Stakeholder Comments on the AESO's Estimating Rate Calculations – July 16, 2021

Stakeholder comments [Posted July 22, 2021]

1. AltaLink Management Ltd.
2. Canada West Ski Areas Association (CWSAA)
3. Heartland Generation Ltd.
4. Industrial Power Consumers Association of Alberta (IPCAA)
5. MATL Canada & MATL LLP (MATL)
6. TC Energy Corp. (TCE)
7. TransAlta Corporation (TransAlta)

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Company	Stakeholder Comments
AltaLink Management	• No comments on Import/export revenue • Highlight the fact that the revenue requirement values for the 2020 and 2021 test years have changed in the updated Calculations Tool (line 9, columns C and D). The values no longer tie to the 2020 and 2021 Tariff Update applications. I believe the AESOs filed Tariff 2020 and 2021 Updates included an estimate for import/export revenue; it appears, on the surface, that these amounts are now double-counted.* **The AESO responded to this comment by publishing Estimating Rate Calculations Tool v0.3 on its website on July 15, 2021.*
CWSAA	See attached submission
Heartland Generation	<u>Question:</u> Relatively minor, but curious about how the "Estimated DOS/XOS Rate" in cells F38 and F42, respectively, are calculated. The $15 estimates don't seem to be a simple average of the test rates (inclusive or exclusive of 2019-2021 test years). It is likely that this value is a very rough approximation without a strict associated calculation. Any information on these values and how they are calculated would be appreciated. <u>Concerns:</u> Further to Heartland Generations comments on Session 6B, we are concerned about the significant and material impact of the drastic increase to rate XOS. This sudden increase to rate XOS during all hours of the year will have serious repercussions to the commercial viability of exports in the vast majority of hours. This is especially true of traditionally lower-priced hours when exports could take advantage of opportunities in neighbouring markets. During these periods of depressed Alberta pool prices, exporters can remain operational and provide reliability/ancillary services/etc. products to the Alberta grid while collecting the foreign price for the majority of production. It is my understanding that the doubling of rate XOS (as this estimate indicates) will evaporate these economic opportunities by eliminating an already slim price spread. This will subsequently force Alberta generators to possibly shutoff during periods when they could have remained operational/online (and thus no longer provide ancillary support to the Alberta grid). Further, the impact of these increased rate XOS fees are felt primarily during periods of lower grid utilization and/or system stress. Charging rate XOS as a flat energy charge is contrary to logic, and at a minimum the AESO should investigate and report on the correlation between rate XOS usage and transmission system costs/stress. A possible conclusion from this report could be a profiling of rate XOS to best reflect transmission capacity/costs through time; there is inherent logic behind shaping rate XOS as different $/MWh charges at different hours of the day. The designation of rate XOS as an opportunity service best illustrates the need to modernize all opportunity service products considering the preferred tariff design. As is, the estimated rate XOS will cause market harm to an already fragile intertie relationship as exports will be further disincentivized relative to the treatment of imports.

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	Heartland Generation requests that the AESO conduct further consultation regarding rate XOS modernization. This could begin with an AESO impact assessment of increasing the associated charges by almost double in all hours for exporters. This research should include impacts to perceived fairness between imports/exports on the intertie and consequences of disincentivizing exports on the domestic Alberta markets for ancillary services and other similar products.
IPCAA	In its spreadsheet, the AESO has used information from the 2020 Long-Term Transmission Plan based on the AESO's Reference Case to calculate Rate DTS - Rates IPCAA would recommend that: • The AESO also provide Rate DTS - Rates based on the "High Cogeneration Sensitivity" scenario. With rising carbon prices and the financial and environmental incentives for industry to install co-generation, the "High Cogeneration Sensitivity" scenario could very well materialize. • The AESO also provide an equivalent analysis for the four distribution utilities. The AESO should include the unit rates ($/kW and $/kWh) for each utility so that consumers can carry out rate impact assessments. Without this information, it will be extremely difficult for consumers to provide evidence to the AUC on potential impacts caused by the proposed tariff design.
MATL	1. MATL understands that the new tariff redesign will increase the cost of exporting energy from Alberta (i.e., through higher XOM/XOS charges, or additional charges beyond XOM/XOS). MATL has the following questions: (a) How will the AESO determine the new XOM/XOS rate, and/or other charges? The AESO has provided a calculator on July 7, 2021 & July 15, 2021. Please provide an example calculation in an excel spreadsheet (with all formulas available) with the current AESO Tariff and under the proposed AESO Tariff. Please demonstrate all potential impacts to XOM/XOS within the calculator and explain how it may impact MATL and its customers. Please provide further explanation on the rationale of the 20% multiplier applied to the Bulk & Regional System Calculations, and the 32% multiplier applied to the Ancillary Services Revenue Requirement. (b) Will the cost increase be higher or lower when compared to services that are recalled after XOM/XOS such as DOS? Please provide an example calculation in an excel spreadsheet (with all formulas available) with the current AESO Tariff and under the proposed AESO Tariff, including proposed mitigations. (c) The AESO has assumed in its rate calculator that the export volumes will be 130,000MWh in the future. Please explain the basis for this amount and how the AESO assessed the amount of export volumes that will result from higher XOM/XOS rates? Please demonstrate the reduced exports that will result from an increase in the XOM/XOS rates. Please provide an example calculation in an excel spreadsheet (with all formulas available) with the current AESO Tariff and under the proposed AESO Tariff. (d) Is the AESO expecting an overall reduction in offsets from export opportunity service revenue? If so, by how much? (e) Please list and fully explain all mitigations that will be put in place by the AESO for stakeholders impacted by the increase in XOM/XOS charges? Please also list and fully explain all mitigation that will not be put in place by the AESO and the reason for them not being considered.

Company	Stakeholder Comments
	(f) Non-firm interruptible rate class was not accepted by the AESO for DOS mitigations as described in the Session 6B on June 24, 2021. Given that XOM/XOS is already a non-firm interruptible rate class, please explain if revisiting the method for calculating XOM/XOS charge would avoid adverse impacts to exports. Please explain the impact if the AESO tariff were to provide firm transmission service for XOM/XOS services. 2. Will the new tariff redesign increase the cost of importing energy into Alberta (i.e., through higher IOS charges, or additional charges beyond IOS)? If yes: (a) How will the AESO determine the new IOS rate, and/or other charges? Please provide an example calculation in an excel spreadsheet(with all formulas available) with the current AESO Tariff and under the proposed AESO Tariff. (b) How has the AESO assessed the reduced import volumes that will result from higher IOS rates? (c) With respect to the AESO's existing and future practices of operating international cross border interties, has the AESO considered compliance to the United States-Mexico-Canada Agreement (USMCA)? With these comments, MATL Canada & MATL LLP is also reiterating its request that the AESO consult with MATL and its customers on the proposed changes to XOM/XOS rates, as there will be a material impact beyond the 10% threshold set by the AESO. MATL is available to discuss the above questions and comments. Due to vacation schedules, anytime after August 10 would be the best time to schedule a consultation.
TCE	The updated rate estimate included for the first time the impact to Rate XOS resulting from the AESO's proposed Bulk & Regional rate design. The following comments are with respect to Rate XOS. As a Rate XOS customer, TC Energy is concerned that the proposed rate design will cause Rate XOS to increase by approximately 80%. This is substantial and can be expected to significantly impact future export opportunities. TC Energy is further concerned that Rate XOS will be inconsistent with prior Commission rulings and cost causation. As a result, we recommend that the AESO consult with parties specifically with respect to Rate XOS. TC Energy has the following questions with respect to Rate XOS: 1. What mitigation measures will the AESO propose for Rate XOS customers that will see an 80% rate impact? 2. What impact will this rate increase have on future exports?
TransAlta	TransAlta appreciates the AESO revised Estimated Rate Calculations Tool but has concerns with the lack of information on the rate for export opportunity services. The estimates provided by the AESO include a significant increase to rate XOS/XOM from the current ~ $8/MWh to ~$15/MWh. TransAlta recommends the AESO to hold further consultation to openly discuss with stakeholders its proposal for rate XOS/XOM including a discussion about any analysis that the AESO has performed on cost-causation including any alternatives that were considered as the methodology behind this proposed XOS/XOM rate. The AESO has not justified the proposed increase to rate XOS/XOM in terms of cost causation and efficient price signals and has not provided information about the impact of the preferred rate design on energy exports. It is unclear how the change to allocate more costs to the energy component is reasonably driven by exporting electricity from the province. The AESO is sending a price signal that represents a significant change to the economics of exporting. We are concerned that this rate change will have unintended consequences and would

Company	Stakeholder Comments
	like to understand the AESO's analysis of how this change could impact export activity. The substantial increase in rate XOS/XOM could potentially reduce demand to export which in turn may reduce the contribution from XOS/XOM to transmission costs and create a shortfall that needs to be recouped from other customers. The AESO must demonstrate that its proposed rate XOS/XOM is not discriminatory and is not treating customers unfairly. We recommend that the AESO explain stakeholders how it determined the appropriateness of applying such a significant increase in the energy charge for the new XOM/XOS rate and provide any analysis that was undertaken of the expected impacts of the proposed change to export activity. We wish to understand the basis for the AESO's estimate that export volumes will be 130,000 MWh/year and will remain at that level for future years and request the analysis that was conducted to determine this estimate. We are concerned with the distorting effect that such a high export rate could have on the wholesale market, which will reduce the attractiveness of and opportunity for export sales, and could result in higher costs to Albertans - Alberta generators would be even more reliant on the Alberta market to earn all of their revenues. Furthermore, we recommend that the AESO consider phasing in this rate over time to provide the market time to adjust to this significant increase in rate just as it is doing with other industrial customers that are being impacted with costs that are greater than 10% of the current rate. Finally, it is unclear whether the new tariff redesign will increase the cost of importing energy into Alberta through higher IOS charges. The AESO should provide this information before filing its tariff, including details about how will the AESO determine the new IOS rate, and/or other charges and assessment of impact on import volumes that will result from higher IOS rates.

CWSAA – Comments & Questions Regarding AESO Updated Rate Estimates

SUMMARY

" Comments and questions regarding the updated rate estimates can be submitted by email to tariffdesign@aeso.ca by July 16, 2021. "

The vast majority of Alberta's electricity consumers receive a flow-through of the AESO's transmission tariff through their local distribution company. The AESO's preferred tariff structure would have potentially major impacts, which can only be assessed by using a distribution flow-through version of that tariff. The information provided by Fortis, EPCOR and ENMAX is insufficient to carry out the required impact assessments; the actual tariff rate sheets are necessary.

The companies also have an inconsistent jumble of demand ratchet policies, which are being applied to AESO bulk tariff charges which have no demand ratchet. This monstrous regulatory inefficiency must be addressed, lest customers literally across the street from one another receive radically different impacts from the single, standard provincial transmission tariff.

With the AESO's coordination, the distribution companies will surely cooperate in providing this information; if cooperation is not forthcoming, the AUC's guidance may be necessary.

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1 CONTEXT OF COMMENTS

> "The Commission expects parties to provide evidence of the potential impacts of any proposed bulk and regional tariff rate design as part of the Commission's consideration of the application." [1]

The AESO's bill impact tool will be very useful for parties who are served at the transmission level. Unfortunately this tool is of no assistance in assessing potential impacts on the majority of Alberta's electric system customers, who are served through distribution utilities' unique versions of the standard, province-wide AESO tariff.

The industry's fragmentation into separate transmission and distribution entities has led to significant seams issues between the two areas, some of which are currently under regulatory review. The AESO tariff flow-through is another such seams issue which must be addressed in order for customer representatives to estimate and analyze these potential rate impacts.

2 DISTRIBUTION UTILITIES ARE INDIFFERENT TO TRANSMISSION FLOW-THROUGH

Ever since PBR Decision 2012-237, para. 666:

> …the AESO related cost items will be dollar-for-dollar flow-through items in the [electric distribution] companies' PBR plans "

The electric distribution companies can neither gain nor lose in this flow-through process, and should therefore be supportive of any calculations and analysis required for its implementation.

3 ASSESSING THE DIFFICULTY OF ESTIMATING DISTRIBUTION FLOW-THROUGH RATES

One might hypothesize that all the data required to estimate distribution flow-through rates under the AESO's preferred tariff design is already available, and it should be a simple matter for customer representatives to calculate these rates in their impact analysis.

To test that hypothesis, the appended analysis reviews the publicly available data and calculation tools.

[1] 25175_X0142_2021-06-01 AUC letter - Ruling on the Alberta Electric System Operator extension request _000175, para.9

[1] The existing and preferred AESO DTS rates are known, and

[2] the forecast DTS & DT rate class billing determinants are said to be available in the annual PBR rate adjustment proceedings.

[3] In those PBR applications, both FortisAlberta and EPCOR Distribution & Transmission provide forecast transmission revenues by rate class, which can be compared to the revenue forecasts provided in the AESO impact analysis. For unknown reason(s), the numbers do not match, and the variances seem quite random.

[4] To assess the overall rates process, the current transmission rate can be compared to the rates implied in the companies' AESO tariff impact analysis.

The residential rate class is universally billed on a ¢/kWh basis for transmission charges, which simplifies the analysis. The implied rate as per the impact analysis can be calculated by taking the stated revenues and dividing them by the PBR forecast. (Except for ATCO, whose impact analysis has not yet been provided).

The result is somewhat disconcerting: the numbers don't match, by a significant amount.

	Total 2019 DTS (On Currently Approved AESO Structure)	2021 Energy (kWh)	Implied Unit Rate	Current Tariff Rate	$ Difference	% Difference
	[A]=Data	[B]=Data	[C]=[A]/[B]	[D]=Data	[E]=[D]-[C]	[F]=[E]/[D]
ATCO Electric Inc.	< Not Provided >	1,400,729,231				
ENMAX Power Corp.	$ 112,475,630	3,044,093,073	$ 0.03695	0.038763	$ 0.0018	4.7%
EPCOR Distribution & Transmission Inc.	$ 77,126,402	2,316,573,488	$ 0.03329	0.03610	$ 0.0028	7.8%
FortisAlberta Inc.	$ 139,040,000	3,339,937,368	$ 0.04163	0.04394	$ 0.0023	5.3%

This analysis in no way suggests that the companies have made any errors in their calculations. There are no doubt several calculation errors in the analysis above, which a technical expert who works with these calculations on an everyday basis would be able to identify.

Its purpose is only to demonstrate that it is extremely difficult to confidently calculate the transmission unit rates that the companies must have used in their internal calculations. The only way in which the typical bill impacts could have been accurately calculated is if the companies had worked out the actual tariff unit rate components. Since this information must already exist, the distribution companies should kindly provide it (with the possible exception of ATCO Electric, which does not appear to have provided any tariff impact analysis).

Without knowing the electric distribution companies' flow-through rates, it is extremely difficult for parties to estimate the customer impacts of the AESO's preferred tariff design option.

4 INCONSISTENCY OF COMPANIES' TRANSMISSION TARIFF FLOW-THROUGH

Both the current and the preferred AESO tariff structures recover bulk / demand related charges through a monthly unratcheted billing determinant. However the distribution utilities have a collectively chaotic jumble of ratchet policies, summarized in the following table. **ATCO Electric** consistently uses an 85% X 12 month ratchet, **ENMAX Power** consistently uses a 90% X 12 month ratchet, while **EPCOR** covers all alternatives.

In **Fortis'** 2012-2014 Phase II Distribution Tariff proceeding (ID 2363, Decision 2014-018), the Commission concluded "that mirroring of the AESO's charges in Fortis' rates is consistent with cost causation" [¶175] and as a result Fortis is the only company that mirrors the AESO's current and proposed rate structures for its general service rate classes.

	TREATMENT OF UNRATCHETED TRANSMISSION CHARGE (Bulk / Demand)				
		Monthly	85% X 12 Mon	90% X 12 Mon.	90% X 24 Mon.
FAI	RATE 22 - FARM SERVICE – DEMAND METERED		X		
FAI	RATE 41 - SMALL GENERAL SERVICE	X			
FAI	RATE 45 - OIL & GAS SERVICE		X		
FAI	RATE 61 - GENERAL SERVICE	X			
FAI	RATE 63 - LARGE GENERAL SERVICE	X			
EDTI	Commercial/Industrial 50 kVA to <150 kVA			X	
EDTI	Commercial/Industrial 150 kVA to <5,000 kVA		X		
EDTI	Primary Commercial/Industrial 150 kVA to <5,000 kVA		X		
EDTI	Commercial/Industrial Greater than 5,000 kVA				X
EDTI	Commercial/Industrial Greater than 5,000 kVA Totalized				X
EPC	Rate D300 - Medium Commercial			X	
EPC	Rate D310 - Large Commercial - Secondary			X	
EPC	Rate D410 - Large Commercial - Primary			X	
AE	Rate D21 - Standard Small General Service		X		
AE	Rate D24 - Standard Small General Service - Isolated Industrial Areas		X		
AE	Rate D31 - Large General Service / Industrial - Distribution Connected		X		
AE	Rate T31 - Large General Service / Industrial - Transmission Connected		X		
AE	Rate D32 - Generator Interconnection & Standby Power		X		
AE	Rate D34 -Large General Service / Industrial - Isolated Industrial Areas		X		
AE	Rate D41 - Small Oilfield and Pumping Power		X		
AE	Rate D44 - Small Oilfield and Pumping Power - Isolated Industrial Areas		X		

The AESO's preferred tariff structure greatly increases the importance of knowing the individual tariff rate components. The unratcheted 'bulk' system charge is dropping by 41% while ratcheted 'regional' system charge is dropping by 23%; this is offset by a 367% increase in the energy charge.

With such massive dislocations occurring, accurate end user rates are essential. Most customers' consumption shows some degree of seasonality, and the preferred tariff structure would greatly alter the costs flowing from seasonal usage.

The Commission has directed Fortis to flow the 'bulk' system charge through to end use customers using "CWSAA's proposed new billing determinant of un-ratcheted 'kW of billing period capacity' for rates 61 and 63." [2014-018 ¶175] The 'kW of billing period capacity' is simply 'the highest metered kW demand in the billing period', a value which is readily available for all demand-metered customers.

The Electric Utilities Act contains a clear policy statement regarding the AESO tariff, that

> (3) The rates set out in the tariff
>
> (a) shall not be different for owners of electric distribution systems, customers who are industrial systems or a person who has made an arrangement under section 101(2) as a result of the location of those systems or persons on the transmission system, and
>
> (b) are not unjust or unreasonable simply because they comply with clause (a).

It is of course reasonable that the AESO tariff flow-through by electric distribution companies reflect local system realities; but these inter-company differences appear to be historical accidents, left unaddressed ever since the change in AESO tariff structure in 2006. This is surely an opportunity to improve regulatory efficiency by adopting a consistent tariff flow-through approach.

Without prejudice as to the ultimate outcome, customers need to assess the potential impacts of a more accurate, harmonized tariff flow-through. This should be provided as an alternative scenario, in addition to rates under the current companies' tariff structures.

5 RELIEF REQUESTED – AESO COORDINATION OF ANALYSIS

What is required is a set of System Access Service rate schedules from each of the utilities, with all the required unit rates populated using the AESO's preferred tariff design, and a narrative defining the specific data sources and calculations used. These unit rates must already exist, given that the companies have calculated typical bill impacts.

The AESO is responsible for its tariff application, and for enabling parties to assess the impacts of its proposals. The AESO is therefore responsible for coordinating with the electric distribution companies to provide the flow-through rates that are required to assess "the potential impacts of any proposed bulk and regional tariff rate design."
In the unlikely event that the companies were not cooperative, the AESO could seek guidance from the AUC. In the unlikely event that the AESO is unwilling to provide this coordination, the parties could approach the AUC with a request that the necessary unit rates be provided.

6 TECHNICAL REVIEW OF DATA & CALCULATION TOOLS AVAILABLE

The required data and calculation tools are described in the identically worded notes to the three utilities' rate impact calculations (see endnote): [i]

1. "Analysis completed by <Company> based on its Transmission Cost Allocation method and Rate Design to DT rate classes as currently approved by the Commission."

2. "Transmission Cost Allocation and Rate Design uses AESO 2019 DTS rates (as presented in AESO Session 5) and the forecast DTS and DT rate class billing determinants (as approved in <Company's> 2021 Annual PBR rate filing) as summed across all <Company's> D-connected PODs."

To summarize, the two inputs are prices and volumes:
[1] the AESO 2019 DTS rates, and
[2] the forecast DTS & DT rate class billing determinants [per PBR filings]. [2]

The two calculation processes are allocation and rate design:
[3] the Transmission Cost Allocation method (to rate classes), and
[4] the Rate Design method.

6.1 AESO 2019 DTS Rates

The AESO 2019 DTS rates are publicly available, per the AESO (see for example the Bill Calculation Tool, tab "Adjust Load Profile") :

Connection Charge					
Bulk System Charge					
3(a)	Coincident metered demand	$10,087.00	/MW/month	$5,980.00	/MW/month
Regional System Charge					
3(b)	Billing capacity	$2,668.00	/MW/month	$2,055.00	/MW/month
Energy Charge					
3(c)	Metered energy	$2.18	/MWh	$10.19	/MWh

[2] "Forecast billing determinants are generally used to allocate K, K-bar, Y and Z factors to rate classes and to calculate the resulting rate adjustments." [25843_X[]_25843-D01-2020 Fortis 2021 Annual PBR Rate Adjustment_000103 ¶ 39, see also 25864_X[]_25864-D01-2020 AE 2021 Annual PBR Rate Adjustment_000055 ¶ 35, and 25865_X[]_25865-D01-2020 EPC 2021 Annual PBR Rate Adjustment_000060 ¶ 32]

6.2 Forecast DTS & DT rate class billing determinants

[2] Forecast DTS & DT rate class billing determinants are available in the annual PBR filings:

Proceeding	Description
25866	EDTI 2021 Annual PBR Rate Adjustment Filing
25865	ENMAX Power Corporation 2021 PBR Rate Adjustment Application
25864	ATCO Electric 2021 Performance Based Regulation ("PBR") Rates Application
25843	FortisAlberta 2021 Annual Rate Adjustment Filing

However the availability of information differs greatly between the four companies.

- FortisAlberta provided a 'bottom up' transmission cost, revenue and annual transmission rate update (TACDA) together with the load forecast as part of its annual PBR filing ID 25843. [3]
    - Note that Fortis uses (unratcheted) 'Monthly non-coincident peak demand' to allocate bulk system transmission charges. [ii]
    - The other three companies use the same ratcheted billing demand approach for both bulk and regional charge recovery (discussed above).

- EPCOR Distribution & Transmission also provided a 'bottom up' transmission update together with the load forecast. [4]

- ATCO Electric provided a 'top down' 2021 transmission rate update in its 2021 PBR application, applying "a scaling approach to its 2020 transmission rates approved in Decision 25645-D01-2020."[5]

- ENMAX Power did not address transmission rate updating in its 2021 PBR application. [6]

[3] "64. In its application, Fortis requested approval of its 2021 SAS rates, to be effective January 1, 2021.56 Fortis indicated that its proposed 2021 SAS rates reflect the rates applied for by the AESO in Proceeding 26054…."
"65. Fortis indicated that to determine the rate class-specific changes in the transmission access component for distribution-connected rate classes, it used the methodologies from its last Phase II distribution tariff application, approved in Decision 2014-01860 and the associated compliance filing, Decision 2014-224."
[4] 25866_X[]_25866-D01-2020 EDTI 2021 Annual Performance-Based Regulation Rate Adjustment, ¶ 59
[5] 25864_X[]_25864-D01-2020 AE 2021 Annual PBR Rate Adjustment, ¶ 49
[6] 25865_X[]_25865-D01-2020 EPC 2021 Annual PBR Rate Adjustment, ¶ 32

6.3 Transmission Cost Allocation method (to rate classes)

The Fortis and EPCOR forecasts contain transmission rate class revenue forecasts which can be compared with the forecasts provided in the AESO impact analysis, as follows. (Note that the % differences are quite irregularly distributed.)

FORTIS ALBERTA INC.

25843_X0005.01_Schedule 3.2 2021 Updated Transmission Cost Allocation - Tab 3.2B DTS Connection

Summary of Transmission Costs by Rate Class ($ 000)

Line	Rate Class Description	Total AESO DTS Charges [A]=Data	Total 2019 DTS (On Currently Approved AESO Structure) [B]=Data	$ Difference [C]=[B]-[A]	% Difference [D]=[C]/[B]
1	Residential	$ 137,071	$ 139,040	$ 1,969	1.4%
2	FortisAlberta Farm	$ 28,011	$ 28,269	$ 258	0.9%
3	REA Farm	$ 23,287	$ 23,575	$ 288	1.2%
4	FortisAlberta Irrigation	$ 17,162	$ 16,637	$ (525)	-3.2%
5	Exterior Lighting	$ 1,964	$ 1,956	$ (8)	-0.4%
6	Small General Service	$ 53,749	$ 56,522	$ 2,773	4.9%
7	Oil and Gas	$ 24,216	$ 25,391	$ 1,175	4.6%
8	General Service	$ 208,561	$ 230,570	$ 22,009	9.5%
9	Large General Service	$ 110,269	$ 113,876	$ 3,607	3.2%
10	Distribution-Connected	$ 604,291	$ 635,836	$ 31,545	5.0%

EPCOR DISTRIBUTION & TRANSMISSION INC.

25866_X0007.01_Appendix E - 2021 SAS COSS_Blackline, Tab SAS-1a 2021

Table 2 - SAS Revenue Requirement Allocated to SAS Rate Classes

	Revenue requirement w/o DC and CST	Total AESO DTS Charges [A]=Data	Total 2019 DTS (On Currently Approved AESO Structure) [B]=Data	$ Difference [C]=[B]-[A]	% Difference [D]=[C]/[B]
1	Residential	$ 79,956,127	$ 77,126,402	(2,829,725)	-3.7%
2	< 50kVA	$ 25,662,480	$ 24,725,583	(936,897)	-3.8%
3	50 to 149 kVA	$ 34,863,775	$ 33,609,945	(1,253,830)	-3.7%
4	150 to 4,999 kVA	$ 65,514,148	$ 63,044,365	(2,469,783)	-3.9%
5	Direct Connects *	$ 10,560,340	$ 10,282,842	(277,498)	-2.7%
6	150 to 4,999 - Primary	$ 22,882,916	$ 21,321,132	(1,561,784)	-7.3%
7	>5,000 kVA - Primary (CS)	$ 23,075,648	$ 22,059,494	(1,016,154)	-4.6%
8	CST *	$ 7,511,504	$ 7,347,761	(163,743)	-2.2%
9	Street Lights	$ 805,593	$ 1,059,008	253,415	23.9%
10	Traffic Lights	$ 119,524	$ 118,991	(533)	-0.4%
11	Lane Lights	$ 50,458	$ 49,369	(1,089)	-2.2%
12	Security Lights	$ 69,940	$ 68,725	(1,215)	-1.8%
13	**Total**	271,072,454	260,813,617	(10,258,837)	-3.9%

There are surely good reasons for these differences, but considerable research appears necessary in order to elucidate their causes; the data come from different sources at different times, involving several different years and critical adjustments like loss factors between the point of delivery and the customer meter.

Since there are no specific sources listed for the companies' calculations, the search for understanding may be prolonged. For ENMAX and ATCO, the challenge is somewhat greater given the lesser amount of available information.

6.4 The Rate Design method

For rate classes billed on energy only (residential, small commercial…), calculating unit rates under the existing and proposed rates should in principle be simple. We need only divide the calculated dollar amounts by the kWh energy forecast to obtain the two rates.

The energy data source is "the forecast DTS and DT rate class billing determinants (as approved in <Company's> 2021 Annual PBR rate filing) as summed across all <Company's> D-connected PODs."

Proceeding	Description	Source File	Reference	2021 kWh
25864	ATCO Electric 2021 Performance Based Regulation ("PBR") Rates Application	25864-X0051, AE-AUC-2020NOV26-001(b) Attachment 3, Appendix I, schedules S.1-S.3	2.1 Summary of Billing Determinants by Revenue Class - Cell I13	1,400,729,231
25865	ENMAX Power Corporation 2021 PBR Rate Adjustment Application	25865_X0046_Appendix 5 - Rate Schedules_000046	13.0 2020-2021 Monthly Billing Determinants and Q Factor Supporting Calculations - Cell AD13	3,044,093,073
25866	EDTI 2021 Annual PBR Rate Adjustment Filing	25803_X0016_EDTI-AUC-2020SEP14-003 Attachment 1_000016	2.0 Revenue True-up of The Previous TAC Annual Rider - Cell D31 (from Sch. 9.0)	2,316,573,488
25843	FortisAlberta 2021 Annual Rate Adjustment Filing	25843_X0007_Schedule 2.4 A to D - 2021 Billing Determinants and Analysis_000007	2.4-B 2021 BD Comparision - Cell H12	3,339,937,368

Taking the revenue data provided by the companies in their impact analyses, "Total 2019 DTS (On Currently Approved AESO Structure)", and calculating a ¢/kWh unit rate that can be compared to current tariffs, we have: [7]

	Total 2019 DTS (On Currently Approved AESO Structure)	2021 Energy (kWh)	Implied Unit Rate	Current Tariff Rate	$ Difference	% Difference
	[A]=Data	[B]=Data	[C]=[A]/[B]	[D]=Data	[E]=[D]-[C]	[F]=[E]/[D]
ATCO Electric Inc.	< Not Provided >	1,400,729,231				
ENMAX Power Corp.	$ 112,475,630	3,044,093,073	$ 0.03695	0.038763	$ 0.0018	4.7%
EPCOR Distribution & Transmission Inc.	$ 77,126,402	2,316,573,488	$ 0.03329	0.03610	$ 0.0028	7.8%
FortisAlberta Inc.	$ 139,040,000	3,339,937,368	$ 0.04163	0.04394	$ 0.0023	5.3%

The AESO's proposal represents major tariff structure change which cannot be assessed by simple rate class % impact calculations. Particularly for seasonal customers (which the CWSAA's ski hill members all are) it is essential to have the actual transmission tariff flow-through rate structures for impact assessment.

All that is needed here is for the four distribution utilities to make public the calculations which three of them have already completed but not disclosed. The three co-operating distribution utilities (EDTI, EPC and FAI) have all provided the same format of information, which speaks to a degree of helpful coordination for which AESO no doubt deserves the credit.

In particular, the estimated impacts on low / typical / high usage customers could only be calculated if unit rates ($ / kW, $ / kWh) had been calculated. Please provide those unit rates, so that customers can carry out rate impact assessments.

There are at least four possible resolutions to this situation:

[A] The AESO could coordinate the four distribution utilities' voluntary provision of this information, and if full cooperation is not forthcoming then

[B] The AESO could itself carry out these calculations, which would ensure transparency and broad access to consistent estimates. Presumably the AESO would itself have understood, reviewed and confirmed the distribution utilities' calculations, and would have the expertise to carry out these calculations as needed.

[C] Industry participants could individually carry out these calculations, likely with different results depending on assumptions made, which could well waste considerable time in the regulatory process as the varying customer impact calculations would then need to be compared through litigation.

[7] Sources: https://www.enmax.com/ForYourBusinessSite/Documents/2021-07-01-DT-Tariff-Rate-Schedule.pdf
https://www.epcor.com/products-services/power/rates-tariffs-fees/Documents2/sas_april2021.pdf
https://www.fortisalberta.com/docs/default-source/default-document-library/2021-july-rates-options-and-riders.pdf?sfvrsn=7eaf9e1b_4

[D] Any party could presumably make a motion in Proceeding 25175 requesting that the AESO or the distribution utilities be directed to provide the necessary customer level rates, so that consistent impact assessments can be carried out by the industry.

ENDNOTES

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[i] **Electric distribution companies' statements re: transmission cost allocation & rates:**

FortisAlberta Inc.

1. Analysis completed by FortisAlberta based on its Transmission Cost Allocation method and Rate Design to DT rate classes as currently approved by the Commission.

2. Transmission Cost Allocation and Rate Design uses AESO 2019 DTS rates (as presented in AESO Session 5) and the forecast DTS and DT rate class billing determinants (as approved in FortisAlberta's 2021 Annual PBR rate filing) as summed across all FortisAlberta D-connected PODs .

ENMAX Power Corp.

1. Analysis completed by EPC based on its Transmission Cost Allocation method and rate design to DT rate classes as currently approved by the Commission.

2. Transmission Cost Allocation and Rate Design uses AESO 2019 DTS rates (as presented in AESO Session 5) and the forecast DTS and DT rate class billing determinants (as approved in EPC's 2021 Annual PBR rate filing) as summed across all EPC D-connected PODs.

EPCOR Distribution & Transmission Inc.

1. Analysis completed by EPCOR based on its approved System Access Service Cost of Service and Rate Design methodology.

2. Transmission Cost Allocation and Rate Design uses AESO 2019 DTS rates (as presented in AESO Session 5) and the forecast DTS and DT rate class billing determinants (as approved in EPCOR's 2021 Annual PBR rate filing) as summed across all EPCOR Distribution-connected PODs

[ii] **FortisAlberta – Transmission Cost Allocation Summary**

25916_X[]_25916-D01-2021 Fortis 2022 Phase II Distribution Tariff Application_000272

Table 2. Summary of transmission cost allocation for distribution-connected load

AESO tariff billing components (i.e., becomes Fortis's sub-functionalization)	AESO tariff billing determinants	Fortis's classification of transmission charges	Fortis's allocation method
[A]	[B]	[C]	[D]
Bulk system demand charges	Coincident system peak demand	Monthly non-coincident peak demand	Rate class forecast monthly coincident peak demand, based on 3-year average of historical load settlement data
Billing capacity and point of delivery (POD) charges	Per POD billing capacity[11]	Annual non-coincident peak demand	Rate class forecast monthly non-coincident peak demand, based on three-year average of historical load settlement data and ratcheted to 90 per cent (to align with the AESO's per billing capacity charges)
Metered energy charges (including the DTS tariff's Bulk System, Local System, Operating Reserve, and Voltage Control Metered Energy charges)	Metered energy	Metered energy	Rate class forecast metered energy
Other transmission charges (including Demand Under-Frequency Load Shedding Credit and Interchange costs)	Monthly capacity and metered energy	Metered energy	Rate class percentage of total demand transmission services charges

Source: Exhibit 25916-X0001, application, paragraphs 97-103, 108-116, and Exhibit 25916-X0121, Attachment FAI-AUC-2021JAN15-001.01.