Utilities in some jurisdictions in North America, including Hydro Quebec and BC Hydro, have introduced alternate rate structures with reduced demand charges as a means of encouraging electrification and driving overall beneficial load growth that otherwise would not materialize, driving additional revenue that can compensate for lost demand charge revenue.

Case for Utility Investment

While the business case for deploying public DCFC infrastructure based on revenue from usage fees can be challenging, electric utilities are in a unique position to overcome this challenge by building a broader business case for DCFC deployment based on the overall load growth from transportation electrification. Even if EV drivers only use public DCFCs for a small fraction of their charging needs, by investing in charging infrastructure the electric utility will recognize revenue no matter where an EV charges within its service territory, such as charging at home every night.

If most EV charging occurs overnight when the grid has excess capacity, the revenue associated with increased electricity sales can far outweigh any costs associated with supporting that load growth. This “beneficial load growth” effectively makes better use of otherwise underutilized grid assets, spreading fixed costs over a greater customer base, and reducing the per-unit electricity costs for everyone. For example, in a study of the costs and revenues associated with EVs from two Californian utilities (Pacific Gas & Electric and Southern California Edison) as of the end of 2019, EV drivers have contributed $806 million more in revenues than associated costs, applying a downward pressure on rates for all customers[9].

Given that a reliable and comprehensive DCFC network is a key ingredient to enabling EV adoption, a portion of the beneficial load growth resulting from increased EV adoption can be attributed to the existence of that DCFC network. This attribution can be established based on assessing likely levels of EV adoption and associated load growth with and without the utility’s intervention, whether that be direct investment in utility-owned charging infrastructure, or programs and rates that encourage third parties to deploy their own charging infrastructure.

[9] https://www.synapse-energy.com/sites/default/files/EV_Impacts_June_2020_18-122.pdf

Rate Structures for EV Fast Charging

Several rate pilots are being deployed by utilities to better manage costs associated with DCFC stations and demand charges. These strategies being tested can be grouped/categorized as:

1. **Temporary Reduction in Demand Charges**: Temporarily eliminating or reducing demand charges, in some cases gradually introducing/increasing demand rates over time as assumed utilization rates improve.
2. **Alternative Maximum Demand Charge Fees capped by kWh Energy Consumption**: Eliminating the demand charge and instead applying it as an energy charge.
3. **Subscription Plans for Charging Services**: Customer indicates what they expect their maximum demand to be and pay a subscription-based service based on that amount.
4. **Time-of-Use Rates**: Energy and demand charges vary depending on the time of use.
5. **Incentives**: An annual/reoccurring incentive for DCFC that declines over time, to provide a similar effect to reducing and then gradually increasing demand charges.

From a review of ten different rates to support DCFC rollout, time of use and temporary reduction in demand charge rates were most common. Three of the ten are explored in more detail on the following pages. **Details on the ten rates reviewed can be found in the appendix**.

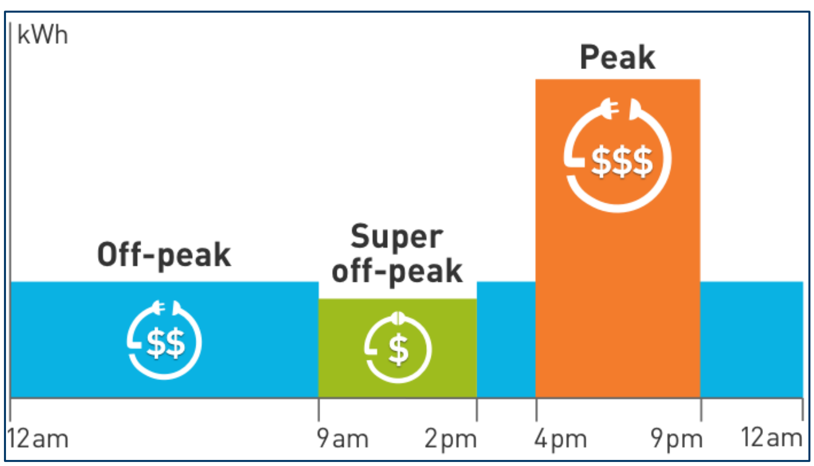
Case Study: PG&E Commercial EV Rate[10]

Pacific Gas and Electric (PG&E) has rolled out a subscription plan for commercial EV (CEV) charging, which allows customers to choose the amount of power they will need for their charging stations and pay for it with a flat monthly fee. This monthly fee replaces the demand charge and is generally much less than the demand charge for typical PG&E rates. If the actual kW exceeds the subscription level, the customer is charged an overage fee of two times the cost of one kW for each kW above the subscription level. The customer has a grace period of three months with no overage fees to help determine the best subscription level for the site. The rate offers two categories:

- Business Low Use EV Rate: For EV charging installations up to 100 kW, best suited for smaller workplaces and multi-unit residential buildings. Subscription level is based on 10 kW blocks at $12.41 per 10 kW block (effectively $1.24 per kW).
- Business High Use EV Rate: For EV charging installations of 100 kW or greater, best suited for fleets and public fast charging stations. Subscription level is based on 50 kW blocks at $95.56 per 50 kW block (effectively $1.91 per kW).

In addition to the monthly subscription fee, the rate includes a time-of-use component based on how much energy the site uses and when it is used. The figure below shows an illustrative idea of the time-of use periods for this rate.

Figure 4: Commercial EV Rate TOU[11]

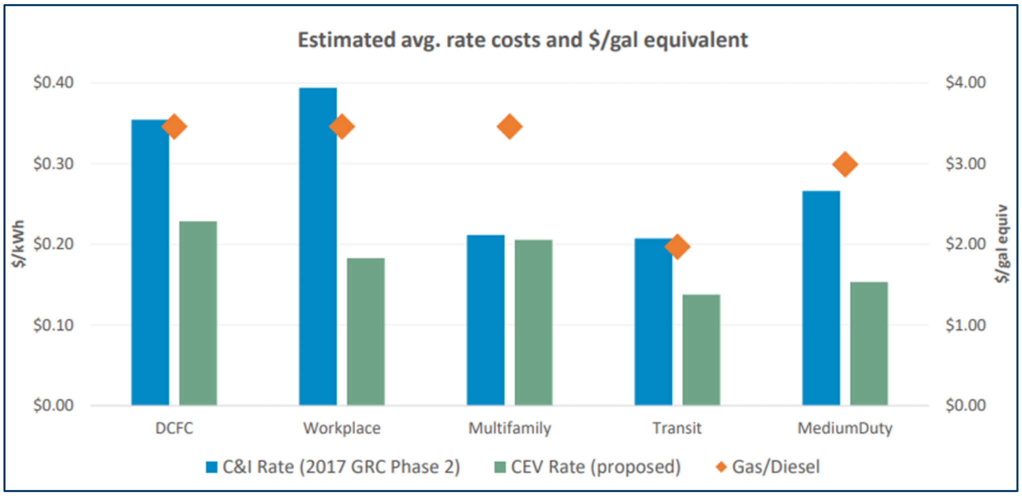


Ideally, electricity from DCFC should cost less than the equivalent amount of gasoline to help encourage adoption of electric vehicles. PG&E's subscription plan results in lower demand charges and reduced costs for customers. The graphic below shows a comparison of the

[10] https://www.pge.com/en_US/small-medium-business/energy-alternatives/clean-vehicles/ev-charge-network/electric-vehicle-rate-plans.page
[11] https://www.pge.com/en_US/small-medium-business/energy-alternatives/clean-vehicles/ev-charge-network/electric-vehicle-rate-plans.page

estimated average rate costs on the standard C&I rate, and on the commercial EV (CEV) rate, in comparison to gas and diesel prices.

Table 0-1: Estimated PG&E Bill Savings for Sample Site Types Under the CEV Rate[12]

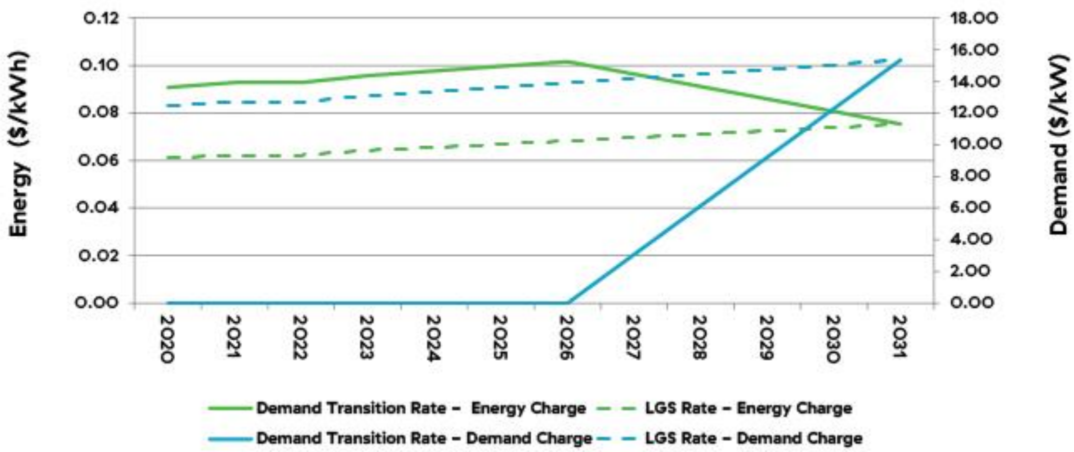


[12] https://pluginamerica.org/wp-content/uploads/2019/02/DCFC-Pricing-Factsheet__Final_190205v1.pdf

Case Study: BC Hydro Demand Transition Rate

BC Hydro provides a Demand Transition Rate for customers looking to electrify their fleet that require mid-day charging during fleet operating hours, with at least 150 kW of demand. The Demand Transition rate eliminates the demand charge for the first six years of the rate offering (April 1, 2020, to March 31, 2026). During the following six years, an escalating demand charge is phased in as customers continue to expand their electric vehicle fleet.

Figure 5: Demand Charge and Energy Charge Escalation Under the Demand Transition Rate compared to Large General Service Rate (LGS) – for Illustrative Purposes Only



BC Hydro has determined that a Demand Transition Rate is justified on an economic basis, although ratepayer benefits may not materialize until the medium term (as shown in the figure below). However, as the load expected to take service under the Demand Transition Rate is associated with long term investments, ratepayer benefits are seen in the medium and long term. The Demand Transition rate is expected to provide incremental utility revenues from electricity sales, which will exceed marginal costs over time. Additional benefits such as reduction in greenhouse gas emissions are also expected, although not included in the economic evaluation of the rate.

Figure 6: Demand Transition Rate Ratepayer Impacts[13]

Time Period for Load Factor	F2021 - F2025	F2026 - F2029	F2030 - F2034
Load Factor	15%	30%	52%
Time Period used for Ratepayer Benefit Cost Analysis	5 Years F2020-F2024	10 Years F2020-F2029	15 Years F2020-F2034
Ratepayer Benefit Cost Ratio	0.74	1.04	1.16

[13] https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/regulatory-filings/fleet/00-2019-10-30-exhibit-b-5-bchydro-fleet-electrification-rate-design-interveners-information-responses-no1.pdf

Case Study: Hydro-Quebec Experimental Rate BR

The experimental BR rate is a five-year pilot that applies to a contract for electricity delivered for the purpose of supplying one or more DCFC and can also apply to a contract for electricity supplied to one or more 240 V stations. The rate removes demand charges completely, but introduces higher energy charges that vary as a function of the peak power level and the overall utilization or “load factor”. The figure below shows the different pricing for the different “tranches” of demand.

Figure 7: Structure of Experimental Rate BR[14]

Price of energy:	
Energy associated with the first 50 kW of power	11.475¢/kWh
Energy consumed in the next bracket	21.504¢/kWh
Remainder of energy consumed	16.911¢/kWh

If little or no electricity is used, a minimum charge is billed. It is $12.815 per month (30-days) when single-phase electricity is delivered or $38.445 per month when three-phase electricity is delivered.

The energy for the first 50 kW, expressed in kWh, is the product of the maximum power demand up to 50 kW times the load factor and the number of hours in the consumption period. The energy charge for the power demand exceeding 50 kW, expressed in kWh, is the product of the excess power level above 50 kW times up to 3% and the number of hours in the consumption period. The overall effect of this approach is a significant reduction in utility costs for low-utilization chargers, with costs gradually approaching the standard rates as utilization increases.

[14] https://www.hydroquebec.com/business/customer-space/rates/rate-br-experimental-rate-fast-charge-stations-billing.html

Conclusion

In conclusion, although DCFC charging infrastructure is essential for the widespread adoption of electric vehicles, the business case of such infrastructure can be challenging for private entities in the current rate environment. Especially if NB Power is not directly investing in DCFC infrastructure, then to reduce barriers in the deployment of additional DCFC by private companies, NB Power should consider developing a DCFC specific rate to help reduce demand costs to improve profitability of DCFC infrastructure.

As a second phase to this study, we propose to conduct detailed analysis to recommend specific rate structures for implementation by NB Power, including:

- **Analysis of the potential profitability of charging sites** under different scenarios using Dunsky's Charging Site Business Case Tool, incorporating NB-specific inputs regarding installation costs, operating costs and utilization rates based on existing deployments in the province, including NB Power's own network. Dunsky will take into account the variability in utilization from site to site during this analysis.
- **Estimate the growth in third party deployment** of charging infrastructure resulting from potential alternate rate structures, as well as **the total cost** of offering demand charge discounts or other incentives.
- **Estimate the beneficial load growth** attributable to the increase in EV infrastructure deployment resulting from the proposed alternate rate structure, using Dunsky's EV Adoption (EVA) model.

This will provide a comprehensive assessment of the best options for NB Power and a thorough understanding of the implications for NB Power, NB Power rate payers, and businesses in the province with an interest in charging infrastructure deployment.

Appendix: Utility Rate Offerings

Utility	Program / Rate	Rate Type	Targeted Vehicles / Stations	Details
Hydro Quebec	Rate BR	Alternative Maximum Demand Charge Fees capped by kWh Energy Consumption	• Loads above 50 kW	• Experimental rate for charging stations, five-year pilot • Rate expressed in energy, but power demand is captured indirectly (different tranches with their own cost of energy – for example, 11.475 cents/kWh for first 50 kW, 21.504 cents/kWh for the associated max power demand exceeding 50 kW, and 16.911 cents/kWh for remaining energy consumption) • The energy for the first 50 kW, expressed in kWh, is the product of the maximum power demand up to 50 kW times the load factor and the number of hours in the consumption period • The energy for the power demand exceeding 50 kW, expressed in kWh, is the product of the excess times up to 3% and the number of hours in the consumption period.
ATCO	D23 Rate	Alternative Maximum Demand Charge Fees capped by kWh Energy Consumption	• Point of service must be equipped with dedicated, revenue-approved time of use metering	• Temporary rate to support EV charging investments, where customers with separately metered fast-charging stations with loads no greater than 500 kW can opt in. • The D23 rate converts the demand component of the electricity charge into an equivalent energy-based charge (per kWh)
Joint Utilities of New York	DCFC Per-Plug Incentive Program	Incentive	• Public	• Provides an annual declining per-plug incentive to qualifying public DCFC operators. Incentive levels vary between utilities, but range generally from $2,000 to $15,000 per year per plug. • Intends to support DCFC chargers while utilization is relatively low by offsetting electric delivery cost • Plugs rated at greater than 75 kW receive the full incentive, while plugs that charge at a rate of 50 – 75 kW receive an incentive equal to 60% of that for plugs capable charging at a rate of 75 kW or higher
SDG&E	Electric Vehicle-High Power (EV-HP) Rate	Subscription Plans for Charging Services	• Medium- or heavy-duty EVs • Operate DCFC equipment • Operate separately metered EV	• Allows EV fleet customers to choose the amount of power they will need to charge their vehicles and pay for it with a monthly subscription fee. • If maximum monthly demand is under 150 kW fleets can subscribe in increments of 10 kW at $37.79 each. Over 150 kW, fleets can subscribe in increments of 25 kW at $103.61 each.

			charging equipment	• There are no overage fees or penalties for exceeding demand, but if a fleet exceeds their monthly subscription level for three consecutive months, SDG&E will enroll the fleet customer in a subscription level that reflects actual monthly demand. • The EV-HP rate plan utilized reduced TOU energy charges
PG&E	Commercial EV (CEV) Rate Plan	Subscription Plans for Charging Services + Time-of-Use Rates	• Customers with separately metered EV charging at locations, such as workplaces, MURBs, and retail, as well as sites with fleets.	• PG&E's business rate includes a monthly subscription charge + TOU rate. Customers determine their subscription level based on their maximum monthly EV charging kW consumption. If the actual consumption exceeds the customer's subscription level, then the customer is charged an outage fee of two times the cost of one kW for each kW over your subscription level. Customers have a grace period with no overage fees for three billing cycles when the customer first enrolls or add EV charging stations to all the customer to determine the best subscription level. • **Business Low Use EV Rate (BEV1):** For EV charging installations up to and including 100 kW. Best for smaller workplaces and MURBs. • **Business High Use EV Rate (BEV2):** For EV charging installations of 100 kW and above. Best for fleets and fast charging stations.
Hawaiian Electric	Commercial EV Pilot Rates: EV-J Rate EV-P Rate	Time-of-Use Rates	• EV-J Rate: for smaller scale DCFC and Level 2 chargers • EV-P Rate: Larger DCFC	• Five-year (2022-2027) pilot program that employs a time-of-use rate structure to incentive charging during mid-day hours • Rate structure has greatly reduced demand charges, which vary with intensity of use (averaging $2/kW)
BC Hydro	Overnight Rate	Time-of-Use Rates	• Fleet • Annual maximum demand of at least 150 kW, and service must be provided by separate meters	• For customers with overnight in-depot charging needs for fleet vehicles and vessels, with minimal daytime charging requirements • Rate has a flat rate energy charge. Demand charge only applies to maximum demand set between the hours of 6 AM and 10 PM daily per billing period. There is no demand charge between 10 PM and 6 AM.
Pacific Power	Public DC Fast Charger Optional Transitional Rate	Temporary Reduction in Demand Charges	• Public sites with at least on DCFC	• Consumers pay $0.10738/kW on peak • On-peak energy charge discount and a demand charge transition discount will be applied on an increasing basis until 2026

NV Energy	[Demand Rate Reduction Transition Period]	Temporary Reduction in Demand Charges	• DCFC chargers over 50 kW	• Fully eliminates demand charges for first years, then each year an additional 10% of the original demand charge is reinstituted until the transition period ends in April 2029.
BC Hydro	[Demand Transition Rate]	Temporary Reduction in Demand Charges	• Fleet • Annual maximum demand of at least 150 kW, and service must be provided by separate meters	• For eligible customers who cannot charge their fleet overnight at the depot and require in-route charging during fleet operating hours. • Rate intends to reduce the impact of high demand charges due to short-duration, high-load charging during the EV fleet ramp up period. The demand transition rate does not have a demand charge for the first 6 years (Apr 2020 – Mar 2026). After which, for the next 6 years, an escalating demand charging will be phased in until April 1, 2032, when the Demand Transition Rate, Demand Charge, and Energy charge will be the same as those for the Large General Service Rate. Therefore, customers will be transitioned to the Large General Service Rate.

"NO DISCLAIMERS" POLICY

This report was prepared by Dunsky Energy + Climate Advisors, an independent firm focused on the clean energy transition and committed to quality, integrity and unbiased analysis and counsel. Our findings and recommendations are based on the best information available at the time the work was conducted as well as our experts' professional judgment.
Dunsky is proud to stand by our work.