2010 POD Cost Function Update

Discussion Paper

AESO 2010 Tariff Consultation

May 28, 2009

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1. Introduction

Following extensive discussion, Alberta Utility 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 proposes to review and update the POD Cost Function. 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.

In reviewing the POD Cost Function, the AESO will perform the following activities.

2.1 Incorporate additional data points

The proposed approach will collect 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 will be included in the update if its cost estimate is accurate to within +20%/-10% or better.

Deconstructed project information will align with the definition of Point of Delivery (POD) as utilized in the AESO's rate design. Project costs will be escalated to 2010 dollars, appropriate to the forecast year of the tariff application.

The AESO will also include projects that are expected to be constructed in the near future or are complete and await final reconciled cost information. To date, 17 projects will be added and one project will be removed as it was cancelled.

2.2 Analyze project cost inflation

Recent data indicates that project cost is increasing and increasing at a rate higher than other general indicators such as the Consumer Price Index (CPI). The AESO will sort project cost information into various categories and apply relevant publicly available cost indices to come up with a composite price index, for comparison to the use of Alberta CPI (which was the inflation index used in the original study).

2.3 Determine raw greenfield interconnection project cost function

The AESO will collect data as outlined above and analyze it in order to determine the raw greenfield interconnection project cost function. The intent is to recommend a cost function that represents the average cost per megawatt (MW) of capacity of greenfield projects.

2.4 Compare the cost of upgrade projects to the cost of greenfield projects

The AESO will compare 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 will be used for this comparison.

3. Methodology Overview

3.1 Availability of Data

This analysis will exclude 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 will include load (DTS) only projects with no customer ownership. 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 will utilize 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 are unavailable, individual cost components will be determined using the estimated costs per Proposal to Provide Service (PPS) documents.

Data will be drawn from AESO-maintained Customer Access Services Project Information Resource (CASPIR) and Transmission Administration System Model (TASMo) databases. In addition, project information will be extracted from internal Customer Contribution determinations and other project information documentation.

Where reliable cost information is not available, the project will be 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.

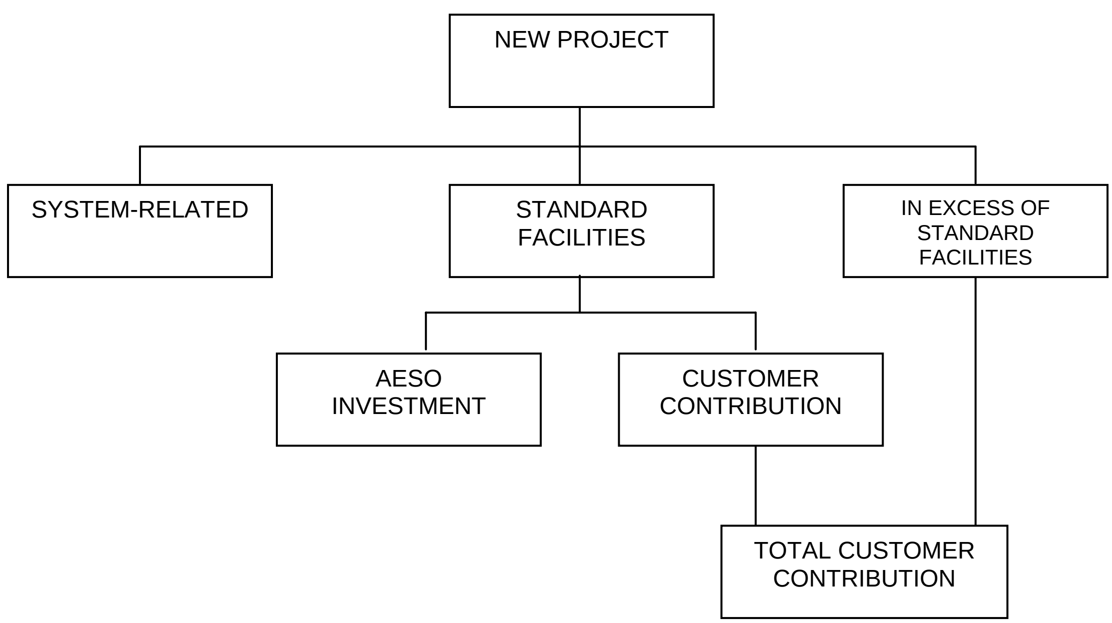
System-related costs are those project costs associated with looped transmission facilities, radial transmission lines that will become looped within five years, or in any circumstance where the AESO deems that for economics or system planning purposes a facility larger than that required to serve the 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. 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 Tariff.

Cost 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.

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 will compile 17 new projects since the last Customer Contribution Study that had Customer Contribution determinations associated with their projects and had applied for DTS contracts or contract increases.

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.
Present Value Factor	Calculated using Alberta CPI values to 2008, and recent Conference Board of Canada values for 2009 and 2010.
AESO Standard Facility Costs	The AESO Standard Facility costs as identified in most recent customer contribution determination
DTS Contract Capacity	The DTS Contract Capacity as identified in most recent customer contribution determination

Other considerations of note include use of the Alberta CPI for inflation rates. The AESO proposes that historical Alberta CPI (from StatCan) will 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 the spring of 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. 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 crossindustry 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 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 public index/indices between full tariff applications. The AESO will perform an analysis to determine an appropriate escalator for the customer interconnection project cost. The AESO will examine the project data to establish appropriate cost categories and corresponding public indices. The AESO will divide the project cost between substation related material, transmission line related material, engineering, and construction. The Canada-wide "Equipment (v735305)" index from Statistics Canada will be used for escalating substation related material cost. The Canada-wide "Materials (v735258)" index from Statistics Canada will be utilized for escalating transmission line related material cost. The Alberta-wide "Industrial services (v92756)" index from Statistics Canada will be used to escalate engineering related cost. The Average of "Total, industrial structures (v7717851)" and "Total, industrial structures (v7717855)" 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. When an index value for the year is unavailable, the average of values for the last five years will be used.

The average value of the composite escalator from 1987-2007 is 3.3% while the average value of an escalator based on Alberta CPI is 3.0%. The composite escalator reaches a maximum of 10.1% in 2007 and a minimum of (4.33%) 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. 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	4.89
1988	2.71	6.11
1989	4.11	9.06
1990	5.78	2.31
1991	5.87	-4.33
1992	1.51	0.54
1993	0.99	1.77
1994	1.47	3.19
1995	2.30	4.26
1996	2.25	0.45
1997	1.97	2.61
1998	1.25	3.90
1999	2.47	0.96
2000	3.39	2.99
2001	2.33	4.88
2002	3.41	1.74
2003	4.40	-2.81
2004	1.44	4.42
2005	2.08	4.80
2006	3.89	7.55
2007	4.99	10.09
Average	2.99	3.30
High	5.87	10.09
Low	0.99	-4.33

The AESO considers that appropriate criteria for selecting an index are:

1) Availability of credible public forecast,
2) Level of volatility, and
3) Likelihood of a year over year decrease.

The AESO needs the forecasted index values to inflate the project cost to the test year. It may take up to two years for the AUC to approve an AESO application, and thus the AESO needs the forecasted index values for at least two future years. The AESO expects to update the investment level using forecasted index values on an annual basis along with a rates update application between GTAs. For this reason an index for which a credible public forecast is available is preferable.

If the index is very volatile then it may affect customer behavior resulting in advancement or delay of the customer interconnection projects thus adversely affecting the related workflow. The issue may be compounded by the fact that index value may decrease year over year thus resulting in a reduction in the investment level.

Over 1987-2007 Alberta CPI values are not, on average, very different from the Composite Price Index values. Price indices that make up the Composite Price Index are not forecasted while Alberta CPI forecasts are available. The Composite Price Index is more volatile, has higher peaks and lower troughs, and was negative in two years (1991 and 2003). In light of above discussion AESO proposes that project costs should be inflated using Alberta CPI.

The AESO also assessed the differences that would result from using Alberta CPI rather than the Composite Price Index for the POD Cost Function developed in the remainder of this paper. The table below compares the tier values from page 13 of this paper, which result from using Alberta CPI for escalation, to values that would result from using the Composite Price Index.

Table 3 – Tier Values for Alberta CPI and Composite Price Index

	Inflation Index Used		
Tier	**Alberta CPI**	**Composite Price Index**	**Increase/(Decrease)**
Fixed	0.852	1.07076	25.68%
First 7.5 MW	0.636	0.779	22.45%
Next 9.5 MW	0.243	0.295	21.32%
Next 23 MW	0.149	0.180	20.84%
Remaining MW	0.083	0.099	20.27%
Average Increase			22.11%

The Tier values go up on average by about 22.1% and the increase is consistent over all Tiers. The reason for this substantial increase is that for 2004-2007 the increase in Composite Price Index is quite higher than the increase in Alberta CPI. It should be noted that for years 2008-2010, the Composite Price Index value was estimated as the average of five preceding values. This may not be a very accurate estimate because of the recent economic downturn that may result in 2008-2010 values being quite lower than 2005-2007 values and thus limiting the increase considerably. The shape of the POD Cost Function does not fundamentally change when the Composite Price Index is used, and therefore the DTS POD charge would not be expected to change as the individual POD charge tier amounts are effectively prorated from the cost function to recover the POD-related revenue requirement.

With respect to forecasting the Composite Price Index for future years, one way to do so would be to take the rolling average of index values in three or five preceding years as the forecasted index value for the upcoming year. Table 4 below shows the results of such an approach.

Table 4 – Forecast Using Rolling Average Approach

Year	Actual Index Value	Three Year Rolling Average	Difference Between Actual and Three Year Rolling Average	Five Year Rolling Average	Difference Between Actual and Five Year Rolling Average
1987	4.89				
1988	6.11				
1989	9.06				
1990	2.31	6.68	-4.37		
1991	-4.33	5.83	-10.16		
1992	0.54	2.35	-1.80	3.61	-3.06
1993	1.77	-0.49	2.27	2.74	-0.96
1994	3.19	-0.67	3.86	1.87	1.32
1995	4.26	1.83	2.43	0.70	3.57
1996	0.45	3.08	-2.62	1.09	-0.64
1997	2.61	2.63	-0.02	2.04	0.57
1998	3.90	2.44	1.45	2.46	1.44
1999	0.96	2.32	-1.36	2.88	-1.92
2000	2.99	2.49	0.49	2.44	0.55
2001	4.88	2.62	2.26	2.18	2.70
2002	1.74	2.94	-1.21	3.07	-1.33
2003	-2.81	3.20	-6.01	2.89	-5.70
2004	4.42	1.27	3.15	1.55	2.87
2005	4.80	1.12	3.68	2.24	2.55
2006	7.55	2.14	5.42	2.60	4.95
2007	10.09	5.59	4.50	3.14	6.95

It is clear that such an approach may not provide a reasonable forecast. Using a three year and five year rolling average approach the difference between the forecasted and actual value may be as large as -10.16% and 6.95% respectively which seems to negate any benefit that may have resulted from the use of this interconnection project specific index.

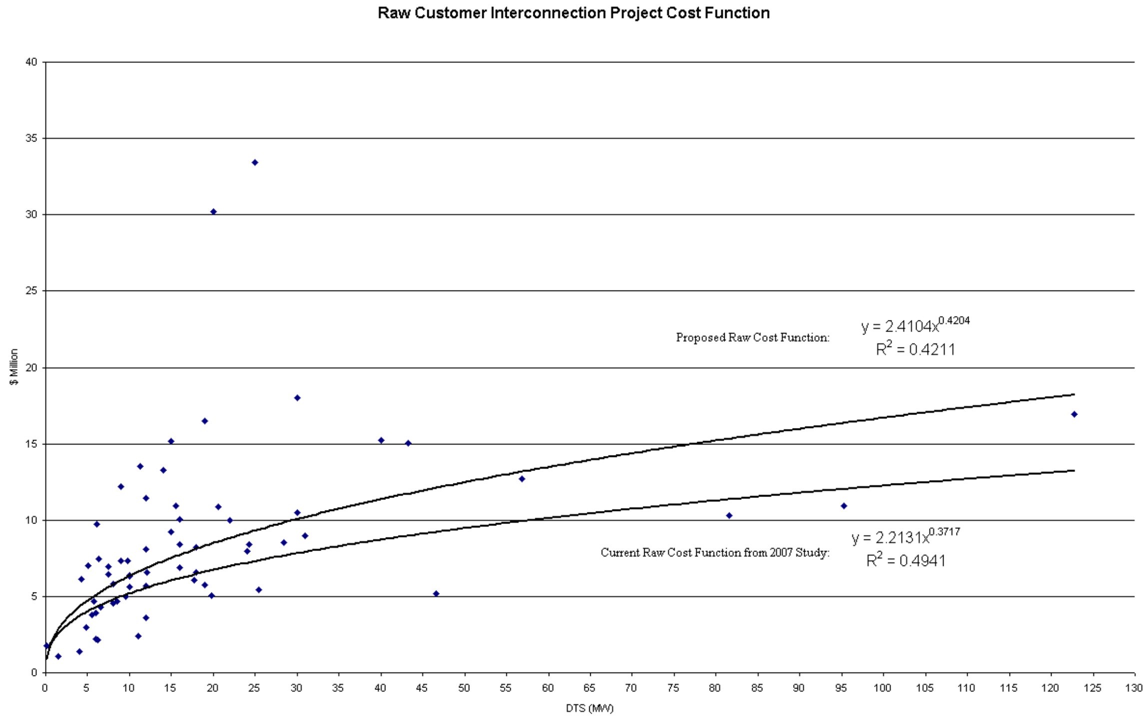
5. Analysis

5.1 Construction

The analysis will consider data from a total of 64 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). Information from the Customer Contribution determinations will be extracted for each of these projects.

Figure 2 shows the relationship between the AESO Standard Facilities 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" and "projects" tabs of the Excel workbook respectively.

Figure 2



The trend line equation represented is $y = 2.4104 * x^{0.4204}$ and it has correlation of $r^2 = 0.4211$.

The projects in the data set exhibit significant variability or “scatter”. For example, three projects near 19 MW capacity had project costs of \$5.8, \$16.5 and \$30.2 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.

5.2 Cost Function Determination

Table 5 summarizes the cost functions that demonstrated the highest correlation in the update.

Table 5 – 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

Analysis	**Cost Function ($M)**	**r^2**
Proposed (Power)	$y = 2.4104 * x^{0.4204}$	0.4211
Logarithmic	$y = 2.7874 * Ln(x) + 1.469$	0.2368
Linear	$y = 0.102 * x + 6.5968$	0.1419
Exponential	$y = 5.4301 * e^{0.0134 * x}$	0.1911
Cubic	$y = 7E\text{-}05 * x^3 - 0.0135 * x^2 + 0.7368 * x + 1.0925$	0.3155
Quadratic	$y = -0.0021 * x^2 + 0.3166 * x + 4.1734$	0.2232

As in the original POD Cost Function determination, the power function has the highest regression coefficient of 0.4211, which indicates moderate positive correlation between 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 project costs, as follows:

$$\text{Average cost} = 2.4104 * (\text{DTS Capacity})^{0.4204}$$

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 is reproduced, and determined to be:

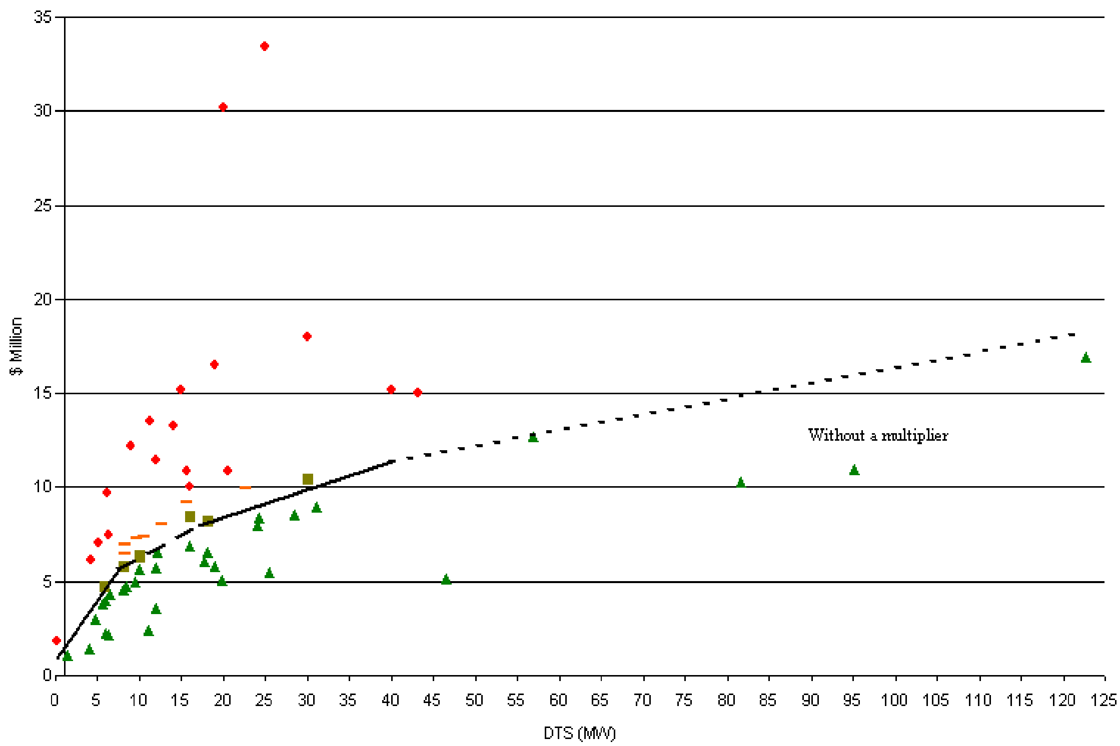
Equation 1

$$\text{Average cost} = 2.4104 * (\text{DTS Capacity})^{0.4204}$$

(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. 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



(c) The AESO therefore recommends the following cost function:

Equation 2

Recommended Cost = $0.852 million
+ ($0.636 million/MW × first 7.5 MW of DTS Capacity)
+ ($0.243 million/MW × next 9.5 MW of DTS Capacity)
+ ($0.149 million/MW × next 13 MW of DTS Capacity)
+ ($0.083 million/MW × remaining MW of DTS Capacity)

The AESO considers the recommended 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" tab of the Excel workbook.

The recommended cost function will be developed using data for load-only projects. Where a project provided interconnection of both load and generation or of multiple loads, the cost function must be 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

DTS POD Cost = \$0.852 million x SF
+ \$0.636 million/MW × first (7.5 multiplied by the SF) MW of DTS Capacity
+ \$0.243 million/MW × next (9.5 multiplied by the SF) MW of DTS Capacity
+ \$0.149 million/MW × next (23 multiplied by the SF) MW of DTS Capacity
+ \$0.083 million/MW × remaining MW of DTS Capacity

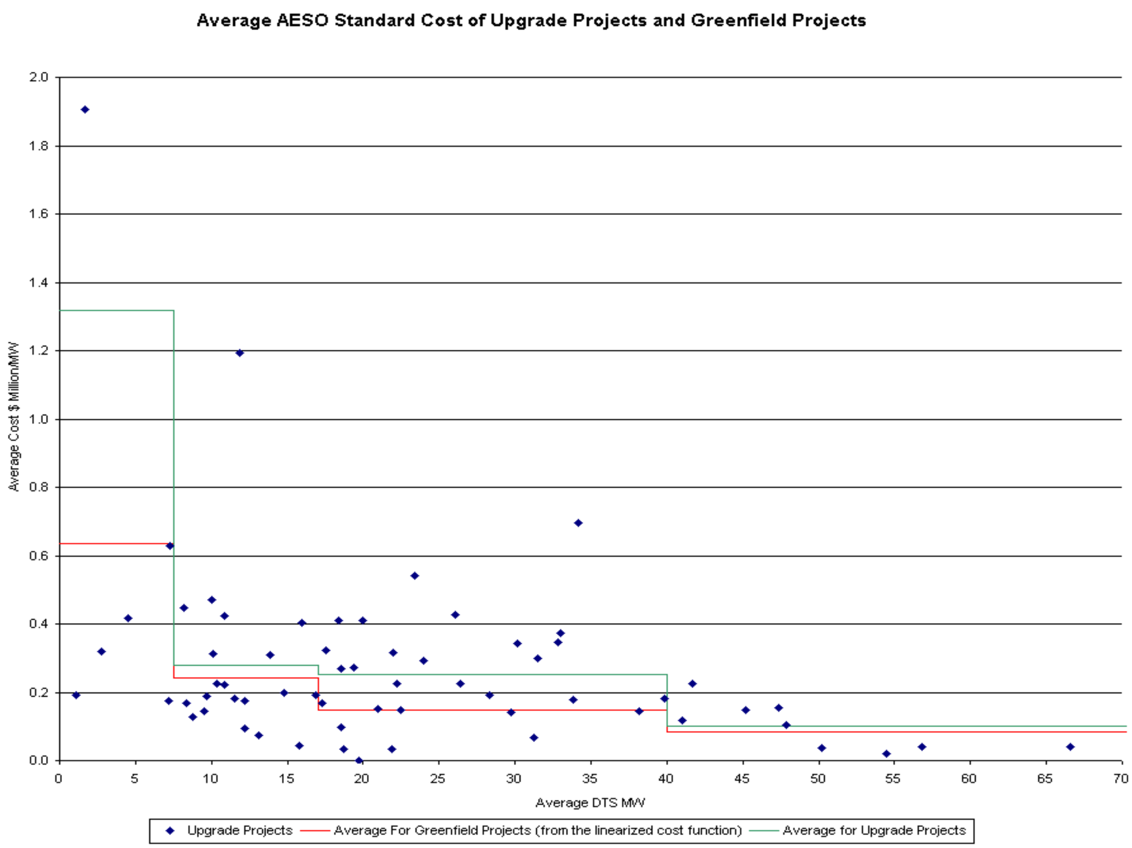
5.4 Reasonability

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

5.5 Upgrades

The AESO will investigate 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 will be plotted against the average of the DTS capacity before and after the upgrade. Then greenfield projects will be grouped according to their DTS capacity of 0-7.5 MW, 7.5-17 MW, 17-40 MW, and 40 MW and larger. The average cost of each group will be plotted resulting in four blocks. 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.

5.6 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 will include 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 will be used for the calculation. The ratio of total substation related cost (that is, excluding line related cost) to total AESO standard cost was calculated to be 0.55 in the last study. This ratio currently stands at 0.56. This information can be found in the “psc” tab of the Excel workbook.

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=0.4212).

The proposed cost function equation 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.

The resulting POD Cost Function is:

Equation 4

DTS POD Cost = \$0.852 million x SF
+ \$0.636 million/MW × first (7.5 multiplied by the SF) MW of DTS Capacity
+ \$0.243 million/MW × next (9.5 multiplied by the SF) MW of DTS Capacity
+ \$0.149 million/MW × next (23 multiplied by the SF) MW of DTS Capacity
+ \$0.083 million/MW × remaining MW of DTS Capacity