

Alberta Electric System Operator

DRAFT Electric Transmission Operating and Maintenance Cost Study

PS Technologies Inc.
Arnie Reimer
August 30, 2009

Table of Contents

1. Executive Summary	3
2. The Alberta Electric Transmission System.....	4
2.1. Results of Previous Studies.....	5
3. TFO Cost Data	6
3.1. Compilation of GTA Data	6
4. Definition of Non Capital Related Costs	7
4.1. Capital Related Costs	7
4.2. Non Capital Related Costs	8
4.2.1 Fuel	8
4.2.2 Operating.....	8
4.2.3 Revenue Offsets	9
4.2.4 Hearings, Self Insurance, Other Taxes	9
5. Cost of Service (Non Capital Costs).....	10
5.1. Functionalization.....	11
5.2. Classification.....	13
5.3. Allocation.....	14
5.4. Results.....	15
6. Prepaid O&M Charges.....	16
6.1. Applicable Costs	16
6.2. Time Frame	17
6.3. Nature of Costs	17
6.4. Determination of Costs	17
7. Summary	18
8. Appendix A – TFO GTA Revenue Requirement	19
9. Appendix B – Capitalization Policies.....	21
10. Background.....	22

1. Executive Summary

This study was completed to better understand the causation of electric transmission operating and maintenance costs. The study was completed to address an AEUB Directions in Decision 2005-096 and Decision 2007-106 (Alberta Electric System Operator – 2006 and 2007 General Tariff Applications, respectively) regarding transmission system costs. This study is a follow up of past studies, the first of which was the Alberta Transmission System: Wires Only - Cost Causation Study that was an Appendix to the AESO 2006 General Tariff Application, and the Alberta Transmission System 2006 Transmission Cost Causation Update that was an Appendix to the 2007 General Tariff Application. Both of these previous reports studied the causation of capital costs of the electric transmission system and did not study the operating and maintenance costs. For the purpose of cost studies and rate design, operating and maintenance costs were assumed to follow in step with capital costs. Capital related costs of the electric transmission system comprise approximately 2/3 of the annual revenue requirement and non capital related costs comprise the remaining 1/3 of the annual revenue requirement.

Generally, the TFO O&M costs are considered all TFO costs that are not capital related costs. However, for some purposes, it is appropriate to separate non capital related costs into O&M and Administrative (or General and Administrative (G&A)).

This study was completed using traditional cost of service methods including: functionalization, classification and allocation of costs. As in previous transmission cost studies, the allocation of costs is not required because there is only one rate class.

The following table outlines the outcome of the previous cost study that considered capital costs, as well as the outcome of this study that considers non capital costs, and the weighting of the two to arrive at a cost basis for rate design.

Capital Related Costs	Bulk System	Local System	POD	Totals
Demand Related	34.0%	14.3%	17.6%	66.0%
Energy Related	7.7%	3.0%	0.3%	11.0%
Customer (POD)	0.0%	0.0%	23.0%	23.0%
Totals	41.7%	17.4%	40.9%	100.0%
Non Capital Related Costs	Bulk System	Local System	POD	Totals
Demand Related	11.3%	32.8%	17.7%	61.8%
Energy Related	2.6%	8.6%	4.0%	15.2%
Customer (POD)	0.0%	0.0%	23.1%	23.1%
Totals	13.8%	41.3%	44.8%	100.0%
Weighted (33.8% Non Capital)	Bulk System	Local System	POD	Totals
Demand Related	26.3%	20.6%	17.7%	64.5%
Energy Related	6.0%	4.9%	1.6%	12.4%
Customer (POD)	0.0%	0.0%	23.0%	23.0%
Totals	32.3%	25.5%	42.2%	100.0%

2. The Alberta Electric Transmission System

The Alberta Interconnected Electric System (AIES) is planned and operated by the Alberta Electric System Operator (AESO) in compliance with the North American Electric Reliability Council (NERC) and Western Electricity Coordinating Council (WECC) standards and the WECC Reliability Management System.

The AIES consists of an electric transmission system connecting generation and loads in Alberta. The AIES is interconnected to BC through a 500 kV AC interconnection along with underlying 138 kV AC lines and is interconnected to Saskatchewan with an asynchronous DC link. The AIES includes transmission facilities with nominal voltages ranging from 69 kV to 500 kV AC. The AIES includes approximately 21,000 km of transmission lines and 500 substations and serves an annual peak load of 10,000 MW.

The cost of Alberta's electric transmission system includes annual costs (2007) of:

Wires	\$ 484 million
Ancillary Services	\$ 266 million
Losses	\$ 251 million
Admin and Other	\$ <u>61</u> million
Total	\$1,062 million ¹

Prior to industry restructuring, the transmission system was part of the vertically integrated electric utility, and the transmission costs were generally considered one function, and were classified as demand related costs.

The Alberta Energy and Utilities Board (AEUB) directed the AESO to study transmission wires costs, and AESO filed the first Alberta Transmission System, Wires Only Cost Causation Study with its 2006 GTA. The AEUB generally approved of the concepts developed in the study and directed upgrades to the study in Decision 2005-096. In response to these directives, the AESO filed an Alberta Transmission System, 2006 Cost Causation Update with its 2007 GTA. The AEUB approved the update in Decision 2007-106 and directed further study in the area of operating and maintenance costs.

Decision 2007-106² includes the following Direction:

6. In the absence of more specific information, the Board is not prepared to direct the AESO to make additional adjustments to the POD cost function or the resulting POD charge component of Rate DTS for the purposes of the 2007 tariff. However, so long as it can be accomplished at a reasonable cost, the Board considers that additional study into the causation of TFO O&M costs may be of value for future AESO rate design purposes as well as for the purposes of understanding TFO O&M forecasts within the context of future TFO GTAs. Accordingly, the Board directs the AESO to indicate in its refiling application the cost and time required to prepare a further study into the causation of TFO O&M costs.....59.

¹ Forecast costs from 2008 AESO Board Decision in Table 2-2 of AESO 2009 Rates Update Application, March 12, 2009.

² Decision 2007-106, Alberta Electric System Operator, 2007 General Tariff Application, December 21, 2007.

This study is in response to the AEUB's Direction and to provide a better understanding of electric transmission system operating and maintenance costs.

The purpose of this study is to refine the cost causation study to include O&M costs to refine cost causation, and the subsequent rate design for the Transmission Tariff.

Intervenors in the 2007 GTA filed a request to review and vary the AEUB Decision 2007-106 in regards to customer contributions, specifically the prepaid O&M component of the customer contribution. The Alberta Utilities Commission (AUC) revised the method of calculating a customer contribution with respect to the prepaid O&M component in Decision 2009-105³. Further, the AUC directed the following in Direction 3 in Decision 2009-105.

- (3) The AESO shall file its analysis of the relationship between incremental O&M and interconnection capital costs, as originally directed by the Board in Decision 2005-096, by no later than the time of its next GTA

This study also responds to the AUC Direction to study incremental O&M costs. The purpose of this study is to provide a better understanding of incremental O&M costs and provide a recommendation as to the validity of the existing 12% prepaid O&M charge.

2.1. Results of Previous Studies

The previous cost causation studies considered only capital related costs and the causation of these costs. Capital related costs consist of the majority of TFO costs and were used as the basis for all TFO costs. The previous studies assumed that O&M costs are incurred proportional to capital costs. This assumption was called into question during the 2006 and 2007 GTAs, and further study was directed to better understand the incurrence of O&M costs.

The following table summarizes the findings of previous studies in terms of the percent of revenue requirement functionalized as Bulk System, Local System and POD, and classified as Demand, Energy and Customer related.

Capital Related Costs	Bulk System	Local System	POD	Totals
Demand Related	34.0%	14.3%	17.6%	66.0%
Energy Related	7.7%	3.0%	0.3%	11.0%
Customer (POD)	0.0%	0.0%	23.0%	23.0%
Totals	41.7%	17.4%	40.9%	100.0%

³ AUC Decision 2009-105, Alberta Direct Connect Consumers Association et al, Review and Variance of Alberta Energy and Utilities Board Decision 2007-106 Second Stage, July 13, 2009.

3. TFO Cost Data

The AEUB Directions deal with study of operating and maintenance costs. To assist in the understanding of operating and maintenance costs, all of the TFO costs are first split into capital related costs and non capital related costs. The non capital costs are all of the costs that are not capital related and are used for the purpose of the cost of service and transmission tariff design. The non capital cost is broader than what is traditionally considered operating and maintenance cost. Non capital costs include general and administrative costs as well as operating and maintenance costs.

One purpose of this report is to study the causation of costs that are non capital related costs. The basic data for this study is compiled from the Transmission Facility Owner's (TFO) General Tariff Application (GTA). Also, further requests were made for each TFO to provide additional information to assist in understanding the costs that comprise the GTA. Also, further meetings were conducted with each TFO to understand the cost information in the GTA and to understand the causation of these costs.

As in the previous studies, data was collected from the four largest TFO's including AltaLink, ATCO Electric, ENMAX Power and EPCOR. In the interest of efficiency, the costs from the remaining TFO's (Cities of Lethbridge and Red Deer, and TransAlta) are not considered. The costs from the three smallest TFO's account for less than 3% of the TFO wires related costs.

3.1. Compilation of GTA Data

TFO cost data was compiled for the years 2006 through 2009 to consider both actual and forecast data where available. The cost data for 2008 was studied in depth to develop the cost causation study for non capital costs. Cost data was extracted from each TFO's GTA, and the data is shown in Appendix A – TFO GTA Data. The summary of the cost data for the four largest TFO's is shown in the following table.

Get rid of 2010, delete Management Fee, - Can we use ATCO Refiling???

Sum of TFO Cost Data				
All Values in \$				
Cost Portions	2006 Actual	2007 Actual	2008 Forecast	2009 Forecast
Fuel	8,394,000	8,700,000	8,200,000	9,300,000
Operating Costs	135,242,780	142,001,488	160,113,555	184,770,788
Depreciation	116,809,507	121,396,515	132,647,804	144,135,060
Return on Rate Base	142,519,512	143,438,597	149,357,495	176,012,613
Income Tax Expense	24,365,115	20,216,661	14,108,326	16,642,146
Revenue Offsets	-16,423,406	-14,288,952	-11,902,901	-9,638,948
Hearings, Self Ins, Other Taxes	18,871,016	16,838,329	19,030,459	21,173,543
Revenue Requirement	429,778,524	438,302,638	471,554,738	542,395,201

4. Definition of Non Capital Related Costs

There is no universally accepted definition of what costs constitute operating and maintenance costs. The possible definitions of O&M costs range from as broad as all costs other than capital related costs to as narrow as the incremental cost of operating and maintaining electrical transmission facilities in use. The broad definition would include costs such as Human Resources that are not directly linked to operating and maintenance activities, while the narrow definition could exclude any overheads associated with operating and maintenance activities.

The AEUB Directions did not provide a definition of O&M costs, and in order to be of assistance to the process of rate design, the definition of O&M costs should be broad so as to include all not capital related costs. Therefore, for the purpose of rate design, O&M costs are defined to be all TFO costs that are not considered capital costs in the previous cost studies. Since all of these costs are based on the TFO revenue requirement, this study is based on embedded costs (\$2008).

The AEUB Direction in Decision 2009-105 did not provide a definition of incremental O&M costs, and in order to be of assistance in the process of determining prepaid O&M costs associated with optional supply facilities, incremental O&M will be considered the direct cost of operating and maintaining electric transmission facilities as well as the overheads of planning and scheduling O&M activities. Therefore, general and administrative costs are excluded from the calculation of prepaid O&M costs. The cost calculation for this exercise is based on \$2008– both RCN capital costs and operating and maintenance costs.

4.1. Capital Related Costs

The costs considered capital related costs include depreciation, return, management fee and income tax expense. The non capital related costs include fuel and operating costs. Revenue offsets are revenues that include both capital and operating related. Hearing, self insurance, other taxes and deferral accounts also include both capital and operating costs. The capital related costs of the electric transmission system comprise approximately 2/3 of the total revenue requirement.

The separation of capital costs from non capital costs is based on a review of all of the costs within the accounts. Each TFO has a Capitalization Policy that outlines which costs should be capitalized. Generally, when an activity will have long term value, the cost of that activity is capitalized. The capitalization policies of the four TFO's studied are included in Appendix B. The cost of replacing and upgrading old equipment is known as capital maintenance and these costs are capitalized, and are not included in operating and maintenance costs.

4.2. Non Capital Related Costs

A transmission cost causation study for non capital related costs becomes more challenging because there is not always a direct correlation between the incurrence of an expense and the impact on the electric transmission system. The non capital related costs will be split into the following components for further review:

- Fuel
- Operating
- Revenue Offsets (some components)
- Hearings, Self Insurance, Other Taxes (some components)

4.2.1 Fuel

Transmission fuel costs are only incurred by one TFO. ATCO Electric incurs fuel costs for isolated generating stations and telecommunications sites that serve remote communities where it is less expensive to operate isolated generating stations instead of constructing transmission facilities to these communities and sites.

The cost of fuel for the electric transmission system is shown in the following table.

Fuel	2006	2007	2008	2009
	Actual	Actual	Forecast	Forecast
Total	8,394,000	8,700,000	8,200,000	9,300,000

The incurrence of this expense avoids the need to extend the Local System and POD.

4.2.2 Operating

The term operating costs is general and includes many of the non capital costs for each TFO. The following table shows the sum of the TFO's operating costs.

Operating	2006	2007	2008	2009
	Actual	Actual	Forecast	Forecast
Total	135,242,780	142,001,488	160,113,555	184,770,788

These operating costs include all of the following:

- Operating costs
- Maintenance costs
- General and Administrative

Operating costs includes costs of operating a system control centre. Maintenance costs include the cost of maintaining electric transmission lines and substations as well as the overheads of planning and scheduling this maintenance.

The General and Administrative costs include costs that are not directly related to the operations and maintenance of the electric transmission system. Examples of these costs include costs associated with office and staff expenses, Community Relations and building services.

4.2.3 Revenue Offsets

Revenue offsets include an assortment of revenues to the TFO's that are not part of the TFO's core business. For example, the TFO's charge for line moves when a customer requests that a line be moved. The TFO incurs a cost to move the line and the TFO levies a charge to the customer to recover this cost.

Revenue offsets include revenues for line moves, joint use (shared use of poles with other utilities), shared services from affiliates and other services to outside parties. The total revenue offsets from the four largest TFO's are shown in the table below.

Revenue Offsets	2006	2007	2008	2009
	Actual	Actual	Forecast	Forecast
Total	-16,423,406	-14,288,952	-11,902,901	-9,638,948

Where revenue offsets occur as the result of operating and maintenance costs, the revenue offsets are treated in the same manner as the operating costs with respect to functionalization and classification of these costs.

4.2.4 Hearings, Self Insurance, Other Taxes

The cost of hearings, self insurance and other taxes are considered non capital related costs. The Taxes other than income tax are associated with electric transmission facilities and can be functionalized while the cost of hearings and self insurance do not have a direct correlation to electric transmission facilities and will be treated as general and administrative costs.

Hearings, Self Ins, Other Tax	2006	2007	2008	2009
Deferral and Reserve Accounts	Actual	Actual	Forecast	Forecast
Total	18,871,016	16,838,329	19,030,459	21,173,543

5. Cost of Service (Non Capital Costs)

The traditional cost of service methods have been based on vertically integrated electric utility companies. The traditional cost of service studies first functionalize costs, then classify costs and finally allocate costs to the appropriate rate class.

Stand alone cost of service studies on the electric transmission system are not common and transmission costs are generally considered as one function, and are generally classified as demand related.

Electric transmission systems are capital intensive and the majority of costs of owning, operating and maintaining an electric transmission system are considered capital costs. As shown in the following table derived from the TFO's GTAs, the operating costs (Fuel and Operating, with the remainder of costs assumed capital related costs) are about 1/3 of the annual TFO revenue requirement.

(Fuel & Operating)/Rev Req	2006	2007	2008	2009	Average
	Actual	Actual	Forecast	Forecast	
AltaLink	26.3%	25.1%	25.6%	26.8%	25.9%
ATCO Electric	35.8%	38.3%	41.8%	41.7%	39.4%
ENMAX	53.4%	57.5%	57.6%	56.8%	56.3%
EPCOR	41.2%	48.1%	43.2%	40.1%	43.2%
Total	33.4%	34.4%	35.7%	35.8%	34.8%

A review of the cost shown in Section 3.1 indicates that revenue offsets include revenue that offset both capital costs and operating costs. The Revenue Offsets were reviewed to assess which costs were capital related and which were associated with operating costs. The revenues associated with operating costs include revenues from affiliates, and from other parties such as movers requesting that lines be raised. When adjusting for revenue offsets, the non capital costs as a percentage of revenue requirement are as shown in the following table.

(Fuel,Op & Offset)/Rev Req	2006	2007	2008	2009	Average
	Actual	Actual	Forecast	Forecast	
AltaLink	25.9%	24.6%	25.1%	26.4%	25.5%
ATCO Electric	34.1%	36.6%	41.0%	41.0%	38.2%
ENMAX	53.4%	57.5%	57.6%	56.8%	56.3%
EPCOR	35.8%	41.5%	41.9%	39.1%	39.6%
Total	32.1%	33.0%	35.0%	35.2%	33.8%

The portions of the costs that are non capital related fluctuate from year to year. To minimize the annual fluctuations, the four year average of 33.8% will be used for weighting of non capital related costs.

5.1. Functionalization

The operating and maintenance costs are sub functionalized into one of the three sub functions:

- Bulk System
- Local System
- POD (Point of Delivery)

For the purpose of this report, the Bulk Transmission System is the 240 kV and 500 kV transmission facilities, including substations that transform voltage to a lower transmission voltage (i.e. 240/138 kV substation). The Local Transmission System consists of the 138/144 kV and 69/72 kV transmission facilities, while the POD includes radial transmission lines and point of delivery substations.

The Wires Cost Causation Report used three methods of functionalizing electric transmission facilities: voltage level, economics and MW-km. All three methods had advantages and disadvantages and all three produced similar results. Since there was no method that was clearly superior to the others, the average of the three methods was used. The voltage level method is easy to understand and correlate to electric transmission facilities. Voltage levels are used for the study of O&M costs for ease of understanding and to simplify the study.

Brushing

Vegetation management occurs in various cycles from grass cutting twice per year around substations and telecommunications sites to every 10 years for base mowing. The difference between brushing under steel towers versus wood poles is the clearance required between the vegetation and the line.

Vegetation management includes trimming, mowing, spraying and slashing and removal and all of these activities are priced in terms of area cleared. The amount spent on brushing varies from year to year, and the actual activities and location of work also vary each year. Therefore the actual cost for 2008 was used and was functionalized on the basis of line length and width of brushing activities. This method removes anomalies associated with studying one year of a multiple year cycle for brushing. For example, line brushing for AltaLink was functionalized as follows:

Brushing Functionalization						
Voltage (kV)	Line Len (kM)	Width (m)	Area (1000 m²)	Total by Function	Proportion by Funct	Funciton
69	847	15	12,707	138,877	40.6%	Local
138	6,309	20	126,170			
240	4,643	40	185,737	203,282	59.4%	Bulk
500	319	55	17,545			
Total	12,118		342,159	342,159	100.0%	

AESO Transmission O&M
DRAFT Cost of Service Study

Line vegetation management was all functionalized to bulk and local systems as shown above and other vegetation management was split between lines and POD's.

The functionalization of AltaLink Brushing costs as summarized as follows:

Brushing (AltaLink)	2006 Actual	2007 Actual	2008 Man Update	2009 Forecast
Bulk	1,989,499	2,455,111	3,004,844	2,558,859
Local	1,359,172	1,677,266	2,052,829	1,748,144
POD	150,000	200,000	150,000	450,000
Total VM	3,498,671	4,332,376	5,207,673	4,757,002

Annual Structure Payments

Annual structure payments were functionalized on the basis of line length and a summary of the results are shown in the table below.

Annual Structure Paymen	2006 Actual	2007 Actual	2008 Man Update	2009 Forecast
Bulk	657,611	856,177	1,215,685	2,293,240
Local	948,249	1,234,573	1,752,969	3,306,760
POD	0	0	0	0
Sub Total	1,605,861	2,090,751	2,968,654	5,600,000

Fuel

Fuel costs are associated with remote communities that are not interconnected to the Alberta Interconnected Electric System (AIES). Instead of interconnecting to the larger grid, it is less expensive to provide service with a local generator, typically diesel fired. This fuel cost is considered transmission, because in its absence, the transmission system would have to be expanded to provide service, incurring greater electric transmission costs. Since all of these communities are small, any transmission system that would be built to interconnect would be a local system and POD, and therefore no fuel costs are functionalized as Bulk System. The fuel cost was functionalized as POD and Local System on the basis of the overall system capital where 40.9% of total property is POD, and 17.4% is Local System. The ATCO fuel cost functionalization is shown in the summary table below.

Fuel	2006 Actuals	2007 Actuals	2008 Forecast	Test Period 2009
Bulk	0	0	0	0
Local	2,502,409	2,593,633	2,444,574	2,772,504
POD	5,891,591	6,106,367	5,755,426	6,527,496

Operations – Net Salary

Salaries are a large item in the Operating account. Salaries are functionalized on the basis of the staff complement. Field personnel are generally in departments that work on either substations or lines and thus the functionalization follows the work of the staff.

AESO Transmission O&M
DRAFT Cost of Service Study

Some office personnel also work on either substations or lines, and the functionalization also aligns with the work of the staff. The System Control Centre is unique in that the personnel are physically located in a centralized control centre, but they operate switches in the field. For the purpose of the System Control Centre, the number of switches in the field was used as the basis of functionalization.

The following example is an extract of the AltaLink Net Salary costs and similar analysis was done for other TFOs:

Net Salaries and Wages	2006 Actual	2007 Actual	2008 Man Update	2009 Forecast
Bulk	3,241,881	3,651,985	4,213,193	4,920,599
Local	6,258,913	6,457,934	7,376,223	8,647,636
POD	<u>12,038,140</u>	<u>11,854,069</u>	<u>13,663,632</u>	<u>16,071,926</u>
Total	21,538,934	21,963,987	25,253,048	29,640,161

Summary

With all of the parts combined, the functionalized cost by TFO is shown in the following table. The table shows the 2008 costs that were analyzed and also other years where the same methodology was applied. The last two columns shows the proportions for 2008 and for the 4 year average.

DRAFT - for Discussion Purposes Only							
	2006	2007	2008	2009	Total	2008 Portion	4 Year Ave Portion
AltaLink							
Bulk	11,692,837	12,387,112	13,471,383	16,172,638	53,723,970	23.6%	23.1%
Local	16,516,616	16,649,548	17,731,936	22,379,803	73,277,903	31.1%	31.6%
POD	23,984,293	24,232,925	25,822,534	31,134,827	105,174,580	45.3%	45.3%
ATCO							
Bulk	4,517,192	4,740,713	5,685,479	6,740,709	21,684,092	9.8%	9.6%
Local	24,499,429	26,166,102	29,250,985	34,118,085	114,034,601	50.5%	50.6%
POD	19,715,379	20,793,185	22,963,536	26,141,206	89,613,306	39.7%	39.8%
ENMAX							
Bulk	257,654	284,806	297,984	313,499	1,153,943	1.6%	1.6%
Local	7,345,746	8,119,832	8,495,551	8,937,869	32,898,999	44.9%	44.9%
POD	8,760,251	9,683,396	10,131,463	10,658,955	39,234,065	53.5%	53.5%
EPCOR							
Bulk	1,658,623	1,685,563	1,774,664	1,887,293	7,006,143	9.1%	9.4%
Local	6,170,326	5,995,008	7,905,895	8,922,146	28,993,376	40.7%	38.9%
POD	9,122,425	9,270,596	9,760,651	10,380,112	38,533,784	50.2%	51.7%
Total							
Bulk	18,126,306	19,098,193	21,229,510	25,114,138	83,568,148	13.8%	13.8%
Local	54,532,117	56,930,491	63,384,367	74,357,904	249,204,879	41.3%	41.2%
POD	61,582,349	63,980,101	68,678,184	78,315,101	272,555,735	44.8%	45.0%
Total							

5.2. Classification

Classification of electric transmission non capital costs is a challenge. Capital costs always have an asset associated with the cost, and the asset has a rating or specification

that provides information on the classification of the cost. Non capital costs do not have any ratings or specifications associated with them to assist in the classification.

The fuel cost is an item that is not normally associated with transmission lines, however, there are a number of remote communities that are served with isolated generators rather than being interconnected to the AIES. The cost of isolated generation is less than the cost of building transmission lines and a POD to supply remote communities, and therefore the cost of the isolated generation replaces the cost of the transmission system and POD. The fuel cost is incurred in order to save transmission infrastructure costs. The fuel cost is a variable cost that is related to the energy consumption in the communities served by remote generators. Therefore, fuel costs are classified as energy related.

Other non capital costs and their associated activities occur for the purpose of ensuring the existing transmission systems continues to perform reliably and adequately in accordance with the design of the system.

Activities such as vegetation management occur in order to avoid contact between vegetation and transmission lines. The activities normally occur on a time based schedule and these activities are independent of the amount of demand on the transmission line, the amount of energy flowing through the line, or the number of POD's connected downstream of the line.

Activities such as breaker and LTC maintenance may occur on a time based schedule, or number of operations (usage based schedule). These activities are also independent of the amount of demand on the transmission line, the amount of energy flowing through the line, or the number of POD's connected downstream of the line.

Operational and maintenance activities may be scheduled by methods other than time or usage based such as reliability based maintenance or may be initiated by predictive maintenance practices and monitoring.

No operational or maintenance activities were identified where costs are incurred in relationship to demand, energy or the number of customers. Since all of the costs that are incurred are done so to maintain the system to service its design function, the capital cost classification is used for non capital related costs other than fuel.

5.3. Allocation

The last step of a traditional cost of service study is not required in this case because there is only one rate class that is responsible to pay for the costs of the transmission system and that is the load customers through the DTS Rate of the AESO Transmission Tariff. The step of allocation is not required for the purpose of the transmission tariff rate design.

5.4. Results

When the revenue requirements from the four TFO's are functionalized and classified as described earlier in Section 5, the result is shown in the following table:

TFO Non Capital Costs (2008)				
	Bulk System	Local System	POD	Totals
Demand Related	17,302,088	50,274,957	27,119,691	94,696,736
Energy Related	3,927,422	13,109,410	6,195,809	23,232,641
Customer (POD)	0	0	35,362,685	35,362,685
Totals	21,229,510	63,384,367	68,678,184	153,292,061

The proportions of these costs are shown in the following table:

Non Capital Related Costs	Bulk System	Local System	POD	Totals
Demand Related	11.3%	32.8%	17.7%	61.8%
Energy Related	2.6%	8.6%	4.0%	15.2%
Customer (POD)	0.0%	0.0%	23.1%	23.1%
Totals	13.8%	41.3%	44.8%	100.0%

The capital related cost proportions from the earlier studies is shown below:

Capital Related Costs	Bulk System	Local System	POD	Totals
Demand Related	34.0%	14.3%	17.6%	66.0%
Energy Related	7.7%	3.0%	0.3%	11.0%
Customer (POD)	0.0%	0.0%	23.0%	23.0%
Totals	41.7%	17.4%	40.9%	100.0%

Based on the analysis, 35% of the revenue requirement is non capital related and the two tables above are averaged together on a weighted basis where 65% of the weight is placed on the capital cost, and the remaining 35% of the weight is placed on the non capital cost as follows:

Weighted (33.8% Non Capital)	Bulk System	Local System	POD	Totals
Demand Related	26.3%	20.6%	17.7%	64.5%
Energy Related	6.0%	4.9%	1.6%	12.4%
Customer (POD)	0.0%	0.0%	23.0%	23.0%
Totals	32.3%	25.5%	42.2%	100.0%

6. Prepaid O&M Charges

New customers to the electric transmission system who require optional facilities (facilities in excess of those provided for in standard service) are levied a charge to ensure existing customers are not required to subsidize the new customers who have a requirement for optional facilities. Optional facilities are typically redundant transformers, redundant lines of supply or extra switchgear that provide additional reliability and operational flexibility.

The charge levied for optional facilities includes the capital cost of installing the equipment plus an additional charge referred to as Prepaid O&M, to cover the future additional costs of operating and maintaining these optional facilities.

The costs associated with optional facilities are by nature variable. The costs will be incurred if the optional facilities are in place, and will not occur if the facilities are not in place. As such, if the customer and the optional facilities cease to exist, the variable costs will also cease.

There are several issues that must be determined in order to determine an appropriate level and structure of the Prepaid O&M charge. These issues require the determination of:

- Costs that apply
- Applicable time frame to calculate costs
- The nature of the costs and the associated structure of the charge

6.1. Applicable Costs

The principle in determining applicable costs is that other customers should not subsidize the new customer who requires optional facilities. The scope of this charge could be as large as all non capital costs described earlier in this report, and could be as narrow as incremental costs identified with the optional facilities.

The broad definition of applicable costs includes all non capital related costs. On an embedded basis, and on the assumption that all non capital costs are correlated to capital costs, it would be reasonable to expect a new customer to pay the total non capital related cost associated with optional facilities.

A narrower definition of applicable costs is those costs that can be demonstrated as incremental as the result of the service of optional facilities. This narrower definition would exclude indirect non capital costs such as the cost of Hearings, and operating costs such as IT and Human Resources. The narrower definition of costs would include all costs related to the operating and maintenance of these facilities including direct cost of operations, maintenance, overheads associated with planning and scheduling of maintenance, and incremental costs such as taxes other than income tax.

6.2. Time Frame

The time frame over which additional costs are applicable must be determined. Electric transmission facilities have long service lives that generally average 30 years of life or longer. This lengthy service life is often longer than the planning horizon of electric utilities or other businesses. The electric transmission system also changes over time and some facilities that may initially be optional will be standard facilities at some point through changes in the electric transmission system.

Business does not normally enter contracts that exceed 20 years because of the uncertainty of business over that period of time. The longest contract term for system access service with the AESO is similarly 20 years.

Given the potential changes in the electric transmission system and the difficulty in planning for and contracting for services in excess of 20 years, a maximum of 20 years should be considered the applicable time for incremental costs associated with optional facilities.

6.3. Nature of Costs

The incremental costs associated with optional facilities are not fixed costs in the long term. If a customer requires redundant facilities and contracts for those facilities, but ceases to operate in the future, the optional facilities can be salvaged and future O&M costs will go to zero. If these facilities have value for other customers in the future, the facilities can be kept in place and other customers that benefit from these facilities should pay for their use.

The existing nature of the Prepaid O&M charge (one time charge at the start of service) does not match the incurrence of costs which will occur periodically. If a customer ceases to require optional facilities and the facilities are salvaged, then the Prepaid O&M portion of the CIAC paid by the customer (less amortization of the CIAC over the elapsed time) should be refunded to the customer.

Given the variable nature of these costs, another approach to recover these costs could be an annual charge applicable for the O&M associated with optional facilities. This annual charge would match costs, and could be cancelled if the customer ceases to exist or incremental costs of optional facilities no longer exist.

6.4. Determination of Costs

Further analysis is being conducted to complete the remainder of this report. The current challenge is to determine the RCN of the existing transmission system to try to find a correlation between RCN and Non Capital costs, or O&M costs.

7. Summary

Parking Lot – O&M costs do not necessarily change with the age of facilities... Capital maintenance costs do increase with the age of facilities, but this is a capital cost, not one of interest in the O&M study.

8. Appendix A – TFO GTA Revenue Requirement

TFO Cost Data				
All Values in \$				
AltaLink	2006	2007	2008	2009
	Actual	Actual	Forecast	Forecast
Fuel	0	0	0	0
Operating Costs	49,807,854	50,806,899	54,891,958	65,971,924
Depreciation	64,826,350	68,519,547	74,462,618	78,041,499
Return on Rate Base	56,357,854	63,523,052	64,422,450	74,739,024
Income Tax Expense	12,356,943	11,709,535	10,437,500	13,000,633
Revenue Offsets	-9,862,478	-9,534,866	-8,655,559	-6,271,699
Hearings, Self Ins, Other Taxes	15,832,979	17,743,162	18,886,693	21,029,776
Revenue Requirement	189,319,502	202,767,328	214,445,660	246,511,157

TFO Cost Data				
All Values in \$				
ATCO	2006	2007	2008	2009
	Actual	Actual	Forecast	Forecast
Fuel	8,394,000	8,700,000	8,200,000	9,300,000
Operating Costs	51,671,900	55,800,000	66,500,000	77,100,000
Depreciation	38,600,000	38,500,000	41,600,000	47,000,000
Return on Rate Base	61,200,000	60,800,000	61,230,000	72,518,378
Income Tax Expense	12,008,171	8,507,126	3,670,826	3,641,514
Revenue Offsets	-4,022,000	-4,100,000	-2,600,000	-2,600,000
Deferral & Reserve Accounts	0	0	0	0
Revenue Requirement	167,852,071	168,207,126	178,600,826	206,959,891

TFO Cost Data				
All Values in \$				
ENMAX	2006	2007	2008	2009
	Actual	Forecast	Forecast	Forecast
Fuel	0	0	0	0
Operating Costs	16,811,652	18,443,422	19,280,387	20,509,312
Depreciation	6,911,024	6,538,419	7,088,576	7,969,376
Return on Equity	3,847,161	3,058,420	2,443,368	2,221,349
Interest Expense	3,937,624	4,056,116	4,650,115	5,380,200
Income Tax Expense	0	0	0	0
Revenue Offsets	0	0	0	0
Hearings, Self Ins, Other Taxes	0	0	0	0
Revenue Requirement	31,507,460	32,096,378	33,462,446	36,080,238

AESO Transmission O&M
DRAFT Cost of Service Study

TFO Cost Data				
All Values in \$				
EPCOR	2006	2007	2008	2009
	Actual	Forecast	Forecast	Forecast
Fuel	0	0	0	0
Operating Costs	16,951,374	16,951,167	19,441,209	21,189,552
Depreciation	6,472,134	7,838,549	9,496,610	11,124,184
Return on Rate Base	17,176,873	12,001,008	16,611,562	21,153,662
Income Tax Expense	0	0	0	0
Revenue Offsets	-2,538,928	-654,086	-647,342	-767,249
Deferral & Reserve Accounts	3,038,037	-904,833	143,767	143,767
Revenue Requirement	41,099,490	35,231,806	45,045,806	52,843,915

Sum of TFO Cost Data				
All Values in \$				
Cost Portions	2006	2007	2008	2009
	Actual	Actual	Forecast	Forecast
Fuel	8,394,000	8,700,000	8,200,000	9,300,000
Operating Costs	135,242,780	142,001,488	160,113,555	184,770,788
Depreciation	116,809,507	121,396,515	132,647,804	144,135,060
Return on Rate Base	142,519,512	143,438,597	149,357,495	176,012,613
Income Tax Expense	24,365,115	20,216,661	14,108,326	16,642,146
Revenue Offsets	-16,423,406	-14,288,952	-11,902,901	-9,638,948
Hearings, Self Ins, Other Taxes	18,871,016	16,838,329	19,030,459	21,173,543
Revenue Requirement	429,778,524	438,302,638	471,554,738	542,395,201

Note: The sum of TFO cost data includes only AltaLink, ATCO, ENMAX and EPCOR.

9. Appendix B – Capitalization Policies

Have EPCOR, AltaLink and ATCO

10. Background.

Decision 2007-106

5.7.8.3 Treatment of TFO O&M Costs in POD Cost Function

PPGA submitted in its evidence that the AESO had provided no evidence, facts or analysis to support its assertion that O&M costs follow capital costs. Given this, PPGA submitted that the AESO's proposed POD charge does not reflect true cost causation. PPGA questioned the validity of the AESO's entire POD charge rate proposal.

PPGA argued that even though TFO O&M costs are in the range of \$130-\$150 million, the AESO had simply asserted that the impact of O&M costs on the POD cost function would be small.

Produce a report for the AESO that will be part of the next AESO GTA outlining operating and maintenance costs of electric transmission systems. The report will address Directive #6 in the EUB Decision 2007-106. The report will study and provide recommendations for the functionalization and classification of O&M costs for use in AESO's transmission tariff design resulting from the TCCU was generally accepted by participants in this proceeding, other than PPGA. The AESO noted that Decision 2005-096 had set out two directions respecting cost classification, including a direction that the AESO analyze the functionalization and classification of O&M costs.

The AESO noted that that PS Technologies' analysis of O&M costs found that data was not available to allow refinement of the functionalization and classification of OMA costs to reflect the impact of equipment vintage and type. In any event, the TCCU expected the impact on total cost functionalization and classification to be small because O&M costs account for about one-quarter to one-third of TFO revenue requirements. The AESO further noted that PS Technologies had not recommended any changes to transmission cost functionalization or classification as a result of its review of O&M costs for the TCCU.

Although the PPGA took issue with the AESO for not having conducted research in support of its assertion that TFO O&M costs vary with POD capital costs, the PPGA provided no evidence indicating that TFO O&M costs do not vary with the level of POD capital costs. The PPGA also did not provide evidence of whether the AESO's proposed POD cost function would understate or overstate the causation of TFO O&M costs.

In the absence of more specific information, the Board is not prepared to direct the AESO to make additional adjustments to the POD cost function or the resulting POD charge component of Rate DTS for the purposes of the 2007 tariff. However, so long as it can be accomplished at a reasonable cost, the Board considers that additional study into the causation of TFO O&M costs may be of value for future AESO rate design purposes as well as for the purposes of understanding TFO O&M forecasts within the context of future TFO GTAs. Accordingly, the Board directs the AESO to indicate in its refiling application the cost and time required to prepare a further study into the causation of TFO O&M costs.

AESO Transmission O&M
DRAFT Cost of Service Study

6. In the absence of more specific information, the Board is not prepared to direct the AESO to make additional adjustments to the POD cost function or the resulting POD charge component of Rate DTS for the purposes of the 2007 tariff. However, so long as it can be accomplished at a reasonable cost, the Board considers that additional study into the causation of TFO O&M costs may be of value for future AESO rate design purposes as well as for the purposes of understanding TFO O&M forecasts within the context of future TFO GTAs. Accordingly, the Board directs the AESO to indicate in its refiling application the cost and time required to prepare a further study into the causation of TFO O&M costs.....59.