Alberta Transmission System Cost Causation Study

prepared for Alberta Electric System Operator by London Economics International LLC[1]

July 3rd, 2013

London Economics International ("LEI") was retained by the Alberta Electric System Operator ("AESO") to perform a transmission cost causation study. In order to reflect cost causation in rate design, transmission costs are separated into categories utilizing methods of functionalization and classification, which can then be allocated to be paid by the appropriate beneficiaries. LEI performed functionalization of transmission costs into bulk, regional, and point-of-delivery ("POD") functions using three methods: by voltage, by economics, and by megawatt-kilometer ("MW-km"). LEI recommends using functionalization by voltage, due to weaknesses in the economics and MW-km approaches. The 2012 Long-term Transmission Plan ("LTP") lays out substantial investment in the bulk system (i.e., high voltage systems carrying large amounts of electricity over longer distances). Classification into demand and energy related costs has been performed using the minimum system approach. For implementation, LEI recommends that 2014, 2016 and 2016 functionalization results be applied independently to each of the three years.

Table of contents

---

[1] The development of this report was supervised by Mr. A.J. Goulding, President, LEI. Mr. Gary Tarplee of Utility System Efficiencies Consulting assisted LEI on engineering and technical matters.

Table of figures

1 Executive Summary

The scope of this transmission cost causation study involves analysis in four key areas: (i) functionalization of transmission facility owner ("TFO") related capital costs, for both existing and planned assets (until 2016), (ii) functionalization of related operations and maintenance ("O&M") costs, (iii) classification of all costs functionalized as bulk and regional, and (iv) implementation considerations, i.e., discussion of the potential impact of implementing functionalization and classification results on rates/recovery of the revenue requirement.

LEI first reviewed AESO's previous cost causation studies and relevant Alberta Energy and Utilities Board ("AEUB" or "Board") decisions, summarizing key elements of each study/decision. LEI has made note of the Board's decisions and comments, as well as their implications for the current study.

Prior to conducting functionalization analysis, it is important to clearly define the three transmission functions: bulk, regional and POD. A high voltage system carrying large amounts of electricity over long distances is defined as serving the bulk function. A regional system transmits electricity from the bulk system to load centers with numerous points of delivery. Finally, a POD system serves distribution utilities or industrial customers that connect directly to the transmission system.

Following the definition of transmission functions, LEI presents a review of various cost causation methodologies/approaches, related to both functionalization and classification. LEI explored four methods of functionalization: voltage, economics, megawatt-kilometer ("MW-km") and MVA-km, and strengths and weaknesses for all four methodologies are presented. Similarly, LEI presents four options for classification methodologies along with their strengths/weaknesses. The methods reviewed are minimum system approach, minimum/zero intercept approach, marginal cost approach and average and excess ("A&E") approach.

The discussion of functionalization and classification methodologies is supplemented with a review of case studies presenting cost causation methodologies in Ontario, California, Australia and Great Britain. It is observed that although no two jurisdictions are the same in terms of their methodologies, elements of functionalization by voltage can be observed across most jurisdictions.

In order to functionalize capital costs, LEI performed analysis using the following three methods of functionalization: voltage, economics, and MW-km. After reviewing strengths and weaknesses of the different approaches, LEI recommends using the voltage method. The voltage method is the most straightforward and simple to understand. The MW-km approach was deemed to be overly dependent on forecast assumptions and a subjective method of setting the breakpoint, while the economics approach was considered to be overly dependent on cost assumptions and a subjective methodology for setting line length.

Figure 1 presents the 2016 capital cost functionalization results using the three approaches. The average of the three approaches provides very similar results to the voltage approach, but significant reliance on assumptions in the MW-km and economics approach, in LEI's view, may not be defensible.

Figure 1. Capital cost functionalization results as of 2016

Method	Bulk System	Regional System	POD
Voltage	$ 10,174,593,886	$ 2,676,825,574	$ 2,396,604,055
Economics	$ 10,866,752,488	$ 1,984,666,972	$ 2,396,604,055
MW-km	$ 9,522,501,818	$ 3,328,917,643	$ 2,396,604,055

Method	Bulk System	Regional System	POD
Voltage	66.7%	17.6%	15.7%
Economics	71.3%	13.0%	15.7%
MW-km	62.5%	21.8%	15.7%
Average	66.8%	17.5%	15.7%

Capital cost functionalization results for the filing period, 2014-2016, using the voltage method are presented in the figures below.

Figure 2. Future capital cost functionalization results by voltage

Future capital cost functionalization (by value)	2014	2015	2016
Bulk	$ 3,257,271,419	$ 5,446,373,445	$ 5,884,908,333
Regional	$ 528,483,048	$ 778,735,290	$ 861,632,964
POD	$ 88,054,830	$ 97,265,394	$ 94,545,243

Future capital cost functionalization	2014	2015	2016
Bulk	84.1%	86.1%	86.0%
Regional	13.6%	12.3%	12.6%
POD	2.3%	1.5%	1.4%

Figure 3.Combined (existing and future) capital cost functionalization results by voltage

Capital cost functionalization (by value)	2014	2015	2016
Bulk	$ 6,681,289,875	$ 9,684,685,012	$ 10,174,593,886
Regional	$ 2,214,899,613	$ 2,561,372,083	$ 2,676,825,574
POD	$ 2,123,557,889	$ 2,261,395,958	$ 2,396,604,055

Capital cost functionalization	2014	2015	2016
Bulk	60.6%	66.8%	66.7%
Regional	20.1%	17.7%	17.6%
POD	19.3%	15.6%	15.7%

In addition to capital cost functionalization, LEI has functionalized related O&M costs for the TFOs given available data. Figure 4 presents O&M functionalization results for the combined TFOs until 2014. The results include information from ENMAX up until 2011 and for EPCOR until 2012. Information for the two largest TFOs, AltaLink and ATCO Electric, is incorporated up until 2014.

Because the current study is reviewing functionalization for 2014-2016, and 2015-2016 projections are not available, LEI has decided to use 2014 results for functionalization purposes. Despite significant bulk investment in 2014, the O&M functionalization ratios have not changed significantly in 2014 as compared to 2012-2013. Moreover, given that future capital cost functionalization ratios (presented in Figure 2) do not change materially between 2014 and 2016, a material change in O&M functionalization ratios over the 2014-2016 period is unlikely.

Figure 4. O&M functionalization results

Combined TFOs ($)	2010	2011	2012	2013	2014
Bulk	26,863,018	30,145,225	34,185,637	32,739,337	36,327,705
Regional	39,275,117	42,375,975	40,558,554	38,703,641	42,240,991
POD	50,063,798	54,566,075	47,370,320	42,147,702	46,106,796
Total	116,201,933	127,087,276	122,114,510	113,590,680	124,675,492

Combined TFOs (%)	2010	2011	2012	2013	2014
Bulk	23.1%	23.7%	28.0%	28.8%	29.1%
Regional	33.8%	33.3%	33.2%	34.1%	33.9%
POD	43.1%	42.9%	38.8%	37.1%	37.0%
Total	100.0%	100.0%	100.0%	100.0%	100.0%

After separately functionalizing capital and O&M costs, the results were combined using TFOs' non-capital to capital ratios in respective years (as presented in Figure 5).

Figure 5. Ratio of non-capital to capital costs for TFOs in 2016

Non-Capital to Capital Costs	2014	2015	2016
Non-Capital	16.0%	14.2%	12.3%
Capital	84.0%	85.8%	87.7%

Figure 6. Recommended combined O&M and capital cost functionalization[2]

Combined cost functionalization (net of RGUCC)	2014	2015	2016
Bulk	55.2%	61.2%	62.0%
Regional	22.5%	20.1%	19.6%
POD	22.3%	18.7%	18.4%

The combined functionalization results show a higher proportion functionalized as bulk, compared to approved functionalization in AESO 2007 GTA (bulk: 41.7%, regional: 17.4%, POD: 40.9%) by the Board. This is sensible given the significant amount of bulk and regional (and insignificant POD) investment planned to come online in the 2012 LTP.

With regards to classification, both demand and energy cost classification is important, as together they provide a mechanism to reduce system peak even when the system peak is not

[2] The combined functionalization results also took into account Regulated Generating Unit Connection Costs ("RGUCC"), which is an annual revenue portion of wires costs arising from TFO-owned facilities providing system access to previously-regulated generators, further discussed in Section 10.1.

coincident with any customer's individual peak. Having an energy component incentivizes customers to reduce load even when they are not at the peak. After reviewing strengths and weaknesses of classification methodologies, the minimum system approach has been utilized. The following figure presents LEI's recommended classification percentages.

Figure 7. Classification results

Classification results	Bulk	Regional
Demand	92.4%	87.7%
Energy	7.6%	12.3%

Finally, LEI has made three observations with regards to implementation of recommended functionalization and classification results. First, as presented in Figure 8, by using the functionalization and classification results discussed above, the revenue requirement across each of the rate components (bulk-demand, bulk-energy, regional-demand, regional-energy and POD) increases on an annual basis, indicating no reversing trends that may otherwise result in erratic pricing signals.

Figure 8. Revenue requirement breakdown using combined functionalization and classification results

Revenue Requirement Split - net of RGUCC ($ million)	2014	2015	2016
Bulk - Demand	764	1,011	1,136
Bulk - Energy	63	83	93
Regional - Demand	295	315	342
Regional - Energy	41	44	48
POD	333	335	365
Total	1,497	1,787	1,984

Second, the impact of applying combined capital and O&M cost functionalization results instead of applying only capital cost functionalization results (as presented in Figure 9) is not in opposing directions, i.e., revenue requirement trend remains positive and increasing across most of the rate components (with the exception of POD, where revenue requirement dips in 2015 before increasing in 2016). For consistency with cost causation, LEI recommends applying combined capital and O&M functionalization results.

Figure 9. Revenue requirement breakdown using capital cost functionalization only

Revenue Requirement Split - net of RGUCC ($ million)	2014	2015	2016
Bulk - Demand	834	1,100	1,221
Bulk - Energy	69	90	100
Regional - Demand	266	278	307
Regional - Energy	37	39	43
POD	291	280	313
Total	1,497	1,787	1,984

Third, for consistency with cost causation, LEI recommends applying separate 2014, 2015 and 2016 functionalization results (as presented in Figure 6) for each of the three years. Cost causation has also been given considerable weight by the Board in its previous decision: "*The Board maintains that cost causation … remains the primary consideration when evaluating a rate design proposal*".[3]

[3] AEUB. *Decision 2007-106: AESO 2007 General Tariff Application*. December 21, 2007. Page 14.

2 List of acronyms

ACSR:	Aluminum Conductor Steel Reinforced
AESO:	Alberta Electric System Operator
AEUB:	Alberta Energy and Utilities Board
AIL:	Alberta Internal Load
AUC:	Alberta Utilities Commission
AER:	Australian Energy Regulator
AFUDC:	Allowance for Funds Used During Construction
A&E:	Average & Excess
BEGA:	Bilateral Embedded Generation Agreement
CAISO:	California Independent System Operator
CIBP:	Clearly Identified Bulk Projects
CTI:	Critical Transmission Infrastructure
CWIP:	Construction Work in Progress
DCC:	Distribution Customer Connections
DFL:	Dual Function Line
DTS:	Demand Transmission Service
FA:	Facility Application
FERC:	Federal Energy Regulatory Commission
FTE:	Full time Equivalent
GTA:	General Tariff Application
GMC:	Grid Management Charge
G&A:	General and administrative
HH:	Half-hourly

HVDC: High Voltage Direct Current

ICRP: Investment Cost Related Pricing

LGIA: Large Generator Interconnection Agreements

LCRIF: Location Constrained Resource Interconnection Facilities

LEI: London Economics International LLC

LTP: Long-term Transmission Plan

MCM: Thousand circular mils

MVA: Megavolt amperes

MW-km: Megawatt-kilometer

NARUC: National Association of Regulatory Utility Commissioners

NBV: Net Book Value

NER: National Electricity Rules

NHH: Non-half-hourly

NID: Needs Identification Document

OEB: Ontario Energy Board

OM&A: Operation, Maintenance, and Administrative

OPA: Ontario Power Authority

O&M: Operations and Maintenance

POD: Point-of-Delivery

POS: Point-of-Supply

PSTI: PS Technologies Inc.

PTO: Participating Transmission Owners

RCN: Replacement cost new

RGUCC: Regulated Generating Unit Connection Cost

ROW: Right of Way

SATR: South Area Transmission Reinforcement

STS: Supply Transmission Service

TAC: Transmission Access Charge

TCCS: Transmission Cost Causation Study

TCCU: Transmission Cost Causation Update

TCCWG: Transmission Cost Causation Working Group

TFCMC: Transmission Facility Cost Monitoring Committee

TFO: Transmission Facility Owner

TNUoS: Transmission Network Use of System

TRIP: Transmission Rate Impact Projection

TRR: Transmission Revenue Requirement

TUOS: Transmission Use of System

WAC: Wheeling Access Charge

contact:
Amit Pinjani/Ian Chow
416-643-6621
amit@londoneconomics.com

3 Scope and information utilized

LEI was engaged to prepare a transmission cost causation study for the AESO. The study will be incorporated into, and filed with, the AESO's 2014 tariff application, which is expected to be submitted to the Alberta Utilities Commission ("AUC" or "Commission") on June 30th, 2013.

3.1 Scope

The scope of the transmission cost causation study includes the following key areas:

Functionalization of capital costs: The study provides results for functionalization of TFO capital-related costs into bulk, regional and POD functions. The results take into account both existing and planned transmission facilities that will give rise to capital-related costs up until 2016, albeit with data limitations, as discussed in the study.

Functionalization of O&M costs: The study provides results for the functionalization of TFO O&M costs into bulk system, regional system and point of delivery functions. The recommended approach takes into account information received from the TFOs via AESO. TFOs do not project their O&M costs up to 2016. ATCO and AltaLink have projected costs up to 2014, EPCOR has projections until 2012, and certain ENMAX projections up until 2011 were derived from their annual finances and operations reports filed under AUC Rule 005.

Classification of bulk system and regional system costs: Following functionalization of capital and O&M costs, the study provides results for the classification of bulk system and regional system costs into demand-related and energy-related costs. Classification of POD costs is not in the scope of the current study.

Implementation considerations: Finally, the study discusses the potential impact of implementing recommended functionalization and classification results on rates/breakdown of revenue requirement to be recovered.

Given that LEI's scope is limited to cost causation analysis, this report does not delve into rate design issues.

3.2 Data utilized and limitations

The AESO provided over two hundred documents (totaling over five hundred megabytes), which aided in the development of this analysis (see Section 14: Appendix of works consulted for a comprehensive list). However, challenges were encountered in obtaining adequate data for the analysis.

In terms of existing asset information, EPCOR's asset information, net book values, voltages, and line lengths have not been received.[4]

For future/planned projects, as data was provided from multiple sources which were not fully cross-referenced, manual data matching was undertaken by LEI. Furthermore, documents such as the project progress reports provided varying levels of detail. Although LEI completed the analysis on a best effort basis, it is not possible to guarantee 100% completeness of the data.

For similar studies in the future, it may be useful to make the TFOs aware of the specific data requirements in advance, and decisions for new accounting systems may take these requirements into account. Adding a few fields to line and substation records kept by the TFOs could reduce the effort required for future cost causation studies or regulatory proceedings by the TFOs and the AESO.

3.3 Summary of data used

The following is a high level summary of where data was sourced and how it was used in the analysis:

- Capital costs
    - Existing assets: 2013 asset net book values have been provided by TFOs and depreciated to 2016. Ongoing connection and maintenance costs have been assumed
    - Planned projects: costs of planned projects for 2014, 2015 and 2016 are sourced from Long Term Transmission Plan, AESO Cost Benchmarking Data, and progress reports. Costs are depreciated to 2016

- Underlying data for capital cost functionalization
    - Voltage approach: does not depend on additional underlying data
    - MW-km approach: uses the 2015 AESO Base Case forecast, published in 2013
    - Economics approach: uses the 2011 AESO Unit Cost Guide

- Underlying data for O&M cost functionalization
    - Revenue requirement and operating cost data provided by TFOs (ATCO and AltaLink up until 2014, ENMAX and EPCOR until 2011 and 2012 respectively)

- Capital and O&M functionalization results for each of the years, 2014-2016, are weighted based on respective capital/non-capital cost ratios. 2015 and 2016 ratios extrapolated from capital/non-capital trend of 2010-2014 using TFO filing data

[4] Due to changes with EPCOR systems and personnel, it was not possible to confirm that the categories provided contain the exact same accounts as the accounts used in the 2005 Transmission Cost Causation Study.

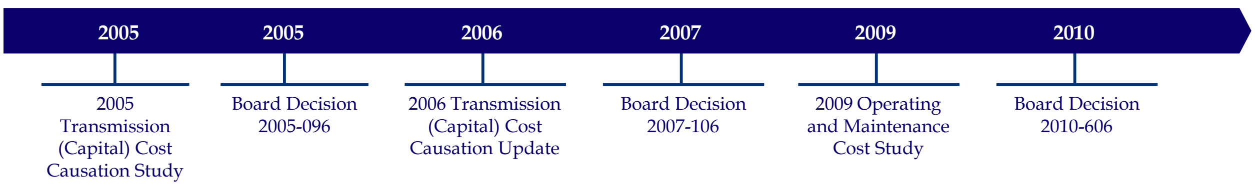
- Underlying data for classification
    - Minimum system approach uses line costs from 2005 to 2013 and substation costs from 2010 for 138 kV and 240 kV conductors
    - 500 kV conductor costs have been sourced from California ISO

4 AESO's previous cost causation studies and Board decisions

This section briefly summarizes key areas of discussion in previous relevant cost causation work performed in Alberta, associated decisions by the AEUB/AUC, and potential implications of those decisions for current study.

For previous work on this matter, the AESO commissioned PS Technologies Inc. ("PSTI") over the period 2004 to 2010 to provide guidance for Alberta transmission cost causation and rate design review and analysis. Information was analyzed for the four largest TFOs: (i) AltaLink, (ii) ATCO Power, (iii) EPCOR, and (iv) ENMAX.

Figure 10. Timeline of previous transmission cost causation studies



4.1 2005 capital cost causation study

4.1.1 Summary of key issues

PSTI submitted its first study on January 25, 2005, entitled "Alberta Transmission System Wires Only – Cost Causation Study", which has been referred to as the Transmission Cost Causation Study ("TCCS") in other AESO documents. PSTI analyzed the capital cost information for the TFOs first functionalizing them into bulk, local and point of delivery ("POD") system costs, and then classifying them into demand, energy and POD costs. To functionalize the costs, PSTI utilized three methods: (i) voltage level, (ii) economics, and (iii) MW-km, discussed in Section 6.1.

Although PSTI considered MW-km to be the strongest method among the three, the results between the three methods were similar, and they recommended a simple average of all three methodologies. Figure 11 presents the functionalization results in the TCCS.

Figure 11. 2005 functionalization results by method

TFO	Bulk System	Local System	POD
Voltage Level	42.7%	18.8%	38.6%
Economics	52.0%	9.5%	38.6%
MW-kM	42.6%	18.9%	38.6%
Recommendation	45.7%	15.7%	38.6%

Source: PSTI. Alberta Transmission System Wires Only – Cost Causation Study. January 25, 2005. Page 33

For classification purposes, the functional groups were classified into three categories: demand, energy, or customer-related. For bulk and local functional groups, there was no customer-related classification, and the minimum system approach was used to differentiate between demand and energy related costs.

The minimum system approach compares a minimum system to an optimal system, whereby the minimum system reflects system costs assuming the lowest construction costs and an optimized system minimizes the total cost of capital and losses. The ratio between the two provides the classification results, where the minimum system cost is considered demand related and the incremental cost increase for the optimized system is considered energy related.

For the POD functional group, the zero-intercept method was used, whereby a linear regression is applied to substation net book value and capacity (in megavolt amperes ("MVA")). The zero intercept of the linear regression was used to determine the fixed cost of a POD substation, while all further costs were broken down by the minimum system approach. POD cost classification is outside the scope of LEI's current study.

Figure 12. 2005 functionalization and classification results

Classification	Bulk System	Local System	POD
Demand (CLMS-NCP)	81.5%	82.5%	43.1%
Energy	18.5%	17.5%	0.7%
POD/Cust			56.2%

Source: PSTI. Alberta Transmission System Wires Only – Cost Causation Study. January 25, 2005. Page 45

4.1.2 Board decision 2005-096

Though the TCCS was considered to be a "good first step" by the Board,[5] the following improvements were suggested for future studies:

- First, a reasonable portion of TFO costs were related to O&M and a material percentage of these could be energy-related. The O&M costs were analyzed by PSTI in the 2009 Electric Transmission Operating and Maintenance Cost Study, summarized later in Section 4.3.

- Second, the Board noted that the TCCS appeared to have studied only two of many bulk lines in its analysis; in future studies, AESO was asked to conduct a more thorough review of all those lines comprising the bulk system, in order to provide a more accurate indication as to the exact portion of costs that are energy related.

- Third, wires costs should be classified as 20% energy to be collected evenly over all hours; the balance of wires costs should be collected through two demand charges – one related to the bulk system and the second relating to local system and POD related costs.

[5] AEUB. *Decision 2005-096: AESO 2005/2006 General Tariff Application*. August 28, 2005. Page 24.

Finally, the Board noted that the costs related to the bulk system, and therefore the percentage of costs allocated to bulk system costs, had the potential to increase in the future. This has been observed in the existing long-tern transmission plan, whereby projects over $13.5 billion are planned to come online.

4.2 2006 cost causation update

4.2.1 Summary of key issues

Following the Board's recommendation in Decision 2005-096 that a 'more thorough review of all those lines comprising the bulk system' be conducted, PSTI submitted its second study on September 15, 2006, entitled "Alberta Transmission System 2006 Transmission Cost Causation Update," which has been commonly referred to as the Transmission Cost Causation Update ("TCCU").

PSTI's qualitative analysis included interviewing AESO system planners regarding transmission paths, upgrades to the bulk transmission system, and causes of maximum stress on bulk transmission lines. The study found that transmission planning is a complex process, and instead of being dominated by any one simple factor such as serving peak load, it is driven by various independent factors such as the location and daily/seasonal profiles of load and generation and the configuration of the electric transmission system.

Quantitative analysis was performed to assess the correlation between the time of maximum stress on the bulk system and the time of Alberta Internal Load ("AIL") peak load, which showed a correlation of only 1% (in 2004) and 8% (in 2005) between individual bulk line loads (weighted by line length) and AIL peak load. Analysis was based on metered data for the 8,760 hours and individual bulk line loads over seventy nine 240 kV bulk transmission lines, and the TCCU acknowledged a shortcoming: transmission planning is conducted without including opportunity sales, while actual meter data includes actual imports and exports (opportunity sales). The AESO however maintained that the total amount of exports was small in comparison to the Alberta load (1.5%) and therefore any adjustment for exports would have only a minimal impact on the circuit loading data. No provision was made for adjustments to the meter data to account for abnormal conditions, such as transmission contingencies or generator outages.

Figure 13. TCCU functionalization and classification results

% of NBV Property	Bulk System	Local System	POD
Functionalization	46.3%	16.0%	37.7%

Classification	Bulk System	Local System	POD
Demand (CLMS-NCP)	81.5%	82.5%	43.1%
Energy	18.5%	17.5%	0.7%
POD/Cust			56.2%

Source: PSTI. Alberta Transmission System 2006 Transmission Cost Causation Update. September 15, 2006. Page 53

As a result of the TCCU, final functionalization and classification results were revised, as presented in Figure 13. Changes were insignificant compared to Decision 2005-096.

4.2.2 Board decision 2007-106

The quantitative analysis presented by TCCU was criticized by the interveners and the Board. The Board rejected the hypothesis presented by TCCU that peak load did not correlate to maximum stress on the system and that it was load in all hours that mattered. The Board maintained that system peak is more important than load in every hour.

The AESO also proposed to use the average & excess methodology to classify wires costs, an alternative to the minimum system analysis presented in the TCCS. In the A&E approach, the average component is determined by the average system load factor, which determines the energy-related classification of transmission costs (estimated at 48.6%); the excess component represents the amount of system load above the average (estimated as 1 - 48.6% = 51.4%). The Board rejected this approach, maintaining that transmission assets represent a long-term fixed investment, and vary little based on usage. Classifying 48.5% of costs as energy-related, in the Board's view, provided a poor price signal to customers to shift their load away from peak hours to reduce demand at the system peak.

The Board recommended continuing using the minimum system approach to classify wires costs. The Board also noted that it does not consider that significant adjustments should be necessary in the foreseeable future.

The Board considered that the portion of wires costs classified as energy-related should remain fairly low and be determined by the cost of service study, and it approved the functionalization and classification ratios, as presented in Figure 14.

Figure 14. Board-approved functionalization and classification results

% of NBV Property	Bulk System	Local System	POD
Functionalization	41.7%	17.4%	40.9%

Classification	Bulk System	Local System
Demand	82.0%	82.0%
Energy	18.0%	18.0%

Source: AEUB. Decision 2007-106: 2007 General Tariff Application. December 21, 2007. Pages 25, 60

4.3 2009 operation and maintenance cost causation study

4.3.1 Summary of key issues

Following the Board's recommendation in Decision 2005-096 to analyze O&M costs and their effect on classification of energy-related costs (as discussed earlier in Section 4.1.2), PSTI submitted its third study on December 10, 2009 titled "AESO Electric Transmission Operating Cost Causation Study."

The study functionalized O&M costs by voltage level only, and classified them largely on the same basis as capital costs. The revenue requirement was first split between capital (~70%) and non-capital costs (~30%). The non-capital costs are made up of O&M costs (related to in-service transmission facilities – primarily labor costs), and general and administrative ("G&A") costs.

Information studied was as of 2008, and while only O&M costs were functionalized, the same ratios were applied to other non-capital costs (i.e. G&A costs). AESO argued that this was sensible given that the non-capital G&A costs reflected costs net of capital G&A costs, which were accounted for in the capital cost study.

For classification purposes, all costs with the exception of fuel were classified using the same ratios as capital costs. Fuel costs however, were classified as 100% energy-related as it was argued that these were directly related to energy consumption in off-grid communities served by remote generators.

4.3.2 Board decision 2010-606

The Commission was generally favourable towards the O&M study, stating the "Commission considers that the Transmission O&M Cost Study results provide useful information which, under normal circumstances, should be reflected in the AESO's rate design".[6] However, the Commission did not incorporate the O&M study into the AESO rate design because the results would have increased regional/POD rates with respect to bulk charges, whereas the major capital additions during the tariff term would have done the opposite. Interveners raised concerns about study data, including use of just a single year, unavailability of ENMAX data, and the lack of detailed accounting data available to PSTI.

The Commission agreed with the AESO that isolated generation charges should be functionalized into regional and POD charges; however, the Commission denied classification of those charges as energy, rather preferring the proportions used for all other regional and POD costs.

The Commission directed AESO to consider a forecast of capital build for the entire expected effective term of the AESO's next tariff, using the LTP as a starting point. Accordingly, LEI's current study is the next step.

4.4 Potential implications of previous decisions for current study

LEI has made note of the comments of the Board, and their implications for the current study. In terms of functionalization, the MW-km method was noted by PSTI as the strongest because it most closely aligns the purpose of transmission facilities to their functional category. As well, the Board mentioned that averaging the three different approaches provides sufficient balance.

---

[6] AEUB. *Decision 2010-606: 2007 GTA*. P 15.

LEI believes that performing the different methods provides a valuable sanity check and has applied the three methods. However, as discussed later in Section 8.3.5, LEI has recommended using the voltage approach.

Although certain interveners recommended using derived replacement cost new ("RCN") values in future studies, LEI believes that net book value ("NBV") should be sufficient, especially given significant investment in projects coming online in recent years. The RCN analysis may be significantly assumptions-driven and may produce arbitrary results. LEI also notes that the Board considered NBV to be an appropriate basis upon which to base the functionalization of costs, given NBV drives the return, tax and depreciation calculations of the TFO revenue requirements. LEI utilized asset NBVs provided by the TFOs for its analysis.

For classification of O&M costs, consistent with Board's 2010 Decision, both isolated generation charges (including fuel and related variable O&M costs) and other O&M costs have been classified on the same basis as capital costs.

Interveners noted in 2010 that there is likely to be a significant increase in the proportion of bulk transmission facilities built for reasons other than providing reliable delivery at times of peak load and, as a result, there is a strong possibility that the classification of bulk transmission facilities will change to a more energy-intensive classification. LEI has divided planned system additions between conventional and special planned projects, whereby special projects are those that are primarily designed for purposes other than meeting peak load needs. A discussion about special projects and their identification is presented later in Section 13.1.

5 Definition of transmission functions

The process of functionalization allocates costs into three functional groups: ***bulk***, ***regional*** and ***POD***. These three functions do not have universally accepted definitions, however, LEI has defined them here generally, based on understanding of the Alberta transmission system, the results of prior cost causation studies, and experience in other jurisdictions.

Traditionally, large-scale generators produce electricity, which is transferred by the bulk, high voltage system over long distances to reach regional systems, and eventually reach loads at the point of delivery. The bulk system represents the backbone of the transmission system, and although in recent years, some generation has been located closer to load, the traditional model generally still holds true. As such, the bulk system is defined as high voltage, which typically carries large amounts of electricity over long distances. Bulk transmission lines also provide high capacity interconnections between adjacent utilities or concentrated load centers geographically separated. These bulk power lines typically operate at 500 kV and 240 kV AC or as High Voltage Direct Current ("HVDC"). Point-of-supply ("POS") substations which are used to connect generation are also considered bulk.

The system which transmits electricity from the bulk system to load centers with numerous PODs is known as regional. The lines are typically lower in capacity and shorter in length than bulk power lines and typically operate at 138 kV and 69 kV.

The point of delivery system serves distribution utilities or industrial customers that connect directly to the transmission system. As such, the POD function is the most obvious to identify – point of delivery substations, radial transmission lines which serve these substations, or radial transmission lines directly serving a customer can be considered POD.

The definition used by LEI is consistent with prior cost causation studies. A summary of the three definitions is presented in the figure below.

Figure 15. Transmission functions

Transmission functions	*Definition*
Bulk system	*High voltage system typically carrying large amounts of electricity over long distances, as well as substations serving generators*
Regional system	*System that transmits electricity from the bulk system to load centers with numerous PODs*
POD system	*System serving distribution utilities or industrial customers that connect directly to the transmission system*

6 Cost causation methodologies

AESO has identified the following five rate design principles based on *Principles of Public Utility Rates* by Bonbright *et al*:[7]

i. recovery of total revenue requirement;

ii. provision of appropriate price signals that reflect all costs and benefits;

iii. fairness, objectivity and equity that avoids undue discrimination and minimizes inter-customer subsidies;

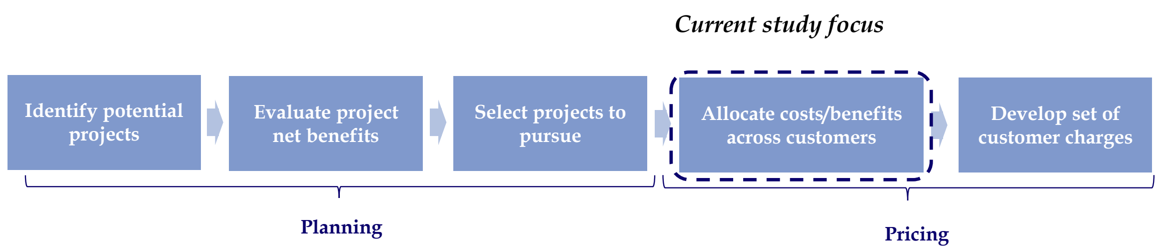
iv. stability and predictability of rates and revenue; and

v. practicality, such that rates are appropriately simple, convenient, understandable, acceptable and billable.

Within the scope of this study, LEI has considered all of the above principles. It is important that revenue requirements are met, and that the burden of fulfilling these requirements is shared fairly amongst users. LEI paid particular attention to the third principle, which closely ties with cost allocation and cost causation, such that where possible, costs need to be allocated to customers that are specifically responsible for particular capital investments, operation and maintenance costs, and costs that need to be socialized.

As presented in Figure 16, cost allocation exists at the boundary between transmission planning and pricing. Three main steps of the cost allocation process are functionalization, classification and allocation.

Figure 16. Transmission planning and pricing steps and focus of this study



In order to reflect cost causation in rate design, transmission costs are separated into a number of categories utilizing methods of functionalization and classification, which can then be allocated to appropriate beneficiaries. Functionalization is the process through which costs are divided into functional categories, such as bulk, regional, and point of delivery costs in Alberta.

[7] Bonbright, James, Albert L. Danielsen and David R. Kamerschen. *Principles of Public Utility Rates, Second Edition*. Public Utilities Reports; 2 Sub edition (March 1988).

Each function is then studied and costs are further classified into categories such as demand-related, energy-related and customer-related costs.

6.1 Overview of functionalization methodologies

Functionalization is defined as grouping costs together with other costs that perform similar functions. Typical functions for the entire system include: (i) production or purchased power; (ii) transmission; (iii) distribution; (iv) customer service and facilities; and (v) general and administrative functions.

When a transmission system is functionalized into only one transmission cost group, it is referred to as the 'rolled-in method' and when placed into multiple groups, it is referred to as the 'sub-functionalized method'.

- The *rolled-in method* is used for highly integrated transmission facilities (where the network allows many alternative flows for power to flow). It is treated as a single system as all elements are considered to contribute to the economic and reliable operation of the overall system; and

- The *sub-functionalized method* is used to further distinguish the network. It can be based on line configuration, geography, or voltage, as well as other features. Due to higher data requirements, this method is usually used for categories which have different cost consequences.

Figure 17. Summary of functionalization methodologies

Method	Strengths	Weaknesses
Voltage	• simple and easy to understand • used across various jurisdictions • results reflect cost causation • results similar to other methodologies	• less sensitive to evolving functions as compared to MW-km (that uses current loading forecasts) • high voltage projects serving a regional purpose and low voltage projects serving bulk purposes may not be taken into account properly
Economics	• unique and measurable metric • results reflect cost causation	• biased in functionalizing more costs as bulk • may not reflect evolving functions over time • may not be appropriate to apply current economics to past projects • setting theoretical line length is subjective
MW-km	• reflects evolving functions over time • more representative of study period, using forecasted flows • multiple metrics used • results reflect cost causation	• subject to error in line loading forecasts • forecast is a single point in time and may not be representative of all hours and years • setting breakpoint is subjective
MVA-km	• avoids errors in line loading forecasts by using rating capacity • multiple metrics used	• may not reflect evolving functions over time • setting breakpoint is subjective

Figure 17 presents a summary of strengths and weaknesses of functionalization approaches utilizing different concepts, which are further discussed in the following sub-sections. The functionalization approach chosen by LEI and the rationale is discussed later in Section 8.3.5.

6.1.1 Functionalization by voltage

Functionalization by voltage uses voltage levels of lines and substations to categorize costs. The theory is that higher voltage lines are designed to carry more power and act as the backbone of the system, thus higher voltages are considered to be bulk. It is a common method, and elements of this method are seen in multiple case studies discussed by LEI in Section 7.

Benefits include simplicity and the fact that on the whole, it provides a realistic breakdown of the transmission system. This was observed in the 2005 TCCS in Alberta, where functionalization by voltage gave similar results to other methodologies. Although simply functionalizing by voltage may not account for exceptional projects, and does not view the system dynamically, this challenge exists for other functionalization methods as well.

Because functions change over time, cost causation studies need to be revised periodically. However, this is not a weakness of any particular functionalization method. While a higher voltage line may have originally been designed to carry more power and be part of the bulk system, an evolving system may change the function of the same line over time. An example of this is the changes in the Alberta system, in which the addition of 500 kV and 240 kV lines has shifted 138 kV lines (initially considered bulk) to serve more regional functions. Alternatively, a 138 kV line may be built to serve a regional function in the future, but current system conditions could have it serving more of a bulk role.[8] This, however, may mean that the voltages associated with a particular function may need to change as studies are updated.

6.1.2 Functionalization by economics

Functionalization by economics determines functional categories by assessing the economics of the transmission line, specifically assessing whether it makes more economic sense, for instance, to build a 240 kV line versus a 138 kV line. When considering economics, it would generally be cheaper to build a 240 kV line for energy delivery over longer distances, but if many points of delivery are required, the cheaper option might be to build a 240/138 kV transformer substation and connect the points of delivery to a 138 kV line.

The economics approach assumes a high voltage line exists, and additional points of delivery are added, reducing line length between PODs. The relative cost of components determines the breakpoint at which it would become economical to build the transformer and lower voltage line in comparison to a higher voltage line. Lines that are below that breakpoint, measured in line length, are considered regional, and lines above the breakpoint are considered bulk. A similar process determines bulk and regional breakdown between 138 kV lines. Line length is a

[8] LEI identified at least twenty 138 kV lines that are functionalized as regional by the voltage approach, but are functionalized as serving bulk by the MW-km approach, as discussed in Section 6.1.3.

key factor in functionalizing using this method, whereby longer lines will be expected to be functionalized as bulk, while shorter lines are functionalized as regional.

An advantage of this method can be that it provides a unique measurable metric to determine functionalization. Utilizing this method provided reasonable results in the TCCS, where results were similar to other approaches.

However, as discussed by PSTI in the TCCS itself, this method is biased towards functionalizing more towards the bulk system, and may not reflect evolving functions of certain facilities over time. Moreover, as economics of the transmission system (POD and substation costs) change over time, it is questionable whether current economics can be applied to older transmission projects, given the differing market conditions at the time of their construction. Finally, there is an element of subjectivity in setting the length of the hypothetical line. The line length impacts the breakpoint, and hence the functionalization results.

6.1.3 Functionalization by megawatt-kilometer

Functionalization by MW-km is based on the concept that bulk lines carry large amounts of power over long distances. The loading (in MW) of each line in the system is forecast and multiplied by its line length to get its MW-km rating. By comparing MW-km values to a breakpoint, this method is able to quantify what percentage of lines at each voltage level is bulk and regional. Lines with high MW-km ratings are either carrying large amounts of power, or are very long, or both, and are therefore bulk.

The primary benefit of this method is taking into account the dynamic nature of the transmission system since it takes into account forecasted flows, which can change on updated assumptions about system conditions. Furthermore, the flows are forecasted for a year that is within the study period, which could lead to results which are more representative than methods which use current or past data. This method also takes into account two metrics (voltage and distance), which may lead to more reliable results. By taking into account distance, this approach will give a lower MW-km rating to a line in a subsequent study, if for example, a POD is built and halves the distance of the line. This is consistent with the logic behind the MW-km approach, which is to take into account the distance that power is carried.

However, one weakness is the possible error in the flow forecast. Changing baseline assumptions could mean the forecast is not accurate. As well, the forecast is a single point in time in the future, which may not be indicative of all hours in a year. The forecast of a single year also may not be indicative of all years in a study period. Moreover, setting the breakpoint is a challenging exercise and can be viewed as subjective. Validating breakpoints using clearly identifiable projects can mitigate some subjectivity if appropriate data is available.

6.1.4 Functionalization by MVA-kilometer

An alternative approach would be to consider the MVA capacity of a transmission line as a key indication of its purpose. The changing dynamics of the transmission system, such as a new 500 kV line serving a bulk power function that was once provided by a 240 kV line or a short or radial 240 kV line now serving in a regional or POD role, can be recognized in different ways.

To make a capacity approach work, the line length needs to be added to the formula to capture this changing dynamic, resulting in a MVA-km approach.

An advantage of this approach is that using the line design rating as compared to the winter peak flow provided by a power flow program will provide greater ease of calculation and stability within functionalization. It will keep lines from changing between bulk power and regional when a new parallel line is built.

There are two key weaknesses of the MVA-km approach. First, like the MW-km approach, setting the breakpoint is a challenging exercise and can be viewed as subjective. Second, unlike the MW-km approach, the MVA-km approach limits the possibility of a transmission line being functionalized differently as the system evolves. Line length becomes the only variable since the design rating is fixed at the highest loading possible. If a line is initially functionalized as regional due to its line design rating and length, it would not be expected to move to the bulk power category unless the line length increases significantly.

6.2 Overview of classification methodologies

Classification separates functionalized costs typically to demand-related costs that vary with kW demand imposed by customer, energy-related costs that vary by energy or kWh, or customer-related costs that are a function of the number of customers.

There are no standardized methods; all methods described below could be adapted for use on the transmission system. In some jurisdictions, such as ISO New England, all costs are recovered through demand, because the transmission planning process primarily considers forecast demand. However, LEI believes that classification into demand as well as energy costs is important, as having some contribution by energy means customers have an incentive to reduce load even when they are not at the peak. Even if the system peak is not coincident with any customer's individual peak, there exists a mechanism to reduce system peak.

Figure 18. Summary of classification methodologies

Method	Strengths	Weaknesses
Minimum system approach	• results reflect cost causation • commonly used in distribution systems • can be adapted for use in transmission systems, which was previously approved by the Alberta Energy and Utilities Board	• actual minimum size can be subjective
Minimum intercept	• may be more accurate • results reflect cost causation	• requires considerably more data than minimum system approach
Marginal cost approach	• may contributes to efficient resource allocation	• marginal costs for transmission related investments are difficult to determine • has been rejected in the past in Alberta • precision and simplicity of embedded cost method may be superior
Average and excess approach	• takes into account actual line loadings	• no generally-accepted standard methodology • has been rejected in the past in Alberta • may provide a poor price signal to customers

Figure 18 presents classification approaches utilizing different concepts, and a summary of their strengths and weaknesses, which are further discussed in the following sub-sections. The classification approach (and underlying rationale) chosen by LEI, as well as the results are discussed later in Section 11.

6.2.1 Minimum system approach

The minimum system approach was first deployed for distribution systems, to classify costs into demand-related and customer-related categories; it was also used to classify transmission costs in the TCCS. As described in the National Association of Regulatory Utility Commissioners ("NARUC") Electricity Utility Cost Allocation Manual, the "minimum-size method involves determining the minimum size pole, conductor, cable, transformer, and service that is currently installed by the utility."[9] The minimum system is classified as customer-related, as in a distribution system, the minimum system is built to serve customers. For distribution systems, the difference between the minimum and total investment is then classified as demand related, since additional investment is used to serve peak load rather than number of customers.

This method was adapted by PSTI to be used in the transmission system. In this modified method, the minimum system was classified by demand because on a transmission system, the minimum system is driven by serving total load, rather than customers. The incremental costs for an optimal system were allocated to energy, since costs that are incurred beyond the minimum system are driven by energy usage considerations and to optimize for energy losses.

Benefits of using this approach are that it is consistent with cost causation principles, it has been used for distribution utilities in the past (as discussed in the NARUC manual), and it has previously been approved for transmission cost causation in the past by the AEUB. A criticism of the minimum system approach is that the actual minimum size can be subjective, which in turn affects the classification results.

6.2.2 Classification by minimum intercept

The minimum intercept method is another way of classifying costs. The concept is to "relate installed cost to current carrying capacity or demand rating,"[10] and with multiple data points, use a regression to determine a zero-intercept, which represents the customer component.

Benefits over the minimum system approach include greater accuracy, however, NARUC argues that the differences may be relatively small and the method requires considerably more data.[11]

---

[9] National Association of Regulatory Utility Commissioners. *Electricity Utility Cost Allocation Manual*. January 1992. Page 90.

[10] Ibid. Page 92.

[11] National Association of Regulatory Utility Commissioners. *Electricity Utility Cost Allocation Manual*. 1992. P 92.

6.2.3 Classification by marginal cost approach

Marginal cost classification is mainly used for production costing. Marginal cost studies use the theory that the market is at equilibrium when the producer's cost of the last unit of a good is equal to the amount consumers are willing to pay for it. The regulator attempts to achieve the same equilibrium by accepting a particular level of service, and setting rates equal to the utilities' marginal cost at that level.

Supporters claim this method contributes to efficient resource allocation, while detractors claim the precision and simplicity of the embedded cost method is superior. Marginal costs for transmission related investments are difficult to determine and may be imprecise, and the marginal cost approaches have been rejected by the regulator in Alberta in the past (when the industry was vertically-integrated).[12] Alberta has consistently used an embedded cost approach.[13]

6.2.4 Classification by average and excess approach

In order to classify by the A&E methodology, the average component is determined by the average system load factor, which determines the energy-related classification of transmission costs, and the excess component represents the amount of system load above the average.

As discussed earlier in Section 4.2.2, the Alberta regulator rejected this approach in 2007,[14] maintaining that transmission assets represent a long-term fixed investment, and varied less based on usage. Poor price signals may be provided to customers if a significant proportion of costs are classified as energy-related.[15]

---

[12] Public Utilities Board, Alberta. *Decision E94076 re: TransAlta Utilities Corporation*, November 4, 1994. P 29.

[13] Alberta Energy. *Transmission Development: The Right Path for Alberta*. December 22, 2003.

[14] Alberta Energy And Utilities Board. *Alberta Electric System Operator: 2007 General Tariff Application*. December 21, 2007. P 30.

[15] AEUB. *Decision 2007-106: AESO 2007 General Tariff Application*. December 21, 2007. Pages 29-30.

7 International case studies

This section discusses methodologies utilized by selected international jurisdictions (Ontario, California, Australia and Great Britain) to identify cost causation. These jurisdictions were chosen in light of some of the following reasons: Ontario represents a geographically large Canadian province with significant industrial load; California because of its importance within the western interconnection of which Alberta is a part; Australia because it is also geographically large, sparsely populated, and has an advanced regulatory regime; and finally Great Britain to provide an example that performs cost causation differently from North American jurisdictions.

Figure 19. Introduction to case study jurisdictions

Jurisdiction	2012 Peak Load (MW)	Transmission Lines (km)	Voltages Used	Degree of Unbundling	Most Recent Tariff Decision			
					Period	Date of Decision	Entity	Regulator
Alberta	10,609	21,000	500kV 240kV 138/144 kV 115/70 kV	Transmission charge unbundled	2011-2013	December 2010	AESO	Alberta Utilities Commission ("AUC")
Australia	31,084	40,000	500 kV 330 kV 275 kV 132 kV	Transmission charge unbundled	2012-13 to 2016-17	April 2012	Powerlink	Australian Energy Regulator ("AER")
California	25,865	41,600	500 kV 230 kV 115 kV 70 kV	Transmission charge unbundled	September 2012 onwards	December 2011	San Diego Gas & Electric Company	FERC
Ontario	23,954	30,000	500 kV 230 kV 115 kV	Transmission charge unbundled	2012	November 2011	Hydro One	Ontario Energy Board ("OEB")
Great Britain	57,086	7,200 *	400 kV 275 kV 132 kV	Transmission charge unbundled	2011-2012	March 2011	National Grid Electricity Transmission	Office of Gas and Electricity Markets (Ofgem)

*Sources: AESO, Alberta Energy, IESO, Australian Energy Regulator, NEM, CAISO, UK Department of Energy & Climate Change, National Grid; * National Grid only*

7.1 Ontario, Canada - Hydro One Networks Inc. (Hydro One) transmission rates case

Hydro One's most recent transmission rate case presents the methodology deployed by the Ontario Energy Board ("OEB") to functionalize transmission assets and thereby determine transmission revenue requirements.[16,17]

> **Ontario - Hydro One transmission**
>
> - **Functional groups**: Network, Line Connection, Dual Function Line, Transformation Connection, Generation Station Switchyards, Wholesale meter, Common, Other
> - **Classification groups**: Network Pool, Line Connection Pool, Transformation Connection Pool, and Wholesale Meter Pool (referred to as Rate Pools)
> - **Allocation method**: based on Coincident or Non-Coincident Peak demand

Transmission assets and costs associated with these assets are first assigned to various functional categories. Next, the values assigned to each functional category are allocated to various Rate Pools in order to calculate the revenue requirements associated with each of the pools.[18] In certain cases, parameter(s) must be used to calculate the proportion of the costs associated with a given asset that will go to more than one functional category/Rate Pool.

The three basic elements of the revenue requirements assigned to the four pools are: (i) operation, maintenance, and administrative ("OM&A") costs; (ii) expenses associated with fixed assets such as depreciation, asset removal costs, return on capital, income taxes, capital taxes, property taxes and amortization costs; and (iii) other components such as non-rate revenues and export revenue credit.

7.1.1 Functionalization of assets

In order to determine its revenue requirement for each Rate Pool, Hydro One must first assign the physical transmission assets that it owns (or a portion thereof) to the various functional categories defined below. This assignment process is based on 'load forecast data for each delivery point, the fixed asset financial database and the electrical system connectivity database that identifies the connectivity between transmission assets (e.g. lines and stations) to which customers are connected.'[19]

---

16 Hydro One filed its initial application on May 28, 2012. On December 20, 2012, OEB approved total transmission revenue requirements of $1,390.8 million for 2013 and $1,439.5 million for 2014. Of these amounts, $440.3 million in 2013 and $449.7 million in 2014, constituted OEB-approved OM&A expenses. $982.4 million in 2013 and $1,121.5 million in 2014, constituted capital expenditures. OEB. EB-2012-0031. *Decision in the matter of an application by Hydro One Networks Inc. for an approving of new transmission revenue requirements and rates for the transmission of electricity in 2013 and 2014.* Decision issued on December 20, 2012.

17 This methodology was initially approved by the OEB in the Decision on Rate Order in Proceeding EB-2010-0002.

18 The methodology involves four Rate Pools: the Network Pool, the Line Connection Pool, the Transformation Connection Pool, and the Wholesale Meter Pool.

19 Hydro One. *EB-2012-0031 Exhibit G1. Tab 2. Schedule 1.* Filed May 28, 2012. Page 1 of 20.

As presented in Figure 20 and the following table, the functional categories to which Hydro One assigned its assets in the context of its latest transmission revenue requirements and rate determinants application were the following: (i) network lines, (ii) dual function line, (iii) line connection, (iv) transformation connection, (v) generation station switchyards, (vi) wholesale meter, (vii) common assets and (viii) other assets.

Hydro One - Functional categories	Description
Network Assets	*Assigned are those "transmission facilities that are used for the benefit of all customers, or have been approved by the OEB as being for the benefit of all customers in the province."[20] Generally comprises facilities operating at 230 kV or above and that link major load centers together with major generation resources. These assets provide reliability to the system and enhanced market efficiency.*
Dual Function Line ("DFL") Assets	*Assigned are those "transmission circuits that are used for both the common benefit of all customers and for providing a connection between a network station and load supply point(s) for one or more customers."[21] Allocation factors are further determined to assign the various costs components to two subcategories of the DFL category: the line connection DFL sub-category and the network DFL sub-category.[22]*
Line Connection Assets	*Assigned are those "transmission circuits and intermediate stations operating at 230 kV or 115 kV that are used to provide a connection between a network station and load supply point(s) for one or more customers and one or more generating stations."[23] The category also includes the transmission circuits that connect transmission circuits categorized as DFL to load supply point(s) for one customer / generating station or more. 230 kV or 115 kV radial stations serving one customer or more are also included in this category.*
Transformation Connection Assets	*This category includes transformer stations used to step down the voltage from above 50 kV to below 50 kV.*
Generating Station	*This category includes switchyards used to connect generating stations to the*

---

20 Hydro One. *EB-2012-0031 Exhibit G1. Tab 2. Schedule 1.* Filed May 28, 2012. Page 3 of 20.

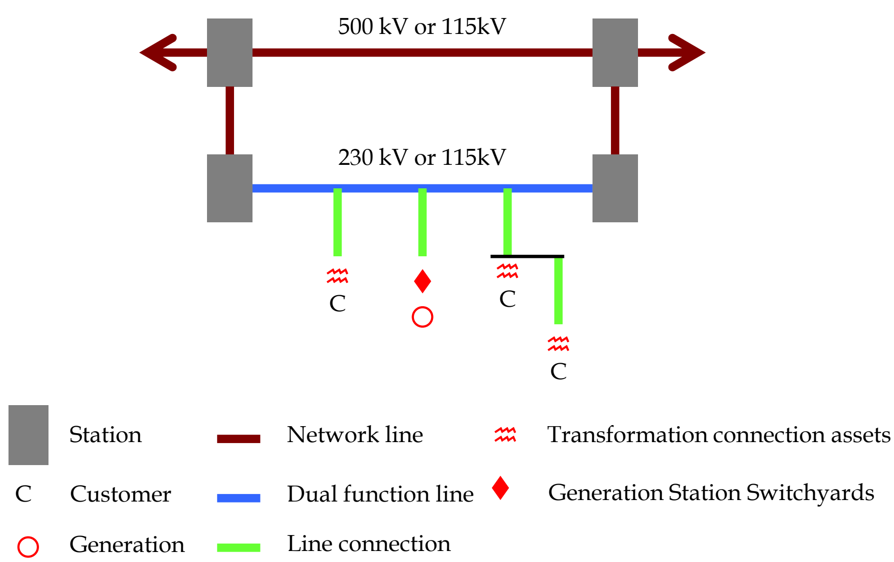
21 Ibid. Page 4 of 20.

22 Further details on how these allocation factors are estimated can be found in Hydro One's *EB-2012-0031 Exhibit G1. Tab 2. Schedule 1.* PP.10-18.

23 Hydro One. *EB-2012-0031 Exhibit G1. Tab 2. Schedule 1.* Filed May 28, 2012. Page 5 of 20.

Switchyard Assets	*transmission system.*
Wholesale Meter Assets	*This category encompasses metering-related facilities that are "used for billing and settlement in respect of transmission and/or wholesale energy charges. These facilities include the recorders, physical meters and related instrument transformers, wiring, and panels that can be separately identified as being used solely for revenue metering purposes."*[24]
Common Assets	*This category encompasses facilities that serve the operation of the overall provincial transmission system such as: telecommunication and control equipment, administration buildings and control rooms, minor fixed assets (such as office computers and equipment) and electrical equipment held in reserve.*
Other Assets	*This category encompasses all remaining transmission facilities that could not be assigned to any functional categories listed above.*

Figure 20. Ontario transmission asset categories



Source: Hydro One. EB-2012-0031 Exhibit G1. Tab 2. Schedule 1. Filed May 28, 2012. Page 2 of 20[25]

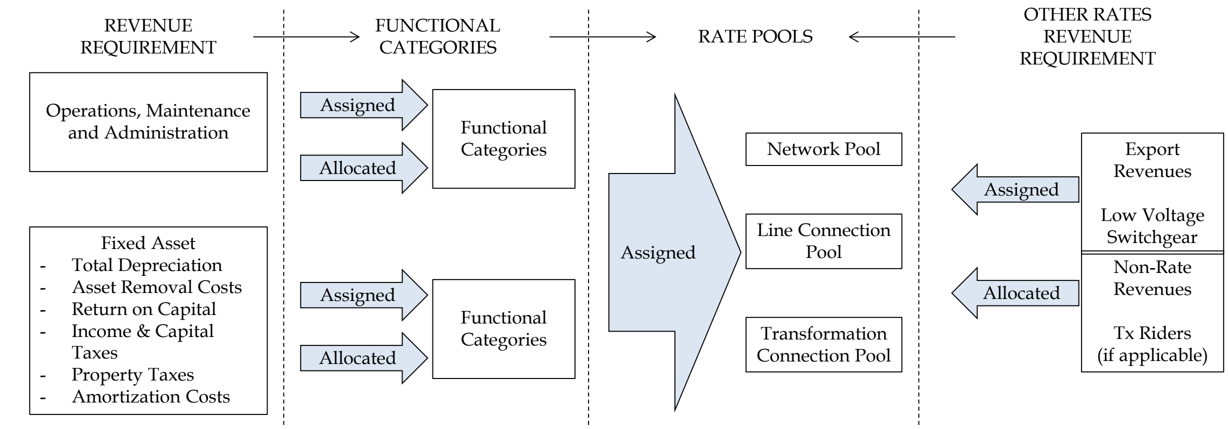
[24] Ibid. Page 7 of 20.

[25] All *Exhibits related to Hydro One's 2013-2014 Transmission Revenue Requirement and Rates Application*, <http://www.hydroone.com/RegulatoryAffairs/Pages/2013-2014Tx.aspx#g>

7.1.2 Allocation of revenue requirements to rate pools

The second step is to attribute the transmission revenue requirements to each of the Rate Pools. Figure 21 below presents the process by which transmission revenue requirements are allocated to various Rate Pools.[26]

Figure 21. Ontario costs-to-revenue requirement process



Source: HONI. EB-2012-0031 Exhibit G1. Tab 2. Schedule 1. Filed May 28, 2012. Page 1 of 20

The costs are assigned as follows:

- costs associated with the Network, Line Connection, and Transformation Connection functional categories, as a result of the prior assignment process, are directly assigned to the correspondingly-named Rate Pools;
- aggregate costs associated with the Generator Line Connection and Generator Station Connection functional categories are both assigned to the Network Pool;
- costs associated with the Wholesale Meter functional category are directly assigned to the Wholesale Meter Pool;
- costs associated with the Dual Function Lines are assigned to either the Network Pool or the Line Connection Pool; and

[26] "The term "Assigned" refers to a value that is designated to a particular Functional Category or Rate Pool (e.g. Export Revenues are directly assigned to the Network Rate Pool). The term "Allocated" indicates that a parameter(s) is used to calculate the proportion of the values that are designated to more than one Functional Category or Rate Pool (e.g. load forecast data is applied to the value of Dual Function Line assets to determine the proportion of its value that is allocated to the Network Functional Category and to the Line Connection Functional Category)." Source: Hydro One. *EB-2012-0031 Exhibit G1. Tab 2. Schedule 1.* Filed May 28, 2012. Page 9 of 20.

- costs associated with the functional categories "Common" and "Other" are allocated to either Network, Line Connection or Transformation Connection Rate Pools in proportion to amounts of costs that have already been assigned to those Rate Pools based on other functional categories. For instance, "Common" and "Other" OM&A costs are allocated to each Rate Pool in proportion of the relative share of OM&A costs already assigned to that Rate Pool.

7.2 California, USA

The California ISO ("CAISO") tariff defines transmission cost determination and responsibility.[27] There are two general cost categories that are determined by the tariff: the Grid Management Charge ("GMC") and the Transmission Access Charge ("TAC"). The GMC is a charge for managing the markets, operating the grid, settlements and administration. It does not include transmission asset costs. The cost responsibility for the various GMC cost buckets is allocated primarily to the users of the services.

California ISO

- **Functional groups**: Network Transmission Facility, Location Constrained Resource Interconnection Facilities
- **Classification groups**: High Voltage, Low Voltage (referred to as further functionalization)
- **Allocation method**: Based on locational and uniform $/MWh rates

The TAC includes transmission facilities that have had their operational control turned over to the CAISO by Participating Transmission Owners ("PTO"s). The TAC segments the transmission function into network transmission facilities and Location Constrained Resource Interconnection Facilities ("LCRIF"). The network transmission facilities are further functionalized into high voltage facilities which are facilities that operate at 200 kV and above and low voltage facilities which are operating below 200 kV.

The cost of the PTOs' facilities that are not under the operational control of the CAISO such as low voltage distribution facilities and radial generator interconnect lines, regardless of voltage, are recovered by the PTO from its load and generator customers respectively.

Revenue generated by wheeling services is collected through the Wheeling Access Charge ("WAC") and is credited to the TAC.

7.2.1 Network transmission facilities – PTO cost recovery

A PTO's cost recovery for facilities turned over to the ISO Operational Control begins with its Transmission Revenue Requirement ("TRR") approved by Federal Energy Regulatory Commission ("FERC"). The TRR is comprised of the total annual revenue requirement associated with such network facilities. The high voltage TRR costs are recovered through a High Voltage Access Charge on a uniform basis from the PTO's load. Summing all PTOs' TRR

[27] California Independent System Operator Corporation. *Fifth Replacement CAISO Tariff*. Mar 20, 2013.

and dividing by the sum of the PTOs' gross load in MWh results in calculating the High Voltage Access Charge. The High Voltage Access Charge is a uniform $/MWh rate for all PTO loads.

The low voltage TRR portion of the TAC is PTO-specific and is based on the TRR associated only with its own low voltage transmission facilities. A calculation similar to the High Voltage Access Charge is performed but it produces a unique Low Voltage Access Charge for each PTO.

The total TAC is paid by entities serving load on the transmission and distributions systems of the PTOs under the ISO's operational control.

7.2.2 LCRIF – cost recovery

Typically, the cost of transmission infrastructure is allocated to load in the United States,[28] but interconnecting generators pay for direct interconnection facilities. However, in the California ISO, a special case is made for interconnection facilities of renewable resources, primarily wind. LCRIF costs are allocated to load until the resource interconnects; once it interconnects, the resource pays for its contribution to the LCRIF (determined by its capacity).[29]

In order to construct transmission facilities of adequate capacity to deliver generation located in transmission constrained resource rich areas, the LCRIF rate methodology was developed and approved by FERC. Eligibility for LCRIF rate treatment requires a demonstration of adequate subscription through large generator interconnection agreements ("LGIA") of at least 25% of the line's capacity and a documented interest for at least an additional 25%.

If a transmission line is eligible for LCRIF rate treatment, the PTO will fund the cost of construction upfront. The recovery of costs comes from two sources. The first is the subscribing generators, and second is the cost of unsubscribed capacity added to the TAC similar to a network upgrade. As generation projects are developed and interconnected to the LCRIF, cost recovery is transferred on a going-forward pro rata basis to the new generation owners and the LCRIF costs included in the TAC are reduced accordingly. Once the anticipated generation is fully developed and the LCRIF capacity fully subscribed, the going forward costs for the LCRIF are borne entirely by the generation owners and are not included in the TAC.

7.3 Australia

All transmission companies operating in the National Electricity Market (Australian Capital Territory, New South Wales, Queensland, South Australia, Tasmania and Victoria) must cost and price their transmission services in accordance with the principles set out in Chapter 6A of

[28] PJM. *A Survey of Transmission Cost Allocation Issues, Methods and Practices*. March 10, 2010. P 23.

[29] Ibid.

the National Electricity Rules ("NER").[30] The NER focus is on the type of service provided rather than the customer types, and NER operates on the following principles:

- generators should pay the costs directly resulting from their connection, that is a 'shallow connection' approach is applied, and do not contribute towards the costs of the shared network, which are covered through prescribed generator transmission use of system ("TUOS") charges; and

- network pricing should be cost reflective.

Australia

- **Functional and classification groups**: Entry Service, Exit Service, Transmission Use of System Service, Common Transmission Service
- **Allocation method**: Based on fixed $/day and $/MW/day maximum demand rates

Under the cost allocation principles, allocation of costs must be determined according to the substance of a transaction or event rather than its legal form. Also, costs may be allocated to a particular category of services so long as they are directly attributable. Where costs are not directly attributable, such costs should be allocated in accordance with an appropriate methodology. In practice, each transmission network service provider will develop its own cost allocation methodology consistent with these principles.

The Australian Energy Regulator ("AER") is also currently developing a range of guidelines, including Shared Asset Guidelines, to clarify cost allocation and other revenue matters. The pricing principles are set out in Section 6A.23 of the NER and generally reflect the notion that prices should be cost reflective. Separate prices are to be developed for each category of prescribed transmission services including:

- prescribed entry services include services provided by assets that can be attributed to one or more generator(s) at a single point of connection - must be a fixed annual amount;

- prescribed exit services include services provided by assets that can be attributed to one or more transmission customer(s) at a single point of connection - must be a fixed annual amount;

- prescribed common transmission services include services provided by assets that cannot be reasonably assigned on a locational basis and that provide equivalent benefits to all transmission customers - postage-stamp basis; and

- prescribed TUOS services cover the costs of shared network assets and non-asset related grid support. They are separated into locational and non-locational components. The locational component must be based on demand whereas the non-locational component

[30] The current version of the National Electricity Rules can be found at http://www.aemc.gov.au/Electricity/National-Electricity-Rules/Current-Rules.html. Chapter 6A focuses on transmission revenue and pricing frameworks.

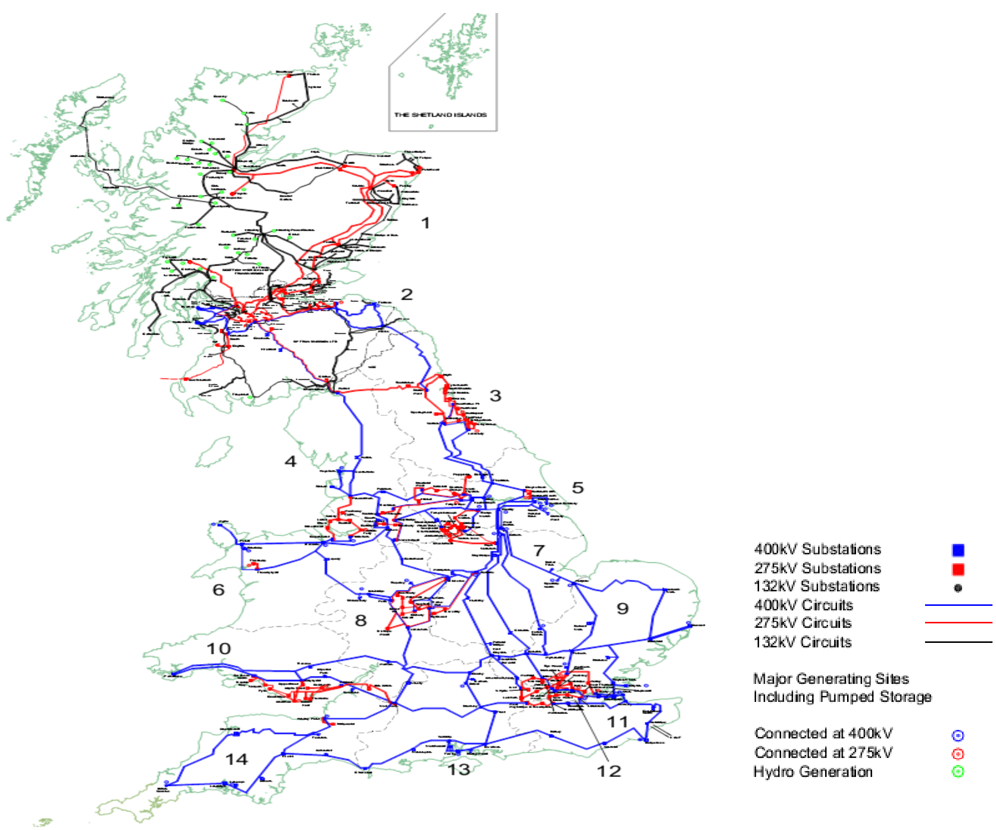
is postage-stamp based. Costs for prescribed TUOS services are generally split 50:50 between locational and non-locational components. Prices for prescribed TUOS services must not change by more than 2% per annum compared with the load weighted average price for this component for the relevant region. This cap can be exceeded if load at the connection point has materially changed and the customer requested a renegotiation of the connection agreement and AER has approved the price change.

A transmission company can offer discounted rates to a customer for TUOS and common transmission services where the actual costs of providing transmission services to that customer (e.g. a smelter) may be lower. Discounts can be recovered from the remainder of the customer base.

7.4 Great Britain

In Great Britain, National Grid charges for the use of the transmission system on behalf of National Grid Electricity Transmission, Scottish Power Transmission and Scottish Hydro-Electric Transmission, using the Transmission Network Use of System ("TNUoS") tariff. Unlike the majority of North America, the TNUoS is paid for by both generation and demand resources, where generation pays for 27% and demand pays for 73% of the costs.

Figure 22. Great Britain demand use of tariff zones



Source: National Grid. TNUoS Demand Zones Map (Geographical). April 22, 2010

The TNUoS is composed of two components: a locational charge and a residual charge. The locational charge is calculated separately, using a marginal cost classification method, for twenty-one generation zones and fourteen demand zones. Generally, tariffs are higher for generators in the north and consumers in the south. The locational component is classified using a marginal cost methodology known as the Investment Cost Related Pricing ("ICRP"). The ICRP estimates long run marginal costs of investment required for the transmission system, caused by an increase in demand or generation at each connection point or node. Hence, different costs are calculated for different locations in the market.[31]

Figure 23. Schedule of Transmission Network Use of System Demand Charges (£/kW) and Energy Consumption Charges (p/kWh) for 2013/14*

Demand Zone	Zone Area	Demand Tariff (£/kW)	Energy Consumption Tariff (p/kWh)
1	Northern Scotland	11.049	1.515
2	Southern Scotland	16.790	2.363
3	Northern	22.347	3.080
4	North West	25.184	3.651
5	Yorkshire	25.485	3.509
6	N Wales & Mersey	25.631	3.665
7	East Midlands	28.213	3.957
8	Midlands	29.201	4.149
9	Eastern	29.892	4.153
10	South Wales	27.542	3.685
11	South East	32.827	4.564
12	London	34.083	4.601
13	Southern	33.752	4.741
14	South Western	33.552	4.598

*Source: National Grid. The Statement of Use of System Charges. Effective from April 1, 2013. * Rounded to 3 decimal places*

The residual, non-locational component of the TNUoS tariff is meant to recover the remaining amount of the revenue requirement that is not recovered by the locational component. This portion exists because the marginal cost model used in the locational component assumes smooth, incremental investment can be made in transmission. However, in reality this capital investment is "lumpy"; large investments can be made for future requirements, which mean the system becomes non-optimal. The difference between the actual, non-optimal system is accounted for by the residual component.

[31] A metric used to measure investment costs is MW-km, which is unrelated to the MW-km method described for functionalization. In the context of the TNUoS, marginal costs are estimated in terms of increases or decreases in units of kilometers of the transmission system, for a 1 MW injection to the system.

Generators that directly connect to the transmission system or embedded generators with a Bilateral Embedded Generation Agreement ("BEGA"), and those that are equal to 100 MW or larger are liable to pay TNUoS charges. These charges are paid with respect to their maximum installed capacity (kW), and are comprised of wider and local charges. Local charges include substation charges as well as circuit charges.

Loads that pay the TNUoS can be differentiated into half-hourly ("HH") metered, which have peak loads larger than 100 kW, and non-half-hourly ("NHH") metered, which are smaller than 100 kW. HH metered loads are charged the average "triad" demand multiplied by the zonal demand tariff (£/kW), where triad means the three half-hours between November and February (inclusive) with the highest peak system demand. The triad half-hours must be separated from system demand peak and each other by at least ten days. NHH metered loads are charged actual energy consumption (kWh) for the hours of 16:00 to 19:00 inclusive, multiplied by the energy zonal energy consumption tariff (p/kWh).

7.5 Applicability to Alberta

The purpose of LEI's review of other jurisdictions was to introduce how transmission costs are allocated elsewhere. It was observed that there is no single template or standard transmission cost causation methodology. Alberta's methodologies may seem unique, however no two jurisdictions are the same in their methodologies.

Despite the differences, LEI noted that elements of functionalization by voltage can be observed across numerous jurisdictions. For example, in Ontario, 230 kV and higher assets are generally functionalized as network assets, which link major load centers, while line connection assets are generally 230 kV or 115 kV. In California, network transmission facilities are functionalized into high and low voltage facilities around a 200 kV breakpoint, which are recovered through different charges. LEI believes functionalization by voltage is more common because it is perceived as being simple and easy to understand.

An interesting feature of the California system is the existence of LCRIF, which creates a special category for projects that are built specifically to interconnect renewable generation. Definition of this separate category is related to the distinction of "special projects" which was requested by Transmission Cost Causation Working Group ("TCCWG") members, which is addressed in greater detail in Section 13.1.

8 Functionalization of capital costs

LEI performed three methods of functionalization: by voltage, economics, and megawatt-kilometer. These three approaches were used in the TCCS, which were well-understood and approved by the AUC, and so represent a good starting point.[32] However, while LEI is informed by the previous studies, we have not been constrained by them. After reviewing the strengths and weaknesses of the different approaches, and considering the rate design principles discussed earlier in Section 5, LEI recommends functionalization by voltage as the method going forward.

8.1 TFO cost data

The following section specifies data sources used by LEI in the capital cost functionalization analysis, and describes the data utilization approach. This section also specifies data limitations and any reasonable assumptions made consequently.

8.1.1 Depreciation

Given that LEI incorporated both existing assets as well as future projects with differing in-service dates, it was important to take into account depreciation rates of the various transmission assets. All net book values were depreciated to December 2016 prior to functionalization. LEI utilized TFO tariff application schedules in order to determine appropriate levels of depreciation to use for AltaLink and ATCO. ENMAX depreciation rates were determined using a confidential data request.

Figure 24. Calculated TFO transmission line and substation depreciation rates

Lines

	2013	2014	2015	2016
Altalink	2.71%	2.84%	2.84%	2.84%
Epcor	2.90%	2.95%	2.95%	2.95%
ENMAX	2.01%	1.83%	1.83%	1.83%
ATCO	3.10%	3.07%	3.07%	3.07%

Substations

	2013	2014	2015	2016
Altalink	3.47%	3.56%	3.56%	3.56%
Epcor	2.95%	2.90%	2.90%	2.90%
ENMAX	2.66%	2.64%	2.64%	2.64%
ATCO	2.29%	2.31%	2.31%	2.31%

[32] Although LEI considered the MVA-km approach, it was not chosen for analysis, due to the subjective nature of setting a breakpoint, an inability to reflect evolution of the system, and lack of prior use in Alberta or elsewhere.

For AltaLink lines, LEI utilized an asset-weighted average of land rights, towers and fixtures, overhead conductors and poles and fixtures. For AltaLink substations, an asset-weighted average of land rights, station equipment and system communication and control was used.[33]

For ATCO lines, an asset-weighted average of total land rights, towers and fixtures, overhead conductor towers, poles and fixtures, and overhead conductor poles was used. For ATCO substations, LEI used an asset-weighted average of land rights, and substation equipment.[34]

For ENMAX lines, an asset-weighted average of land rights, wood poles, steel towers, steel poles, insulators, overhead aluminum conductor, overhead aluminum conductor steel reinforced ("ACSR"), and overhead self-damp conductor was used. For ENMAX substations, LEI used an asset-weighted average of land, buildings, site development, substation transformers, substation switchgear, substation structures, substation protection, telecontrol and supervisory costs.

The EPCOR depreciation forecast was not found in its tariff application, and therefore, was depreciated at a weighted-average of AltaLink, ATCO and ENMAX depreciation rates. Given 2015 and 2016 depreciation forecasts were not available through the tariff applications, and depreciation rates were seen not to vary significantly from year to year, each TFO's 2014 depreciation rate was used for 2015 and 2016.

8.1.2 Existing asset data

LEI has received asset data from all four TFOs with various levels of detail. In order to perform the various functionalization methods, line and substation-level details on net book values, voltages and line lengths were required.

Figure 25. Summary of data received by each TFO

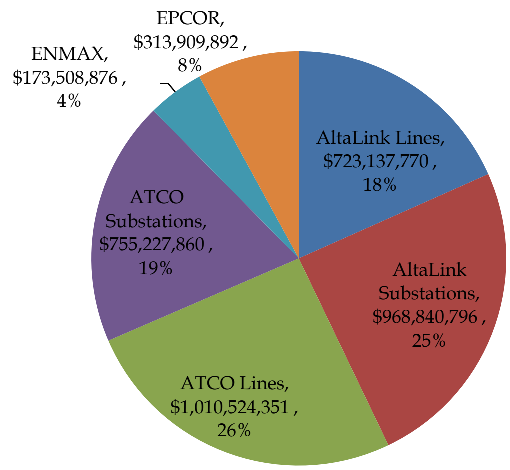
TFO	Data Received	Missing Data
AltaLink	• Line and substation-level details on net book values, voltages and line lengths • Substation secondary voltages	
ATCO	• Original costs for lines and substations • Line and substation-level details on voltages and line lengths • Accumulated depreciation aggregated to line and substation totals	• Line and substation-level details on net book values
ENMAX	• Net book values aggregated to substation and transmission totals • Line and substation-level details on voltages and line lengths	• Line and substation-level details on net book values
EPCOR	• Net book values and accumulated depreciation up to 2011, aggregated to Genesee Switchyard, transmission, and substation totals	• Line and substation-level details on net book values, voltages and line lengths • Net book values and accumulated depreciation for 2012

[33] AltaLink Tariff Application. Schedule 6-3 and Schedule 10-2

[34] ATCO Tariff Application. Schedule 6-6 and Schedule 6-7

AltaLink provided existing asset data with the necessary detail to perform functionalization by voltage, economics and MW-km.[35] ATCO provided voltages and line lengths for most lines and substations,[36] however, net book values for individual assets were not received. Total accumulated depreciation for all assets was provided, which was proportioned by LEI to each asset using cost and years of service. Although this is an approximation, it represents a best effort given the data available.

Figure 26. TFO existing asset net book values depreciated to 2016



ENMAX provided data aggregated to the level of total substation and total transmission, which were assumed to be completely functionalized as POD and regional, respectively. LEI has been able to validate these assumptions through a confidential data request received from ENMAX. All ENMAX lines are 138 kV and 69 kV, and would be functionalized as regional using both the economics and voltage approaches. Over 95% of ENMAX substations will be POD after projects currently in progress are complete.

EPCOR provided total installed assets under three categories: Genesee Switchyard, total transmission, and total substations, which were functionalized as bulk, regional, and POD respectively. EPCOR data was provided for 2011, but not for 2012 or 2013. It was noted that due to changes within EPCOR systems and personnel, it was not possible to confirm that the categories provided contain the exact same accounts as the accounts used in the 2005 TCCS.

[35] AltaLink identified 27 substations which are switching stations or are substations for which the customer owns the transformer. Switching stations have equal primary and secondary voltages, so the secondary voltages apply. Substations which connect directly to customers are functionalized as POD (or according to their substation fraction, described in Section 8.3.1).

[36] ATCO voltage and line lengths for over 94% (by value) of existing line data and over 87% (by value) of substation data was available. Any assets lacking data were functionalized in proportion to other ATCO assets. Secondary voltages for ATCO substations were occasionally provided for multiple years, and for a few substations multiple secondary voltages were given. As it was not possible to identify which subsequent capital investments belonged to which voltage, LEI assumed the secondary voltage of the largest capital investment.

Ongoing capital maintenance for existing projects is assumed to be $253 million per year (sourced from TFO GTAs) and POD connection projects are assumed to be $90 million[37] per year (sourced from AESO 2012 Construction Contribution Policy Application), beginning in 2013.[38] When depreciated to 2016, the total net book value of existing assets equals approximately $5.2 billion.

8.1.3 Future projects

In Decision 2010-606, the AUC instructed the AESO to consider a forecast of capital build for the entire expected effective term of the AESO's next tariff, using the LTP as a starting point. The LTP, filed June 2012, is a report produced by the AESO that forecasts investment in the transmission system for the next 20 years, and makes recommendations on upgrades needed to "*reliably and efficiently serve expanding demand, reduce transmission congestion and related congestion cost and facilitate a competitive market*."[39] The LTP's total cost estimate for projects in service by 2020 is $13.5 billion. The LTP also reconfirmed the need for four CTI projects, which have an estimated cost of $5.2 billion.

8.1.3.1 Future project data sources

AESO provided LEI with additional data sources beyond the data contained in the LTP. An important source of data, particularly for future line data, was the AESO cost benchmarking data file provided by the AESO. The AESO cost benchmarking data file contained 434 rows of line information, mostly manually extracted from Proposal to Provide Services documents, which are usually included with Needs Identification Documents ("NID"s) and/or Facility Applications ("FA"s). Although this information is more up to date than the LTP data, it is subject to wide confidence intervals. LEI understands that NID level documents have a cost estimate which is of a +30%/-30% quality, while FAs are of a +20%/-10% or better quality. As well, the database was not necessarily comprehensive in nature, though AESO expects that it covers 95% of all projects.

Given limitations in AESO cost benchmarking data file data, LEI also reviewed 62 individual project progress report files provided by AESO (referred to as "progress reports"), which are reports submitted to the Transmission Facility Cost Monitoring Committee ("TFCMC"). The reports used were published in November 2012, and represent the most up to date information received by LEI. LEI attempted to match all progress reports with the AESO cost benchmarking data file and LTP projects using project descriptions as well as AESO reference numbers, and

---

[37] $90 million is net of customer contributions. Note that POS capital additions are fully funded by customer contributions. (AESO. *AESO 2012 Construction Contribution Policy Application*)

[38] Note that although ongoing capital maintenance costs and POD connection projects occur in the future, they are distinct from future project functionalization, as the costs will generally be attributable to existing assets. These costs are not allocated to a particular TFO, but are included in overall functionalization results.

[39] AESO. *AESO Long-term Transmission Plan.* Filed June 2012.

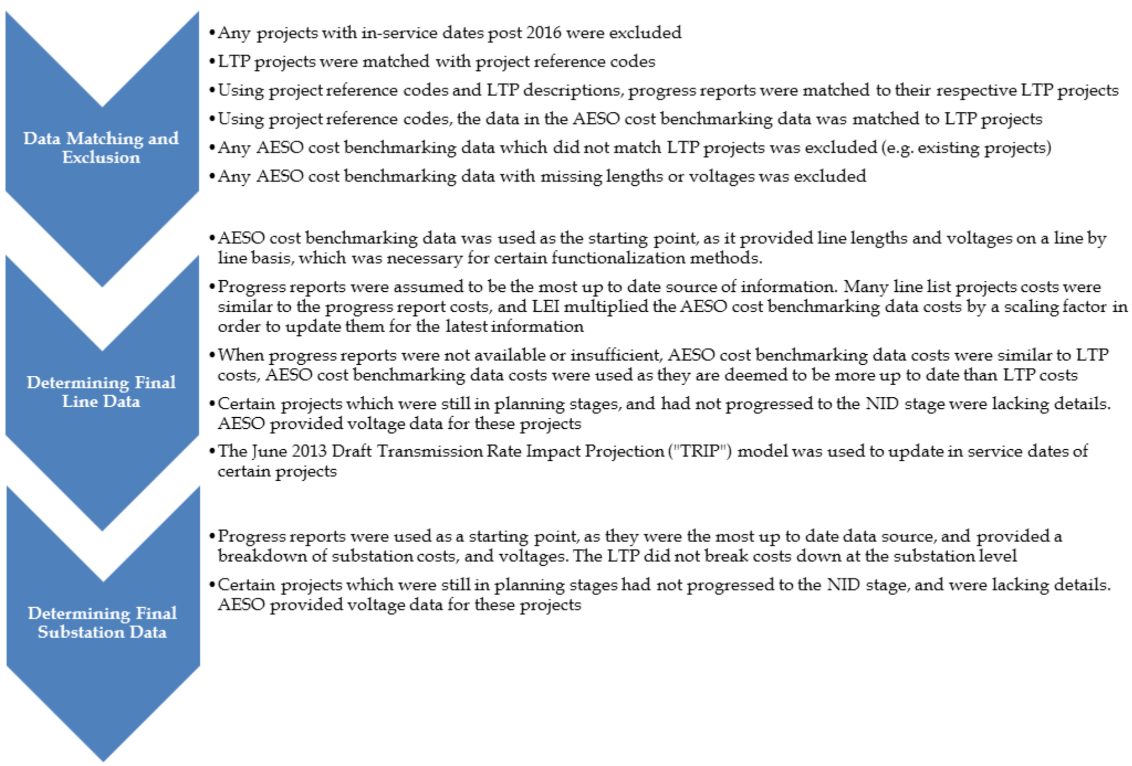
data was updated to match the progress report values. The progress reports were particularly useful in determining future substation costs.

In addition to the LTP, the AESO cost benchmarking data file and progress reports, LEI identified missing data to the AESO, and information for specific projects was provided and taken into account. This included about $2 billion of projects which are still in the planning stage and have not progressed to the point where further details are available. Specifically, $1 billion of these costs can be attributed to the South Area Transmission Reinforcement ("SATR"), which is a staged project meaning some stages are contingent on reaching particular milestones – therefore, detailed cost data is not available.[40] AESO planners provided voltage information for these projects, and they have been directly functionalized.

8.1.3.2 Process to refine future data

The process that LEI utilized to refine the required data from the given data sources is described in Figure 27.

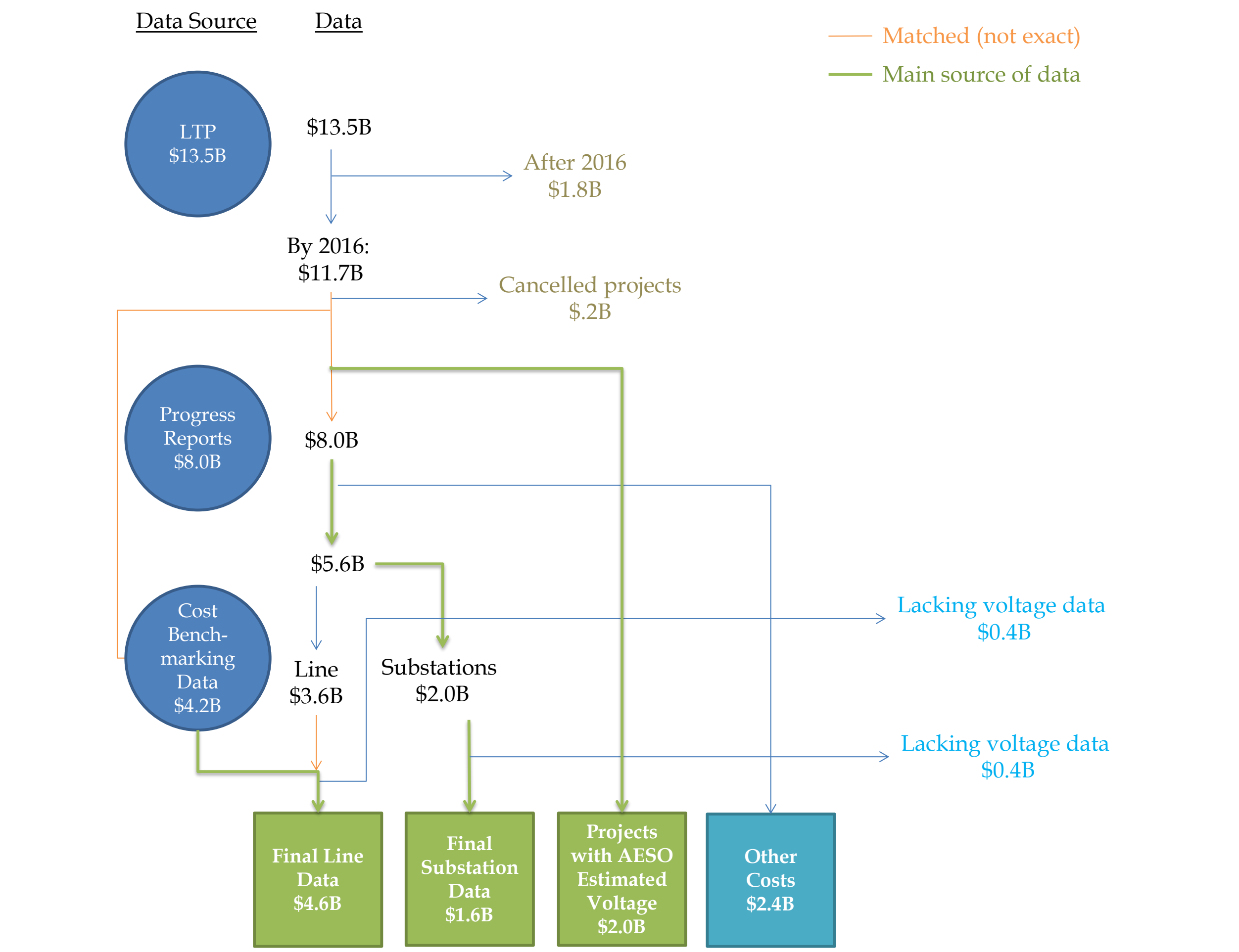
Figure 27. Utilization and refinement of data



[40] Other projects that have not progressed sufficiently in order to have detailed costs are: Thickwood, North Calgary Stage 1, Distribution Customer Connections ("DCC") for Central, DCC for Edmonton, DCC for Northeast, DCC for Northwest, Heartland 240 kV Loop, South Alberta 69 kV Conversion, North Edmonton, Big Rock, Athabasca Telecommunications Upgrade, Northeast Reactive Power Reinforcement, Fort Saskatchewan, Hotchkiss Reactor Banks Addition, and 9L66 240kV Line Relocation (Project 943).

A summary of the available data from each data source is found in Figure 28.[41] The data sources are shown on the left, and through the process explained above, data was matched and organized into data that is usable.

Figure 28. Forward looking data-processing summary (non-depreciated costs)[42]



Note: For projects that come into service after 2016 as per the 2012 LTP (approximately $1.8 billion), no construction work in progress ("CWIP") costs are in the revenue requirement in and before 2016. Source: AESO. *Draft Transmission Rate Impact Projection Model*

[41] Information without cost data cannot be quantified and has not been included. For lines, there is approximately $100 million of lines which contain voltage information, but no length information. These lines were functionalized by voltage across all three methods.

[42] For large projects/sub-projects with a construction duration of more than one year and that come into service between 2013 and 2016 (Hanna, Foothills, SATR, East/West HVDC), we account for allowance for funds used during construction ("AFUDC") by applying AFUDC assumptions in the AESO Draft Transmission Rate Impact Projection Model.

Note, although "Other costs" and data with missing details do not have enough information to be functionalized by the various methods, their values are taken into account when calculating the weighted final functionalization results. This data is represented using turquoise boxes and text in Figure 28.

"Other Costs" are comprised of distributed costs,[43] owners' costs,[44] allowance for funds used during construction ("AFUDC"), salvage,[45] and engineering & supervision costs. Typically, distributed costs make up a large proportion of other costs. These costs do not obviously fit into a specific functional group or asset class. They have been functionalized based on overall planned project functionalization results, which is a good approximation of individual project functionalization.

LEI believes that the data set produced by matching data between the three data sources and updating to the latest information represents a reasonable best effort, given challenges with data availability. In total, net book value of future lines and substations that are analyzed using detailed, direct, and proportional functionalization equals $11.4 billion (non-depreciated).

8.2 Functionalization by intention, current use and future use

In choosing a sensible approach for functionalizing costs, it is important to consider if cost causation should reflect original identified need, current use of facilities, or future need for facilities. LEI believes that original identified need is not appropriate for indefinite use, as the transmission system is dynamic and evolving over time. For example, before 138 kV and 240 kV lines were constructed in the mid-1900s,[46] Alberta's 69 kV would have been considered a bulk system, but in today's system, they clearly do not serve a bulk function. Originally identified need may therefore not be an appropriate way to consider cost causation. LEI is of the opinion that the current use of facilities is the most appropriate way to consider cost causation. All methods of functionalization and classification applied in this section are considered to reflect current use by LEI.[47] Furthermore, future cost causation studies will reflect future use of facilities, allowing for periodic adjustment and addressing intergenerational equity issues.

---

[43] Procurement, project management, construction management and contingency costs distributed over the whole project

[44] Costs related to Proposal to Provide Services, Facility Application, land rights, easement costs, land damage claims costs and land acquisition costs

[45] Cost to remove/salvage and remediate

[46] The first 240 KV line was built in the 1950s: http://www.altalink.ca/about/history.cfm

[47] The voltage approach is consistent with current use at it does not functionalize certain 69 kV lines as bulk going forward, though these lines may have initially been built to serve bulk system. MW-km approach uses current line loading and the economics approach uses current economics of transmission system as inputs.

8.3 Functionalization

8.3.1 Option 1: defined by voltage level

Functionalization by voltage uses voltage levels of lines and substations to categorize costs. For lines, firstly radial lines serving a single point of delivery are considered POD, and radial lines serving a generator are POS, and considered bulk. Then, all lines with voltages 240 kV and higher are functionalized as bulk, which is mostly made up of 240 kV and 500 kV lines.[48] Finally, 138/144 kV and 69/72 kV lines are considered regional. This method of functionalization by voltage was applied to both existing assets and future lines.

Although substations operate at both a high and low voltage level, for the purposes of functionalization by voltage, LEI functionalized whole substations based on secondary voltages, where data was available. Substations with a secondary voltage of 240 kV or higher are considered bulk, a secondary voltage of 138/144 kV or 69 kV is considered regional, and 25 kV or lower is considered POD. LEI functionalized all future substations in this manner.

Existing substations are also functionalized using the AESO POD database, which identifies the contracted capacity for Demand Transmission Service ("DTS") and Supply Transmission Service ("STS"). Substations with only DTS contracts are functionalized as POD, while substations with only STS contracts are considered point-of-supply ("POS") and thus functionalized as bulk. Finally, substations with both DTS and STS contracts are allocated to POD and bulk, respectively, allocated by their contract capacity.[49]

Although the voltage approach does not differentiate between functions within a voltage level, LEI believes that the distortions are few during the rate term (2014-2016), and that this definition will be durable in the long term. An example would be if the 500 kV system were expanded to the point of replacing the function of the 240 kV system. Even in this situation, there will still be a place for 240 kV bulk power lines to fulfill lower capacity and shorter distance requirements at a lower cost compared to 500 kV lines. LEI estimates such an evolution would occur over a period of more than fifteen years, and would thus be captured in subsequent studies.

The results below show functionalization by voltage for existing assets, future assets, and the NBV-weighted overall functionalization results. Note that ENMAX and EPCOR are directly functionalized as described earlier in Section 8.1.2.

---

[48] 240 kV lines have different capacities and lengths but need not be differentiated when functionalizing by voltage. It is likely that both single-circuit and double-circuit 240 kV lines will be serving the bulk system, i.e., typically carrying at least four times the amounts of electricity than 138 kV lines.

[49] The allocation ratio is known as the substation fraction. The formula for calculating a POD SF would be: (sum of all DTS contracts) / (sum of all DTS contracts + Sum of all STS contracts). There were no AltaLink or ATCO substations with a substation fraction of 0%, which indicates only generation is connected. However, there were 14 AltaLink or ATCO substations with substation fractions of less than 1%.

Figure 29. Existing asset functionalization results by voltage, as of December 2016

TFO	Bulk System	Regional System	POD
AltaLink	28.0%	34.0%	38.0%
Atco Electric	39.9%	25.9%	34.2%
ENMAX	0.0%	41.5%	58.5%
EPCOR	30.0%	20.4%	49.5%
All TFOs	29.7%	27.3%	43.0%

Figure 30. Future project functionalization results by voltage, as of December 2016

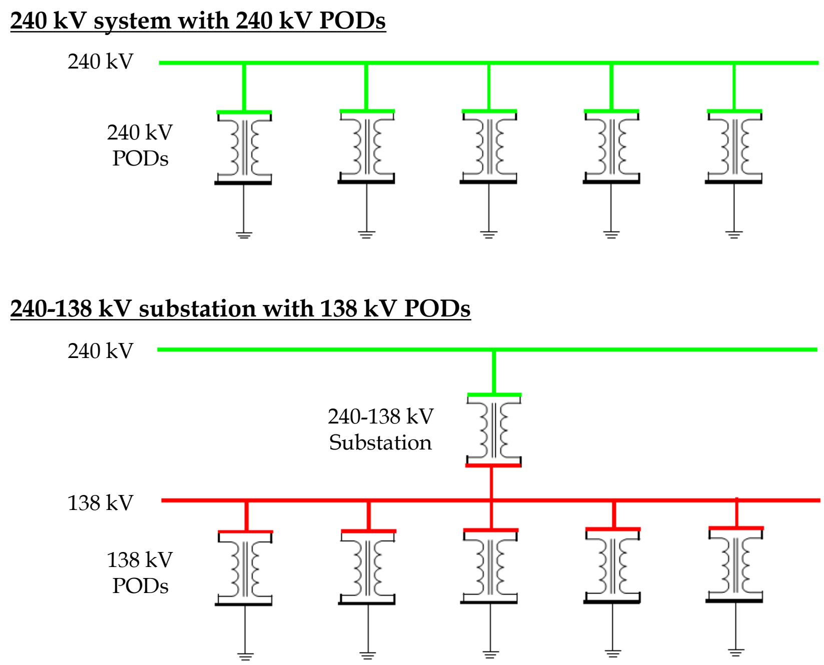
Method	Bulk System	Regional System	POD
Voltage	86.0%	12.6%	1.4%

Figure 31. Overall functionalization results by voltage, as of December 2016

Method	Bulk System	Regional System	POD
Voltage	66.7%	17.6%	15.7%

8.3.2 Option 2: defined by economics

Figure 32. Functionalization by economics illustration

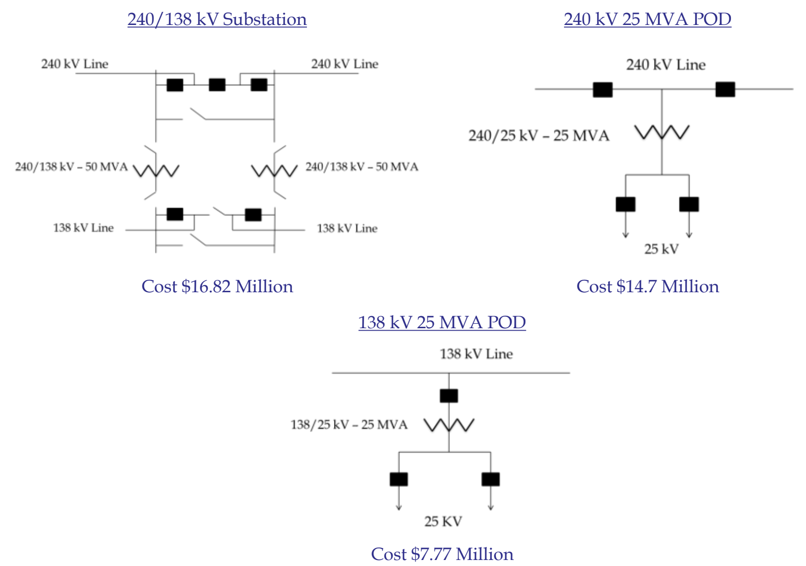


Functionalization by economics maintains some similarities to functionalization by voltage, in that radial lines serving load are still considered POD, radial lines serving generators are bulk, 500 kV lines are still considered bulk, and 69/72 kV lines are considered regional. Substations are also functionalized in the same way, with substations having a secondary voltage of 240 kV or higher considered bulk, a secondary voltage of 138/144 kV or 69 kV considered regional, and 25 kV or lower considered POD.[50] POS substations are considered bulk.

The method differs in how it functionalizes 138 kV and 240 kV lines, by considering the economics of building a high voltage line and high voltage PODs, as compared to the cost of building a step down transformer and lower voltage PODs. The point at which the economics are the same between the two options represents the breakpoint, which is measured in length of the line. Lines longer than the breakpoint are economic as a bulk line, and lines shorter than the breakpoint are more suited to regional systems.

The economic analysis was performed on a hypothetical 240 kV line with 240 kV PODs, compared against the cost of a 240-138 kV substation, 138 kV line and 138 kV PODs. The hypothetical lines are both 150 km long, which is the distance between Calgary and Red Deer, or Red Deer to Edmonton.

Figure 33. Typical 240 kV substation and POD design



Source: LEI analysis; AESO Unit Cost Guide 2011

LEI first worked with AESO planners to determine typical substation and POD design in Alberta (as seen in Figure 33), and consequently applied the costs of the AESO 2011 Unit Cost Guide to the designs.[51] Costs found in the 2011 Unit Cost Guide were then validated against

50 There was insufficient data to match individual substations to their respective secondary voltage lines, making it difficult to functionalize substations by the economics approach.

51 AESO. *2011 Unit Cost Estimates.* <www.aeso.ca/downloads/2011_Unit_Cost_Estimates.pdf>

AESO Benchmarking Database for Alberta Transmission Projects.[52] Using this data, the two options were compared for a range of PODs; as observed in Figure 34, for a low number of PODs, the 240 kV POD system is more economic. However, as more PODs are required, the 138 kV system becomes more economic, which is consistent with theory.

Figure 34. Functionalization by economics showing number of PODs – 240 kV

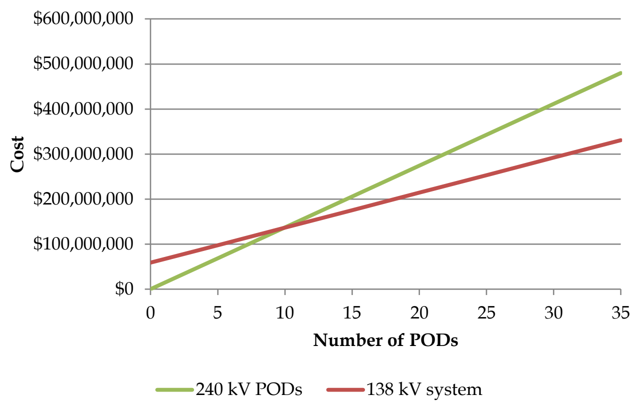
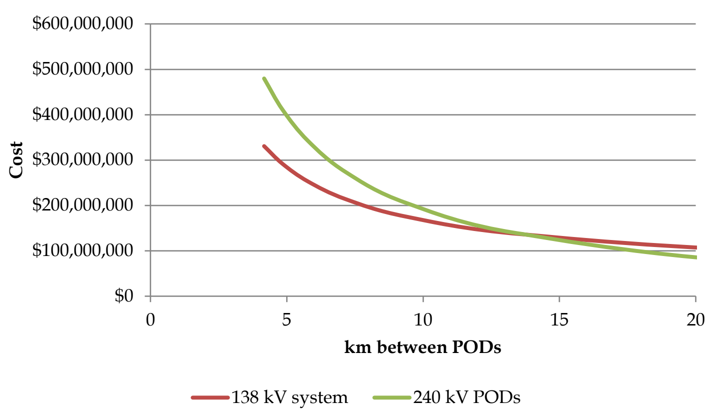


Figure 35. Functionalization by economics showing distance between PODs – 240 kV



Another method of considering this is by assuming the PODs are equal distance from one another, and plotting the same data against distance between PODs, as seen in Figure 35. Considering Figure 35, the point at which the systems are the same cost, or the breakpoint, is at 13.8 km. In this system, 240 kV lines are economic when they are longer than 13.8 km, and thus, should be treated as bulk; 240 kV lines shorter than 13.8 km are actually more economic as 138 kV systems, and therefore should be considered regional.

[52] AESO. *Reasonableness Assessment of Transmission Cost Using Benchmarking Methodology*. March 28, 2013. <www.aeso.ca/downloads/Reasonableness_Assessment_of_Transmission_Cost_Using_Benchmarking_Methodology.pdf>

Similarly, for a 138 kV line, the same breakpoint and analysis applies. 138 kV lines are economic when they are shorter than 13.8 km, and thus, should be treated as regional; 138 kV lines longer than 13.8 km are actually more economic as 240 kV systems, and therefore should be considered bulk. The economics approach uses this theoretical breakpoint of 13.8 km to functionalize both 240 kV and 138 kV lines in Alberta as bulk or regional.

The figures below present results of functionalization by economics for existing assets, future assets, and for combined NBV-weighted existing and future assets.

Figure 36. Existing asset functionalization results by economics, as of December 2016

TFO	Bulk System	Regional System	POD
AltaLink	36.1%	25.9%	38.0%
Atco Electric	55.9%	9.9%	34.2%
ENMAX	0.0%	41.5%	58.5%
EPCOR	30.0%	20.4%	49.5%
All TFOs	39.5%	17.5%	43.0%

Figure 37. Future asset functionalization results by economics, as of December 2016

Method	Bulk System	Regional System	POD
Economics	87.9%	10.8%	1.4%

Figure 38. Overall functionalization results by economics, as of December 2016

Method	Bulk System	Regional System	POD
Economics	71.3%	13.0%	15.7%

8.3.3 Option 3: defined by MW-km

Functionalization by MW-km is based on the definition that bulk lines carry large amounts of power over long distances. Therefore, lines with high MW-km ratings are considered bulk, while lines with lower MW-km ratings are considered regional.

In order to perform this analysis, line lengths were obtained from the data sources described in Section 8.1. Forecasted line loadings were also required, and LEI utilized the AESO 2013 Planning Base Case Suite, specifically using the 2015 winter peak case.[53] The 2015 case was chosen in the absence of a 2016 case, as it lies within the rate period of 2014-2016, and would thus be representative of system conditions during that time. The winter peak case was chosen, because in peak conditions, the system would be heavily loaded, which would emphasize the function of transmission components.

The MW-km method analyzes the MW-km ratings of lines for each voltage, and determines what percentage of lines are bulk versus regional. The percentage is determined based on what

[53] AESO. *2013 Planning Base Case Suite*. January 24, 2013. http://www.aeso.ca/transmission/261.html

percentages of lines (by line length) are higher or lower than a breakpoint, which differentiates the bulk system and regional system; lines with a higher MW-km rating than the breakpoint are functionalized as bulk and lines which are lower are functionalized as regional.

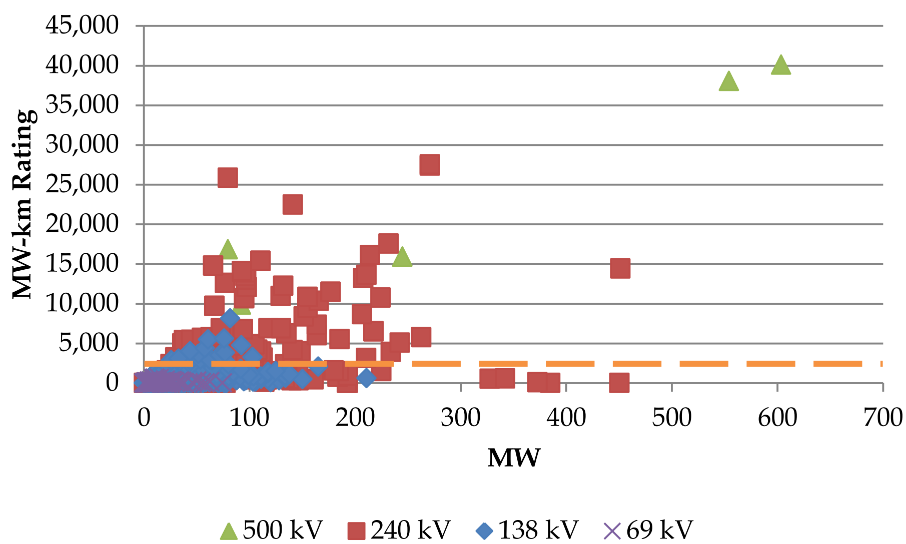
One of the challenges with the MW-km approach is setting an appropriate breakpoint. In the voltage approach, 240 kV lines are considered to be bulk, while 138 kV lines are considered to be regional. As seen in Figure 39, the average MW-km of 138 kV lines is 466 MW-km, while the average of 240 kV lines is 3,662 MW-km; the breakpoint was chosen to be the midpoint of the two, at 2,000 MW-km.

Figure 39. Ranges of MW-km ratings of different voltages

Voltage	MW-km Rating		
	Min	Average	Max
69 kV	0.3	87.2	1,614.0
138 kV	0.1	466.2	8,150.0
240 kV	4.4	3,661.5	27,570.8
500 kV	2,484.4	9,970.4	40,138.8

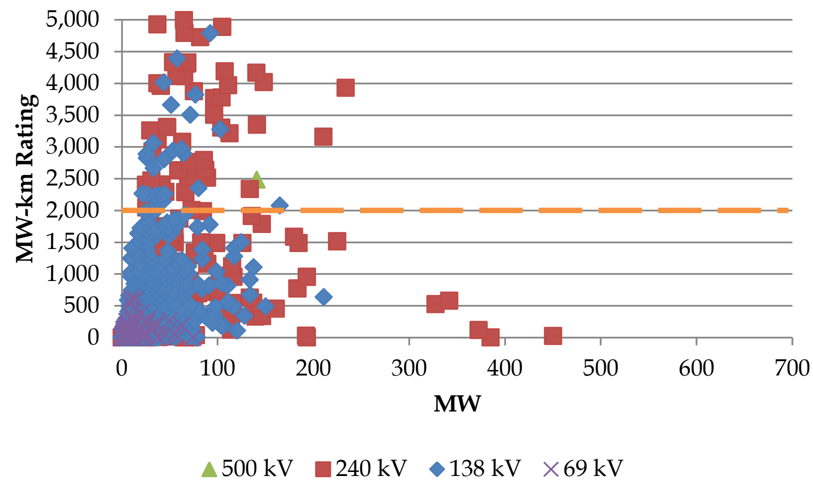
Note: Minimum ratings exclude lines < 1km in length

Figure 40. Scatterplot of MW-km ratings



This breakpoint was validated by ensuring it is higher than the maximum 69 kV MW-km rating observed (1,614 MW-km), which ensures no 69 kV lines will be functionalized as bulk. Furthermore, it was validated as being lower than the minimum 500 kV line rating observed (2,484 MW-km), which ensures no 500 kV lines will be functionalized as regional.

Figure 41. Scatterplot of MW-km ratings (expanded 0 to 5,000 MW-km)



Functionalizing substations occurs by voltage, with substations having a secondary voltage of 240 kV or higher considered bulk, a secondary voltage of 138/144 kV or 69 kV considered regional, and 25 kV or lower considered POD.[54] POS substations are considered bulk.

The figures below show the results of functionalization by MW-km for existing assets, future assets, and for combined NBV-weighted existing and future assets.

Figure 42. Existing asset functionalization results by MW-km, as of December 2016

TFO	Bulk System	Regional System	POD
AltaLink	27.3%	34.7%	38.0%
Atco Electric	35.5%	30.3%	34.2%
ENMAX	0.0%	41.5%	58.5%
EPCOR	30.0%	20.4%	49.5%
All TFOs	27.6%	29.4%	43.0%

Figure 43. Future project functionalization results by MW-km, as of December 2016

Method	Bulk System	Regional System	POD
MW-km	80.5%	18.1%	1.4%

Figure 44. Overall functionalization results by MW-km, as of December 2016

Method	Bulk System	Regional System	POD
MW-km	62.5%	21.8%	15.7%

[54] There was insufficient data to match individual substations to their respective secondary voltage lines, making it difficult to functionalize substations by the MW-km approach.

8.3.4 Summary of capital cost functionalization results

The following figures summarize results of capital cost functionalization by the three methods for existing assets, future/planned assets and combined (existing and future assets) respectively.

Figure 45. Summary of existing assets functionalization results, as of December 2016

Method	Bulk System	Regional System	POD
Voltage	$ 1,552,206,569	$ 1,425,643,547	$ 2,243,050,758
Economics	$ 2,063,639,815	$ 914,210,301	$ 2,243,050,758
MW-km	$ 1,442,430,045	$ 1,535,420,070	$ 2,243,050,758

Method	Bulk System	Regional System	POD
Voltage	29.7%	27.3%	43.0%
Economics	39.5%	17.5%	43.0%
MW-km	27.6%	29.4%	43.0%

Figure 46. Summary of future project functionalization results, as of December 2016

Method	Bulk System	Regional System	POD
Voltage	$ 8,622,387,317	$ 1,251,182,028	$ 153,553,297
Economics	$ 8,803,112,673	$ 1,070,456,672	$ 153,553,297
MW-km	$ 8,080,071,772	$ 1,793,497,572	$ 153,553,297

Method	Bulk System	Regional System	POD
Voltage	86.0%	12.6%	1.4%
Economics	87.9%	10.8%	1.4%
MW-km	80.5%	18.1%	1.4%

Figure 47. Summary of capital cost functionalization results, as of December 2016

Method	Bulk System	Regional System	POD
Voltage	$ 10,174,593,886	$ 2,676,825,574	$ 2,396,604,055
Economics	$ 10,866,752,488	$ 1,984,666,972	$ 2,396,604,055
MW-km	$ 9,522,501,818	$ 3,328,917,643	$ 2,396,604,055

Method	Bulk System	Regional System	POD
Voltage	66.7%	17.6%	15.7%
Economics	71.3%	13.0%	15.7%
MW-km	62.5%	21.8%	15.7%
Average	66.8%	17.5%	15.7%

8.3.5 Recommendation for capital cost functionalization

LEI has considered all three approaches, and suggests using the results of the voltage approach in this study and going forward, given the strengths and weaknesses identified below and summarized earlier in Section 6.1. The average of the three approaches provide very similar results, but significant reliance on assumptions in the MW-km and economics approach, in LEI's view, may not be defensible.

The voltage approach is the simplest to understand and implement, and therefore best satisfies the rate design principle of practicality, which states that "rates are appropriately simple, convenient, [and] understandable." LEI believes that a functionalization method which is easily comprehensible contributes to transparency within the rate design process. Furthermore, the voltage approach requires less data than the other methods, which allowed more costs to be included in the analysis. The simplicity of the voltage approach explains why elements of voltage are used to functionalize transmission systems in other jurisdictions, such as Ontario, California, and Australia.

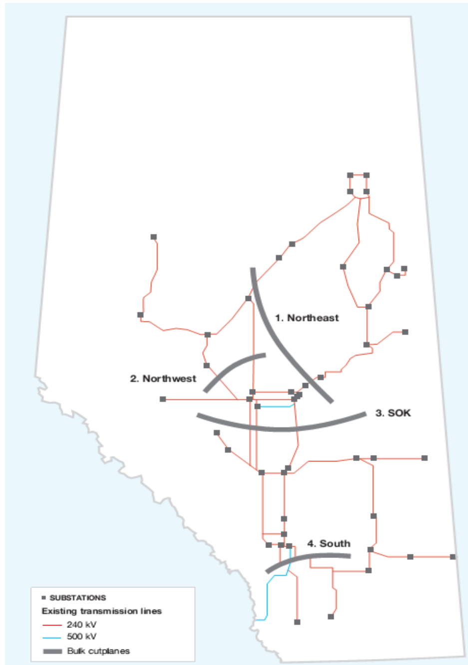
The MW-km approach depends considerably on assumptions and subjective decisions. The primary weakness is that the MW-km breakpoint, which has a significant impact on results, could not be validated in a rigorous way with the data provided. The MW-km approach is also dependent on the output and accuracy of the AESO Base Case forecast. Furthermore, the Base Case only represents single points in time, and the winter peak was chosen because the system would be heavily loaded. However, not all regions and system assets reach peak usage at the same time, and the winter peak cannot be assumed to represent the peak usage of all parts of the system. Finally, the Base Case was only available for 2015, so one year's MW flows were used to determine results for all years, despite the fact flows may differ from year to year.

The economics approach also depends considerably on assumptions and subjective decisions. Specifically, LEI is doubtful that costs of current projects can be applied to older transmission projects, as economics of the transmission system can change over time. As well, setting the length of the theoretical line, which was set to 150 km, is a subjective process and can significantly change results. The dependence on subjective decisions implies that the MW-km and economics approaches do not fully satisfy the rate design principle of "fairness, objectivity and equity that avoids undue discrimination." The voltage approach, due to its transparency, avoids these subjective decisions.

Finally, LEI acknowledges that the voltage approach may be less sensitive to evolving functions of system. The MW-km approach could theoretically be more sensitive, however, similar results achieved using functionalization by voltage indicates that the results are reasonable. The two methods are in fact similar: 240 kV lines are considered bulk by voltage, while 81% are bulk by MW-km; 138 kV lines are considered regional by voltage, while 86% are regional by MW-km. In fact, the average of all three methods, as seen in Figure 47 is very similar to the results of the voltage approach. Due to the weaknesses of the other approaches discussed above, LEI believes the voltage approach satisfies rate design principles the best.

As a method of comparing the functionalization approaches, LEI also determined Clearly Identified Bulk Projects ("CIBP"), which are defined as LTP projects which cross LTP bulk cut-planes. Assuming that all lines built within each clearly identified bulk project are bulk, it is possible to compare the functionalization of the voltage and economics methods.

Figure 48. LTP cut-planes and clearly identified bulk projects



Project Name	LTP Value (2011 $ millions)	Cutplane Crossed
East/West HVDC	2,951	SOK Cutplane
West Fort McMurray 500 kV Stage 1a	1,649	Northeast Cutplane
Foothills (FATD)	711	South Cutplane
Heartland 500 kV	537	Northeast Cutplane
Bickerdike to Little Smoky	205	Northwest Cutplane

Source: AESO. AESO Long-term Transmission Plan. Filed June 2012.

As an example, within the Foothills project, which is a bulk project, a 240 kV line was built to connect Janet 74S to ENMAX No. 25. The voltage approach classified this line as bulk, whereas the economics method classified this line as regional. On aggregate, the available line data showed that the voltage approach functionalized 2% of CIBP as regional, while the economics approach functionalized 4% of CIBP as regional. This comparison highlights the limitations for utilizing functionalization by economics. Data that would allow LEI to determine performance of the MW-km approach in functionalizing CIBP was not available.[55]

[55] The MW-km approach utilizes the 2015 AESO Base Case, which identifies lines by bus, but does not indicate the LTP project to which each line belongs.

LEI's suggested functionalization proportions are presented in Figure 50, while the AEUB-approved functionalization in AESO 2007 GTA is shown in Figure 49. The comparison shows a significantly higher proportion functionalized as bulk under LEI recommended approach, which is consistent with expectations, given the amount of bulk projects in the 2012 LTP.

Figure 49. Functionalization in AESO 2007 GTA

Functionalization - 2007 GTA	
Bulk	41.7%
Regional	17.4%
POD	40.9%

Figure 50. LEI suggested capital cost functionalization

Capital cost functionalization (by value)	2014	2015	2016
Bulk	$ 6,681,289,875	$ 9,684,685,012	$ 10,174,593,886
Regional	$ 2,214,899,613	$ 2,561,372,083	$ 2,676,825,574
POD	$ 2,123,557,889	$ 2,261,395,958	$ 2,396,604,055

Capital cost functionalization	2014	2015	2016
Bulk	60.6%	66.8%	66.7%
Regional	20.1%	17.7%	17.6%
POD	19.3%	15.6%	15.7%

9 Functionalization of O&M costs

9.1 TFO cost information

The information utilized for functionalization of O&M costs was obtained from the TFO General Tariff Applications ("GTA"s) and other TFO filings with the AUC. Information was collected from the four largest TFOs including ATCO, AltaLink, ENMAX and EPCOR. In addition to requesting specific data from the TFOs, the following sources (provided by the AESO) were used for obtaining information:

- ATCO Electric: GTA 2013-2014
- AltaLink: GTA 2013-2014 Schedules
- ENMAX Power: Transmission AUC Rule 005 report: Annual Operations Financial and Operating reporting for the year ended December 31st, 2011
- EPCOR: 2012 Phase I DTA & TFO TA Refiling

TFOs revenue requirement information was compiled for the years 2010 through 2014 where available,[56] and LEI had access to data from 2006 through to 2009 from the previous PSTI O&M study performed in 2009.[57] TFO revenue requirements are presented in Figure 51.

Figure 51. TFO revenue requirement, 2006-2014

Revenue Requirement ($)	2006	2007	2008	2009	2010	2011	2012	2013	2014
AltaLink	189,319,502	202,767,328	214,445,660	246,511,157	283,515,889	351,752,644	410,861,853	525,390,710	683,546,041
ATCO Electric	167,852,071	168,207,126	178,600,826	206,959,891	244,278,000	313,295,000	406,672,300	544,007,448	680,342,105
ENMAX	30,901,470	31,867,568	32,248,072	36,253,000	37,924,000	40,574,000	N.A.	N.A.	N.A.
EPCOR	41,099,490	35,231,806	45,045,806	52,843,915	55,136,688	58,660,364	65,447,452	N.A.	N.A.

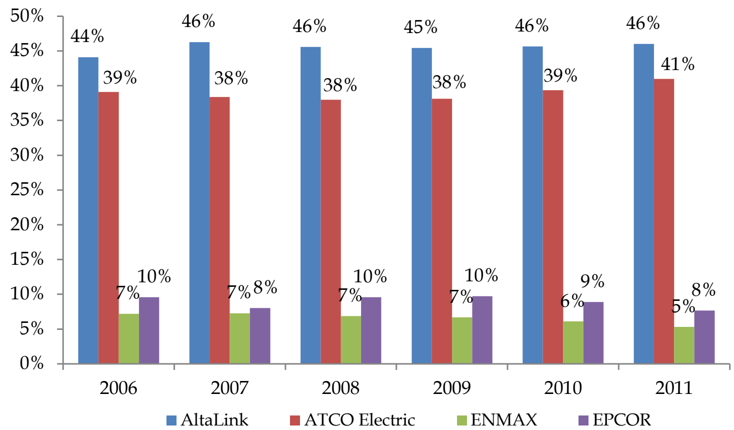
Source: TFO GTA and other filings with AUC; Other TFO-provided data

It is notable that 80-85% of combined transmission revenue requirement is attributable to ATCO and AltaLink over the period 2006-2011, as presented in Figure 52.

[56] ATCO Electric and AltaLink have projected costs up until 2014; EPCOR has projections until 2012; ENMAX costs (up until 2011) have been derived from their annual finance and operations reports filed under AUC Rule 005. ENMAX has been under a formula-based rate regime since 2007, and has accordingly not filed cost-based tariff applications.

[57] The PSTI O&M study did not include 2009 data for ENMAX Power, which LEI obtained from previous transmission Rule 005 reports filed by ENMAX Power.

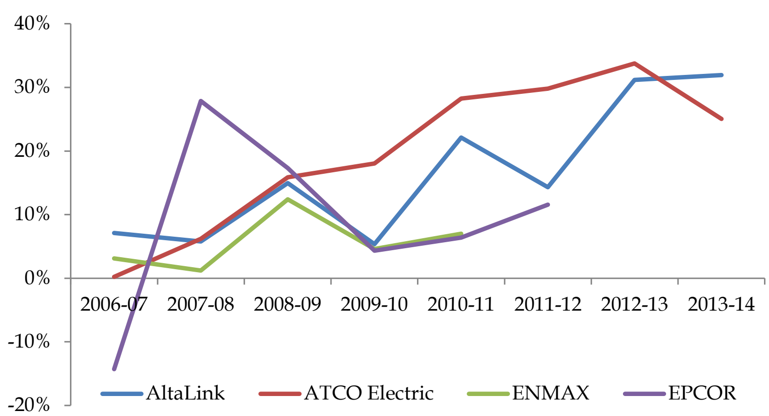
Figure 52. Individual TFO share (%) in combined revenue requirement



Source: TFO GTA and other filings with AUC.

LEI considered projecting the revenue requirement for ENMAX and EPCOR up to 2014 by observing their cost growth patterns relative to ATCO and AltaLink historically, and extrapolating for the future. However, as presented in Figure 53, there are no clear linkages between their respective revenue requirement growth rates, and any such forecasts would be highly assumptions-driven.

Figure 53. Historical and projected growth patterns of TFO revenue requirements



Source: TFO GTA and other filings with AUC.

LEI also reviewed cost information in project progress reports received from AESO to observe the project cost split between the four TFOs; over 95%[58] of costs are attributable to projects owned by ATCO and AltaLink.

---

[58] Out of approximately $8 billion worth of projects, almost $7.6 billion are owned by AltaLink and ATCO Electric.

Given the small share of ENMAX and EPCOR in existing and future projected costs, LEI believes that assumptions-driven revenue requirement forecasts may be unnecessary, as they will have an immaterial impact on functionalization results.

9.2 Breakdown of revenue requirement

After obtaining revenue requirement information, the first step performed was to identify costs that are capital-related and non-capital related.

Capital costs include depreciation, return and income tax associated with TFO assets, annual structure payments, linear and property taxes, and capital-related revenue offsets.

Non-capital costs include O&M costs directly associated with the electric transmission system such as labor costs, G&A costs associated with the operation the overall business of the TFOs, fuel and variable O&M costs associated with isolated generation serving remote communities[59] and affiliate revenue offsets, i.e., revenues that offset labor costs.

Figure 54 and Figure 55 present the breakdown of non-capitalized costs by TFOs, and as a percentage of total revenue requirements for the four TFOs. Since 2009, although the actual amount of non-capital costs has been increasing, the percentage of non-capital costs has been gradually declining steadily (particularly for the two largest TFOs, ATCO and AltaLink), reducing projected overall share of non-capital costs to 16.01% by 2014.[60,61]

Figure 54. TFO non-capital costs ($)

Non Capital Costs	2006	2007	2008	2009	2010	2011	2012	2013	2014
AltaLink	47,672,495	48,124,444	51,354,438	63,230,001	80,346,474	84,551,219	100,207,059	107,336,440	118,860,960
ATCO Electric	44,349,900	47,200,000	53,800,000	62,000,000	61,962,863	72,583,190	85,167,268	91,799,633	99,502,033
ENMAX	15,757,662	17,859,224	17,710,624	20,309,000	20,881,000	23,234,000	N.A.	N.A.	N.A.
EPCOR	11,806,397	13,233,813	14,127,220	14,723,524	18,073,084	19,055,546	20,094,570	N.A.	N.A.
Sum of Four TFO	119,586,453	126,417,481	136,992,282	160,262,525	181,263,421	199,423,955	205,468,898	199,136,073	218,362,993

Source: TFO GTA and other filings with AUC

---

[59] ATCO Electric is the only TFO that reports fuel costs. The underlying rationale is as follows: instead of building transmission facilities (i.e. extending the regional and POD system) to serve certain remote areas, it is more economical to operate isolated generation facilities to serve these areas.

[60] A slight increase in non-capital cost proportions has been observed for ENMAX and EPCOR between 2009 and 2011-2012. However, because their overall costs are a minor portion of combined TFO costs, a consistent decline in the non-capital cost share of the combined revenue requirement can be observed.

[61] The extent of reduction in the share of non-capital costs to 16.01% is not a significant deviation from the fall in share projected by AESO in 2010. "*In response to AUC-AESO-21(d) … AESO prepared an estimate of the relative weighting of capital and non-capital (O&M plus G&A) costs in 2014. The estimate suggests non-capital costs as a percentage of total costs could decrease to half the present level [2010] by 2014 [at 13.8%].*" Source: AESO. *Previous Submissions on Transmission Operating and Maintenance Cost Study Filed as Part of AESO 2010 ISO Tariff Application*. Page 4.

Figure 55. TFO non-capital costs as a % of revenue requirement

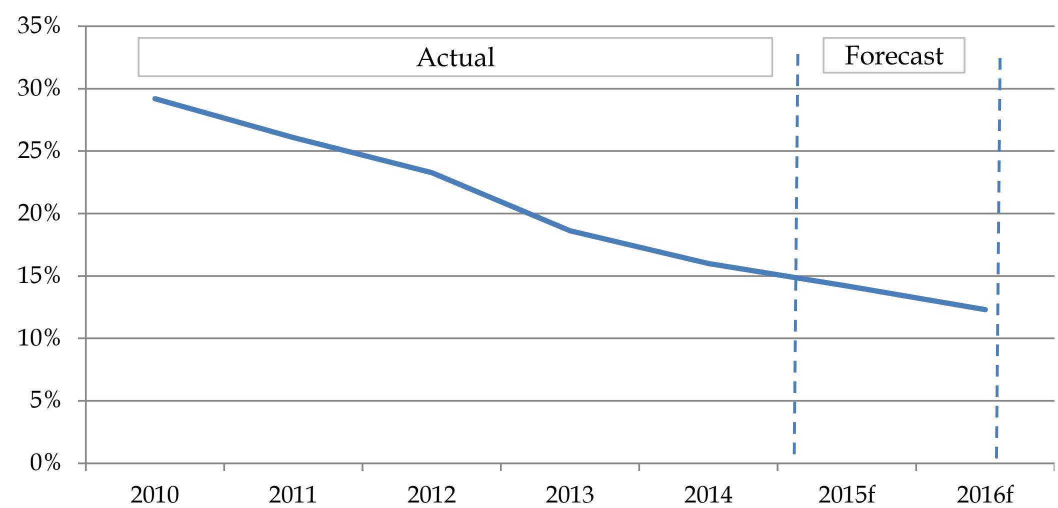
Non Capital Costs/Rev Req	2006	2007	2008	2009	2010	2011	2012	2013	2014
AltaLink	25.2%	23.7%	23.9%	25.6%	28.3%	24.0%	24.4%	20.4%	17.4%
ATCO Electric	26.4%	28.1%	30.1%	30.0%	25.4%	23.2%	20.9%	16.9%	14.6%
ENMAX	51.0%	56.0%	54.9%	56.0%	55.1%	57.3%	N.A	N.A	N.A
EPCOR	28.7%	37.6%	31.4%	27.9%	32.8%	32.5%	30.7%	N.A	N.A
Combined for TFOs	27.9%	28.9%	29.1%	29.5%	29.2%	26.1%	23.3%	18.62%	16.01%

Source: TFO GTA and other filings with AUC

Given the significant capital investment plan in the LTP and a high proportion of investment related to ATCO and AltaLink, it can be reasonably argued that this trend will continue and the non-capital cost share would further decline by 2016. However, if O&M costs associated with existing older transmission facilities increase over this period, they may have an offsetting effect, although potentially insignificant.

In order to estimate the non-capital cost share for 2015, first the year-on-year changes in the non-capital cost ratio for the period 2010-2014 were averaged. The 5-yr average change was applied to the 2014 non-capital cost share to arrive at 14.2% for 2015. Similarly, the 5-yr average for 2011-2015 is applied to 2015 non-capital cost ratio, and the resulting 2016 non-capital cost share is estimated to decline to 12.3% in 2016, as presented in the figure below.

Figure 56. TFO non-capital cost share - trend and projection



Source: TFO GTA and other filings with AUC

9.3 O&M functionalization

Similar to capital cost functionalization, O&M costs have been functionalized into three functional categories: bulk system, regional system and POD. Where useful, O&M cost functionalization utilizes lines and substations capital cost information split between bulk, regional and POD functions (results of capital cost functionalization amounts by the voltage method). Such costs have been used to set allocators for related O&M costs, as discussed further below.

It should be noted that not all non-capital costs have been functionalized. G&A costs, which are not directly associated with the operations of electric transmission system, but assist in overall operation of the business, such as expenses associated with the maintenance of the corporate head office, have not been functionalized. Instead O&M functionalization results have been applied to these costs. A portion of G&A costs are allocated to capital projects as part of the distributed costs discussed in Section 8.1.3.2. The remaining G&A costs are related to non-capital activities and are wholly considered O&M. Given that the G&A costs utilized via tariff filings are not all G&A costs but rather the allocated share of G&A costs to O&M expenses, this approach is reasonable.

With regards to functionalization of other non-capital costs (other than G&A costs), the following approach has been taken. Fuel costs and variable O&M costs associated with isolated generation have been functionalized as regional or POD because any transmission system otherwise being built to serve these small remote areas would likely be regional or POD.[62] The allocation between regional and POD is based on results of overall capital cost functionalization ratio of regional to POD. LEI understands that interveners in the previous study had questioned including isolated generation costs in the cost causation study. LEI believes that this is appropriate and consistent with AESO's response argument that "*the inclusion of isolated generation costs in ATCO Electric's TFO tariff is established by the Isolated Generating Units and Customer Choice Regulation. The AESO submits it is accordingly reasonable to treat isolated generation as wires costs, consistent with the treatment of all other TFO tariff costs*."[63]

Other O&M costs were allocated to functions on their individual basis of cost causation, where appropriate. For example:

- net salaries and wages have been allocated to various groups (such as control center operations, station equipment maintenance, overhead line expenses etc.) using proportion of full time equivalents ("FTE") in each group, where provided, and further allocated between bulk/regional/POD using allocators discussed below

---

[62] As part of the written arguments related to the previous study, AESO stated: "The Isolated Generating Units and Customer Choice Regulation shows that the largest generator is 3.3 MW (in Jasper) and the smallest is 0.024 MW (in Peace Point), with the average size being less than 1 MW. If the electric system were extended to serve one of these isolated communities, this magnitude of load would not cause an expansion of the 240 kV bulk system. It would more likely be served through an extension of the distribution system, a radial transmission line (functionalized as point of delivery), or an expansion of the local transmission system. Therefore, the fuel costs associated with isolated generation and recovered through the ISO tariff are appropriately functionalized as local system and POD." Source: AESO 2010 ISO Tariff Application (1605961 - ID 530): AESO Written Argument: September 14, 2010; Page 14.

[63] AESO 2010 ISO Tariff Application (1605961 - ID 530): AESO Written Argument: September 14, 2010; Page 14.

- costs associated with control centre operations and miscellaneous transmission expenses have been allocated based on combined line and substation costs split between bulk, regional and POD[64]

- vegetation management[65] expenses have been allocated based on a line brushing allocator, estimated using square kilometers of relevant vegetation management area split between bulk/regional/POD. The split is estimated by multiplying the line length by voltage within bulk/regional/POD by the width of the right of way for brushing

- substation expenses have been allocated based on substation cost split between bulk, regional and POD

- overhead line expenses have been allocated based on line costs, i.e., line costs split between bulk, regional and POD

LEI has information for AltaLink and ATCO (up until 2014), EPCOR (up until 2012) and ENMAX (until 2011) to functionalize their O&M costs for the respective years. The functionalization results for AltaLink and ATCO Electric are presented in Figure 57 and Figure 58.

Figure 57. AltaLink functionalization results (non-capital costs)

AltaLink ($)	2010	2011	2012	2013	2014
Bulk	14,951,501	15,753,221	17,150,610	18,971,921	20,743,092
Regional	16,076,836	17,069,925	18,759,659	20,781,095	22,713,870
POD	16,718,324	17,742,335	19,666,909	21,694,378	23,796,713
Total	47,746,661	50,565,481	55,577,179	61,447,394	67,253,675

AltaLink (%)	2010	2011	2012	2013	2014
Bulk	31.3%	31.2%	30.9%	30.9%	30.8%
Regional	33.7%	33.8%	33.8%	33.8%	33.8%
POD	35.0%	35.1%	35.4%	35.3%	35.4%
Total	100.0%	100.0%	100.0%	100.0%	100.0%

Source: TFO GTA and other filings with AUC

[64] For EPCOR, as line and substation cost information was not comprehensive, O&M cost allocators have been estimated based on length and number and of lines and number of substations split by voltage, instead of line and substation costs.

[65] As described in the PSTI O&M study, vegetation management occurs in various cycles from grass cutting twice per year around substations and telecommunications sites to every 10 years for base mowing. Vegetation management includes trimming, mowing, spraying and slashing and removal, and these activities are priced in terms of area cleared.

Figure 58. ATCO functionalization results (non-capital costs)[66]

ATCO Electric ($)	2010	2011	2012	2013	2014
Bulk	9,996,803	12,447,252	14,767,415	13,767,416	15,584,613
Regional	14,217,464	15,488,657	17,619,328	17,922,546	19,527,121
POD	15,938,656	17,559,443	20,269,314	20,453,324	22,310,083
Total	40,152,922	45,495,352	52,656,057	52,143,286	57,421,817

ATCO Electric (%)	2010	2011	2012	2013	2014
Bulk	24.9%	27.4%	28.0%	26.4%	27.1%
Regional	35.4%	34.0%	33.5%	34.4%	34.0%
POD	39.7%	38.6%	38.5%	39.2%	38.9%
Total	100.0%	100.0%	100.0%	100.0%	100.0%

Source: TFO GTA and other filings with AUC

Given the significant transmission investment in the current decade, an increase in functionalization of bulk costs can be observed for AltaLink and ATCO, as compared to previous O&M study performed by PSTI in 2009. However, functionalization results are consistent with AESO's following observation made in 2010: "*The bulk system function has less than average operating and maintenance costs in proportion to capital than the local system and point of delivery functions, which each have more than average operating and maintenance costs in proportion to capital. No participant has disputed this finding, and it would be inappropriate to ignore this when transmission costs will continue to include a substantial component of non-capital costs in the future.*"[67]

ENMAX and EPCOR information is available only until 2011 and 2012 respectively, and their functionalization results are presented in Figure 59 and Figure 60.

Figure 59. ENMAX functionalization results (non-capital costs)

ENMAX ($)	2010	2011
Bulk	0	0
Regional	5,423,642	6,153,662
POD	11,086,062	12,578,241
Total	16,509,704	18,731,903

ENMAX (%)	2010	2011
Bulk	0.0%	0.0%
Regional	32.9%	32.9%
POD	67.1%	67.1%
Total	100.0%	100.0%

[66] Note that the bulk proportion for O&M costs is generally lower for ATCO as compared to AltaLink, mainly due to fuel and O&M costs associated with isolated generation, which are functionalized only as regional and POD.

[67] AESO 2010 ISO Tariff Application (1605961 - ID 530): AESO Written Argument: September 14, 2010; Page 13.

Figure 60. EPCOR functionalization results (non-capital costs)

EPCOR ($)	2010	2011	2012
Bulk	1,914,714	1,944,752	2,267,611
Regional	3,557,175	3,663,731	4,179,567
POD	6,320,756	6,686,056	7,434,097
Total	11,792,645	12,294,540	13,881,275

EPCOR (%)	2010	2011	2012
Bulk	16.2%	15.8%	16.3%
Regional	30.2%	29.8%	30.1%
POD	53.6%	54.4%	53.6%
Total	100.0%	100.0%	100.0%

Figure 61 presents the functionalization results for combined TFOs for 2010-2014. Although this includes ENMAX and EPCOR information until 2011 and 2012 respectively, it is notable that the difference in results since 2012 is not material.

Figure 61. Combined functionalization results (non-capital costs)

Combined TFOs ($)	2010	2011	2012	2013	2014
Bulk	26,863,018	30,145,225	34,185,637	32,739,337	36,327,705
Regional	39,275,117	42,375,975	40,558,554	38,703,641	42,240,991
POD	50,063,798	54,566,075	47,370,320	42,147,702	46,106,796
Total	116,201,933	127,087,276	122,114,510	113,590,680	124,675,492

Combined TFOs (%)	2010	2011	2012	2013	2014
Bulk	23.1%	23.7%	28.0%	28.8%	29.1%
Regional	33.8%	33.3%	33.2%	34.1%	33.9%
POD	43.1%	42.9%	38.8%	37.1%	37.0%
Total	100.0%	100.0%	100.0%	100.0%	100.0%

Source: TFO GTA and other filings with AUC

As the current study is reviewing functionalization for 2014-2016, given 2015 and 2016 projections are not available, LEI has decided to use 2014 results for functionalization purposes. Despite significant bulk investment in 2014, the O&M functionalization ratios have not changed significantly in 2014 as compared to 2012-2013. Furthermore, given that there is no material change in future capital cost functionalization ratios between 2014 and 2016 (as presented earlier in Figure 2), LEI does not anticipate a material change in O&M functionalization ratios over the 2014-2016 period.

10 Combined O&M and capital cost functionalization

10.1 Final functionalization results

Capital cost and O&M cost functionalization results were combined using weights derived from TFOs non-capital to capital costs, estimated for 2014 to 2016 (as presented in figures below).

Figure 62. Ratio of TFOs non-capital to capital costs[68]

Non-Capital to Capital Costs	2014	2015	2016
Non-Capital	16.0%	14.2%	12.3%
Capital	84.0%	85.8%	87.7%

Figure 63. Combined O&M and capital cost functionalization (not accounting for RGUCC)

Capital cost functionalization	2014	2015	2016
Bulk	60.6%	66.8%	66.7%
Regional	20.1%	17.7%	17.6%
POD	19.3%	15.6%	15.7%

O&M cost functionalization	2014	2015	2016
Bulk	29.1%	29.1%	29.1%
Regional	33.9%	33.9%	33.9%
POD	37.0%	37.0%	37.0%

Combined cost functionalization	2014	2015	2016
Bulk	55.6%	61.4%	62.1%
Regional	22.3%	20.0%	19.6%
POD	22.1%	18.6%	18.3%

However, before applying these combined results to the wires revenue requirement in order to estimate the amounts needed to be recovered through the different components of the AESO's Rate DTS, one portion of wires costs recovered from generators needs to be accounted for. This is known as the Regulated Generating Unit Connection Cost ("RGUCC"), which is only available as an annual revenue amount and does not relate to specific property. RGUCC gradually declines over time until it expires in 2020. Since it arises from TFO-owned facilities providing system access to previously-regulated generators, annual revenue is deducted from

[68] We explored the sensitivity of non-capital to capital cost ratio on functionalization results (before accounting for RGUCC). For instance, by reducing the non-capital cost share by 1% (to 11.3%) in 2016, combined cost functionalization results for 2016 change to bulk 62.5% (vs. 62.1%), regional 19.4% (vs. 19.6%) and POD 18.1% (vs. 18.3%). Alternatively, by increasing the non-capital cost share by 1% (to 13.3%) in 2016, combined cost functionalization results for 2016 change to bulk 61.7% (vs. 62.1%), regional 19.7% (vs. 19.6%) and POD 18.5% (vs. 18.3%). Thus, a 1% change in non-capital cost share may result in functionalization ratios changing by approximately 0.1%-0.4%.

the bulk system annual revenue requirement. The RGUCC is $11.4 million, $9.6 million, and $7.9 million for 2014, 2015, and 2016 respectively.[69]

Figure 64 presents an example of how RGUCC has been taken into account for 2016 functionalization. Note that the amount functionalized to bulk system (after accounting for RGUCC) is slightly lower than the same amount before accounting for RGUCC. The ratio of the revised amounts presents the final combined O&M and capital cost functionalization (presented only for 2016 in Figure 64).

Figure 64. Accounting for RGUCC in combined O&M and capital cost functionalization - 2016 example

Revenue Requirement (nominal $ million) $1,992

Functionalization Results (before RGUCC, in $ millions)

Method	Bulk System	Regional System	POD
Voltage	$ 1,237.01	$ 389.68	$ 365.18

RGUCC (to deduct from bulk, in $ millions) $7.89

Functionalization Results (net of RGUCC, in $ millions)

Method	Bulk System	Regional System	POD
Voltage	$ 1,229.12	$ 389.68	$ 365.18

Final Functionalization (%)

Method	Bulk System	Regional System	POD
Voltage	62.0%	19.6%	18.4%

Figure 65 represents the final recommended functionalization, including both capital and O&M costs for 2014, 2015 and 2016.

Figure 65. Combined O&M and capital cost functionalization (net of RGUCC)

Combined cost functionalization (net of RGUCC)	2014	2015	2016
Bulk	55.2%	61.2%	62.0%
Regional	22.5%	20.1%	19.6%
POD	22.3%	18.7%	18.4%

10.2 Analysis of functionalization results

The combined functionalization results show a higher proportion functionalized as bulk, as compared to AEUB-approved functionalization in AESO 2007 GTA, presented in Figure 66. This is sensible given the significant amount of bulk and regional investment planned to come online in the 2012 LTP, as discussed in earlier sections.

[69] AESO. *TCE.AESO-004 (a-d) Revised*. February 14, 2007.

Figure 66. AESO 2007 GTA functionalization

Functionalization	
Bulk	41.7%
Regional	17.4%
POD	40.9%

The decline in POD functionalization since the 2007 GTA is due to this bulk and regional investment, and minimal POD investment, which can be observed in the figure below. Between 2007 and 2016, bulk system costs have increased just under $9.5 billion, regional system costs have increased by approximately $2.4 billion, while POD costs increased by around $1.8 billion.

Figure 67. Capital costs functionalized ($ millions)

Capital costs functionalized	2007 GTA	2014	2015	2016	Increase (2016 vs. 2007)
Bulk	678	6,681	9,685	10,175	9,497
Regional	233	2,215	2,561	2,677	2,444
POD	572	2,124	2,261	2,397	1,825
Total	1,482	11,020	14,507	15,248	13,766

Source: 2007 AESO GTA; LEI analysis (existing and planned project costs)

11 Classification of bulk and regional costs

Classification is the process by which costs for each function are separated into demand or energy or customer related. As briefly discussed in Section 6.2, while some argue for demand only costs, LEI believes an energy component is important as it incentivizes customers to reduce load even when they are not at peak.

LEI's scope of work targets specifically the classification of bulk and regional functions. Earlier in Section 6.2, the following classification approaches were discussed: minimum system, minimum intercept, marginal cost, and average and excess approach.

LEI believes that the most appropriate approach is the minimum system approach because it is consistent with cost causation and principles discussed in Section 5. The minimum system approach adapted for the transmission system uses the ratio between a minimum transmission system and an optimized system in order to determine the demand component, since minimum system costs are driven by serving total load. Additional costs are allocated to energy since costs incurred beyond the minimum system are driven by energy usage considerations.

LEI considered acceptability of these approaches to the regulator. The simplicity of the minimum system approach made it a more suitable option than the zero intercept approach, which requires considerably more data. LEI further believes that the minimum system approach is reflective of cost causation and is a reasonable method to classify costs into both demand and energy-related categories. Finally, it is commonly used in the distribution system, and has been previously approved by the Board for use in transmission in its adapted form.

11.1 Conductor classification

In order to perform the minimum system approach, a minimum line and optimized line must be identified. In defining minimum and optimum lines, LEI takes into account that the minimum system in a transmission system is not necessarily the minimum size conductor that can be constructed. The transmission system is inherently not serving minimum loading requirements like the distribution system, and TFOs are required to perform a conductor optimization study to determine the most economic conductor size, considering both capital costs and line losses, for all lines above 100 kV and longer than 10 km. All 240 kV lines greater than 50 km in length must conduct a "full bulk transmission line optimization study"[70] which includes costs of structures. Therefore, in a practical sense, it can be argued that there is no minimum system for a transmission line. However in LEI's analysis, in order to approximate demand versus energy related costs, LEI has defined "minimum" and "optimal" conductor sizes as comparable lines that TFOs would consider, where the optimized line minimizes losses over the minimum line.

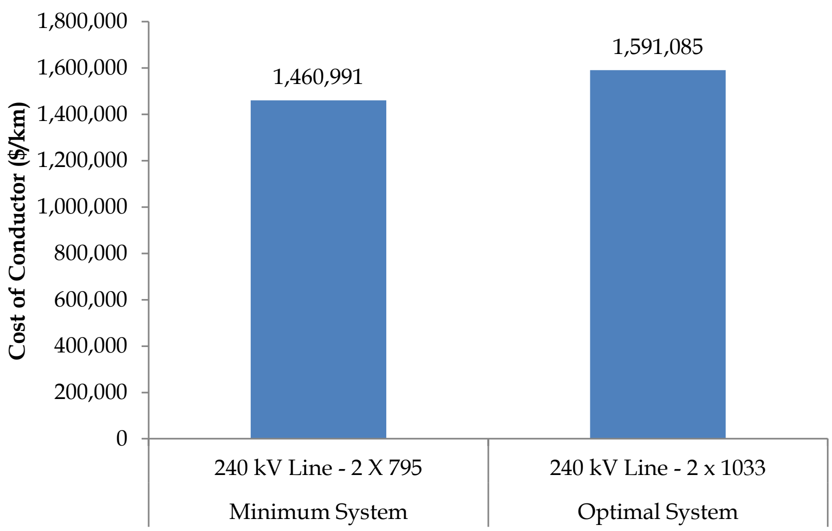
Cost information for various conductor sizes was sourced from the AESO cost benchmarking data file, which was also used to determine future line details, as discussed in Section 8.1.3.1.

[70] AESO. *ISO Rules, Section 502.2 Bulk Transmission Technical Requirements*. January 1, 2012. P 5.

The AESO cost benchmarking data file is estimated to contain 95% of the projects since 2005,[71] and was filtered for new projects with no missing conductor size or voltage data. From this data set, conductor costs per kilometer were determined for the minimum and commonly used conductor sizes, using a length-weighted average (longer conductors are assumed to provide more indicative results). As well, the data set contained double circuit, single circuit, and a double circuit line with one circuit installed – all costs were normalized in order for them to be comparable.

For bulk classification, the minimum and optimized system was determined for 240 kV and 500 kV lines separately, and results were weighted using their relative costs to arrive at a final bulk classification. After discussion with AESO staff, LEI was able to determine the commonly used conductor sizes in Alberta - for the 240 kV system, the two most commonly constructed conductor sizes are 2x795 and 2x1033 thousand circular mils ("MCM") ACSR. These two conductor sizes could be compared by a TFO designing a 240 kV line, where the 2x795 MCM ACSR conductor is the less expensive "minimum" option, and the 2x1033 MCM ACSR conductor would be more expensive while minimizing losses, as the "optimized" option. Costs were normalized to a double circuit line strung both sides, which is a common configuration in Alberta.

Figure 68. 240 kV - minimum and optimal conductor size costs



A test case (presented in Figure 69) was analyzed for a 240 kV transmission line comparing the minimum system conductor to the optimal system conductor, in order to demonstrate that it is reasonable for a TFO to be comparing the minimum and optimal conductor sizes. A 50 km line length was assumed since a bulk transmission line optimization study is required for 240 kV lines that are 50 km or greater in length. The present value of conductor losses was determined

[71] After discussions with AESO, LEI's understanding is that NID/PSS costs/details for the remaining 5% could not be located and that these 5% are similar in nature to 95%.

for the minimum system (2 X 795) and the optimal system (2 X 1033) for a 65 year conductor life[72] using simplifying assumptions for average annual energy cost[73] and a nominal discount rate.[74] The capital costs of both lines were added to the losses, and the two were compared.

Figure 69. Test case - calculation for comparable minimum and optimal 240 kV lines

Assumptions	
Line length (km)	50
Annual Discount Rate %	6
Average lifetime Energy Price $/MWh	68
Life of overhead conductors in years	65
2x1033 MCM AC resistance @ 75 C in ohms / km	0.03462
2x795 MCM AC resistance @ 75 C in ohms / km	0.04315
Cost of 2x1033 MCM overhead transmission $/km	$1,591,058
Cost of 2x795 MCM overhead transmission $/km	$1,460,991
Lines capacity factor %	40
2x1033 ampacity @ 75 C, amps	2094
2x795 ampacity @75 C, amps	1814

Minimum System		
Annual power losses (MWh)		29,852
Annual cost of losses	$	(2,029,923)
Present Value	$	33,065,670
Line cost		$73,049,550
Total PV		$106,115,220

Optimal System		
Annual power losses (MWh)		23,951
Annual cost of losses	$	(1,628,643)
Present Value	$	26,529,165
Line cost		$79,552,900
Total PV		$106,082,065

In the test case, the optimal system is economically justified if the line capacity factor was at least 34%. Consequently, lines which deliver higher levels of energy will benefit from an optimal design that reduces transmission line losses. Since reasonable assumptions can lead to a minimum and optimal system with comparable costs, LEI concludes that these are comparable conductor sizes and valid choices for minimum and optimal systems. The 240 kV conductor classification results in a ratio of 91.8% demand to 8.2% energy.

500 kV conductors were also classified using the minimum system approach. Limited data was found for 500 kV conductors in Alberta, so costs were sourced from the CAISO jurisdiction.[75] The minimum was defined to be a 2x2156 MCM ACSR conductor, with a cost of

[72] "AltaLink 2013-2014 General Tariff Application, Appendix 8 – Depreciation Study" dated July 30, 2012 was the basis for the life of the conductors.

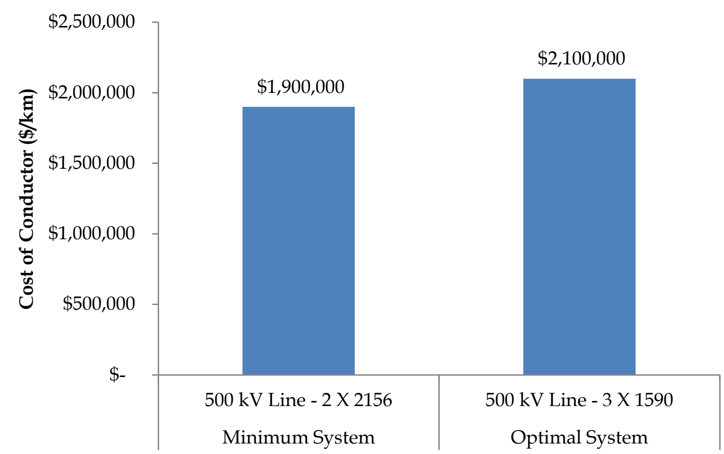
[73] "Chase Power Fundamental Report for the Alberta Energy Industry" dated June 10, 2013 was used as the basis for determining the average lifetime energy costs used in the test case.

[74] AESO document "Information Document Discount Rates for 2011 Tariff ID No. 2011-115T" dated October 7, 2011 was used as the basis for the discount rate.

[75] Costs do not include engineering, right of way ("ROW") or G&A costs.

$1.9 million per km, and the optimal was defined to be a 3x1590 MCM ACSR conductor, with a cost of $2.1 million per km. The 500 kV conductor classification results in a ratio of 90.5% demand to 9.5% energy.

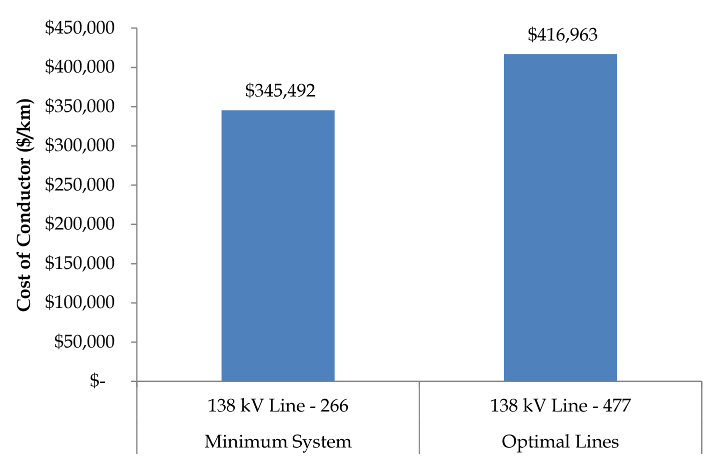
Figure 70. 500 kV - minimum and optimal conductor size costs



The final bulk classification was determined by weighting 500 kV and 240 kV classifications together, using their respective 2016 line asset costs. The bulk conductor classification results in a ratio of 91.6% demand to 8.4% energy.

In order to determine regional classification, the minimum and optimized system was determined for a 138 kV line.

Figure 71. Regional - minimum and optimal conductor size costs



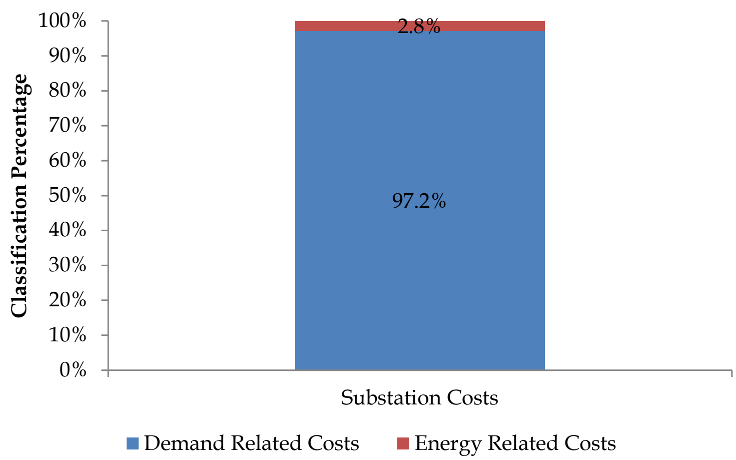
For the regional system, the two most commonly constructed conductor sizes are 266 and 477 MCM ACSR. These two conductor sizes could be compared by a TFO designing a 138 kV line, where the 266 MCM conductor is the less expensive "minimum" option, and the 477 MCM conductor would be the more expensive "optimized" option minimizing losses. Costs were normalized to single circuit lines in order for them to be comparable. The regional conductor classification results in a ratio of 82.9% demand to 17.1% energy.

11.2 Substation classification

LEI defines the optimized substation as one which minimizes losses over a minimum substation. LEI was able to obtain a quote for a POD transformer which included both a “Standard Losses and Sound Level” transformer, which LEI has considered a minimum system, and a “Lower NLL & Sound Level” transformer,[76] which given its lower loss characteristic, LEI considers the optimal system.[77]

These quotes indicate that the "minimum system" POD transformer is approximately 2.8% less expensive than an "optimal system" POD transformer. It was assumed that regional and bulk power transformers would also have a similar percentage cost increase in material and manufacturing costs for an "optimal system" transformer.[78] Consequently, this percentage cost increase was also applied to regional and bulk power transformers.

Figure 72. Substation classification results



---

[76] NLL stands for No-Load Loss.

[77] The quote, from November 2010, was obtained from a TFO. LEI requested additional quotes from the TFOs, through the AESO, but did not receive additional data. Given that the results of substation classification are similar to the TCCS and correspond with expectations based on experience, LEI believes they are suitable.

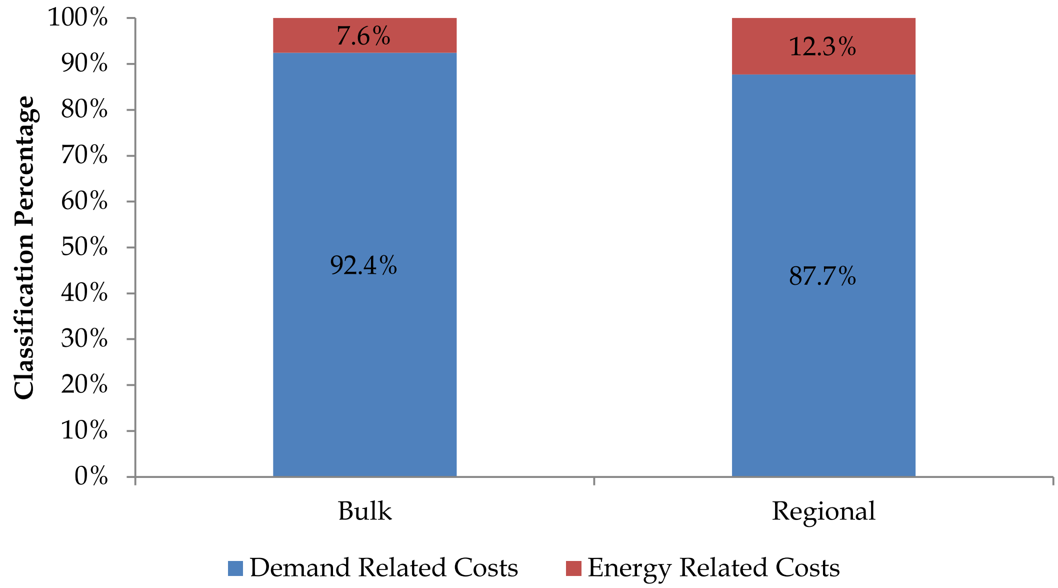
[78] Analyzing HVDC systems in terms of minimum and optimal systems is challenging, as each component is individually optimized, i.e., there may be no “minimum” system. However, converter stations would likely have a similar percentage cost increase in material and manufacturing costs for an "optimal system" transformer compared to a hypothetical “minimum” system.

11.3 Classification results

To obtain the final bulk and regional classification results, the line classification results were weighted with substation classification results using line and substation asset values.

Figure 73 presents LEI's recommended classification results for both bulk and regional systems, which as one would expect, have significantly higher proportions for demand-related costs as compared to energy-related costs.

Figure 73. Classification results by functional group



12 Implementation considerations

In order to assess the impact of implementing the functionalization and classification results, LEI was specifically asked to comment on the following three considerations, which it analyzed by studying the resulting revenue requirement breakdown:

- whether results from the study would result in reversing trends in rates that could give confusing price signals;
- if one part of the study would result in a change that was opposite to a change from another part of the study; and
- whether functionalization and classification recommendations justify averaging or trending results in order to improve stability of rates.

Functionalization and classification results of the study have been discussed in detail in earlier sections and are presented below in Figure 74.

Figure 74. Combined functionalization and classification results

Combined cost functionalization (net of RGUCC)	2014	2015	2016
Bulk	55.2%	61.2%	62.0%
Regional	22.5%	20.1%	19.6%
POD	22.3%	18.7%	18.4%

Classification results	Bulk	Regional
Demand	92.4%	87.7%
Energy	7.6%	12.3%

In order to comment on any reversing trends, it is important to review the revenue requirement breakdown[79] after implementing functionalization and classification results.

Figure 75. Revenue requirement breakdown using combined results

Revenue Requirement Split - net of RGUCC ($ million)	2014	2015	2016
Bulk - Demand	764	1,011	1,136
Bulk - Energy	63	83	93
Regional - Demand	295	315	342
Regional - Energy	41	44	48
POD	333	335	365
Total	1,497	1,787	1,984

[79] Total revenue requirement ($ million) projections for 2104, 2015 and 2016 were provided by AESO's "Draft Transmission Rate Impact Projection Model" and LEI deducted RGUCC amounts as discussed earlier in Section 10.1.

The resulting revenue requirement breakdown (as presented in Figure 75) shows that the requirements across bulk and regional rate components (bulk-demand, bulk-energy, regional-demand and regional-energy) is increasing on an annual basis, indicating no reversing trends and thus providing consistent price signals.

LEI also reviewed the impact on revenue requirement breakdown if only capital cost functionalization results were applied, versus applying combined capital and O&M cost functionalization results, as discussed above. LEI understands that this issue arose in AESO's 2010 tariff proceeding, where implementing the O&M study results would decrease bulk system charges.

If only capital cost functionalization results are applied (ignoring O&M cost functionalization results), the resulting revenue requirement breakdown is presented in Figure 76. Although the impact is not in opposing directions, i.e., revenue requirement trend remains positive and increasing across most of the rate components (with the exception of POD where revenue requirement reduces slightly in 2015), it is important to note that applying only capital cost functionalization results will result in more costs being functionalized as bulk.

Figure 76. Revenue requirement breakdown using capital cost functionalization only

Revenue Requirement Split - net of RGUCC ($ million)	2014	2015	2016
Bulk - Demand	834	1,100	1,221
Bulk - Energy	69	90	100
Regional - Demand	266	278	307
Regional - Energy	37	39	43
POD	291	280	313
Total	1,497	1,787	1,984

This can be observed by comparing capital cost functionalization results (presented below in Figure 77) to combined capital and O&M cost functionalization results presented earlier in Figure 74.[80] Proportion of costs functionalized as bulk is approximately 4%-6% lower in the combined results.

Figure 77. Capital cost functionalization results

Capital cost functionalization	2014	2015	2016
Bulk	60.6%	66.8%	66.7%
Regional	20.1%	17.7%	17.6%
POD	19.3%	15.6%	15.7%

This is sensible given that the bulk system function has less than average associated O&M costs in proportion to capital costs, as compared to the regional and POD functions, as discussed earlier in Section 9.3. LEI recommends applying combined capital and O&M functionalization

[80] Note that the classification results remain the same.

results as they are consistent with cost causation, and they do not pose an issue of declining bulk charges in the face of extensive bulk investment planned.

Finally, LEI analyzed whether resulting functionalization results change significantly year-on-year, warranting changes during the filing period. To be consistent with cost causation, LEI recommends applying 2014, 2015 and 2016 functionalization results separately to each of the three years (as presented in Figure 74).[81]

[81] As referenced in footnote 3, the Board has previously maintained that cost causation remains a primary consideration when evaluating rate design principles.

13 Appendix A: Special projects functionalized separately

13.1 Special projects not primarily driven by load

Discussions with the TCCWG[82] indicated that members desired a distinction between "conventional" transmission projects in the LTP, which are primarily driven by load, and "special" projects. LEI has defined "special" projects as projects which are clearly driven to interconnect renewable energy or driven by reliability purposes, but not primarily driven by load.

Of note, there is precedent of treating renewable generation interconnection as special in California, which was discussed earlier in Section 7.2.2. The OEB also developed a framework for transmission project development plans, and proposed filing requirements for firms seeking to develop transmission projects in Ontario that are required for connecting renewable generation, as identified by the Ontario Power Authority ("OPA").[83] Specifically, OEB stated: "*The Board's goal in developing a policy for transmission project development planning is to facilitate the timely development of the transmission system to accommodate renewable generation*."[84]

NIDs and details from the 2012 LTP have been used for identification of special projects. LEI reviewed all 2012 LTP projects with costs greater than $100 million, accounting for $12.3 billion (approximately 91% of all planned projects by value in the 2012 LTP).

In the main body of the report, LEI has not functionalized or classified special projects any differently than conventional projects. At the request of AESO/TCCWG, functionalization results with special projects separated out have been presented in Section 13.2.

LEI believes that special transmission projects are triggered as a result of public policy, and despite distinct purposes, arguably have similar cost causation drivers to the rest of the system. The costs of special projects may be recovered in one of two ways:

- treating it broadly as a social good, and recovering it as a tax (i.e. taxing every MWh equally); or
- recovering it consistent with purpose or key driver

---

[82] TCCWG participants include: Alberta Direct Connect Consumers Association, AltaLink, Athabasca Oil Corp. and Dover Operating Corp, ATCO Electric, Devon Canada, Dual Use Customers, ENMAX, EPCOR, Industrial Power Consumers Association of Alberta, Powerex, Suncor Energy, TransAlta Corporation, TransCanada Energy and the Office of the Utilities Consumer Advocate. Source: AESO. *2013-01-17 AESO 2014 Cost Causation Working Group - Meeting #1 Presentation*. Posted January 22, 2013.

[83] Ontario Energy Board. *Filing Requirements: Transmission Project Development Plans*; August 26, 2010.

[84] Ontario Energy Board. *Board Policy: Framework for Transmission project Development Plans*; August 26, 2010.

Note, however, that 'purpose' may not necessarily be the same as the 'cost causation driver'. For instance, for grid strengthening related to emissions-free projects, it may be considered prudent to recover costs from customers who are causing some environmental impact. Peak use likely causes greater emissions, which in turn drives demand for zero-emitting resources. While a line's purpose may be to serve renewables, ultimately the needs for it may be driven by peak users.

Furthermore, although a project may be built for the purposes of interconnecting renewable energy, significant portions of the project are likely to serve peak load as well. Similarly, projects which are built for reliability purposes may not be primarily serving peak, but in practice, are likely to still serve load in some capacity.

13.1.1 Identified special projects

LEI identified two special projects with a total value of $2.5 billion, out of a total of $11.7 billion LTP projects, coming in-service by 2016.

13.1.1.1 South Area Transmission Reinforcement

LTP Value: $2,287 million

SATR was identified as a special project because its NID clearly states that:

> "*the proposed reinforcements are required to principally respond to the anticipated development of wind generation in Southern Alberta*" and goes on to say the "*need for transmission reinforcement in southern Alberta is driven predominantly by the forecast development of wind generation… it is anticipated that between 1,700 and 3,200 MW of the provincial totals will be located in southern Alberta*".[85]

As LEI has defined special projects as those that interconnect renewable entry, rather than primarily serving peak load, SATR qualifies as a special project.

13.1.1.2 Bickerdike to Little Smoky

LTP Value: $205 million

Although Bickerdike to Little Smoky has not yet progressed to the NID stage, the description of the project in the LTP identifies it as primarily driven by non-load related reliability reasons. The LTP states:

> *"The Northwest region is primarily a load area and relies heavily on power transfers from the Wabamun Lake area and, under certain conditions, from the northeast. As a result, a major transmission outage between Wabamun Lake and the Northwest region could cause a phenomenon called voltage collapse, which could cause a sustained outage. To mitigate the*

[85] AESO. *South Area Transmission Reinforcement Needs Identification Document*. December 15, 2008.

potential voltage collapse, the AESO is proposing two new projects. The first is a double circuit 240 kV line from Bickerdike (near Edson) to Little Smoky"[86]

From this description, the driver behind Bickerdike to Little Smoky is to mitigate voltage collapse in the Northwest region, caused by a transmission outage. This is not a reliability situation which is related directly to peak load, rather, this project has been primarily planned to serve the system under abnormal system conditions. Therefore, Bickerdike to Little Smoky also qualifies as a special project, although it should be re-evaluated once an NID is published.[87]

13.1.2 Critical Transmission Infrastructure Project Analysis

LEI reviewed Critical Transmission Infrastructure ("CTI") projects as part of the special project review; however none were categorized as special. Given the heightened interest in these projects, this section describes the reasons for not treating them as special projects. Note, given that they are CTIs, NIDs have not been filed for these projects and all information is from the LTP. CTI projects have an estimated total cost of $5.2 billion, or 39% of total LTP projects.

Critical Transmission Infrastructure

<u>Electric Statutes Amendment Act, 2009 (known as Bill 50) passed in fall of 2009</u>

- Government of Alberta gave provincial cabinet the authority to designate future transmission facilities as critical transmission infrastructure

<u>The Electric Utilities Amendment Act (known as Bill 8) effective December 2012</u>

- Removed cabinet authority
- Future transmission projects must pass a needs assessment process before the Alberta Utilities Commission

13.1.2.1 East/West HVDC

LTP Value: $2,951 million

The LTP specifies that the East/West HVDC is required to address reliability issues, improve efficiency, accommodate long-term growth, support the energy market, as well as provide access to renewable generation. Although access to renewable generation is one of the drivers, it is not the primary driver, and because one of the drivers is stated to be 'accommodating long-term growth', it is not qualified as a special project.

13.1.2.2 West Fort McMurray 500 kV Stage 1a

LTP Value: $1,649 million

According to the LTP, West Fort McMurray 500 kV Stage 1a is driven by "oilsands development," which is load growth, and is as well "required for Northeast load." Therefore, it is not special.

---

[86] AESO. *AESO Long-term Transmission Plan.* Filed June 2012. Page 93.

[87] In the June 2013 AESO Draft Transmission Rate Impact Projection, Bickerdike to Little Smoky is scheduled to be in service in 2017.

13.1.2.3 Heartland 500 kV

LTP Value: $537 million

The LTP states Heartland is required to serve Northeast load, which is primarily driven by the oilsands industry, as well as supplying Heartland load. Therefore, it is also not special.

13.1.2.4 South Calgary Source

LTP Value: $39 million

South Calgary Source is a relatively small project at only $39 million, however due to its status as a CTI, LEI reviewed it for special status. The underlying rationale for the project is that "City of Calgary peak load is expected to reach approximately 2,000 MW by 2020… the south part of the city in particular is expected to continue to grow." South Calgary Source is required for load and reliability; therefore, it is, again, not special.

13.2 Special project functionalization results

At the specific request of stakeholders/AESO, this section presents key functionalization results with special projects separated in a different functional group. Existing assets and O&M functionalization results do not change – special projects are only planned projects.

Figure 78. Summary of future project functionalization results separating special projects

Future capital cost functionalization (by value)	2014	2015	2016
Bulk	$ 2,900,582,661	$ 4,982,405,725	$ 5,181,182,788
Regional	$ 488,990,895	$ 738,927,693	$ 794,904,249
POD	$ 88,054,830	$ 97,265,394	$ 94,545,243
Special	$ 396,180,911	$ 503,775,316	$ 770,454,260

Future capital cost functionalization	2014	2015	2016
Bulk	74.9%	78.8%	75.7%
Regional	12.6%	11.7%	11.6%
POD	2.3%	1.5%	1.4%
Special	10.2%	8.0%	11.3%

Figure 79. Summary of capital cost functionalization results, separating special projects

Capital cost functionalization (by value)	2014	2015	2016
Bulk	$ 6,324,601,117	$ 9,220,717,292	$ 9,470,868,342
Regional	$ 2,175,407,460	$ 2,521,564,487	$ 2,610,096,859
POD	$ 2,123,557,889	$ 2,261,395,958	$ 2,396,604,055
Special	$ 396,180,911	$ 503,775,316	$ 770,454,260

Capital cost functionalization	2014	2015	2016
Bulk	57.4%	63.6%	62.1%
Regional	19.7%	17.4%	17.1%
POD	19.3%	15.6%	15.7%
Special	3.6%	3.5%	5.1%

Figure 80. Final combined O&M and capital cost functionalization, separating special projects

Combined cost functionalization (net of RGUCC)	2014	2015	2016
Bulk	52.5%	58.4%	57.9%
Regional	22.2%	19.8%	19.2%
POD	22.3%	18.7%	18.4%
Special	3.0%	3.0%	4.4%

Note: Results utilize the voltage approach

Comparing functionalization results (Figure 50 and Figure 79) shows that special projects include costs that are primarily functionalized as bulk, with a minor proportion of regional costs and none of them functionalized as POD. Implications of separating out special projects will depend on how these projects are classified and incorporated into rates, if in a different manner, compared to other projects.

14 Appendix B: Works consulted

14.1 Works Consulted

AESO. *AESO 2010 ISO Tariff Application (1605961 - ID 530): AESO Written Argument.* September 14, 2010

AESO. *2011 Unit Cost Estimates*. <www.aeso.ca/downloads/2011_Unit_Cost_Estimates.pdf>

AESO. *2013 Planning Base Case Suite*. January 24, 2013.

AESO. *2013-01-17 AESO 2014 Cost Causation Working Group - Meeting #1 Presentation*.

AESO. *AESO Long-term Transmission Plan*. Filed June 2012.

AESO. *Reasonableness Assessment of Transmission Cost Using Benchmarking Methodology*. March 28, 2013. <www.aeso.ca/downloads/Reasonableness_Assessment_of_Transmission_Cost_Using_Benchmarking_Methodology.pdf>

AESO. *TCE.AESO-004 (a-d) Revised*. February 14, 2007

AEUB. *Decision 2005-096: 2007 GTA*.

AEUB. *Decision 2007-106: 2007 GTA*.

AEUB. *Decision 2010-606: 2007 GTA*.

Alberta Energy. *Transmission Development: The Right Path for Alberta.* December 22, 2003.

Bonbright, James, Albert L. Danielsen and David R. Kamerschen. *Principles of Public Utility Rates, Second Edition*. March 1988. Print.

California Independent System Operator Corporation. *Fifth Replacement CAISO Tariff*. Mar 20, 2013.

Hydro One. *EB-2012-0031 Exhibit G1. Tab 2. Schedule 1*. Filed May 28, 2012.

National Association of Regulatory Utility Commissioners. *Electricity Utility Cost Allocation Manual*. January 1992.

OEB. *EB-2012-0031. Decision in the matter of an application by Hydro One Networks Inc. for an approving of new transmission revenue requirements and rates for the transmission of electricity in 2013 and 2014*. Decision issued on December 20, 2012.

Ontario Energy Board. *Filing Requirements: Transmission Project Development Plans*; August 26, 2010.

Ontario Energy Board. *Board Policy: Framework for Transmission project Development Plans*; August 26, 2010.

PS Technologies Inc. *Alberta Transmission System Wires Only – Cost Causation Study*. January 25, 2005.

PS Technologies Inc. *Alberta Transmission System 2006 Transmission Cost Causation Update*. September 15, 2006

PS Technologies Inc. *Electric Transmission Operating and Maintenance Cost Study*. December 10, 2009

14.2 Additional documents provided by AESO

AESO Point of Delivery database

AESO Draft Transmission Rate Impact Projection Model

ATCO quotes for transformer

Alberta Interconnected Electric System Map

Interveners' submissions on Transmission O&M study

Need Identification Documents for Planned Projects

Planning Base Case - 2015 data files

Project Progress reports – cost and schedule information (approx. 62 files)

Rule 005 Annual Reports

TCWG meeting notes and underlying AESO analysis

TFO depreciation studies

TFO Asset Data for Capital Cost Study

TFO Data for O&M Study

TFOs tariff applications and underlying Excel files

15 Appendix C: Background on LEI

LEI has been actively involved in the Alberta market since its inception. The firm has worked with clients across the electricity sector value chain on a range of issues associated with both regulated and competitive assets in Alberta. In addition to the AESO, the Balancing Pool, and the Alberta Department of Energy, LEI has worked with generators, transmission companies, distributors, and industry associations in Alberta. This broad experience provides LEI with a significant depth of understanding of the Alberta market.

The firm also maintains a continuously updated model of the Alberta competitive wholesale market, and produces twice yearly off the shelf Alberta forecasts. LEI has the ability to perform quantitative analysis of the Alberta market both prospectively and retrospectively across time scales of a client's choosing, and to do so on a relatively quick turnaround basis.

15.1 Background on the firm

LEI is a global economic, financial and strategic advisory professional services firm specializing in energy and infrastructure. The firm combines detailed understanding of specific network and commodity industries, such as electricity generation and distribution, with a suite of proprietary quantitative models to produce reliable and comprehensive results. LEI is involved in strategic consultancy, with a key differentiating factor from its competitors in combining strategic analysis with an in depth focus and understanding of the dynamics of the energy sector. The firm has advised private sector clients, market institutions, and governments on privatization, asset valuation, deregulation, tariff design, market power, and strategy in virtually all deregulated markets worldwide.

Figure 81. LEI clients throughout the world

15.2 Alberta-specific experience

LEI has considerable experience advising governments, arms-length government agencies, and private companies on a range of issues related to the Alberta electricity sector. The following are a sample of those engagements.

Cost-benefit analysis of potential transmission projects in Alberta: LEI was retained by Alberta's electricity transmission regulator to conduct a cost-benefit analysis of potential transmission projects in the province to demonstrate the techniques of our VITAL methodology. LEI's team focused on the North-South interconnector and examined the impact of new generation, retirements, intertie expansion, and load growth on the value of the line.

Advice on the selection of a sale process for strip contracts: LEI was retained by the Alberta Electric System Operator to advise on the selection of a sale process for strip contracts. After reviewing the theoretical arguments and relevant case studies, LEI concluded that a discriminatory sealed-bid sale process was preferred.

Develop holding restrictions for PPA auctions: LEI proprietary model of strategic behavior in electricity markets, known as CUSTOMBid. As a result of our analysis, a series of holding restrictions were developed which allowed for sale of capacity into the market without increasing the potential for strategic bidding.

Devise holding restrictions for Alberta's ancillary services market: LEI was engaged by Alberta's Balancing Pool to devise relevant holding restrictions for the Canadian province's ancillary services market. LEI's work included a survey of generators capable of providing ancillary services, technical and rules-based restrictions on the provision of these services, as well as stipulations regarding ESBI's procurement policies. LEI's report focused on regulating and operating reserves, and assessed the mechanisms associated with the other ancillary services required in Alberta. This included transmission must-run ("TMR") status, black start, reactive power and voltage control.

Devise regulatory strategy for an Alberta transmission company: LEI designed for one of Canada's largest electricity transmission companies a regulatory strategy for its interaction with the relevant provincial utilities board regarding PBR methods. LEI utilized the capital asset pricing model ("CAPM") to independently develop a range of ROEs, and suggested an "earnings sharing" (shared savings) approach to rate design based on the need to demonstrate a transition to incentive rates while maintaining simplicity and predictability in rate design.

Workshop in incentive regulation for transmission companies: For North America's first independent transmission company, LEI facilitated a workshop on how to dovetail company attributes with the type of PBR advocated for, on specific examples of areas of cost declines as a result of incentive regulation, and on the impact of performance standards for transmission companies.

Real option-based valuation for a Alberta generating unit: LEI was retained by the Balancing Pool of Alberta to conduct a real options-based valuation of the Clover Bar unit so as to provide a realistic, market-based foundation for determining the reservation price of the Clover Bar unit contracts. LEI's analysis suggested that the value of Clover Bar is intimately related to the flexibility of the plant.

Long-term Alberta electricity power pool price forecasts: LEI was retained by a Canadian power utility to develop several forecasts of the long-term Alberta electricity power pool prices (2010 to 2030) based on different market parameters and offer recommendations for strategic action. The forecast also made special note of the effect on the market, if any, of the following conditions: (i) greenhouse gas legislation; (ii) increase in unconventional (shale) natural gas production; (iii) effect of the enactment of Bill 50; and (iv) effect on the market by external jurisdictions.

Assess costs and benefits associate with output from coal fired power stations in Alberta: LEI was retained by a Canadian power utility to assess costs and benefits associated with output from coal fired power stations in Alberta. This engagement involved considering only information known as of 2000, to be used in a tax litigation case. LEI created pro forma valuation of contracts as of 2000, including forecast costs and revenues, and rendered an opinion on the appropriate cost of capital to be used.

Comprehensive review of Alberta's electricity market: LEI performed for the Alberta Provincial Government a comprehensive review of the province's electricity market, which included analysis of the roles of the Power Pool, the Transmission Administrator, the Market Surveillance Administrator, the Balancing Pool, and the System Controller. LEI performed extensive stakeholder consultation, and prepared an analysis of how these roles are performed in ten competitive wholesale markets worldwide. LEI then created a series of models for the evolution of all of the entities studied and the industry as a whole. Based on further stakeholder and government input, these models were distilled into final recommendations regarding how the industry components should be structured in the future.

Study to further deregulate Alberta's retail electricity market: LEI supported the Alberta Department of Energy ("ADOE") in an attempt to select the most appropriate way to further deregulate its retail market. LEI's team analyzed the economic impact of five different options being considered by ADOE on customer bills by using historical data as well as developing a cost benefit analysis model that looked at both quantitative and qualitative issues that were prioritized by the ADOE. We provided a ranking of options and recommendations as to which would best meet ADOE needs.

Theoretical analyses and quantitative simulation modeling for Alberta regulatory regime: LEI was retained by the Alberta Provincial Government to conduct theoretical analyses and quantitative simulation modeling in the design and testing of recommended new regulatory regimes in Alberta on the eve of the existing regime's expiration.

Study of the Alberta electricity market with special focus on wind power: LEI produced for a major Canadian financial institution a complete study of the Alberta electricity market, with a special focus on the market for wind power. The study analyzed the prevailing regulatory status and expected regulatory changes, evaluated the market participants, discussed impending developments and gauged the current and future direction of the market. Using proprietary forecasting tool POOLMod, LEI developed 10-year price projections and analyzed the sensitivity of prices to changes in underlying market conditions. Finally, LEI reported on the special potential for wind power, including government incentives and the possibility for sales at above market prices.

Estimate impact of Alberta power price changes for a litigation-related project: LEI was retained by a Canadian industrial conglomerate to estimate damages incurred because of power price changes during the life of a five-year swap agreement, which obligated the client to pay a fixed price in exchange for a floating-rate payment based on an hourly average pool price. LEI first investigated whether a material change in the determination of market-clearing prices in the Power Pool of Alberta had occurred on a specific date in 2001 and then estimated the magnitude of the price shift attributable to the change in the Clover Bar's pricing strategy over the term of the swap agreement and the amount of the resulting damages.

Review of reasonableness of the proposed penalty by Alberta's Market Surveillance Administrator ("MSA"): LEI conducted an independent review and provided a professional opinion regarding the reasonableness of the proposed penalty included in the Settlement Agreement between client and Alberta's MSA related to export scheduling activities in November 2010. The MSA has requested that the Settlement Agreement be approved by the AUC. LEI reviewed relevant cases of asserted market manipulation in other jurisdictions, reviewed Alberta's power market and its specific market rules, studied relevant economic and legal theory, and conducted quantitative analyses involving the manipulation of wholesale and retail market prices and loads. We presented our overall findings in a written testimony.

15.3 Cost causation study experience

LEI has conducted cost causation studies in the past along with counseling governments and regulators to design tariffs that allocate costs in an economically efficient manner.

Self-funding tariff for ISO New England including cost causation study: LEI provided support for ISO New England throughout the design and submission to FERC of ISO New England's self-funding tariff. LEI first defined the basic underlying economic principles for specifying the tariff, then undertook to show how the tariff should be applied to various system users. The engagement involved an intensive financial modeling effort, frequent interaction with stakeholders, and written testimony before FERC.

Economic advice on cost causation and tariff regime: LEI provided Australia's former power market regulator, NEMMCO, economic advice on the appropriate regime for charging market participants for the costs incurred by the client in providing its services, in accordance with the National Electricity Code. In making its recommendation on participant fees, LEI considered the criteria specified by the National Electricity Code. LEI also considered the issues and arguments raised in submissions provided by participants in response to the issues paper released in December 1999.

Methodologies for transmission cost allocation: LEI advised a state public utilities commission on methodologies for transmission cost allocation by comparing and contrasting alternative planning approaches and pricing models employed within the US and one international jurisdiction, the United Kingdom. The final report provided a 'strawman' recommendation for an effective cost allocation methodology.

Distribution cost allocation and customer class definition: LEI, in consortium with an engineering firm, analyzed the customer density and distribution service costs for one of Ontario's largest utility. This engagement had three specific objectives: (i) evaluate the relationship between customer density and distribution service costs; (ii) assess whether utility's existing density-based rate classes and density weighting factors appropriately reflect this relationship; and (iii) consider, qualitatively, the appropriateness and feasibility of establishing alternative customer class definitions.

Cost of service tariff design for electricity, water and wastewater services in Saudi Arabia: On behalf of a utility serving industrial areas in Saudi Arabia, LEI developed a regulatory framework for power and water utilities not regulated by the government, developed a charter for a new regulatory body, established and recommended cost of service (and alternative incentive regulation) based tariff structure and accompanying tariff model for all business activities, and assisted filing of tariff petitions with the applicable regulatory authorities for approval.

Design of wheeling tariff and pilot program for Saudi Arabia: For the Saudi regulator, developed proposed plan for wheeling of power in Saudi Arabia, including proposed pilot program, assessment of impact on incumbent, relative economics of wheeling versus the industrial tariff, and review of associated commercial and regulatory issues.

Tariff design for Kingdom of Saudi Arabia: Led engagement with international team assessing tariff design, modeling, and electricity market evolution in Saudi Arabia; engagement resulted in a revised tariff system, including performance based rates, tolling agreements for generation, and an open access tariff. Included holding workshops for regulator in explaining cost of capital, tariff design, and other regulatory issues.

15.4 Transmission related experience

LEI has also advised transmission developers on a wide range of additional issues including:

Analyzing elasticity of demand for transmission services: LEI was retained by a Canadian consortium to analyze the elasticity of demand for electricity transmission services between the province of Quebec and surrounding markets. This project was undertaken in the context of a rate filing by a Quebec transmission company for a rate increase, based on an assumption that demand for electricity transmission service is inelastic.

Potential economic benefits of a proposed transmission project: LEI was commissioned by a Northeastern utility to determine the potential economic benefits of a proposed transmission project. Using detailed hourly simulation modeling of future power market conditions, LEI studied the potential market implications of the project for ten years from a notional expected date of commercial operation of 2014. LEI reached the following conclusions: New England ratepayers could expect cumulative energy cost savings attributable to the project over ten years under normal operating conditions; the transmission project would create regional energy market impacts; each phase of the project would create energy market benefits over the ten-year modeling horizon; the project would provide an insurance hedge against stressed system events; and NEEWS would offer market access to renewable resources in Northern New England/Canada.

Analysis of customer benefits from expansion of market through new transmission: LEI performed a fifteen (15) year simulation analysis to estimate the market impacts resulting from a new transmission interconnection (covering the timeframe 2015-2029) and project the impact on Maine customers (including Northern Maine customers). LEI evaluated the market evolution with and without the interconnection and described the potential ramifications for purchasing electricity for Northern Maine customers. The analysis also estimated the potential impact on ratepayers from the re-allocation of the ISO-NE Pool Transmission Facility rate to incorporate the Northern Maine load and franchise area under a pro forma 10-year transitional agreement. LEI performed the modeling using our up-to-date ISO-NE simulation model (which covers the energy and capacity markets), extended to represent in detail the Maritimes control area.

Project evaluation for a HVDC transmission line in the Northeast market in US: LEI advised Transmission Developers Inc. on the financial implications of a proposed new HVDC transmission line to New York City from Quebec, Canada. LEI analyzed the impact of new transmission, given its goal of delivering 100% carbon-free energy, on electricity prices and emissions levels in New York. We evaluated both the congestion rents in support of analyzing the economic potential for the project and their negotiations with anchor tenants (buyers of the transmission rights) and we also looked at market impacts and provided testimony on market benefits to ratepayers. LEI then testified at the NY Public Service Commission regarding this project in July 2012.

Market analysis in support of Northern Pass: LEI prepared a presentation that discusses the electricity market impacts and benefits of Northern Pass Transmission project for New Hampshire and New England consumers. In May 2011, LEI staff also assisted in the preparation of an op-ed piece for dissemination to New Hampshire press outlets. LEI staff also testified before state regulators regarding the project.