EV Delivery Rates Addendum 1: Analysis and Rate Design

Prepared for: Ontario Energy Board

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EXECUTIVE SUMMARY:

On April 13, 2023, the OEB published a report titled "Electric Delivery Rates for Electric Vehicle Charging" (the Report) which was prepared by Power Advisory. As part of the report, illustrative designs for a Low Load Factor rate applicable to public Direct Current Fast Charger (DCFC) customers in the General Service Greater than 50 kW rate class were developed.

The rationale for the rate design is the observation that some costs which are currently recovered using a demand charge on the customer's noncoincident peak (NCP) demand are caused by that customer's contribution to coincident peak (CP) in an area. In addition, low load factor consumers like public DCFCs tend to have a lower contribution to CP than high load factor consumers.

The CP-related costs identified in Power Advisory's Report comprise 1) the Retail Transmission Service Rate (RTSR) and 2) a portion of the LDC's Distribution Volumetric Rate. Subsequent analysis has refocused the low load factor rate on RTSR only.

Power Advisory's Report included a high-level assessment of public DCFC peak contribution, which was used to develop illustrative rate designs for three representative LDCs. This assessment has been improved using more comprehensive load shape analysis and additional data that was not available while the Report was drafted. Additional smart meter data for existing customers has also become available, enabling a more detailed treatment of existing customers in the analysis and consideration of allowing all low load factor customers (i.e., DCFCs and low load factor customers that are not DCFCs) to access the low load factor rate.

The detailed assessment ultimately led to a similar outcome to Power Advisory's April 2023 Report. As a result of improved data and analysis, a key parameter defining the relationship between load factor and coincident peak contribution has been updated from 1.85 to 1.73. The bill impact for a typical General Service Greater than 50 kW customer is also modelled more accurately, addressing stakeholder concerns, and results are calculated for all LDC rate zones.

Bill savings for low load factor customers could be substantial, with the highest savings available for customers with the lowest low factors. The RTSR share of total bill – and the potential savings from a reduction in RTSR – varies substantially by distributor. Maximum, minimum, and average savings are presented in Table 1.

Table 1: Bill Impact (Absolute and % Decrease) of Low Factor Rates for 300kW Public DCFC, Option 2c, Various Load Factors

Load Factor	Minimum ($/kWh)	Average ($/kWh)	Maximum ($/kWh)	Minimum (%)	Average (%)	Maximum (%)
5%	0.081	0.136	0.206	13%	31%	42%
10%	0.037	0.062	0.093	10%	22%	30%
15%	0.022	0.037	0.056	8%	17%	22%
20%	0.015	0.024	0.037	7%	13%	17%

A reduction in RTSR for low load factor customers would lead to a bill increase for remaining customers relative to the current rate design. There are several variables that could affect the magnitude of this increase, including the amount of long-term demand growth from public DCFCs, long-term DCFC load factors, whether eligibility is limited to DCFCs or to all low load factor customers, and whether the foregone revenue from low load factor customers is recovered from the General Service Greater than 50 kW rate class or from the larger set of all LDC-connected customers. Because demand from DCFCs is currently very low, the bill impact for existing customers in 2026 would be approximately 0.1% if the foregone revenue is recovered from all rate classes.

1. LOAD RESEARCH FOR LOW LOAD FACTOR RATE DESIGNS

In Power Advisory's Report, the illustrative low load factor rate was designed by quantifying the contribution of public DCFCs to CP relative to other customers. Coincident Peak Contribution (CPC), or the ratio of CP demand to NCP demand, for public DCFCs was assumed to be a linear function of load factor.

For a given low load factor public DCFC, the demand charge (in $/kW) that minimizes cross-subsidization to other customers is:

$$C_N + a * C_C$$

Where C_N is the demand charge related to NCP demand, C_C is the demand charge related to CP demand for customers other than public DCFCs, and a is the CPC for the public DCFC divided by the average CPC for customers other than public DCFCs. See Appendix 1 for a detailed explanation.

The overall approach to develop a proposed low load factor rate was to:

- Assess the likely timing of summer and winter CP demand;
- Describe the average CPC for existing customers using smart meter data from three LDCs in Ontario;
- Describe the relationship between load factor and CPC for public DCFCs using a public dataset for public DCFCs in the United States and a non-public dataset for public DCFCs in Canada; and
- Create rate design options which approximate the idealized demand charge described above.

1.1 Coincident Peak Timing

The likely contribution of a customer to CP-related costs depends on the timing of CP at its feeder, substation, and region. These peak times will vary across the province depending on load patterns and load composition.

In Appendix 3, demand and loss of load probability analysis is presented from the IESO's 2022 Annual Planning Outlook, the IESO's 2022 Pathways to Decarbonization Report, historical zonal demand data, and anonymized consumption profiles of 55 LDCs in Ontario.

The summer peak period is primarily in hour ending (HE) 15 to HE 19, with some likelihood of CP as early as HE 11 or as late as HE 22. The winter peak period is primarily in HE 18 and HE 19. There is some potential for a morning peak, which would be greater in areas with higher use of electric space heating. An area with abundant solar generation would also tend to peak later in the evening, particularly in the summer.

Table 2: Timing of Peak Hours

Hour	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Summer																		
Winter																		

Red = most frequent peak hours, yellow = less frequent peak hours

1.2 Existing Customer Load Profiles

The next step of the analysis was to evaluate the CPC of existing General Service customers. This assessment aims to determine how closely a customer's NCP demand charge reflects the peak contribution of most customers on the transmission and distribution system.

While using an NCP demand charge alone does not directly measure contribution to CP, for most customers it is understood that this is a reasonable approximation. The rationale for the low load factor rate design was to recognize the lower probability that public DCFCs contribute to CP such that public DCFCs are treated similarly to other General Service customers.

Power Advisory's Report assumed that all non-EV General Service customers had CP contribution that was equal to their NCP demand. However, if typical General Service Greater than 50 kW customers have consistently higher NCP than CP, the demand charge reduction offered to public DCFCs should be lower.

Customer-level smart meter data for General Service Greater than 50 kW customers was obtained for three LDCs covering the period from January 2018 to September 2023. Each year of the dataset was divided into summer (May to October) and winter (November to April) periods. For each season, the peak day was identified by finding the system peak demand hour[1] and customer-level CPC was calculated for each hour between HE 8 and HE 20. Customer consumption on the peak day for each hour was divided by the average of their six monthly NCP demand values in the season.[2]

CPC for summer and winter are shown in Figure 1 and Figure 2 below, weighted by NCP demand. Some customers have a CPC exceeding one. This occurs because the NCP used as the denominator in the CPC calculation is the average over six months.

[1] Using IESO zonal demand data consistent with the location of the LDC

[2] Demand charges are set at the same rate each month, but system costs for coincident peak demand are related to seasonal or annual peak. A customer that reaches 100 kW every month of the year will pay substantially more in demand charges than a customer that reaches 100 kW only in the month of summer peak. Calculating CPC using the average monthly noncoincident demand over a six-month season more closely reflects how customers are billed.

Figure 1: Summer CPC for HE 18, Existing Customers, Demand Weighted

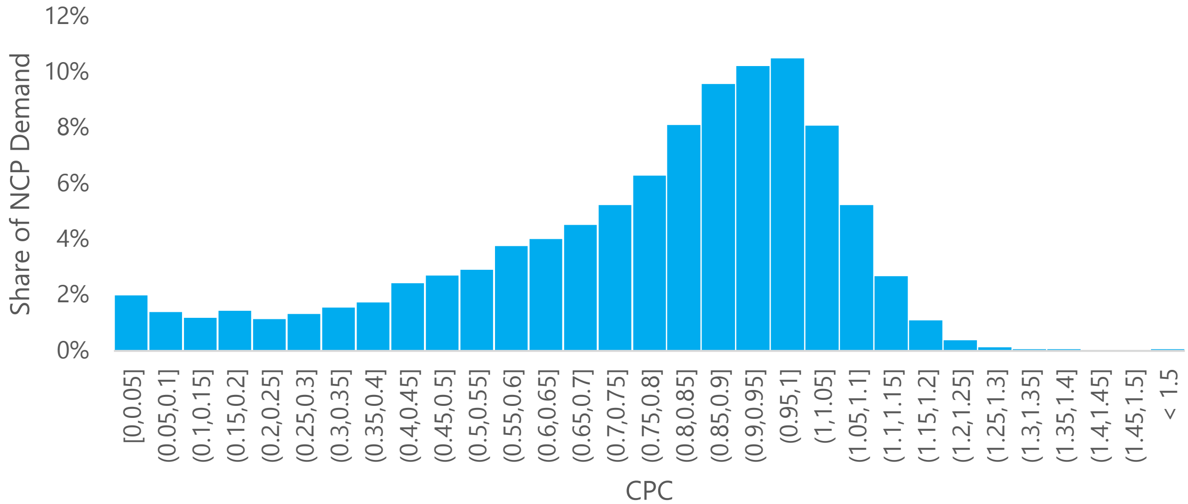
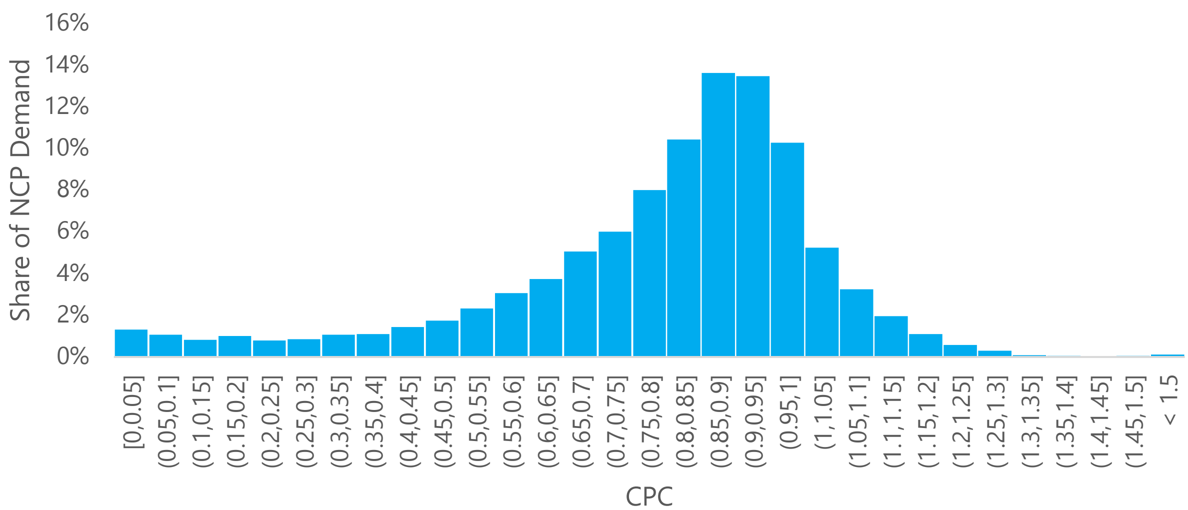


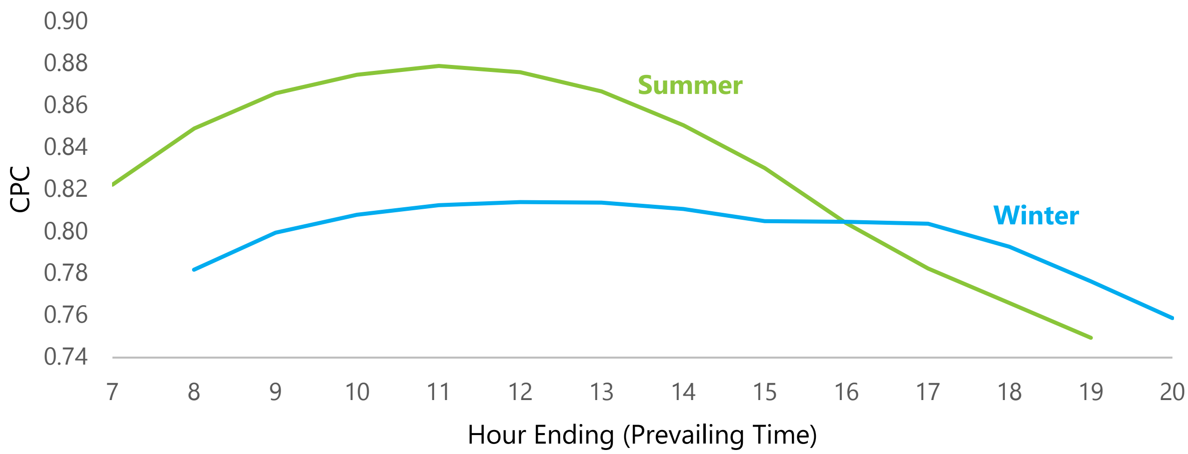
Figure 2: Winter CPC for HE 18, Existing Customers, Demand Weighted



CPC in both seasons is concentrated around 0.9, indicating that for HE 18 on the coincident peak day, General Service Greater than 50kW customers most commonly consume approximately 90% of their six-month average NCP demand. There is a long tail in both seasons, with CPC for many customers falling below 0.5.

For the low load factor rate design, the most important consideration is the demand-weighted average, shown in Figure 3. For the HE 18 and 19 peak period, demand-weighted average CPC is in the 0.75 to 0.80 range.

Figure 3: Demand-Weighted Average CPC by Season, Existing Customers



At a high level, commercial customers tend to have higher peak day demand during business hours and residential customers have higher peak day demand in the mornings and evenings. For a feeder or substation serving primarily commercial or industrial load with limited solar, CP demand may be in the middle of the day. For the higher-voltage parts of the system, or for a local area with mixed residential and commercial loads, peak demand is more likely to be later in the evening.

1.3 Public DCFC Load Data

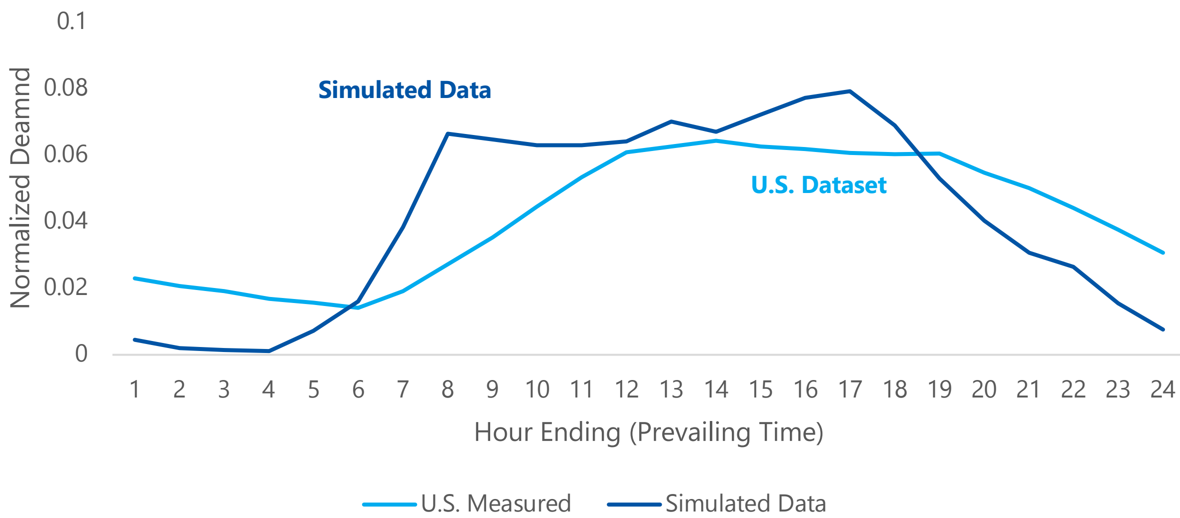
The public DCFC analysis uses a publicly accessible dataset of public DCFC charging sessions in the United States.[3] This data is supplemented by simulated data published by researchers at the National Renewable Energy Laboratory (NREL).[4] NREL's simulation uses transportation data to model arrival and departure times at the charging station. Power Advisory also obtained non-public data from a major charging network for public DCFCs operating in Canada. Analysis performed on the non-public data produced similar results as the analysis presented here.

Public DCFCs are generally busiest during the day and moderately busy in the late evening (Figure 4). Some research suggests that they are most congested on holiday long weekends as drivers take longer trips. The empirical datasets have generally the same daily trend, while the simulated data is higher in the morning.

[3] Pavuluri, Yash. *EV Watts Public Database*. United States. https://doi.org/10.15483/1970735

[4] Gilleran, M., Bonnema, E., Woods, J. et al. *Impact of electric vehicle charging on the power demand of retail buildings*. Advances in Applied Energy 4, (2021). https://doi.org/10.1016/j.adapen.2021.100062

Figure 4: Normalized Daily Public DCFC Load Profile for Weekdays

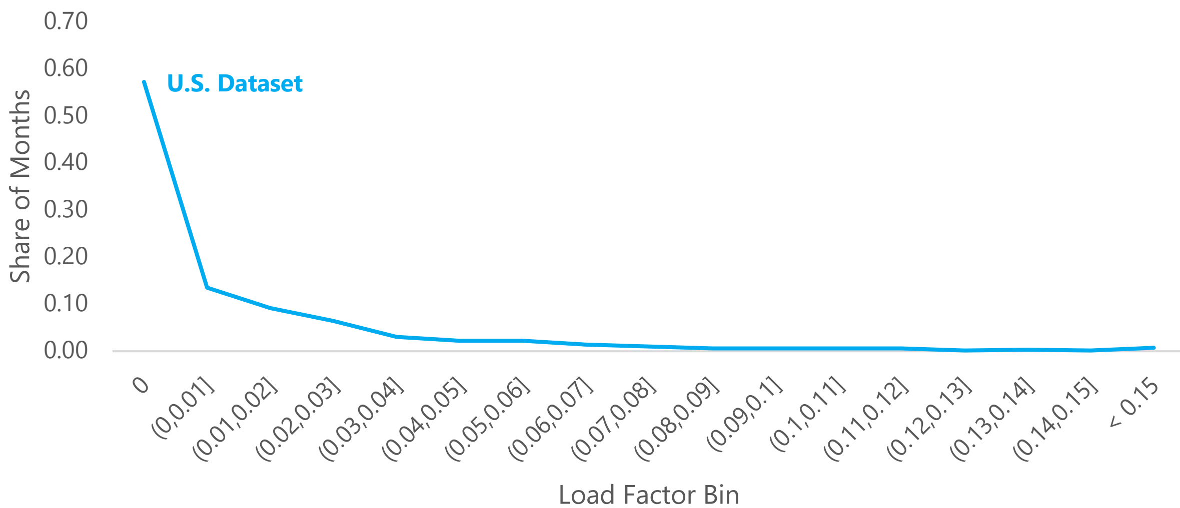


Charging session data typically reports start time, end time, and energy delivered. Session data was converted to an hourly timeseries profile by assuming a constant power level during the charging session. For each month, a load factor was calculated and CPC for each hour of the day was estimated by averaging all days in the month. A key assumption in the Report and this analysis is that public DCFCs have load profiles that are independent from one another, so the likely contribution to CP of multiple public DCFCs in an area is well-approximated by average CPC and any day of public DCFC charging which occurs on a weekday is equally likely to be the coincident peak day.[5]

Figure 5 shows the range of load factors in the U.S. dataset. Over half of the station-month pairs in the U.S. dataset had a load factor of zero (i.e. no charging sessions in the month).

[5] Seasonal trends were investigated to test the latter assumption. In both empirical datasets, load factors increased over time, which likely reflected increasing EV adoption. There was no clear seasonal pattern.

Figure 5: Load Factor of DCFCs in Dataset

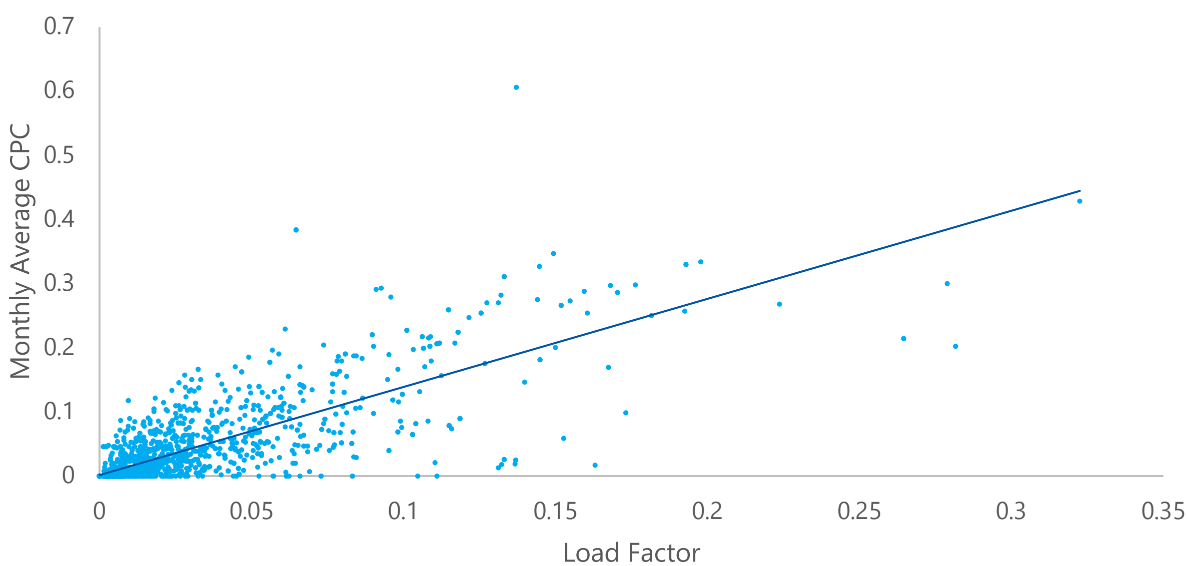


1.4 Public DCFC Load Contribution

The purpose of this analysis is to predict CPC for a public DCFC as a function of its load factor. CPC is expected to increase monotonically with load factor, and CPC during the daytime high demand period is expected to be higher than the load factor. One of the key assumptions in this analysis is that each weekday of driving and charging behaviour is independent of weather and other factors which influence daily peak electricity demand.

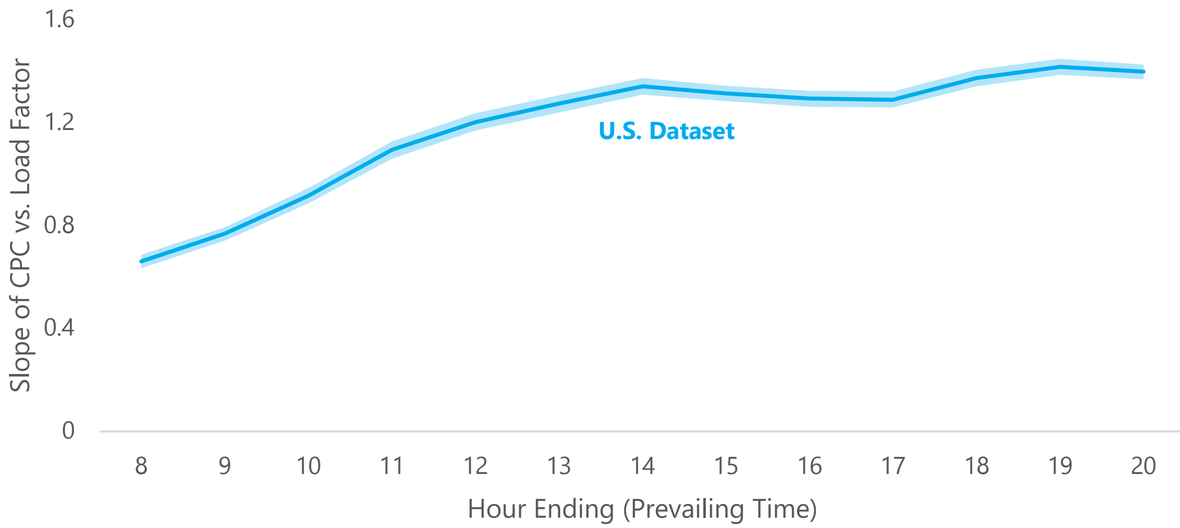
Figure 6 shows the relationship between the average monthly CPC on weekdays and monthly load factor for HE 18 in the U.S. datasets with a linear regression.

Figure 6: Monthly CPC vs. Load Factor, U.S. Dataset. HE 18



The hour of CP is uncertain and varies by location, so CPCs and linear regressions were calculated for multiple daytime hours. Figure 7 plots the slope of these regressions with a confidence interval. The slope is lower in the early morning because expected demand is lower during that period.

Figure 7: Slope of CPC vs. Load Factor with 95% Confidence Intervals



1.5 Estimating an Idealized Low Load Factor Rate Design

As discussed in Appendix 1, this analysis seeks to define the appropriate reduction of CP-related demand charges for low load factor public DCFCs. This reduction *a* is the ratio between CPCs for public DCFCs and other customers.

$$a = \frac{CPC_{\mathrm{DCFC}}}{CPC_{\mathrm{Other}}}$$

The analysis of public DCFC charging data shows that CPC can be approximated using a slope *m* and the load factor. CPC for existing customers is estimated in Figure 3 above.

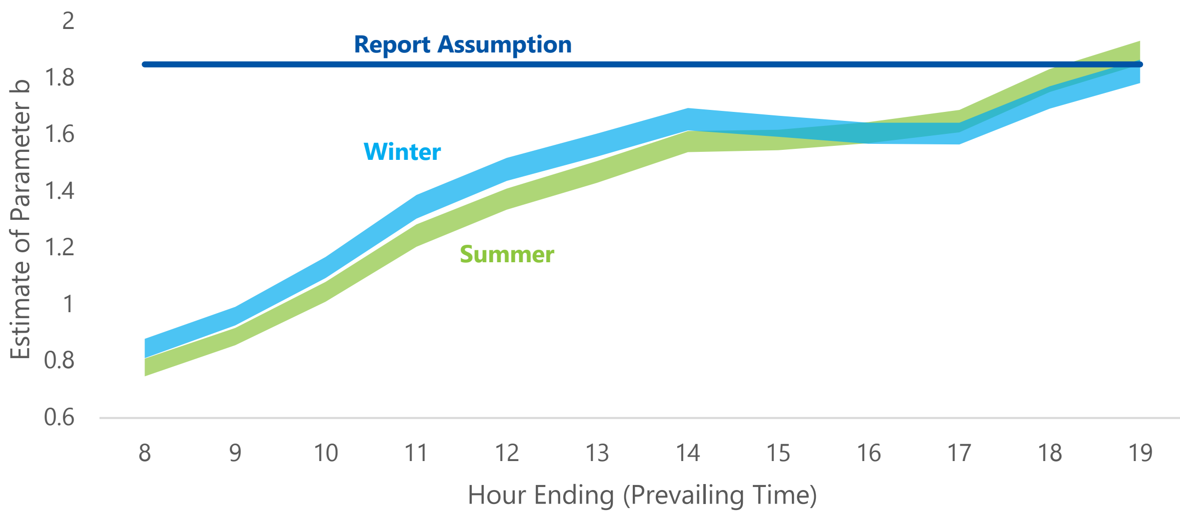
$$a = \frac{m * LF_{DCFC}}{CPC_{\mathrm{Other}}}$$

The reduction *a* can now be expressed as the product of load factor and a new parameter *b*, defined as *m* divided by CPC_{Other}.

$$a = b * LF_{DCFC}$$

Results from Figure 3 and Figure 7 can be used to estimate a range for *b* in each hour and season, plotted in Figure 8 below.

Figure 8: Estimate of Parameter *b* for HE 8 to HE 19



For the most common peak hours identified in Table 2 – HE 18 and 19 in the winter and HE 15 through 19 in the summer – the parameter *b* ranges from 1.55 to 1.93 with an average of 1.73. This result is visualized in Figure 9. In the April 2023 Report, parameter *b* was approximated as 1.85.

Figure 9: Idealized Share of Base CP-Related Cost vs. Load Factor

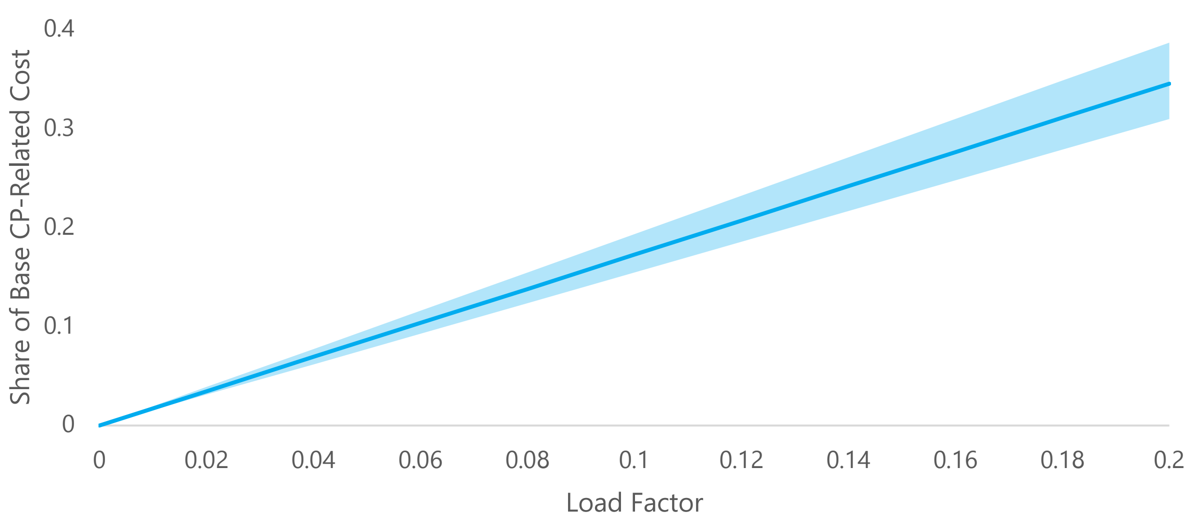


Table 3 shows the original design options from Power Advisory's Report as well as revised options using the same methodology but with a lower CPC consistent with 1.73 times the load factor rather than 1.85 times the load factor.

The low load factor rate options presented in Table 3 are designed to approximate the idealized cost allocation developed in Figure 9, where RTSR is used to represent CP-related cost. Each option is defined in terms of the "base" RTSR rate charged to high load factor customers. For Options 2a and 2b, the ratio between the low load factor rate and the high load factor RTSR rate is specified. In the revised Option 2a, all customers with a load factor below a threshold (15% in this case) have the same RTSR rate, which is set at 13% of standard RTSR. The 13% share of base RTSR is calculated by taking the average CP-related cost for the range of load factors from 0 to 15% in Figure 9. Option 2b takes a similar approach, except four load factor ranges below 15% are defined, each with a separate fraction of base RTSR applied.

Option 2c, the demand transition rate, is also adjusted to use an energy-only rate which is calculated based on the standard RTSR rate and the parameter *b* (1.7262). The expression for the Option 2c rate is derived in Appendix 2.

Table 3: Change in Low Load Factor Rate Options

<table>
<tr><th>Load Factor</th><th>Option 2a: Original</th><th>Option 2a: Revised</th><th>Option 2b: Original</th><th>Option 2b: Revised</th><th>Option 2c: Original Demand</th><th>Option 2c: Revised Demand</th><th>Option 2c: Original Energy ($/kWh)</th><th>Option 2c: Revised Energy ($/kWh)</th></tr>
<tr><td>0 to 3%</td><td rowspan="4">0.14</td><td rowspan="4">0.13</td><td>0.04</td><td>0.03</td><td>0</td><td>0</td><td>0.035</td><td rowspan="4">$\frac{1.7262}{\text{Number of hours in billing period}}$</td></tr>
<tr><td>3 to 7%</td><td>0.09</td><td>0.09</td><td>0.05</td><td>0</td><td>0.025</td></tr>
<tr><td>7 to 11%</td><td>0.16</td><td>0.16</td><td>0.12</td><td>0</td><td>0.015</td></tr>
<tr><td>11 to 15%</td><td>0.23</td><td>0.22</td><td>0.19</td><td>0</td><td>0.005</td></tr>
<tr><td>above 15%</td><td>1</td><td>1</td><td>1</td><td>1</td><td>1</td><td>1</td><td>0</td><td>0</td></tr>
</table>

Table 4 shows how the rate options could be calculated for an LDC with a base RTSR demand charge of $5.65/kW. Option 2a is set at $0.73/kW, or 13% of $5.65. Option 2b is set based on a different fraction of $5.65/kW for each load factor tier. The energy rate for Option 2c is set by multiplying $5.65/kW by *b* (i.e. 1.7262) and dividing by 730, the average number of hours in a month each year.

Table 4: Example of Low Load Factor Rate Calculation

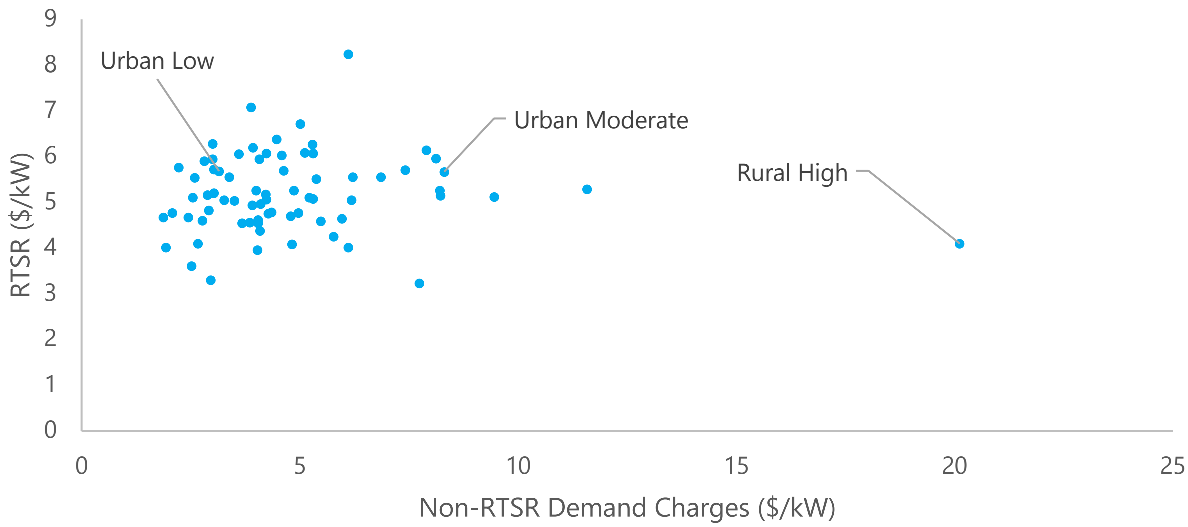
<table>
<tr><th>Load Factor</th><th>Status Quo ($/kW)</th><th>Option 2a ($/kW)</th><th>Option 2b ($/kW)</th><th>Option 2c</th></tr>
<tr><td>0 to 3%</td><td rowspan="5">5.65</td><td>0.73</td><td>0.15</td><td rowspan="4">$0.0134/kWh
Assuming annual average of 730 hours per month</td></tr>
<tr><td>3 to 7%</td><td>0.73</td><td>0.54</td></tr>
<tr><td>7 to 11%</td><td>0.73</td><td>0.93</td></tr>
<tr><td>11 to 15%</td><td>0.73</td><td>1.27</td></tr>
<tr><td>above 15%</td><td>5.65</td><td>5.65</td><td>$5.65/kW</td></tr>
</table>

2. IMPACT OF PROPOSED ALTERNATIVE RATE DESIGNS

In this section, the rate design developed in the previous section is applied to each LDC rate zone and implications for public DCFCs and other customers are explored. The illustrative rates are developed considering only the RTSR component of CP-related costs. In other words, the full Distribution Volumetric Rate would continue to be charged to a customer's NCP demand.

Figure 10 presents RTSR and non-RTSR demand charges for all LDC rate zones. RTSR typically ranges from $4 to $6/kW, while other demand charges vary more widely. Three of the rate zones identified in Power Advisory's Report are highlighted in the figure.

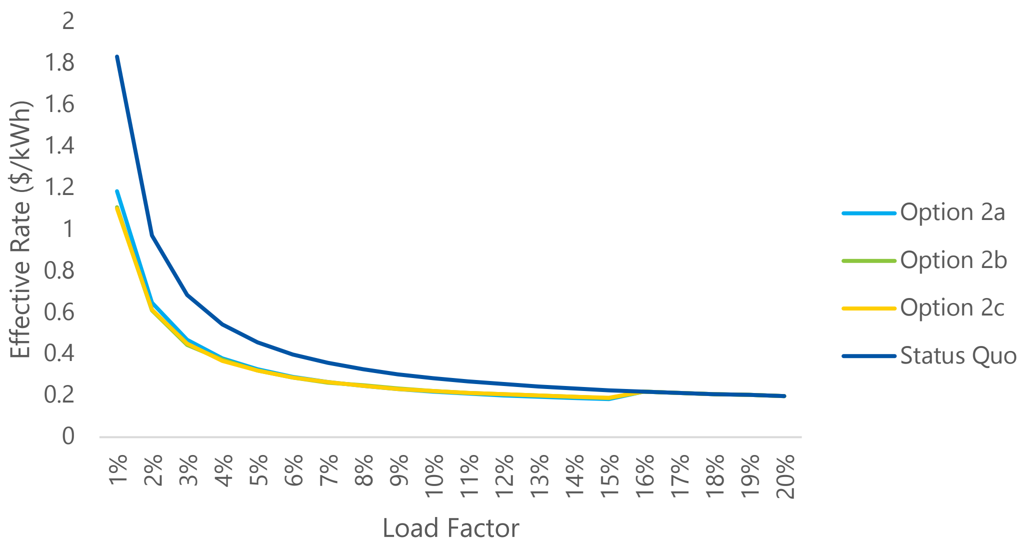
Figure 10: RTSR and Non-RTSR Demand Charges for a 300 kW Customer, by LDC Rate Zone, 2022



2.1 Public DCFC Customer Bill Impact

Figure 11 shows the effective rate (i.e. total bill divided by total energy consumption) for loads with varying load factors. Each of the rate options performs similarly when expressed as an effective rate.

Figure 11: Effective Rate ($/kWh) for Low Load Factor Rate Options



There is a sudden transition from the alternative rate at a 15% load factor to the regular rate above a 15% load factor. This transition averages $0.037/kWh across all LDCs but can be as much as $0.056/kWh. Increasing the load factor threshold above 15% could mitigate this transition (Table 5) because at higher load factors there is a smaller gap between the low load factor and regular rates in $/kWh terms.

Table 5: Bill Increase at Low Load Factor Threshold (Weighted Average of LDCs)

Load Factor Threshold	Magnitude of Increase at Threshold ($/kWh)	Relative Increase at Threshold (%)
10%	0.062	28%
15%	0.037	19%
20%	0.024	14%
25%	0.017	10%

Figure 12 shows the percentage bill savings for a 300 kW public DCFC station with a typical 5% load factor. Average savings are approximately 31%, and range from 13% to over 40%.

Figure 12: Bill Impact of Low Load Factor Rates for 300kW Public DCFC with 5% Load Factor

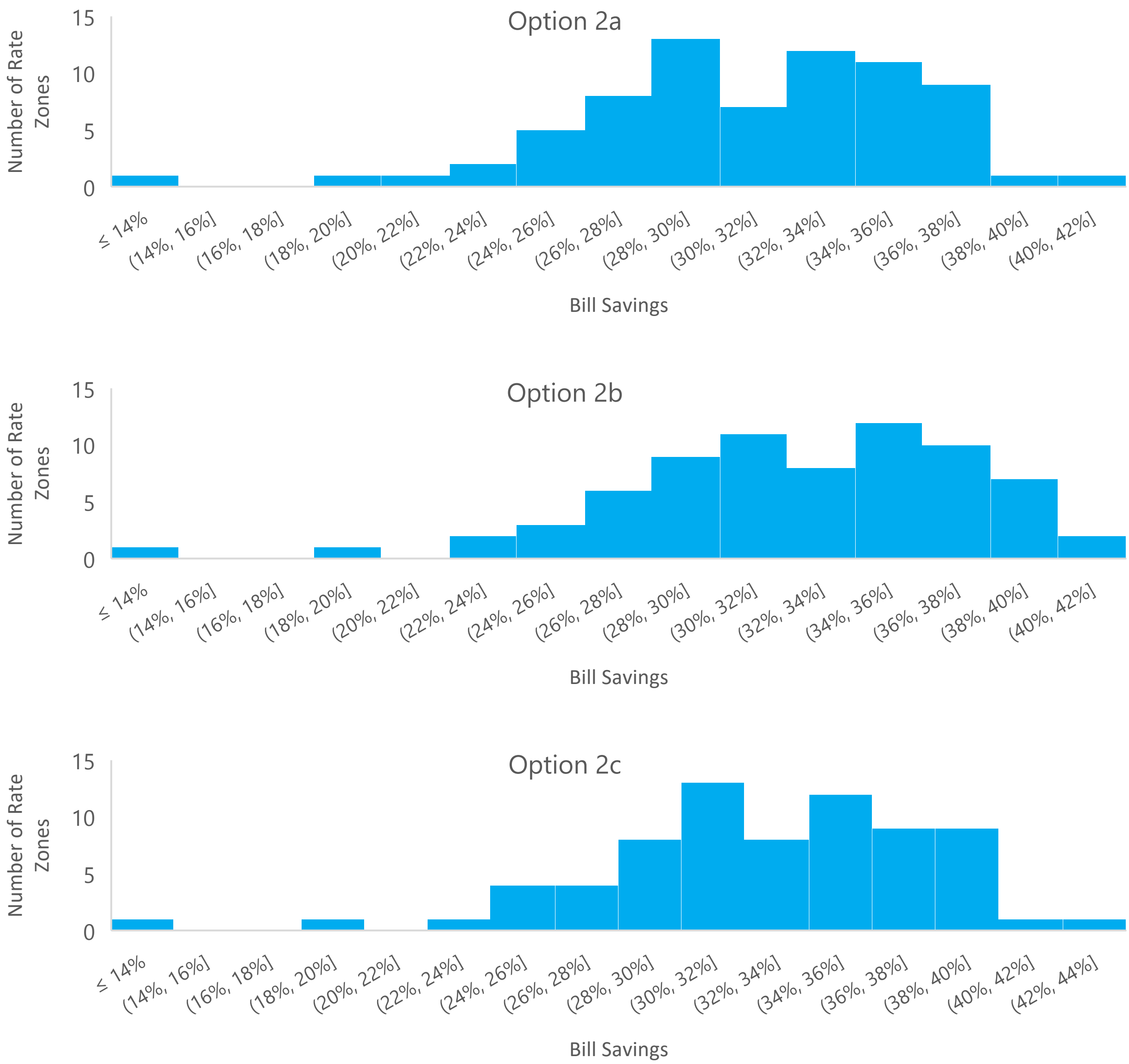


Table 6 shows the average total bill savings for multiple load factors, assuming Option 2c and extension of eligibility up to a 20% load factor. The range across all LDC rate zones is also shown.

Table 6: Bill Impact of Low Load Factor Rates for 300kW Public DCFC, Option 2c, Various Load Factors

Load Factor	Minimum ($/kWh)	Average ($/kWh)	Maximum ($/kWh)	Minimum (%)	Average (%)	Maximum (%)
5%	0.081	0.136	0.206	13%	31%	42%
10%	0.037	0.062	0.093	10%	22%	30%
15%	0.022	0.037	0.056	8%	17%	22%
20%	0.015	0.024	0.037	7%	13%	17%

2.2 Typical Customer Bill Impact

Bill impacts of the low load factor rate for customers other than public DCFCs are similar between the three options considered. The histograms and statistics in this section are presented for Option 2c.

For a forecast of DCFC requirements by 2035, there is a 0.46 cent/kWh increase on average for General Service Greater than 50 kW (GS>50) customers compared to status quo rates (Figure 13), ranging from 0.27 to 0.69 cents/kWh. In relative terms, the increase is 3.3% on average, ranging from 2.0% to 4.8% (Figure 14). Consistent with previous analysis, the bill impact assessment assumes 1.7 TWh of public DCFC load in 2035. Total General Service Greater than 50 kW load of 57 TWh is estimated by scaling up the 2021 load of 49 TWh by the Commercial Sector growth rate in the IESO's 2022 Annual Planning Outlook. Public DCFCs in 2035 were assumed to have load factors in a uniform distribution between 1% and 15%.

Figure 13: Estimated 2035 Bill Impact for Typical Customers, cents/kWh, GS>50

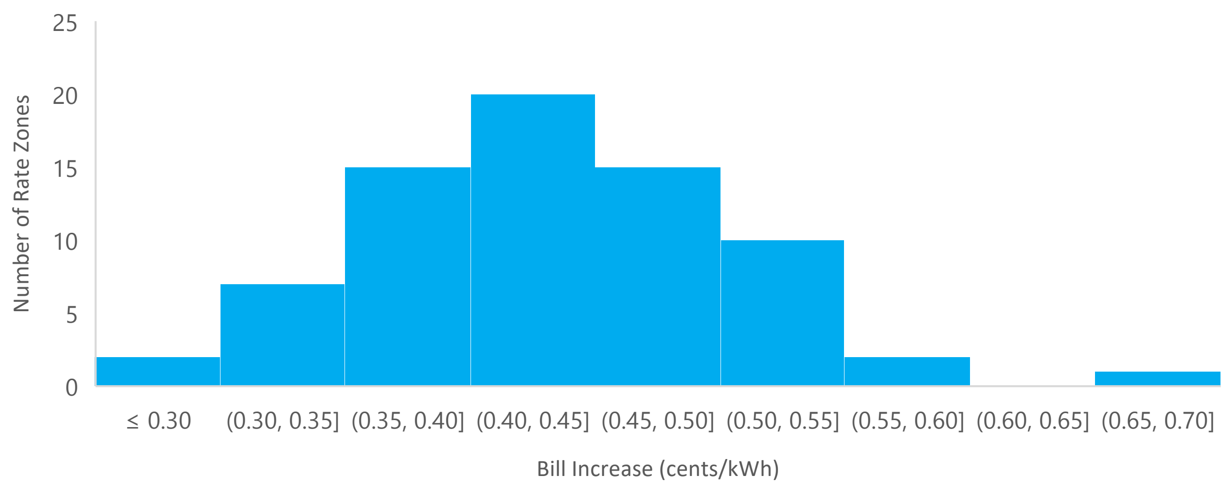
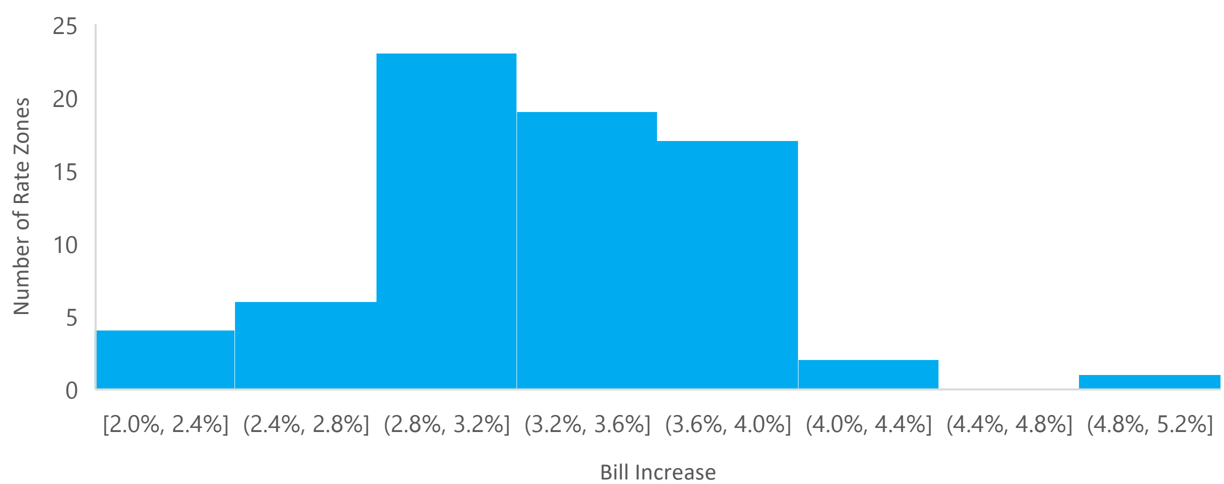
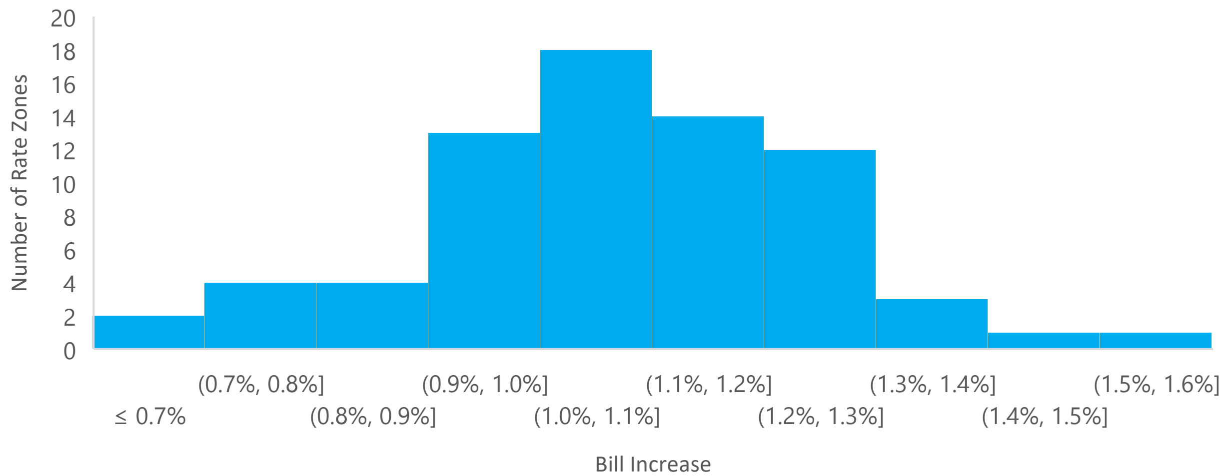


Figure 14: Estimated 2035 Bill Impacts for Typical Customers, relative, GS>50



The bill impact assessment in Figure 13 and Figure 14 assumes revenue neutrality within the General Service Greater than 50 kW rate class, so the impact on other customers varies depending on the savings available to public DCFCs in each rate zone. An alternative approach for the RTSR-only option is to recover the revenue shortfall from all LDC-connected customers, which could spread the bill impact across nearly three times as much load. The average bill impact in this scenario is reduced to 1.1%, ranging from 0.6% to 1.6% (Figure 15).

Figure 15: Estimated 2035 Bill Impact for Typical Customers, relative, All LDC-Connected Load

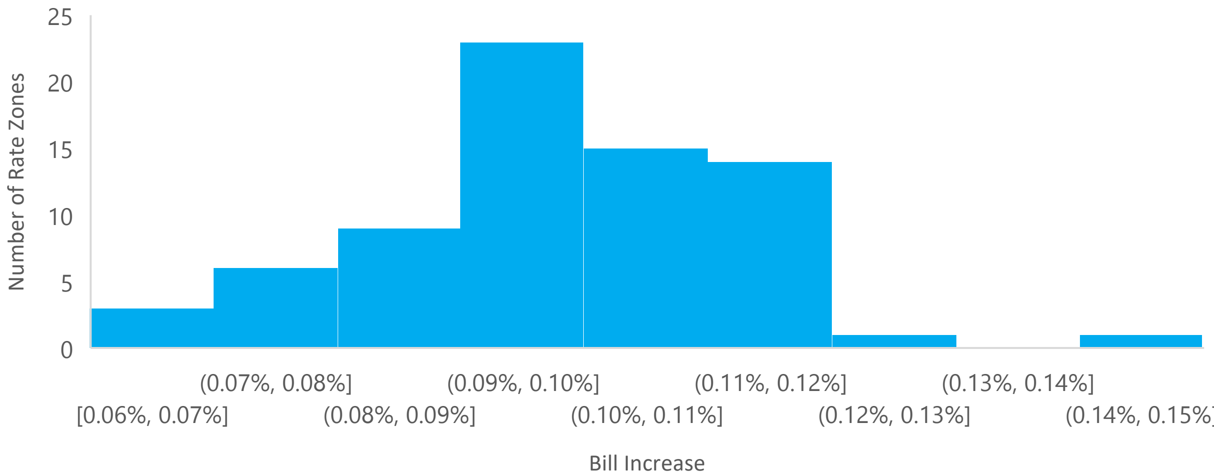


For a forecast of DCFC requirements by 2026, and assuming recovery from all LDC-connected customers, the average bill impact is 0.013 cents/kWh, ranging from 0.008 to 0.02 cents/kWh. In relative terms, the increase is 0.10% on average, ranging from 0.06% to 0.14% (Figure 16). The 2026 bill impact assessment assumes 0.12 TWh of public DCFC load, which is based on assuming 100kW average power per port, 5% average load factor, and the number of ports in July 2026 exponentially extrapolated from the 2019 to 2024 trend.[6] Total LDC-connected load of 134 TWh by 2026 is estimated by scaling up the 2022 LDC-connected load reported by LDCs[7] by the forecast increase in net demand between 2022 and 2026 as published in the IESO's 2024 Annual Planning Outlook.

[6] Historical data on number of DCFC ports in Ontario is from Natural Resources Canada Electric Charging and Alternative Fuelling Stations Locator https://natural-resources.canada.ca/energy-efficiency/transportation-alternative-fuels/electric-charging-alternative-fuelling-stationslocator-map/20487

[7] https://www.oeb.ca/open-data/electricity-reporting-record-keeping-requirements-rrr-section-2154-demand-and-revenue

Figure 16: Estimated 2026 Bill Impact for Typical Customers, relative, All LDC-Connected Load



The bill impacts presented in this section are relative to the status quo rate structure in which public DCFC charging customers that contribute less to peak demands would be paying the same peak demand-related transmission charges as regular General Service Greater than 50 kW customers, thereby cross-subsidizing other customers. Since the alternative rate designs better align demand charges for public DCFCs with the incremental transmission costs incurred by LDCs, they would cause minimal RTSR impacts on other customers.

3. ADDITIONAL CONSIDERATIONS

Some LDCs own and operate transmission assets and others have made capital contributions toward Hydro One-owned transmission assets. These transmission-related costs are included in distribution revenue requirements and are recovered within distribution rates instead of RTSR. Incurring these costs typically has the impact of reducing the LDC's Uniform Transmission Rates (UTR) payments and their customers' RTSRs. Limiting Low Load Factor Rates to RTSRs would create some inconsistencies among LDCs with respect to the share of total transmission costs considered within the alternative rate design. This inconsistency could be resolved by including the annual revenue requirement of transmission assets currently within distribution revenue requirements in RTSRs.

The current distribution rates of most LDCs were set without substantial public EV charging loads in load forecasts, revenue forecasts, and rate designs. Therefore, introducing EV charging distribution rates will not have a significant impact on other customers. Once distribution rates are set with material revenues coming from public EV charging customers, and once those revenues are higher than the costs caused by EV charging, there would be adverse impacts on other customers if lower EV distribution rates were to be implemented in the future. If EV distribution charges will be implemented at any point, it is most efficient to implement the charges in the near future before there is substantial commercial EV load.

Though this alternative rate design is described as including only RTSRs, it would be appropriate to also include low voltage charges. Low voltage charges are applicable to embedded LDCs that are served by other distributors. These charges are allocated to customers based on the same allocation of RTSR, are determined within the OEB's RTSR model, and are not included in distribution revenue requirements. It would not be burdensome to extend the RTSR rate design to low voltage rates, and this could be implemented in annual Incentive Rate-setting Mechanism (IRM) processes.

4. ANALYSIS OF LOW LOAD FACTOR RATE CLASS ELIGIBILITY

The rationale for offering low load factor rates to public DCFCs also applies for other consumers. Ratemaking principles generally do not support separate rates for specific sectors or consumption types; ideally rates are based only on consumption patterns.

The smart meter data used to define CPC for existing customers can also be used to explore the existing low load factor customers. Figure 17 and Figure 18 show the distribution of load factor for General Service Greater than 50 kW customers in the smart metering dataset. About 1.4% of customers, representing 0.8% of demand, have a load factor below 15%. If a 25% cutoff is used, those numbers rise to 6% of customers, representing 3.2% of demand.

Figure 17: Summer Load Factor Distribution, Existing Customers

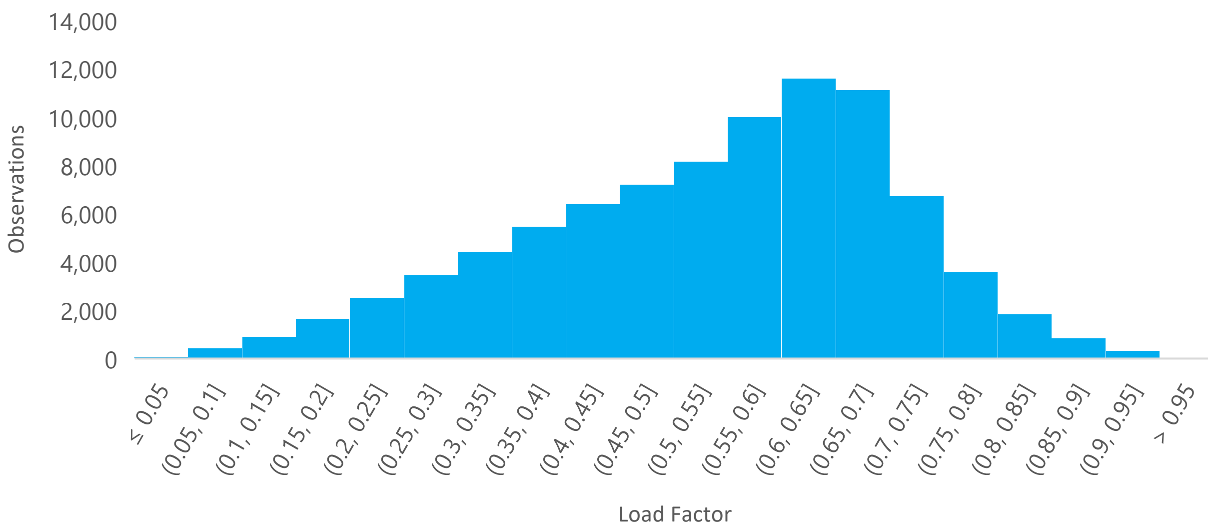
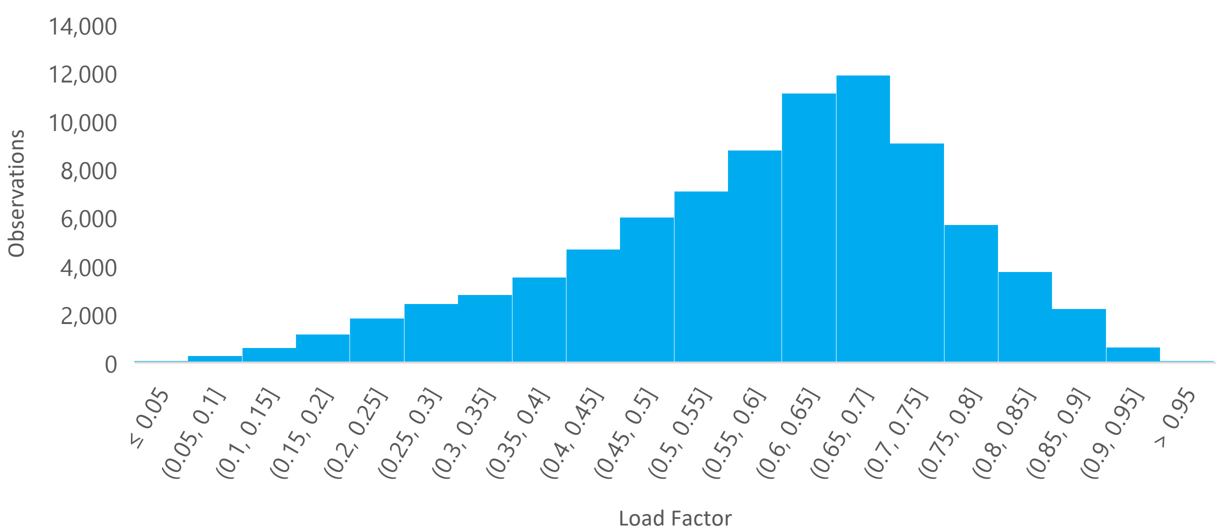
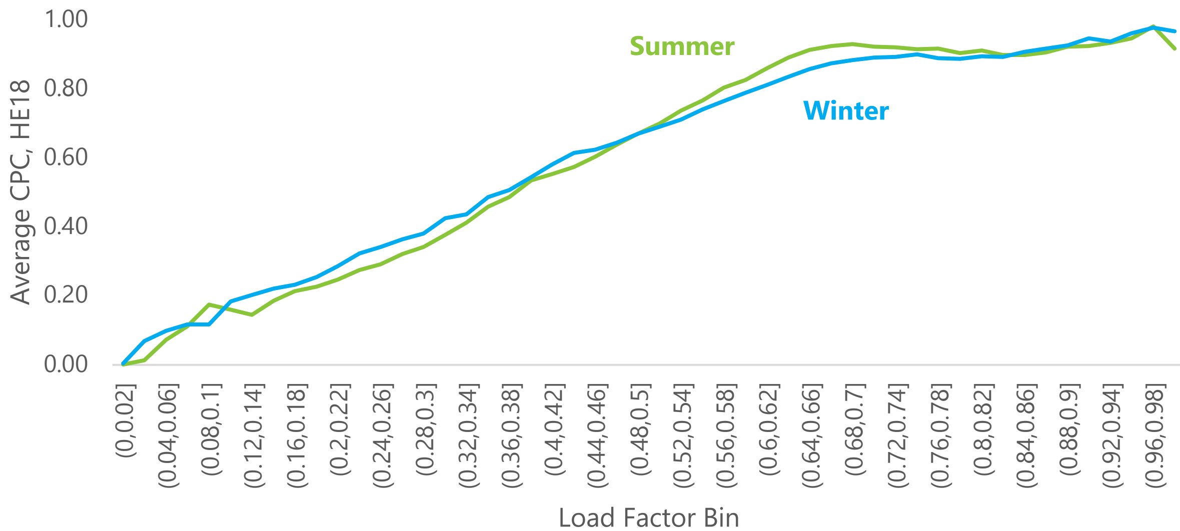


Figure 18: Winter Load Factor Distribution, Existing Customers



The relationship between CPC and load factor for existing low load factor customers is similar to the relationship developed for public DCFCs. There is a predictable linear relationship with a similar slope for load factors below approximately 60% (Figure 19).

Figure 19: CPC vs. Load Factor, Existing Customers, HE 18



Allowing all existing low load factor customers to access the low load factor rate would lead to a larger and more immediate bill impact for remaining customers. The magnitude of the bill increase would depend on the low load factor threshold and the distribution of customer load factors, with lower load factor customers receiving greater bill savings and causing greater bill impact for remaining customers.

Table 7 shows the bill impact under various scenarios for a customer with a 65% load factor (the approximate mode of the distributions in Figure 17 and Figure 18). The bill impact shown is the weighted average of all LDC rate zones, averaged for Options 2a, 2b, and 2c. Figure 14 illustrates how bill increases in individual LDC rate zones could differ from the weighted average. The reduction in RTSR revenue from low load factor customers can be recovered from remaining General Service Greater than 50 kW customers or from all LDC-connected customers. These two options are also shown in Table 7.

The load factor distribution for existing customers with load factors below 25% is modelled using a triangular distribution with the minimum at 1% and the mode and maximum at 25%. This approximates the actual load factor distribution found in Figure 17 and Figure 18. Two options are shown for the load factor distribution of DCFC customers: a uniform distribution between 5% and 15%, and a uniform distribution between 1% and 15%.

If the 3.2% of existing General Service Greater than 50 kW demand with a load factor below 25% were automatically moved to the low load factor rate, the immediate bill impact for remaining General Service Greater than 50 kW customers would be 1.1%. This could be reduced to 0.4% if the costs were shifted to all LDC-connected customers. The bill impact by 2035 from DCFCs ranges from 1.6% to 3.3% depending on the load factor distribution assumption. If load factors were lower, for example ranging only from 1% to 10%, the bill impact could be even greater.

Table 7: Estimated Bill Impact for Typical Customers (% Increase)

Eligibility	Recovered from General Service > 50 kW Rate Class	Recovered from all LDC-connected Customers
Existing Customers Below 25% Load Factor	1.1%	0.4%
Anticipated DCFC Customers by 2035, 5% to 15% Load Factor	1.6%	0.5%
Anticipated DCFC Customers by 2035, 1% to 15% Load Factor	3.3%	1.1%
Existing Customers Below 25% Load Factor and 2035 DCFC Customers, 1% to 15% Load Factor	4.4%	1.5%

5. LIMITATIONS OF THE ANALYSIS

There are two key assumptions justifying the low load factor rate. First, that public DCFCs are independent of one another and independent of weather, such that a random sample from historical consumption days reasonably approximates the expected consumption pattern of multiple public DCFCs on a peak day. Second, that there are sufficient public DCFCs at each transformer station that the law of large numbers applies for the purposes of cost causation on coincident peak days.

The data sources used provide very valuable customer-level insight, but they are not fully representative of existing customers and cannot capture future changes in consumption patterns. The smart meter data for existing General Service customers was from three large LDCs. While they account for a representative fraction of total LDC-connected load, they may not fully capture General Service consumption patterns.

The public DCFC data used does not include all current charging networks, and public DCFC consumption patterns may evolve as EV adoption increases. Finally, historical demand was used to determine the timing of a coincident peak that is applicable to most LDCs. Changes in the system over time, most notably from distribution-connected solar and heating electrification, could lead to more early morning or late evening demand peaks.

Throughout the analysis, maximum hourly demand is used as a proxy for billing demand. This will underestimate billing demand which is measured over 15-minute intervals. The distinction between RTSR-Network, RTSR-Connection, and other CP-related costs is also not fully addressed. A single indicator of consumption during CP is used as a proxy for these costs.

The methodology in this addendum proposes a single, Ontario-wide, set of parameters to define the low load factor rate as a function of each LDC's RTSR. A general-purpose methodology inevitably sacrifices accuracy compared to custom rates for each LDC, which could be tailored to each LDC's peak season, coincident peak timing, and existing customer mix. While customizing the rate for each LDC may increase accuracy, on balance it would not necessarily be preferred due to the added complexity. While in principle the low load factor rates should also be periodically updated to account for evolving trends, the frequency of these updates is another trade-off between accuracy and complexity.

There are several assumptions in the bill impact assessment which have limited support. For example, the future size of General Service Greater than 50 kW rate class, anticipated future public DCFC demand, and public DCFC load factor distribution are all subject to forecast uncertainty. Bill impact could be greater if most public DCFCs have very low load factors (i.e., less than 5%) in the long term. Customer bill impact would also be greater in 2050 compared to 2035 if 100% electrified personal transport forecasts materialize. The bill impact of expanding eligibility to customers with low load factors other than public DCFCs is estimated based on the load factor distribution in three LDCs where smart meter data was available. If an LDC has a higher share of low load factor customers than the three LDCs that were reviewed, the bill impact on their remaining customers could be greater.

6. RECOMMENDATIONS

6.1 Selection of Rate Option

All rate options achieve similar bill reductions for low load factor DCFCs (Figure 11), so the main criterion for the recommendation is simplicity. Option 2a, a single tier, is simpler than Option 2b's multiple tiers, but a single tier could be challenging to apply if the load factor cutoff is raised from 15%. Option 2c, which was redesigned in this addendum as an energy-only charge, is simple to calculate and most closely approximates the idealized demand charge in Figure 9. It takes a similar approach to Hydro-Québec's Rate G9, effectively lowering the demand charge and raising the energy charge. Power Advisory recommends Option 2c.

6.2 Low Load Factor Cutoff

There are two main considerations for selecting a low load factor cutoff: bill impact from transitioning out of the rate and bill impact on high load factor customers.

Hydro-Québec uses 25% for their low load factor rate G9.[8] Rate BR has a more complex design. New York is also implementing a demand transition rate for load factors below 25%.[9] The New York Public Service Commission carefully designed the rate to avoid an abrupt transition as customers' load factors increase and they become ineligible for the rate. A low threshold with an abrupt transition could lead to inefficient incentives.[10]

The increase in effective $/kWh rate when a customer loses eligibility for the low load factor rate is shown in Figure 11. Holding other factors constant, a higher threshold reduces the magnitude of this bill increase.

For additional context, the public DCFCs in our sample ranged from 0 to 34%. However, most stations were well below 15%, and stations which are consistently above 20% load factor would have a high risk of queues during busy periods.

Finally, if eligibility is expanded to non-DCFC customers, a higher cutoff would enable more customers to benefit from the rate, increasing the bill impact for the remaining high load factor customers.

Overall, Power Advisory believes that 25% is an appropriate cutoff for a low load factor rate.

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[8] "When the minimum billing demand reaches 65 kilowatts or more, the contract ceases to be eligible for Rate G and becomes subject to Rate M or, if the average load factor for the last 12 consumption periods is less than 26%, to Rate G9." https://www.hydroquebec.com/data/documents-donnees/pdf/electricity-rates.pdf

[9] Order Establishing Framework for Alternatives to Traditional Demand-Based Rate Structures, January 2023. https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={2043A628-EC7D-4064-9F32-662D82598760}

[10] "The JU note that this price step would provide a significant perverse incentive for customers to maintain load factors below the 20 percent threshold recommended in the DPS Whitepaper to remain enrolled in the EV Phase-In Rate Solution instead of allowing load factors to increase" ibid.

6.3 Expanding Eligibility

Preliminary analysis, particularly Figure 19, supports allowing low load factor customers in the General Service Greater than 50 kW rate class other than public DCFCs to also access a low load factor rate. Removing the public DCFC requirement would also eliminate the need to document and verify eligibility.

However, allowing these customers to access the rate could add complexity, and further analysis focusing on low load factor customers other than public DCFCs may be needed.

Bill impact for high load factor customers is another important consideration. One of the benefits of the public DCFC rate is that there are currently very few DCFCs operating in Ontario, so the immediate bill impact is low. While still small, there would be more of a step change for high load factor customers if all existing low load factor customers switched to a lower rate. The step change could be more significant, averaging 1.1%, if a 25% load factor threshold were used. A low load factor rate for all General Service Greater than 50 kW customers is reasonable, provided that a 0.4% to 1.1% initial bill increase for average high load factor customers (depending on whether costs are recovered from all LDC-connected customers or only from General Service Greater than 50 kW customers, respectively) is acceptable.

The rationale for low load factor rates works best for customers that are small relative to their substation. While a low load factor rate for Large Use (i.e. greater than 5,000 kW) customers is worth consideration, there is not sufficient data and analysis to make a recommendation.

APPENDIX A. DERIVATION OF LOW LOAD FACTOR REDUCTION

Let cost *C* be the total costs related to noncoincident peak and coincident peak across a distributor's system. Each unit of noncoincident demand D_N leads to costs at a rate C_N and each unit of coincident demand D_C leads to costs at a rate C_C.

$$C = D_N C_N + D_C C_C$$

A noncoincident demand charge *R* (in $/kW) can be set to recover cost *C* across the total noncoincident demand in the system.

$$R = \frac{C}{D_N}$$

$$R = \frac{D_N C_N + D_C C_C}{D_N}$$

$$R = C_N + \frac{D_C}{D_N} C_C$$

The CPC for the system is total coincident demand divided by total noncoincident demand (i.e. D_C/D_N); it enables coincident peak-related unit costs C_C to be converted to a noncoincident demand charge *R*.

$$R = C_N + CPC * C_C$$

This rate design causes customers whose CPC is lower than the system average to cross-subsize customers whose CPC is higher than the system average. One method to reduce this cross-subsidization is to recover the same total costs from a set of low load factor customers, Group 1, and a set of high load factor customers, Group 2.

$$C = Group\ 1\ Costs + Group\ 2\ Costs$$

$$C = D_{N1} C_N + D_{C1} C_C + D_{N2} C_N + D_{C2} C_C$$

Total costs are recovered using two noncoincident demand charges R_1 and R_2, which are calculated by dividing each group's costs by each group's total noncoincident demand.

$$C = \left(C_N + \frac{D_{C1}}{D_{N1}} C_C\right) D_{N1} + \left(C_N + \frac{D_{C2}}{D_{N2}} C_C\right) D_{N2}$$

$$C = (C_N + CPC_1 C_C) D_{N1} + (C_N + CPC_2 C_C) D_{N2}$$

$$C = R_1 D_{N1} + R_2 D_{N2}$$

Finally, the low load factor rate for Group 1 can be expressed in terms of the rate for Group 2. The reduction *a* is the ratio of the CPCs for Group 1 and Group 2.

$$R_1 = C_N + a * CPC_2 C_C \ where\ a = \frac{CPC_1}{CPC_2}$$

The same principle can be extended to any number of groups. In the extreme case where all customers are considered separately, each customer would be billed based on their actual coincident peak demand instead of their group's average CPC.

APPENDIX B. DERIVATION OF OPTION 2C RATE

The CP-related bill for a low load factor customer is the product of the low load factor rate reduction *a*, the CP-related demand rate for high load factor customers *R*, and the customer's noncoincident demand D_N.

$$a * R * D_N$$

Noncoincident demand D_N can be expressed in terms of load factor *LF* and energy E_N using the number of hours in the monthly billing period.

$$E_N = LF * D_N * number\ of\ hours\ in\ billing\ period$$

$$D_N = \frac{E_N}{LF * number\ of\ hours\ in\ billing\ period}$$

This addendum develops an approximation for *a* in terms of load factor and a parameter *b* which is estimated based on hourly consumption data.

$$a = b * LF_{DCFC}$$

Substituting the expressions for D_N and *a* into the formula for a low load factor customer's CP-related costs leads to:

$$a * R * D_N = \frac{b * LF * E_N * R}{LF * number\ of\ hours\ in\ billing\ period}$$

Which simplifies to an energy rate that is applied to E_N.

$$\frac{b * R}{number\ of\ hours\ in\ billing\ period} * E_N$$

The appropriate fraction of demand rate *R* for low load factor customers can now be recovered using an energy rate.

APPENDIX C. REVIEW OF SYSTEM PEAK TIMING

Figure 20: Historical Zonal Peak Demand, Summer 2019-2023

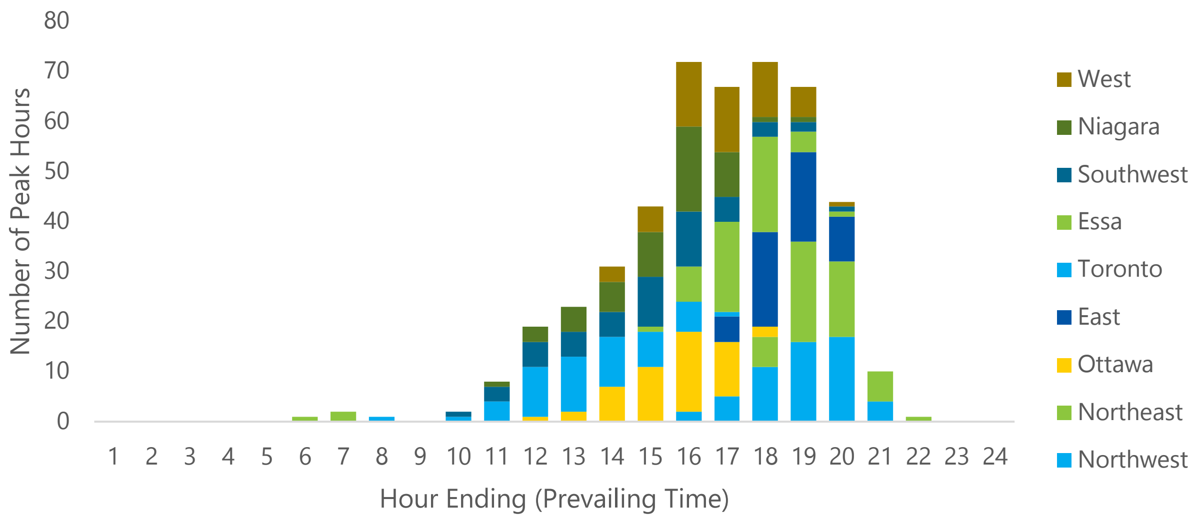

Figure 21: Share of Top 5 Summer Demand Hours, 2018-2022, for 55 LDCs

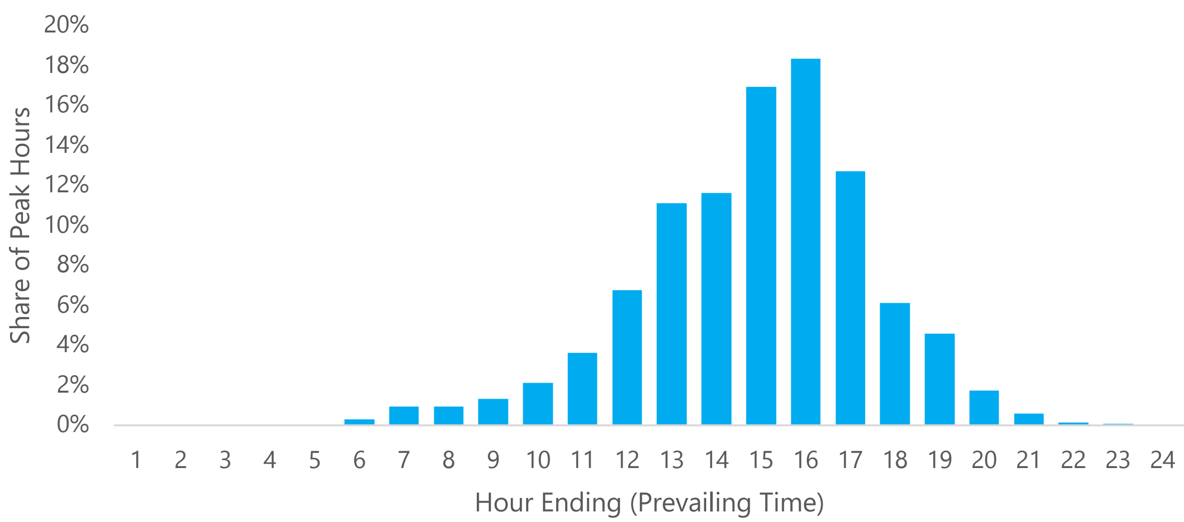

Figure 22: Historical Zonal Peak Demand, Winter 2019-2023

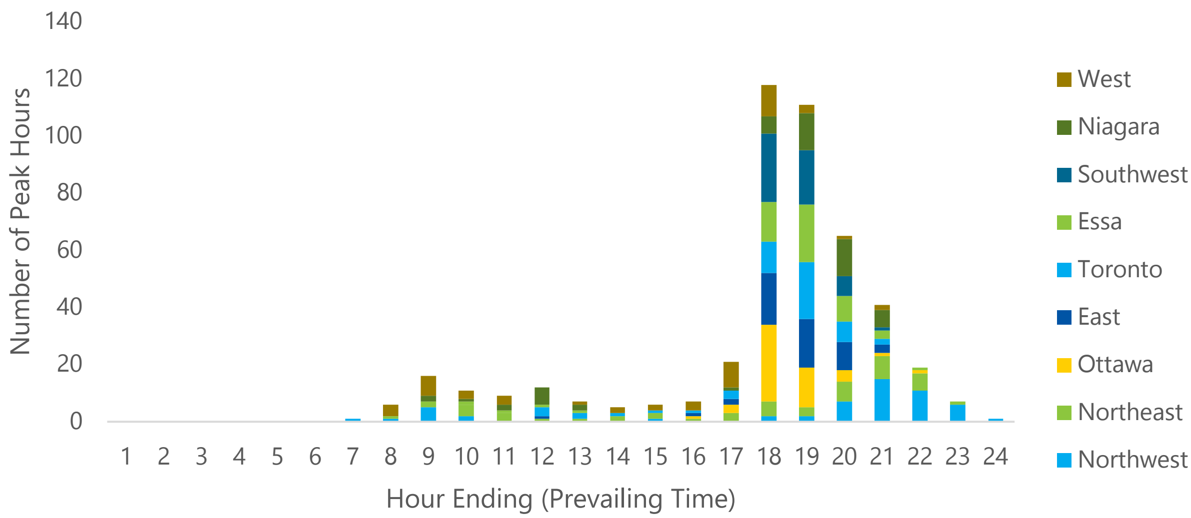

Figure 23: Share of Top 5 Winter Demand Hours, 2018-2022, for 55 LDCs

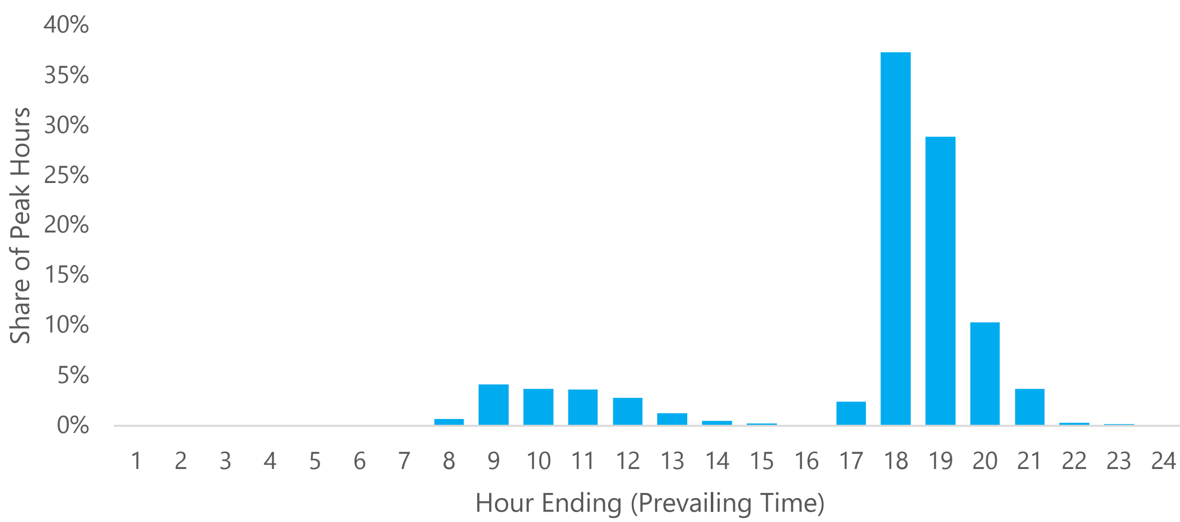

Figure 24: High Demand Normalized Load Shapes, IESO 2022 Pathways to Decarbonization Study

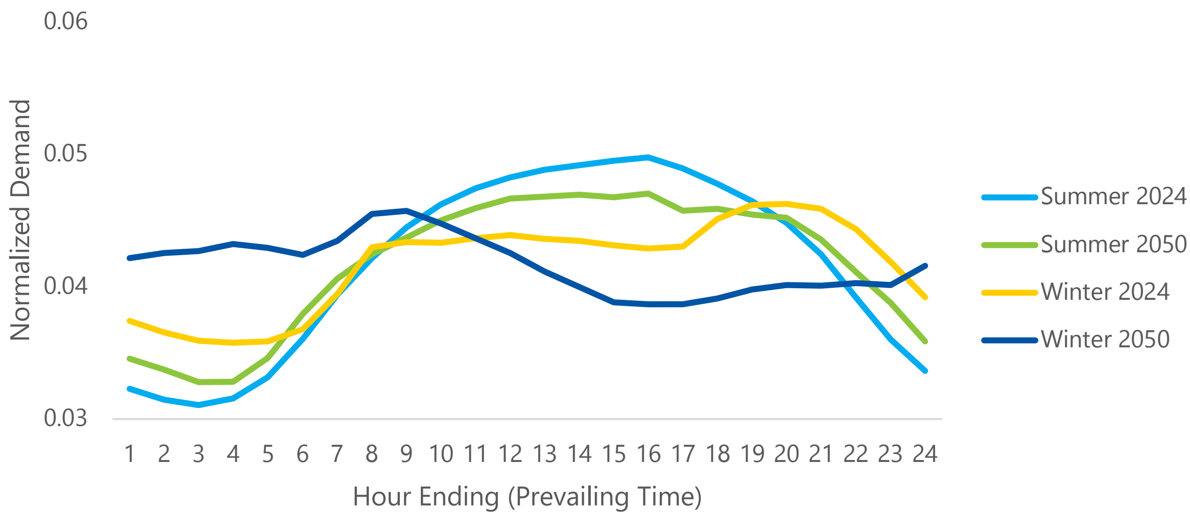

Figure 25: Summer 2029 Loss of Load Probability, IESO 2022 Annual Planning Outlook