Topic: Rate Design- Recovery of Future Capital Costs in Northwest Alberta

Reference: Section 4.5.4; Paragraph 219

Preamble: “The AESO has proposed that capital costs allocated to Fort Nelson be levelized over the life of the facilities and recovered through the Rate FTS local system charge to BC Hydro, which is the approach currently used for the original ATCO Electric line to Fort Nelson. Such an approach would generally recover the allocated capital costs over a period of about 40 years.”

Request:

Please explain why it is considered necessary to continue the levelized cost recovery approach for future capital additions. Explain why the recovery of future capital costs may not follow the revenue requirement pattern of cost recovery bearing in mind, the levelized approach may result in intergenerational inequities between existing and future customers.

Response:

The cost of a future transmission development proposed to be allocated and recovered through Rate FTS would be related to a transmission system development rather than point of delivery facilities. It is therefore reasonable to recover that cost over time (rather than as a construction contribution) comparable to the recovery of other system development costs over time through Rate DTS.

A levelized approach was approved in 2006 for the recovery of the cost of the original ATCO Electric line providing service to Fort Nelson, and remains appropriate for the recovery of other transmission developments in the future. Under Rate FTS, the local system charge is the greater of the Rate DTS local system charge or the cost of system facilities built for or allocated to service to Fort Nelson. Levelizing those costs makes them more readily comparable to the Rate DTS local system charge. If the costs were recovered based on the revenue requirement pattern, the charge would initially be higher and then decrease over time. The Rate DTS local system charge would establish the Rate FTS local system charge more quickly, and after that point could result in inappropriately higher charges to BC Hydro.

As the levelized charge would be determined using the capital structure, return on equity, cost of debt, and income tax rate applicable to the owner of the transmission facilities, intergenerational inequities would be minimized.
Topic: Rate Design- Demand Opportunity Service

Reference: Section 4.6; Paragraph 230

Preamble: “To determine the Rate DOS charges, Rate DTS costs are first converted, by component, to $/MWh charges, as provided in Table 5-9 in section 5 of this application. The demand opportunity service rate is then allocated the variable components of costs which are attributable to demand opportunity service — namely, the variable components of the bulk system and local system charges and the operating reserve charge.”

Request:

Please provide a schedule showing how the DOS charges are calculated as per the above description. In particular, please show how the operating reserves are allocated to DOS on an hourly basis.

Response:

All calculations are included in Table 5-9 in the Microsoft Excel workbook provided as section 5 of the application.

Operating reserves are not allocated to Rate DOS on an hourly basis. Rate DOS is an opportunity service rate. In general, opportunity services need certainty of price to allow market participants to be able to assess the opportunity costs of a transaction to determine whether to make the transaction or not. Rate DOS is therefore offered at a fixed $/MWh price, and is also not subject to retrospective deferral account reconciliation.
Topic: Rate Design- Export Opportunity Rate

Reference: Section 4.7.1; Paragraph 238

Preamble: “As available transfer capability for exports is expected to remain limited in the near future, providing only opportunity service for export remains appropriate.”

Request:

(a) Please provide the reasons why the AESO believes transfer capability for exports is expected to remain limited in the near future.

(b) Please indicate the measures that are planned to improve transfer capability for exports and when these measures would come into effect.

(c) The AESO states in an hour when the contingency reserve requirement is established by the sum of 5% of hydro and wind generation and 7% of thermal generation, operating reserves are allocated proportionately to export volumes and domestic load volumes in that hour. [Para 248] Please explain why it is considered appropriate to allocate operating reserves to exports proportionately as opposed to using a true incremental approach.

Response:

(a) As explained in AESO Operating Policies and Procedures (OPPs) 304 and 521, the total Alberta export capability is determined by the north-south transfer limits, specifically the South of Keephills/Ellerslie/Genesee (KEG) or SOK-240 operating limits. The predominant limiting factor for SOK-240 flow is thermal overloading, which will not be addressed until additional north-south transmission developments are complete. Those developments will not be in service until at least 2013.

(b) The AESO Long-Term Transmission System Plan 2009 is provided as an attachment to information response AUC.AESO-021 (a). Section 4.9.2 (page 50) of the plan states, “The export capacity of the B.C. intertie cannot be restored significantly until the Edmonton to Calgary transmission system is reinforced. The AESO’s plan to bring the Alberta-B.C. intertie up to its full design rating is included as part of the required reinforcement of the Edmonton to Calgary transmission system previously described in Section 4.3 [on Edmonton to Calgary transmission system reinforcements]. The expected in-service date for these reinforcements is 2013.”

(c) The AESO considers that allocating operating reserves proportionately is an incremental approach in an hour when the contingency reserve requirement is established by the sum of 5% of hydro and wind generation and 7% of thermal generation. In such an hour, every additional MWh of either load or export volumes will require an additional 5-7% (depending on the generation mix) of contingency reserve. Every additional MWh is
therefore allocated its proportionate share of operating reserve costs. It is not possible to further attribute an additional MWh of volume specifically to load or exports, as load volumes are not scheduled in advance and export volumes may be scheduled up to 20 minutes before the hour.
Topic: Rate Design- Primary Service Credit

Reference: Section 4.9; Paragraph 262

Preamble: “The result of the updated analysis provides a weighted average value of 79% to be used in determining the primary service credit. The analysis is included in the POD Cost Function Workbook provided as Appendix G to this application.”

Request:

(a) Given the significant change in the PSC in the current analysis of 46 projects versus the analysis submitted in the 2007 GTA, what tests did the AESO carry out in order to satisfy itself the PSC would not continue to change with the use of different data sets. In other words how did the AESO satisfy itself the PSC calculated would provide a stable result over time?

(b) Would the calculation of the primary service credit provide more stable results if the POD cost function reflected the radial line costs as a separate component of the cost function such that a primary service credit could then be based on the substation component of the cost function (as opposed to the use of a ratio as per the AESO proposal). Please discuss.

Response:

(a) As noted in section 4.9 (page 53) of the application, the AESO updated the primary service credit analysis using detailed connection cost data for 49 projects used for the POD Cost Function Update filed with the 2010 tariff application. In particular, the analysis allocated indirect costs (including owner costs, distributed costs, and engineering and supervision) proportionately to substation and line costs, whereas the less detailed analysis used for the AESO’s 2007 tariff had the effect of considering all indirect costs to be line costs. The analysis for the 2010 tariff application also used the composite inflation index discussed in section 6.11.7 (page 118) of the application to more accurately represent the replacement cost new value of the connection projects. The AESO estimates about two-thirds of the increase in the primary service credit percentage results from those aspects of the analysis, rather than the use of a larger data set.

The AESO also considers that the 46 connection projects used in the 2010 primary service credit analysis is a significant increase over the 30 projects used in the 2007 analysis. The increased size of the data set should provide a more stable result. As additional projects are added to the data set in future tariff applications, the AESO does not expect to see significant variability in the primary service credit percentage.
(b) Reflecting radial line costs as a separate component of the POD cost function would have little, if any, impact on the variability of the primary service credit as it would still be based on the same connection project data.
Topic: Rate Design- Rider I

Reference: Section 4.16; Paragraph 309

Preamble: “However, it is difficult to assess how large this risk premium should be, due to the lack of examples of abandoned transmission system access services. The AESO has been unable to find any transmission system access service that has been fully abandoned after entering commercial operation. Sometimes the facilities which are being served change in purpose, function, or ownership, but the AESO is not aware of any that have been fully abandoned. Even in the absence of such examples, the AESO considers it prudent to add a small risk premium in the discount rate used in the calculation of Rider I amortized contribution payments.”

Request:

(a) Please indicate whether the AESO considered the use of letters of credit or Bank guarantees to meet the prudential requirements for recovery of remaining contribution amounts in the event of default.

(b) Please explain why the AESO chose the risk premium approach, which makes all Rider I customers pay a premium, instead of other means that would require prudential requirements from individual Rider I customers such as through letters of credit or Bank guarantees. Discuss having regard to the costs and benefits of the different options to market participants.

Response:

(a-b) The AESO understands that letters of credit or bank guarantees provide little benefit for market participants over the payment of construction contributions in cash. Letters of credit, bank guarantees, and cash contributions all reduce the capital otherwise available to a market participant and have similar impacts on the market participant’s cash flow and credit metrics. As a result, the AESO concluded that requiring letters of credit or bank guarantees would not address the concerns of market participants arising from the frequency and amount of contributions and the magnitude of costs (and associated contributions) when projects require significant connection facilities.

Under the risk premium approach, the market participants who utilize Rider I cover the risk of default if a project requiring system access service is abandoned due to the availability of Rider I. The AESO considers such an approach to be reasonable in attributing a potential cost associated with Rider I to those market participants who utilize Rider I.

The costs and benefits of the different options to market participants would need to be assessed by market participants themselves. The AESO notes that market participants
did not object to a risk premium approach during the AESO's consultation on the amortized contribution rider, other than requesting that the level of the premium be reasonable and appropriate.
Topic: Rate Design - Rider I
Reference: Section 4.16; Paragraph 309

Preamble: "A market participant could only convert the construction contribution to an amortized payment after the project has entered commercial operation. The AESO considers that this approach addresses the period of greatest risk that a project might be abandoned or cancelled."

Request:

Please indicate whether market participants would be allowed to convert legacy contribution amounts to Rider I? If so, has the AESO given consideration to the impact this initial conversion would have on TFO cash flows and potentially, their credit ratings? Please discuss.

Response:

Please refer to information response AUC.AESO-011.

The AESO has not given specific consideration to the impacts on TFO cash flows and credit metrics. The AESO notes that TFOs were included in the AESO’s consultation on the amortized contribution rider and did not raise such impacts as a concern.
Topic: Rate Design- Wind Forecasting Service

Reference: Section 4.17; Paragraph 321

Preamble: “Although the cost of the wind forecast service is about the same in each year, a greater share of costs is recovered in later years in proportion to the production from the greater wind capacity expected to be generating in those years. In addition, the $/MWh charge in Rider J increases by 10% each year, to allow a slight “phase-in” or the rider and to defer some additional costs to later years.”

Request:

Please indicate whether the carrying costs of deferring wind forecasting costs will be borne by the Wind supply participants. If so please explain the proposed mechanism for recovery of such carrying costs.

Response:

The AESO does not propose to include in Rider J any carrying costs related to deferring recovery of wind forecasting service costs. The AESO similarly does not include carrying costs in its quarterly determination of deferral account adjustment Rider C or losses calibration factor Rider E, or on the deferral account balances settled in its annual deferral account reconciliations. The AESO also considers that including carrying costs adds unnecessary complexity to the determination of the rider charge and goes beyond the concept of the charge representing a service that the wind generators could arrange and manage themselves, although less efficiently and effectively.

Any carrying costs that do arise would be allocated to and recovered from load services and exporters in the same manner as carrying costs arising from other AESO deferral account balances. Also, based on the forecast amounts in subsection 2(2) of the Rider J rate sheet, carrying costs may arise in 2010 and 2011 while carrying credits may arise in 2012 and 2013. On balance the wind forecasting service is expected to be fully funded through Rider J.
Topic: T&Cs- Determination of Local Investment

Reference: Section 6.11.7; Paragraph 509

Preamble: “Subsection 8(5) of section 8 of the proposed terms and conditions explains that, for a connection project to accommodate an increase in load at an existing system access service, the calculation of investment will be based on the change in contract capacity since the most recent change in construction contribution at the point of delivery. This proposal is expected to remove an existing disincentive that discourages market participants from requesting contract capacity increases that do not require construction.”

Request:

(a) Please describe the circumstances under which an increase in contract capacity would result in no additional investment by the AESO.

(b) If the initial contract capacity at a site were insufficient to cover the cost of participant related costs and a contribution was initially levied, will a portion of that contribution be refunded if the participant increases contract capacity. Does Subsection 8(5) apply to such situations?

Response:

(a) An increase in contract capacity results in no additional investment when:
• no additional transmission facilities are required to be constructed, and
• no construction contribution had been paid (or a construction contribution had been paid and fully refunded) at the point of delivery.

In general, no additional investment would be available if the cost of the connection project had already been fully funded by investment.

(b) A construction contribution previously paid at a point of delivery would typically be refunded, in whole or in part, if contract capacity is increased and if no additional transmission facilities are required to accommodate the increase. In such a case, when no additional transmission facilities are required, section 9 of the proposed tariff would apply, specifically subsections 2(2)(a) and 4(1).

Subsection 8(5) of section 8 of the proposed tariff applies only when additional transmission facilities are required to accommodate a contract capacity increase. In that case, when additional transmission facilities are required, the costs associated with the additional facilities are considered a separate connection project and the available investment is determined under subsection 8(5) of section 8.
Topic: T&Cs-Determination of Local Investment

Reference: Section 6.11.7; Paragraph 510

Preamble: “The AESO believes that the net present value calculation was appropriate under earlier contribution policies of the AESO that include significant term amounts, but the current per year and per MW structure of the maximum investment level no longer requires such a calculation. Accordingly, the AESO proposes to remove the net present value calculation and to instead simply sum the investment amounts applicable to each year of the investment term as described in subsection 8(6) of section 8 of the proposed terms and conditions.”

Request:

(a) Does the proposed policy result in existing customers having to bear the carrying cost of AESO investments made in order to accommodate future capacity increases by market participants until such time as the capacity increases materialize?

(b) The AESO indicates planned contract capacity increases have less value (since they are discounted through a net present value calculation) than increases requested just prior to being needed. Did the AESO give consideration to providing the undiscounted investment but charging the market participant for the carrying costs thereby avoiding any undue cross subsidies between existing and future loads.

(c) Please comment on the use of a mechanism such as Rider I for recovery of carrying costs from participants who receive undiscounted AESO investments in contemplation of future capacity increases.

Response:

(a) The AESO considers that the proposed approach is a reasonable balance of several considerations. For example, a market participant who contracts for a capacity increase in years 6 through 20 of a 20-year investment term receives only 15 years of investment for that increase. If instead the market participant waits until year 5 to request the increase, the full 20 years of investment may be available for the increase.

As well, staged contracts generally provide for a more efficient and orderly development of a connection project. Determining the present value of investments in staged contracts makes staging less attractive to market participants, in addition to a market participant’s general reluctance to commit in contract to load increases several years into the future.

A carrying cost may be attributable to some staged contracts, but would be small when stages occur in the early years of a project and when contract capacity changes are
relatively small. The AESO suggests that such carrying costs would be offset by the benefits mentioned above.

(b) The AESO did not specifically consider adding a carrying cost charge to a market participant's costs when a staged contract was entered into. As discussed in part (a) above, staged contracts provide for efficient and orderly development of a connection project, and additional charges would be perceived as a disincentive to entering a staged contract. As well, incorporating a carrying cost calculation would add more complexity to an already complex calculation.

(c) Undiscounted investment for future years has historically been available under the AESO's tariff for initial contract capacity at a connection project, and the AESO considers it reasonable that undiscounted investment for future years also be available for future contract capacity. For example, the AESO's tariff currently provides a certain amount of investment for capacity contracted in the 10th year from the date of service, if that capacity is also contracted in the first year of service. It seems unreasonable to discount investment for that same amount of capacity contracted in the same 10th year, simply because it was not contracted for until the 3rd or 4th year of service. As long as the commitment to future capacity is made in contract, it should have the same value today.

As well, the maximum investment level approach of the AESO contribution policy averages costs over all market participants. Some receive less-than-average investment while others receive above-average investment. Implementing policies such as adding carrying costs (through a Rider I or other mechanism) will simply add complexity and distort the price signal, without making the underlying averaging any more precise.
Topic: T&Cs-Shared Facilities

Reference: Section 6.12.2; Paragraph 534

Preamble: “The provisions of subsection 3 of section 9 of the proposed terms and conditions provide significantly greater detail with respect to shared facilities than the current Article 9.10. The AESO also notes the proposed section abandons the “full refund for five years then straight-line declining balance for fifteen years” approach of the current terms and conditions. The AESO considers that the 20-year average contract capacity and substation fraction approach described in proposed subsection 3 provides an equitable allocation of the costs of shared facilities to market participants over time.”

Request:

(a) Please confirm the proposed change in the method of determining allocation factors ignores the time value of capacity payments over the 20 year period.

(b) If yes to (a) please explain why the AESO considers the 20-year average contract capacity and substation fraction approach described in proposed subsection 3 provides an equitable allocation of the costs of shared facilities to market participants over time.

(c) Please explain why an allocation method which recognizes the time value of capacity payments as at present, cannot be continued.

Response:

(a-b) Confirmed, inasmuch as a facility shared for a single year in year 1 will have the same impact as a facility shared for a single year in year 20. However, a facility shared in year 1 is likely to remain shared for the full 20-year period whereas a facility shared in year 20 will likely be shared for only a 1-year period. The latter sharing will therefore have only 1/20 the impact of the former sharing, which the AESO considers appropriately reflects the relative value of the two sharing scenarios.

(c) The shared facilities approach in the AESO’s current tariff recognizes the time value of money only after the first five years of service. It is also premised on constant contract capacity levels for all involved market participants over the term of the contract, and cannot readily accommodate staged contracts and multiple market participants.

The approach proposed in the 2010 tariff was designed to address staging and multiple market participants. Including further recognition of the time value of capacity payments would add more complexity to an already complex calculation.

Finally, recognizing the time value of capacity payments would potentially add a “first mover” cost to shared facilities, whereby a market participant could benefit by requesting
system access service following, rather than concurrent with, another market participant. Such behaviour can obstruct the efficient and orderly development of a connection project.

On balance, the AESO considers the average contract capacity and substation fraction approach proposed in its 2010 tariff to be reasonable and equitable, and to encourage market participants to plans and contract for the capacity they require for service.
Topic: T&Cs-Facilities in Excess of Good Electric Industry Practice

Reference: Section 6.11.3; Paragraph 486

Preamble: “Good electric industry practice is proposed to be defined in the authoritative documents glossary as “the standard of practice attained by exercising that degree of knowledge, skill, diligence, prudence and foresight which would reasonably and ordinarily be expected from a skilled and experienced person engaged in the same type of undertaking in the same or similar circumstances, including determining what is reasonable in the circumstances having regard to economic considerations.” The AESO considers that this provision provides prudent protection against abuse of its contribution policy.”

Request:

(a) Please identify the objective criteria that would be used to determine good electric industry practice from a technical and commercial point of view.

(b) Please elaborate on the interpretation of the phrase “determining what is reasonable in the circumstances having regard to economic considerations”.

(c) Please explain the process for resolving any disputes regarding AESO’s and the market participant’s interpretations of good electric industry practice.

Response:

(a) Please refer to information response AUC.AESO-018 (d-f).

(b) The AESO considers the reference to “having regard to economic considerations” captures the concept of considering economics, while not being restricted to least-cost approaches to the exclusion of all others. Good electric industry practice should instead comprise the spectrum of reasonable practices, methods, or acts applicable to the circumstances. As discussed in section 6.11.3 (page 115) of the application, economic discipline is expected to be provided through construction contributions being more commonly required due to the alignment between costs and investment level and due to investment being limited by the maximum available based on the market participant’s contract capacity and investment term.

(c) Please refer to information response AUC.AESO-019 (a-b). The AESO suggests that disputes will be rare, but if they occur and could not otherwise be resolved they would be addressed in accordance with section 103.2 of the ISO rules, as provided for in subsection 4(1) of section 1 of the proposed tariff.
Topic: T&Cs-Valuation of Facilities for Contribution Determination

Reference: Section 6.11.4; Paragraph 489

Preamble: “The second provision provides a reduction in costs for a connection project if a transformer is removed and replaced with a larger transformer. The reduction in costs is the RCN value of the transformer that is removed, which is consistent with the RCN value that will be assigned to the transformer when it is returned to service at another site. This is a simple, consistent, and fair approach that recognizes the value of transformers removed from service when increasing the capacity of a system access service in response to a market participant’s request.”

Request:

(a) Please explain why the AESO considers it appropriate for the reduction in costs for a connection project, if a transformer is removed and replaced with a larger transformer, to be valued at RCN whereas for plant accounting purposes the TFO would take back the replaced transformer into stores at net book value.

(b) Would this proposal not result in indirectly crediting the market participant for the depreciation he should be responsible for in any event, during the time he had use of the replaced transformer?

Response:

(a) The AESO notes that valuing a transformer at RCN is done solely for the purpose of determining the construction contribution under the ISO tariff, and does not affect the property accounting practices of the TFO.

As stated in subsection 5(1) of section 8 of the proposed tariff, equipment used for a connection project will be valued at RCN for the purpose of determining the market participant’s construction contribution. Regardless of the actual age of the transformer and other equipment that is installed, the market participant receives the same system access service and should therefore be responsible for the same level of costs. For the purpose of determining a construction contribution, it does not matter whether a transformer has been newly received from a manufacturer or has been supplied from inventory after many prior years of use — it supplies the same function in providing system access service and is valued at RCN.

Similarly, when a transformer is removed from service as part of an upgrade connection project, it is also valued at RCN for the purpose of determining a construction contribution. It does not matter whether the transformer is new because an older one had failed in service and had been replaced, or whether it is old and near the end of its life — it had been supplying the same function in providing system access service and is
valued at RCN. As well, the transformer that is removed and credited at RCN will typically be returned to inventory, installed some time later at a new connection project, and then be charged at RCN. Its value for the purpose of determining a construction contribution is consistently RCN.

(b) The market participant is not, and should not be, responsible for depreciation associated with the specific equipment used to provide system access service to the market participant. The market participant does not own the assets and equipment used to provide the service. In particular, if older equipment from inventory is used to provide system access service, the market participant should not be charged a lower rate because the equipment is already significantly depreciated.

The TFO owns, operates and maintains the equipment, and is therefore responsible for the depreciation expense. The TFO's costs are recovered through an average rate for service to market participants.
Topic: POD Cost Function-Cost Function Determination

Reference: Appendix F Section 5.2; Page 12

Preamble: “Although the variability of costs within the data set is significant, the projects nevertheless exhibit a clear trend of cost increasing as contract capacity increases. Combined with the moderate regression coefficient, the AESO concludes this equation is a reasonable average cost function for recent transmission connection projects.”

Request:

(a) Please confirm that given the r squared value of .4144, there is less than 50% probability the shape of the chosen POD cost function is in fact reflective of the pattern of cost changes with capacity increases.

(b) Given that radial line costs do not vary with capacity, please explain why AESO did not consider radial line extension as a separate component of the cost function for AESO investment in customer facilities, in order to improve the r squared values.

(c) Please indicate whether radial line extension costs are included as part of the local system costs.

(d) If radial line customer extension costs are not part of the local system costs why is it not appropriate to include them as part of local system costs and design the tariffs and investment levels accordingly?

(e) If the radial line extension costs are included as part of the local system costs would it be more appropriate to treat radial line extension costs as a separate cost for investment purposes than as it is for tariff purposes.

Response:

(a) The common interpretation of the $r^2$ value is that it indicates “the proportion of the total sample variability (of the dependent variable) explained by the regression relationship.” (Statistics, 10th edition (2006), James T. McClave and Terry Sincich, Pearson Prentice Hall, Upper Saddle Ridge, NJ) In other words, the $r^2$ value is the percentage of the sample variation in project costs that can be explained by (or attributed to) using contract capacity to predict costs in the regression model. The $r^2$ value of 0.4144 therefore indicates that about 41% of a connection project’s costs is attributable to the project’s contract capacity, while the balance is attributable to other factors.

The $r^2$ value in the 2010 POD cost function analysis is comparable to the 0.49 value for the POD cost function on which the AESO’s current tariff is based. With respect to that
2007 POD cost function analysis, the Alberta Energy and Utilities Board stated in Decision 2007-106 (page 46):

*The Board considers that the comparatively low $R^2$ values reflect the fact that factors unrelated to a POD’s DTS contract capacity will have a significant impact on the cost of specific PODs…. While the statistical fit may not be high, the Board does not consider that statistical analysis should be discarded solely on the basis that $R^2$ values fall in the lower range.*

(b) Consistent with findings for the 2007 POD cost function, radial line costs are positively correlated with contract capacity, although weakly. As well, removing radial line costs does not significantly increase the correlation factor of remaining costs. The AESO considers that creating a separate radial line component in the maximum investment level and in the Rate DTS POD charge would increase the complexity of those already complex calculations without improving the correlation or representation of the underlying costs.

(c) Radial line extension costs are part of the point of delivery (POD) function and not part of the local system function in the transmission system cost studies on which the AESO’s tariff is based.

(d-e) The local system function delivers electricity from the bulk system to a small number of points of delivery in a local region. The local system is generally shared by the points of delivery in the region.

The point of delivery function includes all facilities that deliver electricity from the local system to a single substation. Point of delivery facilities normally provides service to one market participant at the substation (or two or more market participants at a single shared substation). The point of delivery function includes radial transmission extensions that are used exclusively by a single load substation.

It would be inappropriate to include radial extensions in the local system function as radial extensions are not shared by multiple points of delivery, and should be attributed to a single substation.
Topic: POD Cost Function-Inflation

Reference: Appendix F Section 4.2; Page 8

Preamble: “The AESO agrees with the concept of escalating the maximum local investment using publicly-available indices both for the investment levels included in a tariff application and annually between full tariff applications. The AESO examined the project cost data to establish appropriate cost categories and determine corresponding public indices.”

Request:

(a) Please indicate whether the four published indices used by the AESO and identified at page 8 are based on the escalation rates applicable to the inputs such as materials, labour, etc going into the cost of constructing substations, transmission lines, etc.

(b) Please confirm that input cost indices such as used by the AESO would not capture any productivity improvements achieved by the owners in constructing transmission facilities.

(c) Please confirm that an output based index such as CPI which captures the cost increases relative to a representative basket of goods and services reflects productivity improvements in the general economy.

(d) Has the AESO reviewed or carried out any studies or estimates to determine the historical productivity achieved by owners of transmission facilities in Alberta, Canada or in the US. Please provide any information the AESO considers relevant to determination of productivity factors for transmission facilities.

Response:

(a) The substations equipment, transmission line systems materials, and industrial services indices would generally be considered input cost indices. Statistics Canada explained that the industrial structures indices reflects the contractor’s selling price for work-in-place and includes a factor for productivity when appropriate, and would therefore generally be considered an output cost index.

(b) The substation and transmission line systems indices are applied to substation-related and transmission line-related material costs, respectively, and use of input cost indices are therefore appropriate. As noted in part (a) above, the industrial structures indices that are applied to construction-related costs is an output cost index. An output cost index would perhaps be somewhat more applicable to the engineering-related costs for which the industrial services index is used, but those costs represent only 18% of total project costs and a suitable publicly-available output cost index could not be located.
(c) Confirmed, to the extent that productivity improvements in the general economy actually affect cost increases captured by the representative basket of goods and services in an output based index such as CPI. As well, the basket of goods and services represented by CPI does not seem reflective of the magnitude and timing of changes to transmission-related costs, based on the comparison of year-over-year increases in Alberta CPI and the composite inflation index on page 9 of the 2010 POD Cost Function and Investment Level Update provided as Appendix F to the application.

(d) No, the AESO has not reviewed or carried out any such studies. The AESO notes that AltaLink included information on the Handy-Whitman average transmission cost index from the United States in its 2009-2010 TFO tariff application, and also discussed that information during its industry consultation process discussed in section 3 of the 2010 ISO tariff application. The AESO understands the Handy-Whitman index is an output cost index, but did not review it in detail as it is not readily publicly available.
Topic: POD Cost Function Investment Level Multiplier

Reference: Appendix F Section 5.4; Page 16

Preamble: “Based on total facilities costs with a multiplier of 1.06, 32 data points (or 50%) receive full investment, 5 data points (or 8%) receive over 90% investment, 9 data points (or 14%) receive 80% to 90% investment and hence a total of 46 data points (or 72%) received at least 80% investment. Fewer projects receive 80% investment based on total facilities costs compared to standard facilities costs, which is reasonable since total facilities cost more than standard facilities for several projects while total investment remains the same. The same total amount of investment is provided in both cases.”

Request:

(a) Please provide the reasons why the level of investment based on total facilities cost is more than that based on standard facilities notwithstanding the averaging that takes place when total facilities costs are averaged over several projects resulting in smoothing out the outliers.

(b) Please explain why the AESO considers it appropriate to use a multiplier based on total facilities costs rather than using standard facilities costs based on good electric industry practice with no multiplier, given that the latter, if based on RCN, would be more reflective of what is typical and forward looking as opposed to the former which reflects historical outliers within the data set analyzed.

(c) Please recalculate the project coverage described above under the proposed POD cost function assuming project costs are inflated using the AESO proposed indices minus an annual productivity factor of 1% per annum. Please include supporting calculations in Excel format.

Response:

(a) The level of investment is not more based on the total facilities cost approach proposed in the application. The following table compares the investment level based on total facilities cost and a 1.06 multiplier to that based on standard facilities cost and a 1.15 multiplier.
<table>
<thead>
<tr>
<th>Tier</th>
<th>Maximum Investment Level</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Total Facilities 1.06 Multiplier</td>
</tr>
<tr>
<td>Substation fraction (for new points of delivery only)</td>
<td>$51,050/year</td>
</tr>
<tr>
<td>First (7.5 × substation fraction) MW of contract capacity</td>
<td>$34,650/MW/year</td>
</tr>
<tr>
<td>Next (9.5 × substation fraction) MW of contract capacity</td>
<td>$12,800/MW/year</td>
</tr>
<tr>
<td>Next (23 × substation fraction) MW of contract capacity</td>
<td>$7,750/MW/year</td>
</tr>
<tr>
<td>All remaining MW of contract capacity</td>
<td>$4,200/MW/year</td>
</tr>
</tbody>
</table>

In each case the investment level is determined such that the same total amount of investment is provided over the 64 projects included in the POD cost function analysis.

(b) The AESO considers that the 64 recent projects in the POD cost function analysis are representative of what is typical and forward looking. These are projects that were actually required for system access service in the recent past, and there is no reason to think they are not representative of projects that will be required for system access service in the near future. The project costs included in the analysis were escalated to 2010 using the composite inflation index, which should make those costs reasonably representative of RCN.

Basing investment level on average costs with no multiplier would limit investment to the average cost of a project, would not be consistent with the maximum investment level approach used by electric utilities in Alberta, and would not satisfy some of the principles summarized in section 6.11 (pages 107-110) of the application.

The AESO also considers that all the projects included in the POD cost function analysis would comply with good electric industry practice, although a comprehensive review of all the connection proposals has not been performed from that perspective.

As noted in Decision 2007-106 (page 95), “Setting the appropriate level for the maximum investment allowance is a balancing act.” The AESO considers the approach proposed in its 2010 tariff application appropriately balances relevant considerations for its contribution policy.

(c) If project costs are inflated using the composite inflation index minus 1% per year and if the maximum investment level is based on total facilities cost (which the AESO considers to represent good electric industry practice) with no multiplier, then

- 28 project (or 44%) would be fully covered by investment,
- 4 projects (or 6%) would have at least 90% (but not 100%) of costs covered by investment,
- 5 projects (or 8%) would have 80% to 90% of costs covered by investment, and
- overall a total of 37 projects (or 58%) would have 80% or more of costs covered by investment.
The investment in all 64 projects would total $392 million compared to the $439 million with the investment level proposed in the application.

Please see Attachment CCA.AESO-15 (c) for the supporting calculations in Microsoft Excel format.
Topic: POD Cost Function Reasonability

Reference: Appendix F Section 5.5; Page 16

Preamble: “The AESO also considered whether the total facilities cost function would impact the DTS POD charge, compared to the standard facilities cost function. The POD charge depends primarily on the “shape” of the cost function rather than its level, as the POD charge revenue requirement is allocated proportionately over the cost function tiers. The total facilities cost function results in a POD charge that is essentially the same as that resulting from a standard facilities cost function, with POD charge components varying by no more than ±1% between the two approaches.”

Request:
(a) Please indicate whether the existing POD charges are based on a standard facilities cost function.
(b) Please provide the input data and analysis used to determine the standard facilities cost function on which the structure of POD charges are based.
(c) Please provide the data and analysis based on which the AESO came to the conclusion the total facilities cost function results in a POD charge that is essentially the same as that resulting from a standard facilities cost function, with POD charge components varying by no more than ±1% between the two approaches.

Response:
(a) Yes, the existing POD charges are based on a standard facilities cost function.
(b) A standard facilities cost function based on the 64 projects in the 2010 POD cost function update is provided on the “raw-cost-function-Std” and “cost-function-std” sheets in the POD Cost Function Workbook filed as Appendix G to the application.

The AESO notes that the existing POD charge was based on the standard facilities cost function developed from analysis of 48 projects as part of the AESO’s 2007 tariff proceeding. The standard facilities cost function provided in Appendix G to the 2010 tariff application follows the same methodology but uses the updated and expanded 64-project data set.
(c) Please see Attachment CCA.AESO-016 (c) for the analysis on which the AESO’s conclusion was based.
In addition to stakeholder involvement in the AESO’s Budget Review Process discussed in section 2.1 of this application, the AESO conducted extensive stakeholder consultation as part of the development of its 2010 tariff proposals. The stakeholder consultation on the AESO’s 2010 tariff was conducted from February through November 2009 and included three main initiatives:

• initial meetings with individual stakeholders to discuss matters to be addressed in the tariff application and consultation approaches to be used in addressing them;

• three general stakeholder meetings to provide information on the development of the tariff application proposals and receive feedback and comments on those proposals; and

• nine small working groups established to examine specific topics in depth, including investigation of different approaches to addressing the various matters under consideration for the tariff application. [Page 20]

Request:

(a) Please provide AESO’s understanding of a “stakeholder” and provide a list of all stakeholders who were (i) invited to participate (ii) asked to participate but were not made part of the stakeholder sessions and/or one or more of the 9 small working groups in the tariff consultation process.

(b) AESO states the working groups “were limited to six to eight members, and sometimes group membership was adjusted to ensure diversity and balanced representation of views.” Please provide details and rationale in respect of all adjustments made to the composition of groups to ensure these working groups adequately reflected “diversity and balanced representation” of the various parties. For those groups which were so adjusted, please explain whether it was AESO or the stakeholders who decided there needed to be an re-alignment of the group(s) to achieve the necessary “diversity and balanced representation”.

(c) Please provide meeting notes or other such summary notes of each such stakeholder session.

(d) Please provide a summary of the recommendations and/or conclusions put forward by each of the working groups, and other such consultative initiatives.
Response:

(a) For its tariff consultation, the AESO considers a stakeholder to be any party (including any representative of a party) who can reasonably expect to be affected by the AESO’s tariff. The AESO’s invitation to participate in its tariff consultation was broadly distributed as well as publicly posted on the AESO’s website.

To the best of the AESO’s recollection, no party who asked to participate in the initial meetings with individual stakeholders or in the general stakeholder meetings were declined the opportunity to do so (excluding any schedule conflicts that may have prevented a stakeholder from attending one or more of those meetings). All stakeholders also had the opportunity to contact the AESO at any time and discuss aspects of the 2010 tariff application.

With respect to the small working groups, five of the nine working groups had requests greater than the maximum of six to eight members (including AESO employees and consultants) that had been established in the working groups’ terms of reference. The following stakeholders asked to participate in the listed small working groups but were not able to be accommodated:

- POD Cost Function and Investment Level Update Working Group:
  - ATCO Electric
  - CCA

- DTS Operating Reserve Charge Design Working Group:
  - CCA

- Export and Import Rates XTS and ITS Working Group:
  - AltaLink
  - ENMAX
  - TransAlta

- Amortized Customer Contribution Option and Other Contribution Provisions Working Group:
  - ATCO Electric
  - CCA
  - ENMAX
  - Statoil

- Tariff Provisions Related to Customer-Owned Substations Working Group:
  - ATCO Electric

Where a stakeholder was interested in participating on a working group but could not be accommodated, the AESO encouraged the stakeholder to contact one of the working group members to ensure its views were represented on the working group.

(b) The only adjustments to membership in the working groups were those restrictions described in part (a) above. The restrictions were determined by the AESO and reflected duplication of interest within a working group. For example, if more than one TFO asked to participate in a working group, only one TFO was generally accepted. Where requests
from similar-interest stakeholders were received, the AESO gave preference to the stakeholder who first asked to participate.

In the case of CCA, it asked to participate on working groups where UCA already represented the interests of Alberta residential, farm, and small business consumers of electricity and natural gas. CCA was also unable to submit its request until after the deadline established for stakeholders to indicate their interest in specific working groups, whereas UCA submitted its request before the deadline.

(c) Please see Attachment CCA.AEOS-017 (c) for a compilation of all documents distributed as part of the AESO’s consultation meetings.

(d) The AESO did not formally document the conclusions of the working groups. As noted in the working groups’ terms of reference, the working groups were forums for stakeholders to provide perspective, advice, and expertise to the AESO on specific topics for the 2010 tariff application. More specifically, the scope of the working groups was defined as follows:

   Working Groups will review and discuss options and alternatives for proposals being considered for inclusion in the AESO’s 2010 tariff application. Working Groups are not decision-making bodies. Consultation within Working Groups will not replace general stakeholder consultation.

As noted in section 3 (page 21, paragraph 88) of the application, “The AESO remains accountable for the proposals in its 2010 tariff application and for ensuring those proposals are consistent with legislation, policy, and the AESO’s mandate. In developing the proposals, however, the AESO did consider the input and advice of stakeholders provided during consultation.”
Topic: O&M Cost Study – General

Reference: X007, App C, page 7

Preamble: TFO revenue requirement data was compiled for the years 2006 through 2009 and includes both actual and forecast data where available. The cost data for 2008 was studied in depth to develop the cost causation study for O&M costs. TFO revenue requirement data is summarized in the cost study in Schedule Sum 1.0 of Appendix A. TFO revenue requirements are summarized in Table 3. Please note that some forecast data has been replaced with actual data and therefore may not reconcile to other data filed with the AUC. [Page 7]

Request:

(a) Page 7: Table 3 provides the RFO Revenue Requirement for the years 2006-2009. Please confirm the 2010 O&M Study does not use 2009 data as it was determined the “Forecast 2009 Revenue Requirement for ENMAX was dated and is not used.” If so confirmed, please explain if AESO plans to update this study once the 2009 actual data is available from ENMAX.

(b) If 2009 data is not used for purposes of the 2010 O&M Study, please provide the point of including it in this study.

(c) TFO capital and non-capital Revenue Requirement costs in respect of each of the 4 largest TFO’s are sourced from approved forecasts and/or actual results, and in some cases, have been re-stated to reflect actual results. Please indicate which of the years 2006 to 2009 is the data (i) actual (ii) forecast and (iii) mixture of actual and forecast.

(d) Please provide all specific situations where co-mingling of forecast and actual data was done, and provide rationale for it and quantify the change in Revenue Requirement arising from this co-mingling of forecast and actuals.

(e) Please confirm the TFO costs as filed in this Application for each of the years 2006-2009 have, in fact, been reviewed by each of the TFO’s for reasonableness.

Response:

(a) Confirmed. The Electric Transmission Operating and Maintenance Cost Study uses data only up to and including 2008. The AESO does not plan on requesting that the study be updated when 2009 actual data becomes available.

(b) The 2009 data was obtained from the various TFO tariff applications and was included to indicate if a TFO has plans that would materially change costs going into the future.
(c) The basic data for the *Transmission O&M Cost Study* is forecast data obtained from the various TFOs’ tariff applications. Further breakdowns of costs were obtained on both forecast and actual data to complete the study. Therefore, co-mingling of data occurs throughout the study years of 2006 through 2008.

(d) The use of forecast and actual data occurs in order to match basic data from the TFO tariff filings and to use the best data available. The TFO tariff applications start with actual data from years prior to the test period, and include forecast data for the test period. The AltaLink 2009-2010 TFO tariff application included actual data for 2006 and 2007, a mix of forecast data with some updates for 2008 (the 2008 Management Update), and forecast data for 2009 and 2010. The ATCO 2009-2010 tariff application used actual data for 2006 and 2007 and forecast data for 2008 through 2010. The ENMAX formula-based ratemaking application used actual data for 2006 and included forecast data for 2007 through 2016. The EPCOR 2007-2009 tariff application used actual data for 2005 and 2006 along with forecast data for 2007 through 2009. Given the different time frames for the starting point data, a mixture of forecast and actual data is used for the purpose of the *Transmission O&M Cost Study*. The cost study uses the revenue requirement in the TFO tariff applications as the base, and reconciles other factors back to the revenue requirement. Ultimately, the *Transmission O&M Cost Study* develops percentages of functionalized and classified costs, so that these values can be applied for rate design for future years, regardless of changes to revenue requirement in the future.

(e) The TFO tariff application was used as a starting point for the *Transmission O&M Cost Study*, and the assumption was made that each TFO had reviewed its own application. During meetings with each TFO, discussions were held to obtain further data in order to functionalize and classify the non-capital costs. The evolution of the *Transmission O&M Cost Study* was shared with each TFO during meetings to discuss the methodology and to obtain further data, but the TFOs were not asked to review or verify the final study.
Topic: O&M Cost Study – Allocation of G&A costs

Reference: X007, App C

Preamble: Generally, the TFO O&M costs are considered all TFO costs that are not capital related costs. However, for the purpose of this report, non-capital costs and O&M costs are not synonymous. For the purpose of this report, non-capital costs are further separated into Operating and Maintenance (O&M) and General and Administrative (G&A). The O&M costs were further studied for fictionalization and classification. The functionalization and classification of O&M costs are applied to the total amount of non capital costs (both O&M and G&A) in order to complete the cost study for the entire revenue requirement. [Page 3]

Request:

Please provide rationale as to why the drivers for functionalization and classification of O&M costs necessarily apply to the functionalization and classification of G&A costs.

Response:

The distinction of G&A as part of the non-capital costs was developed because some costs have no demonstrable link to cost causation, either in terms of the capital or operating costs associated with the electric transmission system. Examples of such costs include hearings, community relations, and allocated administrative expenses. No defendable methodology was found to functionalize or classify these costs, and yet these are costs associated with an electric transmission system.

The G&A expenses such as office expenses, staff expenses, training, buildings, and telecommunications will be a function of the number of staff employed. These costs appear to relate to O&M more closely than to capital, and therefore all G&A costs were functionalized and classified on the same basis as O&M.

In addition, the two obvious choices for functionalizing and classifying these costs are to assume these costs track operating and maintenance costs or capital costs. According to the capitalization policies of the TFOs, these G&A costs are not capital-related costs and therefore they are considered to track O&M costs.

Please refer to information response AUC.AESO-002 for additional information.
Topic: O&M Cost Study – G&A Costs

Preamble: Non-capital costs are further identified as either O&M costs or G&A costs. This breakdown is influenced by the TFO data and further defined by O&M costs having a relationship to the in-service electric transmission facilities, whereas G&A costs do not have a strong relationship to transmission facilities and are incurred to operate the business of the utility company. Based on this distinction, O&M costs are further studied to determine causation, while G&A costs are allocated on the basis of O&M costs. [Page 9]

Reference: X007, App C

Request:

Instead of allocating G&A costs on the basis of O&M, to the extent such costs “are incurred to operate the business of the utility company,” please quantify the change in the results of the O&M Study should the Commission approve an allocation of such costs on the basis of all other costs i.e. both capital and O&M. Please provide all calculations.

Response:

If the G&A costs are allocated on the basis of all other costs (capital and O&M), then the final result is as shown below in the first table (with original results shown in the second table). Please refer to the spreadsheet provided as Attachment CCA.AESO-020 for further details.

<table>
<thead>
<tr>
<th>G&amp;A based on Total Other Costs As per CCA.AESO-020</th>
<th>Bulk System</th>
<th>Local System</th>
<th>POD</th>
<th>Totals</th>
</tr>
</thead>
<tbody>
<tr>
<td>Demand Related</td>
<td>29.5%</td>
<td>16.7%</td>
<td>17.7%</td>
<td>63.8%</td>
</tr>
<tr>
<td>Energy Related</td>
<td>6.7%</td>
<td>4.3%</td>
<td>2.2%</td>
<td>13.2%</td>
</tr>
<tr>
<td>Customer (POD)</td>
<td>0.0%</td>
<td>0.0%</td>
<td>23.0%</td>
<td>23.0%</td>
</tr>
<tr>
<td>Totals</td>
<td>36.1%</td>
<td>21.0%</td>
<td>42.9%</td>
<td>100.0%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Weighted Capital and Non Capital Base Case - Updated as per IR's</th>
<th>Bulk System</th>
<th>Local System</th>
<th>POD</th>
<th>Totals</th>
</tr>
</thead>
<tbody>
<tr>
<td>Demand Related</td>
<td>28.1%</td>
<td>17.4%</td>
<td>17.7%</td>
<td>63.1%</td>
</tr>
<tr>
<td>Energy Related</td>
<td>6.4%</td>
<td>4.7%</td>
<td>2.7%</td>
<td>13.8%</td>
</tr>
<tr>
<td>Customer (POD)</td>
<td>0.0%</td>
<td>0.0%</td>
<td>23.0%</td>
<td>23.0%</td>
</tr>
<tr>
<td>Totals</td>
<td>34.5%</td>
<td>22.1%</td>
<td>43.4%</td>
<td>100.0%</td>
</tr>
</tbody>
</table>
Topic: O&M Cost Study – O&M Costs deemed to be capital-related

Reference: X007, App C

Preamble: For the purpose of this Study, annual structure payments, linear and property taxes, and capital related revenue offsets (all generally included in TFO operating costs) were deemed to be capital related because such costs are proportional to the capital employed, not to labour costs, and management has little discretion in managing these costs in the short term. Revenue offsets were deemed capital related where leasing of electric transmission facilities is associated with capital investment. Revenue that offset labour costs, such as affiliate revenue, was deemed to be non-capital related. [Page 8]

Further details are needed to assess impacts if AESO were to mirror the treatment of operating costs by the TFOs in its O&M Study.

Request:

(a) Please provide an assessment on the results of the AESO O&M Study if costs which are treated as operating costs by the TFO, such as those described in the preamble above (ASP’s, linear/property taxes etc) were deemed to be also operating costs for purposes of AESO’s O&M Study. Provide all supporting calculations.

(b) Please explain whether the TFOs have approved the reclassification of the operating costs as capital costs for purposes of AESO’s 2010 O&M Study.

(c) Please provide AESO’s definition of a “period cost”.

(d) Please confirm operating costs such as ASP’s, linear/property taxes etc. do not have a “lasting benefit” as described in Section 4.1 of the O&M Study.

(e) Please confirm the treatment of “capital maintenance” and “emergency maintenance” in the O&M Study is the same as that employed by the TFOs i.e. as capital-related.

Response:

(a) There are differences between what TFOs consider operating and maintenance costs, and what is considered operating and maintenance for the purpose of the Transmission O&M Cost Study. For the purpose of the study, the costs were reviewed from the perspective of cost causation, while from the TFOs’ perspective their regulatory applications follow their capitalization policies. Therefore differences occur in areas such as linear and property taxes, where the tax is proportional to capital assets and is considered capital-related for this study, while linear and property taxes are not capitalized within a TFO and are considered an operating cost by the TFO.
(b) The TFOs have neither approved nor disapproved the reclassification of operating costs as capital-related costs, nor have they been asked to approve any part of the *Transmission O&M Cost Study*. Please refer to information response CCA.AESO-018 (e) for additional information.

(c) The term “period cost” is not used in the *Transmission O&M Cost Study*, although the AESO understands a "period cost" is a cost identified with the accounting period in which it is incurred.

(d) Operating costs such as annual structure payments and linear and property taxes do not have a lasting benefit and are not capitalized according to the capitalization policy of the TFOs.

(e) Confirmed.
Topic: O&M Cost Study – Fuel Costs

Reference: X007, App C

Preamble: The amount of fuel used in the isolated generating plants is proportional to the energy consumption and is not directly linked to the peak demand, or number of customers being served.

As a result, fuel costs (and variable O&M costs associated with isolated generation) are considered O&M costs and are functionalized as Local and POD and classified as energy related. [Page 9]

Request:

While fuel costs may be viewed as a surrogate for building transmission lines (see also discussion at page 9), please confirm that to the AESO’s knowledge, there are no imminent plans to construct such lines and obviate the need for fuel.

Response:

The AESO is not aware of any imminent plans to do so, but notes it has happened in the recent past. The community of Fox Lake was served by isolated generation until 2005 when it was connected to the Alberta interconnected electric system.
Topic: O&M Cost Study – Miscellaneous Revenues

Reference: X007, App C

Preamble: Revenue offsets include various amounts of revenue to the TFOs that do not form part of the TFO core business. Revenue identified in Revenue offsets arises from affiliates for services, joint use (shared use of poles with other utilities) and other services to outside parties.

Revenue offsets are provided in Schedules AL 2.0 and AT 2.0 and are separated into capital costs where the revenue offset is related to a capital investment or non-capital costs where the costs are related to labour. [Page 10]

Request:

(a) Schedule AL 2.0: For each component of the Miscellaneous Revenues deemed to be capital-related, please provide a detailed assessment that led to the conclusion the amount is in fact related to capital.

(b) Schedule AE 2.0: Please provide information similar to that requested in (a) above.

(c) At a high level, it appears AESO has considered about 91% [$6.8/7.5M] of AML’s revenue offsets are deemed capital-related in 2006, as compared to 27.8% [$1,117/4,022]. Please explain steps taken by the AESO to determine the reasonableness of AML having more than 3 times the capital-related Revenue Offsets than that for AE.

Response:

(a) Three items of Miscellaneous Revenue are related to labour costs and are considered operating. The three items are listed in Schedule AL 2.0 and include revenue from TransAlta for maintenance and technical services, revenue from TransAlta for working with First Nations, and revenue from affiliates.

The remainder of the revenue is from lease arrangements of capital, and therefore is considered capital-related. For example, FortisAlberta leases telecommunications from AltaLink and this revenue is shown in the first line of the block of the breakdown of Miscellaneous Revenue. The second line shows the revenue from joint use where FortisAlberta attaches its distribution lines to transmission structures, and pays AltaLink for the right to attach its circuits to AltaLink’s structures. Similarly, TransAlta uses AltaLink’s telecommunications system and Control Centre and compensates AltaLink for that use. Likewise, leases to other parties occur because AltaLink made investments in capital facilities, which also provide service to other parties and this lease revenue is an offset to the cost of having these facilities in place. The assessment of the split between
capital and operating offsets was developed on the basis of AltaLink’s tariff application filing and information gathered during meetings with AltaLink.

(b) The ATCO Electric Miscellaneous Revenue was reviewed in the same manner as with AltaLink. If the revenue offset was associated with labour costs, then the revenue offset was considered operating and maintenance, while if the revenue offset was associated with the lease of capital facilities, the revenue offset was considered capital-related as shown in Schedule AT 2.0.

(c) The breakdown of the Miscellaneous Revenues was determined in the Cost Study and the results are summarized in the question. As shown in the Schedules, much of AltaLink’s miscellaneous revenues comes from TransAlta and corporations that were formerly part of TransAlta. Prior to the sale of various parts of TransAlta, one control center and telecommunications system provided service to all parts of the organization. With the sale of various parts, there are now arrangements where some facilities are still shared, and this results in Miscellaneous Revenue to AltaLink. ATCO Electric did not go through the same evolution, and therefore the makeup of Miscellaneous Revenue for ATCO Electric is different.
Reference: X007, App C – Cost Functionalization

Preamble: Each group is studied to determine how costs are incurred, and then the Net Salary is functionalized where possible. For example, the System Control Center has personnel that are physically located in a centralized control Center, but staff operates switches that are located in substations. While the switches are located in the substations, the switches are used to switch transmission lines and substation equipment such as transformers. For the purpose of the System Control Center, the number of elements (lines and transformers) in service is used to functionalize costs. The voltage of each element is used to determine the function of the element. The number of elements in each function is the basis for cost functionalization of System Control Center costs as shown in Table 8 (extracted from Appendix A, AL Sch 5.0). [Page 13]

Request:

(a) Table 8 shows the total number of elements to be 763; however, AL Schedule 5.1[L48] indicates 436. Please reconcile.

(b) Please explain the derivation of the number of elements in AL Schedule 5.1, L48. If based on a single year, please provide the average for the last 3 years for which actuals are available and explain why such an average would not be appropriate.

(c) Page 14: AESO states where it was not possible to determine the cost causation for all groups, costs were allocated based on all other Net Salary and Wages.
   (i) Please reconcile the amounts shown on Table 10 to the details provided on AL Schedule 5.2, L36-38. For example, the bull net salary on AL Schedule 5.2, L36 is shown at $3.472M whereas on Table 10, it is shown as $3.790M.
   (ii) Please discuss why net salary and wages is deemed a reasonable basis to functionalize costs which cannot otherwise be directly functionalized.
   (iii) Please provide an assessment of functionalizing these costs on the basis of both capital and all other non-capital costs, and provide computations demonstrating this alternative.

(d) 2008 Brushing costs were functionalized on the proportion of area for each function. Please provide an assessment of using the longer term average of the areas brushed rather than simply using 2008, and provide a computation using the date for the actual years 2006-2008, inclusive.

Response:

(a) The Schedules in Appendix C are correct and the Appendix D spreadsheet is in error. The total number of elements is 763, with 120, 207, and 436 in the bulk system, local system, and POD functions respectively.
(b) The number of elements was based on the number of lines and transformers at the end of 2007. The use of data from one year was used to simplify the process of completing the project in a timely and cost-effective manner. The data for other years is not readily available. To obtain the requested data, assistance of other parties is required, and this is not practical given the schedule for the completion of information responses.

(c) (i) Table 10 is an extract of the last two blocks of Schedule AL 5.2. The first block shows the amounts of Net Salary and Wages that are allocated to each function. As shown at the end of Schedule AL 5.1, some of Net Salary and Wages was not practical to functionalize, and the groups include Operations Management, IT, and Facilities. The Net Salary and Wages for these three groups are functionalized on the basis of all other Net Salary and Wages to arrive at the total Net Salary and Wages.

(ii) The assessment was made that Net Salary and Wages for Operations Management, IT, and Facilities was more closely related to other Net Salary and Wages than to other factors, because these groups support other employees whose costs make up the rest of Net Salary and Wages.

(iii) If the Net Salary and Wages of these three groups were functionalized on the basis of capital, there would be a small impact on the result of the study. These costs are already allocated on the basis of other operating costs, and therefore, allocating these costs on the basis of all other non-capital costs would be negligible. The extreme assumption would be that all G&A costs are allocated on the basis of capital, and the calculations of this assumption are provided in information response CCA.AESO-020.

(d) The total area brushed is a relatively stable parameter upon which to allocate brushing costs. The addition of lines and substations over the years will impact the total area brushed, and in the case where the system is rapidly expanding, there may be merit in reviewing each year. The assessment was made that the Alberta system is not rapidly expanding and that the review of one year provides a reasonable view of the proportion of brushing in each function. The actual amount of brushing in each function will vary depending on the brushing cycle which is typically 5 to 7 years. In any one year, there may be more or less than average brushing associated with any function (bulk system, local system, or POD). The data for other years is not available. To obtain the requested data, assistance of other parties is required, and this is not practical given the schedule for the completion of information responses.
Topic: O&M Cost Study – Proposed Allocation Factors

Reference: X007, App C, Schedule 5

Preamble: Further information is needed in respect of the proposed allocators.

Request:

(a) For each of the proposed allocators, please provide working papers to demonstrate the derivation of these allocators. Where a single year has been used, please provide the merits of using a longer term average for smoothing purposes.

(b) Re AL:8, please explain why breakers are not included as part of “elements”.

Response:

(a) The use of multiple years of data to obtain an average for smoothing is a good method for addressing anomalies in any one year. The use of multiple years also has the drawback of increasing the resources required to complete the work as well as increasing the complexity of managing additional data, and reconciling changes from year to year. Organizational changes also provide challenges as staff and responsibility is moved from one group to another. Therefore, in this report, 2008 was the year of focus, and additional years are shown for reference. The following describes the derivation of allocators as shown in Schedule AL 5.1.

(i) All:AL:1 – Line Length Allocator. The line length allocator is simply an inventory of transmission lines by voltage and by length. This allocator is not used directly, but is used for the development of other allocators. The transmission lines are functionalized on the basis of voltage level, 240 kV and above being bulk system and 144 kV and below being local system. Any lines that are 144 kV and below that are radial lines or taps are functionalized as POD instead of local system because these sections of line are dedicated to the POD to which it is connected.

(ii) All:AL:2 – Land Owner Allocator. The land owner allocator is one step in developing an allocator to allocate costs associated with staff who work with land owners. The land owner allocator is based on line length and the assumption that there is one land owner for each ½ mile of line, and one land owner for each substation.

(iii) All:AL:3 – Line Brushing Allocator. The line brushing allocator is used to allocate line brushing costs and is based on the area of land. Clearing of vegetation is done on the basis of area to be cleared (and the type of clearing required). The area of land is based on the line length, and the typical right of way width associated with a line. The highest voltage lines have the widest rights of way. Actual right of way widths vary depending on landowner requirements and line...
and construction standards. Some lines may be constructed along road allowances and thus have no right of way. The area of land that may require brushing by the three functions becomes the basis for the functionalization of brushing costs.

(iv) All:AL:4 – Substation Brushing Allocator. The brushing associated with substations is based on the count of substations for each of the functions.

(v) All:AL:5 – Inventory Allocator. The inventory allocator is used for costs of personnel working in purchasing and inventory. This allocator is based on the property associated with each function as determine in the prior Transmission Cost Causation Study and Update.

(vi) All:AL:6 – Contracted Manpower Allocator. The contracts for services were reviewed and assigned to each function on the basis of the voltage of the equipment that was being maintained.

(vii) All:AL:7 – EH&S Allocator. The number of staff and their roles were reviewed to functionalize the costs associated with environment, health, and safety. The last block of AL Sch 5.0 shows the percent of staff associated with each group, and their roles were reviewed in order to develop an assessment of the functionalization of costs associated with the group.

(viii) All:AL:8 – Control Centre. The costs of Net Salary and Wages of the Control Centre were assessed as proportional to the number of elements in the electric transmission system. An element was defined as a transmission line or transformer. The elements were functionalized on the basis of voltage level. The number of transformers is functionalized on the basis of the voltage on the low side of the transformer, where a transformer with a low side voltage of 138 kV is functionalized as bulk system, a low side voltage of 69 kV is functionalized as local system, and a low side voltage of 25 kV and below is functionalized as POD. The number of lines is functionalized on the basis of voltage, and radial connection. Lines with a voltage of 240 kV and up are functionalized as bulk system, and lines with a voltage of 144 kV and below are functionalized as local system, except those lines that are taps and radial lines which are functionalized as POD.

(ix) All:AL:9 – Asset Management. The Asset Management allocator was developed on the basis of full-time equivalent positions, and their roles within the Asset Management group as shown at the bottom of AL Sch 5.0. 45% of the staff in Asset Management work in transmission lines, 22% work in substations, and 33% work in protection and control. The transmission line FTEs are allocated to bulk system and local system on the basis of the transmission line lengths. The substation FTEs are allocated to POD. The protection and control FTEs are allocated to bulk system, local system, and POD on the basis of the number of circuit breakers by voltage level. The following table shows the calculation for the bulk system function for Asset Management.
<table>
<thead>
<tr>
<th>Function</th>
<th>Group</th>
<th>FTE</th>
<th>Portion</th>
<th>Portion</th>
<th>Basis for Portion</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bulk Transmission</td>
<td>44%</td>
<td>41%</td>
<td>18.2%</td>
<td>Line Length</td>
<td></td>
</tr>
<tr>
<td>Substation</td>
<td>22%</td>
<td>0%</td>
<td>0.0%</td>
<td>Substation Considered POD</td>
<td></td>
</tr>
<tr>
<td>P&amp;C</td>
<td>33%</td>
<td>14%</td>
<td>4.7%</td>
<td>Percentage of Breakers</td>
<td></td>
</tr>
</tbody>
</table>

**Asset Management Functionalization - Bulk 22.9%**

<table>
<thead>
<tr>
<th>Function</th>
<th>Portion</th>
<th>Portion</th>
<th>Basis for Portion</th>
</tr>
</thead>
<tbody>
<tr>
<td>Local Transmission</td>
<td>44%</td>
<td>59%</td>
<td>26.2% Line Length</td>
</tr>
<tr>
<td>Substation</td>
<td>22%</td>
<td>0%</td>
<td>0.0% Substation Considered POD</td>
</tr>
<tr>
<td>P&amp;C</td>
<td>33%</td>
<td>42%</td>
<td>13.9% Percentage of Breakers</td>
</tr>
</tbody>
</table>

**Field Operations Functionalization - Bulk 17.0%**

<table>
<thead>
<tr>
<th>Function</th>
<th>Group</th>
<th>FTE</th>
<th>Portion</th>
<th>Portion</th>
<th>Basis for Portion</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bulk Transmission</td>
<td>28%</td>
<td>41%</td>
<td>11.5%</td>
<td>Line Length</td>
<td></td>
</tr>
<tr>
<td>Substation</td>
<td>33%</td>
<td>0%</td>
<td>0.0%</td>
<td>Substation Considered POD</td>
<td></td>
</tr>
<tr>
<td>Telecom</td>
<td>39%</td>
<td>14%</td>
<td>5.5%</td>
<td>Percentage of Breakers</td>
<td></td>
</tr>
</tbody>
</table>

**Field Operations Functionalization - Local 32.7%**

<table>
<thead>
<tr>
<th>Function</th>
<th>Group</th>
<th>FTE</th>
<th>Portion</th>
<th>Portion</th>
<th>Basis for Portion</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bulk Transmission</td>
<td>28%</td>
<td>0%</td>
<td>0.0%</td>
<td>Line Length</td>
<td></td>
</tr>
<tr>
<td>Substation</td>
<td>33%</td>
<td>100%</td>
<td>33.3%</td>
<td>Substation Considered POD</td>
<td></td>
</tr>
<tr>
<td>Telecom</td>
<td>39%</td>
<td>44%</td>
<td>17.0%</td>
<td>Percentage of Breakers</td>
<td></td>
</tr>
</tbody>
</table>

Please note that there was an error in the FTEs in this allocator in the Transmission O&M Cost Study and Workbook filed as Appendices C and D with the application. This error is corrected in the revised Transmission O&M Cost Workbook submitted with these IR responses.

**Field Operations Functionalization - POD 50.4%**

All:AL:10 – Field Operations. The Field Operations allocator was developed on the basis of full-time equivalent positions and their roles within the Field Operations group, similar to the Asset Management group as shown in the bottom of AL Sch 5.0. The FTEs within Field Operations include 28% in transmission, 33% in substations, and 39% in telecommunications. The following table shows the calculation for the bulk system function for Field Operations.

<table>
<thead>
<tr>
<th>Function</th>
<th>Group</th>
<th>FTE</th>
<th>Portion</th>
<th>Portion</th>
<th>Basis for Portion</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bulk Transmission</td>
<td>28%</td>
<td>41%</td>
<td>11.5%</td>
<td>Line Length</td>
<td></td>
</tr>
<tr>
<td>Substation</td>
<td>33%</td>
<td>0%</td>
<td>0.0%</td>
<td>Substation Considered POD</td>
<td></td>
</tr>
<tr>
<td>Telecom</td>
<td>39%</td>
<td>14%</td>
<td>5.5%</td>
<td>Percentage of Breakers</td>
<td></td>
</tr>
</tbody>
</table>

**Field Operations Functionalization - Bulk 17.0%**

<table>
<thead>
<tr>
<th>Function</th>
<th>Group</th>
<th>FTE</th>
<th>Portion</th>
<th>Portion</th>
<th>Basis for Portion</th>
</tr>
</thead>
<tbody>
<tr>
<td>Local Transmission</td>
<td>28%</td>
<td>59%</td>
<td>16.6%</td>
<td>Line Length</td>
<td></td>
</tr>
<tr>
<td>Substation</td>
<td>33%</td>
<td>0%</td>
<td>0.0%</td>
<td>Substation Considered POD</td>
<td></td>
</tr>
<tr>
<td>Telecom</td>
<td>39%</td>
<td>42%</td>
<td>16.1%</td>
<td>Percentage of Breakers</td>
<td></td>
</tr>
</tbody>
</table>

**Field Operations Functionalization - Local 32.7%**

<table>
<thead>
<tr>
<th>Function</th>
<th>Group</th>
<th>FTE</th>
<th>Portion</th>
<th>Portion</th>
<th>Basis for Portion</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bulk Transmission</td>
<td>28%</td>
<td>0%</td>
<td>0.0%</td>
<td>Line Length</td>
<td></td>
</tr>
<tr>
<td>Substation</td>
<td>33%</td>
<td>100%</td>
<td>33.3%</td>
<td>Substation Considered POD</td>
<td></td>
</tr>
<tr>
<td>Telecom</td>
<td>39%</td>
<td>44%</td>
<td>17.0%</td>
<td>Percentage of Breakers</td>
<td></td>
</tr>
</tbody>
</table>

Please note that there was an error in the FTEs in this allocator in the Transmission O&M Cost Study and Workbook filed as Appendices C and D with the application. This error is corrected in the revised Transmission O&M Cost Workbook submitted with these IR responses.

**Field Operations Functionalization - POD 50.4%**

(x) All:AL:11 – Operational Services. The Operational Services allocator is derived from two previous allocators, 50% on allocator #2 and 50% on allocator #5. This allocation is based on the full-time equivalent positions as described at the bottom of AL Sch 5.0 where 50% of the group works in land (allocation on the
basis of number of land owners) and 50% works in the area of purchasing and inventory (allocation on the basis of property).

(b) Breakers are not considered elements for the purpose of the *Transmission O&M Cost Study* because their purpose is to protect and switch elements of the power system, not to actually transmit power from the generator to the consumer. While control centre operators switch breakers, they do so for the purpose of switching transmission lines, transformers, or other equipment in and out of service. Breakers are the means of controlling and operating the electric transmission system.