Customer Contribution Study

Preliminary Results

AESO 2007 GTA Terms and Conditions Consultation

May 12, 2006

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Introduction

The AESO proposed a number of changes to the Customer Contribution Policy as part of its 2005-2006 GTA. Following extensive discussion during the hearing, EUB Decision 2005-096 directed the AESO to make a number of revisions to Article 9 of the AESO's terms and conditions.

In its decision, the EUB stated that the maximum investment function proposed by the AESO was "overly simple. As a result, it does not achieve an appropriate balance between simplicity and appropriate economic signals." The EUB's concern was that the AESO proposal placed an emphasis on revenues as a function of the Customer Contribution, whereas the EUB considered that cost was the appropriate starting point for establishing the investment policy. As such in Direction 13 the AESO was directed to adjust the investment levels to reflect the following:

- *A minimum investment allowance of $2.5 million, and*
- *An additional investment of $100,000 per MW of project capacity.*

Assuming a maximum 20 year contract term, the AESO refiled Article 9 with investment levels of $125,000/year of contract term plus $5,000/MW/year of contract term.

In Decision 2005-096 the EUB also directed the AESO to conduct additional work on the Customer Contribution Policy and report back to the EUB with its results for the AESO's 2008 GTA:

> *13A. In respect of the longer term beyond 2006, the Board directs the AESO to conduct further study so that it may devise a more comprehensive investment function proposal which avoids the Board's concerns with the AESO's 2006 Application and reflects the design principles described by the Board in this Decision. The Board considers that this task will involve several distinct steps, as reflected in the following list of Board directions:*
>
> *1. The Board hereby directs the AESO to conduct a study for the purpose of devising a simplified maximum investment function. Such study to be completed in time for review no later than the 2008 GTA proceeding. The study should incorporate a sufficient number and diversity of data points to enable the study to consider the current costs of several different interconnection project sizes. Interconnection project costs for the purposes of the investment function study should only reflect the costs of standard facilities as described in the AESO Standard Facilities definition approved by the Board in this decision.*

2. *On the basis of the results of the study described in the preceding direction, the AESO shall recommend an investment function that represents the average cost per MW of capacity. The Board expects that the resulting interconnection cost function derived will exhibit significant economies of scale and, as a result, may be non-linear in nature. For the purposes of the remaining steps of the Board's maximum investment function directions, the average cost function derived in accordance with this step will be referred to as the "Raw Interconnection Project Cost Function".*

3. *In accordance with the notion of a tolerance as discussed in the argument of IPCAA, the Board directs the AESO to analyze the results of the above study for the purposes of determining an appropriate multiplier such that approximately 80% of the projects included have a cost greater than implied by the Raw Interconnection Project Cost Function fall within the selected tolerance multiplier.*

The Board directs the AESO to present the results of the above analysis for review no later than the time of filing its 2008 GTA, along with its proposal for an appropriate maximum investment formula. [p. 58]"

Prior to refiling the responses to the directions outlined by the EUB in Decision 2005-096, the AESO conducted a pre-filing stakeholder session to discuss the investment level as outlined in Direction 13. The AESO presented analysis that suggested that the investment levels as identified in Direction 13 resulted in significantly higher contributions than the AESO's previously approved investment policy.

All documents relating to these customer consultations can be accessed on the AESO's website by following the paths:

- Tariff ▶ Current Consultation ▶ 2007 Terms and Conditions, and
- Tariff ▶ Previous Applications ▶ 2005-2006 Tariff Refiling.

Issues

In responding to Direction 13A the AESO intends to address the following issues raised by parties:

- The 2006 approved investment levels appear to be significantly lower than the previous AESO investment policy. Under the 2006 investment policy, about 40% of projects will require a customer contribution, compared to less than 10% under the AESO's previous investment policy.

- Concerns were expressed with the sample data provided by the AESO, including, for example, lack of thorough analysis of the data, definition consistency with rate design, and unexplained anomalies in the data.

- Potential intergenerational equity concerns were raised.

- Some participants questioned whether the target 80% of projects being covered by investment is determined based on the number of projects or the dollar value of projects.

- The combined effects of high transmission development costs, a reduction in investment levels, and increased number of projects required to pay a contribution create a barrier to new industrial load development.

- The contribution policy needs to balance previously stated customer contribution principles and the evolution of the Alberta electric industry.

The AESO produced Terms of Reference for the Customer Contribution Study, which proposed to address these issues. Stakeholders provided input on the Terms of Reference, and a revised document was issued on February 28, 2006.

Scope

The three components as outlined in Direction 13A will be the basis for the scope of this study. During the course of the study, the AESO will:

1. Incorporate a sufficient number and diversity of data points

The study approach entails the gathering of data for the most recently constructed substations for which the AESO has information (i.e. for the years 2000 to 2006) and deconstructing the project and cost information. Deconstruction of project costs would entail separating the facility project costs as follows:

- Transformer, transmission line and other costs;
- Standard vs. optional facility costs; and
- System vs. customer related costs.

As per the Terms of Reference, the AESO also committed to consider additional information during the course of the customer contribution study. The following information may prove useful in the analysis of POD costs:

- Voltage level of the customer's interconnection;
- Single-customer, multi-customer or multi-use (DTS or STS) substation;
- Load factor at the substation; and
- Transformer size (MVA capacity).

The study will also attempt to identify whether the customer contribution was for optional facilities, or in excess of the maximum investment amounts.

The deconstructed project information will align with the definition of Point of Delivery (POD) as utilized in the AESO's rate design and project costs will be updated to current dollars.

The AESO proposes to undertake a detailed review of all the substations that went into service from 2000 through 2006. The AESO recognizes that the contract capacity distribution may be limited by the sample size, but the AESO feels information accuracy is of primary importance. The detail and accuracy of information available is far greater for actual projects (substations constructed during the period 2000 to 2006) compared to information surrounding the circumstances and drivers that impacted the development of an existing substation during the vertically integrated utility environment. For example, the AESO would not have information on the original contracted load at the substation, if and when upgrades were made to the substation, or contract capacity changes at the substation that may or may not have included facility expansion.

The AESO also intends to compare and test the data collected with projects that are expected to be constructed in the near future to further check that the projects are appropriately representative of the recent past.

2. Determine the Raw Interconnection Project Cost Function

The AESO will collect data as outlined above and will analyze the results in order to determine the Raw Interconnection Project Cost Function. The intent would be to recommend an investment function that represents the average cost per MW of capacity but will investigate whether the data exhibits any significant economies of scale, if the relationship between contract capacity and cost is linear or non-linear in nature or if relationships other than contract capacity and cost exist.

3. Determine an appropriate multiplier such that 80% of projects do not pay a contribution.

Once the Raw Interconnection Project Cost Function has been determined the AESO will investigate different multipliers to achieve an investment where 80% of projects do not pay a contribution.

The AESO feels the "80/20 rule" continues to be an appropriate guideline and will review the impact of the multiplier to achieve the 80/20 investment level for the projects from 2000 through 2006.

The Preliminary Customer Contribution Study Results

The preliminary results of this Customer Contribution Study address the first two components of the study, as outlined in Direction 13A. The third component of the study, the "multiplier" that will be applied to the cost function so that 80% of projects do not pay a contribution, will be addressed with the final results of the study, when an appropriate cost function has been established.

Methodology Overview

Availability of data

The proposed scope of work for the study envisioned utilizing historical data to determine the individual cost components that form the basis of substation construction costs. This information primarily relied on final cost data submitted by TFOs. Where final reconciled costs or their allocations were unavailable, every effort was made to allocate final actual costs based on estimate information using Proposal to Provide Service ("PPS") documents or Order of Magnitude documents.

The data was drawn from AESO maintained databases – CASPIR (Customer Access Services Project Information Resource) and TASMo (Transmission Model Database). In addition, project information was extracted from internal Customer Contribution Decisions and other project information documentation.

Actual cost data is used where available. Cost data has been adjusted to reflect present day dollar values. The inflation rate is based on the transmission construction price index produced by Statistics Canada (www.statcan.ca). The base case year used for present values was 2007, which was considered to be when the proposed customer contribution policy would first be effective (as part of the AESO 2007 GTA).

Where limited cost information was available, the project was excluded from the study.

Criteria for Inclusion

The AESO determined that using substation information from those substations that went into service during the years 2000 through 2006 would most accurately represent substation costs. During the course of the study, it was found that enough cost information was available to include those substations that were constructed in 1999, so these projects were also included.

Only Point-of-Delivery ("POD") substations were included in the sample. The AESO investment policy compensates load customers that wish to interconnect, in exchange for a contract of future revenues. Substations constructed for dual-use customers (i.e. generation and related load services interconnected at the same substation) were not included in the study. However, substations connected with more than one load customer (i.e. multi-user) were included. The AESO does not have reliable cost data for substations built before 1999.

Excluded from the study were projects that involved upgrades to existing substations, substation expansions, rebuilds, and substation relocation projects. In one case, there was a replacement of a substation: this project was included in the sample as it was deemed that the costs appropriately reflected real substation costs.

Sample Size

Initially, it was determined that 75 substations were constructed from 1999 to 2006. From this, substations that were associated with any generation or supply were excluded (on the basis of the ultimate analysis of a DTS customer investment function). Substation loads that were dual-use, that is, supplied load for generation, were also excluded.

Also excluded were projects that were deemed 100% system-related.

A final sample size of 28 substations was used in the study.

Project and Category Classification

The AESO identifies each connection proposal as a "Project" and assigns project identifications on a numerical basis. Currently, the AESO information systems track more than 500 projects from inception to completion.

All project information is maintained both electronically and in hard copy, in numerically ordered project files. Project files are filed by their assigned number.

A single project to interconnect a customer may involve more than the construction of a substation. It may also involve upgrades to adjacent substations, transmission lines, etc. Analysis of complete projects indicated that some projects involved the construction of more than one substation. In these cases, each substation was deconstructed, based on information availability, so that project numbers have appeared twice identifying different substation names. This is the case for Project #10 (involving the construction of Algar and Mariana substations) and Project # 79 (involving the construction of Crow and Gregoire substations). For these two projects, an attempt was made to isolate just those costs associated with the identified substation. For the balance of the projects, total project costs were identified.

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 POD 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.

Excess of standard facility costs are those costs that are in excess of the AESO deemed standard facility interconnection configurations. For example, “acceleration” payments are deemed in excess of standard costs, and customer preferences to construct premises 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.

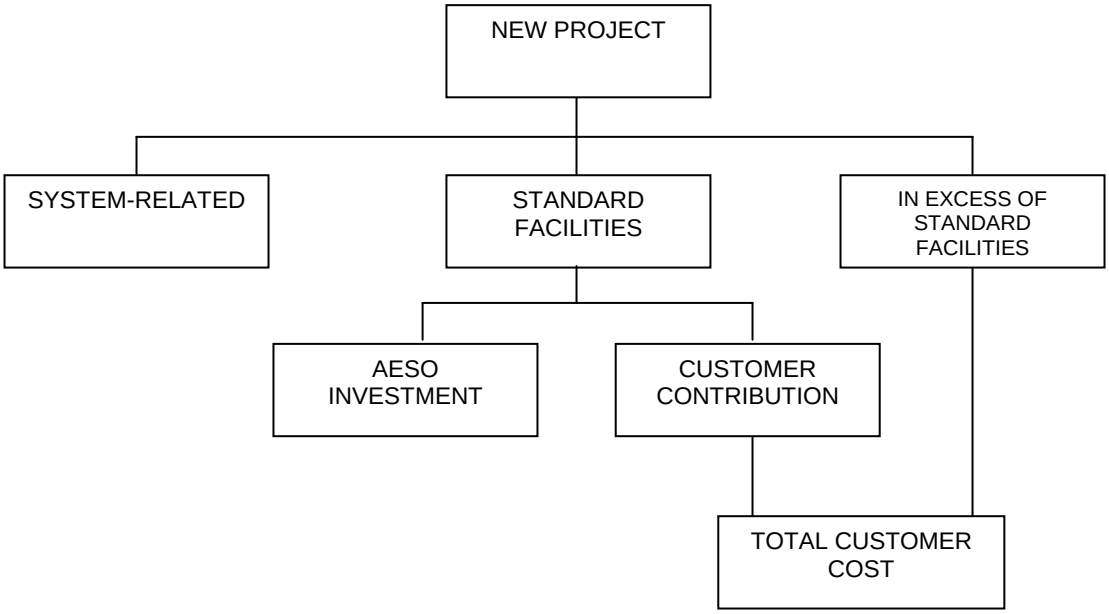
Total substation costs are those costs distinctly associated with substation construction, including labour. Transmission line construction, and work performed at adjacent substations in respect to the project would not be included in substation costs. Transformer and breaker costs are strictly material costs, and do not include the labour involved to construct and install the items. Where total substation costs were available, but transformer and breaker costs were not identified, an estimate was used for transformer and breaker costs (Blackmud 155S, Edmonton 216S, Marlboro 348S and Carvel 432S). These standard estimates were gathered by the AESO in 2004 for an unrelated project, and present value multipliers were applied.

Total project costs include all costs associated with a project, which form the basis of customer contribution investment calculations. Substation equipment, protection, SCADA and transmission line costs are strictly material costs and all labour costs are included in the labour category.

Two projects in the sample (Yasa 332S and Ellis 286S) were constructed and subsequently totalized with existing substations and associated DTS contract capacities. DTS contract capacities in these cases were allocated to the increase in load that was attributable to the substation being analyzed.

Figure 1 demonstrates the cost determination process for new projects.

Figure 1



Collected Information

The following information was collected for each project:

Information	Source
Facility/Substation Information	
Project Number	Projects are assigned numbers upon receipt of a proposal.
Substation Name, ID	Substations are assigned names (TASMo)
Facility (Substation) Code	Substations are assigned codes (TASMo)
Year	The year in which the PPS was issued, or as recorded in cost estimation data.
DTS Contract Capacity	As per DTS contract agreement, information obtained from Settlements systems
Physical Aspects of PODs	
Voltage	TASMo
Single or Multi Loads	Settlements
Number of Transformers	TASMo
Transformer Size	TASMo
Transmission Line Length	TASMo
Substation Costs	
Substation Costs (Total)	Project Files (TFO submissions)
Transformer Costs	Project Files (TFO submissions)
Breaker Costs	Project Files (TFO submissions)
Break Down of Project Costs	
Labour	TFO issued PPS or final actuals where available
Sub-Equipment	TFO issued PPS or final actuals where available
Protection	TFO issued PPS or final actuals where available
SCADA	TFO issued PPS or final actuals where available
Transmission Line Costs	TFO issued PPS or final actuals where available
Overhead	TFO issued PPS or final actuals where available
Customer Contributions	
Standard vs. Optional Costs	Customer Contribution Decisions
System vs. Customer-Related Costs	Customer Contribution Decisions
Actual Contribution	Customer Contribution Decision, Finance
Tariff Year Applied	Customer Contribution Decisions
Contract Term (years)	Customer Contribution Decisions

Findings

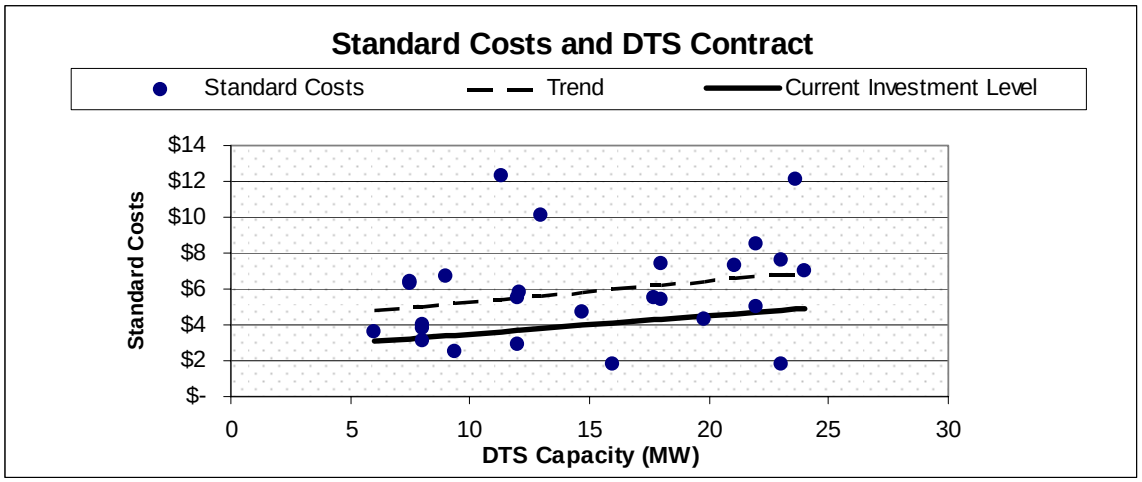
DTS Contract Capacities and Standard Costs

A number of variables were analyzed in determining an investment cost function for DTS customers wishing to interconnect to the Alberta Interconnected Electric System ("AIES"). The variables as identified in the Terms of Reference were analyzed to determine if a strong relationship existed that could prove useful as a basis for a customer contribution cost function.

While the study aimed to determine relationships that might provide a useful cost function, of note is that very few variables proved to have a linear relationship, and only a few had correlation coefficients of greater than r^2=0.3, which would indicate a very little correlation. The following information is provided for reference.

Figure 2 shows the relationship between AESO deemed "standard" costs and DTS contract capacity. Standard costs (as defined on pages 9-10) are the costs associated with AESO standard facilities, or the least-cost interconnection facilities that meet reliability, protection, and operations criteria. There appears to be very little correlation between standard costs and DTS contract capacities.

Figure 2



There appears to be some similarity between the current AESO investment policy and the standard cost trend line. However, only 21% of the projects would be fully covered under the current investment policy.

The DTS contract capacities were analyzed to determine if a linear function existed for small projects (for example, projects of less than 10 MW in size), and a different line function existed for larger projects (for example, 10 to 30 MW in size).

The following table illustrates further analysis of the DTS contract capacity and standard costs relationship. The slope provides the additional capacity component of the investment function, in $ million/MW, and the y-intercept provides the minimum allowance component of the investment function, in $ million. Shading highlights negative values for the slope and ye-intercept.

Table 1

($M)	All	0-10 MW	10+ MW	0-13 MW	13+ MW
Slope	.133	.347	.066	.545	.404
Standard Deviation	1.35	3.66	2.73	3.40	4.03
Y-Intercept	3.88	2.04	5.28	.429	-2.20
Coefficient (r^2)	.096	.074	.012	.182	.257

Maximum of Standard Costs	$12.35
Minimum of Standard Costs	$1.78
Average of Standard Costs	$5.95

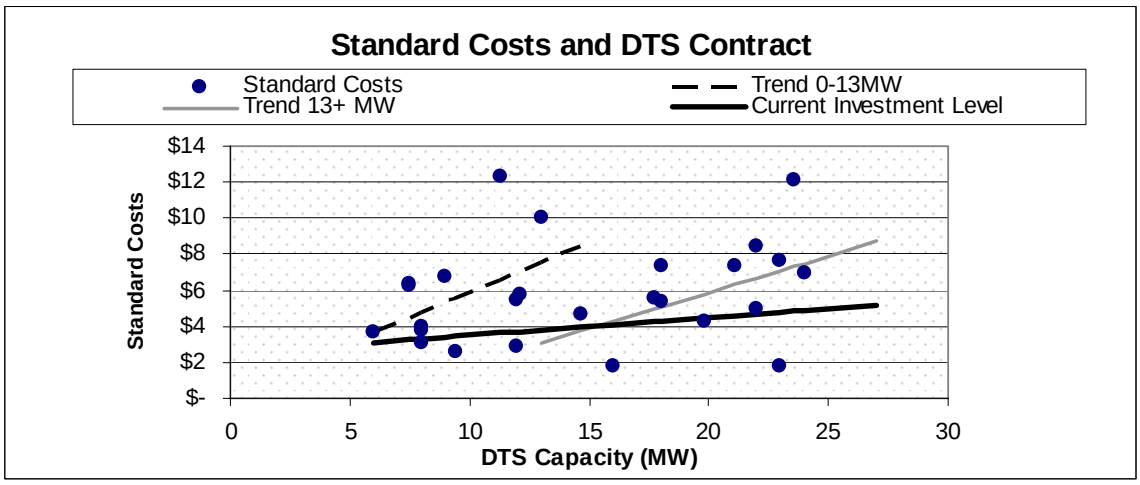
Linear equation functions (in the form y = b + mx) and the associated correlation coefficients are provided for substation costs for a number of DTS contract capacity ranges in Table 2.

Table 2

All	y = $3.877 + ($0.133 x DTS)	r^2=0.096
0 – 10 MW	y = $2.039 + ($0.347x DTS)	r^2=0.074
10 + MW	y = $5.276 + ($0.066 x DTS)	r^2=0.012
0 – 13 MW	y = $0.429 + ($0.545 x DTS)	r^2=0.182
13 + MW	y = $-2.201 + ($0.404 x DTS)	r^2=0.257
0 – 15 MW	y = $2.205 + ($0.338 x DTS)	r^2=0.098
15 + MW	y = $-3.388 + ($0.456 x DTS)	r^2=0.252

Further analysis of standard costs and DTS contract capacities are shown in Figure 3. This graph shows the relationship between projects that had DTS contract capacities of 0 to 13 MW, and of DTS contract capacities of more than 13 MW. These two ranges provided the highest correlation factors for the two separate lines.

Figure 3

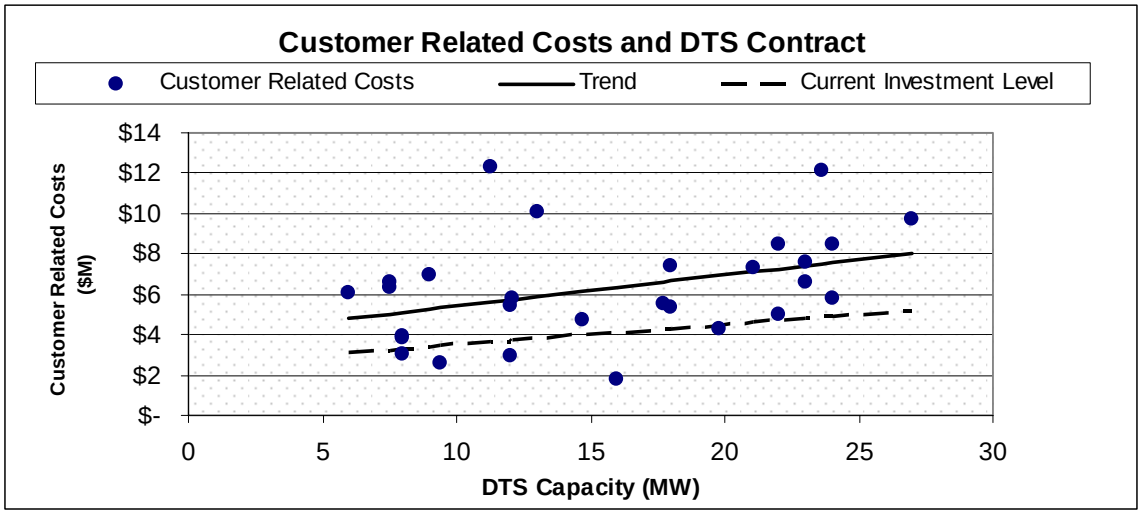


The 13+ MW DTS contract capacity range crosses the x-axis (where $ = 0) at 5.44 MW.

DTS Contract Capacities and Customer-Related Costs

Additional analysis was performed on the relationship between customer-related costs and DTS contract capacity, as shown in Figure 4. Customer-related costs include AESO standard facility costs, and those costs deemed in excess of standard facilities. Figure 4 includes the current (2006) investment level for reference.

Figure 4



DTS contract capacities were also analyzed for different ranges of MW contract capacities. Table 3 provides further statistical information on this analysis. Highlighted items denote negatives.

Table 3

($M)	All	0-8 MW	8+ MW	0-12 MW	12+ MW
Slope	.154	-1.216	.153	.980	.256
Standard Deviation	1.25	5.83	2.04	5.56	2.23
Y-Intercept	3.88	14.08	3.92	-2.40	1.66
Coefficient (r^2)	.142	.381	.089	.234	.230

Maximum of Customer-related Costs	$12.35
Minimum of Customer-related Costs	$1.83
Average of Customer-related Costs	$6.29

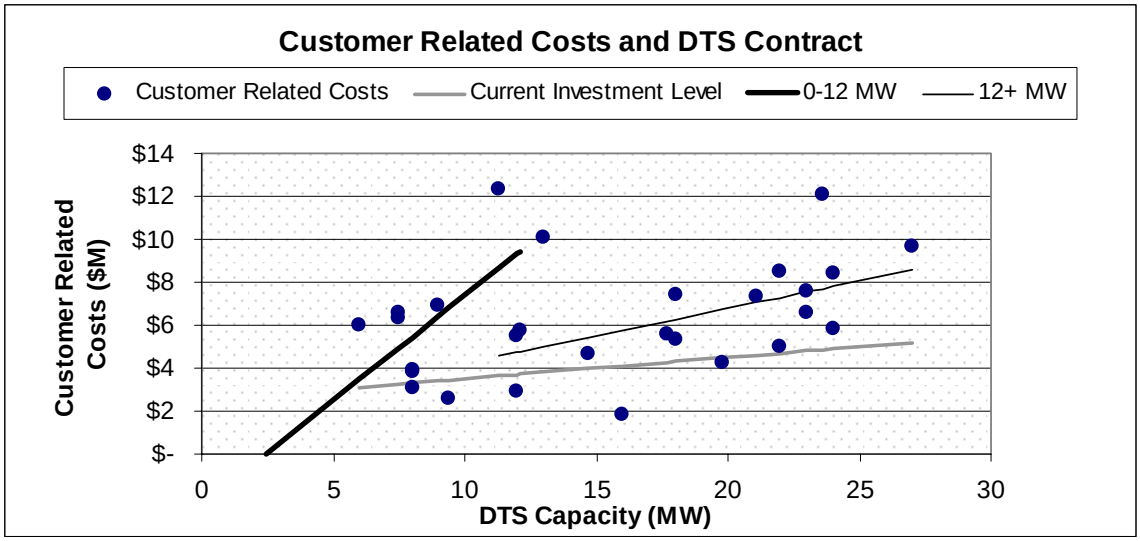
Linear equation functions (in the form y = b + mx), and the associated correlation coefficients are provided for a number DTS contract capacity ranges in Table 4.

Table 4

All	y = $3.882 + ($0.154 x DTS)	r^2=0.142
Current Investment Level	y = $2.500 + ($0.100 x DTS)	n/a
0 - 8 MW	y = $14.082 + ($-1.216 x DTS)	r^2=0.381
8 + MW	y = $3.918 + ($0.153 x DTS)	r^2=0.089
0 - 10 MW	y = $10.373 + ($-0.690 x DTS)	r^2=0.166
10 + MW	y = $4.403 + ($0.130 x DTS)	r^2=0.053
0 - 12 MW	y = $-2.404 + ($0.980 x DTS)	r^2=0.239
12 + MW	y = $1.661 + ($0.256 x DTS)	r^2=0.230
0 - 15 MW	y = $3.539 + ($0.223 x DTS)	r^2=0.044
15 + MW	y = $-5.031 + ($0.555 x DTS)	r^2=0.464

Further analysis of customer-related costs and DTS contract capacities are shown in Figure 5. This graph shows the relationship between projects that had DTS contract capacities of 0 to 12 MW, and of DTS contract of 12+ MW. This threshold provided the highest correlation factors for the two separate lines.

Figure 5

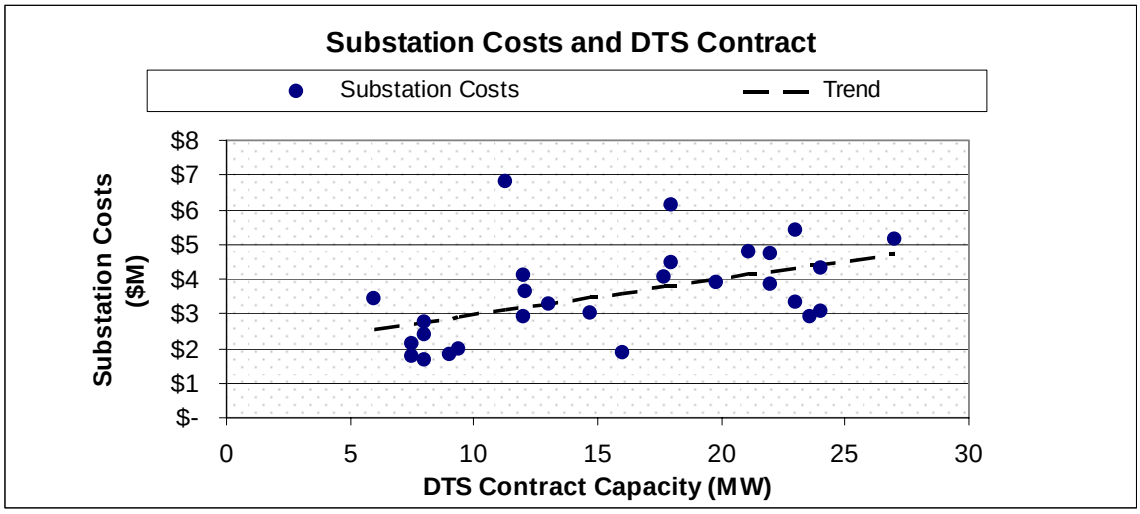


The 0 to 12 MW DTS contract capacity range crosses the x-axis (where $ = 0) at 2.45 MW.

DTS Contract Capacities and Substation Costs

Figure 6 identifies the costs that are allocated to the substation that was constructed, versus DTS contract capacity. From total project costs, which include such items as transmission line construction, labour costs, and overhead, substation costs were isolated for each substation constructed.

Figure 6



Recall that substation costs make up one component of total project costs, and customer-related costs are determined based on total project costs. Substation costs were only available separately at the project level, and not at the customer-related costs level (where those levels are as depicted in Figure 1).

The following table identifies some areas of further analysis, using different DTS contract capacity ranges.

Table 5

($M)	All	0-10 MW	10+ MW	0-13 MW	13+ MW
Slope	.105	-.385	.016	.306	.079
Standard Deviation	.59	1.38	1.10	1.56	1.85
Y-Intercept	1.91	5.28	3.78	0.06	2.41
Coefficient (r^2)	.255	.454	.005	.250	.060

Maximum of Substation Costs	$6.79
Minimum of Substation Costs	$1.67
Average of Substation Costs	$3.56

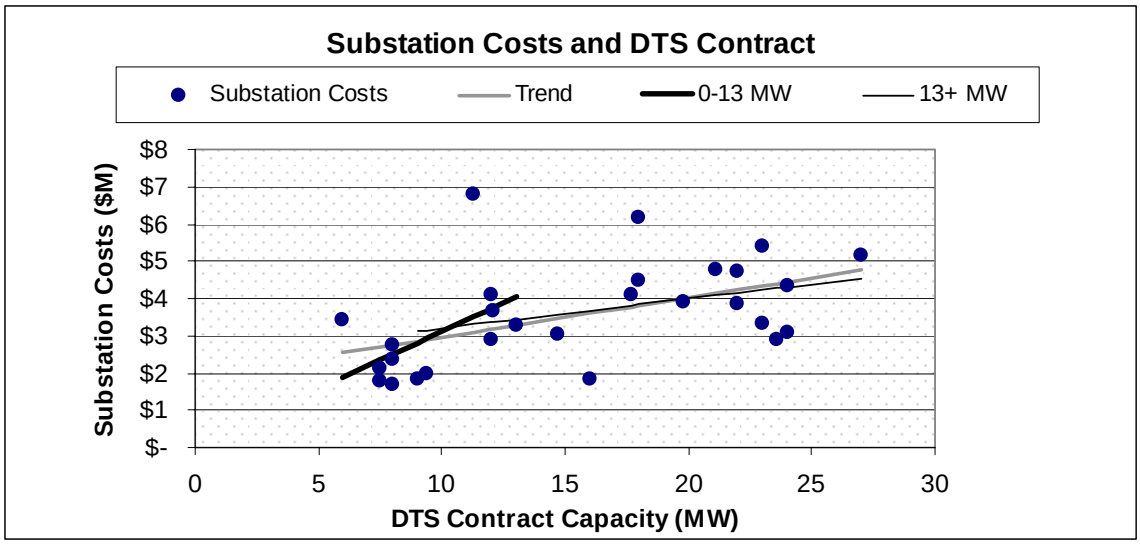
Linear equation functions (in the form y = b + mx) and the associated correlation coefficients are provided for substation costs for a number of DTS contract capacity ranges in Table 6.

Table 6

All	y = $1.912 + ($0.105 x DTS)	r^2=0.255
0 - 10 MW	y = $5.286 + ($-0.386 x DTS)	r^2=0.454
10 + MW	y = $3.782 + ($0.016 x DTS)	r^2=0.005
0 - 13 MW	y = $0.057 + ($0.306 x DTS)	r^2=0.250
13 + MW	y = $2.405 + ($0.079 x DTS)	r^2=0.060
0 - 15 MW	y = $0.782 + ($0.222 x DTS)	r^2=0.183
15 + MW	y = $3.065 + ($0.050 x DTS)	r^2=0.019

Further analysis of substation costs using DTS contract capacity ranges of 0 to 13 MW, and 13+ MW, are shown in Figure 6.

Figure 7



Observations

Analysis of standard and customer-related costs does not support a strong correlation between the variables. No single dependent variable analysis resulted in correlations of higher than r^2=0.255. This would indicate that the relationship between DTS contract capacities and standard or customer-related costs is not particularly strong.

However, using different DTS contract capacity ranges results in higher correlations. Higher correlations in the study were found when analyzing the subset relationship between DTS contract capacities and standard costs, which had correlations of r^2=.182 for the 0 to 13 MW range and r^2=.257 for the 13+ MW range. Each of these correlations were higher than when the whole DTS contract capacity range was used, which had a correlation of 0.096.

In addition, using DTS ranges showed higher correlations when using the DTS contract capacity variable and the customer-related cost variable. The linear equation using the whole range of DTS contract capacities indicated a correlation coefficient of r^2=.142, whereas the 0 to 12 MW range showed a correlation of r^2=.239 and the 12+ MW range had a correlation of r^2=.230.

Analysis also indicated a correlation of r^2=0.255 for substation costs and DTS contract capacities.

Analysis of other combinations of variables (such as costs and voltage levels) were also examined, but resulted in no observable trends. All study data, including the figures and trend analysis discussed above, are provided in the attached Microsoft Excel workbook.

While the results of this preliminary study may not conclude a strong relationship exists between DTS contract capacity and various costs, it may provide useful information on the appropriateness of applying DTS contract MW ranges to a future investment policy function.

Next Steps

Interested parties are invited to provide further comments on the information discussed in this paper. All comments will be published on the AESO website a www.aeso.ca as part of the consultation documentation available by following the path Tariff ▶ Current Consultation ▶ 2007 Terms and Conditions.

This discussion provides preliminary background material on the Customer Contribution Study. The AESO intends to conduct further analysis and investigation, and expects that the results and final study will be available at the end of May 2006.

Comments should be provided to Ed Hucman at ed.hucman@aeso.ca and copies to Lee Ann Leduc at leeann.leduc@aeso.ca. In addition, please contact Ed Hucman at (403) 539-2469 or Lee Ann Leduc at (403) 539-2741 (both in Calgary) or by e-mail at the above addresses if you have further questions on this analysis.