Alberta Utilities Commission (AUC)

Electric Distribution System Inquiry – Combined Module
Proceeding ID 24116

Information Response Round 2 to:
Alberta Utilities Commission (AUC)

<u>Brattle-AUC-2020JUN03-001</u>

Reference: Exhibit 24116-X0512, Pembina responses to preliminary IRs;

Exhibit 24116-X0568, Energy Efficiency Alberta (EEA) written submission;

Exhibit 24116-X0570, Modernizing ATCO's Rate Design (Brattle Report)

Issue: Advanced metering infrastructure (AMI), back-end data processing infrastructure and access to data

Quote: Exhibit 24116-X0512, Pembina preliminary IR responses, PDF pages 9-10:

> "AMI serves several important purposes in allowing retail customers to respond to market conditions. These purposes include: optimizing the use of photovoltaics and storage; shifting loads; and enabling smart EV [electric vehicle] charging. Functions that are enabled through AMI include dynamic rates, feedback on energy usage, and measurement and verification of demand response/storage resources. AMI also allows for better understanding of location, timing, and source of peaks on the system and enhanced granularity and accuracy of load forecasting …"

> "From the customer's perspective, improved granularity can help tailor effective programs by identifying how customers might adjust their net load to avoid demand charges (if those charges are metered at a 15-minute interval). From the utility perspective, more granular measurement can aid in planning for resource deployment."

Exhibit 24116-X0568, EEA written submission, PDF page 40:

> "AMI can provide multiple benefits to utilities and AESO [Alberta Electric System Operator] in managing the grid in a world with higher levels of DER [distributed energy resources] penetration. AMI data can be used in combination with Distributed Energy Resource Management Systems (DERMS) to enable real-time

> monitoring and dispatch of DERs to optimize the balance of distribution assets …"

Exhibit 24116-X0570, Brattle Group report, PDF page 31:

> "There has been continued growth in adoption of advanced meters in the world over the past decade as utilities replace legacy metering systems and modernize their power grids. The deployment of smart meters can lead to both operational and demand side management benefits. Utilities may be able to reduce meter reading costs as well as costs related to disconnects and reconnects or identifying theft, at the same time implementing new rate designs due to the availability of more granular and more frequent consumption data."

Preamble: For the purposes of the IRs in this document, "AMI" means metering devices that are capable of being read remotely at an hourly (or more frequent) interval for both energy and demand.

For the purposes of the IRs in this document, "back-end data processing infrastructure" means the communication networks, head end systems, meter data management systems, and customer information systems, which would allow the meter data manager to collect data from the AMI meters at an hourly (or more frequent) interval for billing. Specifically, this infrastructure would provide utilities and retailers the ability to bill customers based on their actual consumption in the hour, rather than on a load profile allocation based on their monthly consumption.

It is clear from the experience of Alberta's distribution facility operators (DFOs) that the deployment of AMI and the deployment of back-end data processing infrastructure can be implemented separately. Therefore, the Commission is of the view that these elements should be considered separately. Most questions below contain sub-parts prompting the responder to also consider these as separate elements in their responses.

Request:

(a) Do you agree with the benefits of AMI and back-end data processing infrastructure articulated in the quotes above? Can you identify any additional benefits?

(b) Please provide your view on whether widespread deployment of: (i) AMI; or, if AMI is already in place, (ii) back-end data processing infrastructure, is necessary to accommodate the emerging economic and technological forces that may affect the planning and operation of the grid (e.g., the adoption of DERs). What, in your view, is a reasonable timeline for the adoption of either AMI or back-end data processing infrastructure in Alberta, and why?

(c) Please explain what benefits would accrue to customers, beyond those that would accrue to DFOs, from the widespread deployment of: (i) AMI; or, if AMI is already in place, (ii) back-end data processing infrastructure.

(d) Please provide your view as to whether widespread deployment of: (i) AMI; or, if AMI is already in place, (ii) back-end data processing infrastructure, will occur under the existing DFO business incentives and regulatory framework. If so, please state approximately when this might occur.

(e) Are you aware of any jurisdictions that have achieved widespread deployment of: (i) AMI; and/or (ii) back-end data processing infrastructure, without regulatory intervention or legislative directions?

(f) Please explain the benefits and drawbacks of mandated (i.e., through regulatory intervention or legislative directions) deployment of: (i) AMI; or, if AMI is already in place, (ii) back-end data processing infrastructure, for DFOs, customers and any other affected stakeholders.

(g) Please explain the benefits and drawbacks for DFOs, customers and any other affected stakeholders of partial (or narrow) deployment of: (i) AMI; or, if AMI is already in place, (ii) back-end data processing infrastructure (if achievable), as may occur in response to market forces, relative to widespread deployment as may occur in response to regulatory intervention.

(h) Is the deployment of back-end data processing infrastructure an “all-or-nothing” situation? If not, and if there was a partial (or narrow) deployment of: (i) AMI; or, if AMI is already in place, (ii) back-end data processing infrastructure, please explain how distribution and transmission tariffs could be structured so as to make use of AMI data where it is available, even though it may not be universally available. Please comment on setting rate structures that ensure those who benefit from a narrow deployment of AMI and back-end data processing infrastructure are not subsidized.

(i) If deployment of AMI and back-end data processing infrastructure are left to market forces, should customers have the ability to opt in and pay for installation of an AMI meter in order to gain exposure to the related benefits?

(j) Please provide your view as to whether deployment of: (i) AMI; or, if AMI is already in place, (ii) back-end data processing infrastructure, should be mandatory for customers that engage in self-supply and export, for example small micro-generation.[1]

[1] See Exhibit 24116-X470, [Responder]-AUC-2019NOV29-001 and [Responder]-AUC-2019NOV29-003 for additional details and context for small micro-generation customers.

Response:

(a) Yes, in general I agree with the benefits identified above. From the DFO's perspective, a major benefit of AMI and back-end data processing infrastructure would be the automation of meter reading. The Brattle report also identifies additional operational and planning benefits for the DFO that would flow from AMI, including reduced costs associated with disconnects and reconnects.[2] In addition, AMI would provide utilities an opportunity to enhance customer engagement through the provision of detailed information about their energy use patterns and possibly innovative products and services. However, AMI benefits will depend on both market forces and utility planning requirements. For example, the benefits of AMI deployment will be lower when savings for meter reading are already realized through Automatic Meter Reading (AMR).

I would like to note another caveat, that most of these benefits would accrue to residential and small business customers, especially to those located in in dense, urban centers. Non-residential customers, especially customers with sophisticated equipment and infrastructure, would experience fewer incremental benefits from AMI. Thus, the implementation/penetration of AMI would be service territory specific.

(b) Prior to deploying AMI on a system-wide scale in each service territory, it would be best to analyze the benefits and costs of that type of deployment. Commonly, utilities would carry out a pilot study with a select group of customers to study the advantages and drawbacks of AMI deployment on their specific system. This type of pilot is necessary because every distribution system has different technological, geographical economic, and regulatory characteristics. As discussed above, other unique characteristics by service territories must be considered, including geographical density, customer class mix and rate impacts.

It is my understanding that ATCO has been approved by AUC to conduct a pilot to deploy AMI to a small subset of its customers (in Grande Prairie). As with any pilot

[2] Exhibit 24116-X0570, "Modernizing Distribution Rate Design", Faruqui, Ahmad, et al., March 13, 2020.

project, the goal is to test the technology and its capabilities, both from a system planning perspective and a customer perspective. With this in mind, it would be best to review the results of the pilot before making a decision on AMI system-wide deployment.

(c) First and foremost, widespread deployment of AMI and/or back-end data processing infrastructure would provide customers with more information on their energy usage patterns. Furthermore, not only is AMI beneficial for customers, but it would also help the utility understand its customers more. For example, AMI data can help utilities analyze customers' energy usage and identify changing patterns, such as electric vehicle adoption. Such insights can better inform the operational and planning of the system. By increasing access to energy usage information, AMI allows customers to control their energy consumption more readily and easily in a manner that is consistent with their preferences and lifestyles. At the same time, AMI enables utilities (or the electricity market) to implement innovative pricing options. For example, energy providers can offer time-of-use (TOU) and demand charge rate structures, both of which, when accompanied a well-designed customer education and outreach program, can help reduce customer bills.

(d) AMI technology has evolved substantially in the past two decades, and it is now a mainstream metering technology in North America. As older metering equipment reaches the end of its life, it is likely to be replaced with metering equipment that embodies digital capabilities. The time it takes to achieve widespread deployment depends on the "natural" turnover rate, which in turn depends on the network's characteristics, including the age and performance status of existing infrastructure, rate of new connects, among others. For example, a network with aging metering infrastructure may have a higher turnover relative to one with recent upgrades. Business incentives and regulatory framework are of course major factors, and I discuss these in greater detail below.

(e) No. Widespread deployment cannot occur without the Commission or the Government authorizing it.

If, however, the question aims to ask if utilities can take the lead in AMI deployment instead of the regulators, then the answer is yes, and it has happened in several jurisdictions. For example, multiple U.S. utilities have taken the initiative to deploy AMI without being prompted by regulators or legislators. One primary reason for such pro-activeness is that these utilities were able to add AMI-related investment to their rate base, a strong financial incentive.

It is important to note that utilities are not always authorized to proceed with AMI deployment. This usually happens when the net present value of benefits are unambiguously negative.

(f) Mandated AMI and/or back-end data processing infrastructure would accelerate the modernization of the grid and would result in increased access to information for a wider set of customers. However, a benefit-cost analysis is needed to evaluate the prudency of such an initiative. As explained earlier, the benefits and costs of a mandated rollout will differ dramatically by utility and by the categories of benefits and costs being considered. For example, a utility with AMR may already be benefitting from reduced meter-reading expenses, thus lowering the potential benefit to be derived from mandated AMI.

In addition, any benefit-cost analysis needs to consider the specific business incentives associated with deploying AMI and the regulatory framework for doing so. For instance, one major barrier to AMI deployment in Alberta is the unrecovered costs of existing infrastructure. It is my understanding that per the Utility Asset Disposition (UAD) decision, utilities in the province are not able to recover costs related to the infrastructure that will be replaced. Depending on its size, this sunk cost may pose a substantial disincentive for utilities to build out new AMI infrastructure. It is important to note that in other jurisdictions known to me, utilities are allowed to recover the remaining costs of old metering infrastructure as they transition to AMI capable meters. I doubt whether they would have proceeded with AMI without being granted such cost recovery.

Costs related to Information Technology (IT) can be substantial as well, because the utility would need the technology and human resource to build interactive features, including customer billing.

A mandated deployment should only be carried out if a business case has been carried out which shows a positive benefit-cost analysis.

(g) AMI cannot be driven by market forces alone. However, with AMI in place, market forces can play out more effectively. For example, retailers can rely on AMI to produce new products and services that will be more appealing to customers. As customers become more knowledgeable about their energy usage, they will adopt the new products and services which AMI has enabled. To the extent that customers are aware of and have access to different billing items, products can be tailored to different parts of electricity supply (transmission, distribution, energy).

(h) In my opinion, if AMI is shown to be cost-effective, then AMI and/or back-end data processing infrastructure should be deployed universally with customers being given an opt-out option subject to a fee. There are substantial fixed costs associated with AMI deployment which would limit participation if the fixed costs are allocated to a limited customer base. Limited deployment of AMI can result in unrealized benefits. In order for benefits to be fully realized and to reach all customers, universal, widespread deployment of AMI is necessary.

(i) No. This is unlikely to be successful.

(j) As stated above, if AMI is found to be effective for the utility and the customer, it should be universally deployed for all customers.

Alberta Utilities Commission (AUC)

Electric Distribution System Inquiry – Combined Module
Proceeding ID 24116

Information Response Round 2 to:
Alberta Utilities Commission (AUC)

Brattle-AUC-2020JUN03-003

Issue: Access to data

Request:

(a) Please discuss the implications of the ownership rights to customer data, if customers have access to their own data and the data owner and/or customers have the ability to share this data, based on some set of criteria, in a commonly used file format.

(b) In your view, does the lack of access to data create market entry barriers and limit competition? If so, please specify the data required to facilitate market entry and competition. Please discuss whether having access to, for example (i) customer usage information data; or (ii) distribution and transmission system flows and characteristics, would facilitate market entry and competition. If so, how would market entry be facilitated?

Response:

(a) It is common practice among utilities with AMI to adhere to the Green Button initiative, which according to the U.S. Department of Energy allows AMI customers to "securely download their own detailed energy usage with a simple click of a literal 'Green Button' on electric utilities' websites."[1] Customers are able to view their energy data and sell or share the data to a third party if they desire. The energy data is compiled in a common format called Download My Data (DMD) and then the data can be shared with a third party through Connect My Data (CMD).[2] The Green Button is used throughout the U.S., and currently 36 utilities are

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1 Department of Energy, "Green Button: Open Energy Data", accessed June 10, 2020, https://www.energy.gov/data/green-button

2 "Smart Grid in Canada", Natural Resources Canada, 2018. https://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/canmetenergy/pdf/Smart%20Grid%20in%20Canada%20Report%20Web%20FINAL%20EN.pdf

committed to the program.[3] This program is used in Canada as well and is specifically popular in Ontario. By 2018, about 60% of customers in Ontario had access to the Green Button initiative, including small business customers.[4]

(b) Increased availability of individual load data would allow energy providers and energy service companies to identify market gaps and assess their commercial viability of different products and business strategies. This will be done in the service of providing customers with more options to control and reduce their energy usage. By sharing data with third party entities, the customer may receive energy solutions that are tailored to their specific circumstances. For example, a distributed solar company can rely on energy consumption data to evaluate the payback time and overall economic benefits for a potential customer. Similarly, an energy efficiency company can review energy usage pattern to propose the most cost-effective measure for a customer to reduce their bills.

3 Ibid

4 A. Wadhera, J. Ayoub, M. Roy, "Smart Grid in Canada 2018", 2019-066 RP-FIN DER-SGNETS, Natural Resources Canada, April 2019, PDF page 49, https://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/canmetenergy/pdf/Smart%20Grid%20in%20Canada%20Report%20Web%20FINAL%20EN.pdf

Alberta Utilities Commission (AUC)

Electric Distribution System Inquiry – Combined Module
Proceeding ID 24116

Information Response Round 2 to:
Alberta Utilities Commission (AUC)

Brattle-AUC-2020JUN03-004

Reference: Exhibit 24116-X0571, Distribution Inquiry Report prepared by Charles River Associates;

Exhibit 24116-X0570, Modernizing ATCO's Rate Design (Brattle Report);

Exhibit 24116-X0579, Evidence of Ren Orans (E3);

Exhibit 24116-X0575, InterGroup Consultants, on behalf of the Office of the Utilities Consumer Advocate (UCA), written submission;

Exhibit 24116-X0650, Council of European Energy Regulators (CEER) Paper on Electricity Distribution Tariffs Supporting the Energy Transition

Issue: Rate designs that provide for effective price signals

Quote: Exhibit 24116-X0575, InterGroup Consultants written submission, PDF page 20:

> "Distribution costs are fixed costs: Distribution costs are largely fixed in that they do not vary materially in the short-term with energy consumption, unlike some other electricity generation costs such as fuel expense. A near term response to increasing capacity needs in the medium to long-term may however drive higher costs in the future. As noted by Bonbright, capacity costs can be considered variable in the longer-term. While higher proportions of fixed costs appear to address largely fixed costs for capacity in the short term, they provide no price signal for customers to consider measures that may reduce their capacity requirement in the long-term. The concept of variability for capacity costs in the longer term is an appropriate consideration for rate design when this longer-term perspective is considered."

Exhibit 24116-X0650, CEER paper, PDF page 11:

> "The long-run marginal costs of distribution depend mainly on peak utilisation of the network. This implies that tariffs should

include a component reflecting peak utilisation. However, when defining the necessary price signals, there exists an inherent mismatch in time between the infrastructure costs and the network user's utilisation. The infrastructure costs included in present distribution tariffs have already been incurred, and changes in the user's network utilisation will not lead to a reduction or increase in the infrastructure costs already incurred (i.e. residual costs). However, the network utilisation will impact on the need for new network investment and congestion management services. As a result, the part of the distribution tariff related to infrastructure costs is said to have a long-term perspective and is consequently forward-looking. Therefore, the link between present distribution tariffs sending price signals for future infrastructure network costs is necessarily of a theoretical nature, and can be interpreted in different ways across different jurisdictions. In the case of short-run marginal costs, e.g. network losses, it is easier to establish the causality between the network user's behaviour and the resulting costs."

Table: DSO costs

	Present cost			**Future cost**
Cost categories	**Short-run marginal costs**	**Customer specific costs**	**Residual (sunk) costs**	**Long-run marginal costs**
Description	Network losses and variable payment related to DSR	Metering and data processing	Other costs for coverage according to the regulation	Cost for increasing capacity (wire and non-wire option)
Preferred tariff design	Marginal pricing (Energy Time of Use)	Cost-based (Fixed)	Cost-based (capacity, Fixed)	Semi-marginal pricing (Energy Time of Use, capacity peak pricing)

Exhibit 24116-X0571, Charles River Associates report:

"We suggest that several key elements comprise a regulatory framework, particularly as they relate to rate design, to achieve adherence to the principles we advance. Our recommendations apply across the various customer configuration and connection schemes detailed in the AUC's preliminary IRs. These elements include:

- Implementation of three-part rates, including for residential customers deploying DCG [distribution connected generation] and/or EVs, with rates that include fixed, demand, and variable components.

- To the extent that certain customer classes already face three-part rates – or similar rates with reduced emphasis on variable charges – rate structures will likely still need to be revisited to balance the relative size of fixed, demand, and variable charges to reflect costs and send effective signals to lead to efficient investment and operational decisions." (PDF page 9)

"Customers with large microgenerators also tend to be in commercial or industrial rate classes, which in Alberta generally have three-part rate structures (or at least structures with demand charges). The structure of DCG billing and rates appears generally consistent with our stated principles. Without performing any specific cost of service analysis, the prevailing three-part rates shown in Exhibit 7 [below] are more consistent with what we would expect to see in a rate that appropriately differentiates between the fixed and variable costs of providing distribution service." (PDF page 52)

Exhibit 7: Current Example C&I Distribution Rates in Alberta

DER / Rate	Customer Charge	Demand Charge[104]	Variable Charge
ATCO D31 [105]	$0.4923 / day	28.39 cents / kW-day (first 500 kW) 18.72 cents / kW-day (over 500 kW)	n/a
ENMAX D300 [106]	$6.87 / day	4.66 cents / kVA-day	0.48 cents / kwh
EPCOR DAS-MC [107]	$0.95 / day	17.47 cents / kVA-day	0.51 cents / kwh
Fortis Rate 61 [108]	n/a	26.88 cents / kw-day (first tier)	n/a

Exhibit 24116-X0579, evidence of Ren Orens (E3), PDF page 51:

"One example [of cost-based rates] is 'three-part rates,' as illustrated in Figure 13 [below]. The three different parts are meant to recover the costs of serving customer interconnection, capacity and energy. The interconnection component corresponds to the costs of transformers, wires, meters, and other interconnection services and forms a monthly customer charge. The capacity component corresponds to the costs of meeting peak energy demand and is priced as $/kW [kilowatt hour] using a peak capacity allocation methodology. It typically collects the fixed costs of distribution facilities. The energy component corresponds to the costs of providing energy and is priced as $/kWh, ideally with a time-varying rate that reflects the time-dependent costs of generation."

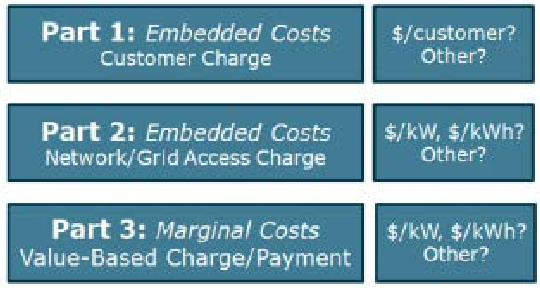

Figure 13: "Three-part rates," an example of cost-based rates.

Preamble: In their submissions, parties to this proceeding pointed out that rate design typically requires balancing competing objectives and principles. Parties pointed out that of all the rate design principles, the principle of economic efficiency appears to come to the forefront. Parties also appear to agree that if the goal is to design rates that support economically efficient outcomes (i.e., results comparable to those produced by competitive markets), then additional emphasis should be placed on setting rates based on underlying costs to produce and deliver the service, and communicating effective price signals to the customer.

Request:

(a) Please comment on the preamble, which concludes that the principle of economic efficiency should be of prominent importance in designing distribution and transmission rates. To what extent can and should distribution and transmission rates be based on the underlying costs to deliver service, so that effective price signals are communicated to the customer?

(b) Do you agree with the statements in the InterGroup Consultants' evidence and the CEER paper (both quoted above) that a wires tariff should balance the need to recover the costs for capacity, which are largely fixed in the short term (arguing for more fixed charges), with the need to provide customers with effective price signals incorporating incentives to reduce their capacity requirement in the long term (arguing for some form of variable charges)? Please provide your views on "balancing" of these objectives, and any rate design challenges in achieving this balance.

(c) **For InterGroup Consultants and Brattle Group only**: Please provide your recommendation on the characteristics of a distribution tariff that would send effective price signals; that is, a tariff that provides incentives to pursue least cost alternatives for (i) price responsive load; (ii) self-supply; and (iii) grid scale generation resources. If you do not have a recommendation, please comment on the merits of the respective tariff recommendations offered by Charles River Associates, E3 and the CEER paper, as quoted above.

(d) Please explain how your recommended tariff design characteristics would balance recovering the infrastructure costs already incurred with sending price signals that will promote efficient, least cost future system infrastructure choices.

(e) Please provide your view on what kinds of information a customer should receive, and with what frequency, to create effective price signals.

(f) Does the mechanism by which price signals are communicated matter? What mechanism would you recommend and why?

(g) Please explain how your responses to (d)-(f) may depend on the state of deployment of: (i) AMI; or, if AMI is already in place, (ii) back-end data processing infrastructure.

(h) Please explain if your responses to (d)-(f) might change if the adoption of DERs was expected to increase.

Response:

(a) Professor Bonbright argued that cost-causation should be the primary principle of rate design. Electricity pricing should reflect the economic cost of providing electricity to customers. Not only does the cost-causation principle promote economic efficiency and equity, it also provides an incentive for customers to respond to price signals, aligning their usage patterns with system conditions. In this formulation, customers consume more electricity when it is least expensive for the utility to produce and deliver. In the long run, this efficient use of the system defers or pre-empt a need for capacity upgrades, leading to lower costs in the long run. Of course, the rate design must also balance cost causation with customer considerations, including simplicity and acceptability. These are described in detail in the Brattle report.[1]

(b) Yes. Utilities should balance the embedded costs (recovered through fixed charges) with the need to provide effective price signals to customers. The latter could take the form of a variable $/kW charge, such as a capacity or demand charge, which would send a signal to customers to reduce their demand. I realize that volumetric charge, expressed as cents/kWh, is widely practiced today for recovering distribution cost. However, that practice needs to change. There is no

[1] Exhibit 24116-X0570, “Modernizing Distribution Rate Design”, Faruqui, Ahmad, Ryan Hledik and Long Lam, The Brattle Group, March 13, 2020.

theoretical justification for having variable volumetric charge to recover fixed costs of distribution.

In addition, utilities in the short run could encourage the adoption of efficient and “smart” appliances. New appliances are more energy-efficient, and they help to lower energy demand. Customers can take advantage of their “smart” capabilities to vary their energy usage patterns to minimize the impact on the grid. For example, customers can program their smart thermostats so that they would be used less frequently during peak hours.

(c) The characteristics of a distribution tariff with effective price signals depend on the system constraints. For example, when there is slack in the system capacity, there is less of a need to encourage peak clipping. But lower off-peak prices can help promote better system utilization. When the system has capacity constraints, higher on-peak prices can help reduce peak loads and flatten load curves. In either case, time-of-use pricing would be helpful though as discussed in Brattle-AUC-2020JUN03-001, the cost/benefit of AMI deployment would also have to be considered. As an example, Consolidated Edison of New York recently introduced the Smart Energy Plan, in which distribution charges differ between peak and off-peak periods. The charges also vary seasonally. Similar rates are being introduced in Australia and New Zealand, as cited in the Brattle report

(d) For DFOs, a fixed charge coupled with a demand charge will balance recovering infrastructure costs with sending the right price signals. The fixed charge will recover the infrastructure costs, while the demand charge will promote efficiency, as it signals to customers to reduce their overall demand.

(e) In addition to a monthly bill, customers should receive information on their hourly loads. Ideally, they would also receive data on their disaggregated load by major appliances and electric vehicles (EV). Such a level of granularity would allow customers to reduce their consumption more effectively. This type of service and technology are relatively new. For example, a company provides appliance end-use load shapes by accessing a customer's AMI data.[2]

(f) Yes. In general, the most simple and readily available signals are the best way to communicate. For instance, customers should be able to access their data on their smart phones, the same way they can check their email or banking information

(g) None of this would be possible without AMI. Even in the case of a firm like Bidgely, which provides granular energy data, they need households with AMI in order to collected sufficient data for their statistics. However, the cost of AMI deployment needs to be taken into consideration as well when assessing the potential net benefits.

(h) In the near term, I would expect no changes. However, in the long term, a dramatic increase in DERs adoption will alter the average customer load shapes. As a result, the rate structures, and price signals, would have to be adjusted to accommodate load shape changes. In my experience, the two-part rate (fixed charges and demand charges) structure is the most robust and would be the most efficient and cost-effective rate option for a distribution utility faced with widespread adoption of DERs.

[2] Bidgely, "Insights Engine", accessed June 10, 2020. https://www.bidgely.com/solutions/insights-engine/

Alberta Utilities Commission (AUC)

Electric Distribution System Inquiry – Combined Module
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Information Response Round 2 to:
Alberta Utilities Commission (AUC)

Brattle-AUC-2020JUN03-005

Reference: Exhibit 24116-X0570, Modernizing ATCO's Rate Design (Brattle Report);

Exhibit 24116-X0650, Council of European Energy Regulators (CEER) Paper on Electricity Distribution Tariffs Supporting the Energy Transition;

Exhibit 24116-X0571, Distribution Inquiry Report prepared by Charles River Associates;

Exhibit 24116-X0640, Fortis response submission

Issue: Dynamic tariffs

Quote: Exhibit 24116-X0650, CEER paper, PDF pages 14-16:

> "Power consumption is not the only determinant of the level of network costs. As the network requires enough capacity for peak consumption, the time-of-use is also important to consider. Time-differentiated 'static' tariffs are characterized by offering different price signals for energy and power, based on discrete time periods (or 'time-bands') that are fixed in advance, possibly differing between relevant locations on the network. This is separate from pure static energy-based or power-based tariffs, which don't send signals to users about the times when they are causing costs on the system. Both the energy and the power component of the tariff can be time differentiated using time-of-use principles.
>
> Generally, with time-differentiated static tariffs the time periods and the price signals themselves do not change for several years. Relatively short time periods targeting expected peak hours may be implemented, with some variations depending on the voltage level and the delivery point. Time-differentiated static tariffs offer a reasonable balance between efficiency and complexity, but lack the most desirable advantage of dynamic tariffs, i.e. short-term changes in prices, reflecting the actual network conditions. This is especially true when actual critical peak hours are highly volatile.

…

Improvements in the available information about the real-time status of the network and the consumption of each individual customer make it more realistic to implement dynamic tariffs. A dynamic tariff means that the price signal is defined at shorter notice, possibly close to real-time. This contrasts with static tariffs, where the price signals are associated with predetermined time periods. Dynamic tariffs are one way that DSOs [distribution system operators] could make use of flexibility to avoid or defer reinforcement, which is due to increasing intermittent production and variation in consumption/load. One way of implementing dynamic tariffs is through a critical peak price (CPP).

The objective of a dynamic network tariff is to promote more efficient network use under a scenario where network use has become more uncertain (e.g. due to intermittent production or new consumption patterns) and where new technological solutions are enabling demand response (smart meters, automation, storage). Being dynamic, the price signals can be sent closer to real time, increasing the cost-reflectiveness of the network tariff, which should achieve a more cost-efficient system, benefitting all network users.

A dynamic network tariff should not be confused with the dynamic electricity price contracts envisaged by Electricity Directive (2019/944) or other forms of valuing flexibility. Dynamic electricity price contracts reflect the price variation in the wholesale spot markets, including in the day-ahead and intraday markets. Thus, they are designed to send scarcity price signals about the matching of supply and demand on the wholesale market (at system level, due to system marginal price), independently from the scarcity that may occur locally in the distribution network.

A truly dynamic end-user price is the sum of a dynamic network tariff and a dynamic (spot market) electricity price. The sum of the two price signals would enable the consumer to decide at each moment how much to consume for a given price. Obviously, the two price signals would not always be aligned since they are measuring scarcity on different levels: while a dynamic retail price measures scarcity in the wholesale market at system level (which could be regional, encompassing several countries), the dynamic network tariff measures scarcity on the distribution (or transmission) network at a local level."

Exhibit 24116-X0571, Charles River Associates, PDF page 14:

"Economically efficient utility rates are ones that discourage wasteful investment and encourage efficient consumption of utility services. Rates set to provide these goals help to diminish

> the risk of excess utility investment relative to consumer demands (leading to stranded costs) and guide investment in long term assets up to where consumers' demand is met (with sufficient capacity reserves). For instance, rates that are set below marginal costs will only encourage wasteful investment by encouraging consumers to use services that are priced below their cost-based value. This, in turn, creates losses at the utility level that must be recovered from all consumers. Although marginal-based costs are the most efficient way to incentivize economically efficient buying behavior, setting rates entirely on a marginal cost basis will not provide a sufficient level of cost return for the utility and, in turn, will violate capital attraction need. Marginal costs, however, can be used as a guide in pricing."

Exhibit 24116-X0570, Brattle Group report:

> "Alternatively, the timing and price level of peak periods may vary depending on coincidence with system peaks, a pricing structure known as critical peak pricing (CPP). Under the CPP design, the peak price would be significantly higher for the limited number of days during which the system load is the highest – typically 10 or 15 days out of the year. The peak time rebate (PTR) is similar to a CPP. Rather than charging customers a higher rate during peak events, PTR provides customers with a payment for reductions in consumption below a predetermined baseline. Real-time pricing (RTP), a more dynamic pricing option, provides customers with either an hourly or sub-hourly price. While each of these dynamic pricing options has been used by utilities to reflect variation in energy prices or the cost of generation capacity, they could also be applied at the distribution system level to reflect distribution system capacity constraints (though we are not aware of the utilization of this approach by any utility as of yet)." (PDF page 12)

Figure 3: Elements of Volumetric Charges

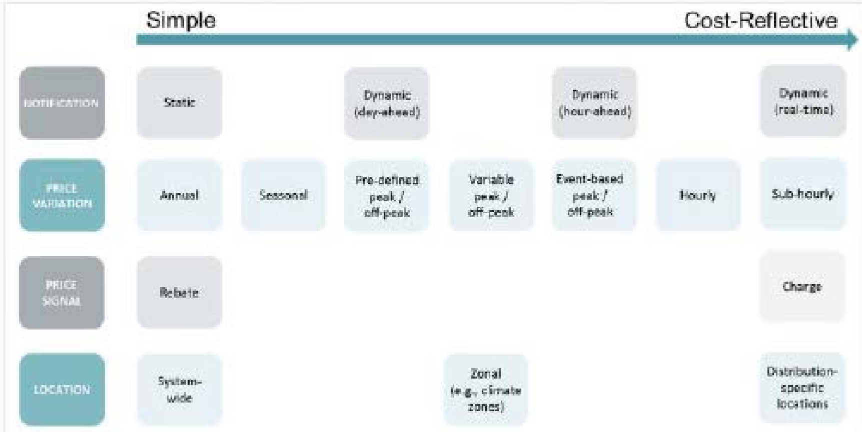

Figure 4: Elements of Demand Charges

Figure 5: Elements of Fixed Charges

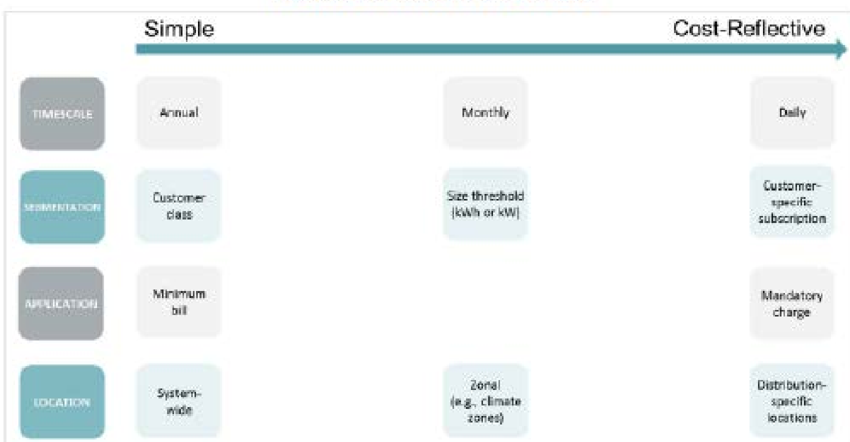

Exhibit 24116-X0640, Fortis response submission, paragraph 16:

> "FortisAlberta acknowledges and is generally supportive of the report entitled '*Modernizing Distribution Rate Design*' commissioned by ATCO and prepared by the Brattle Group, but

> would like to provide some comments on a couple of positions based on its own experience. The report states that a customer load at the time of coincident peak (CP) reflects costs. From FortisAlberta's experience this statement is incorrect. Distribution costs do not change based on use during any given hour. The system is designed based on a large number of factors (i.e., voltage drop, customers requested capacity requirements at time of construction, standardized sizes of transformers and wires, etc.). Secondly, the report focuses on energy consumption during different periods of time (i.e., time of use rates), but does not discuss having different demand charges for different periods of time. FortisAlberta uses on-peak and off-peak demand in its cost allocation studies. From FortisAlberta's perspective, rates could be designed for on-peak and off-peak demands which could be very helpful to incent EV charging on off-peak hours. However, this cannot happen until residential meters can measure demand as well as energy."

Preamble: For the purposes of the IRs in this document, the Commission adopts the definition of "dynamic tariffs" (or "dynamic pricing") as expressed in the CEER paper referenced above. Namely, "that the price signal is defined at shorter notice, possibly close to real-time" and varies with the marginal cost of distribution and transmission system delivery to the customer. The Commission considers that the CEER paper makes a useful distinction between dynamic tariffs and "time-differentiated static tariffs," which are "characterized by offering different price signals for energy and power, based on discrete time periods (or 'time-bands') that are fixed in advance, possibly differing between relevant locations on the [system]."

The Commission notes that several examples of dynamic tariffs were described by the Brattle Group (i.e., critical peak pricing, peak time rebates, and real-time pricing.) It also provided a "spectrum" of tariff options that might rely on volumetric, demand or fixed charges. These are quoted above.

For the purposes of this question, the responder may assume that any form of dynamic pricing would be based on the marginal cost of delivering an additional unit of energy to a location during a specific time interval. The responder may also assume that any form of dynamic pricing would be paired with some form and amount of fixed charges to ensure full cost recovery for the sunk costs of the system being priced.

Request:

(a) Please comment on the quoted passages from the CEER paper in the preamble above. In particular, please comment on its applicability and relevance to pricing distribution systems in Alberta.

(b) Please comment on the feasibility of dynamically pricing the costs of the electric distribution and transmission systems at this time. Please specify if dynamic pricing can be reasonably implemented either temporally (i.e., prices based on the system-wide marginal cost of delivering an additional kWh during a specific time interval), locationally (i.e., prices based on the marginal cost of delivering an additional kWh to a location) or both (i.e., prices based on the marginal cost of delivering an additional kWh to a location during a specific time interval).

(c) Please provide your view on whether it is more important to vary prices over time or across locations for distribution and transmission tariffs. Please explain the extent to which your view is affected by the feasibility of implementation, and why.

(d) Please comment on the feasibility of dynamically pricing (either temporally, locationally or both) the costs of the electric distribution and transmission systems based on demand charges, rather than volumetric charges.[1]

(e) Please comment on whether volumetric-based dynamic prices are preferable to demand-based dynamic prices, or if the two approaches may be complementary.

(f) Please provide any relevant examples of jurisdictions that price distribution and transmission systems dynamically, and for which customer classes.

(g) Would you recommend dynamic pricing for distribution and transmission tariffs for all customer classes in Alberta? If so, please explain your recommendation in the context of the spectrum of possible options provided by the Brattle Group (quoted above).

(h) As an alternative, should dynamic pricing be contemplated only for large commercial and industrial customers that already have the necessary metering infrastructure installed?

(i) If full dynamic pricing were adopted (i.e., real-time pricing of distribution and transmission systems temporally and locationally), would this remove the need for any investigation into the “value proposition of DERs,” as has been recommended by several parties?[2] Why or why not?

(j) Please compare the effectiveness and desirability of different tariff approaches, including dynamic pricing, as an alternative to contracting for grid services from DERs for the provision of grid services and non-wires alternatives.

[1] Please note that for the purposes of this question, the Commission reminds parties of the distinction made in this document between “dynamic pricing” and “time-differentiated static tariffs” set out in the preamble to this IR, where the rates referenced by Fortis in the quote above might be better characterized as time-differentiated static tariffs. For this question, the Commission is referring to a tariff structure where the price applied per kW fluctuates based on the marginal cost of supplying that demand (either instantaneously or over a narrowly defined time period). The band over which the price might fluctuate would be set through a regulatory process, but for the purposes of this question can be assumed to be any non-negative rational number.

[2] See, for example, Exhibit 24116-X0634, paragraph 51.

Response:

(a) Tariff design involves making several trade-offs amongst competing objectives. The more complex rate designs would do a better job of reflecting cost causation than the less complex ones, but they are also likely to cause customer confusion and possibly consternation. Dynamic pricing of distribution charges might be difficult for most customers to grasp for the next several years. It could yield incremental benefits that exceed costs, but that proposition should be quantified by carrying out scientifically designed experiments or pilots. Until such time, it would be best to recover distribution costs through a combination of fixed and demand charges. The next step would be to introduce time variation in the demand charge. The final step would be to introduce dynamic demand charges but that should only be done after pilots have been carried out. It is my understanding that in Alberta, customers get a single bill from the retailer, but it does show energy and distribution charges separately. Thus, if dynamic pricing is offered for distribution systems, it would be possible to show it as a separate line item in the bill.

(b) Locational variation in demand charges could be introduced if two conditions are met: (1) there is a cost basis for it, and (2) customers can understand the reasons for why some of them have to pay higher charges than others.

There is a large body of literature on the benefits of dynamic pricing for energy consumption, and much of it comes from regions where all charges are bundled into a single element. However, there are cases when the time varying charge only applies to the energy portion of the bill, such as Ontario. In theory, these benefits may apply to the electric transmission and distribution systems as well, but because every system is different, a cost of service study and/or a pilot study must be conducted first to ascertain the prudency of such a program. For instance, if a network does not experience significant congestion issues, then a simple time-of-use structure may be adequate. I am not aware of a transmission or distribution company with a market structure as seen in Alberta that currently implements dynamic pricing. At the same time, AMI remains a major technological barrier – it is simply not feasible to implement dynamic pricing without AMI. The apparent benefits of dynamic pricing must also consider the incremental cost of AMI where it is not currently available.

(c) It is not possible to answer this question without conducting an empirical study on the topic. The answer will vary by jurisdiction.

(d) Since distribution and transmission costs do not vary with the volume of electricity flowing through the wires, but they do vary with the capacity imposed on the system by customer load, it would be best to offer dynamic pricing based on demand charges rather than volumetric charges.

(e) Demand-based dynamic pricing is preferable to volumetric based dynamic pricing for distribution and transmission systems.

(f) I am not aware of any such examples.

(g) I would recommend time-varying tariffs for all classes with the appropriate metering. But the tariffs should be based on a cost-of-service study.

(h) Dynamic pricing of transmission and distribution costs based on demand charges should be instituted for large commercial and industrial customers if there is sufficient cost justification for it. It should also be considered for residential customers once smart meters have been installed

(i) No, it would not. In my view, rate design should be based on cost of service and not on value of service. If distribution and transmission systems are priced through a combination of a fixed charge and demand charge, possibly with some locational variations, there would be no need to analyze the value of DERs. On the other hand, if the province wants to promote DERs, a cost-benefit analysis should be carried out, just like it would be carried out for an energy efficiency investment. If the analysis yields a net present value, then the best way to proceed would be to provide in rate design financial incentives to customers that would lower the lifetime costs of the DERs.

(j) Dynamic pricing could be a valid alternative to contracting for grid services from DERs, but a study would need to be done on comparative technical feasibility and economics of DERs versus other grid solutions.

Alberta Utilities Commission (AUC)

Electric Distribution System Inquiry – Combined Module
Proceeding ID 24116

Information Response Round 2 to:
Alberta Utilities Commission (AUC)

<u>Brattle-AUC-2020JUN03-006</u>

Reference: Final report for Proceeding 22534, Alberta Electric Distribution System-Connected Generation Inquiry;

Decision 22942-D02-2019,[1] 2018 ISO (Independent System Operator) Tariff Application

Issue: Distribution-connected generation (DCG) credits

Quote: AUC final report for Proceeding 22534, paragraph 277:

> "The AUC observes that because the AESO does not provide a credit to the distribution wire owners for reduced transmission system costs due to DCG, the distribution wire owners that provide this credit today must recover the cost of this credit from all of its distribution customers. This amounts to a cross-subsidy from non-DCG customers to DCG customers."

Decision 22942-D02-2019, paragraph 787:

> "The Commission observes that there is evidence on the record of this proceeding on the cross subsidy created by DCG credits and the resulting transfer of transmission costs to load customers without a corresponding reduction in the actual cost of the transmission grid, requiring recovery in the ISO tariff. Nevertheless, the Commission agrees with parties that the continuation of DCG credits is a distribution tariff matter. Further, an examination of the claim by the DGWG [Distribution Generation Working Group] that there are significant differences in the characteristics of 'dispatchable' and 'non-dispatchable' forms of DCG warranting the continuation of DCG credits for certain types of generation should be included in any future examination of the continued availability of DCG credits."

[1] Decision 22942-D02-2019: Alberta Electric System Operator, 2018 ISO Tariff Application, Proceeding 22942, September 22, 2019.

Request:

(a) To the extent you are familiar with the DCG credits offered by the DFOs to DCG in Alberta, please provide your view on whether you agree or disagree with the Commission's prior observation on the current design of DCG credits.

(b) Based on your knowledge of other jurisdictions, please provide any relevant examples where DCG is compensated for avoiding distribution or transmission system upgrades or replacements, based on their location, that you would recommend Alberta consider.

Response:

(a) As structured, the DCG credit does create a cross-subsidy problem. Whereas, DCG customers receive a credit, the revenue requirement for non-DCG customers does not change. A demand charge on distribution rates should be able to mitigate this problem. However, it would not address the revenue deficiency that occurs at the transmission level. Because distribution wire owners with DCG do not enjoy the same credit – even though they too can help reduce transmission system costs – the subsidy can also be seen to exist between the distribution customers paying the subsidy and other transmission customers who benefit from any avoided costs. In that regard, it is important to note that the benefit of system upgrade avoidance or deferral associated with DCG is smaller if the system has a lot of slack in capacity.

(b) Commonwealth Edison in Illinois offers compensation for DG behind the meter, which comes in the form of a rebate for avoided costs. They have paid $2.5 million in the first half of 2019 to compensate C&I customers with DG, with a rate of $250/kW of installed solar.[2] Additionally, Consolidated Edison in New York implemented a demand-side management project in Brooklyn Queens, providing customers with energy efficiency and conservation incentives. The project is not directly related to DCG, but it does lead to significant benefits stemming deferred substation upgrades, saving the utility $1 billion in upgrade costs.[3]

[2] ComEd Press Release, "More ComEd Customers Going Solar", July 18, 2019, https://www.comed.com/News/Pages/NewsReleases/2019_07_18.aspx#:~:text=ComEd%20has%20paid%20%242.5%20million,of%20installed%20solar%20power%20capacity.

[3] "The non-wire alternative: ConEd's Brooklyn-Queens pilot rejects traditional grid upgrades", UtilityDive, August, 3, 2016, https://www.utilitydive.com/news/the-non-wire-alternative-coneds-brooklyn-queens-pilot-rejects-traditional/423525/

Alberta Utilities Commission (AUC)

Electric Distribution System Inquiry – Combined Module
Proceeding ID 24116

Information Response Round 2 to:
Alberta Utilities Commission (AUC)

<u>Brattle-AUC-2020JUN03-007</u>

Reference: Exhibit 24116-X0640, Fortis response submission;
Exhibit 24116-X0619, ENMAX response submission;
Decision 24747-D01-2020,[1] ATCO Electric Ltd., 2019 Distribution Tariff Phase II Application

Issue: Rate classes

Quote: Exhibit 24116-X0640, Fortis response submission, PDF page 11:

> "25. Consistent with the Company's view in its submission, customers across all rate classes, including future DER customers, all share and use the same integrated system. In the future, distribution ratemaking should transform over time to reflect the integrated nature of the distribution grid and cost causation driven by customers' capacity size requirements rather than end-of-use demand.
>
> 26. Based on the above, the Company took the initial step to transition to capacity-based distribution rates in its recent Phase II DTA [distribution tariff application], where the Company further unbundled its distribution system costs into Shared System, Local Facilities and Customer Service Costs, based on classification of the system (as either: non-coincident peak (NCP) demand (annual or monthly), energy, customer service, or distance related). This approach aims to create a single wires distribution rate for all distribution load customers over a period of transition."

Exhibit 24116-X0619, ENMAX response submission, PDF page 9:

> "… EPC [ENMAX Power Corporation] could envision the situation where an underground cable needs to be replaced due to a fault forcing EPC to allocate hundreds of thousands of dollars in costs to a relatively small group of customers, which will potentially cause rate shock. Similar to people challenging their property assessments, EPC would likely need to create and administer a process to address numerous complaints and

[1] Decision 24747-D01-2020: ATCO Electric Ltd., 2019 Distribution Tariff Phase II Application, Proceeding 24747, April 30, 2020.

> challenges it would receive from implementing individual customer rates leading to further increased costs. This rate design could have other socially undesirable knock-on effects such as potentially reducing property values in older neighbourhoods where risk of cable replacement is high."

Decision 24747-D01-2020, paragraph 189:

> "Therefore, the Commission approves, as filed, Price Schedule D23 for the EV Fast Charging Service rate to be included in ATCO Electric's price schedules, on a pilot basis. ATCO Electric is directed to provide a detailed analysis of the EV Fast-Charging Service rate class, including but not limited to the uptake of customers in the rate class and the load factors for this rate class, in its next Phase II application."

Request:

(a) Please provide your view on whether the current approach to defining rate classes, which is typically based on end-use rates in Alberta (e.g., residential, farm, commercial, industrial), should be reconsidered, as contemplated by Fortis.

(b) Please comment on if (and how) the definition of rate classes might influence the adoption of DERs by certain customers.

(c) Please explain if your response to (a) might change depending on the level of deployment of: (i) AMI; or, if AMI is already in place, (ii) back-end data processing infrastructure.

(d) Please explain how your response to (a) might change if the adoption of DERs was expected to increase.

(e) How might concerns such as those raised by ENMAX be addressed if rate classes were restructured based on end-use?

(f) Please provide your view on whether the capacity size requirements and expected load profiles of direct current fast charging stations for EVs (Level-3 chargers) merit consideration of individual rate classes and tariffs, comparable to ATCO Electric's pilot rate of D23, approved in Decision 24747-D01-2020 and referenced in the quote above.

Response:

(a) Rate classes should still be defined by end-uses, such as residential, commercial, and industrial. However, within each end-use, a two-part rate should be used: a fixed charge and a demand charge.

(b) It is best to influence the adoption of DERs through non-tariff mechanisms, such as tax credits, rebates, and low interest financing, rather than through rate design. Rate design should be based on costs and should not be redesigned to encourage or discourage any particular technology.

(c) No. It does not involve tariffs, instead it is related to financial mechanisms

(d) My response to (a) does not change if the adoption of DERs was expected to increase.

(e) It depends. There are many factors at work, and a benefit-cost analysis should be carried out to answer the question.

(f) A rate class for a customer group depends on characteristics of that group, including total energy usage, load profiles, delivery voltage, metering characteristics, and other important drivers of service. To the extent that it is possible and practical to implement, rate structure for a particular class should adhere to the cost-causation principle that I previously describe. For DCFC stations, a pilot program and subsequent benefit-cost analysis can provide insights into what factors should be considered.

Alberta Utilities Commission (AUC)

Electric Distribution System Inquiry – Combined Module
Proceeding ID 24116

Information Response Round 2 to:
Alberta Utilities Commission (AUC)

Brattle-AUC-2020JUN03-008

Reference: Exhibit 24116-X0578, Fortis written submission;
Exhibit 24116-X0576, Pembina Institute written submission;
Exhibit 24116-X0561.01, Community Generation Working Group (CGWG) written submission

Issue: Grid services provided by DERs

Quote: Exhibit 24116-X0578, Fortis written submission, PDF page 41:

Figure 8: NWA Value Stack

Exhibit 24116-X0576, Pembina written submission, PDF page 20:

> "Energy storage and smart inverters can provide advanced services such as frequency regulation, and Volt-VAR support. A broad set of resources, including solar, storage, energy efficiency, and flexible loads can provide relief for localized capacity needs, reducing or deferring the need to upgrade distribution transformers or build out new substations to meet growing needs. Energy storage, smart inverters, and flexible loads can potentially be used to mitigate reverse power flows or over-voltage conditions from DERs and help increase local hosting capacity."

Exhibit 24116-X0561.01, CGWG written submission, PDF page 8:

> "Equal Access for New Technology – new technologies should be able to provide all services to wholesale markets and distributors that they are technically capable of providing, regardless of fuel or technology type, and should be compensated based on the value they provide to customers."

Request:

(a) In contrast to the grid services from DERs quoted above, please explain which services transmission-connected generators are compensated for providing, and which are, either explicitly or implicitly, part of their connection requirements.

(b) For the grid services that could be provided by both DERs and large transmission-connected generators, should DERs be compensated for any services for which transmission-connected generators are not compensated? Why or why not?

Response:

(a) This response is intentionally left blank as the focus of Brattle's report/engagement was on rate design and price signals.

(b) This response is intentionally left blank as the focus of Brattle's report/engagement was on rate design and price signals.

Alberta Utilities Commission (AUC)

Electric Distribution System Inquiry – Combined Module
Proceeding ID 24116

Information Response Round 2 to:
Alberta Utilities Commission (AUC)

Brattle-AUC-2020JUN03-009

Reference: Exhibit 24116-X0556.01, Alberta Federation of Rural Electric Associations (AFREA) written submission

Issue: Markets and regulation

Quote: "*Custody transfers at the meter*

27. AFREA submits that the ownership of the energy needs to be considered by the Commission as a principle. In particular, AFREA submits that the care and custody of electric energy is an issue squarely at the heart of this inquiry: who owns the energy and at what stage?

28. As the energy is produced, utilized, and possibly stored, it is imperative the ownership of that energy is known, and that the regulatory framework can outline this. As the energy crosses the meter, the custody changes hands. If the consumer is producing the energy, it is within their care and control. If the consumer decides to send their excess energy back to the grid, then they would be relinquishing that custody. However, the utility cannot be allowed to 'reach behind the meter' and claim ownership or custody of that energy.

…

AFREA Recommendations to achieve greater neutrality

88. AFREA submits it is important to regulate the installation concept and the location of the metering. As discussed earlier in this Submission, ownership and custody are important considerations, especially as it pertains to storage. There is value in the energy produced, and the utility should not be able to reach behind the meter and claim ownership of the stored energy.

90. As consumers install the generating equipment, storage equipment, and upgrades to their metering to allow for two-way flow,

> then the consumer is in the ownership and custody of that power until it crosses the meter back to the grid.
>
> …
>
> *Size of the consumer is significant*
>
> 31. AFREA submits it is important for the Commission to recognize the differences between small generators and large generators. The size of the consumer is crucial: a fair balance needs to be found when creating the regulatory framework for the emerging technologies. AFREA notes that there is a significant difference between a 150kW threshold for small generation and a 1MW [megawatt] generator versus a 5 MW generator. These distinctions have a practical outcome and directly impact the scale, cost, and management of the project. For example, creating an energy management plan for a large generation facility (like a production plan) is more cost efficient and easier to maintain than it is for a small generator. The impact on the grid and for the consumer is more difficult to manage for a small generator."

Request:

(a) Please comment on the statements from AFREA quoted above regarding the importance of the location of the meter, and that the custody transfer of energy accessed or egressed from the grid should take place at the customer meter.

(b) Regarding pricing energy exports to the Alberta Interconnected Electric System (AIES), to what extent should the system operator and/or regulator define the desired services (such as energy, reliability and ancillary services) and set a consistent mechanism to price the provision of those services, regardless of the source of the energy or the point (i.e., distribution or transmission) that it enters the AIES?

(c) Please comment on the statements from AFREA quoted above regarding the regulation of various sizes of generators. Can the size of the generator (or the average net export to the AIES if the generator engages in both self-supply and export) result in certain market outcomes that may necessitate regulatory intervention?

(d) Considering your response to the previous set of questions, what metering configuration would you recommend? Some examples may include:

    (i) One bi-directional interval meter for tariffs and settlement for those connected to the grid, regardless of whether they are considered "load" or "generation" or a combination of the two.

(ii) One interval meter for tariffs and settlement dedicated to on-site load and a separate meter dedicated to generation, regardless of whether they are considered “load” or “generation” or both.

(iii) One bi-directional interval meter for tariffs and settlement for those connected to the grid, regardless of whether they are considered “load” or “generation” or both, but a second meter dedicated to gross generation for visibility purposes for the system controller and other market participants.

(e) With respect to your response to (d) above, please comment on how the installation and operating costs of the meters factor into your recommendation. How should the costs of your recommended option be recovered?

(f) Do your answers to (a)-(d) above depend on the type of load or generation resource that is connected? In particular, please consider in your response energy storage projects in any configuration, including those connected to load, other generating assets or as stand-alone resources.

(g) If a customer pairs an energy storage resource with any other generation assets, what are the benefits and drawbacks for different stakeholders to treating the resources separately in terms of metering, instead of requiring only one bi-directional interval meter for the customer that would recognize only that energy is flowing past the meter, but not the source from which it was generated?

(h) A number of parties commented on how rules concerning who is permitted to own storage projects might affect the wholesale electricity market. Please provide your views on how energy storage ownership rules might affect the ancillary services market, including market power issues that may arise.

Response:

(a-h) This response is intentionally left blank as the focus of Brattle’s report/engagement was on rate design and price signals.

Alberta Utilities Commission (AUC)

Electric Distribution System Inquiry – Combined Module
Proceeding ID 24116

Information Response Round 2 to:
Alberta Utilities Commission (AUC)

Brattle-AUC-2020JUN03-010

Reference: Exhibit 24116-X0561.01, CGWG written submission;
Exhibit 24116-X0576, Pembina written submission;
Exhibit 24116-X0578, FortisAlberta written submission;
Exhibit 24116-X0595, Lionstooth written submission;
Exhibit 24116-X0597, AltaLink written submission

Issue: Grid planning and operation

Quote: Exhibit 24116-X0561.01, CGWG written submission, PDF page 19:

> "System planners must evaluate how the current system will respond to the forecasted needs of customers, including where new demand will arise (new connections) and where existing demand may decrease, or consumption/use patterns may materially change. As the penetration of DERs increases, they will contribute to the changing use of the electricity system and will therefore need to be integrated into the forecasts planners use and the solution sets they design."

Exhibit 24116-X0576, Pembina written submission, PDF page 29:

> "It is important that an integrated distribution planning process include open and collaborative engagement from a variety of stakeholders (consumers, businesses, environmental advocates, project developers, TFOs [transmission facility owners], DFOs, and the AESO) at each step in the process. Meaningful engagement includes the opportunity to provide input on methodology and process to ensure fair and transparent decision-making."

Exhibit 24116-X0578, FortisAlberta written submission, PDF pages 23, 24, 25:

> "On an annual basis, FortisAlberta updates the distribution system power flow models and local area load forecasts utilizing metered annual feeder peak load incorporating individual large customers' capacity requirements. Distribution system capacity needs and reliability needs are identified based on metered peak loads. Solutions to these identified needs are then

> determined through a local area study which considers distribution and transmission solution alternatives, or a combination thereof. Technically acceptable solution alternatives are then compared to determine the most cost-effective solution.
>
> …
>
> Only when these identified distribution needs require upgrades to the transmission system does the DFO make an application to the AESO. The AESO then, through a collaborative process with the DFO and TFO, ultimately determines the preferred transmission alternative to address the identified distribution system need.
>
> …
>
> Traditional distribution planning will need to evolve to encompass the integrated planning needs of the transmission and distribution systems to ensure that capacity, reliability, energy and market needs are all addressed in parallel."

Exhibit 24116-X0595, Lionstooth written submission, PDF page 8:

> "In our view, the most pressing regulatory issue is the need for a collaborative, integrated approach to planning the electric system, that involves all customers and market participants in defining the level of service required from utilities, and subsequently the assets best suited to provide that service."

Exhibit 24116-X0597, AltaLink written submission, PDF page 5:

> "… [T]he power system should be evaluated on an integrated basis to ensure that there is cost effective investment throughout the power system."

Request:

(a) Do you have any recommendations for improving the coordination of transmission system and distribution system planning? Ideally, to what extent, and at what time, if any, should the regulator get involved, ignoring any potential jurisdictional impediments?

(b) Considering the current approach to distribution system planning in Alberta, as summarized by Fortis in the above quote, are you aware of any jurisdictions where the transmission system operator (e.g., ISO) is involved in distribution system planning to a greater extent than in Alberta (for example, if the transmission system operator collaborates with the DFO on its local area study)? If so, please provide an overview of the extent of involvement or collaboration. Are there any benefits or drawbacks experienced by stakeholders in the jurisdictions you reference in your response?

(c) Are you aware of any jurisdictions where customers are involved in distribution and transmission system planning (that is, consultations or other processes that take place at the planning stage, leaving the cost approval stage aside for the purposes of this question)? If so, are there any benefits or drawbacks experienced by stakeholders in the jurisdictions you reference in your response?

Response:

(a-b) This response is intentionally left blank as the focus of Brattle's report/engagement was on rate design and price signals.

(c) In some jurisdictions, there may be customer involvement in stakeholder meetings and in a few cases, active participation in the hearings. Additionally, indirectly, customers are involved because consumption patterns influence the forecast.

Alberta Utilities Commission (AUC)

Electric Distribution System Inquiry – Combined Module
Proceeding ID 24116

Information Response Round 2 to:
Alberta Utilities Commission (AUC)

Brattle-AUC-2020JUN03-011

Reference: Exhibit 24116-X0470, AUC Preliminary IRs to All Parties;
Exhibit 24116-X0511, ATCO responses to preliminary IRs;
Exhibit 24116-X0522, FortisAlberta responses to preliminary IRs;
Exhibit 24116-X0558, AddÉnergie and ChargePoint written submission

Issue: Regulatory oversight of EVs

Preamble: AddÉnergie and ChargePoint submitted that the Commission should provide guidance on whether EV charging station owners would be subject to regulatory oversight in Alberta. AddÉnergie and ChargePoint noted in their joint submission that there is no province, territory or state that actively regulates EV charging stations and a number of states have found that third-party EV charging station owners are outside the regulatory jurisdiction of utilities commissions.

No parties argued in favour of regulating EV charging stations. Although the regulatory framework governing EV charging stations in Alberta has not been explicitly set out and the market for EV charging stations is still in its infancy in Alberta, the Commission notes there is a range of approaches to how EV charging stations bill customers. In their responses to the Commission's preliminary IRs, ATCO provided a number of rate designs, including a per-unit-of-time rate of $0.20 per minute or a flat rate of $5 per session,[1] whereas Fortis stated the price was best addressed by the owners.[2]

Request:

(a) In your view, please explain to what extent EV charging stations should be regulated. For example:

(i) Should there be minimum mandatory requirements for price transparency and disclosure to customers? If so, why?

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[1] Exhibit 24116-X0511, PDF pages 73-75.
[2] Exhibit 24116-X0522, PDF page 43.

(ii) Should there be some minimum level of reporting to the regulator on location and operation? If so, why?

Response:

(a) (i-ii) There is no universal answer to this question. Regulatory practice regarding price transparency for charging stations varies by jurisdiction across the U.S. In many jurisdictions, regulators have ruled that EV charging stations are not considered utilities. In Massachusetts, regulators have jurisdiction over "distribution companies" and "electric companies"; charging stations do not qualify as either of these.[3] EV charging station pricing is not regulated either. Similarly, the New York PUC does not regulate Consolidated Edison's ownership and pricing of charging stations.[4] By Q2 2019, at least 32 states have exempted EV charging stations from utility regulations in various jurisdictions.[5] On the other hand, Maryland's PUC has approved utility public charging and mandated a separate rate class for the EV public charging stations, which requires the Commission's oversight.[6] In California, by-the-minute charging rates have been prohibited by a regulation that will apply to chargers installed in 2023 and after. The regulation would apply to all chargers by 2033, regardless of their installation date.[7]

[3] The Commonwealth of Massachusetts Department of Public Utilities, D.P.U. 13-182-A, August 4, 2014.

[4] 18-E-0138-Proceeding on Motion of the Commission Regarding Electric Vehicle Supply Equipment and Infrastructure", New York Department of Public Service, January 13, 2020.

[5] NC Clean Energy Technology Center, "50 States of Electric Vehicles, Q2 2019 Quarterly Report Executive Summary", August 2019. https://nccleantech.ncsu.edu/wp-content/uploads/2019/08/Q2-19_EV_execsummary_Final.pdf

[6] "Maryland PSC Approves Modified Utility Electric Vehicle Portfolio", Maryland Public Service Commission Press Release, January 14, 2019, https://www.psc.state.md.us/wp-content/uploads/MD-PSC-Approves-Modified-Utility-EV-Charging-Portfolio_01142019-1.pdf

[7] "Electrical Vehicle Fueling Systems, Final Statement of Reasons", California Department of Food and Agriculture, November 1, 2019, https://www.cdfa.ca.gov/dms/pdfs/regulations/EVSE-FSOR.pdf