



2010 POD Cost Function and Investment Level Update Draft Recommendations

AESO 2010 Tariff Consultation

September 16, 2009

TABLE OF CONTENTS

1. Introduction	4
2. Scope	4
2.1 Additional data points	5
2.2 Project cost inflation.....	5
2.3 Raw greenfield interconnection project cost function	6
2.4 Cost of upgrade projects.....	6
3. Methodology Overview	6
3.1 Availability of Data	6
3.2 Project and Category Classification	7
4. Data Collection	11
4.1 New Projects.....	11
4.2 Inflation	14
5. Analysis	18
5.1 Construction.....	18
5.2 Cost Function Determination	23
5.3 Raw Cost Function	24
5.4 Investment Level Multiplier	27
5.5 Reasonability	32
5.6 Upgrades	33
5.7 Primary Service Credit	35
6. Conclusion	36

1. Introduction

Following extensive discussion, Alberta Utilities Commission (AUC) Order U2008-217 approved a number of changes to the Alberta Electric System Operator (AESO) Customer Contribution Policy and Demand Transmission Service (DTS) Point of Delivery (POD) charge rate design. Both the investment levels in the Customer Contribution Policy and the POD charge were based on a POD Cost Function.

For its 2010 General Tariff Application (GTA) the AESO reviewed and updated the POD Cost Function and the resulting investment levels. All documents relating to consultation for the 2010 GTA, including the POD Cost Update, can be accessed on the AESO's website by following the path: Tariff ► Current Consultations ► 2010 Tariff.

2. Scope

The AESO's current POD Cost Function is based on 48 projects from the years 1987-2006. Final cost figures for most of those projects are now available. New projects have also been initiated since 2006 providing additional data for the 2010 POD Cost Function. All data, formulas, and figures discussed in this report are provided in an accompanying Excel workbook.

In reviewing the POD Cost Function, the AESO performed the following activities.

2.1 Additional data points

The AESO collected data for interconnections since the last Customer Contribution Study (filed as Appendix F to the AESO 2007 GTA on November 3, 2006). An interconnection project is included in the update if its cost estimate is accurate to within +20%/-10% or better.

Deconstructed project information aligns with the definition of POD as utilized in the AESO's rate design. Project cost was escalated to 2010 dollars, appropriate to the forecast year of the tariff application.

The AESO also included projects that are expected to be constructed in the near future or are complete and await final reconciled cost information. To date, 17 projects were added and one project was removed as it was cancelled, for a total of 64 greenfield projects in the POD Cost Function data set.

2.2 Project cost inflation

Recent data indicates that project cost is increasing and increasing at a rate higher than other general cost inflation indicators such as the Consumer Price Index (CPI). The AESO sorted project cost information into various categories and applied relevant publicly available cost indices to come up with a composite price index that was used to escalate the project cost instead of Alberta CPI (which was the inflation index used in the last Customer Contribution Study).

2.3 Raw greenfield interconnection project cost function

The AESO collected data as outlined above and analyzed it in order to determine the raw greenfield interconnection project cost function. The objective was to determine a cost function that represents the average cost per megawatt (MW) of capacity of greenfield projects.

2.4 Cost of upgrade projects

The AESO compared the cost of upgrade projects to the cost of greenfield projects to see if a cost function based on greenfield projects will reasonably represent the cost of most upgrade projects. Information from 64 upgrade projects was used for this comparison.

3. Methodology Overview

3.1 Availability of Data

This analysis excluded dual use projects (both DTS and Supply Transmission Service, STS), projects for generators (STS) only, and projects partially owned by the Customer. In other words this analysis included load (DTS) only projects with no customer ownership. Other types of projects were excluded for the following reasons:

- Dual use facilities are typically built to accommodate a larger generator capacity.
- STS interconnections are not charged POD costs on a monthly basis and do not receive investment.
- The AESO does not have the cost data for customer owned facilities.

The preliminary analysis component of the update utilized historical data to determine individual cost components of the project costs. This information primarily comes from the final cost data submitted by the Transmission Facility Owners (TFOs). Where final reconciled costs or their allocations were unavailable, individual cost components were determined using the estimated costs per Proposal to Provide Service (PPS) documents. Data was drawn from AESO-maintained Customer Access Services Project Information Resource (CASPIR) and Transmission Administration System Model (TASMo) databases. In addition, project information was extracted from internal Customer Contribution determinations and other project information documentation. Where reliable cost information is not available, the project was excluded from the update.

3.2 Project and Category Classification

The AESO identifies each interconnection proposal as a “Project” and assigns project identifications on a numerical basis. All project information is maintained both electronically and in hard copy, in numerically ordered project files. Project files are filed by their assigned number.

The classification of system and customer-related costs is as outlined in Article 9 of the AESO’s Terms and Conditions. When project costs are determined, the

AESO allocates these costs to the system or the customer, based on the nature of the project. For load customers, customer-related costs are the costs associated with the construction project, entailing radial transmission extensions and enhancements at adjacent substations. These costs can normally include the point of interconnection, communication enhancements at adjacent substations, a new breaker at an existing substation if required, and other enhancements required to complete the customer's interconnection.

System-related costs are those project costs associated with looped transmission facilities, radial transmission lines that will become looped within five years, or in any circumstance where the AESO deems that for economics or system planning purposes a facility larger than that required to serve the customer is necessary. In those cases, the AESO classifies these portions of the project as system-related costs.

Customer-related costs are those costs that the customer is responsible for, and include standard facility costs and those costs that are deemed in excess of standard facility costs.

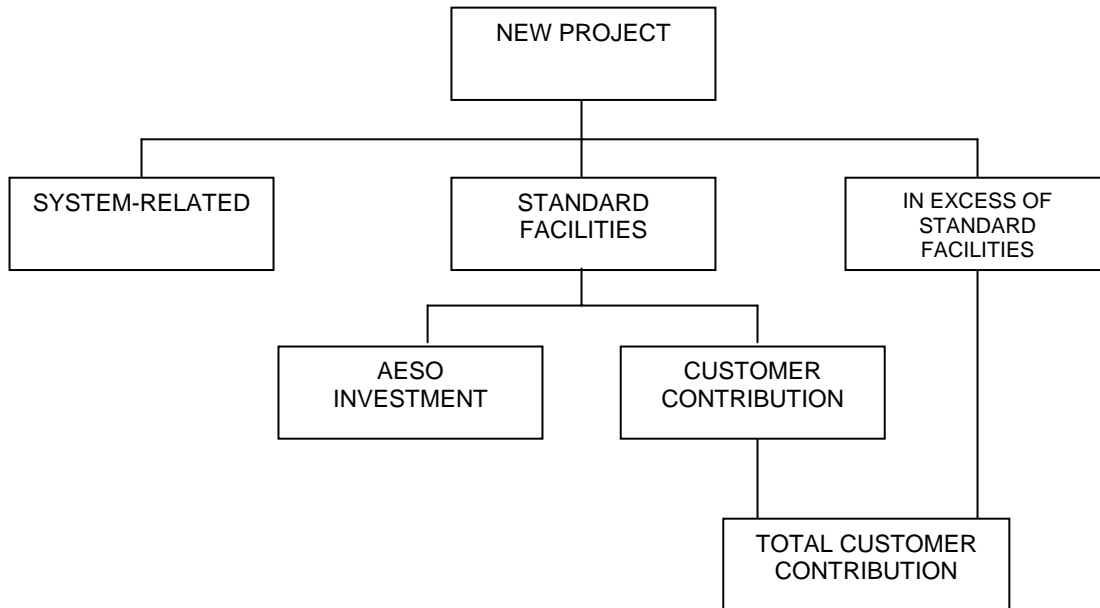
As defined in its 2007 tariff, AESO standard facilities are the least-cost interconnection facilities which meet good transmission practice, including reliability, protection and operating criteria and standards. These generally consist of a single radial transmission circuit and a single transformer to supply an individual Point of Connection. Standard facilities for any interconnection proposal meet the forecasted load requirements for that interconnection. Standard facility costs are the only costs eligible for investment under the AESO's 2007 tariff.

Costs in excess of standard facilities are those costs that exceed the cost of the AESO deemed standard facility interconnection configurations. For example, customer preferences to construct facilities that are larger or provide more capacity than is deemed necessary by the AESO are in excess of standard facility costs. The customer is responsible for paying all customer costs in excess of AESO standard facility costs, and these costs are not eligible for AESO investment.

All costs in this study exclude any prepaid operations and maintenance (O&M) charge applied under the AESO's 2006 and 2007 tariffs.

Figure 1 illustrates the cost determination process for new load projects.

Figure 1



4. Data Collection

4.1 New Projects

Table 1 lists information gathered for each project. For the “year” category, the AESO notes that the year recorded is the year in which the most recent cost estimate or actuals were received or the dollar year mentioned in such most recent document. This assumption minimizes the effect of project construction spanning several years. The AESO recognizes that cost estimates change over time, but also assumes that the most recently submitted costs reflect costs incurred “to date” on a project, and likely are a better indicator of construction-in-progress dollars. At this time final costs for 42 out of 64 projects are known.

The AESO compiled 17 new projects since the last Customer Contribution Study that had Customer Contribution determinations associated with their projects and had applied for new DTS contracts.

Table 1 – Project Information

Information Category	Source of Information
Project #	Internally assigned project numbers
Project Name	The name associated with the project
TFO	The Transmission Facility Owner associated with the project
Project Description	A brief outline of the nature of the project
Year	The recorded year is the year in which actual costs were reconciled, or where unavailable the year of most recent PPS submittal.
AESO Standard Facility Cost	The AESO Standard Facility costs as identified in most recent customer contribution determination
Total Project Cost	The total project cost as identified in most recent customer contribution determination
DTS Contract Capacity	The DTS Contract Capacity as identified in most recent customer contribution determination
Substation Cost	The substation related project cost broken down into materials, engineering and construction categories.
Line Cost	The transmission line related project cost broken down into materials, engineering and construction categories.
Indirect Cost	The indirect cost that are spread over the whole project.

Other considerations of note include use of the composite price index for escalation. The AESO proposes that composite price index be utilized for years 1987 through 2008. For years 2009 and 2010, the AESO proposes to utilize Alberta CPI as estimated by the Conference Board of Canada in its Provincial Outlook Summer 2009 Economic Forecast completed on July 16, 2009.

4.2 Inflation

During 2008, AltaLink led a stakeholder process to identify industry concerns with the AESO's customer contribution policy and deliver recommendations for change. These recommendations are available on the AESO website at www.aeso.ca by following the path Tariff ► Current Consultations ► 2010 Tariff, in the document titled “AltaLink Stakeholder Process – Recommendations”¹. One of the recommendations was to “*use an inflation factor that is representative of the Alberta market place, and incorporate a mechanism to adjust the contribution formula to account for regulatory lag*”. The cross-industry stakeholder working group stated that “*The AESO customer contribution formula is based on actual project costs escalated at CPI. However, the CPI escalator is significantly lower than actual transmission cost escalation rates in Alberta. The net result is increased contributions for most interconnections. Regulatory lag is further complicating this problem, which can result in a single contribution formula being*

¹ http://www.aeso.ca/downloads/2008-11-21_AltaLink_Stakeholder_Process_-_Recommendations.pdf

in place for 2-3 years. In addition, the cycle time to build a transmission interconnection is reaching lengths of 2-4 years". In support of this statement the group provided an appendix determining the transmission cost escalation rate to be 9% for 2006-2007 as compared to a CPI escalator of 5%. The group recommended that *"The AESO include an annual automatic escalator within the contribution policy, and that this should be tied to a published index"* and *"The AESO should also adopt an inflation factor which is reflective of transmission costs in Alberta"*.

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. The AESO divided the project cost between substation related material, transmission line related material, engineering, and construction. The index values were used to calculate their year over year percentage increase, use of which avoids issues arising from different base years for the different indices.

The AESO considers the following indices to be representative of the different cost categories established for interconnection projects:

- (a) The Canada-wide "Electric Utility Construction Price Indexes – Substations - Equipment (v735305)" index from Statistics Canada will be used for escalating substation related material cost.
- (b) The Canada-wide "Electric Utility Construction Price Indexes – Transmission Line Systems - Materials (v735258)" index from Statistics Canada will be utilized for escalating transmission line related material cost.
- (c) The "Consulting engineering services price indexes by market and by field of specialization - Alberta - Industrial services (v92756)" index from Statistics Canada will be used to escalate engineering related cost. Values for this index are not available for 1987-1989 and 2007-2008. For 1987-1989, the index values were approximated as the average increase in the index for the years 1990-1994. For 2007-2008, the index values were replaced with the "APEGGA - Value of Professional Services - Engineers - All Industries"² values calculated using the dollar-weighted average of the escalation rates for all levels.
- (d) The average of "Non-residential building construction price indexes - Calgary, Alberta - Total, industrial structures (v44176046)" and "Non-residential building construction price indexes - Edmonton, Alberta - Total, industrial structures (v44176050)" from Statistics Canada, for Calgary and Edmonton respectively, will be used to escalate construction cost.

Weighting the cost in each category by the corresponding escalator provides a composite escalator.

² <http://www.apegga.org/Members/Publications/salarysurvey.html>

The average value of the composite escalator from 1987-2008 is 3.54% per year. For comparison, the average value of an escalator based on Alberta CPI is 2.99% per year. The composite escalator reaches a maximum of 9.77% in 1989 and a minimum of (5.2%) in 1991 while the escalator based on Alberta CPI reaches a maximum of 5.87% in 1991 and a minimum of 0.99% in 1993. For eight years the increase in Alberta CPI is higher than the increase in the Composite Price Index, and for 14 years the increase in Alberta CPI is lower than the increase in the Composite Price Index. This information can be found in the “escalator” tab of the supporting Excel workbook. Table 1 below shows the escalator values for 1987-2007.

Table 2 - Escalator Values

Year	% Year Over Year Increase in Alberta CPI	% Year Over Year Increase in Composite Price Index
1987	4.08%	6.74%
1988	2.71%	7.25%
1989	4.11%	9.77%
1990	5.78%	1.10%
1991	5.87%	-5.20%
1992	1.51%	0.11%
1993	0.99%	2.04%
1994	1.47%	3.90%
1995	2.30%	4.66%
1996	2.25%	0.49%
1997	1.97%	2.67%
1998	1.25%	3.72%
1999	2.47%	0.80%
2000	3.39%	2.86%
2001	2.33%	4.11%
2002	3.41%	1.92%
2003	4.40%	-3.22%
2004	1.44%	4.78%
2005	2.08%	3.83%
2006	3.89%	7.82%
2007	4.99%	8.80%
2008	3.14%	8.87%
Average	2.99	3.54%
High	5.87	9.77%
Low	0.99	-5.20%

5. Analysis

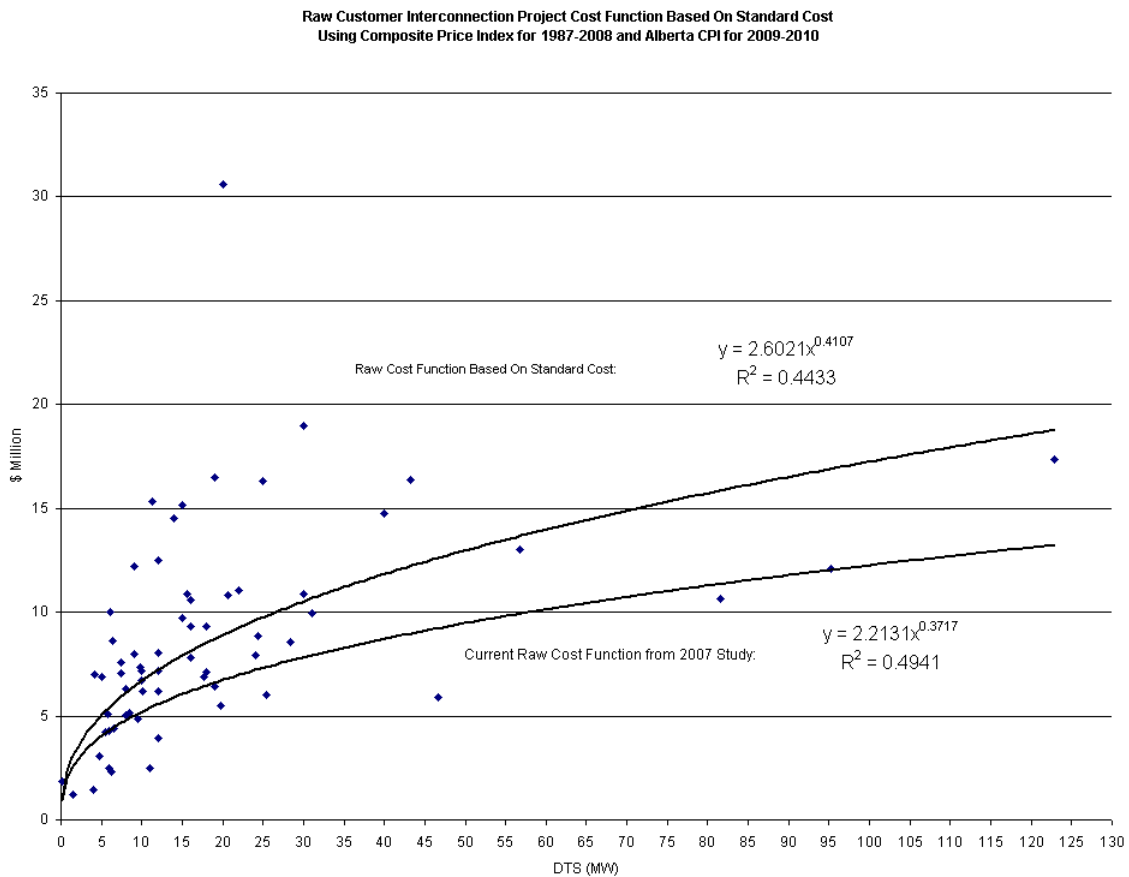
5.1 Construction

The analysis considered data from a total of 64 greenfield projects initiated during the 1987-2009 period. All of these projects are load-serving and have Customer Contribution determinations (except for the 18 historical projects

included as a result of Decision 2007-106, for which Customer Contribution determinations are not available). Information from the Customer Contribution determinations was extracted for each of these projects.

Figure 2 shows the relationship between the AESO Standard Facilities cost determinations and DTS contract capacity. The currently approved POD Cost Function is also provided for comparison purposes. This figure and source data can be found in the “raw-cost-function-std”, “projects” and “escalator” tabs of the Excel workbook respectively.

Figure 2



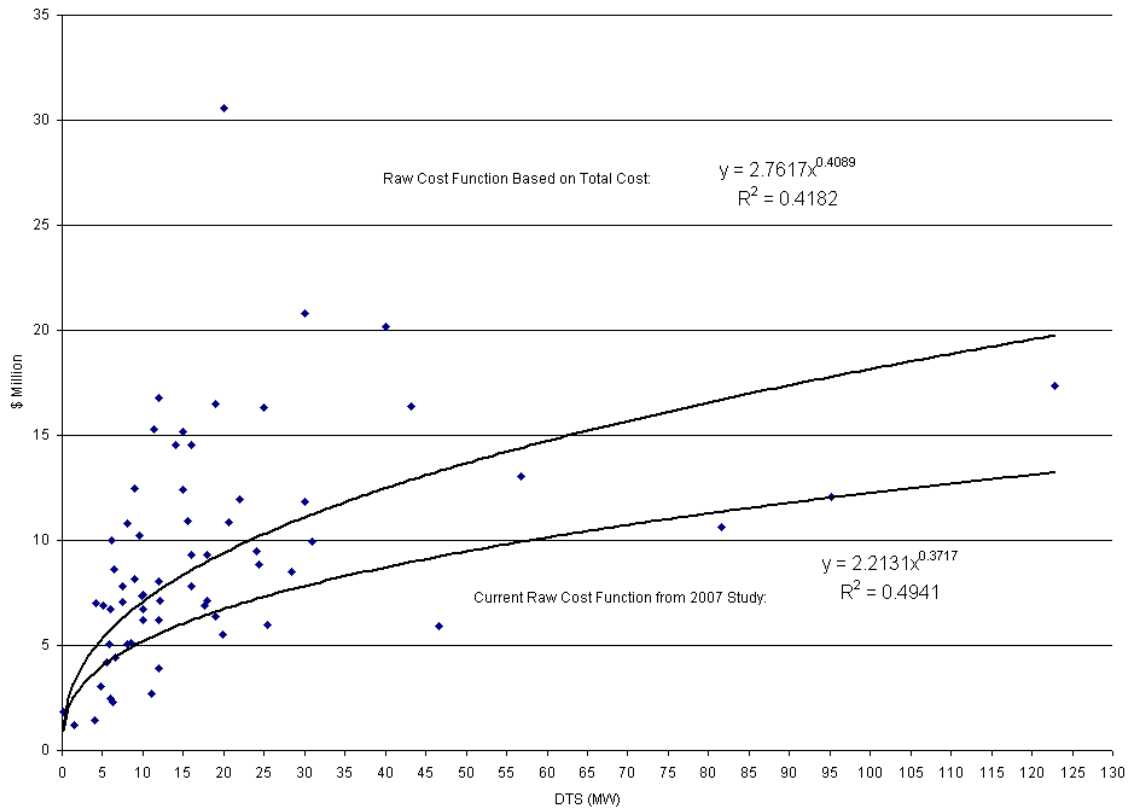
The trend line equation represented is $y = 2.6021 * x^{0.4107}$ and has correlation of $r^2 = 0.4433$.

The projects in the data set exhibit significant variability or “scatter”. For example, three projects between 18-20 MW capacity had project costs of \$5.504, \$16.499 and \$30.583 million. The variability reflects different amounts of radial line required for interconnection, different substation configurations, varying geography and construction conditions, and varying levels of complexity for each interconnection.

Figure 3 shows the relationship between the total project cost and DTS contract capacity. The currently approved POD Cost Function is also provided for comparison purposes. This figure and source data can be found in the “raw-cost-function-tot”, “projects” and “escalator” tabs of the Excel workbook respectively.

Figure 3

Raw Customer Interconnection Project Cost Function Based On Total Cost
Using Composite Index for 1987-2008 and Alberta CPI for 2009-2010



The trend line equation represented is $y = 2.7617 * x^{0.4089}$ and has correlation of $r^2 = 0.4182$. This is similar to the trend line equation obtained using the standard project cost. The exponent is slightly lower and the constant multiplier is slightly higher.

In the AESO’s 2010 GTA, the AESO proposes to discontinue the standard facilities definition that exists in the current tariff, and to rely on the maximum investment level to provide an appropriate cost signal to customers. This document uses total project cost to determine the POD Cost Function, reasoning for which is provided in section 5.4.

5.2 Cost Function Determination

Table 3 summarizes the cost functions based on total project cost that demonstrated the highest correlation.

Table 3 – Cost Function

Original cost function based on 48 projects from 1987-2006

Analysis	Cost Function (\$M)	r ²
Current (Power)	$y = 2.2131 * x^{0.3717}$	0.4941

Updated functions based on 64 projects from 1987-2009 (based on total project cost)

Analysis	Cost Function (\$M)	r ²
Proposed (Power)	$y = 2.7617 * x^{0.4089}$	0.4182
Logarithmic	$y = 2.7796 * \ln(x) + 2.2365$	0.2793
Linear	$y = 0.0995 * x + 7.393$	0.1601
Exponential	$y = 6.1516 * e^{0.0125 * x}$	0.1738
Cubic	$y = 7E-05 * x^3 - 0.0127 * x^2 + 0.6996 * x + 2.1792$	0.3450
Quadratic	$y = -0.002 * x^2 + 0.3049 * x + 5.0742$	0.2484

As in the original POD Cost Function determination, the power function has the highest regression coefficient of 0.4182, which indicates moderate positive correlation between total project costs and DTS capacity. The function is very similar to the POD Cost Function approved in Decision 2007-106. The AESO believes that the power cost function provides the best representation of the total project costs, as follows:

$$\text{Average cost} = 2.7617 * (\text{DTS Capacity})^{0.4089}$$

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

5.3 Raw Cost Function

The complete derivation of the proposed POD cost function is summarized as follows:

- (a) As discussed in the preceding section, the average cost function for the data based on total project cost is reproduced, and determined to be:

Equation 1

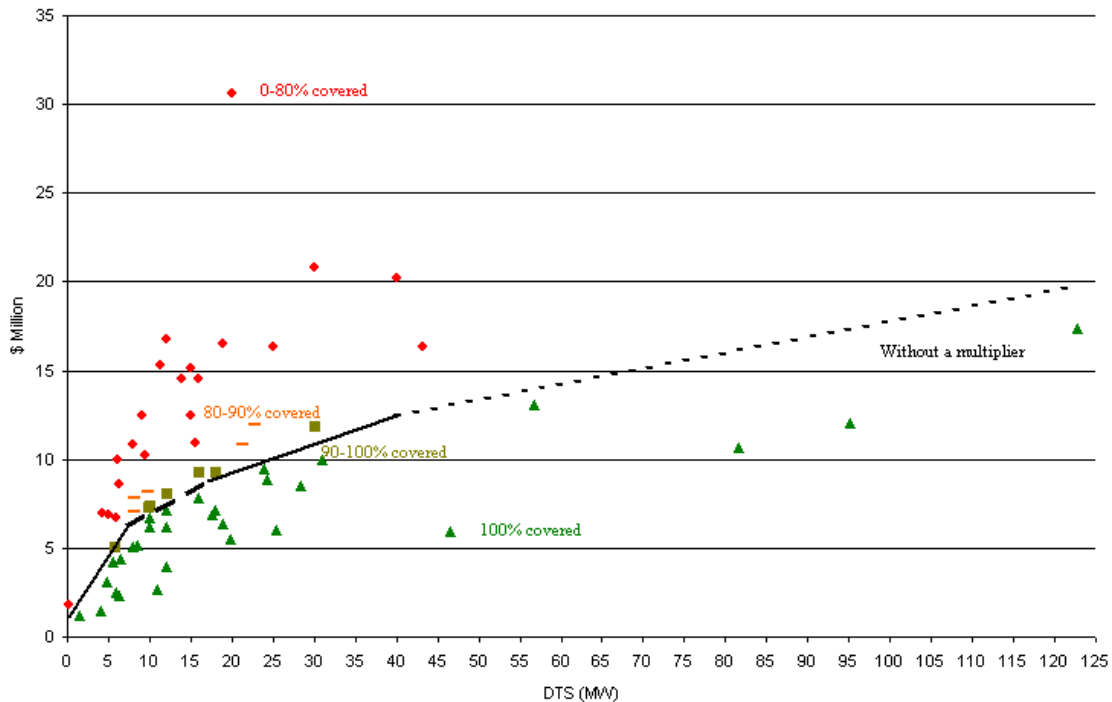
$$\text{Average cost} = 2.7617 * (\text{DTS Capacity})^{0.4089}$$

- (b) Fitting a series of linear functions to replicate the slopes of the power function for 0.1, 7.5 MW, 17 MW, 40 MW, and 122.8 MW points results in a cost function which is a summation of five terms. 0.1 MW is the smallest

project size while 122.8 MW is the largest project size in the 64-project data set. Breakpoints of 7.5 MW, 17 MW, and 40 MW will be used consistent with the approach approved in Decision 2007-106.

Figure 3

Linearized Customer Interconnection Project Cost Function Using Total Cost Using Composite Index for 1987-2008 and Alberta CPI for 2009-2010



(c) Linearizing the power cost function results in the following cost function:

Equation 2

$$\begin{aligned} \text{Linearized Cost} = & \$1.007 \text{ million} \\ & + (\$0.705 \text{ million/MW} \times \text{first 7.5 MW of DTS Capacity}) \\ & + (\$0.263 \text{ million/MW} \times \text{next 9.5 MW of DTS Capacity}) \\ & + (\$0.160 \text{ million/MW} \times \text{next 13 MW of DTS Capacity}) \\ & + (\$0.088 \text{ million/MW} \times \text{remaining MW of DTS Capacity}) \end{aligned}$$

The AESO considers the cost function (Equation 2) to appropriately reflect project costs for the purposes of establishing investment levels and for rate design in the AESO’s Tariff. This information can be found in the “cost-function-tot” tab of the Excel workbook.

5.4 Investment Level Multiplier

The investment levels in the AESO's 2007 tariff were determined by multiplying the raw cost function based on standard project costs by 1.15 and then linearizing it. It resulted in 27 data points receiving full investment, 6 data points receiving over 90% investment, 5 data points receiving at least 80% investment and hence 38 out of 48 data points, or 79% of the data points received at least 80% investment and the majority of these points receive full investment.

The final analysis component of this document proposes a similarly-developed investment cost function. However, the approach has been modified to reflect a total facilities cost basis rather than a standard facilities cost basis.

The AESO first assessed the total investment that would occur using an investment level based on a standard facilities cost function and a multiplier of 1.15, as used for the AESO's 2007 tariff. The raw cost function based on standard facilities cost was multiplied by 1.15 and then linearized to obtain the investment function. The lower of the project standard facilities cost and the amount obtained by applying the investment function determined the available investment. The sum of the investment available for all projects was about \$471 million. Of the 64 projects in the data set, 39 data points (or 61%) receive full investment, 8 data points (or 13%) receive over 90% investment, 3 data points (or 5%) receive over 80% investment and hence a total of 50 (or 78%) data points received at least 80% investment. Close match with the corresponding figures (see first paragraph of this section) resulting from AESO's 2007 tariff suggests that using a multiplier of 1.15 remains appropriate for a standard facilities approach.

The AESO's experience since the currently-approved "standard facilities" definition was implemented has revealed shortcomings with the "standard facilities" approach. The AESO has reexamined this approach, and provides the following comments.

- (a) The standard facilities definition was implemented when the AESO's tariff did not align particularly well with the cost of facilities used to provide service to customers. Defining standard facilities was an approach that limited investment when maximum investment levels could otherwise have significantly exceeded the actual project cost. However, under the current tariff there is better alignment between costs and investment levels. As well, the POD charge is well-aligned with investment levels. There is accordingly less need to limit investment levels through use of a standard facilities definition.
- (b) The inclusion of the phrase "generally consist of a single radial transmission circuit and a single transformer" in the definition of standard facilities has resulted in a single line, single transformer configuration being considered acceptable for most projects. This was not the intent of

the standard facilities definition. The inclusion of the single line, single transformer phrase was meant to provide additional information such that a customer would not be surprised if such a configuration was proposed for an interconnection. Based on all existing interconnections, however, about half of all load substations contain more than one transformer, and about two-thirds are connected through two or more lines. It is therefore inconsistent with historical practice to consider one transformer and one line to be the standard service for an interconnection.

- (c) It is generally impractical for the AESO to determine the facilities that would meet reliability, protection, and operating criteria and standards *to the satisfaction of the customer*. It is ultimately the customer who determines what facilities are required for satisfactory reliability and operation of the interconnection. As a result, the “standard facilities” do not limit what facilities are actually installed — only what costs are eligible for investment. The standard facilities definition’s primary impact is therefore to limit investment. The AESO considers that, with the better alignment of costs, investment level, and rates as discussed above, investment is effectively limited through the maximum investment function. There is no need for additional limitation through a “standard facilities” definition.
- (d) Finally, since the majority of interconnection projects (both historically and currently) exceed the single transformer, single line “standard facilities” configuration, significant resources are expended by the AESO, the TFOs, and customers on determining, evaluating, and estimating costs for standard facilities which will never be constructed. This is inefficient, particularly in recent periods of customer load growth when resources could be more efficiently focused on project configurations that are more likely to be constructed.

For these reasons, the AESO proposes to remove the current standard facilities approach in its 2010 tariff. Instead, the interconnection for a customer will be based on those facilities which the customer considers necessary for the interconnection. Investment will be limited through a maximum investment function which would provide the same total investment based on total project costs as the standard facilities approach would provide, developed as follows.

As explained above, the standard facilities approach applied to the standard facilities cost of the 64 projects in the data set resulted in a total investment of about \$471 million.

An investment function was developed using similar methodology but based on the total facilities cost for the 64 projects. The AESO calculated that a multiplier of 1.06 applied to the raw cost function based on total project cost resulted in a similar total investment for all projects of about \$472 million.

Based on total facilities costs with a multiplier of 1.06, 32 data points (or 50%) receive full investment, 7 data points (or 11%) receive over 90% investment, 6 data points (or 9%) receive over 80% investment and hence a total of 45 data points (or 70%) 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.

As well, the same total amount of customer contributions is required in both cases. Under the standard facilities approach, customer contributions are required both for facilities in excess of standard and for standard facilities above the maximum investment level. Under the total facilities approach, customer contributions are provided for facilities above the maximum investment level. However, under both approaches, the total amount of customer contributions is essentially the same.

5.5 Reasonability

The recommended cost function was developed using data for load-only projects. Where a project provided interconnection of both load and generation or of multiple loads, the cost function was adjusted to reflect the “substation fraction” approach established by the EUB during the course of the AESO’s 2005-2006 GTA. The AESO therefore proposes that the recommended cost function incorporate the substation fraction (“SF”) into each tier as follows:

Equation 3

$$\begin{aligned} \text{DTS POD Cost} = & \$1.007 \text{ million} \times \text{SF} \\ & + \$0.705 \text{ million/MW} \times \text{first (7.5 multiplied by the SF) MW of DTS Capacity} \\ & + \$0.263 \text{ million/MW} \times \text{next (9.5 multiplied by the SF) MW of DTS Capacity} \\ & + \$0.160 \text{ million/MW} \times \text{next (23 multiplied by the SF) MW of DTS Capacity} \\ & + \$0.088 \text{ million/MW} \times \text{remaining MW of DTS Capacity} \end{aligned}$$

The AESO tested the reasonableness of these results by comparing them with the current DTS POD costs and the close match suggests that equation 3 above is a reasonable representation of average POD costs. A consistent and proportionate increase in all five terms of the cost function indicates that all costs have risen since the last study.

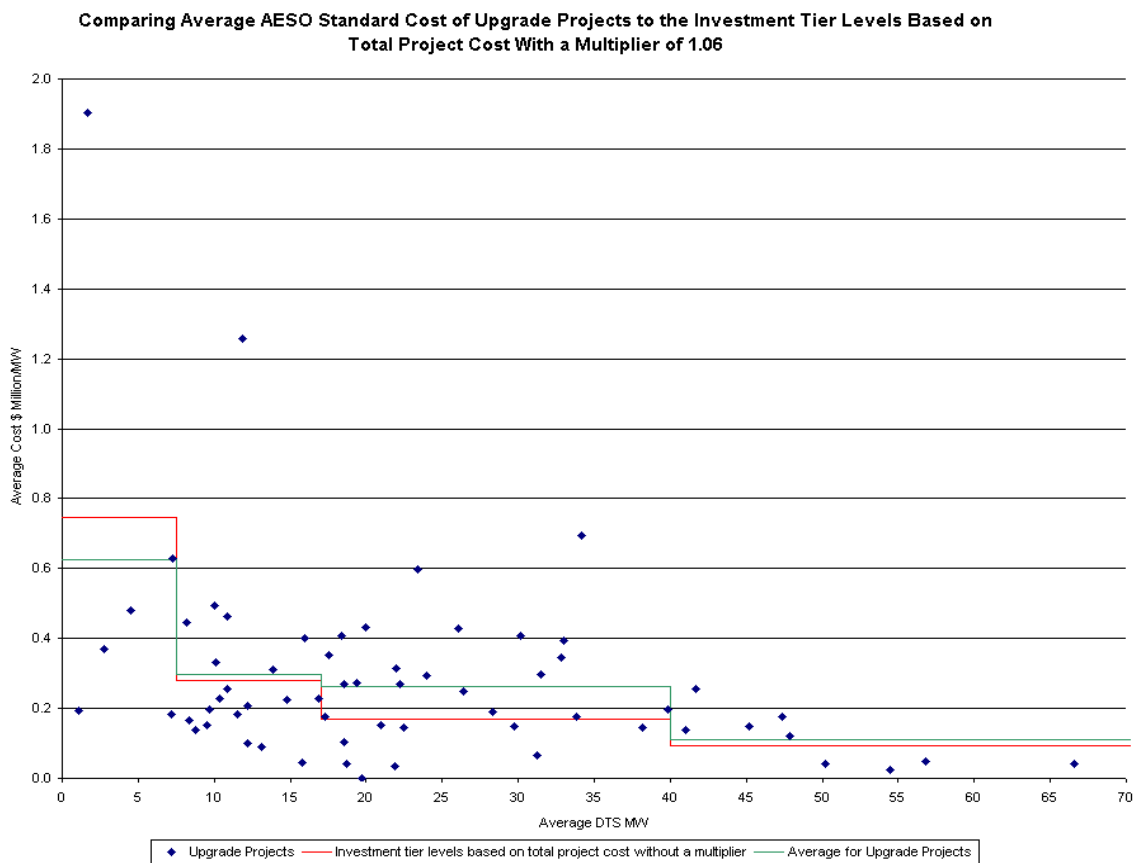
The AESO also considered whether the total facilities cost function would impact the DTS POD charge, compared to the standard facilities cost function. The POD charge depends primarily on the “shape” of the cost function rather than its level, as the POD charge revenue requirement is allocated proportionately 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 $\pm 1.2\%$ between the two approaches. The AESO also notes that the POD charge resulting from the proposed total facilities cost function also varies only slightly from the POD

charge that would result from the POD cost function approved during the AESO's 2007 GTA. The AESO therefore concludes that the proposed total facilities cost function is a reasonable basis for determining the DTS POD charge.

5.6 Upgrades

The AESO investigated whether projects that involve upgrades to existing PODs have a different relation between upgrade cost and incremental DTS capacity. Unit cost of these upgrade projects was plotted against the average of the DTS capacity before and after the upgrade. Investment tier levels based on total project cost with a multiplier of 1.06 are plotted to compare with. This information can be found in the "upgrade-projects" tab of the Excel workbook.

Figure 4



The AESO considers that the proposed cost function, though based on the data from greenfield projects, sufficiently reflects the cost of most upgrade projects.

5.7 Primary Service Credit

Currently the Primary Service Credit (PSC) determination is based on the division of cost of interconnection between substation related costs and line related costs. The AESO included interconnection project cost information that has become available since the last PSC determination to update the

abovementioned division. Greenfield projects for which such division is available were used for the calculation. The ratio of total substation related cost (that is, excluding line related cost) to total project cost was calculated to be 0.55 in the last study. Based on the updated data and additional projects included in the data set for the 2010 GTA, this ratio now increases to 0.78. This information can be found in the “psc” tab of the Excel workbook.

The AESO notes that this represents a significant increase to the ratio. The data for the increased ratio has been thoroughly examined and supports the higher ratio. As well, a review of the limited data on costs examined in the POD cost function in the Wires-Only Cost Causation Study filed with the AESO’s 2006 GTA supports the higher ratio of substation costs.

The AESO proposes to continue the approach for determining the Primary Service Credit which was approved in its 2007 GTA. That is, credits for the fixed (\$/month) and first three demand (\$/MW) tiers will be 78% of the corresponding component of the POD charge. The credit for the final demand (\$/MW) tier will be 100% of the corresponding component of the POD charge.

Similar, the maximum investment available to a customer receiving the Primary Service Credit will be reduced by 78% for the fixed and first three demand tiers. No investment will be available for the final demand tier.

6. Conclusion

The AESO believes this update meets the requirements of Decision 2007-106 and provides an updated POD Cost Function.

The AESO notes that the interconnection project construction costs showed moderate correlations with DTS contract capacities ($r^2=0.4182$).

The proposed cost function (equation 3) is based on the establishment of a fixed component of the cost function. The fixed component represents costs a customer cannot avoid regardless of what decisions the customer makes.

Using a multiplier of 1.06 as discussed in section 5.4 results in the DTS POD Cost given by equation 4 below:

Equation 4

$$\begin{aligned} \text{DTS POD Cost} = & \$1.067 \text{ million} \times \text{SF} \\ & + \$0.747 \text{ million/MW} \times \text{first (7.5 multiplied by the SF) MW of DTS Capacity} \\ & + \$0.279 \text{ million/MW} \times \text{next (9.5 multiplied by the SF) MW of DTS Capacity} \\ & + \$0.170 \text{ million/MW} \times \text{next (23 multiplied by the SF) MW of DTS Capacity} \\ & + \$0.093 \text{ million/MW} \times \text{remaining MW of DTS Capacity} \end{aligned}$$

Equation 4 above assumes contract terms of 20 years. Therefore, the per year investment level is:

Equation 5

Investment Level = \$53,352/year of contract term x SF +
+ \$37,370/MW/year of contract term for first (7.5 multiplied by the SF) MW of DTS Capacity
+ \$13,956/MW/year of contract term x next (9.5 multiplied by the SF) MW of DTS Capacity
+ \$8,491/MW/year of contract term x next (23 multiplied by the SF) MW of DTS Capacity
+ \$4,649/MW/year of contract term x remaining MW of DTS Capacity