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April 25, 2025

Alberta Utilities Commission
Eau Claire Tower
1400, 600 Third Avenue S.W.
Calgary, AB T2P 0G5

Attention: Nicole Morter
Director, Electric and Gas Transmission, Rates

Dear Ms. Morter:

Re: ENMAX Power Corporation ("EPC")
Draft Report on Time Varying Rates – Assessment of Costs and Benefits

On March 24, 2025, the Alberta Utilities Commission ("AUC") circulated a draft version of a report (the "Report") titled, "Time Varying Rates – Assessment of Costs and Benefits" for feedback and comments from distribution utilities and the AESO.

EPC's preliminary feedback on the Report accompanies this letter. We appreciate the opportunity to work collaboratively with the AUC and other stakeholders to better understand this issue and we look forward to participating in future consultations.

Should you have any questions with respect to this letter, please contact the undersigned at Dstanghetta@enmax.com.

Sincerely,

Dean Stanghetta

Dean Stanghetta
Vice President, Regulatory

On March 24, 2025, the AUC released a draft version of a report (the "Report") titled, "Time Varying Rates – Assessment of Costs and Benefits" outlining a high-level cost-benefit analysis of implementing time-varying rates for residential and small commercial customers in Alberta. It is EPC's understanding that after finalization of the Report, the AUC will initiate broader engagement to discuss enabling time-varying rates and the steps required to support this potential transition. This will include development of a better understanding of the real-world capabilities and constraints of different stakeholders in Alberta.

EPC supports working with the AUC and industry stakeholders on this initiative and agrees with the AUC on the importance of collaboration and consultation within the wider industry and the next steps outlined in its Report.[1] As the Commission moves forward with this initiative, EPC has identified the following preliminary considerations to help the Commission in its planning.

1. **Establishing a Common Understanding:** A foundational step will be to align industry stakeholders on the concept of time-varying rates across the industry, its costs and benefits and what is feasible in Alberta.
2. **Cost Recovery Mechanism:** Clarity on the cost recovery mechanism is needed before transitioning to time-varying rates. Additional costs, beyond meter data management, such as funding for EPC to install a functional AMI system within the PBR3 term must also be addressed.
3. **Implementation Timelines:** Stakeholders should have an opportunity to provide feedback on realistic implementation timelines. The AUC's proposed three to four-year timeline is aggressive and likely not feasible for EPC without additional funding.
4. **Demand-Side Management ("DSM"):** Consideration should be given to additional utility-managed DSM measures that could substantially enhance the benefits of time varying rates and mitigate against unintended consequences of time of use ("TOU") rates. Each DFO will experience unique operating constraints and customer behaviours that will influence their DSM needs and opportunities.

EPC notes that the above list is not exhaustive and that stakeholders should continue to be given the opportunity to comment on the scope and content of future steps to ensure a smooth transition and implementation of a time varying rate design that will be of net benefit to Alberta customers.

Finally, while EPC supports the initiative and recognizes that there may be a potential net benefit of implementing time varying rates based on the high-level analysis done in the report, it cannot endorse the cost-benefit analysis and timing provided in this Report at this time given the supporting data and financial models were not provided.

EPC elaborates below on some of its key points for further consideration.

[1] Paragraphs 6 and 75.

Costs and timelines of implementing time varying rates

It is important that all costs of implementation for time varying rates, including capital investments in permanent infrastructure and systems are included in distribution facility owner ("DFO") rate base. Ongoing increases in operational costs should also be accounted for. The incremental cost associated with installing AMI is one example of a cost that was not included in the analysis in the Report. EPC will require incremental funding for AMI to meet the three to four-year timeline stated in the report.[2] The transition to 5-minute settlement as part of the Restructured Energy Market technical design will also have an impact on costs and enablement timelines.

Consideration should also be given to the unique nature of each DFO service territory and system requirements and how it would impact costs. Meter data management costs, for example would differ for each DFO. EPC's current estimate anticipates the costs to be at the higher end of the $18 to $75 million range noted by the AUC for a centralized data management system.[3] EPC expects TOU rates will drive greater customer adoption of DERs, requiring upgrades to its operational technology platforms to ensure grid stability with increased dynamic load and microgeneration.

Lastly, rate design for time varying rates should strike the right balance between allowing a utility to recover its revenue requirement, as well as giving customers an incentive to shift their load. Rate design for time varying rates must ensure that cumulatively these rates continue to recover the actual distribution system costs. Rate design would also need to factor in any potential changes in customer behaviour and usage that could affect cost recovery.

Other DSM measures should be concurrently explored

DSM measures aim to modify the timing and/or level of energy consumed by customers to achieve desired outcomes, including energy efficiency and demand response (shifting and/or curtailing load), as outlined in the Guidehouse Net-Zero Analysis of Alberta's Electricity Distribution System.[4] Other research also shows that coupling TOU rates with other utility-managed DSM measures significantly increases benefits to customers.[5]

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[2] EPC application to Review and Vary Decision 27388-D01-2023 under AUC Rule 016, paragraph 5.

[3] Even though the PwC study only considered the costs for centralized management system, EPC notes that AUC will have further consultations on the different options for meter data management (such as a centralized versus decentralized).

[4] Guidehouse Net-Zero Analysis of Alberta's Electricity Distribution System, Section 2.4.

[5] The effect of utility time-varying pricing and load control strategies on residential summer peak electricity use: A review: This study shows that a simple TOU program can only expect to realise on-peak reductions of 5%. TOU program plus DSM measures such as critical peak price program can increase peak load reduction by 30%. https://www.sciencedirect.com/science/article/abs/pii/S0301421510000510#preview-section-introduction

The coupling of TOU rates with other utility-managed DSM measures can also address unintended consequences of TOU rates on electric vehicle ("EV") charging. Studies have shown that while TOU pricing is effective at shifting EV charging into off-peak hours, it can create new and larger "shadow peaks" of simultaneous charging. Other DSM measures, such as managed charging, can mitigate this by preventing excessive simultaneous charging to optimize existing system capacity.[6]

EPC recognizes there is a potential net benefit of implementing time varying rates, but cannot endorse the analysis in the Report at this time

In its Report, the AUC included a high-level and generic assessment of benefits and costs but did not provide the supporting data and financial models from PricewaterhouseCoopers ("PwC") and London Economics Inc. ("LEI").

There is significant potential for improvement in the assumptions used in the Report. For example, the Guidehouse Net-Zero Analysis of Alberta's Electricity Distribution System did not account for scenarios involving space and water heating electrification, which could substantially amplify the results. Additionally, assumptions such as the amount of peak demand reduction required to defer or avoid capital spending require further testing.[7]

As identified by the AUC, wider industry engagement inclusive of retailers is required for implementing time varying rates. These engagements will help establish a common understanding of expected costs and benefits of implementation that takes into account the capabilities and constraints of different stakeholders in Alberta.

[6] Electric Vehicles and the Energy Transition: Unintended Consequences of a Common Retail Rate Design, PDF page 3.
[7] Paragraph 18.