Comments on R-4333-2026 Proposed Tariff for CB and CD Customer Class

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1. Introduction and Overview of Remarks

1. Power Advisory was retained by Fasken on behalf ASIC, First Block, Flumen, Hive et MWC ("Group") to provide commentary and analysis on Hydro Quebec Distributor's (HQD) proposed tariff before the Régie de l'énergie ("Regie") for Crypto-Mining and Data Centre customers (the CB and CD customer classes, respectively, in proceeding R-4333-2026).

2. The proposed tariffs mark a significant departure from existing rates for the CB rate class and existing (and future) data centre customers that will be migrated to the new proposed CD tariff. In particular, the proposed tariff moves away from the current cost allocation methodology for these customers that largely allocates ***average*** system costs to one that allocates what HQD is referring to as ***marginal*** system costs, which is the cost of procuring, delivering and balancing new supply (i.e. the full installed cost of the marginal unit added to the grid with all associated services). This is a structural change in rate design for HQD.

3. The result of allocating the full marginal cost of new supply – to existing customers that have been operating in Quebec for multiple years in the case of CB customers – are rate increases that are beyond levels typically approved in a regulated rate-setting processes. For existing CB customers, the proposed tariff will increase the tariff by 61% in the first year, which includes HQD's proposed mitigation plan. The total rate increase for the CB customers class over the next three years is 185%. For existing data centre customers being migrated to the CD tariff, the total increase is more than 90% over the next five years. In both the CB and CD mitigation proposal, the annual rate increases are "front loaded" to the early years – meaning the rate shock is highest at the outset and then declines gradually.

4. Based on the filed evidence and response to interrogatories, the proposed tariffs:

    (1) Impose what can be considered a punitive rate structure on both current and future customers served by HQD in the CB and CD rate classes. For existing customers, in particular, the proposed rate tariff fundamentally undermines the economics of being an electricity consumer in Quebec for bitcoin and data centre clients and potentially results in stranded investment. Many CB and data centre clients may have made substantial investments in Quebec and will now see those investments either fully stranded or the value significantly eroded. The "regulatory compact" – that both customers and utilities are treated fairly – between existing customers and HQD is undermined by the proposed tariff. Both existing and future CB and CD customers will be paying a significant premium

for supply compared to the total, average cost of the system and the rate being charged to other customer classes that are also likely contributing to an overall increase in system costs. Future load customers will need to consider a similar policy being on imposed on them when weighing an investment in Quebec.

(2) For CB customers, in particular, the proposed 50% premium to the marginal supply tariff being proposed for CD customers is arbitrary, unrelated to the costs that these existing customers have imposed on the system and considers none of the benefits of the load profile of this customer class. The increase is not substantiated by detailed analysis.

(3) The proposed tariff incorporates a “mitigation” plan that is insufficient given the magnitude of the rate increase being proposed over the next 3 to 5 years. The rate increases for both CB and CD customers go well beyond a range of what are considered “rate shock” thresholds in other Canadian jurisdictions and, as such, undermine the regulatory compact between monopoly utilities and its customers.

(4) The tariffs also do not recognize the benefits that load customers such as crypto-mining customers have provided to HQD in recent years, including providing significant Demand Response (DR) capacity while also providing a flat load profile through most of the year that can lower total system costs for all rate classes, among other potential benefits such as siting in regions where there is surplus capacity on the grid. Large load customers such as CB and CD customers offer a flat load profile and high curtailment capabilities that more efficiently utilizes the grid’s existing capacity without requiring significant expansion. In doing so, CB and CD customers can spread the costs of the existing grid without increasing overall costs, which reduces the share of costs that have to be paid (or allocated to) by other customers and ultimately reduces the rates for all other customers. The proposed tariff undermines the economic efficiency of load customers that provide significant curtailment during peak demand periods.

(5) The marginal cost assumption included in HQD’s proposed tariff is outdated and no longer relevant to the potential cost of new supply. HQD has not filed any substantial and recent evidence to support the proposed value of the marginal cost of supply being allocated to CB and CD customers. The proposed marginal cost of supply also includes multiple non-supply components such as balancing costs and incremental transmission costs. These two components alone add more than $30/MWh to the marginal cost of supply being proposed by HQD. The cost of new capacity is also included in the proposed marginal cost

value even though CB customers are required to provide significant curtailment during peak demand hours and, as such, are not contributing to peak capacity needs. The benefit of curtailment from these customers can support lower supply, distribution and transmission costs.

(6) While other jurisdictions are including additional requirements to be included in contracts with existing and future CD clients to mitigate their impact on peak system costs to avoid a significant need for new peak capacity, none has been explicitly proposed by HQD. Overall, there is a lack of evidence on other, non punitive mechanisms that can be considered to protect existing ratepayers from the impact of new, large load customers.

(7) HQD's proposed tariff is not justified when compared to other jurisdictions. The supporting evidence filed by Dunsky is limited in nature and does not consider the potential benefits of the structure of current tariffs that mitigates the impact these resources impose on system expansion needs (particularly for CB customers). Ultimately, the comparison to a limited number of existing data centre tariffs in jurisdictions with wholly different market structures and existing rates in neighbouring markets that have historically had much higher supply costs than Quebec provides limited value in determining the appropriateness of HQD's proposed tariffs.

2. Detailed Comments on HQD's Proposal

2.1 *Proposed Tariff Results in Rate Shock*

5. The regulatory framework in multiple jurisdictions in Canada would classify the proposal by HQD as one that imposes "rate shock" on existing customers. Rate shock is typically seen as an increase in rates that is unexpected, material and undermines one of the core concepts of rate regulation that regulated rates should be stable, predictable and allocate costs in a reasonably fair manner. Rate shock is also typically viewed as a rate increase that would impose significant financial and economic hardship on the affected customer class over the proposed term. While there is no one, universal value for what constitutes rate shock, a number of jurisdictions have introduced various thresholds that can be useful in this proceeding as a comparative benchmark. Rate shock policies are typically of focus for residential customers, but can also considered for other rate classes.

6. In Ontario, the Ontario Energy Board's (OEB) handbook for utility applications includes a policy requiring the "filing of a mitigation plan when the total bill impact is 10% or more for any customer class."[1]

7. In British Columbia, the British Columbia Utilities Commission (BCUC) has laid out a number of "rate setting principles" that include an attempt to "avoid rate shock (>10 percent change in rates per annum is generally considered "Rate Shock)."[2]

8. In Manitoba, the Public Utilities Board (PUB) does not provide a pre-determined threshold for rate shock, but "considers both Manitoba Hydro's short-term revenue needs and its long-term projections in an effort to achieve rate stability and avoid rate shock for consumers."[3]

9. And finally, as part of Maritime Electric's proposed rate changes in Prince Edward Island (PEI), a review of those rate increases noted that while there is "no consensus" on what constitutes rate shock "some commissions appear to view increases of 14 percent or more as constituting rate shock, while other commissions have used a threshold of closer to 20 percent."[4]

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[1] See: Handbook for Utility Rate Applications (Rate Handbook)

[2] See: British Columbia Utilities Commission ~ Thermal Energy Systems Framework Revisions to the Thermal Energy Systems Regulatory Framework Guidelines ~ Final Order - British Columbia Utilities Commission and Kyuquot Power Ltd. ~ Revenue Requirements Application ~ Decision and G-213-21 - British Columbia Utilities Commission and British Columbia Hydro and Power Authority ~ Application for F2025 Deferral Account Rate Rider and Trade Income Rate Rider and Reconsideration Related to the TIRR ~ Decision and G-43-24 - British Columbia Utilities Commission

[3] See: 43-26-revised.pdf

[4] See: Exhibit-C-4-Synapse-Report-MECL-Rate-Application-May-13-2022.pdf

10. Importantly, a number of jurisdictions – including in Quebec – have also recently imposed "caps" on rate increases, predominantly for residential customers that can be used as a proxy for "rate shock" thresholds. In Quebec, Decree 1239-2025 includes a policy to cap annual rates increases for certain rate classes – including residential customers (among others) – to 3%.[5] In British Columbia, the government mandated rate increases of 3.75% for residential customers.[6] And in Manitoba, the government specifically froze rates in 2025.[7]

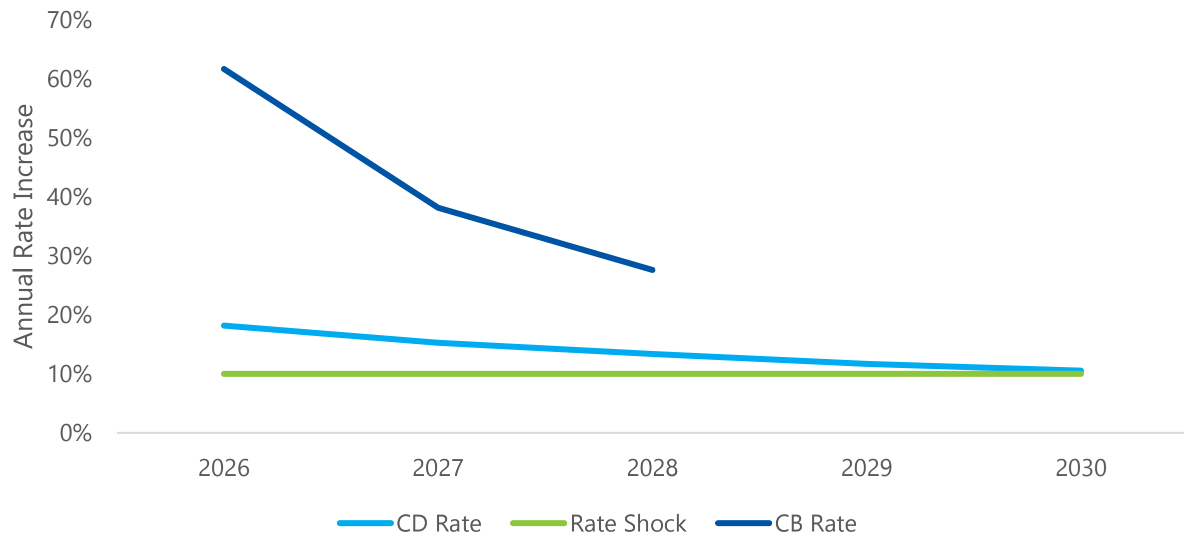
11. Again, while the residential rate caps recently introduced for BC, Manitoba and Quebec – among other jurisdictions – do not include a definition of "rate shock", they incorporate an implicit tolerance for annual rate increases that are well below both the 10% threshold described above and the rate increases proposed for the CB and CD tariff. More specifically, all of the rate shock policies implemented by regulatory bodies in Canada and the rate caps introduced by provincial governments allow for rate increases that are materially below what is being proposed by HQD for CB and CD customers – which in both cases is more than 15%. Lacking a specific policy or regulation to support such an increase, the proposed tariff would be considered "rate shock" by regulatory bodies and require extensive mitigation – either through a direct reduction or a longer mitigation period. HQD's proposed tariff would be insufficient to pass even the broadest examples of allowed rate shock by other regulatory bodies.

2.2 *HQD's Proposed Rate Mitigation is Insufficient*

12. The proposed rate mitigation plan from HQD is insufficient, as it does not address the rate shock issue described previously or align more broadly with rate shock policies currently in place. As noted, a number of regulatory bodies across Canada would be expected to require HQD to implement a rate mitigation strategy given the magnitude of the rate increase over a short period of time. The graph below shows the annual increase in rates for both the crypto mining and data centre customers compared to a 10% annual increase consider the benchmark for rate shock. Rate increases for other customers classes is expected to be around 3% annually until 2028, as filed in HQD's last rate application.

[5] 86575.pdf
[6] B.C. moving to cap annual hydro rate increase
[7] Province of Manitoba | Freezing Hydro Rates

Figure 1 Annual Rate Increases for CB and CD Rate Class



13. For CB customers, in particular, the initial rate increase is more than 61%. While the annual increase is lower in the following two years, it remains higher than 25% – again, well above other proxies for what constitutes rate shock. The total rate increase over the next three years for the CB rate class is 185%.

14. HQD has also proposed to "front load" the rate increases, with the highest rate increase for both the CB and CD rate class in the first year without any justification for why the rate increases cannot be lower in the front end to allow the existing clients time to potentially introduce energy efficiency measures to offset the impact of the new tariff and more closely align with procurement in-service dates (discussed in more detail below). Given the magnitude of the rate increase, HQD's proposal will likely result in demand "destruction" rather than incenting more efficient consumption over the long-term. If existing load is not replaced by new load, it can increase the cost on a per unit basis for all existing customers. While reduced load can allow for surplus supply to exported into neighbouring markets, there is a limited ability to offset a reduction in load on transmission and distribution costs, which are predominantly fixed in the short and medium term. While the stated proposal of the proposed tariff is to limit rate increases for HQD's existing customers, it has the potential to increase rates for existing customers.

15. Additionally, while HQD is expecting to procure new supply over the next decade, most of this supply will not be in-service (i.e. adding new cost to the system) prior to 2030. The current wind procurement, for example, does not require any new capacity to come online prior to 2031.[8] As such, the proposed tariff for the CB and CB rate classes is potentially "front-running" future costs

[8] See: b3e56e2f659ea4d29a5f3031517909de_1. AO 2026-01 - Document dappel doffres.pdf

and imposing those costs on these customer classes even prior to them being realized. In a traditional "used and useful" regulatory environment, the costs of the new supply should not be allocated until the benefits (i.e. the actual supply) is incurred. Additionally, HQD's most recent estimate for post-heritage supply costs over the 2026-2028 time period forecasts the cost of this supply to decline from $119/MWh in 2026 to $109/MWh in 2028.[9]

16. In the case of existing CB clients, their demand was already being served by existing supply and is not a driver of new costs from a supply or delivery perspective. The total load from CB customers is not expected to have materially changed since 2022.[10] HQD and the Quebec government have been limiting the allocation of supply to CB customers since 2022 and HQD says the maximum peak demand from this customer class is just 14 MW out of a total peak demand of more than 42,000 MW (or just 0.03%).[11]

2.3 *Data Centres Shown to Have Limited or Positive Rate Impacts for Existing Customers*

17. The premise that crypto mining and data centres will increase total system costs for all customers is contradicted by multiple other studies that looked at new large load customers.

18. A recent study by the Electric Power Research Institute (EPRI) showed from 2015 to 2024, data centres "caused average retail electricity rates to fall modestly…the finding is consistent with economic reasoning: existing large power system fixed costs, economies of scale in transmission and distribution, and declining unit costs for generation imply that durable demand growth lowers average prices."[12] The report found that, in particular, every 10% increase in data center capacity resulted in average residential retail prices falling by approximately 0.4%.

19. Another study from E3 showed there is evidence "that data centers generate surplus utility revenues from paying more than the cost to serve them, which can potentially lower electric rates for other customers."[13] The study also concluded that "state-level" analyses "show no clear relationship between load growth and rising rates."

20. While the studies above highlight that new large load customers have not historically caused an increase in rates for other customer classes, the main reason for that outcome is that new customers can allow fixed costs to be spread across a greater number of "units" (i.e. amount of MWhs sold) –

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[9] See: HQD-2, Document 1 Page 9 of 20, Table 3
[10] See: HQD-6, Document 1.1 Page 30 de 50
[11] See: HQD-6, Document 10.1, Page 12
[12] See: Have Data Centers Raised Your Electric Bill? Causal Evidence from the United States
[13] See: RatepayerStudy.pdf

particularly as it relates to fixed transmission and distribution costs.[14] A recent whitepaper discussing cost allocation for new large load customers noted that "Historically, load growth has put downward pressure on electricity prices because the fixed cost of the existing power system could be spread across more customers, reducing the average rate paid by all customers. The benefits of new large load customers has been documented in the studies."[15] Nonetheless, all of the studies do caution that a sudden increase in demand can put upward pressure on rates. As discussed in more detail below, if new load customers are also incented – or required – to reduce load during peak demand hours, their impact on total system costs can be mitigated (or eliminated altogether) as they do not require reliability-related investments to support higher peak demand.

21. Importantly, what nearly all studies show is that the tariff for new large load customers needs to be designed in manner that both allocates specific interconnection costs to those customers, incorporates some level of Demand Response or Flexibility and mitigates to the extent possible the potential that the new costs to serve the customers are not greater than what is recovered in rates. All of the following points are discussed below as they relate to HQD's filed evidence.

2.4 *Managing Interconnection Costs*

22. First, nearly all crypto-mining operations are existing load customers and, as such, do not require additional system upgrades to maintain existing load. The proposal for existing CB customers ignores that these customers will have no economic impact on other ratepayers, as they are not increasing their load substantially and have already paid for their related interconnection costs and associated delivery and transmission costs to serve them. In short, the system is not being expanded to serve this load, but HQD proposes to charge CB and CD customers as though it is incurring costs to expand the system, and the "beneficiary pays" principle of economic regulation is not being used in the proposed tariff for existing CB and CD customers.

23. For any new load related to crypto-mining operations, the Conditions of Service (COS) from HQD requires that all connection costs are paid for by the customer. The COS clearly states that the crypto-mining customer "must assume the entire cost of the work required to make the connection… [and] payment in full must be received before Hydro-Québec will start the work." Additionally, the COS requires that customers with a peak demand greater

[14] HQ has extensive storage capability at its hydro facility and – unless there is a significant decline in demand – can manage surplus supply through a combination of storage and exports.

[15] https://www.esig.energy/wp-content/uploads/2026/05/ESIG-Large-Load-Rate-Impacts-primer-WP-2026.pdf

than 5 MVA will have their load monitored for the next five years. If the billing demand for each of the 5 years is below the anticipated power demand, HQD will impose an "allowance adjustment charge" for the difference between the billed demand and anticipated demand. As such, there is a financial penalty to these customers if the demand requested from HQD does not materialize, which can act as a benefit to existing customers and limit the potential that the system was expanded to serve load that never materializes.

24. For new and existing data centre customers, the interconnection costs are also imposed on the load customer. In response to an interrogatory on whether HQD "analyzed an approach whereby each data center would bear the transport and distribution costs it generates based on its location on the network," HQD responded that "no such analysis exists…[and] reiterates that the cost of the work associated with the power requests specific to each subscription are covered by the contribution agreements."[16] As a result of this requirement, there is no (or limited) interconnection costs that are imposed on other rate classes and if these customers are imposing broader system-wide costs, HQD has not explicitly provided them in the this proceeding.

2.5 *The Value of Requiring Demand Response and Flexibility*

25. One the most prominent methods of reducing the system impact of both new and existing large load customers is to mitigate their impact on peak demand requirements for the total system. For all of the three main components of the electricity grid – generation, transmission and distribution – the electricity grid is planned and built to accommodate peak demand needs. Peak demand is the maximum demand – in power terms (MWs or MVA) – in any given interval or hour. If a new load customer imposes no new load during peak demand hours – i.e. it fully reduces its load when total system demand is at its highest – it will impose little-to-no new costs of expansion from a capacity or demand perspective, as its demand can be served by existing assets. In that case, this load customer's cost to the system is the average cost of maintaining and replacing existing assets, not system expansion. Most rate designs – including HQD rates – incorporate both a demand and energy charge for medium and large-volume customers in order to allocate a portion of system costs based on usage during peak demand hours. In short, these customers are allocated their portion of total system expansion and can reduce this cost by limiting their peak demand through energy efficiency or other means – supporting broader economic efficiency and reducing total system costs.

26. HQD already imposes significant peak demand reductions for the CB rate class. For existing crypto-mining customers, HQD has the ability to fully curtail

[16] See (note our translation): AHQ-ARQ Inquiry No.1, Question 3.7.2

their load consumption for up to 300 hours during the peak winter demand months. As part of the tariff, these customers are obligated to reduce their load to 5% of their "highest value [of demand] recorded during a consumption period included in the 12 consecutive monthly periods ending at the end of the consumption period in question."[17] The curtailment can be called with 2 hours of notice to the customer.

27. In recent years, crypto-mining customers have faced curtailment for multiple hours and various blocks on the same day (i.e. being curtailed in both the morning and evening peak hours). If the customer does not respond to the curtailment requests, they are charged $1,038/MWh – or more than 30 times higher than the current heritage pool rate and around ten times higher than the marginal cost of supply value included in the proposed CB and CD tariff application – for all consumption during those hours. Given these conditions, this customer class does not appear to materially impose and peak demand expansion and related costs. This was confirmed by HQD with its response that 5% of peak CB load amounts to just 14 MW. As noted in the studies highlighted previously, limiting consumption during peak demand hours provides value to existing ratepayers, as it ensures these customers are consuming energy in off-peak hours when there is surplus supply and excess capacity on the system. This reduces total system costs for other rate classes. Importantly, in contrast to other Demand Response programs included in HQD's tariffs, crypto-mining customers are provided no compensation of their curtailment.

28. Going forward, for data centre clients – particularly those with large loads of 100 MWs or more – HQD can include specific Demand Response requirements that are already explicitly included in the requirements for crypto-mining customers. A number of data centre clients are already subject to the LG tariff and, as such, will have energy contracts that may include Demand Response requirements.[18] Most large-scale data centre clients in other jurisdictions are being required to either include significant peak demand reduction capability or provide their own supply ("Bring Your Own Generation"). The proposed tariffs by HQD do not explicitly include Demand Response requirements and, as such, are limiting the value that new large load customers – either through flexibility or curtailment potential – can provide to existing customers by more efficiently utilizing the existing network. HQD has not presented any proposal to explicitly require Demand Response or other flexibility arrangements with future CD customers, even though this can provide significant value to

[17] See: 2026 Rate Handbook

[18] Recent reports suggest that data centres are building Demand Response capabilities into their operations: Google expands utility deals to curb data-center power use during peak demand | Reuters

existing ratepayers and is being actively considered or imposed on data centre customers in other jurisdictions.

2.6 *CB and CD Contracts Included Protections for Existing Ratepayers*

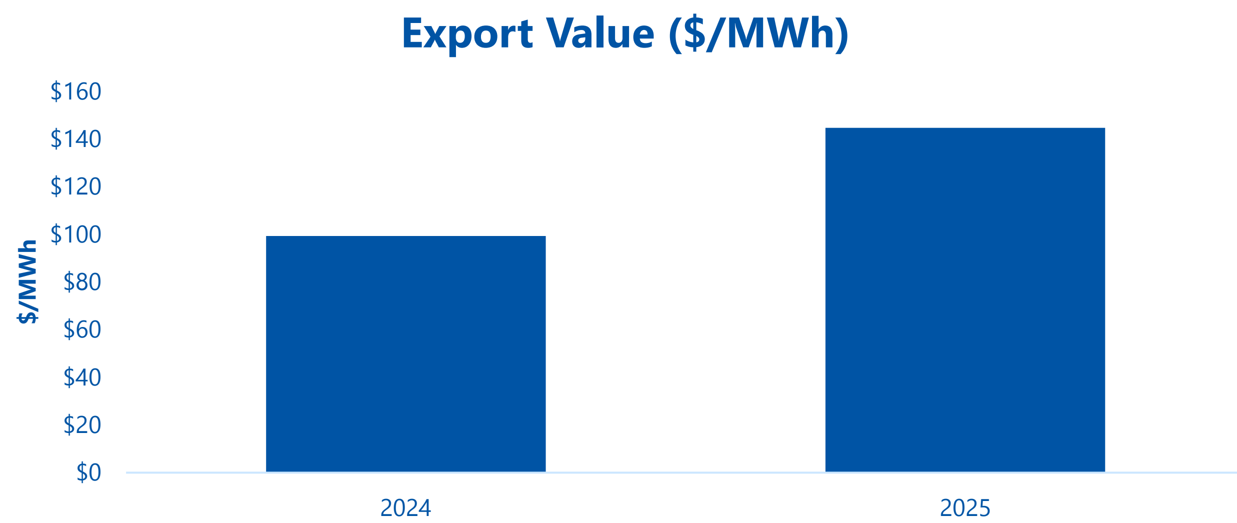
29. As noted, there are already some protections for existing ratepayers regarding load growth from CB (existing) and CD (both future and existing) customers. First, new customers are charged a financial guarantee for an allocation of the portion of costs related to serving their load by HQD – with HQD reducing that guarantee each year but retaining the right to fully retain the guarantee if the customer is in default or does not consume a sufficient amount of energy to pay for the cost of the upgrades. The term of the guarantee can be up to 20 years.[19]

30. Second, CD customers have to commit to "ramp-up" period, with the potential to pay penalties if they fail to reach their ramp-up consumption volumes. As stated in the filed evidence, if, during a calendar year, the customer's largest actual power demand is less than 60% of the power expected according to the committed load ramp-up, the difference between these two values will be subject to a premium for unused power of $ 92.280/kW. Converting that value to a $/MW-year is more than $92,000-MW year – or more than 50% of HQD's long-term value for new capacity. This means that any unused MWs by CD customers will pay more than 50% of the cost of new long-term capacity if they fail to meet their forecasted load requirements.

31. Surplus supply is not a stranded cost. The value of supply exported from HQ into neighbouring markets in 2025 was higher than HQD's avoided cost of new supply. In 2025, the average value of supply exports was $144/MWh compared to HQD's as-filed cost of new supply of $83/MWh.[20] The value for 2025 was higher than the $100/MWh received on average for exports in 2024, which was still higher than the marginal cost value presented in this proceeding. In short, more than 50% of the cost of new capacity is potentially recovered through charges if demand does not materialize, while HQ's extensive interties into neighbouring wholesale markets has historically provided it with an opportunity to export surplus supply at a price that exceeds its estimate on the cost of new supply.[21]

[19] See: Responses to AHQ-ARQ's Request for Information No. 1, 3.9
[20] See" HQ's 2025 and 2024 annual reports
[21] HQ also has the opportunity to export capacity in the summer months.

Figure 2 HQ's Realized Value of Exports



32. For CB customers (below 5 MWs), they are allocated a demand charge for volumes between maximum power demand (i.e. what they are allowed or contracted to consume) and their highest real power demand, up to the 5 MW threshold. For both small and large CB customers – i.e. those with less than or greater than 5 MWs of peak load – there is a minimum billing demand that is allocated to the customer, regardless of how low their consumption is, of 65% and 75%, respectively. For large CB customers, the minimum billing demand will be no lower than 5 MWs. As a result, if that customer were to consume 0 MW in a given month, it would be charged the minimum demand rate. Again, the current rate structure for CB and CD clients provides protection to existing customers from expanding the network and a subsequent lack of realized demand growth.

2.7 *Lack of Evidence Related to the System Cost CB and CD Customers Are Imposing on Other Rate Classes*

33. HQD's application provides a lack of explicit evidence to support its claim that data centres (and to a lesser extent crypto-mining customers) "requires significant investments in the grid" and that "this growth thus puts increased pressure on the costs of electricity distributors, pressure which ultimately impacts tariffs."

34. Hydro Quebec as a whole was already planning extensive investment in the electricity grid prior to the large-scale introduction of date centres and similar large loads. Particularly, the 2035 Action Plan ("Action Plan") called for $45 and $50 billion of transmission spending by 2035 "to increase the capacity of our

transmission system in order to maximize access to new generation."[22] Regarding generation costs, the Action Plan called for "$30 billion in private and public investments." And finally, the Action Plan called for $45 to $50 billion "to make the power grid more durable over the long term."[23] This investment would "deploy new equipment in the distribution system, such as composite poles and conductor covers, and adopt innovative practices like the direct, or "light," burial of power lines."

Figure 3 2035 Action Plan Investments

Summary of required investments and operating expenses

	Total amounts by 2035	Annual average
Investments to ensure service reliability and quality (reliability projects)	$45–$50 billion	$4–$5 billion
Investments to meet demand growth (growth projects)	$90–$110 billion	$7–$9 billion
Additional operating expenses	$20–$25 billion	$1–$2 billion
TOTAL	**$155–$185 billion**	**$12–$16 billion**

The projected average annual investments and additional expenses from now until 2035 are three to four times higher than those of the past five years.

35. All told, HQ was anticipating, conservatively, $120 billion in new investment over the next 10 years on expansion and upgrades to the electricity grid – all of which was forecast in large part prior to the large-scale introduction of data centres. At the same time, existing crypto-mining customers were not forecasted to materially expand operations in the province and, as such, were not a primary driver of system expansion. Under HQD's proposal, some portion of those costs are now being fully allocated to two customer classes, even though a significant need for the investment was expected prior their connection requests and will benefit all existing and future ratepayers.

2.8 *HQD's "Marginal" Cost of New Supply is Outdated and Overstated*

36. Even if the Regie were to consider a marginal cost or avoided cost rate as is being proposed by HQD, for the CB and CD rate classes, the value being proposed is not appropriate. HQD's proposal relies on a value that is no longer relevant to current or future supply costs.

[22] See : 2035 Action Plan
[23] See: HQD-1, Document 1.1, page 5

37. The value was set in a 2023 procurement that did not explicitly include the value of the Investment Tax Credit (ITC), which can lower the up-front capital cost of a renewable energy facility by 30%. While the full value of the ITC may not be incorporated into the bid price by participants, some portion of it would be expected to be included. As such, the required PPA price from the 2023 procurement no longer reflects that realized cost of new supply (i.e. the cost that participants will include in their bid and will be paid by HQD ratepayers). Recent procurements in Canada have posted lower prices than the $83/MWh being proposed by HQD. In BC, for example, its 2024 RFP for 4.8 TWh of new supply had an average weighted price of $74/MWh.[24] In Nova Scotia, its Green Choice procurement in 2025 for new wind projects had an average price of $63/MWh.[25] Using these prices as a comparator, HQD's marginal cost of supply (ignoring balancing and transmission costs discussed below) is overstated by anywhere from $9/MWh to $20/MWh.

38. HQD's current procurements also include alternative resource types to wind, such as solar power. As such, the previous wind procurement is not the only comparator for the cost of new supply in Quebec. Recent procurements have shown that solar can increasingly be a cost-effective source of new supply compared to wind. In Ontario's recent long-term contracts – which only provides 20-year term lengths compared to the 30-year term lengths in previous HQD PPAs – the largest solar facility (200 MW) was awarded a PPA price of $71.74/MWh.[26]

39. New supply needs are not solely subject to HQD procurements going forward. As laid out in both HQ's "Wind Power Development Strategy" and updates to the regulatory framework due to Bill 69, HQ itself will be taking a more proactive role in developing new supply. Previously, nearly all new supply – particularly from wind developments – were built, owned and operated with Independent Power Producers (IPPs), which typically have both higher borrowing costs and Retorn on Equity (ROE) expectations. With HQ taking a more active role in procuring new supply – and incorporating different ROE and financing assumptions than are typically used by IPPs – the "competitive" value of the most recent wind procurement is no longer reflective of potential future supply costs.

40. The last wind procurement is unconnected to the costs that CB and CD customers are imposing on Hydro Quebec. As stated previously, the last wind procurement was undertaken prior to the forecasted demand growth from data centres or any material forecast in demand growth from CB customers.

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[24] See: Statement: BC Utilities Commission accepts BC Hydro's 2024 Call for Power Electricity Purchase Agreements

[25] See: Green Choice Program Greening the Grid, Creating Jobs, Improving Energy Independence | Government of Nova Scotia News Releases

[26] See: https://www.ieso.ca/-/media/Files/IESO/Document-Library/long-term-rfp/energy/LT2e-1-Public-Result-Table-with-Prices-2026-05-08.pdf

As such, this value is not reflective of the costs that these customers may potentially incur going forward and should not be the basis of a CB and CD specific tariff.

2.9 *Marginal Cost for Supply Also Includes Balancing and Interconnection Costs*

41. HQD's proposal includes both balancing and interconnection costs that are either higher than comparable charges in other jurisdictions or lack significant supporting evidence.

42. Regarding the wind balancing costs, NB Power has undertaken extensive studies to determine the balancing cost to its system of integrating wind resources. In its 2024/25 to 2025/26 general rate application NB Power applied – and was approved – for a wind balancing charge of $2.27/MWh. In approving the wind balancing charge, the New Brunswick Utilities and Energy Board noted that the balancing was used to evaluate costs incurred to provide the additional automatic generation control ("AGC") and load following, and the system dispatch changes required to integrate non-dispatchable wind generation and wind forecast error costs."[27] In Ontario, the system operator (the Independent Electricity System Operator (IESO)) recognized the need for greater flexibility and introduced a policy of purchasing additional Operating Reserves (OR). These costs are allocated to all customers and would be significantly lower than the charges proposed by HQD.[28] At the time when the flexibility mechanism was introduced (2017), OR costs were less than $8/MW-hour. The balancing cost being proposed by HQD is $19/MWh – or more than 6 times higher than the rate being proposed by NB Power, which often relies on high marginal cost thermal units for balancing services, and nearly double the cost of OR in Ontario when the flexibility mechanism was introduced to manage wind variability.[29]

43. HQD has not filed an extensive analysis or study on the impact that either existing or new wind supply will have on future total balancing costs for HQ's supply mix. In particular, HQD has also not filed any evidence related to the amount of procurement that is specifically being undertaken due to load growth from CB and CD customer classes – and the ultimate cost that this is imposing on other customer classes or total system costs. As such, any procurement for new supply that is undertaken for load growth outside of those customer classes – i.e. any new supply that is needed to meet non-CB

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[27] See: New Brunswick Energy and Utilities Board Reasons for Decision March 31, 2025

[28] See the Market Surveillance Panel report on the Flexibility Procurement: Market Surveillance Panel Report 32 - July 16, 2020

[29] See page 43: R-4307-2025-B-0083-DDR-RepDDR-2025_11_07.pdf

and CD load growth – should be allocated a portion of balancing costs rather than these costs being full borne by CB and CD customers.

44. In terms of interconnection costs, HQD has filed "transmission" costs related to the 2023 wind procurement.[30] On average, the transmission cost related to the 2023 procurement was $16.47/MWh, but that includes one significant project with transmission costs of more than $26/MWh. Overall, there is a lack of evidence on whether this historic value is appropriate going forward and whether future transmission plans that are being undertaken – regardless of procurement related to CB and CD load growth – that will reduce the need for procurement-specific transmission costs.

45. Additionally, given that future supply needs will be met in part by solar resources, which have less uncertainty regarding intermittent output (i.e. solar output is much easier to forecast than more intermittent wind supply), there is a lack of support to conclude that the previous balancing charge is relevant going forward.

46. And finally, HQD has not filed a detailed cost allocation to determine how the balancing costs of future procurements should be allocated to different customer classes. All rate classes benefit from reliability services and, as such, should be allocated some portion of the balancing cost of future procurements. Under HQD's proposal, if it procures 9 TWh of new supply to meet its forecasted demand for data centres, it will result in two potential outcomes

(1) If the full data centre forecast is realized, these customers are allocated all of the balancing costs for this supply, even though some portion of the balancing costs would benefit other customers, as these assets would be imposing only ***incremental*** balancing costs. HQD already provides balancing costs for its existing fleet of resources and there is no evidence in this application supporting the HQD's tariff that the cost of balancing incremental supply is the same as the cost of balancing for existing generation fleet.

(2) If HQD's data centre load is less than forecast, the current tariff may allocate the full cost of balancing to CB and CD customers, even though other rate classes will benefit from this new supply.

[30] R-4264-2024-B-0015-Dem-Piece-2024_05_31.pdf

2.10 *HQD's Proposed Tariff Does Not Consider the Value of Curtailment for CB and CD Customers*

47. HQD's application attributes no value to the curtailment obligations of the current rate structure, particularly as it relates to the existing CB rate class.

48. As noted previously, the existing CB rate class is required – without any compensation – to curtail demand to 5% of their maximum load for up to 300 hours per year. The curtailment can be requested within 2 hours and can be called upon multiple times on the same day. The extensive nature of that curtailment nearly fully limits the impact of this customer class on HQD's planning requirement, particularly as it relates to non-heritage supply needs.

49. In the R-4307-2025 application, HQD provided a detailed review of its existing assts and its installed capacity to meet peak demand needs in Quebec.[31] The application breaks out the installed capacity between heritage and non-heritage supplies. The installed capacity of the heritage supply is 37,442 MW. We can then compare this number to domestic demand values for 2025.

50. The number of hours where average domestic demand was, on average, greater than the installed capacity of heritage supply was 21 hours in 2025. This number is well below the 300 hours of imposed curtailment on the CB customer class and, as such, limits their impact on the reserve requirement and expansion of the electricity grid to peak demand needs.

51. HQD's filed application provides a value of avoiding the need for new capacity of $166,000/MW-Year (also included in this tariff proposal). Assuming that a CB customers consume in all hours of the year outside of the 300 hours of curtailment, it would have load factor of 96%. Converting the $166,000/MW-Year to a load customer with a load factor of 96% is $19.62/MWh. This represents the per unit value of the rate tariff for existing CB customers and one that could similarly be applied to future CD customers under future contracts if they include similar or related Demand Response obligations. Regarding the proposed tariff, the $19.62/MWh represents a value that should either be provided in compensation or a credit to the energy cost – i.e. the marginal cost value being proposed should be reduced accordingly – for these customers, given it is a value they provide to reduce total system costs by an equivalent amount.

52. Based on the reviews of new large loads cited previously, the value of Demand Response is one of the key drivers of extracting the value of new large loads – these customers will be required to utilize the system when there is surplus capacity and mitigate their impact on peak supply needs. Given that HQ is an

[31] See: R-4307-2025, Approvisionnements en électricité, Page 7 of 20

extreme winter-peaking jurisdiction – its winter peak demand is nearly double that of its summer peak demand – the value of capacity and curtailment is likely significantly higher than in other jurisdictions and should be recognized, particularly as it relates to the existing CB customer class.

2.11 *Dunsky Evidence Insufficient and Flawed*

53. The Dunsky evidence is both limited in its scope and its value in determining whether the proposed CB and CD rate is appropriate or reasonable when compared to other jurisdictions.

54. First, the report – as highlighted by Dunsky – was not a detailed review ("marking exercise" in our translation) of actual rates and tariff structures for data centres, but rather an analysis that relied on public databases and pre-existing data and estimates to "highlight general findings." Importantly, the analysis "does not take into account any special contracts [for data centres] that may exist…" The data centre tariffs the report does provide include a number of jurisdictions that either have no geographic relationship to Quebec (all of the jurisdictions surveyed) or a supply mix that is structurally different (nearly all of them apart from Washington state, which is home to large-scale hydroelectric facilities). Given the significant difference in supply mix for the non-Washington jurisdictions, there is little relevance in comparing these jurisdictions to HQD's tariffs and the relevance of their rate structure to HQD's. The El Paso tariff, for example, shows that there is almost no difference to the data centre tariff compared to the standard industrial rate. In the case of Washington, the proposed data centre tariff is more than one-third below the tariff being proposed by HQD.[32] Overall. it is not clear what value the table provides other than to highlight that tariffs between jurisdictions vary materially and the premium being charged to data centre customers is also highly variable. The table provides no insight into the market structure of the jurisdictions (discussed in more detail below) or the broader context of electricity pricing, system planning or forecasted demand growth.

[32] 6 cents USD converted by 1.35 to CAD is 8.1 cents.

Figure 4 Dunsky Data Centre Tariff

Tableau 1 Coûts moyens (¢/kWh) pour un tarif industriel *grande puissance* et *centre de données*

	Grande puissance *Archétype 1*	Centre de données *Archétype 1*	Grande puissance *Archétype 2*	Centre de données *Archétype 2*	Différences entre Grande puissance et Centre de données
Arizona Public Services *Arizona*	11,16	14,48	11,15	14,47	3,32 (~30%)
Chelan County Public Utility District *Washington*[B]	3,15	6,05 - 8,48[C]	3,15	6,01 - 8,44[C]	2,88 - 5,31 (~168%)
El Paso Electric *Texas*[D]	9,27	9,44	9,26	9,42	0,15 (~2%)

55. The Dunsky report provides a highly limited discussion on the market structure of Quebec compared to other jurisdictions. In US states in particular, there is both a sophisticated secondary market of energy retailers, as well as a growing trend of Corporate Power Purchase Agreements (C-PPAs). C-PPAs allow customers to lock in a portion of their supply needs with a developer or other third party. In 2025, there was as much as 27 GW of capacity contracted to corporate buyers in the US.[33] As a result, the utility rate is not the only option for data centres and other large consumers to manage supply costs, which can rely on alternatives to provide a cost-effective alternative to the utility rate. In contrast, given the market and regulatory structure in Quebec, there is a very limited secondary market of retailers and limitations on what types of C-PPAs can be entered into by medium and large-volume customers (as laid out in Bill 69). The Dunsky report highlights the material differences in market structure in passing, for example, by stating in Virginia that “Some data centers purchase their electricity on the competitive market through alternative providers.” This is a structural difference in market structure that makes a comparison between rates for data centres in the different jurisdictions highly nuanced and can provide a misleading representation of supply costs between HQD and other jurisdictions.

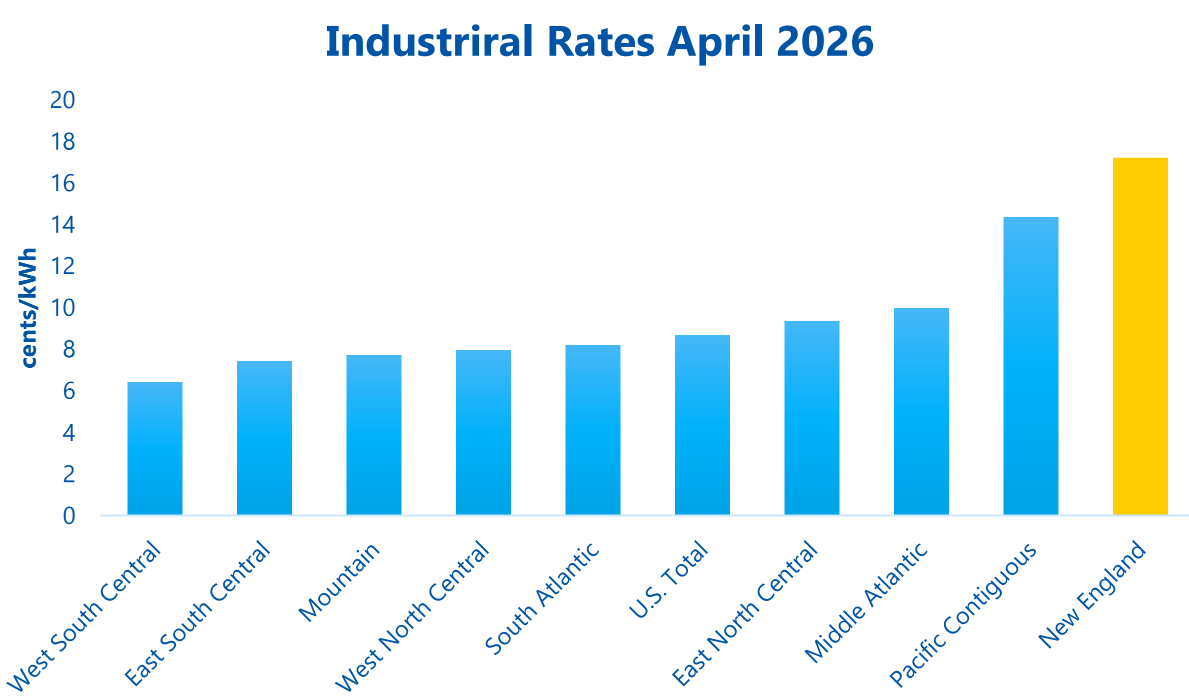
56. When the Dunsky report does provide a comparison of the proposed tariff to other jurisdictions, it considers neighbouring jurisdictions that have either historically had higher electricity rates than Quebec or highlight an assortment of jurisdictions that have materially different supply mixes and

[33] See: CEBA-2026-State-of-the-Market-v4.pdf

market structures than Quebec – or some combination of the two. The neighbouring jurisdictions – as discussed above – also nearly all have highly active secondary markets (i.e. retailers and corporate PPAs), which can materially reduce supply costs compared to the posted utility tariff.

57. The comparison to electricity rates in neighbouring New England states is particularly concerning given that these are states with historically some of the highest – if not the highest – electricity rates in the United States. The figure below plots the industrial rate for the New England states compared to other regions in the United States – highlighting that this region is a high-cost jurisdiction. In using this region as a benchmark to compare the reasonableness of the new tariff, Dunsky is relying on a region that is in many respects an outlier when it comes to electricity costs for large volume consumers (and has been so historically).

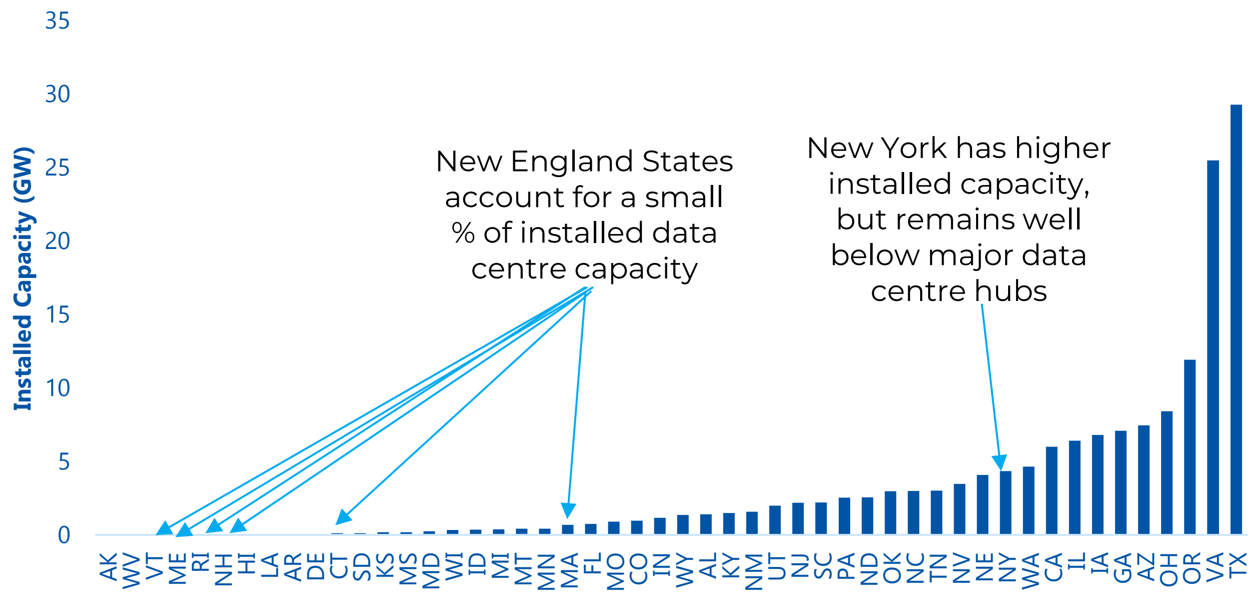
Figure 5 Industrial Rates in the United States[34]



58. Given the high-cost nature of New England and New York, these states account for just 3% of installed data centre capacity as of 2024 – with nearly all of the capacity located in New York, which itself is a small portion of total installed data centre capacity in the US. The figure below provides installed data centre capacity in 2024 based on EPRI data.

[34] See: See: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a

Figure 6 Installed Data Centre Capacity[35]



59. The comparison of electricity rates to neighbouring Canadian jurisdictions is also misleading, as these provinces are either served by a grid that is heavily reliant on high marginal cost thermal resources (in the case of Nova Scotia and New Brunswick) or have policies that allow industrial customers to avoid a significant portion of fixed supply costs through peak demand reductions, as is the case in Ontario. As a result, the rate comparison provides a misleading view of comparable rates to determine the appropriateness of HQD's proposed tariff. HQ's own rate comparison – which is cited by Dunsky as part of its resources – has repeatedly shown that both New Brunswick and Nova Scotia are higher cost jurisdictions compared to nearly all of the hydro-dominated provinces across the country, including Quebec.[36] Given that data centres in particular are a major source of new investment in Canada – and increasingly a focus of economic sovereignty – the relevance of comparing the proposed CB and CD rate to higher cost jurisdictions provides limited value in determining the reasonableness of the proposed tariff and the impact that these customers will have on rates for existing customers.

60. The Ontario comparison is particularly problematic. In Ontario, large – and some medium – volume electricity consumers can qualify for what is known as the Industrial Conservation Initiative (ICI).[37] Participants in the ICI program are provided an incentive to reduce consumption during the highest hour of demand on the 5 days of a year with peak demand (known as the "peak 5"). By reducing consumption, these customers are allocated a smaller portion of the

[35] See: State-Level Data Center Power Data | Powering Intelligence 2026
[36] See: Comparison of Electricity Prices in Major North American Cities 2025
[37] See the Market Surveillance Report for a review of the ICI program: MSP Report - The Industrial Conservation Initiative: Evaluating its Impact and Potential Alternative Approaches (Dec 18, 2018)

fixed supply costs of the electricity system that are not recovered through the wholesale market. These costs are collected from customers through a charge known as the Global Adjustment (GA). What is relevant for this proceeding is that a large majority of industrial customers in Ontario have developed sophisticated processes and invested heavily in a range of different assets in order to reduce their consumption during peak periods and benefit from lower supply costs. As a result, these customers are typically able to avoid a significant amount of supply costs. In 2023 and 2024, the GA charges were $35/MWh and $31/MWh, respectively.[38] In short, these represent supply costs that an industrial customer – such as an existing data center – could avoid by curtailing demand on the highest demand days in a given year. In the same years (2023 and 2024), the average wholesale market price was $28/MWh and $32/MWh. If an industrial customer were to completely avoid GA charges through curtailment during the peak demand events, the supply cost, on average, would be less than $40/MW, as they would be required only to pay the wholesale price and uplifts for supply (in addition to distribution and transmission charges that are not included in this value). In comparing these values to those in the Dunsky report, there is a significant divergence between the realized electricity price for an industrial customer based on the design of the ICI and what is being presented as a comparator value. When asked to confirm whether this approach was reasonable in determining the supply cost for a large customer in Ontario, Dunsky concluded that it was not part of its mandate in this proceeding.

61. And finally, the Dunsky report provides no insight on the value of curtailment that, particularly in the case of CB customers, is provided to HQD as part of the current tariff structure. Dunsky's review of other data centre tariffs concluded that "no active peak erasure obligations have been identified… but this issue is being discussed in some jurisdictions, including Texas." Dunsky did not provide any commentary on whether the value of current curtailment obligations for existing customers (or future load customers) should be considered in setting the new tariff, while recognizing that other jurisdictions are reviewing the issue. Again, based on Dunsky's review it is not clear whether HQD's rate is appropriate when compared to other jurisdictions that are included specific contract or other clauses that may be more appropriate in mitigating the potential that data centres will impose new costs on other rate classes.

[38] See: https://www.ieso.ca/-/media/Files/IESO/Power-Data/data-directory/Global-Adjustment-Components-Costs-Consumption-by-Class.xlsx

2.12 *Supply Shortfall a Result of HQ and HQD Business Decisions*

62. While HQD's application for new CB and CD tariffs points to these customers – data centres in particular – as the key driver of supply costs, HQD makes no reference to other key driver for new supply needs: long-term export contracts to the United States. Beginning this year, HQ has agreed to export more than 19 TWh of supply to US jurisdictions on a firm-basis (i.e. HQ cannot materially reduce these exports without facing financial penalties). HQD's forecast for up to 9 TWh of new supply from data centres is less than half of the amount that HQ is now providing to US customers, which would include data centres and other energy intensive industries. The two long-term contracts in question are:

(1) ***New England Clean Energy Connect (NECEC)*** – In 2019 HQ was successful in a Massachusetts Request for Proposal (RFP) to provide 9.45 TWh of supply annually to New England for the next 20 years. NECEC became operational in the winter of 2025/26. While the contracted amounts to flow on the NECEC are 9.45 TWh, there are additional obligations in a number of the contracts with participating utilities to maintain historical exports from Quebec to New England. As such, the total volumes of supply that are essentially contracted to New England are greater than 9.45 TWh.

(2) ***Champlain Hudson Power Express (CHPE)*** – In 2021 HQ was successful in the NYSERDA Tier 4 solicitation procurement and was contracted to provide 10.4 TWh of supply annually over the next 25 years.

63. Together the two long-term contracts require at a minimum of 19.85 TWh of supply from Quebec to US jurisdictions. While the value of these contracts is not part of this proceeding, publicly available estimates of the contracts highlight that the annual payment for contracted energy is below the \$130/MWh and \$190/MWh that HQD is proposing for data centres and crypto-mining customers, respectively.[39] As noted, the forecast for data centre load by 2035 is currently 9 TWh, which is less than half of the contracted supply on the two contracts to New England and New York.

64. Importantly, these sales may provide limited economic benefit to Quebec in the short-term, while supporting economic activity in neighbouring jurisdictions that will utilize these imports to limit the carbon intensity of their grid and support new load growth. The long-term export sales also reduce the ability of HQ to provide low marginal cost supply to both existing and future customers in Quebec. It should be noted that both of these supply contracts

[39] In the case of NECEC, the energy value is \$51.51 (USD), as shown in D.P.U. 18-64/18-65/18-66 , Exhibit JU-3-A. Page 75 of 87. For CHPE, the initial value is \$97.50/USD, but that will have to net off transmission costs. A high-level estimate of the transmission cost on a \$6 billion USD line (the cost of the line from Quebec to NYC) is anywhere from \$30-\$40/MWh depending on how the tariff is calculated – making the net value to HQ between \$57-\$67/MWh (USD).

were signed at a time when HQD had significant volumes of surplus supply and export sales on a per unit basis provided less value than long-term sales.

2.13 *A Broader Review of Supply Adequacy and Reliability Policies*

65. Quebec is not the only jurisdiction managing the potential impact that hyper-scalers – i.e. data centre customers with loads greater than 100 MW – may have regarding costs for existing ratepayers, as well as reliability obligations and supply adequacy more broadly. As highlighted in the Dunsky evidence, regulatory frameworks and policies regarding rates for data centres are being updated rapidly across North America. HQ, the Regie and the provincial government may benefit from a high-level review on how to manage this risk. The Dunsky report and evidence filed in this proceeding provides little context on whether there is a fundamental change facing electricity grids due to the rise of data centres and what is the most economically efficient way to manage it going forward given the challenges are expected to remain in place for some time.

66. For example, the PJM system operator – which is the largest system operator in North America with a peak demand greater than 160,000 MW (or 4 times that of Quebec) and home to states with high concentrations of data centres – recently released a detailed paper that discussed both the challenges and options regarding data centre load growth and the impact it is having on its system planning and market design options going forward ("Powering Reliability Through Market Design: Addressing Rising Demand and Constrained Supply, and Stimulating Investment To Support Durable Reliability.")[40] The paper noted that over the last two decades – similar to Quebec – the PJM region "managed its electricity system in an era of relative stability" but that "those conditions have fundamentally changed." Importantly, it warned that the transition from "an era of managing surplus to an era of managing scarcity…is anticipated to persist for some time based on current projections, because new generation simply cannot be built fast enough to offset the combined effect of retiring supply and surging demand."

67. Ultimately, the report highlighted that the sudden rise in load growth from data centres may require a fundamental review of the "basic architecture" the electricity market. While HQ's electricity market differs materially than that of PJM's the need for a detailed review remains relevant.

   (1) *"The rapid growth of hyperscale data centers is straining this compromise in a way its designers did not anticipate. The compact's design assumed that new loads would enter the system gradually and*

[40] 20260506-powering-reliability-through-market-design.pdf

in rough proportion to the growth of supply. Today, large loads are interconnecting at a pace that outstrips available supply…"

(2) *"The consequence is a sustained affordability shock that has generated governmental pressure of a different character than occasional scarcity spikes: pressure to revisit the market's basic architecture rather than merely adjust its parameters.* ***That pressure reflects a question that was never considered when the original compact was made: whether loads that impose a net strain on the system's reliability margins – even while paying the going market rate – should have the same standing in the shared pool as loads whose presence preceded the scarcity they now share. (emphasis added)"***

68. As such, PJM system operator took the opportunity to ask fundamental questions facing system operators in the face of rapid demand growth for an emerging sector, such as:

(1) *"Should we preserve the concept of resource adequacy as a common good that is shared by all, also known as the 'shared reliability compact' – and if so, who is responsible for making it financially durable?"*

(2) *"Or should we decide that reliability, in a period of scarcity, must be explicitly rationed? If not all load can be served at the historical 1-in-10 standard, the system must develop the operational capability to prioritize – whether by geography, by customer class or by contractual contribution to supply. This requires acknowledging that reliability is not always a common good shared equally by all."*

69. Importantly for this proceeding, the paper acknowledged that there is a range of different types of data centre customers and their impact on the electricity grid is not uniform. For data centres, in particular, some AI data centres focus on "training", which has "fundamentally different flexibility" profile and characteristics than other types of data centres ("inference"). This flexibility can be used to the benefit of existing ratepayers – as described throughout this report – as it can minimize the impact of system-wide expansion and more effectively utilize existing capacity on the grid. As noted previously, the proposed tariff for CB and CD customers as currently proposed does not explicitly consider the value or flexibility or curtailment and whether this can used to reduce the cost of system expansion.

(1) *"Google estimates that 40% of its AI energy use comes from the training phase. Training workloads have built-in "flex points" at checkpoint intervals, gradient accumulation windows and parallelism strategy boundaries that can tolerate short slowdowns or pauses without compromising the training run's ultimate output*. **These are not**

theoretical flexibilities; they represent real operating practices that sophisticated operators already manage to allow them to reschedule lower urgency computational needs while protecting the highest priority workloads. (emphasis added)"

(2) *"Next-generation data center facilities are being designed with granular, software-controlled load management that can reduce facility demand on a graduated rather than binary basis**. This is qualitatively different from traditional industrial curtailment (which typically means stopping a process entirely): These systems can reduce power by 10%, 20% or 30% in seconds through integrated, coordinated control of workload scheduling flexibility and onsite storage discharge. (emphasis added)"***

70. And finally, the paper highlights that price scarcity may potentially be a more effective tool in managing supply scarcity than administrative pricing, which is largely what is being proposed in this proceeding. Price scarcity may allow for more economically efficient outcomes than the fixed price being proposed by for CB and CD customers.

(1) *"At a certain price point, it becomes economically rational for a sophisticated data center to seamlessly transition to its on-site backup generation, discharge its batteries or throttle its compute load. Just as importantly, it becomes economically rational for these new loads to invest in more sophisticated demand management approaches and more efficient on-site backup generation that could operate more frequently, in periods beyond the most severe grid emergencies."*

71. The current application and evidence does not fulsomely address the important foundational questions that are required today given the known challenges of rapidly increasing demand growth and the difficulty (and cost) of integrating new sources of supply. The PJM study provides an example for the foundational questions that need to be asked prior to upending the regulatory framework in Quebec to mitigate theoretical costs that may be dealt with in other more economically efficient means.

3. Recommendations to Regie

72. Based on my review of the filed evidence, the Regie should consider the following:

(1) Reject the current proposal and instead further consider specific contracted clauses to protect existing customers from the risk that large new data centres will result in higher rates for existing customers, among other options.

(2) In order to formulate a range of contractual clauses, request a detailed review of these clauses in other jurisdictions or undertake an Request For Information (RFI) from potential data centre customers in order to provide insight into what steps or contractual clauses – operational or financial – they will accept (or propose) to mitigate the financial impact HQD's existing customers.

73. In the meantime, if the Regie were to consider implementing a new tariff for CB and CD customers it should consider the following:

(1) Base it on supply costs only, as there is limited evidence on the allocation of transmission and balancing costs. Additionally, HQD has not filed a detailed cost allocation study on how to allocate transmission and balancing costs to the CB and CD rate classes in particular. The base supply cost is $83/MWh and should form the high end of a marginal cost of supply for CB and CD customers.

(2) Consider eliminating the premium between CB and CD tariffs or minimizing it materially. CB customers provide value to HQD customers by consuming (and paying for) consumption during non-peak demand hours and are not contributing to system expansion for new supply or transmission and distribution. In doing so, they are helping to allocate fixed costs across a greater volume of supply without contributing to expanding the system (and the associated costs of that expansion), thus reducing the rates paid by other customers. If the Regie were to approve a CB and CD tariff that is based on the marginal cost of supply, these customers would be paying for supply that they have not required to be developed and should not be allocated a premium.

(3) The mitigation plan should potentially be reworked. First, the term of the mitigation should be done over ten years to account for the timeline for future procurements that will be adding over the next decade. Second, the mitigation should be "back-loaded", meaning rate increases would be lower in the early years and increase over time – allowing these customers the opportunity to invest in energy efficiency and more

closely align with how supply will likely be added to the grid (i.e. slow at first and increasing over time).

(4) The CD tariff should explicitly include some form of Demand Response obligation in return for a lower rate.

(5) The Regie should consider requesting a detailed cost allocation and balancing study to determine an appropriate value for both the transmission and balancing charges that it is incorporating in its marginal supply cost.

74. These comments are submitted respectively.

Brady Yauch, Director Markets and Regulatory, Power Advisory LLC

July 20th, 2026