REVIEW OF THE COST STATUS OF MAJOR TRANSMISSION PROJECTS IN ALBERTA

From The Transmission Facilities Cost Monitoring Committee

JUNE 2012 REPORT

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Message From The Chair

This is the third report from the Transmission Facilities Cost Monitoring Committee (TFCMC) to its stakeholders. The report provides a detailed and structured summary of cost, scope and schedule information on all transmission projects being monitored by the Committee on a monthly basis for the period of November 1, 2011, to April 31, 2012.

Since the last report, the Alberta Electric System Operator (AESO) has provided the Committee detailed information on two new projects: the Foothills Area Transmission Development – East Project, with costs estimated at $420 million, and the Christina Lake Area Transmission Development at an estimated cost of $410 million. Details for these two projects can be found in Section 2, and in Appendix B and Appendix C. Section 2 also includes pertinent observations from Committee members while monitoring the progression of the 14 transmission projects.

Section 3 provides a status update on the Transmission Cost Recovery Subcommittee (TCRS) initiative. The TCRS report has been delivered to the Department of Energy but at the time of the writing this report, the Department of Energy has not indicated its intention for this report.

The Committee notes that in response to the report issued by the Critical Transmission Review Committee (CTRC), the Government indicated its intention to use the TCRS findings as preliminary input to an Alberta Utilities Commission (AUC) inquiry. The inquiry would look into ways to mitigate short-term transmission rate impacts from the very aggressive transmission development program underway in the province. I would like to take this opportunity to recognize the contributions from the Transmission Facility Owners (TFOs) and several TFCMC member organizations in making this initial initiative a success.

Around $100 million a month is expected to be invested in Alberta on transmission development for the next 10 years. Through its planning process, AESO has shown that this massive development is needed to support the growth of the province. Through ongoing monitoring of project costs after approval, the TFCMC has identified opportunities to control costs and the AESO has implemented several of these recommendations. Section 4 provides an update on the status of all previous recommendations, along with details on two recommendations currently being implemented: creating a cost benchmark database and enhancing cost accountability.

In addition to monitoring the cost progression of all the major transmission development projects, the TFCMC has also undertaken initiatives to get a better understanding of several subjects that can contribute to the Committee's collective competency in examining ideas to minimize transmission project costs. Section 5 of this report describes several of such initiatives undertaken by the Committee during this report period.

The TFCMC has been exposed to information that suggests there could be significant opportunities to reduce costs of transmission construction in this province. The TFCMC has demonstrated its value in enabling ratepayer groups to understand cost factors after the projects have been approved. There is, however, a present and urgent need to enable stakeholders to gain better understanding of decisions made at the project design stage if we wish to take advantage of our collective wisdom to explore opportunities for cost reductions in this era of massive transmission build-up. The current legislative framework also presumes prudence of project execution after a project has been approved by the Alberta Utilities Commission, unless interveners come forward to make a challenge.

Thank you for your continuing support. The TFCMC's next report is scheduled for the fourth quarter of 2012. Your comments to improve this report will be much appreciated. Please email your comments to **TFCMC@gov.ab.ca**

Henry Yip
Chair, Transmission Facilities Cost Monitoring Committee

1. Transmission Projects Covered Under The TFCMC's Mandate

The TFCMC has the authority to review records relating to the cost, scope and schedule of transmission facility projects that are expected to cost more than $100 million. These projects include all lines and substations, which make up the transmission facilities required to transfer power between generators and loads. The current list of monitored projects, in alphabetical order, is:

- **ALBERTA INDUSTRIAL HEARTLAND BULK TRANSMISSION DEVELOPMENT (HBTD);** PROJECT 629 – Construction of a double-circuit 500 kV transmission line, which will connect the Heartland region (northeast of Fort Saskatchewan) to existing 500 kV transmission facilities in the Edmonton area.
- **CENTRAL EAST AREA TRANSMISSION DEVELOPMENT (CETD);** PROJECT 811 – Transmission development in Wainwright, Lloydminster, Provost, Vegreville and Cold Lake.
- ***NEW* CHRISTINA LAKE AREA 240 KV TRANSMISSION DEVELOPMENT (CHL);** PROJECT 1101 – To establish transmission facilities to serve new oilsands developments and enhance reliability to existing oilsands operations.
- ***NEW* FOOTHILLS AREA TRANSMISSION DEVELOPMENT – EAST PROJECT (FATD);** PROJECT 1117 – To meet growing demand in South Calgary, High River and the surrounding area.
- **EDMONTON REGION 240 KV LINE UPGRADES (ERLU);** PROJECT 786 – Upgrading 240 kV lines in the Edmonton area; adding one 240 kV phase shifter at Dover substation.
- **ENMAX NO. 65 SUBSTATION (ESCS);** PROJECT 922 – New 240 kV substation in south Calgary and 138 kV development due to overloading in south Calgary.
- **FORT MCMURRAY AREA TRANSMISSION BULK SYSTEM REINFORCEMENT (FMAC);** PROJECT 838 – Construction of 500 kV transmission lines from the Edmonton region to the Fort McMurray area.
- **HANNA REGION TRANSMISSION DEVELOPMENT (HATD);** PROJECT 812 – Transmission development in Hanna, Sheerness and Battle River.
- **NORTH FORT MCMURRAY TRANSMISSION DEVELOPMENT (NFMD);** PROJECT 791 – Transmission development to relieve constraints and to serve forecast demand north of Fort McMurray.
- **NORTH SOUTH TRANSMISSION REINFORCEMENT (HVDC);** PROJECT 737 – Construction of two 500 kV HVDC transmission lines from the Edmonton area to the Calgary and south regions. **This project, as of February 23, 2012, received provincial government approval to proceed after previously being put under review by the government.**
- **NORTHWEST TRANSMISSION DEVELOPMENT (NWTD);** PROJECT 535 – Transmission expansion and enhancement in northwest Alberta.
- **RED DEER REGION TRANSMISSION DEVELOPMENT (RDTD);** PROJECT 813 – Transmission system reinforcements in the Red Deer area.
- **SOUTHERN ALBERTA TRANSMISSION REINFORCEMENT (SATR);** PROJECT 787 – To accommodate wind generation in southern Alberta.
- **YELLOWHEAD AREA TRANSMISSION DEVELOPMENT (YATD);** PROJECT 671 – To serve increased electricity demand, replace aging infrastructure and improve reliability in the Drayton Valley, Hinton, Edson and Alberta Beach areas.

2. TFCMC Observations To Date

As the TFCMC moves forward with its mandate to review the cost of major transmission projects, and after having completed initial in-depth assessments of these undertakings[1], the Committee has shifted its focus to a more detailed analysis of the projects based on the monthly information it receives.

As a result, a new monthly summary report was created to allow the TFCMC to more closely monitor costs as these projects proceed. By way of these new summary reports, the Committee has observed the following concerns and or issues. Projects are listed alphabetically.

HEARTLAND BULK TRANSMISSION PROJECT

(Project 629)

The Alberta Electric System Operator's (AESO) Long-Term Transmission Plan (filed June 2012) estimate for the Heartland Transmission Project was $537 million (2011 dollars). There has been a $41.5-million increase from the Proposal to Provide (PPS) estimate of $579.6 million (and the authorized budget) in May 2011; as of April 2012, the authorized budget is $621.1 million.

In the Alberta Utilities Commission (AUC) Decision 2011-436, the AUC directed Heartland to proceed with the East Preferred route using 9.5 kilometres of monopole structures, triggering approximately $27 million in additional costs.[2] This change also contributed to a seven-month delay to the in-service date, which is now September 30, 2013. The result of the AUC decision and the delay to the in-service date explains most of the $41.5-million increase in the authorized budget.

NORTH FORT MCMURRAY TRANSMISSION DEVELOPMENT

(Project 791)

There has been a $133.3-million increase in the authorized budget, from May 2011 to April 2012.

The largest single cause of the increase has been the rise in foundation costs given the more extensive geological data that was obtained for the area. It showed subsurface interference required grillage and caisson foundations at sites where H-piles cannot be used.

Construction contract prices have also come in above budget due to constrained contractor capacity. Furthermore, a five-week delay occurred due to exceptionally warm weather preventing access to areas that required frozen ground conditions in order to be reached. These previous cost increases, in turn, resulted in higher Engineering and Supervision costs.

SOUTHERN ALBERTA TRANSMISSION REINFORCEMENT

(Project 787)

Current authorized budgets for Southern Alberta Transmission Reinforcement (SATR) projects total $1.34 billion.

Several large Stage 2 projects and all Stage 3 SATR projects (for a line and terminals from Ware Junction to Langdon) do not currently have authorized budgets. The original Needs Identification Document (NID) estimate for all three stages of the SATR project, which included allowance for funds used during construction (or carrying costs) and escalation of $1.61 billion, was $3.44 billion.

When compared to the original NID estimates, there have been substantial increases in the costs of the Cassils to Bowmanton (CB) and Bowmanton to Whitla (BW) projects. These are primarily attributed to line length increases (11% for CB and 7% for BW), tower designs requiring heavier towers to meet new transmission line standards, more dead-end and angle structures than originally estimated, and increased costs for consulting, development of Facility Applications, facility hearings, and land acquisition.

1 New projects added to the TFCMC's purview will continue to receive an in-depth review in addition to being inserted into the Committee's month-to-month examination process.

2 See Alberta Utilities Commission Decision 2011-436, page 235, paragraph 1088.

Observations On New Projects

In the first part of 2012, two new transmission projects – Christina Lake Area[3] and the Foothills Area Transmission Development (East) – were added to the list of the projects the TFCMC monitors. The Committee's observations are as follows:

CHRISTINA LAKE AREA 240 KV TRANSMISSION DEVELOPMENT

(Project 1101)

The AESO presented information from the Christina Lake Area 240 kV Transmission Development NID as well as a cost summary to the TFCMC. The Christina Lake NID was approved by the AUC on April 24, 2012.

The AESO identified the need to expand the transmission system in the Christina Lake area, located northeast of the town of Lac La Biche, to serve increasing industrial demand. The existing transmission system facilities in the area are inadequate to serve growing demand, including the connection of new industrial customers. Depending on the customer/location, there is either no transmission infrastructure in the area to connect to, or the existing infrastructure lacks the capacity to serve the customers' load.

The AESO forecasts that electricity demand required for future industrial connections in the area will increase from approximately 50MW to between 390MW and 570MW by 2018/19. Growth is primarily related to expanding oilsands development in the area. The proposed transmission development plan for the area includes developing a 240 kV looped transmission system, including three new 240 kV substations, approximately 100 to 150 km of new 240 kV transmission line, and, modifications and expansion of existing transmission substations in the area.

Transmission development will occur in stages, with the first stage in service in the second quarter of 2013 at an estimated cost of $25 million (2013 dollars). The second stage is required in 2014 at an estimated cost of $105 million (2014 dollars). The final stage, required in 2015, is estimated at $280 million (2015 dollars).

AltaLink Management Ltd. and ATCO Electric Ltd. are currently developing Facilities Applications to support this development.

FOOTHILLS AREA TRANSMISSION DEVELOPMENT – EAST

(Project 1117)

The AESO presented information from the Foothills Area Transmission Development NID as well as a cost summary to the TFCMC. The Foothills Area – East NID is scheduled to be filed with the AUC in the summer of 2012.

The AESO identified the need for upgrades to the existing transmission system extending from South Calgary to within the vicinity of the Town of High River. Transmission system development is required to ensure the transmission system will serve growing electricity demand in developing areas, enable new generation facilities to be connected to the transmission system, and to maintain reliable electricity transmission and supply.

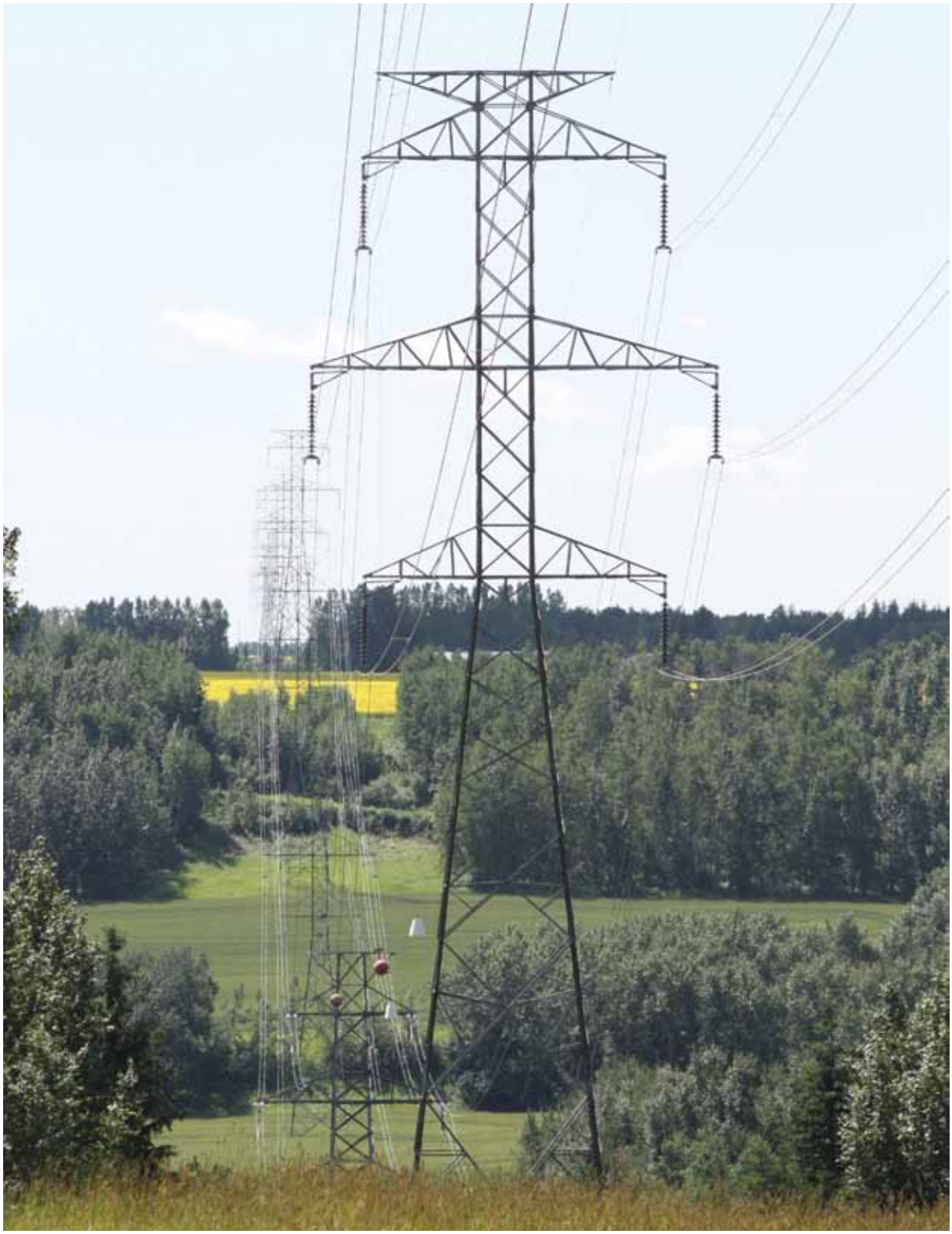
The AESO forecasts a 415MW load increase in the area by 2020. The compound average growth rate of electricity demand for the region is estimated at 2.4% (summer peak) by 2020.

The proposed transmission development plan includes new 240 kV transmission lines and a new 240/138 kV substation called Foothills 237S, along with upgrades and modifications at other substations in the area, including the Janet and Langdon substations. New 138 kV transmission lines will also be developed in the Okotoks and High River areas.

3 Material on the Christina Lake project was actually presented to the TFCMC in May 2012, during the production stages of this report. Committee members, however, felt it was important that this project should be added to the June 2012 Report rather than waiting until the end of the year for the December 2012 Report.

The target in-service date for this transmission development is winter 2014. The estimated cost is $420 million (2011 dollars).

AltaLink Management Ltd. and ENMAX Power Corp. are the Transmission Facility Owners (TFOs) for this project. Both are continuing to work on the associated Facilities Applications related to the NID.



3. The TCRS: An Update

Earlier this year the TFCMC accepted the report prepared by the Transmission Cost Recovery Subcommittee (TCRS), along with the accompanying simulation model developed by the subcommittee to evaluate the various options outlined in the report. The report and the simulation model were submitted to Alberta Energy as instructed by the then Minister of Energy Ron Liepert, when he directed the TFCMC to undertake the TCRS initiative.

The material was submitted on April 29, 2012. To date, as of the writing of this report, Alberta Energy has not officially released the report to stakeholders.

On February 23, 2012, the Alberta Government released its response to the Critical Transmission Review Committee Report (CTRC)[4]. In it, the Government laid out an action plan that included the following:

> *2. Pursue options to reduce the impact to consumers of the cost of transmission projects. This work will include:*
> - *Developing preliminary transmission cost recovery options by the existing Transmission Cost Recovery Subcommittee.*
> - *Directing the AUC to conduct a public transmission cost recovery inquiry into approaches that could mitigate the rate impact of new transmission on consumers.*
> - *Implementing changes to transmission cost recovery approaches as appropriate prior to the completion of the Western and Eastern Alberta Transmission Lines.*

As outlined in the December 2011 TFCMC Report, the TCRS examined several alternatives, including:

- Using a deferral account to manage rate increases;
- Levelizing tariffs for major projects using contractual agreements to mitigate a longer than normal recovery period, and
- Utilizing the Provincial Government's favourable credit rating to reduce financing costs for certain transmission projects.

Given the expressed intent of the Government as mentioned above, the TCRS report has been structured to lay out the options and their relative merits in order to achieve the end goal of moderating the rate impact from the transmission infrastructure development.

TCRS Backgrounder

In 2011, the TFCMC saw an opportunity where it could help to find ways to potentially minimize projected rate increases from Alberta's major electrical transmission build. With this in mind, the Committee approached the Minister of Energy to secure an expanded mandate so that it could move forward on this dossier.

Advising the Minister about its belief of a need to explore creative rate-setting solutions, the TFCMC submitted a formal request for a mandate extension, which was approved in late June 2011. The Minister's response noted that the TFCMC was well placed to undertake this endeavour and work with industry partners: the Transmission Facility Owners (TFOs), and, the Alberta Electric System Operator (AESO).

The TFCMC then formed the TCRS, with select members of the TFCMC taking part as well as representatives from AESO, AltaLink Management Ltd., ATCO Electric Ltd., ENMAX Power Corp. and EPCOR Distribution and Transmission Inc. The first meeting was held on August 10, 2011, and the last meeting on April 5, 2012, with deliberations to complete the TCRS report continuing over the next few weeks.

4 The CTRC was a special committee (composed of an independent panel of experts) appointed by the Alberta government in late 2011. It was handed a mandate to review plans for two high-voltage transmission lines between the Edmonton and Calgary areas.

4. Results to Date: Status of Previous TFCMC Recommendations

In its first two reports, June 2011 and December 2011, the TFCMC made eight recommendations – six in June 2011 and two in December 2011 – to help to improve the management of transmission costs.

Of the eight recommendations, six were directed to the Alberta Electric System Operator (AESO) and two have been made to the Alberta Department of Energy.

A number of the recommendations made to the AESO have been adopted. They are:

- That the AESO improve future NID estimates by including fully loaded costs – allowance for funds used during construction (AFUDC), escalation, engineering and supervision, and owners' cost (*June 2011 Report*);
- That the AESO improve the estimates in the AESO Long-Term Transmission Plan by employing third-party cost estimates or cost estimate verification as well as from benchmark data being compiled by AESO (*June 2011 Report*);
- That the AESO enhance compliance of the material procurement provisions of Rule 9.1 (*June 2011 Report*).

These recommendations to the AESO are in the process of being implemented:

- That the AESO develop a transmission cost benchmarking competency and database (*June 2011 Report*);
- Initiate a review process on the current framework for cost accountability (*June 2011 Report*);

A status report on the actions taken by the AESO to date on these two recommendations follows shortly. As to the last recommendation for the AESO, below, the AESO has expanded this December 2011 Report recommendation into the broader context of the cost accountability recommendation; to coordinate with the AUC on the development of a reporting protocol with respect to the reporting of transmission project costs.

- That for each Direct Assigned project, the AESO provide to the Alberta Utilities Commission (AUC) a summary of the scope changes authorized by the AESO for that project including the following:
  - I. The AESO's assessment on whether each scope change was needed;
  - II. A summary of the alternatives available to meet each scope change;
  - III. The AESO's assessment on whether the alternative recommended by the TFO to address each needed scope change was the most appropriate alternative, and
  - IV. The AESO's assessment on whether the cost of each scope change as estimated by the TFO was reasonable.
  - V. This information would form part of the AUC's consideration, under section 25(4) of the Transmission Regulation, in determining the TFO's prudence in managing the cost of the Direct Assigned project (*December 2011 Report*).

The TFCMC is encouraged by the overall direction the AESO is taking on these recommendations. The benchmarking database could enhance the Committee's approach to monitor project costs.

AESO Cost Benchmarking Recommendation Update

Based on the recommendations from the TFCMC, listed in the June 2011 Report, the AESO is developing a cost benchmarking database. The database will enable the AESO to further assess the reasonableness of the costs proposed by Transmission Facility Owners (TFOs) in the Needs Identification Document (NID) and Proposal to Provide Service (PPS) stages of a transmission development project.

The AESO has developed benchmarks of transmission cost estimates internal to Alberta and the data shows approximately 60% of transmission costs are dependent on market discipline and competitive pricing; these hard costs consist of labour, material and land acquisition. The remaining estimated 40% are categorized as soft costs and include items such as project management, contingency, escalation and others.

The AESO is currently developing benchmarks based on transmission projects external to Alberta to further develop the competency and database for use in evaluating costs for transmission projects in Alberta.

AESO Transmission Cost Accountability Recommendation Update

Also based on the recommendations from the TFCMC's June 2011 Report, the AESO began a review of the cost accountability framework in November 2011.

The review began with the publication of a discussion paper, which addressed several key areas of focus, and included stakeholder sessions to request comments and feedback.

The AESO recommended making adjustments within the current cost accountability framework based on the following considerations: stakeholder comments received on the discussion paper, public policy, and the current legislative and regulatory framework.

The recommended adjustments to the current framework include: developing a suitable reporting protocol with the Alberta Utilities Commission (AUC), continuing to work with the TFCMC, enhancing cost estimating quality and reporting, and initiating changes to ISO rules Section 9.1.

The AESO held stakeholder sessions in May 2012 and received stakeholder comments on the Draft Recommendation Paper on June 4, 2012.

The AESO is currently reviewing stakeholder feedback and will issue a Recommendation Paper in summer 2012 detailing the specific steps it will take to improve the current framework.

The Remaining Recommendations

Of the two recommendations directed to the Alberta Department of Energy, one[5] was considered premature by the Department given the implementation of the other recommendations from the June 2011 Report.

In the December 2011 Report[6], the TFCMC made a second recommendation for the Department to consider. The TFCMC is awaiting a response from the Department. The recommendation reads:

- That the Minister of Energy modify the Transmission Regulation to require TFOs to seek AESO authorization of CTI pre-construction expenditures incurred prior to AUC approval of the Facility Application.

5 The recommendation reads: That for non Critical Transmission Infrastructure (CTI) projects, the Department of Energy consider legislative changes to require a second approval stage by the AUC if cost estimates exceed a pre-determined limit. The TFCMC recognizes the need to avoid unnecessary project delays due to factors outside the control of the TFOs.

6 The December 2011 Report was actually released in early 2012 to accommodate the input of additional information. As well, a new provincial cabinet was named in 2012 and a new minister was appointed to the Energy portfolio.

5. TFCMC Conclusions & Recommendations

The TFCMC continues to receive monthly reports from the Alberta Electric System Operator (AESO) and the Transmission Facility Owners (TFOs) on all projects valued at $100 million and over. In addition, it undertakes more in-depth reviews on new projects. Recently, in-depth reviews were done on the Christina Lake Area 240 kV Transmission Development and the Foothills Area Transmission Development – East project.

In an effort to enhance the Committee's collective competence in understanding the factors affecting the cost of transmission infrastructure and in identifying opportunities to optimize costs, the TFCMC invited industry experts and TFO representatives to share their views and knowledge on selected subjects. Brief reports on three such subjects are included: FERC Order No. 1000, Tower Weights, and Enhancing Cost Monitoring.

FERC Order No. 1000: Transmission Planning And Cost Allocation

At the April 2012 TFCMC meeting, a presentation on Federal Energy Regulatory Commission (FERC) Order No. 1000 was provided by Andrew Young of K&L Gates LLP.

FERC Order No. 1000 has come into effect in the U.S. and deals with new guidelines respecting transmission planning and cost allocation for inter-connections. Although FERC Orders do not apply directly to Alberta, these new processes may have implications for our interties, and may provide some insight into the issues of planning and cost allocation as Alberta moves forward with its transmission build program.

The presentation covered a range of issues, several of which are current topics of concern for the Committee. The use of incentive-based rate treatment for new investments may have some application to keeping Alberta projects on time and within budgets. The six cost allocation principles enumerated by Mr. Young, whose area of practice concentrates on issues related to the energy industry, certainly touch on TFCMC concerns:

- Costs must be roughly commensurate with benefits;
- No involuntary allocation of costs to non-beneficiaries;
- No benefit to cost threshold ratio exceeding 1.25;
- Allocation solely within planning region, unless entity outside region voluntarily assumes costs;
- Transparent method for determining benefits and identifying beneficiaries, and
- Different methods may be used for different types of projects.

The discussion on non-incumbent (merchants or TFOs developing outside their area) developers also provides some guidelines for Alberta as it incorporates competitive bid practices:

- FERC eliminated Right of First Refusal ("ROFR") by incumbent transmission owners except for (1) local transmission facilities, and (2) upgrades to existing transmission facilities;
  - Does not pre-empt State siting or permitting rules;
  - Controversial and subject to many requests for rehearing;
- Develops qualification criteria for non-incumbent developers;
  - Criteria can address a range of issues but must include financial resources and technical expertise to build and operate transmission facilities, and
  - Competitive RFP process permitted but not required.

Mr. Young indicated that the initial FERC Order No. 1000 compliance filings are due in the fall of 2012 and may be quite controversial. The Committee will continue to monitor the application of FERC Order No. 1000 with respect to its impact and lessons for Alberta.

Tower Weights

During its deliberations, the TFCMC made the observation that the steel transmission towers being constructed by AltaLink for the 240 kV Cassils to Bowmanton to Whitla (CBW) portion of Project 787 – the Southern Alberta Transmission Reinforcement project – are substantially larger than existing towers on comparable similar voltage transmission lines.

This led to the concern as to whether the design parameters of the new towers and their associated costs were optimal. In response to a TFCMC Information Request (IR), AltaLink stated that the CBW towers were 2.5 times heavier than tangent structures and dead-end towers were 3.5 times heavier than similar towers (i.e., referred to as HW towers) used in Project 416 – SW 240 kV Transmission. It is noted that the CBW conductors are almost 50% larger than in the SW Project. The total thermal capacity of the CBW transmission lines are approximately twice that of the SW lines.

This concern led to some analysis by the Alberta Electric System Operator (AESO), to determine to what extent the change in "return periods" may have contributed to the larger and heavier structures – return periods are the inverse of the average probability that an event will happen in any given year. For example, a 75-year return period means there is a 1-in-75 year probability (on average) that an event, such as a certain radial ice accumulation, will occur. Stresses that cause transmission towers to fail are typically high winds, ice accumulation or heavy wet snow loading. Transmission towers must be designed to be able to withstand reasonably predicable levels of environmental loading that may occur in different parts of the province in order to maintain reliability.

The change in return periods arising from ISO rule Section 502.2 for 240 kV transmission lines is a change from a 50-year return period to a 75-year return period for single-circuit 240 kV transmission lines and a 100-year return period for double-circuit 240 kV transmission lines. This increase in the return period was based on recognition of the importance of the 240 kV system to the Alberta interconnected electric system reliability. The level of wind velocity and wet snow loading are based on specific weather conditions that vary across Alberta. Southern Alberta has the most stringent loading in Alberta. Combined wet snow and wind loading is based on a temperature of -5 degrees Celsius.

The AESO conducted a sensitivity analysis to determine the impact of varying the return periods of 240 kV double-circuit transmission line design. Three areas of Alberta, Zones B, C and D were evaluated, which included all of Alberta except for Zone A. Zone A is in the southwestern part of Alberta and encompasses Lethbridge and the Crowsnest Pass. The AESO utilized a weight estimating formula for tower weights and validated the model to known actual tower weights. There was no actual weight data for Zone D so comparisons were made to Zone B. The AESO's sensitivity analysis indicated that reducing the return period from 100-years to 50-years reduces tower weights by approximately 5% to 7% and reduces costs by approximately 3% to 8%.

Snow and Ice Loading Zones

Weather Loading Summary - AESO Tower Development

Wet Snow & Wind Loadings

100 Year Return Values

	Radial Wet Snow Accretion (mm)	Wind Speed (km/hr) at 10m Height	Wind Pressure (Pa) at 20 m Height	Wind Pressure (Pa) at 30 m Height	Wind Pressure (Pa) at 40 m Height
Zone A	70	77	295	320	340
Zone B	70	71	240	260	280
Zone C	50	67	210	230	245
Zone D	50	64	190	205	220

75 Year Return Values

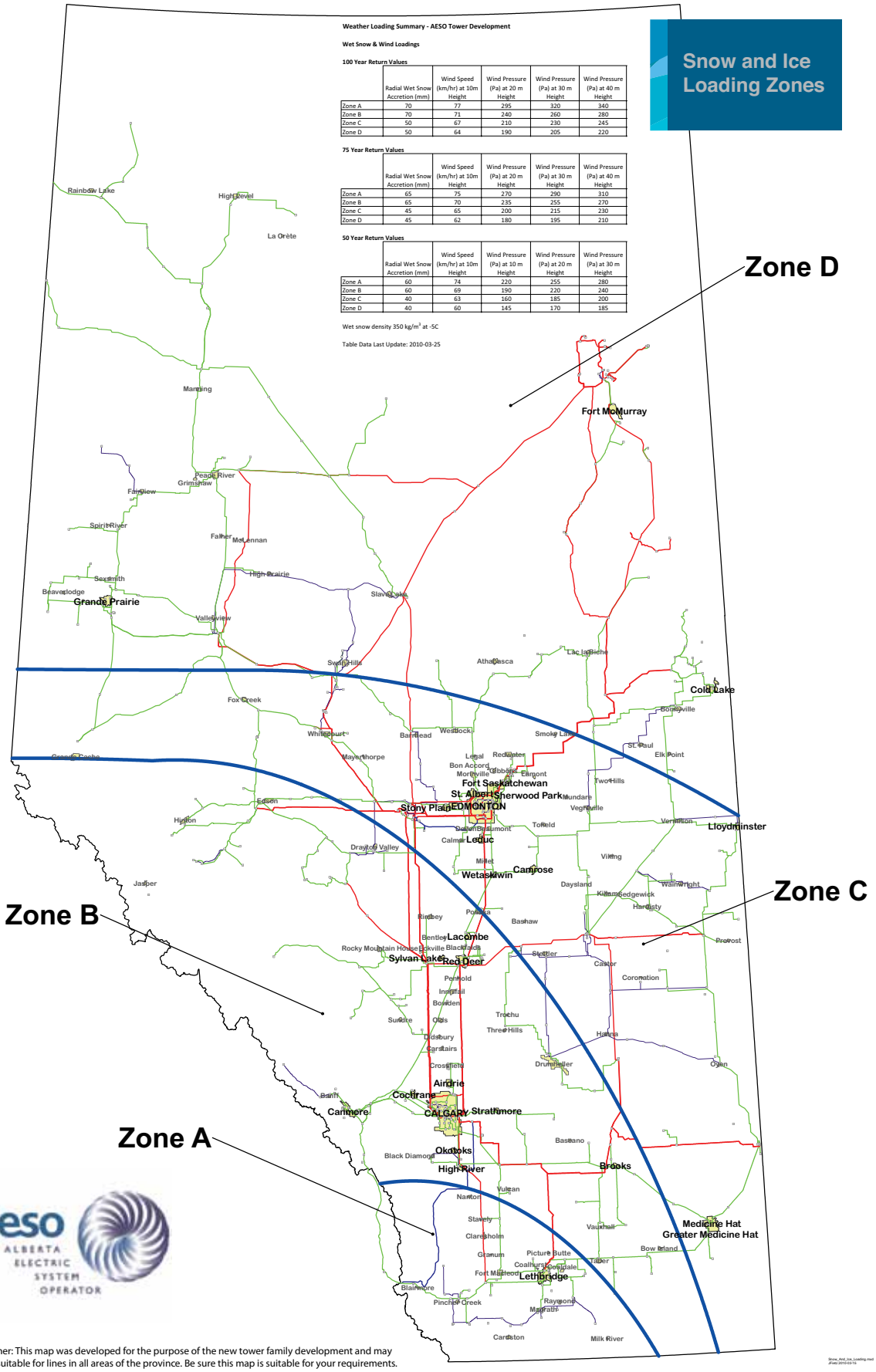
	Radial Wet Snow Accretion (mm)	Wind Speed (km/hr) at 10m Height	Wind Pressure (Pa) at 20 m Height	Wind Pressure (Pa) at 30 m Height	Wind Pressure (Pa) at 40 m Height
Zone A	65	75	270	290	310
Zone B	65	70	235	255	270
Zone C	45	65	200	215	230
Zone D	45	62	180	195	210

50 Year Return Values

	Radial Wet Snow Accretion (mm)	Wind Speed (km/hr) at 10m Height	Wind Pressure (Pa) at 10 m Height	Wind Pressure (Pa) at 20 m Height	Wind Pressure (Pa) at 30 m Height
Zone A	60	74	220	255	280
Zone B	60	69	190	220	240
Zone C	40	63	160	185	200
Zone D	40	60	145	170	185

Wet snow density 350 kg/m^3 at -5C

Table Data Last Update: 2010-03-25



Disclaimer: This map was developed for the purpose of the new tower family development and may not be suitable for lines in all areas of the province. Be sure this map is suitable for your requirements.

Snow_And_Ice_Loading.mxd
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The sensitivity analysis conducted by the AESO suggests that the return-period is not contributing materially to tower weight increases and thereby total line cost increases. The AESO suggests the drivers for the increased tower weights are, (1) increased wet snow loading criteria, (2) galloping criteria (HW design does not consider this), and (3) unequal leg extension considerations and other minor factors; with each contributing roughly a third of the weight increase.

AltaLink's statement that the towers are 2.5 times heavier than previous towers may also be driving substantial increases in foundation costs. The analysis is further complicated by the increased conductor size used in the CBW project.

Increased tower weight and consequently more steel may drive increased shipping and installation costs, and possibly longer construction periods. In areas where construction is not allowed in certain parts of the year, a longer construction period runs the increased risk of requiring another construction year – leading to a considerable increase in costs, due to interest charges, storage, security, mobilization and demobilization costs. Finally, the TFCMC notes that given that there are a number of interacting factors involved in driving tower weights and associated construction costs, analysis of these costs to identify any potential sub-optimality is complex. The TFCMC expects to continue exploring these cost drivers in its efforts to monitor transmission costs.

Enhancing TFCMC Cost Monitoring/TFCMC Future Considerations

To date, the TFCMC has focused on the linear aspects of the major transmission line projects under review – mainly overall project costs and schedules.

Less attention has been paid to the costs of the component parts of the projects such as right-of-way expenses, tower footing designs, steel tower designs, alternative conductor selection and ancillary materials and equipment required in substations. AC integration studies carried out by the AESO define the characteristics and components of each of the major transmission lines being developed. An estimate of costs is prepared by the AESO in the Needs Identification Document (NID) and forwarded to the appropriate TFOs for development into a Proposal to Provide Service (PPS).

The PPS reflects the functional specification documents. The TFO's transmission line designs generally reflect specific climate conditions of the province and consider future developments in the regional area.

As a means to check on the feasibility of the project design, the AESO is planning to establish a benchmarking program during which they will compare component costs with other jurisdictions across Canada. Proposed designs will be compared with other projects in the same area in the province. The return periods will be examined for compliance with climate patterns in various areas of the province. Weather conditions vary dramatically in Alberta from the ice and wind prone southwest to the drier and colder northeast, thus transmission line designs will vary considerably and likewise so will costs per kilometre.

The next step in the process will be to determine necessary actions to keep transmission line development component costs within a zone of reasonableness compared to other jurisdictions in Canada.

It is important that TFCMC members have some knowledge of the major components of transmission lines and high-voltage equipment so that they are able to make informed decisions regarding the cost of equipment to be installed. Knowledge of labour rates comparative to the Alberta market and the rest of Canada would also assist members with overall project costs.

The details of the component parts of transmission projects could be provided by designers from the AESO. There is a general feeling among TFCMC members that transmission and station projects in Alberta may be more costly than other areas of the country. Specification comparisons for similar voltage projects elsewhere in Canada would also be valuable to review.

The TFCMC intends to take advantage of data made available from AESO's benchmarking program to broaden its focus on monitoring project costs.

Recommendations

As recommended in the TFCMC's June 2011 Report, AESO is developing an effective and comprehensive benchmarking database. The information contained in this database will enhance AESO's ability to evaluate estimated project costs by cost elements.

The Committee believes the information from benchmarking database can be of assistance in the regulatory approval process for transmission projects. The TFCMC therefore recommends:

That for each Direct Assigned Capital project estimated to cost in excess of $100 million[7] at the Needs Identification Document stage, the AESO will publish a cost benchmarking report at the time the Transmission Facility Owner files its Facility Application with the Alberta Utilities Commission for approval. To the extent that there are significant project cost changes between the Proposal to Provide Service stage and the TFO's application before the AUC for rate base approval, the AESO will update and publish its cost benchmark report.

7 According to Section 10 of Ministerial Order 64/2010, the mandate of the TFCMC is to review all Transmission Facility Projects forecast to cost in excess of $100 million. In a letter dated January 12, 2011, the Minister of Energy clarified that the starting point for the TFCMC when reviewing cost variances is the estimate in place when a project is approved by an Order in Council for Critical Transmission Infrastructure (CTI) projects, or, the estimate in place when the Needs Identification Document (NID) is approved by the Alberta Utilities Commission (AUC). The AESO, of course, is at liberty to file benchmarking cost reports with various stakeholders, including the AUC, in respect of projects below the $100-million threshold.

Appendix A: About The TFCMC

Origin And Composition Of The Transmission Facilities Cost Monitoring Committee

The Government of Alberta created the Transmission Facilities Cost Monitoring Committee (TFCMC) on July 31, 2010, through a Ministerial Order issued by the Honourable Ronald Liepert, then Minister of Energy, in order to make sure Albertans have the benefit of increased transparency on the cost of transmission projects.

According to the Ministerial Order, number 64/2010, the TFCMC can consist of up to 13 individuals as follows:

- the **Alberta Association of Municipal Districts and Counties** may appoint one member;
- the **Alberta Chambers of Commerce** may appoint one member;
- the **Alberta Direct Connect Consumers Association** may appoint one member;
- the **Alberta Federation of Rural Electrification Associations** may appoint one member;
- the **Alberta Urban Municipalities Association** may appoint one member;
- the **Consumers' Coalition of Alberta** may appoint one member;
- the **Canadian Federation of Independent Business** may appoint one member;
- the **Industrial Power Consumers Association of Alberta** may appoint one member;
- the **Independent Power Producers Society of Alberta** may appoint one member;
- the Minister may also appoint up to two ***independent members*** with technical, regulatory, transmission facility development or other experience that, in the opinion of the Minister, will benefit the Committee;
- the **Independent System Operator** ("Alberta Electric System Operator") shall appoint one member, and
- the **Office of the Utilities Consumer Advocate** shall appoint one member.

The TFCMC's Mandate

The TFCMC's mandate is to review records that relate to the cost, scope, schedule and variances of Alberta transmission facility projects forecast to cost in excess of $100 million. This may include more than one transmission facility, if it is a part of a contiguous transmission facility project. The Alberta Electric System Operator (AESO), a not-for-profit entity that is responsible for the safe, reliable and economic planning and operation of Alberta's transmission system (also known as the Alberta Interconnected Electric System) determines which transmission facilities are part of a transmission facility project.

In a letter dated January 12, 2011, the Minister of Energy clarified that the starting point for the TFCMC when reviewing cost variances is the estimate in place when a project is approved by an Order in Council for Critical Transmission Infrastructure (CTI) projects, or, the estimate in place when the Needs Identification Document (NID) is approved by the Alberta Utilities Commission (AUC). The TFCMC, therefore, does not review any of the projects from an initial prudence, need, technology choice or staging perspective.

The TFCMC cannot delay or slow the development of transmission facility projects.

In late June 2011, the Minister of Energy provided his support of a request from the TFCMC to explore and develop innovative approaches to cost recovery for new transmission facilities in Alberta. The TFCMC was asked to undertake this initiative on a priority basis, together with the Transmission Facility Owners (TFOs), the AESO and Alberta Energy. The findings of this initiative were submitted in April 2012 to the Assistant Deputy Minister, Electricity, Alternative Energy and Carbon Capture and Storage, for consideration and action.

The TFCMC's Members

The 11 organizations and two independents named in the Ministerial Order forming the TFCMC represent a cross-section of industry, consumer and business groups with ties to Alberta's electricity sector.

Organizations and independent members are listed alphabetically:

Alberta Association of Municipal Districts and Counties (AAMDC)

The AAMDC advocates on behalf of the province's 69 municipal districts and counties. The association assists its members in achieving strong, effective local government. The AAMDC representative on the TFCMC is **Dwight Oliver, Past Director for AAMDC District 2**.

Alberta Chambers of Commerce (ACC)

The ACC is a federation of 125 Chambers of Commerce, which in turn represents more than 23,000 businesses. The ACC ensures its members' business interests are improved through the development and advocacy of policy to the provincial and federal governments. The ACC representative on the TFCMC is **Ken Kobly, ACC President & CEO**.

Alberta Direct Connect Consumers Association (ADC)

The ADC represents nine large industrial consumers who have facilities directly connected to the transmission system. The ADC members represent the key sectors of forestry, chemical and cement manufacturing. The aggregate electricity demand of the membership represents about 7% of the Alberta load. The ADC representative on the TFCMC is **Colette Chekerda, ADC Executive Director**.

Alberta Electric System Operator (AESO)

The AESO is a not-for-profit entity, is independent of any industry affiliations, and owns no transmission or market assets. It is responsible for the safe, reliable and economic planning and operation of the Alberta Interconnected Electric System. The AESO representative on the TFCMC is **Jerry Mossing, AESO's Director of Transmission Support**.

Alberta Federation of Rural Electrification Associations (AFREA)

The AFREA is a not-for-profit cooperative association representing member Rural Electrification Associations (REAs) who provide rural power services throughout Alberta. It is committed to promoting the economic welfare and value of its cooperative members by providing strong representation to government and industry stakeholders with one voice. The AFREA representative on the TFCMC is **Dan Astner, AFREA 2nd Vice President**.

Alberta Urban Municipalities Association (AUMA)

The AUMA represents Alberta's 277 urban municipalities including cities, towns, villages, summer villages, and specialized municipalities. AUMA represents and advocates the interests of its members to the provincial and federal governments. The AUMA representative on the TFCMC is **Darren Aldous, AUMA Past President**.

Canadian Federation of Independent Business (CFIB)

The CFIB is an association representing small- and medium-sized businesses across Canada that takes direction from its more than 109,000 members, providing independent businesses a voice at all levels of government. The CFIB representative on the TFCMC is **Richard Truscott, the CFIB's Director of Provincial Affairs for Alberta**.

Consumers' Coalition of Alberta (CCA)

The CCA is comprised of the Consumers' Association of Canada (Alberta Division) and the Alberta Council on Aging. The CCA, a coalition of two public interest groups, participates as a collective in public utility hearings to ensure rates, tolls and charges for residential customers are just and reasonable. The CCA representative on the TFCMC is **Azad Merani, CCA Consultant**.

Independent Power Producers Society of Alberta (IPPSA)

The IPPSA represents Alberta's power producers. IPPSA is a forum for dialogue among Alberta's power producers and a proponent of competition in Alberta's electricity market. The IPPSA representative on the TFCMC is **Evan Bahry, IPPSA's Executive Director**.

Industrial Power Consumers Association of Alberta (IPCAA)

The IPCAA is an organization representing large industrial customers, including such key sectors as oil & gas, forest products, petrochemicals and steel. Its mission is to take a leadership role in achieving a fair, open and efficient marketplace for electricity sales and service in Alberta. The IPCAA representative on the TFCMC is **Sheldon Fulton**.

Office of the Utilities Consumer Advocate (UCA)

The UCA is the voice of small consumers in Alberta's electricity and gas markets. The UCA advocates on behalf of Alberta's low-volume or smaller users of electricity and natural gas, those being residential, small business and farm utilities consumers, and helps them to make informed choices. As well, the UCA represents and protects their interests by participating in utility hearings and inquiries. The UCA representative on the TFCMC is **Wayne Taylor**.

TFCMC Independent Members:

Allen Snyder, of Winnipeg, brings a background and a wealth of knowledge in the electricity sector to the TFCMC. He held several key executive positions with Manitoba Hydro including Vice President of Transmission & Distribution, Power Supply and Corporate Services over the past 20 years. He also established a very successful Manitoba Hydro International with sales of software and services to more than 60 countries worldwide. Currently, he is Vice President of Energy Services for Wood West & Associates.

Henry Yip is a senior business executive with more than 30 years of broad business experience in Canada and the USA. He has held senior executive positions in large corporations and entrepreneurial business enterprises, and has advised governments in the area of city planning, strategy development, technology commercialization, international business collaboration and grant application approval. His current business interests include Executive Chair at Nirix Technology, and President of C'andcee Development. He is the past Chair of the Board at Edmonton Economic Development Corporation.

The Operations Of The TFCMC

The TFCMC meets monthly, alternating between the cities of Calgary and Edmonton. The primary purpose of the meetings is to review reports provided by AESO on the cost status of transmission projects that are within the Committee's purview. The first meeting took place in September 2010.

The TFCMC reviews the reasons for cost variances of all these projects. When appropriate, it retains external experts to prepare information requests (IRs) to AESO and the Transmission Facility Owners (TFOs) for further illumination on the reasons for the variances.

Each calendar year, the TFCMC is required to provide at least two reports to the member organizations represented on the committee as well as at least one report to the Ministers of Energy and Service Alberta. The reports summarize the records it reviews and the status of the transmission facility projects.

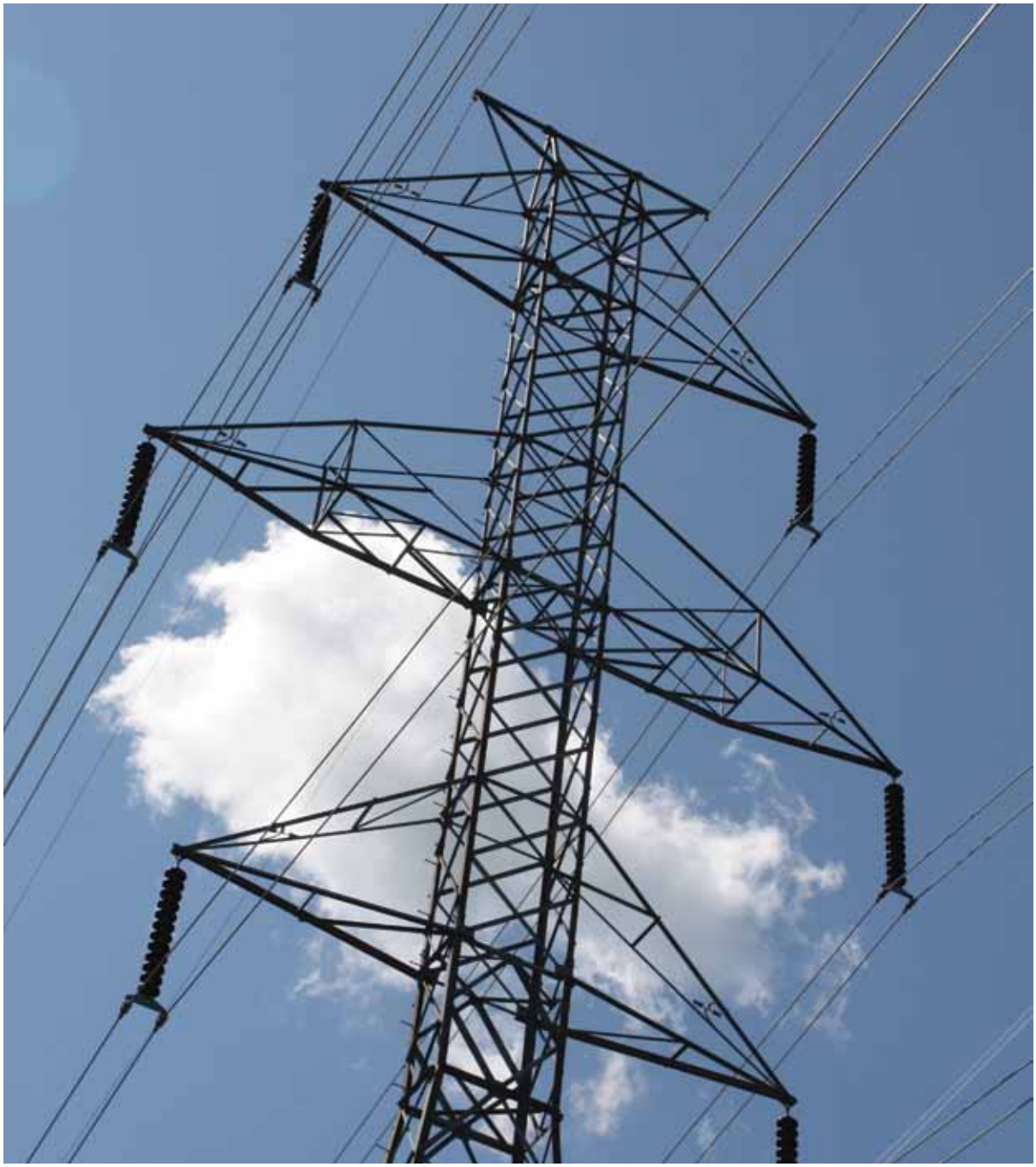
The TFCMC strives for consensus in its decision-making process but a simple majority of those present at a meeting is the minimum threshold for agreement.

Independent member Henry Yip chairs the TFCMC. The TFCMC secretary is Laura Severs, engaged through the Office of the Utilities Consumers Advocate (UCA) for the purpose of this role.

The TFCMC will also form subcommittees from time to time to facilitate the workings of the Committee. There were three active subcommittees in operation during the period of this report:

- A standing subcommittee to monitor and approve expenditures incurred by the members of the TFCMC during the course of discharging its mandate. Sheldon Fulton chairs this subcommittee.

- The Information Request (IR) subcommittee. This group develops appropriate questions for the TFOs in order to get clarifications on information previously provided by the TFOs on the cost status of the various transmission projects. This subcommittee is supported by external expert advisors when required. Allen Snyder chairs this subcommittee.
- The Transmission Cost Recovery Subcommittee (TCRS) was created in response to the June 28, 2011, letter from the Minister of Energy requesting the TFCMC to explore and develop innovative approaches to cost recovery for new transmission facilities in Alberta. The TCRS, whose members include representatives from AltaLink, ATCO, ENMAX and EPCOR as well as some of the TFCMC members, met on an as-required basis. The first meeting took place in August 2011. TFCMC Chair Henry Yip and TFCMC secretary Laura Severs reprised their roles for this subcommittee, which completed its original undertakings in April 2012.



Appendix B: The Transmission Projects At A Glance

1. **ALBERTA INDUSTRIAL HEARTLAND BULK TRANSMISSION DEVELOPMENT (HBTD);** PROJECT 629 – Construction of a double-circuit 500 kV transmission line, which will connect the Heartland region (northeast of Fort Saskatchewan) to existing 500 kV transmission facilities in the Edmonton area.

THE PROJECT: The Alberta Industrial Heartland Bulk Transmission Development calls for the construction of a double-circuit 500 kV transmission line, which will connect the Heartland region (northeast of Fort Saskatchewan) to existing 500 kV transmission facilities on the south side of Edmonton. This upgrade is to respond to the growing demand for power in this region. The Heartland project will form the foundation of electricity supply into northeast Alberta and will support oilsands development, local demand in the Heartland area and strengthen the entire provincial network.

THE COMPONENTS: A 500 kV AC double-circuit transmission line connecting the 500 kV system on the south side of Edmonton to the new Heartland 12S Substation (the 500 kV Line Project); a 240 kV/500 kV Heartland 12S Substation, located approximately 15 kilometres northeast of Edmonton in the Gibbons-Redwater region (the Heartland 12S Substation Project), and a 240 kV double-circuit transmission line connecting the existing 240 kV system in the area to the new Heartland 12S Substation (the 240 kV Line Project). The Industrial Heartland region includes parts of Sturgeon, Strathcona and Lamont counties.

FACILITY APPLICATION NAME	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
500 kV 1206L/1212L	Sixty-five kilometres of 500 kV double-circuit line from Ellerslie to Heartland substation	September 30, 2013
Heartland 12S Ellerslie 89S and 1054L/1061L	Heartland 500 kV sub and 22 kilometres of 240 kV lines to tie in the existing system	September 30, 2013

THE TRANSMISSION FACILITY OWNER(S): AltaLink L.P. and EPCOR Distribution & Transmission Inc.

PROJECT COST:

TRANSMISSION PROJECT	AESO LONG-TERM TRANSMISSION PLAN (FILED JUNE 2012)[8] ESTIMATED COST	CURRENT ESTIMATED COST
Alberta Industrial Heartland Bulk Transmission Development	**$537 Million** (2011$ without escalation)	**$622 Million** (ISD$ with escalation)[9]

CURRENT STATUS: On November 1, 2011, the Alberta Utilities Commission (AUC) approved the Heartland Transmission Project, including its preferred east route option, with conditions. The preferred east route for the line skirts the city of Edmonton to the south and east and travels through an existing transportation and utility corridor (TUC) for roughly half the line's length. The AUC concluded the preferred east route is both in the public interest and superior to the alternate west route based on land use, cost and environmental considerations. The preferred east route would utilize the public lands of the TUC, which were set aside to provide a location for this type of project.

The AUC concluded an underground option would not be in the public interest as the evidence presented indicated it would not mitigate electric and magnetic fields (EMF) or materially mitigate the impact on property values, while it would substantially raise costs. On EMF, the AUC found evidence showed there would be no material difference between underground and overhead lines at the nearest residences, schools, daycares, hospitals and businesses, and that EMF produced by the lines "will be much lower, and likely indistinguishable from, background magnetic field levels at the nearest residences, schools,

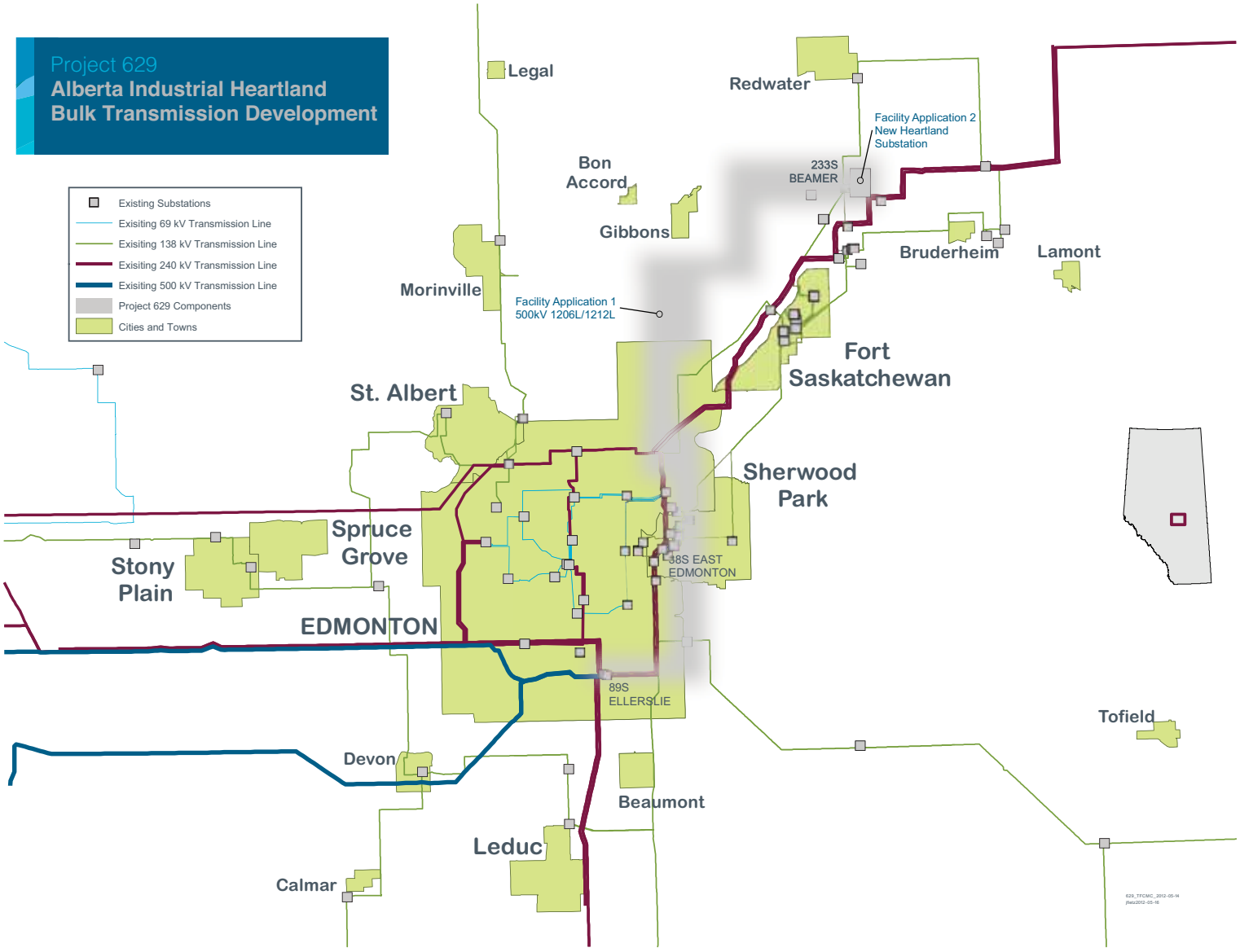
8 The AESO Long-Term Transmission Plan, as noted here in Appendix B, was filed in June 2012 during the production of this report and is being used to provide more up to date project costs and information.

9 The cost is based upon either the TFO's April 2012 Monthly Project Progress Report or other information provided to the TFCMC; this material was actually provided to the TFCMC in June 2012, during the production of this report.

daycares, hospitals and businesses." The AUC has required that EMF monitoring be conducted at Colchester Elementary School before and after construction of the line.

The AUC has required monopoles for a 9.5-kilometre stretch from Highway 14 to Baseline Road, to reduce the visual impact on residents in the area. The AUC also asked the applicants to examine additional options for routing the line near the Colchester Elementary School to reduce visual impact, which could move the line a further 50 metres, to 190 metres from the schoolyard, while remaining 213 metres from the school building. Following receipt of Permit and License (P&L) on December 22, 2011, the Heartland team has submitted a $41.1-million change notice to reflect AUC hearing commitments and decision requirements. The AESO subsequently approved the change resulting in an amended project budget of $622 million and a revised in-service date of September 30, 2013 – previously, the forecast in-service date was March 30, 2013.

The project is currently under construction.



2. **CENTRAL EAST AREA TRANSMISSION DEVELOPMENT (CETD);** PROJECT 811 – Transmission development in Wainwright, Lloydminster, Provost, Vegreville and Cold Lake.

THE PROJECT: The Central East project serves the dual purpose of meeting the growing demand for electricity from oilsands development and pipelines, and will enable the connection of more than 500 MW of proposed gas-fired generation and wind farms in the eastern region of Central Alberta. Aging infrastructure, overloads and low voltages in the large area east of Edmonton from Cold Lake in the Northeast region to Hardisty necessitate the substantial rebuild of the 138 kV and 144 kV systems, and decommissioning of aging 69 kV and 72 kV lines.

THE COMPONENTS: There are two stages of transmission development for the project.

The major components for Stage 1 of the project are: a new 144/25 kV Watt Lake substation; the conversation of three existing 72/25 kV substations to 144/25 kV; a new 240 kV switching station in the Cold Lake Area that will be energized at 144 kV initially; a new double-circuit 144 kV line from the existing Mahihkan 837S to the new switching station; a new 240 kV double-circuit line (one side strung) from the new switching station to the existing Bonnyville 700S and initially energized at 144 kV; a new single-circuit 138 kV line from Provost 545S to Hayter 277S; a new 138 kV double-circuit line from Killarney 267S to the existing 749L; a new single-circuit line from the existing Wainwright 51S to the existing Edgerton 899S; a new 144 kV capacitor bank at Vermilion 710S; the addition of a 138/72 kV transformer at the existing Wainwright 51S; rebuild six existing 138 kV or 144 kV lines to increase capacity, and restore ratings of the existing 144 kV lines by mitigating line clearances and discontinuing the use of existing 72 kV equipment at existing substations or lines.

The major components for Stage 2 of the project are: rebuild one existing 144 kV line to increase capacity and a new 240 kV double-circuit line (one side strung) from the new switching station to the existing Marguerite Lake 826S.

FACILITY APPLICATION NAME	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
Cold Lake Area Reinforcements (Except Bonnyville to Bourque)	New 144 kV switching station (Bourque 970S), new 144 kV double-circuit line from existing Mahihkan 837S to new 144 kV switching station and rebuild existing 144 kV lines (7L87, 7L74 and 7L83)	March 1, 2013
Cold Lake Area Reinforcements – Bonnyville	New 240 kV double-circuit line (one side strung) from new 144 kV switching station to existing Bonnyville 700S and initially energized at 144 kV	August 1, 2013
St. Paul Area Upgrades – Watt Lake, 7LA92	New 144/25 kV Watt Lake and new 144 kV line from Watt Lake to existing 7L92	December 1, 2012
St. Paul Area Upgrades – St. Paul 707S, Whitby Lake 819S & 7L139/7L70	Rebuild St. Paul 707S from 72/25 kV to 144/25 kV substation, new 144 kV double-circuit line from St. Paul 707S to existing 7L70 creating an "in and out" configuration	October 1, 2013
Vermilion 710S Substation Upgrade	Addition of 144 kV – 25 MVar capacitor bank; addition of a new 144/25 kV transformer; relocation of existing 144/72/25 kV transformer to Heisler 764S; discontinue use of existing 72 kV equipment at Vermilion 710S and discontinue use of 6L06 (Kitscoty 705S to Vermilion 710S)	October 1, 2012

FACILITY APPLICATION NAME	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
Heisler Area Upgrades	Convert Heisler 764S from 72 kV to 144 kV; addition of 144/72/25 kV transformer from Vermilion 710S; new 144 kV single-circuit line from Heisler 764S to existing 7L701 and discontinue use of existing 6L05	November 1, 2012
Kitscoty Area Upgrades	Convert Kitscoty 705S from 72 kV to 144 kV; addition of 144/72/25 kV transformer from Heisler 764S, new 144 kV double-circuit line from Kitscoty 705S to existing 7L14	July 1, 2013
7L749 Replacement	Rebuild existing 749L/7L749 from Metiskow 648S to Lloydminster 716S	January 1, 2014
Line Clearance Mitigations	Restore ratings of existing 144 kV lines by mitigating line clearances	December 31, 2012
Provost & Wainwright Area Upgrades	New single circuit 138 kV line from Provost 545S to Hayter 277S; new 138 kV double-circuit line from Killarney 267S to existing 749L; new single circuit line from existing Wainwright 51S to existing Edgerton 899S; addition of a 138/72 kV transformer at existing Wainwright 51S, rebuild three existing 138 kV lines to increase capacity	September 1, 2014

THE TRANSMISSION FACILITY OWNER(S): AltaLink L.P. and ATCO Electric Ltd.

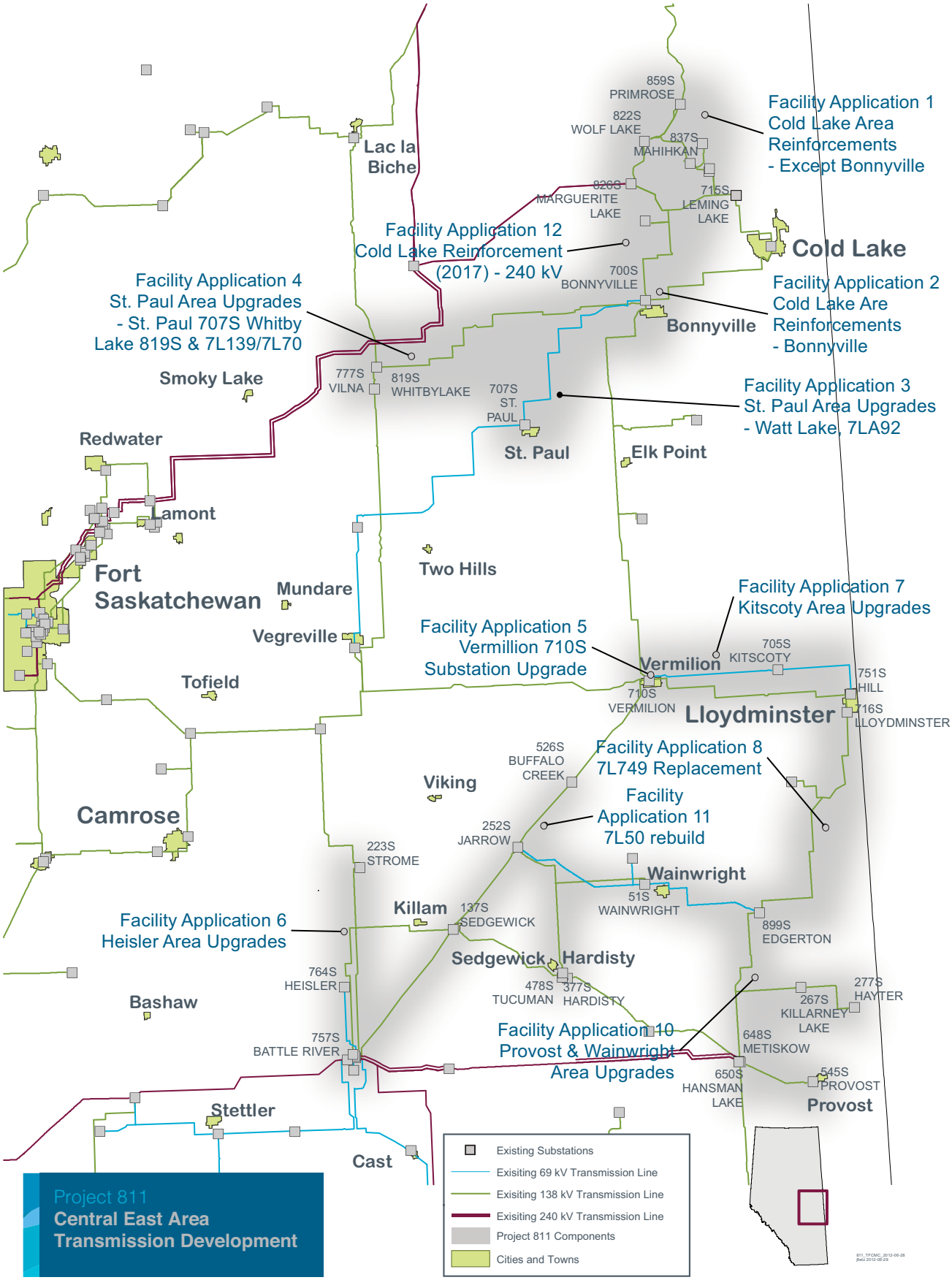
PROJECT COST:

TRANSMISSION PROJECT	AESO LONG-TERM TRANSMISSION PLAN (FILED JUNE 2012) ESTIMATED COST	CURRENT ESTIMATED COST
Central East Area Transmission Development	**$352 Million** (2011$ without escalation)	**$449 Million** (ISD$ with escalation for Stage 1)[10]

CURRENT STATUS: The AUC approved the Central East Transmission Development Needs Identification Document (NID) in February 2011. For Stage 1 of the Central East Transmission Development, ATCO has received AUC approval for four Facility Applications (7L701 Clearance mitigation, Heisler 764S, Whitby Lake and Vermilion 710S) and moving through the construction phase. As well, four Facility Applications (Watt Lake, 7L87 rebuild, Bourque substation and associated lines, and Bonnyville substation and Bonnyville to Bourque) have been filed with the AUC, and it is expected that ATCO will be filing the remaining Facility Applications in Q3 2012. Further, the Alberta Electric System Operator (AESO) has identified the need to advance the 7L50 upgrade as a result of a generation connection project that will affect this line.

In regards to Stage 2 of the CETD, the NID identified that this was required by 2017. Once the regional plan for this area is completed in 2013, the AESO will be able to determine the timing for the remaining Stage 2 development for the Hanna Region Transmission Development.

10 The cost is based upon either the TFO's April 2012 Monthly Project Progress Report or other information provided to the TFCMC; this material was actually provided to the TFCMC in June 2012, during the production of this report.


Facility Application 1
Cold Lake Area
Reinforcements
- Except Bonnyville
859S
PRIMROSE
822S
WOLF LAKE
837S
MAHIHKAN
826S
MARGUERITE
LAKE
715S
LEMING
LAKE
Cold Lake
Lac la
Biche
Facility Application 12
Cold Lake Reinforcement
(2017) - 240 kV
700S
BONNYVILLE
Facility Application 2
Cold Lake Are
Reinforcements
- Bonnyville
Bonnyville
Facility Application 4
St. Paul Area Upgrades
- St. Paul 707S Whitby
Lake 819S & 7L139/7L70
Smoky Lake
777S
VILNA
819S
WHITBYLAKE
707S
ST.
PAUL
Facility Application 3
St. Paul Area Upgrades
- Watt Lake, 7LA92
St. Paul
Elk Point
Redwater
amont
Fort
Saskatchewan
Mundare
Two Hills
Vegreville
Facility Application 7
Kitscoty Area Upgrades
Facility Application 5
Vermillion 710S
Substation Upgrade
705S
KITSCOTY
Vermilion
751S
HILL
710S
VERMILION
Lloydminster
716S
LLOYDMINSTER
Tofield
526S
BUFFALO
CREEK
Facility Application 8
7L749 Replacement
Viking
Facility
Application 11
7L50 rebuild
Camrose
252S
JARROW
223S
STROME
Wainwright
51S
WAINWRIGHT
Killam
137S
SEDGEWICK
Facility Application 6
Heisler Area Upgrades
899S
EDGERTON
Sedgewick
Hardisty
764S
HEISLER
478S
TUCUMAN
377S
HARDISTY
277S
HAYTER
Bashaw
267S
KILLARNEY
LAKE
Facility Application 10
Provost & Wainwright
Area Upgrades
757S
BATTLE RIVER
648S
METISKOW
650S
HANSMAN
LAKE
545S
PROVOST
Provost
Stettler
Cast
Existing Substations
Exisiting 69 kV Transmission Line
Exisiting 138 kV Transmission Line
Exisiting 240 kV Transmission Line
Project 811 Components
Cities and Towns
Project 811
Central East Area
Transmission Development

3. ***NEW* CHRISTINA LAKE AREA TRANSMISSION DEVELOPMENT (CHL);** PROJECT 1101 – Reinforcing transmission facilities for oilsands developments and enhanced reliability to existing oilsands operations.

THE PROJECT: Strong oilsands development, including Steam Assisted Gravity Drainage (SAGD) and pump station facilities, in the Christina Lake area, located approximately 140 km south of the City of Fort McMurray and 100 km to the northeast of Lac La Biche, is driving this development. This project would ensure the area's transmission network is reinforced to support current load and to ensure adequate capacity to connect customers in the near-and-long term. The Christina Lake plan will reinforce the existing 138 kV network in the southern part of the area through the development of the new CHL2 240/138 kV substation, and will reinforce the 240 kV network in the north of the Christina Lake area by closing the loop through the existing Heart Lake A898S substation.

THE COMPONENTS: The AESO has proposed a transmission development plan for the area that includes developing a 240 kV looped transmission system, including three new 240 kV substations; approximately 100 km to 150 km of new 240 kV transmission line, and modifications and expansion of existing transmission substations in the area. The project consists of a new 240 kV switching station and a new 240/138 kV substation.

FACILITY APPLICATION NAME	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
Black Spruce substation and 240 kV lines	Black Spruce substation and interconnecting 240 kV lines	June 3, 2013
Pike substation and 240 kV lines	Pike substation and interconnecting 240 kV lines	February 28, 2014
Pike to Ipiatik to Heart Lake and 240 kV lines	240 kV line from Ells River to Birchwood Creek substation	August 28, 2015
Heart Lake expansion	Expand Heart Lake sub for the termination of 9L930 in/out and the new 240 kV line to Ipiatik	August 28, 2015

THE TRANSMISSION FACILITY OWNER(S): AltaLink L.P. and ATCO Electric Ltd.

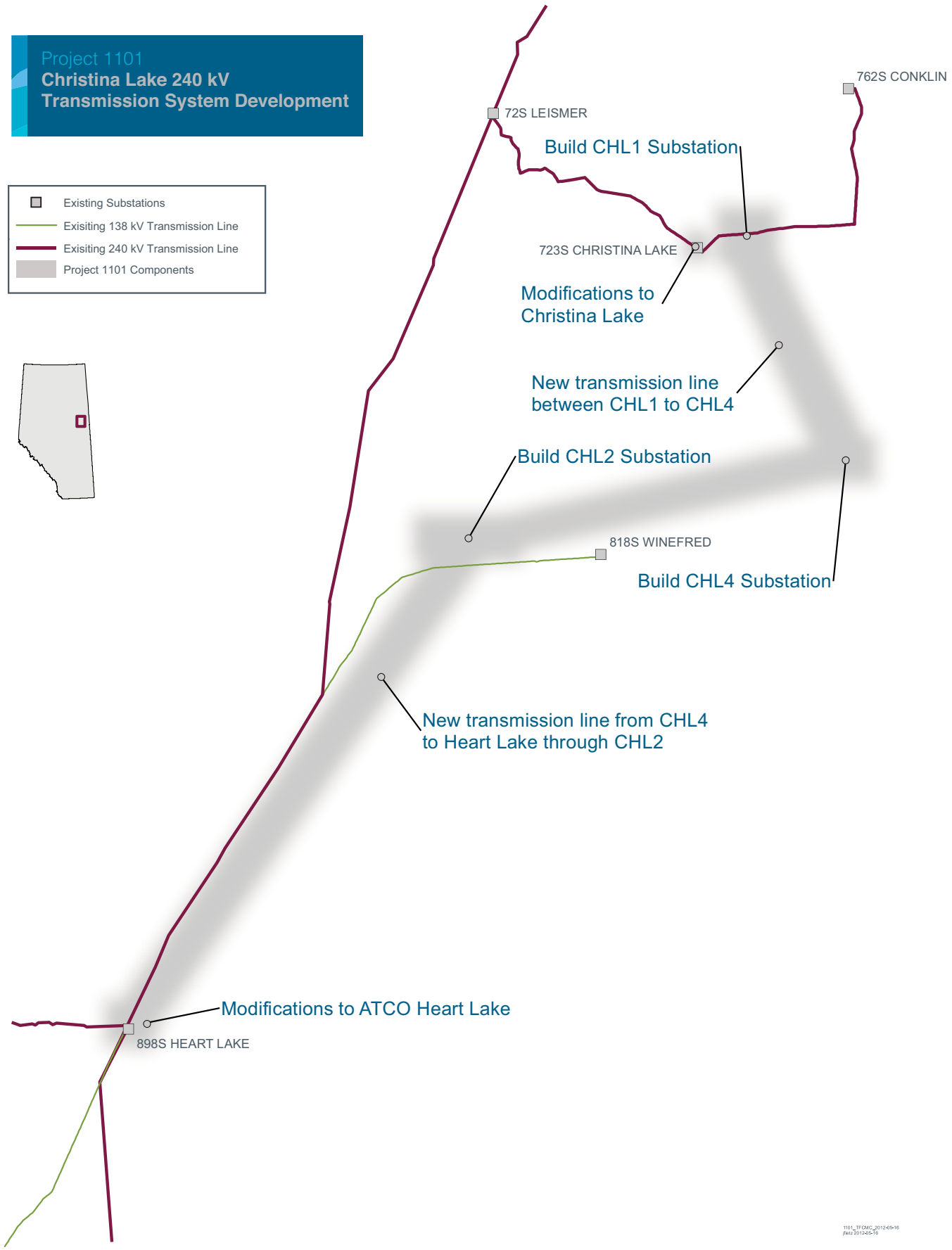
PROJECT COST:

TRANSMISSION PROJECT	AESO LONG-TERM TRANSMISSION PLAN (FILED JUNE 2012) ESTIMATED COST	CURRENT ESTIMATED COST
Christina Lake Area Transmission Development	**$358 million** (2011$ without escalation)[11]	**$410 million** (ISD$ with escalation)[12]

CURRENT STATUS: This is a brand new project. The NID was approved by the AUC on April 24, 2012. AltaLink and ATCO have begun siting and routing work, including preparing Proposal to Provide Service (PPS) estimates.

11 This combines the two projects of Christina Lake ($350 million) and Heart Lake ($8 million) in the 2011/2012 AESO LTP.

12 The project cost is based upon the Needs Identification Document (NID) estimates (±30%) used in the NID dated October 2011.


Project 1101
Christina Lake 240 kV
Transmission System Development
Existing Substations
Exisiting 138 kV Transmission Line
Exisiting 240 kV Transmission Line
Project 1101 Components
762S CONKLIN
72S LEISMER
Build CHL1 Substation
723S CHRISTINA LAKE
Modifications to
Christina Lake
New transmission line
between CHL1 to CHL4
Build CHL2 Substation
818S WINEFRED
Build CHL4 Substation
New transmission line from CHL4
to Heart Lake through CHL2
Modifications to ATCO Heart Lake
898S HEART LAKE

4. ***NEW* FOOTHILLS AREA TRANSMISSION DEVELOPMENT – EAST PROJECT (FATD);** PROJECT 1117 – To meet growing demand in South Calgary, High River and the surrounding area.

THE PROJECT: The AESO has forecasted that transmission reliability constraints in the south Calgary and High River areas will occur within the 2014 to 2019 timeframe. The FATD East development will ensure the transmission system will serve growing electricity demand in Calgary, High River, and the surrounding area, enable new generation facilities to connect, and maintain system reliability. The development will also facilitate wind generation development within adjacent areas and mitigate thermal overloads and voltage violations.

THE COMPONENTS: The project has both a 240 kV and 138 kV scope. The 240 kV scope consists of building a new 240/138 kV substation designated Foothills 237S; adding a new 240 kV double-circuit line from the proposed Foothills 237S substation to the future ENMAX SS-65; a new 240 kV double-circuit line from the existing Langdon 102S to the existing the Janet 74S; a new 240 kV double-circuit line from Langdon 102S to East Calgary 5S using a combination of existing lines; a 240 kV double-circuit line between the future ENMAX SS-65 substation to the proposed ENMAX SS-25 substation; and the de-energization of sections of existing transmission lines.

The 138 kV scope consists of adding a new 138 kV single-circuit line from the proposed Foothills 237S to the existing Okotoks 678S; a new 138 kV single-circuit line from Foothills 237S to the existing High River 65S; a 138 kV single-circuit line from Okotoks 678S to Carseland 525S, and the de-energization of transmission lines and modifications to lines in the area.

FACILITY APPLICATION NAME	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
North Foothills Transmission Project	Construction of Foothills 235S 240/138 kV switching station, and construction of approximately 52 km of 240 kV double-circuit transmission line from Foothills 237S to ENMAX SS-65	June 2015
Langdon to Janet Project	Construction of approximately 18 km of 240 kV double-circuit transmission line from Langdon 102S to Janet 74S; expansion of Janet 74S substation; removal of terminations at Janet 74S resulting in two new circuits terminals at East Calgary 5S and Crossing 511S, and salvage of approximately six km of 240 kV transmission line from Janet 74S to ENMAX SS-25	June 2015
Foothills 138 kV Project	Addition of two 240/138 kV transformers at Foothills 237S; construction of approximately 14 km of 138 kV double-circuit transmission line from Foothills 237S to High River 65S; rebuild of approximately seven km of existing transmission line to 678S, and salvage of approximately 30 km of existing line from Janet 74S to Okotoks 678S	October 2015
ENMAX No.25 Substation 240kV Line Additions and ENMAX No.65 Substation 240kV Line Additions	Interconnection of two new AltaLink L.P. 240 kV transmission lines at ENMAX SS-25, and termination of three new AltaLink L.P. 240 kV transmission lines at ENMAX SS-65	June 2015

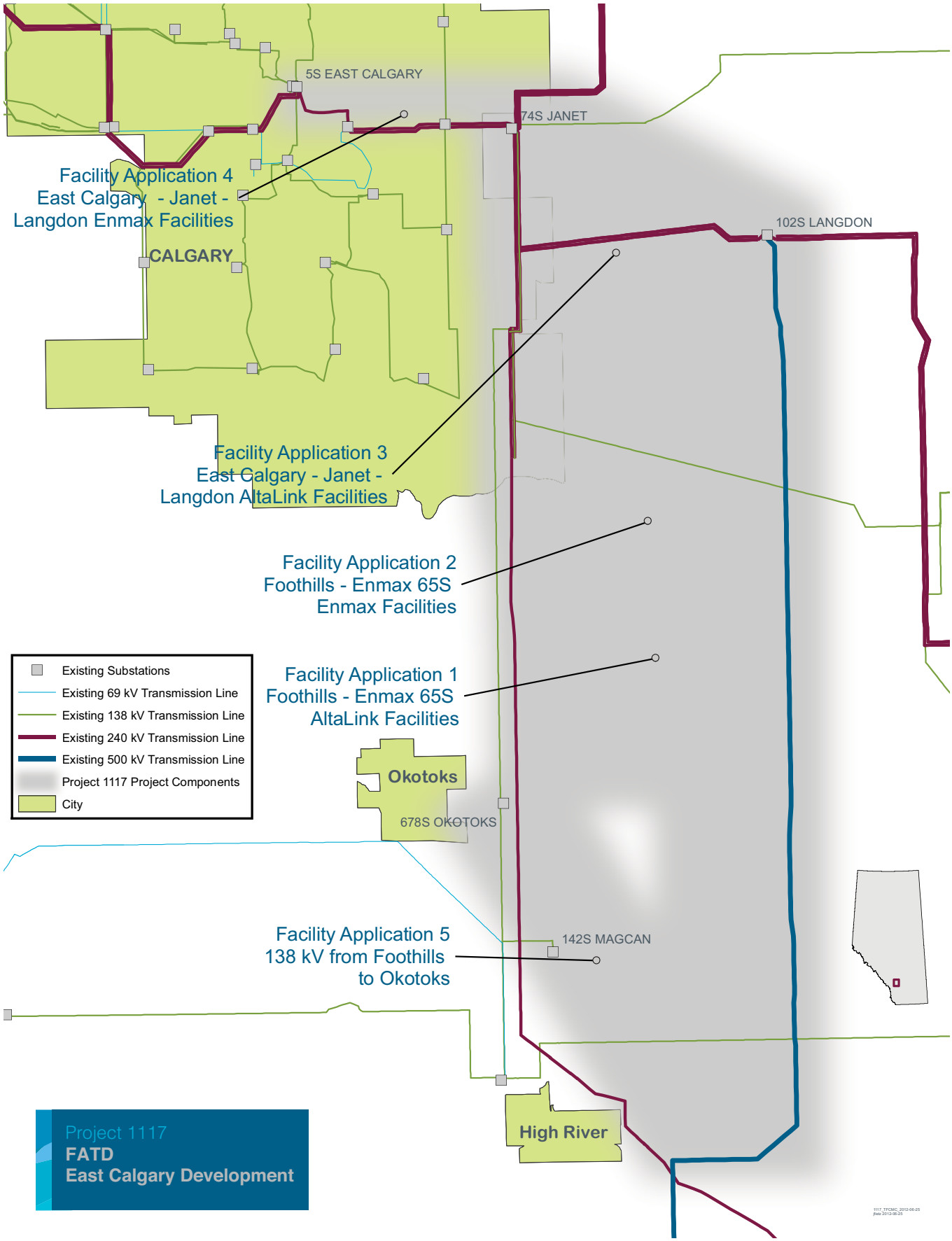
THE TRANSMISSION FACILITY OWNER(S): AltaLink L.P. and ENMAX Power Corp.

PROJECT COST:

TRANSMISSION PROJECT	AESO LONG-TERM TRANSMISSION PLAN (FILED JUNE 2012) ESTIMATED COST	CURRENT ESTIMATED COST
Foothills Area Transmission Development – East Project	**$711 Million*** (2011$ without escalation) *entire FATD plan, including: ■ FATD – East ■ ECTP (719, East Calgary Transmission Project, also known as ENMAX Shepard Energy Centre) ■ 138kV line between SS-65, SS-54 and SS-41 ■ FATD – West	**FATD East: $420 million** (ISD$ with escalation but without AFUDC)[13] ECTP system portion: $100 million

CURRENT STATUS: This is a brand new project. In the summer of 2012, the AESO will file the NID (to the AUC) for approval.

13 The project cost is based upon the Proposal to Provide Service proposal estimates (+20/-10%) received in June 2012 (during production of the TFCMC Report) from the TFOs for the NID.


5S EAST CALGARY
74S JANET
Facility Application 4
East Calgary - Janet -
Langdon Enmax Facilities
CALGARY
102S LANGDON
Facility Application 3
East Calgary - Janet -
Langdon AltaLink Facilities
Facility Application 2
Foothills - Enmax 65S
Enmax Facilities
Facility Application 1
Foothills - Enmax 65S
AltaLink Facilities
Existing Substations
Existing 69 kV Transmission Line
Existing 138 kV Transmission Line
Existing 240 kV Transmission Line
Existing 500 kV Transmission Line
Project 1117 Project Components
City
Okotoks
678S OKOTOKS
Facility Application 5
138 kV from Foothills
to Okotoks
142S MAGCAN
High River
Project 1117
FATD
East Calgary Development

5. **EDMONTON REGION 240 KV LINE UPGRADES (ERLU);** PROJECT 786 – Upgrading 240 kV lines in the Edmonton area; add one 240 kV phase shifter at Dover substation.

THE PROJECT: More than 4,000 MW of baseload generation that serves as the main source of electricity for the majority of the province is situated near Wabamun Lake in the Edmonton region. This generation supports central and south Alberta loads, northwest region loads, Edmonton area loads and major industrial loads located in the Fort Saskatchewan area. There are major thermal overloads of transmission facilities throughout the Edmonton region, the 138 kV transmission paths from Wabamun to North Calder, East Edmonton to Nisku, and from East Edmonton to the Fort Saskatchewan area, that are weak during peak load conditions and voltage violations occur in those two areas due to weak system support.

THE COMPONENTS: The 240 kV transmission system developments in the area include a rebuild of some sections of the existing transmission line, an increase in capacity of the lines by replacing conductors, the reconfiguration of the system, building new line, and the installation of a special protection scheme for multiple contingencies to ensure system reliability in the area. Also, a 240 kV phase shifter transformer will be installed at Livock 939S in the Fort McMurray area.

FACILITY APPLICATION NAME	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
AML Rebuild 240 kV 904L (1043L)	Rebuild approximately 50 km of the existing 240 kV line 904L between Jack Fish Lake in west of Edmonton and Petrolia 816S; salvage the existing 240 kV structures, conductor and hardware; build a new section of approximately 12 km of 240 kV line utilizing double-circuit structures with one side strung to connect Keephills 320P substation to the rebuild of 904L – renumbered to 1043L. (Keephills 320P to Petrolia 816S)	January 2013
AML 902L Restring & 909L Retermination	Restring eight km of 902L at each line end, Wabamun 19S and Sundance 310P substations	March 2013
	Retermination of the existing 240 kV 909L at Sundance 310P (Ellerslie 89S to Sundance 310P)	
AML 908L, 909L Restring	Restring four km of 908L and 909L outside Sundance 310P substation (first four km of the lines); 908L is renumbered to 1045L	March 2011
EPCOR Jasper, Petrolia	Upgrade bus work and protections	June 2011
EPCOR 1044EL, 1045EL	Restring approximately 24 km of existing 904L at Jasper 805S – in/out line section; Renumber EPCOR's portion of the line to 1044EL (going to Petrolia 816S) and 1045EL (going to Sundance 310P)	October 2011
ATCO Phase Shifter	Add 600 MVA phase shifting transformer at Livock 939S	December 2012
TransAlta 902L, 1043L	Delegate the work to AML	March 2013

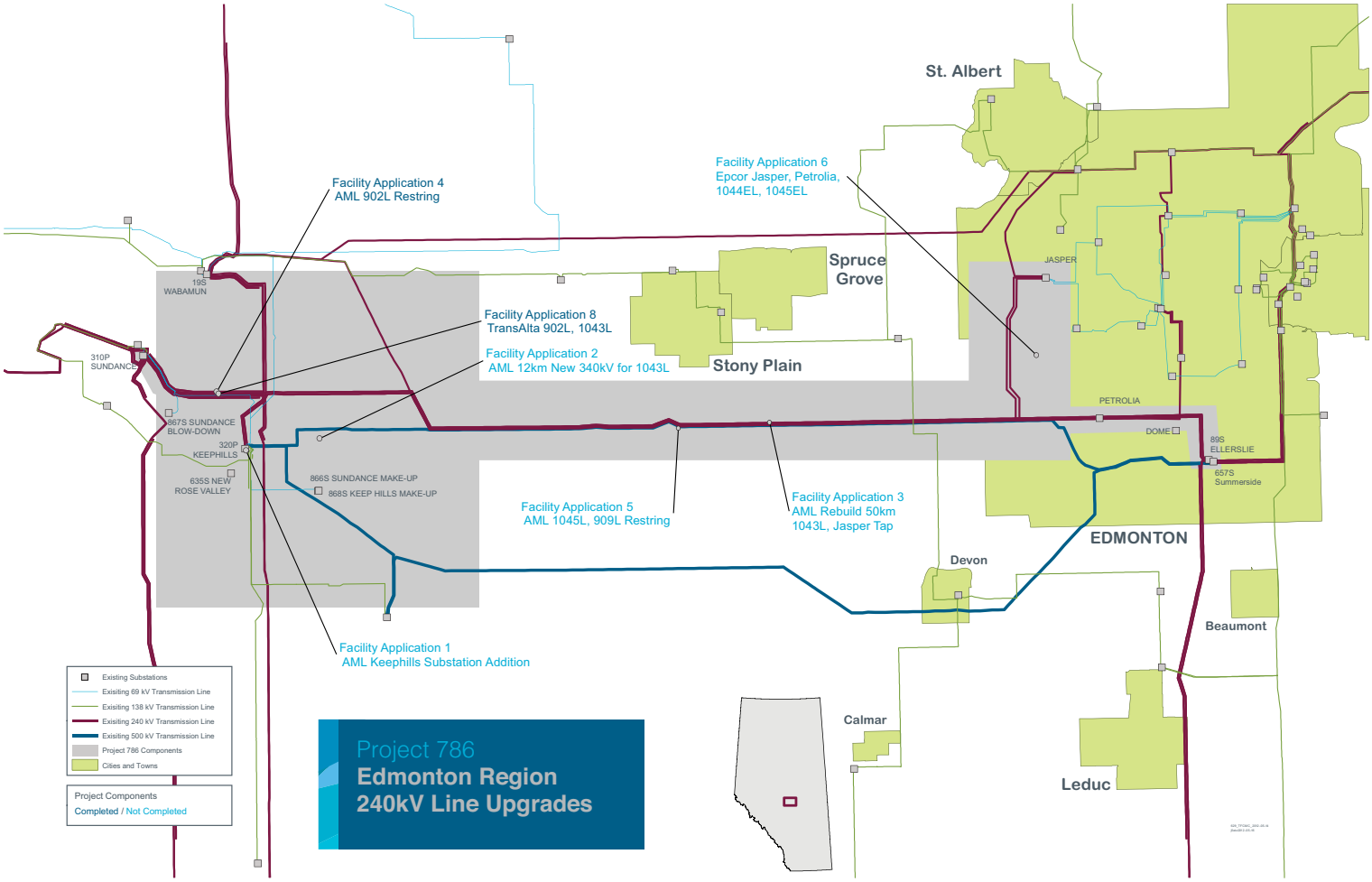
THE TRANSMISSION FACILITY OWNER(S): AltaLink L.P. and EPCOR Distribution & Transmission Inc., ATCO Electric Ltd. and TransAlta Corp.

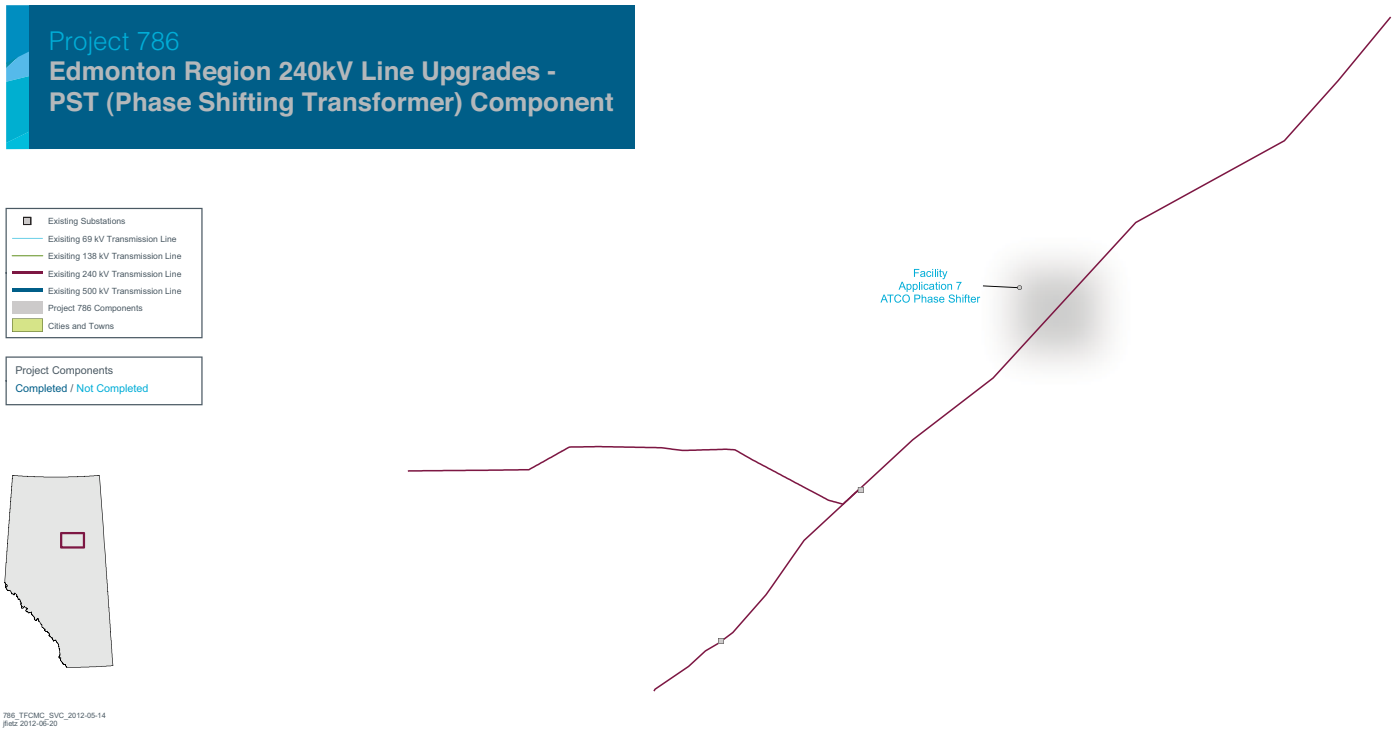
PROJECT COST:

TRANSMISSION PROJECT	AESO LONG-TERM TRANSMISSION PLAN (FILED JUNE 2012) ESTIMATED COST	CURRENT ESTIMATED COST
Edmonton Region 240 kV Line Upgrades	**$153 Million** (2011$ without escalation)	**$165 Million** (ISD$ with escalation)[14]

CURRENT STATUS: AltaLink received Permit and License (P&L) for the 904L rebuild September 30, 2011, and plans to complete the work in early 2013. The Facilities Application for the 902L restring was submitted to the AUC in early August 2011. A public AUC hearing was held in Spruce Grove in April 2012. Regulatory delays have contributed to delaying the target in-service date for the entire project to March 2013.

14 The cost is based upon either the TFO's April 2012 Monthly Project Progress Report or other information provided to the TFCMC; this material was actually provided to the TFCMC in June 2012, during the production of this report.


St. Albert
Facility Application 6
Epcor Jasper, Petrolia,
1044EL, 1045EL
Facility Application 4
AML 902L Restring
Spruce
Grove
JASPER
19S
WABAMUN
Facility Application 8
TransAlta 902L, 1043L
Facility Application 2
AML 12km New 340kV for 1043L
Stony Plain
310P
SUNDANCE
PETROLIA
867S SUNDANCE
BLOW-DOWN
320P
KEEPHILLS
DOME
89S
ELLERSLIE
657S
Summerside
635S NEW
ROSE VALLEY
866S SUNDANCE MAKE-UP
868S KEEP HILLS MAKE-UP
Facility Application 5
AML 1045L, 909L Restring
Facility Application 3
AML Rebuild 50km
1043L, Jasper Tap
EDMONTON
Devon
Beaumont
Facility Application 1
AML Keephills Substation Addition
Calmar
Leduc
Existing Substations
Exisiting 69 kV Transmission Line
Exisiting 138 kV Transmission Line
Exisiting 240 kV Transmission Line
Exisiting 500 kV Transmission Line
Project 786 Components
Cities and Towns
Project Components
Completed / Not Completed
Project 786
Edmonton Region
240kV Line Upgrades


Project 786
Edmonton Region 240kV Line Upgrades -
PST (Phase Shifting Transformer) Component
Existing Substations
Exisiting 69 kV Transmission Line
Exisiting 138 kV Transmission Line
Exisiting 240 kV Transmission Line
Exisiting 500 kV Transmission Line
Project 786 Components
Cities and Towns
Project Components
Completed / Not Completed
Facility
Application 7
ATCO Phase Shifter
786_TFCMC_SVC_2012-05-14
jfietz 2012-06-20

6. **ENMAX NO. 65 SUBSTATION (ESCS);** PROJECT 922 – New 240 kV substation in south Calgary and 138 kV developments due to overloading in south Calgary.

THE PROJECT: The AESO has recommended transmission reinforcement in the South Calgary area. The ENMAX No. 65 Substation is to serve significant load growth due to the increasing population in this sector of the city. The proposed development includes a new 240/138 kV substation located east of 88 Street SE and north of Highway 22X, with about one km of double-circuit 138 kV transmission line that ties into an existing 138 kV transmission line, and a double-circuit 240 kV transmission line from the current 911L to connect into the existing transmission system.

THE COMPONENTS: The proposed development includes the aforementioned new 240/138 kV substation located east of 88 Street SE and north of Highway 22X, and associated 138 kV and 240 kV lines to interconnect into the existing system.

FACILITY APPLICATION NAME	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
New 240/138 kV Substation	New ENMAX No. 65 Substation and about one km of 138 kV transmission line to connect the new substation to the existing transmission system	August 2013
ENMAX No. 65 Substation Interconnection	Addition of double-circuit line from existing 911L to create an "in and out" configuration into the new ENMAX No. 65 Substation	August 2013 substation to the AltaLink 911L

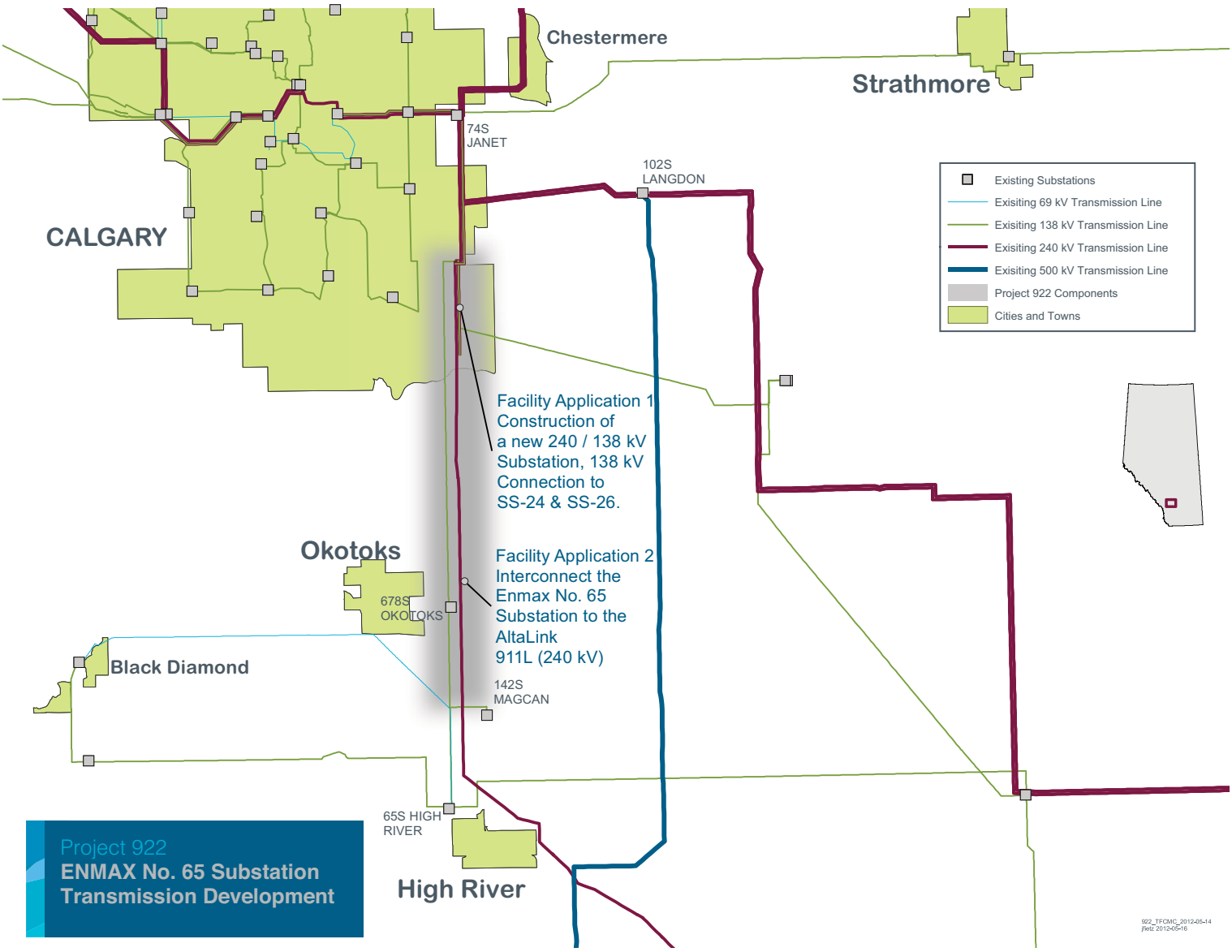
THE TRANSMISSION FACILITY OWNER(S): ENMAX Power Corp. and AltaLink L.P.

PROJECT COST:

TRANSMISSION PROJECT	AESO LONG-TERM TRANSMISSION PLAN (FILED JUNE 2012) ESTIMATED COST	CURRENT ESTIMATED COST
ENMAX No. 65 Substation	**$37 Million** (2011$ without escalation)	**$38 Million** (ISD$ with escalation)[15]

CURRENT STATUS: On November 3, 2011, the AUC approved the FA and issued the P&L for the project. Construction started in April 2012 and the forecasted in-service date is now August 2013 instead of July 2013.

15 The cost is based upon either the TFO's April 2012 Monthly Project Progress Report or other information provided to the TFCMC; this material was actually provided to the TFCMC in June 2012, during the production of this report.


Chestermere
Strathmore
74S
JANET
102S
LANGDON
CALGARY
Existing Substations
Exisiting 69 kV Transmission Line
Exisiting 138 kV Transmission Line
Exisiting 240 kV Transmission Line
Exisiting 500 kV Transmission Line
Project 922 Components
Cities and Towns
Facility Application 1
Construction of
a new 240 / 138 kV
Substation, 138 kV
Connection to
SS-24 & SS-26.
Okotoks
678S
OKOTOKS
Facility Application 2
Interconnect the
Enmax No. 65
Substation to the
AltaLink
911L (240 kV)
Black Diamond
142S
MAGCAN
65S HIGH
RIVER
High River
Project 922
ENMAX No. 65 Substation
Transmission Development

7. **FORT MCMURRAY AREA TRANSMISSION BULK SYSTEM REINFORCEMENT (FMAC);** PROJECT 838 – Construction of 500 kV transmission lines from the Edmonton area to the Fort McMurray area.

THE PROJECT: The Fort McMurray area transmission project is to serve load from the expected growth of the oilsands industry in the northeastern part of the province. The AESO has recommended a 500 kV AC line from the Genesee generating station to a new 500 kV substation in the Fort McMurray area and a 500 kV AC line from the new Heartland substation to the new Fort McMurray area 500 kV substation.

THE COMPONENTS: The major components for Stage 1 of the project (West 500 kV Line) are: approximately 500 km of 500 kV single-circuit transmission line from Thickwood Hills 951S to Sunnybrook 510S; a 500 kV substation switchyard at Thickwood Hills 951S to terminate the north end of the West 500 kV line; modifications to the Sunnybrook 510S substation to terminate the south end of the West 500 kV line, and a 500/240 kV 1200 MVA transformer bank at Thickwood Hills 951S.

The major components for Stage 2 of the project (East 500 kV Line) are: approximately 400 km of 500 kV single-circuit transmission line from Thickwood Hills 951S to Heartland 12S; modifications to the Thickwood Hills 951S substation to terminate the north end of the East 500 kV line; modifications to the Heartland 12S substation to terminate the south end of the East 500 kV line, and a second 500/240 kV 1200 MVA transformer bank at Thickwood Hills 951S.

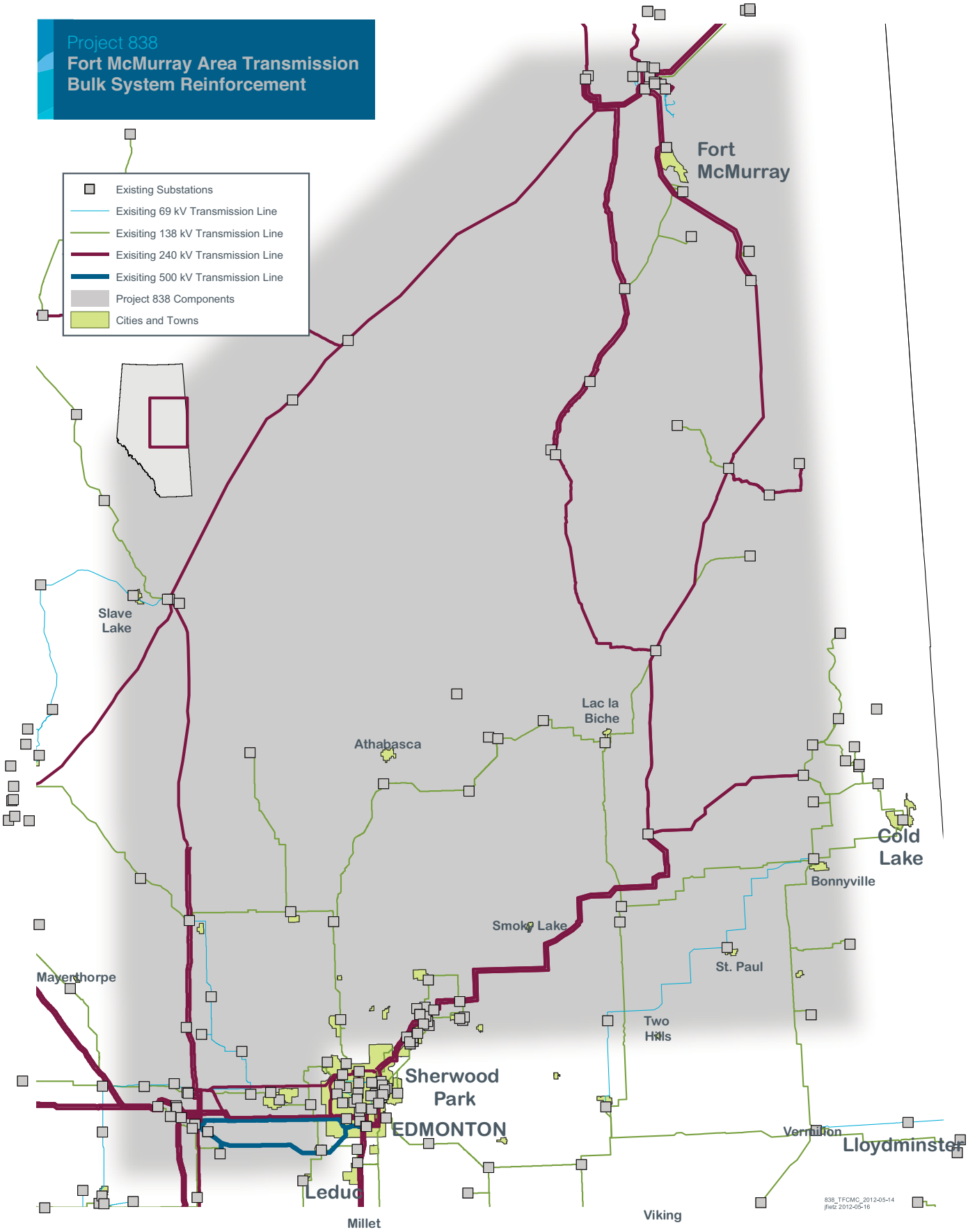
FACILITY APPLICATION NAME	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
Fort McMurray Area Bulk System Development Stage 1 – West Line	One 500 kV transmission line will be constructed from a new substation at Thickwood Hills to the Genesee area, called the West 500 kV line	2018
Fort McMurray Area Bulk System Development Stage 2 – East Line	A second 500 kV transmission line will be constructed from a new substation at Thickwood Hills to the Heartland area, called the East 500 kV line	2020

THE TRANSMISSION FACILITY OWNER(S): The Transmission Facility Owner (TFO) will be determined through the Competitive Process.

PROJECT COST:

TRANSMISSION PROJECT	AESO LONG-TERM TRANSMISSION PLAN (FILED JUNE 2012) ESTIMATED COST	CURRENT ESTIMATED COST
Fort McMurray Area Transmission Bulk System Reinforcement	***Stage 1:*** **$1,649 Billion** (2011$ without escalation) ***Stage 2:*** Not Available	Not Available

CURRENT STATUS: The Fort McMurray Area Transmission Bulk System Reinforcement will utilize the competitive process. The AESO's Competitive Process Application was filed with the AUC on September 15, 2011, and is currently being reviewed by the AUC; the public hearing is scheduled to begin on September 10, 2012, in Edmonton.


Project 838
Fort McMurray Area Transmission Bulk System Reinforcement
Existing Substations
Exisiting 69 kV Transmission Line
Exisiting 138 kV Transmission Line
Exisiting 240 kV Transmission Line
Exisiting 500 kV Transmission Line
Project 838 Components
Cities and Towns
Fort McMurray
Slave Lake
Athabasca
Lac la Biche
Cold Lake
Bonnyville
Smoky Lake
St. Paul
Mayerthorpe
Two Hills
Sherwood Park
EDMONTON
Vermilion
Lloydminster
Leduc
Millet
Viking
838_TFCMC_2012-05-14
jfietz 2012-05-16

8. **HANNA REGION TRANSMISSION DEVELOPMENT (HATD);** PROJECT 812 – Transmission development in Hanna, Sheerness and Battle River.

THE PROJECT: Transmission reinforcement in the Hanna region (East Central Alberta) will allow for the connection of up to 700 MW of wind power and serve demand of about 970 MW, largely driven by industrial development in the area. The AESO's system studies indicate that the key drivers for the project are to provide transmission capacity to meet growth (load and generation), improve the reliability of the transmission system and alleviate transmission constraints that can result in generation curtailment in the region.

THE COMPONENTS: There are two stages of transmission development for the project.

The major components for Stage 1 of the project are: a new 240/144 kV substation near Hardisty with a 240 kV double-circuit line connecting the new substation to the 240 kV line between Cordel and Hansman Lake, and a 138 kV double-circuit line connecting the new substation to the existing Tucuman 478S; a 240 kV doublecircuit line from Anderson to a new 240 kV switching station south of Anderson 801S; a 240 kV double-circuit transmission line (one side strung) from the new 240 kV switching station to existing Hansman Lake 605S and two new 240/144 kV substations near Oyen and Monitor; addition of -100/+200 MVAr static Var compensators at existing Hansman Lake 650S and new Lanfine 959S substations; a double-circuit 240 kV line (one side strung) west from the new 240 kV switching station to a new 240/144 kV substation near the Hand Hills area, and various local area 138 kV or 144 kV enhancements.

The major components for Stage 2 of the project are: string conductor on the open side of the 240 kV lines from the 240 kV switching station south of Anderson 801S to Hansman Lake 650S; string conductor on the open side of the 240 kV line west from the 240 kV switching station south of Anderson 801S to the new 240/144 kV station in the Hand Hills area; addition of a second 240/144 kV transformer at source substations near Oyen, Monitor and Hand Hills, the addition of -100/+200 MVAr static Var compensator, and various local area 138 kV and 144 kV enhancements.

FACILITY APPLICATION NAME	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
Youngstown 772S Capacitor Bank addition	Youngstown 772S – Capacitor Bank addition, 144 kV breaker and communication tower	October 6, 2011
Battle River 757S Capacitor Bank addition	Battle River 757S – 72 kV Capacitor Bank addition, 144 kV circuit breaker and substation alterations	October 3, 2011
New Lanfine 240/144 kV substation	New 240/144 kV substation designated Lanfine 959S	March 30, 2013
Lanfine 959S 200 MVAr SVC	Addition of a -100/+200 MVAr SVC at Lanfine 959S	May 31, 2013
Lanfine-Oyen 144 kV S/C Line 7L132	Double-circuit 144 kV line (one side energized) from Lanfine 959S to Oyen 767S	May 31, 2013
Relocate 7L98 Oyen 767S – Lanfine 959S	Decommission and salvage of transmission line 7L98 and 7LA98	May 31, 2013
Oakland 946S 240 kV S/S combined with Anderson-Oakland line	New 240 kV double-circuit transmission line (designated as 9L70/9L97) from Anderson 801S to Oakland 946S, Oakland 946S substation and related alterations	May 30, 2013
Oakland-Lanfine 240 kV S/C line 9L924	New 240 kV double-circuit transmission line (one side strung) designated 9L24, from Oakland 946S to Lanfine 959S and alterations to Oakland 946S	March 30, 2013

FACILITY APPLICATION NAME	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
Coyote Lake 963S 240 kV S/S combined with Oakland-Coyote line	New 240/144 kV Coyote Lake 963S; new 240 kV double-circuit transmission line (one side strung) designated as 9L29 from Oakland 949S to Coyote Lake 963S and alteration to Oakland 946S	April 30, 2013
Coyote Lake 963S – Michichi Creek 802S 144 kV SC Line 7L128	New single-circuit transmission line designated as 7L128 from Michichi Creek 802S to Coyote Lake 963S and alterations to existing Michichi Creek 802S	May 31, 2013
Pemukan 932S 240 kV Substation	New 240/144 kV substation designated Pemukan 932S	May 31, 2013
New Lanfine-Pemukan 240 kV S/C Line 9L46	New 240 kV double-circuit transmission line (one side strung) designated 9L46, from Pemukan 932S to Lanfine 959S and alterations to Lanfine 959S	March 31, 2013
144 kV Capacitor Bank and Circuit Breaker additions at Three Hills Substation 770S	Three Hills 770S 144 kV Capacitor Bank addition; 144 kV circuit breaker and substation alterations	December 13, 2011
Hansman Lake-Pemukan 240 kV S/C Line 9L966	New 240 kV double-circuit transmission line (one side strung) designated 9L966, from Pemukan 932S to AltaLink's service territory and alterations to Pemukan 932S	May 31, 2013
Pemukan 932S-Monitor 774S 144 kV S/C Line 7L127	Double-circuit 144 kV line (one side energized) from Pemukan 932S to Monitor 774S	May 31, 2013
Relocate 7L79 line from Monitor 774S – Pemukan 932S	Retermination of existing 7L70 from Monitor 774S to Pemukan 932S and alterations to Pemukan 932S	May 31, 2013
Heatburg 948S – Three Hills-Nevis 144 kV D/C Line 7L16/7L159	New 144/25 kV Heatburg 948S substation; new 144 kV double-circuit transmission line from Heatburg 948S to existing 7L16; modification of 7L16 to create an "in and out" configuration to Heatburg 948S and alterations at existing substations	May 31, 2012
Rowley 768S – Michichi-Three Hills 144 kV DC Line 7L25	Expansion and rebuild of existing Rowley 768S substation; construction of about 13 km of new 144 kV double-circuit transmission line designated as 7L25 and 7L137 and alterations at existing substations	June 1, 2012
Stettler 769S – Nevis 768S 144 kV S/C Line 7L143	New 144 kV single-circuit transmission line from Nevis 766S to Stettler 769S; alterations to Nevis 766S and alterations to Stettler 769S	May 31, 2013

FACILITY APPLICATION NAME	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
Nilrem 574S combined with D/C 240 kV 953L – 1047L and Tucuman 478S combined with D/C 138 kV 679L-680L	New 240/138 kV Nilrem 574S; new 240 kV double-circuit transmission line (designated as 953L/1047L) from connection point on existing 240 kV line 953L to Nilrem 574S; alteration to existing 953L; new 139 kV double-circuit transmission line (679L/680L) from Tucuman 478S to Nilrem 574S and alterations to existing Tucuman 478S	March 30, 2013
Hardisty 377S Substation Capacitor Bank	138 kV Capacitor Bank addition at Hardisty 377S substation and other associated work	June 30, 2012
New 240 kV line 966L from Pemukan 932S – Hansman Lake 650S	New 240 kV double-circuit transmission line (one side strung) designated 966L, from Hansman Lake 650S to ATCO's service territory and alterations to Hansman Lake 650S	May 30, 2013
Hansman Lake 650S Substation SVC Addition	Addition of a -100/+200 MVAr SVC at Hansman Lake 650S	October 15, 2012
New 240 kV line 1060L from Ware Junction 132S-West Brooks 28S	New 240 kV single-circuit transmission line (designated 1053L) from Ware Junction 132S to Cassils 324S; alterations to Ware Junction 132S and alteration to Cassils 324S	September 1, 2013

THE TRANSMISSION FACILITY OWNER(S): AltaLink L.P. and ATCO Electric Ltd.

PROJECT COST:

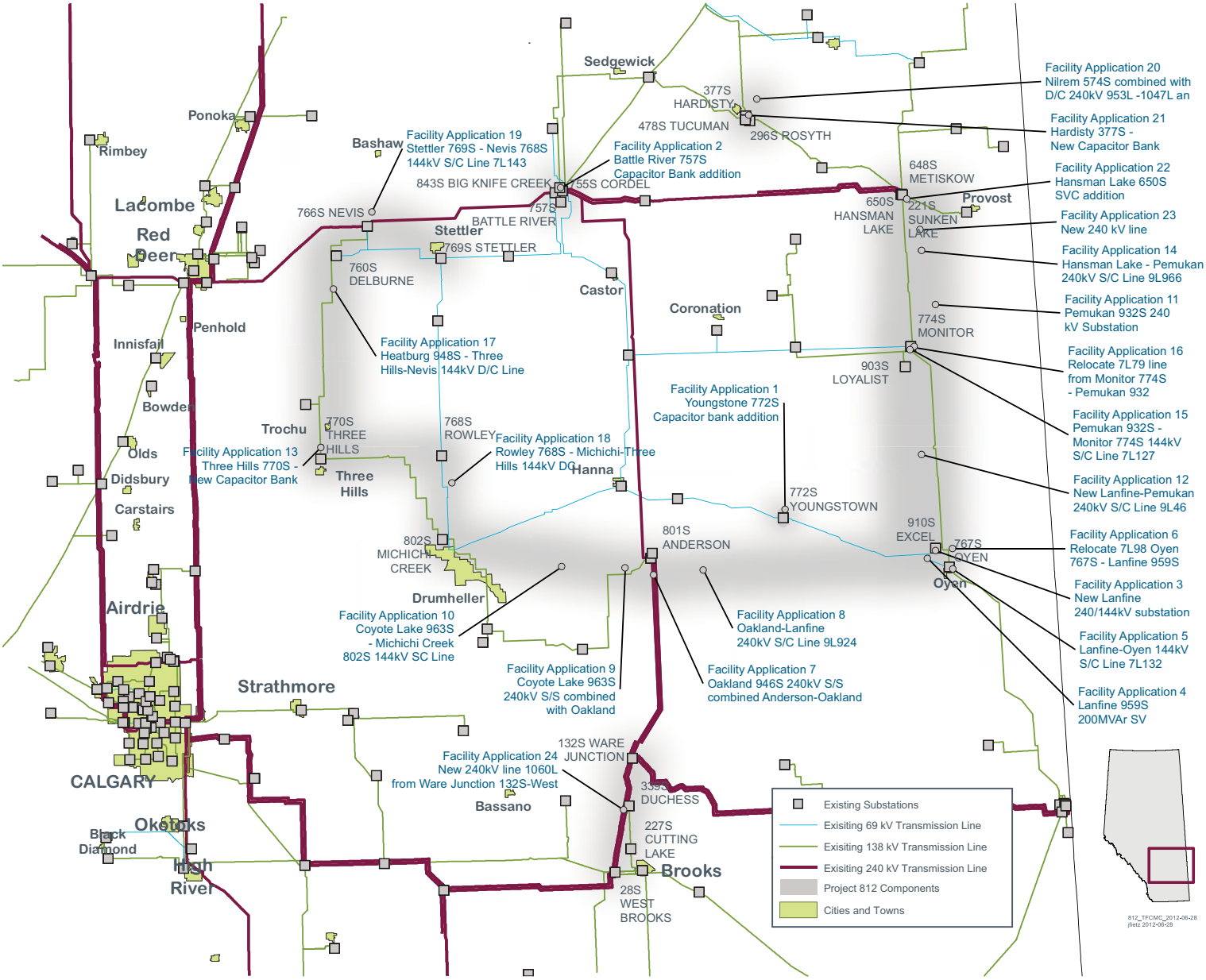
TRANSMISSION PROJECT	AESO LONG-TERM TRANSMISSION PLAN (FILED JUNE 2012) ESTIMATED COST	CURRENT ESTIMATED COST
Hanna Region Transmission Development	**$909 Million** (2011$ without escalation)	**$909 Million** (ISD$ with escalation for stage 1)[16]

CURRENT STATUS: The Hanna Region Transmission Development NID was approved April 29, 2010. All Facilities Applications related to Stage 1 of the project have been approved by the AUC with the last FA for the Heatburg 948S and Three Hills-Nevis 144 kV D/C transmission line being approved on June 13, 2012. All components are moving through the construction phase of development.

In regards to Stage 2 of the Hanna project, the NID identified that this development was required by 2017. Once the regional plan for this area is completed in 2013, the AESO will be able to determine the timing for the Stage 2 development for the Hanna project.

16 The cost is based upon either the TFO's April 2012 Monthly Project Progress Report or other information provided to the TFCMC; this material was actually provided to the TFCMC in June 2012, during the production of this report.

Project 812
Hanna Region Transmission Development



9. **NORTH FORT MCMURRAY TRANSMISSION DEVELOPMENT (NFMD);** PROJECT 791 – Transmission development north of Fort McMurray.

THE PROJECT: The North Fort McMurray Transmission Development Project is to relieve transmission constraints and to serve forecast electrical demand as industrial load (oilsands) continues to grow in the area north of Fort McMurray.

THE COMPONENTS: The project calls for a 240 kV double-circuit line from Kearl Lake to Salt Creek; addition of the McLelland 240 kV switching station near Kearl Lake, and a 240 kV switching station at Black Fly.

FACILITY APPLICATION NAME	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
North Fort McMurray 240 kV Transmission Development	Provide electrical service to oilsands components	March 11, 2013

THE TRANSMISSION FACILITY OWNER(S): ATCO Electric Ltd.

PROJECT COST:

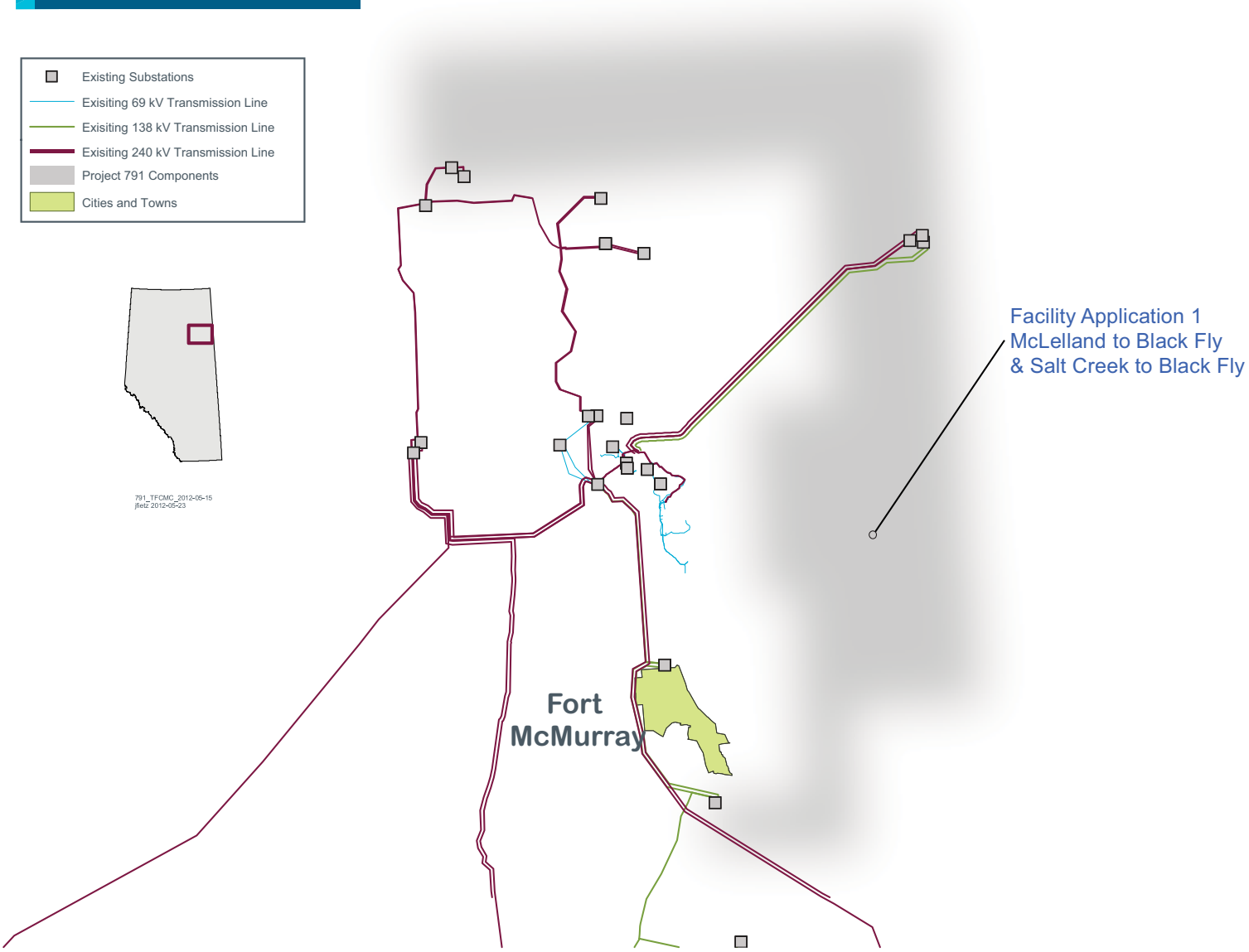
TRANSMISSION PROJECT	AESO LONG-TERM TRANSMISSION PLAN (FILED JUNE 2012) ESTIMATED COST	CURRENT ESTIMATED COST
North Fort McMurray Transmission Development	**$197 Million** (2011$ without escalation)	**$328 Million** (ISD$ with escalation)[10]

CURRENT STATUS: The North Fort McMurray NID was approved June 24, 2011. On July 28, 2011, the AUC approved the south portion of the FA and on December 23, 2011, granted approval to the overall project. Line 9L84, the 240 kV line from Salt Creek to the location of the new Black Fly substation, was commissioned on May 15, 2012. The new Black Fly substation is scheduled for commissioning on November 15, 2012. The north part of the project, 9L69 from Black Fly to McLelland, is scheduled for completion on April 1, 2013.

The AESO submitted a letter on March 13, 2012, to the AUC that highlighted an increase in the cost for the North Fort McMurray Transmission Development exceeding the accuracy tolerance identified in the NID.

17 The cost is based upon either the TFO's April 2012 Monthly Project Progress Report or other information provided to the TFCMC; this material was actually provided to the TFCMC in June 2012, during the production of this report.

Project 791
North Fort McMurray Transmission Development



10. NORTH SOUTH TRANSMISSION REINFORCEMENT (HVDC); PROJECT 737 – Construction of two 500 kV HVDC transmission lines from the Edmonton area to the Calgary and south regions.

THE PROJECT: The North South Transmission Reinforcement is to address increased demand in southern and central Alberta, mitigate issues with reliability, maximize efficiency, accommodate long-term growth and lead generation decisions. The project calls for two high-capacity lines between Edmonton and Calgary to reinforce the backbone of the grid and replace aging 240 kV lines. One line will be located on the west/centre portion of the province, connecting to the existing Wabamun Lake hub west of Edmonton to the Calgary area hub near Langdon. The second line will be located on the east side of the province connecting the Heartland hub northeast of Edmonton to a southern hub in the Brooks area.

THE COMPONENTS: The new lines will be 500 kV high-voltage direct current (HVDC) technology and will be built to transfer up to 1000 MW of power. The lines and stations will be upgradable to 2000 MW at a future date. Four HVDC converter stations will be required, one at the source and one at the destination point, to convert AC power to DC and DC to AC.

FACILITY APPLICATION NAME	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
EATL Facility Application – ATCO	Application to construct and operate a High Voltage DC line from Heartland to West Brook	2014/15
WATL Facility Application – AltaLink	Application to construct and operate a High Voltage DC line from Genesee to Langdon	2015

THE TRANSMISSION FACILITY OWNER(S): AltaLink L.P. will build the Western Alberta Transmission Line (WATL) and ATCO Electric Ltd. will build the Eastern Alberta Transmission Line (EATL).

PROJECT COST:

TRANSMISSION PROJECT	AESO LONG-TERM TRANSMISSION PLAN (FILED JUNE 2012) ESTIMATED COST	CURRENT ESTIMATED COST
North South Transmission Reinforcement – EATL	**$1.622 Billion** (2011$ without escalation)	**$1.832 Billion** (ISD$ with escalation)[18]
North South Transmission Reinforcement – WATL	**$1.329 Billion** (2011$ without escalation)[19]	**$1.564 Billion** (ISD$ with escalation)[20]

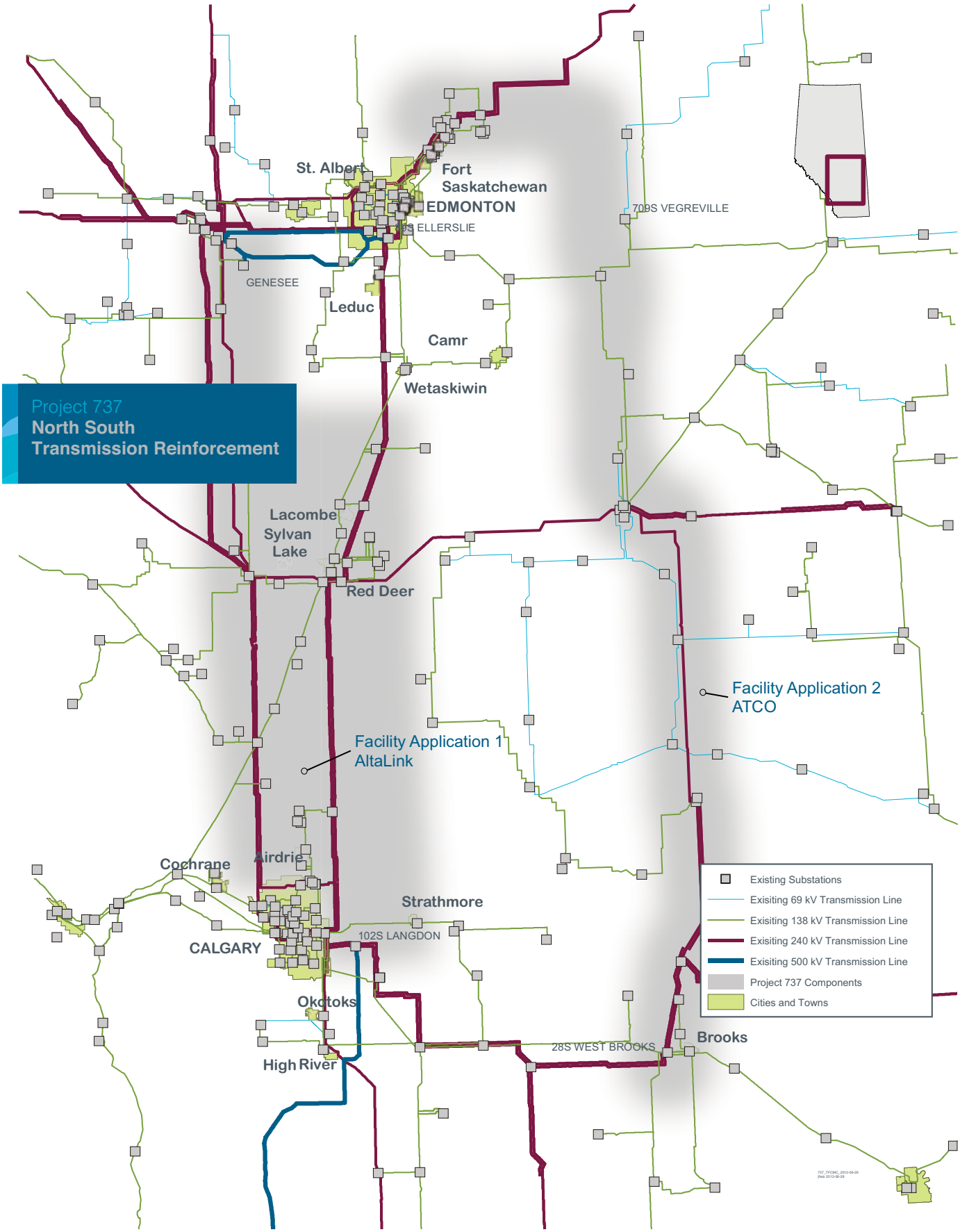
CURRENT STATUS: The AUC public hearing for the WATL began on June 11, 2012. The EATL AUC public hearing is scheduled to begin July 23, 2012. In April 2012, the AESO approved three WATL Change Proposals from AltaLink for a cost increase of $22 million[21]. As a result, the current authorized budget is $1.442 billion.

18 The cost is based upon either the TFO's April 2012 Monthly Project Progress Report or other information provided to the TFCMC; this material was actually provided to the TFCMC in June 2012, during the production of this report.

19 This 2011/2012 LTP did not contain approximately $50 million in AFUDC.

20 The cost is based upon either the TFO's April 2012 Monthly Project Progress Report or other information provided to the TFCMC; this material was actually provided to the TFCMC in June 2012, during the production of this report.

21 Authorized WATL cost changes due to AltaLink TCA#1 (delay in regulatory process and delay in ISD from October 2014 to April 2015; TCA#2 (scope reduction due to modifications on 138kV/240kV where DC line crosses not required) and TCA#3 (delay in ISD results in a required temporary 500 kV substation). TCA is the acronym for project Trend/Change Authorization Form.


Project 737
North South
Transmission Reinforcement
St. Albert
Fort
Saskatchewan
EDMONTON
ELLERSLIE
709S VEGREVILLE
GENESEE
Leduc
Camr
Wetaskiwin
Lacombe
Sylvan
Lake
Red Deer
Facility Application 2
ATCO
Facility Application 1
AltaLink
Cochrane
Airdrie
Strathmore
102S LANGDON
CALGARY
Okotoks
High River
28S WEST BROOKS
Brooks
Existing Substations
Exisiting 69 kV Transmission Line
Exisiting 138 kV Transmission Line
Exisiting 240 kV Transmission Line
Exisiting 500 kV Transmission Line
Project 737 Components
Cities and Towns

11. NORTHWEST TRANSMISSION DEVELOPMENT (NWTD); PROJECT 535 – Transmission development in northwest Alberta.

THE PROJECT: The Northwest (Alberta) Transmission Development identifies transmission issues in three areas of the Northwest region.

THE COMPONENTS: The transmission development includes adding new 240/144 kV transformers, capacitor banks and reactive support devices, a 240 kV line from Brintnell to Wesley Creek, and the addition of four new 144 kV transmission lines.

A fair number of the enhancements have already been completed.

FACILITY APPLICATION NAME	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
9L15 240 kV Wesley Creek 834S 240 kV single-circuit line	Energized to Brintnell 876S, 2 300 MVA Tx Brintnell to Wesley Creek, 2-300 MVA transformers at Wesley Creek	March 19, 2010
7L131/7L106 – 144 kV D/C line CTs Wesley Creek to Meikle 905S	144 kV double-circuit line from Wesley Creek to new Meikle	September 29, 2010
7L133 – 144 kV S/C line Sulphur Point 828S to High Level 786S	144 kV single-circuit line from Sulphur Point 828S to High Level 786S	March 19, 2011
High Level 786S +1 -30 MVAr SVC	High Level +1 -30 MVAr Static VAr Compensator	June 30, 2010
7L113 – 144 kV S/C line Ring Creek 853S to New Arcenciel 930S	144 kV single-circuit line from Ring Creek to new Arcenciel 930S substation and 1 – 30 MVAr Capacitor Bank at Arcenciel	December 19, 2011
Arcenciel 930S -30 +50 MVAr synch conductor	Arcenciel 930S -30 +50 MVAr synchronous condenser	March 1, 2013
Arcenciel 930S +1- 30 MVAr	Arcenciel 930S +1 -30 MVAr Static VAr Compensator	September 7, 2011
Little Smoky 813S - install +/-100 MVAr SVC & 2-144 kV MVAr Static VAr Compensator and breakers	Little Smoky 813S +/-100 MVAr SVC and 2-144 kV MVAr Static VAr Compensator and breakers	March 31, 2010

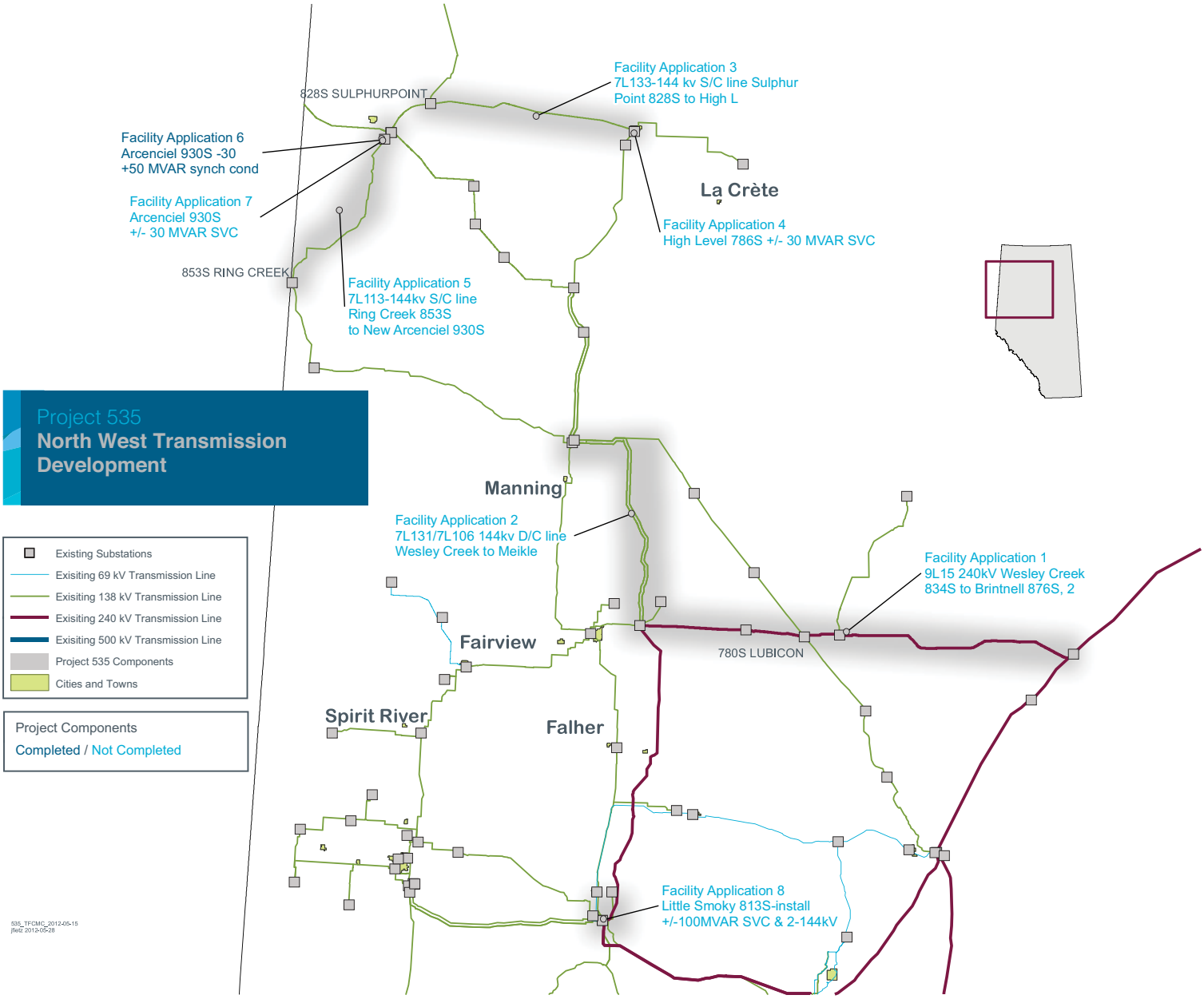
THE TRANSMISSION FACILITY OWNER(S): ATCO Electric Ltd.

PROJECT COST:

TRANSMISSION PROJECT	AESO LONG-TERM TRANSMISSION PLAN (FILED JUNE 2012) ESTIMATED COST	CURRENT ESTIMATED COST
Northwest Transmission Development	Not estimated in 2011 Long-Term Transmission Plan	**$550 Million** (ISD$ with escalation)[22]

CURRENT STATUS: The Northwest Transmission Development will be completely in-service by March 2013 when a synchronous condenser is energized at the Arcenciel 930S substation.

22 The cost is based upon either the TFO's April 2012 Monthly Project Progress Report or other information provided to the TFCMC; this material was actually provided to the TFCMC in June 2012, during the production of this report.


Project 535
North West Transmission Development
Existing Substations
Exisiting 69 kV Transmission Line
Exisiting 138 kV Transmission Line
Exisiting 240 kV Transmission Line
Exisiting 500 kV Transmission Line
Project 535 Components
Cities and Towns
Project Components
Completed / Not Completed
828S SULPHURPOINT
Facility Application 3
7L133-144 kv S/C line Sulphur Point 828S to High L
Facility Application 6
Arcenciel 930S -30 +50 MVAR synch cond
Facility Application 7
Arcenciel 930S
+/- 30 MVAR SVC
La Crète
Facility Application 4
High Level 786S +/- 30 MVAR SVC
853S RING CREEK
Facility Application 5
7L113-144kv S/C line
Ring Creek 853S
to New Arcenciel 930S
Manning
Facility Application 2
7L131/7L106 144kv D/C line
Wesley Creek to Meikle
Facility Application 1
9L15 240kV Wesley Creek
834S to Brintnell 876S, 2
Fairview
780S LUBICON
Spirit River
Falher
Facility Application 8
Little Smoky 813S-install
+/-100MVAR SVC & 2-144kV
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12. RED DEER REGION TRANSMISSION DEVELOPMENT; PROJECT 813 – Transmission system reinforcements in the Red Deer area.

THE PROJECT: Growing demand from industrial, commercial, farming, and residential, along with existing constraints on the system, have created the need to strengthen the transmission system in the Red Deer region.

THE COMPONENTS: There are two stages of transmission development for the project.

The major components for Stage 1 of the project are: building new 240/138 kV substations near Didsbury, Ponoka and Innisfail; upgrading substations near Benalto and West Lacombe; adding approximately 150 km of new and rebuilt transmission line, and salvaging more than 100 km of existing transmission line.

The major component for Stage 2 of the project is the rebuilding of 166L Didsbury 152S to Harmattan 256S.

FACILITY APPLICATION NAME	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
Red Deer Area Transmission Development Stage 1 – Brownfield	Split 768L and 778L; 240/138 kV transformer at Benalto 17S, Capacitor Banks at Joffre 535S, Prentiss 276S and Ellis 332S	December 31, 2012
Red Deer Area Transmission Development Stage 1 – Rebuilds	Rebuild 80L from S. Red Deer 194S to N. Red Deer 217S; rebuild 80L from S. Red Deer 194S to Red Deer 63S; rebuild 755L from Red Deer 63S to Piper Creek 247S to Joffre 535S, and rebuild 717L from Red Deer 63S to Benalto 17S	July 8, 2014
Red Deer Area Transmission Development Stage 1 – New Builds	New Johnston 240/138 kV substation and new transmission lines; 138 kV line from NE Lacombe 212S to Ellis 322S; new Wolf Creek 240/138 kV substation and new transmission lines; new Hazelwood 240/138 kV substation and new transmission lines, and salvage 80L from Red Deer 63S to Innisfail 214S to Olds 55S	September 15, 2014
Red Deer Area Transmission Development Stage 1 – Salvage	Salvage 80L from Ponoka 331S to West Lacombe 958S, and salvage 716L from Wetaskiwin 40S to Ponoka 331S	June 13, 2015
Red Deer Area Transmission Development Stage 2	Rebuild 166L from Didsbury 152S to Harmattan 256S	July 9, 2014

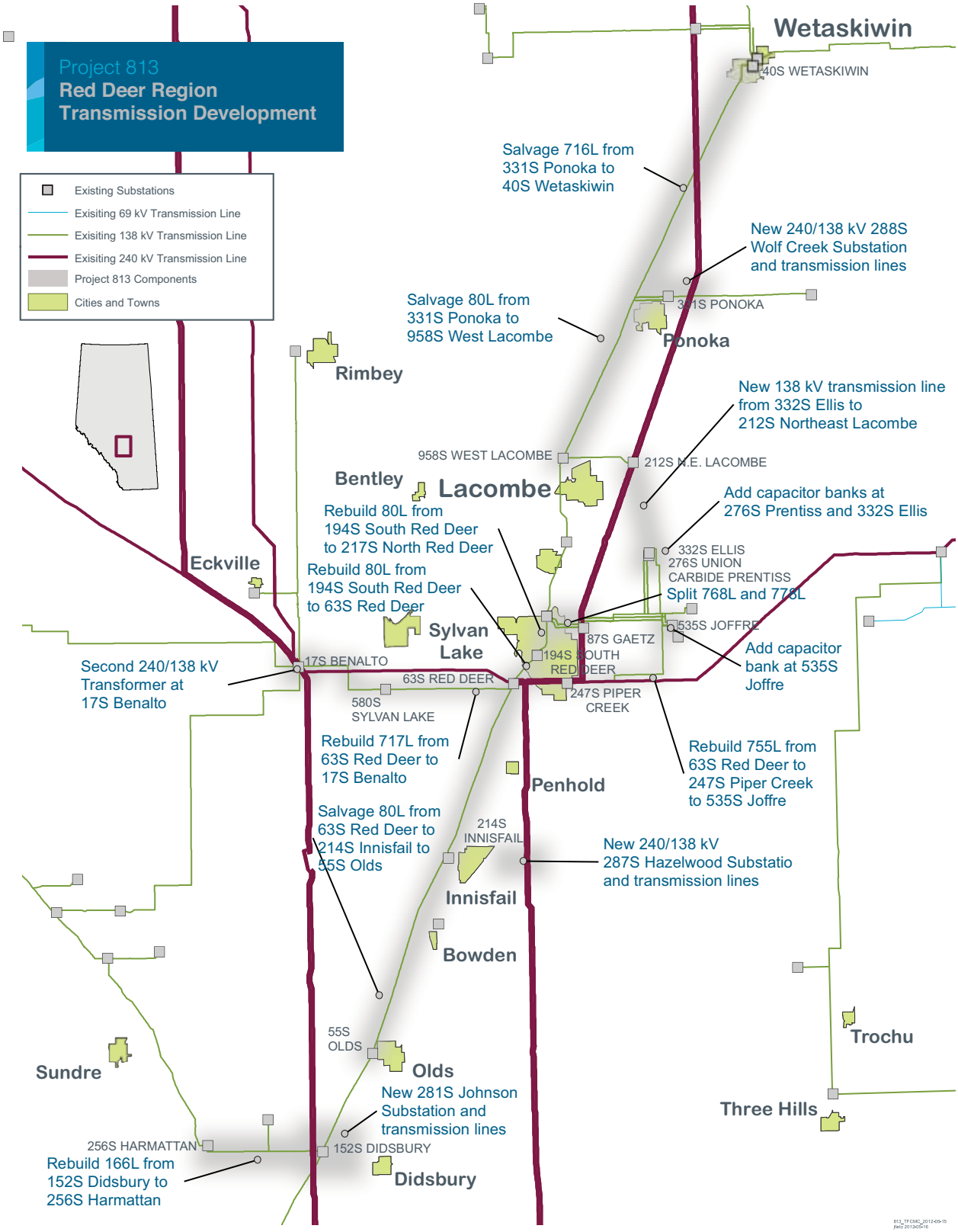
THE TRANSMISSION FACILITY OWNER(S): AltaLink L.P.

PROJECT COST:

TRANSMISSION PROJECT	AESO LONG-TERM TRANSMISSION PLAN (FILED JUNE 2012) ESTIMATED COST	CURRENT ESTIMATED COST
Red Deer Transmission Development	**$204 Million** (2011$ without escalation)	**$223 Million** (ISD$ with escalation)[23]

23 The cost is based upon either the TFO's April 2012 Monthly Project Progress Report or other information provided to the TFCMC; this material was actually provided to the TFCMC in June 2012, during the production of this report.

CURRENT STATUS: AltaLink filed the first FA for Brownfield on September 26, 2011. AltaLink will be filing Facility Application Rebuilds and Facility Application New Builds in summer 2012. Stage 2 development related to the 166L capacity increase is being advanced to facilitate the connection of a generation facility in the Harmattan area.



13. SOUTHERN ALBERTA TRANSMISSION REINFORCEMENT (SATR); PROJECT 787 – To accommodate wind generation in southern Alberta.

THE PROJECT: The existing capacity of the transmission system in southern Alberta is insufficient to provide adequate system access for the interconnection of additional wind-powered generation. Additional substations and upgrades to existing facilities are required. The AESO has outlined the need for a 240 kV AC looped system with three stages of implementation.

THE COMPONENTS: The project includes three stages of development. The first two stages consist of various 240 kV lines and a 240 kV system loop connection to the 500 kV Langdon-Cranbrook line. The third stage is a 240 kV line between Ware Junction and Langdon.

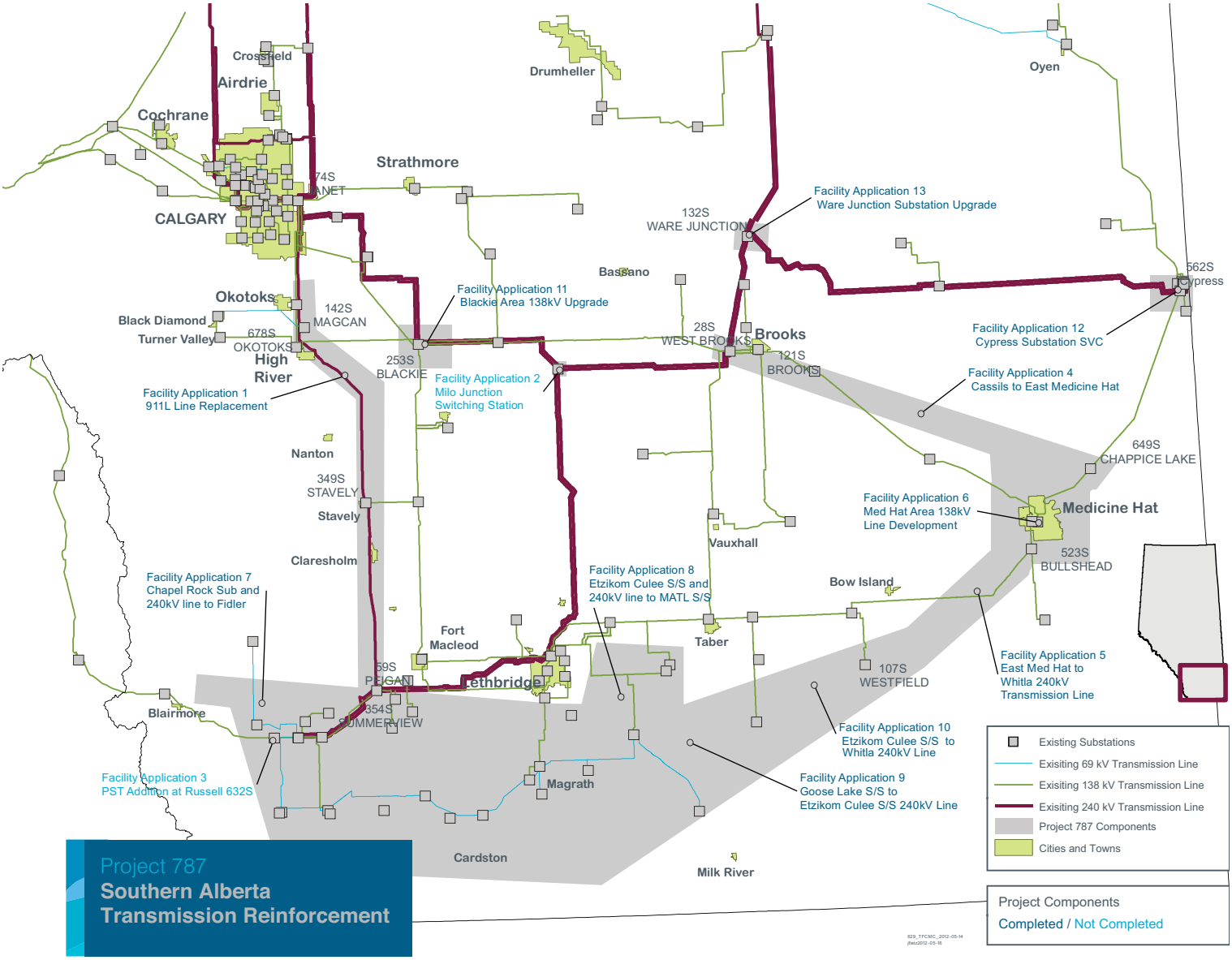
FACILITY APPLICATION NAME	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
911L Line Replacement	Build new 240 kV lines from Foothills substation to Windy Flats substation	June 13, 2015
Milo Junction Switching Station	Build a switching station at Milo Junction	October 31, 2011
PST Addition at Russell 632S	Phase shifting transformer and new Russell substation	April 25, 2012
Cassils to East Medicine Hat	240 kV lines from Cassils to Bowmanton	March 25, 2014
East Med Hat to Whitla 240 kV Transmission Line	240 kV lines from Bowmanton to Whitla	March 31,2014
Med Hat Area 138 kV Line Development	138 kV system upgrades in the Medicine Hat area	May 30, 2014
240 kV lines from Goose Lake to Crowsnest/Chapel Rock substation	240 kV Line from Fidler to Chapel Rock and new Chapel Rock 500 kV substation	Q2 2016
Etzikom Coulee S/S and 240 kV line to MATL S/S	240 kV line from Journault to Picture Butte (formerly called MATL) substation	November 1, 2015
Goose Lake S/S to Etzikom Coulee S/S 240 kV Line	240 kV line from Goose Lake to Journault substation	September 30, 2016
Etzikom Coulee S/S to Whitla 240 kV Line	240 kV line from Journault to Whitla substation	September 1, 2015
Blackie Area 138 kV Upgrade	138 kV system upgrade in the Blackie area	July 15, 2015
Cypress Substation SVC	SVC addition at Cypress substation	August 15, 2014
Ware Junction Substation Upgrade	933L line in/out at Ware Junction	July 15, 2013

THE TRANSMISSION FACILITY OWNER(S): AltaLink L.P.

PROJECT COST:

TRANSMISSION PROJECT	AESO LONG-TERM TRANSMISSION PLAN (FILED JUNE 2012) ESTIMATED COST	CURRENT ESTIMATED COST
Southern Alberta Transmission Reinforcement	**$2,287 Billion** (2011$ without escalation)	**$2.82 Billion** (ISD$ with escalation for Stage 1, 2 and 3)[24]

CURRENT STATUS: The Cassils-Bowmanton and Bowmanton-Whitla portions of this development are currently under construction.



24 The cost provided is based upon the TFO's April 2012 Monthly Project Progress Report; the April material was actually provided to the TFCMC in June 2012, during the production of this report. There are seven Proposal to Provide Service (PPS) cost estimates totaling $1,338 million (including AFUDC and escalation) that correspond to $891 million in NID cost estimates (excluding AFUDC and escalation). The ratio between PPS (including AFUDC and escalation) and NID (excluding AFUDC and escalation) is about 1.5. This estimate of $2.82 billion is based on the total NID estimate of $1.83 million (without AFUDC and escalation) and this ratio.

14. YELLOWHEAD AREA TRANSMISSION DEVELOPMENT (YATD); PROJECT 671 – Improve reliability in the Drayton Valley, Edson, Hinton and Alberta Beach areas.

THE PROJECT: The AESO identified the need for a number of transmission system upgrades to replace facilities that have deteriorated with age in Drayton Valley, Edson, Hinton and the Alberta Beach areas, and to meet the growing residential and commercial demand for electricity in the area.

THE COMPONENTS: Conversion of the 69 kV systems to 138 kV from Wabamun to Drayton Valley and Wabamun to Barrhead, and re-configuration and enhancements to the 138 kV system in the Edson-Hinton area.

FACILITY APPLICATION NAME	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
Hinton/Edson Area Transmission	Hinton/Edson Area 138 kV transmission upgrades	August 15, 2012
Cold Creek 602S 138 kV, 27 MVAr Capacitor Bank	Cold Creek 602S 138 kV, 27 MVAr Capacitor Bank	February 9, 2011
Cherhill Substation and 240 kV Interconnection	Cherhill substation and 240 kV interconnection	April 2, 2012
Drayton Valley Area 138 kV Transmission	Drayton Valley Area 138 kV transmission development and cap bank installations	December 21, 2011

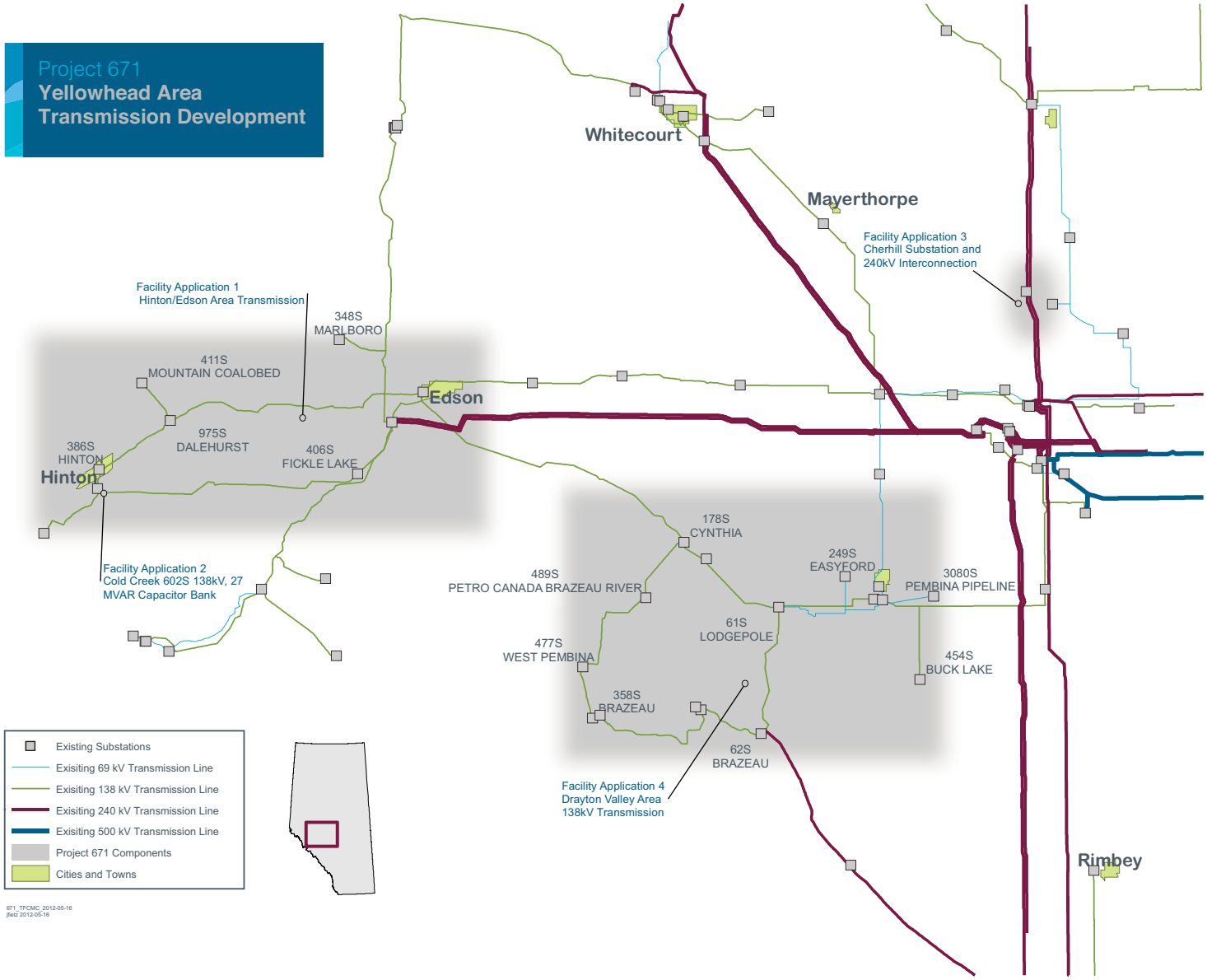
THE TRANSMISSION FACILITY OWNER(S): AltaLink L.P.

PROJECT COST:

TRANSMISSION PROJECT	AESO LONG-TERM TRANSMISSION PLAN (FILED JUNE 2012) ESTIMATED COST	CURRENT ESTIMATED COST
Yellowhead Area Transmission Development	**$123 Million** (2011$ without escalation)	**$135 Million** (ISD$ with escalation)[25]

CURRENT STATUS: The Hinton/Edson area upgrade is the only outstanding component of the Yellowhead Area Transmission Development. The forecasted in-service date is August 2012.

25 The cost is based upon either the TFO's April 2012 Monthly Project Progress Report or other information provided to the TFCMC; this material was actually provided to the TFCMC in June 2012, during the production of this report.


Project 671
Yellowhead Area
Transmission Development
Whitecourt
Mayerthorpe
Facility Application 3
Cherhill Substation and
240kV Interconnection
Facility Application 1
Hinton/Edson Area Transmission
348S
MARLBORO
411S
MOUNTAIN COALOBED
Edson
975S
DALEHURST
386S
HINTON
Hinton
406S
FICKLE LAKE
Facility Application 2
Cold Creek 602S 138kV, 27
MVAR Capacitor Bank
178S
CYNTHIA
249S
EASYFORD
489S
PETRO CANADA BRAZEAU RIVER
3080S
PEMBINA PIPELINE
61S
LODGEPOLE
477S
WEST PEMBINA
454S
BUCK LAKE
358S
BRAZEAU
62S
BRAZEAU
Facility Application 4
Drayton Valley Area
138kV Transmission
Rimbey
Existing Substations
Exisiting 69 kV Transmission Line
Exisiting 138 kV Transmission Line
Exisiting 240 kV Transmission Line
Exisiting 500 kV Transmission Line
Project 671 Components
Cities and Towns
671_TFCMC_2012-05-16
jfletz 2012-05-16

Appendix C: New Transmission Projects: A More Detailed Look At Costs

Two new projects, the Christina Lake Area 240 kV Transmission Development and the Foothills Area Transmission Development – East, are now on the TFCMC's list of monitored transmission projects, with both developments being in excess of $100 million.

Earlier in this report (Section 2) the TFCMC presented its observations on these two new projects. Below, is a more detailed cost analysis based on presentations the Alberta Electric System Operator (AESO) made to the Committee.

Christina Lake Area 240 kV Transmission Development (Project 1101)

Identified in the AESO 2011 Long-Term Plan, the Christina Lake development will establish transmission facilities to serve new oilsands developments and enhance reliability to existing oilsands operations. The project's Needs Identification Document (NID) has been approved; Facility Applications (FA) will be filed in the third and fourth quarters of 2012.

CHL Area – Historical Load

- Load in CHL area has grown from 6 MWs in 2005 to 46MWs in sept 2011.
- Recent load growth in the area has been driven by Oilsands and associated industrial developments.
- In-Situ Oilsands extraction processes, product processing and pumping are the primary processes contributing to recent area load growth.
- Consistent with these types of industrial activities, load increase have come in significant increments.

Summer Peak Historical Load

Year	Christina Lake Study Area	Area 25 Fort McMurray	NE Region	AIL System Load
2005 HX	6	803	2,026	8,595
2006 HX	6	1,046	1,908	8,931
2007 HX	18	1,046	1,979	9,133
2008 HX	27	1,162	2,101	9,075
2009 HX	34	1,298	2,227	9,587
2010 HX	40	1,322	2,261	8,741

Winter Peak Historical Load

Year	Christina Lake Study Area	Area 25 Fort McMurray	NE Region	AIL System Load
2005 HX	4	753	1,792	7,601
2006 HX	7	1,008	1,995	8,541
2007 HX	13	996	1,875	7,849
2008 HX	14	1,229	2,060	7,510
2009 HX	21	1,176	2,019	7,721
2010 HX	35	1,197	2,094	8,377
2011 HX (to-date)	46	1,239	2,174	8,874

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CHL Area – Load Forecast

- Area load growth is expected to continue at a rate well-exceeding general provincial growth rates. Consistent with forecasts for continued investment in Oilsands sector.
- The AESO's forecast considered input from DFO's and Oilsands lease operators in the area as well as other economic factors as documented in FC2009.
- FC2009 average annual load growth rates, for the period 2010 (historical) to 2020, are 26%, 7% and 6%, respectively, for each of: the CHL area; FMM area and the Northeast planning region.

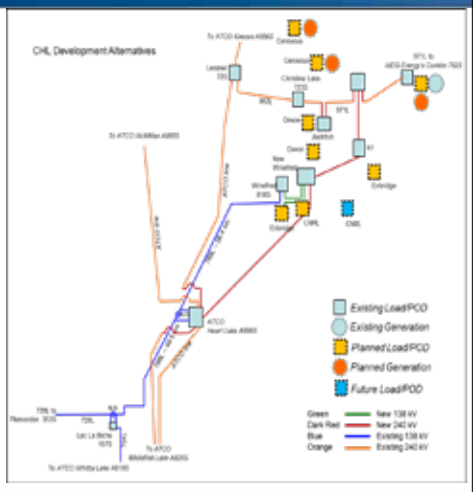
Winter Peak Forecasted Load – FC2009 (MWs)

Year	CHL2	CLH4	Total Christina Lake Study Area	Area 25 Fort McMurray	NE Region	AIL System Load
2011 F	11	0	112	1,440	2,656	10,515
2012 F	55	0	201	1,657	2,927	11,016
2013 F	59	7	245	1,811	3,112	11,577
2014 F	62	7	308	1,942	3,263	12,102
2015 F	66	12	310	2,074	3,416	12,753
2016 F	67	12	314	2,224	3,597	13,331
2017 F	67	12	367	2,445	3,831	13,746
2018 F	68	12	391	2,553	3,958	14,163
2019 F	69	12	394	2,692	4,118	14,568
2020 F	69	12	397	2,782	4,226	14,963

7

CHL Development-Studied Scenarios

- **Selection of Preferred Alternative**
  - Utilized Base Forecasted generation and load growth in the CHL area
  - Selected preferred Alternative must meet Alberta Reliability Standards under all Category B (N-1) and all credible Category C N-2 conditions (with mitigation measures).
- **Robustness and Expansion of Preferred Alternative**
  - Evaluated using two accelerated development scenarios for Load and Generation.
  - Established need for stringing the second circuit and requirement for double circuit structure build under accelerated load development scenario.
  - Minor future VAR reinforcement required in the long term (100MVAR at CHL1)



CHL Forecast (FC-2009) (MWs)	Base Scenario 2015	Base Scenario 2018	Accelerated 2018
CHL Load	310	390	570
CHL Generation	255	255	425

12

CHL Preferred Development - Staging

Q2 2013
•New 240kV switching substation, CHL1, at 971L

2013-14
•New 240/138kV sub, CHL4 including 2x240/138kV 200MVA transformers.

•New 240kV, double ckt, single side strung with 2x795 kcmil conductors transmission line CHL4-CHL1 (approximately 30 Km)

2014-15
•New 240/138kV sub CHL2, including 1x240/138kV 200MVA transformer.

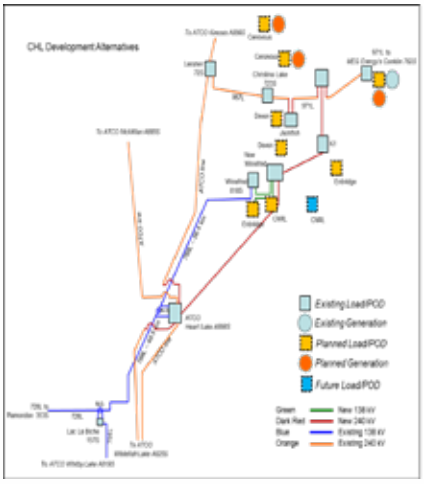
•New 240kV, double ckt, single side strung with 2x795 kcmil conductors line between Heart Lake A898S and CHL2 240/138kV substation (approximately 60 Km)

•New 240kV, double ckt, single side strung with 2x795 kcmil conductors line CHL2 - CHL4 (approximately 30Km)

•Termination of the 240kV transmission line 9L930 at Heart Lake A898S as an in/out configuration

•Termination of the 138kV transmission line between Winefred 818S and CNRL Kirby substations at CHL2 substation as an in/out configuration

• Re-terminations and associated bus work at CHL 723S



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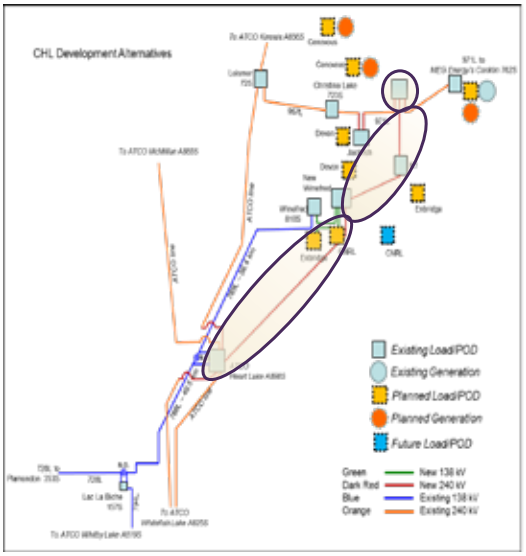
CHL Preferred Development - Cost

- Project construction in three stages to meet customer connection needs
- Stage 1 (Q2-2013) –

  $25 Million (+/-30%, $2013)
  - 240kV switching Station CHL1 with In/Out on existing 971L
- Stage 2 (2014)

  $105 Million (+/-30%, $2014)
  - 240/138kV Station CHL4
  - ~2x30km 240kV Line CHL1-CHL4 and CHL4-CHL2
- Stage 3 (2015)

  $280 Million (+/-30%, $2015)
  - ~60km, 240kV Line CHL2-Heartlake and HeartLake 9L930 In/Out Terminations



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Foothills Area Transmission Development – East (Project 1117)

Identified in the AESO's 2009 Long-Term Plan, Foothills Area Transmission Development – East will meet Alberta Reliability Criteria in South Calgary, High River and Okotoks, integrate Southern Alberta Transmission Reinforcement 911L ECTP, and ENMAX SS65. A combined NID and FA was ready to be filed.

FATD–EAST PROJECT FACILITIES PPS COST OVERVIEW

- TFOs - AltaLink L.P and ENMAX POWER CORP
- Project consists of multiple Facility Applications based on ownership as described below
- AltaLink: 3 - PPS Estimates

1.	North Foothills Transmission Project	$ 247,900,000
2.	Langdon to Janet	$ 104,637,000
3.	Foothills 138kV	$ 86,587,000

- ENMAX: 2 PPS Estimates

4.	65 Sub Line Additions	$ 3,477,775
5.	25 Sub Line Additions	$ 908,126
➢	**Total Project Cost**	**$ 443,546,901**

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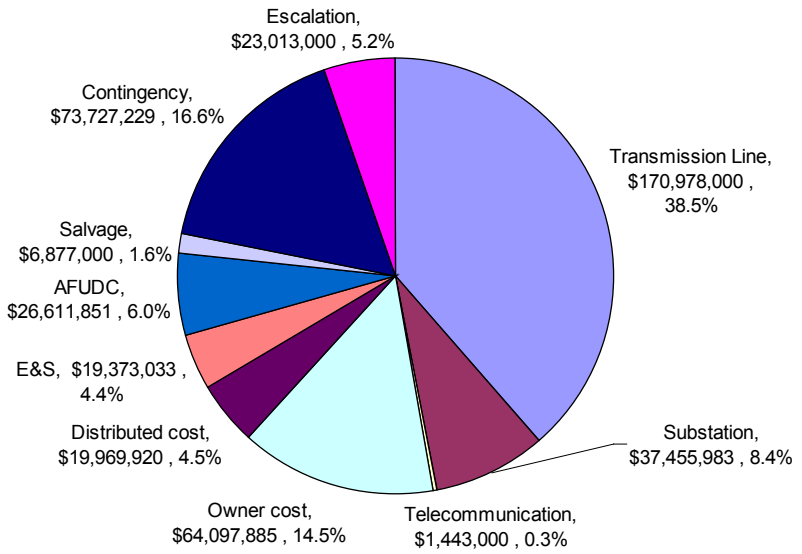
FATD–EAST PROJECT FACILITIES PPS COST BREAK-DOWN



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FATD-East Detailed PPS Cost Breakdown

PPS Estimate	[redacted]					Total	Ratios		
Total-Transmission line						$ 170,978,000	81.5%	62.4%	38.5%
Total-Substations						$ 37,455,983	17.8%	13.7%	8.4%
Total-Telecommunication						$ 1,443,000	0.7%	0.5%	0.3%
Total Facility Cost						$ 209,876,983	100%	76.6%	47.3%
Owner Costs									
Proposal to Provide Service						$ 1,225,160	0.6%	0.4%	0.3%
Facility Applications						$ 22,483,826	10.7%	8.2%	5.1%
Land Rights - Easements						$ 13,246,000	6.3%	4.8%	3.0%
Land - Damage Claims						$ 7,246,000	3.5%	2.6%	1.6%
Land - Acquisitions						$ 19,813,000	9.4%	7.2%	4.5%
Total - Owner's Cost						$ 64,097,885	30.5%	23.4%	14.5%
Distributed Costs									
Procurement						$ 1,489,000	0.7%	0.5%	0.3%
Project Management						$ 8,999,920	4.3%	3.3%	2.0%
Construction Management						$ 9,481,000	4.5%	3.5%	2.1%
Escalation						$ 23,013,000	11.0%	8.4%	5.2%
Contingency						$ 73,727,229	35.1%	26.9%	16.6%
Total - Distributed Costs						$ 116,710,149	55.6%	42.6%	26.3%
Total-Salvage						$ 6,877,000	3.3%	2.5%	1.6%
AFUDC						$ 26,611,851	12.7%	9.7%	6.0%
E&S						$ 19,373,033	9.2%	7.1%	4.4%
Total - Other Costs						$ 45,984,884	21.9%	16.8%	10.4%
TOTAL PROJECT COSTS	$ 86,587,000	$ 104,637,000	$ 247,937,000	$ 3,477,775	$ 908,126	$ 443,546,901			100%
Ratio	19.5%	23.6%	55.9%	0.8%	0.2%	100%	L + M	L+M+O	All

FATD-EAST Facility Cost - Lines

PPS	Scope	Line	kV	Type	circuit	bundle	kM	conductor	structure	Mil$ / kM	[redacted]	Ratio %
1117: PPS - NFTP	Construct new 240kV d/c line between Foothills 237S and Enmax No. 65	1106L/1107L	240	oh	2	2	52	1033	ltc & stp	**1.79**		**54.4%**
	Build temporary 240kV lines	911L temporary line	240	oh	1	2	3	1033	wd	**0.49**		0.9%
	Build temporary 240kV lines	850L temporary line	138	oh	1	2	3	1033	wd	**0.41**		0.7%
	Salvage temporary lines	850L/911L salvage	240	oh			2x3					0.0%
1117: PPS - Foothills 138kV	1109L line	1080L/1109L	240	oh								0.0%
	Construct d/c 138kV line between Foothills 237S and High River 65S	434L/646L	138	oh	2	1	13	1033	stp	**1.52**		**11.6%**
	Construct approx. 800m of line 727L/850L from existing 911L to Okotoks 678S	646L/850L	138	oh	2	1	0.8	1033		**0.80**		0.4%
	Rebuild 727AL /646L to d/c from Tap to 911L	727AL/646L rebuild to d/c	138	oh	2	1	0.8	1033 & 266		**0.88**		0.4%
	Salvage 30km of existing 727L line from Janet 74S to Okotoks 678S	727L salvage	138	oh			30			**0.00**		0.0%
	Build temporary line	727L temporary	138	oh	1	1	7	266	wd	**0.21**		0.9%
	Rebuild existing 727L to d/c from High River 65S to Aldersyde area	727L/646L rebuild to d/c	138	oh	2	1	7	1033 & 266	ltc	**1.32**		**5.4%**
	Line 753L	753L	138	oh			0					0.1%
	Reconfigure 911L from Aldersyde to near Okotoks 678S	911L reconfigure	138	oh			6.5			**0.02**		0.1%
1117: PPS - Langdon to Janet	Construct approx. 18km 240kV d/c from Langdon 102S to Janet 74S	1064L/1065L	240	oh	2	2	18	1033	ltc & stp	**1.65**		**17.4%**
	Relocate portion of 936L/937L	936L/937L	240	oh	2	1	2	1033	ltc	**2.74**		3.2%
	Relocate portion of 850L/911L	850L/911L	240	oh	2	1	2	1033	ltc	**2.16**		2.5%
	Construct approx. 200m of direct bury 240 kV line	917L	240	cbl			0.3			**11.50**		2.0%
										Total		
											34.9%	65.1%

FATD-EAST Facility Cost - Substations

RP#	Scope	Substation	voltage	Transformer	Breaker	CT	PT	Switch	[redacted]	Ratio (%)
1117: PPS - NFTP	Build new Foothills 237S substation	Foothills 237S	240		6*300Lt	18*285	12*240cvt	12*240m&2*240a		32.6%
1117: PPS - Foothills 138kV	Install transformers and 138kV equipment to Foothills 237S	Foothills 237S 138kV	240	2*245-400	4*145Dt			2*145a&2*145a&2*240a&8*145m		28.4%
	Upgrade High River 65S to accommodate 646L 138kV line	High River 65S	138		1*145Dt		2*145cvt	4*145m		4.1%
	Upgrade Okotoks 678S to accommodate 434L 138kV line	Okotok 678S	138		1*145			2*145		3.7%
	Carseland 525S substation	Carseland 525S	138							0.1%
1117: PPS - Langdon to Janet	Expand Janet 74S	Janet 74S expansion	240		2*300Lt	6*285	2*240cvt	3*240a&6*240m		14.1%
	Connect 1064L/1065L to existing termination points at Langdon 102S	Langdon 102S	500		4*300Lt	12*285	6*240cvt	2*240a&4*240m		10.6%
1117: PPS - 65 Sub Line Additions	Modify Enmax No. 65 substation to accommodate line connections	Enmax No. 65	240		2*240		6*240cvt	2*240a&2*240m		5.2%
1117: PPS - 25 Sub Line Additions	ENMAX No. 25 Substation 240kV Line Additions	Enmax No. 25	240							1.2%
								Total		
									100% 46.1% 53.9%	

Appendix D: TFCMC Working Documents

The TFCMC receives reports and cost summary updates, on a monthly basis, so that the Committee can better understand the costs and changes associated with the transmission projects it monitors. In this part of the report, samples of the cost summary updates are included to provide readers with a better insight as to the type of material the TFCMC studies.

The cost summaries on the following pages are just a portion of the individual documents, which also include detailed information on authorized cost changes and cost estimate changes from the Needs Identification Document (NID) phase to the Proposal to Provide Service (PPS) stage.

The format of the cost summaries was updated and revised in 2011, after an initial round of project cost summaries was completed. At that time, the TFCMC decided it would like to continue with an updated version of the summaries but with more detailed information provided[26]. Examples are provided of most, but not all, of the transmission projects monitored.

Project Cost Reporting for TFCMC, Project 535: Northwest Transmission Development (NWTD); April 2012

Cost Committee Monthly Summary

Project 535: North West Transmission Development

Project Description:
North West Transmission Development

NID Application			
Filing Date	**Approval Date**	**TFO / Stage**	**NID Estimated Cost**
06-Mar-06	Aug 17, 2006	ATCO	$312.0
		Total	$312.0

Month of TFCMC Meeting : 2012 / Apr
Report for the Month of : 2012 / Feb

Facility					Costs		
Facility Application Number	**Facility Application Name**	**Facility Application Filing Date**	**Facility Application Approval Date**	**Overall Facility In Service Date**	**PPS Estimated Cost**	**Authorized Cost Changes**	**Authorized Budget**
1	9L15 240kV Wesley Creek 834S to Brintnell 876S, 2 300MVA Tx P598 (Formerly P598)	Jun 19,2007	Nov 23,2007	Mar 19,2010	$208.33		$208.33
2	7L131/7L106 144kv D/C line Wesley Creek to Meikle 905S & CTs P599 (Formerly P599)	Jul 29,2008	Dec 19,2008	Sep 29,2010	$193.19		$193.19
3	7L133-144 kv S/C line Sulphur Point 828S to High Level 786S P600 (Formerly P600)	May 19,2009	Sep 11,2009	Mar 19,2011	$77.56	-$48.01	$29.55
4	High Level 786S +/- 30 MVAR SVC (Formerly P601)	Apr 14,2009	Sep 1,2009	Jun 30,2010	$12.30		$12.30
5	7L113-144kv S/C line Ring Creek 853S to New Arcenciel 930S (Formerly P602,P604)	Jun 30,2010	Dec 2,2010	Dec 15,2011	$121.25	-$55.34	$65.90
6	Arcenciel 930S -30 +50 MVAR synch cond (Formerly P603)	Jul 15,2011	Nov 15,2011	Mar 1,2013	$43.75		$43.75
7	Arcenciel 930S +/- 30 MVAR SVC (P605)	Jun 30,2010	Dec 2,2010	Sep 7,2011	$12.05	-$1.10	$10.95
8	Little Smoky 813S-install +/-100MVAR SVC & 2-144kV breakers (Formerly P606)	Jun 29,2009	Jun 29,2009	Mar 31,2010	$21.55	$0.17	$21.72
				Total:	**$690.0**	**-$104.29**	**$585.7**

Project Comments:
• All cost numbers are in Million$; New PPS estimate for Synchronous Condenser submitted Nov 18/2011

26 In the December 2011 Report, it was noted that the monthly summary for October 2011 was not available – it was not in the same form as the earlier reports – and that it would instead be included in this June 2012 Report. At this point, that information is out-of-date. Instead, the examples provided here from April 2012 are up-to-date versions of the October 2011 material.

Project Cost Reporting for TFCMC, Project 629: Alberta Industrial Heartland Bulk Transmission Development (HBTD); April 2012

Cost Committee Monthly Summary

Project 629: Alberta Industrial Heartland Bulk Transmission Development

Project Description:

The project includes a new Heartland 12S substation, a new 500 kV double circuit line from Ellerslie 89S to Heartland 12S and connecting to a new 240 kV double circuit line from Heartland 12S into 942L and 943L 240 kV lines.

Month of TFCMC Meeting : 2012 / Apr
Report for the Month of : 2012 / Feb

NID Application			
Filing Date	Approval Date	TFO / Stage	NID Estimated Cost
CTI	Dec 09, 2009		
		Total	

Facility					Costs		
Facility Application Number	Facility Application Name	Facility Application Filing Date	Facility Application Approval Date	Overall Facility In Service Date	PPS Estimated Cost	Authorized Cost Changes	Authorized Budget
1	500kV 1206L/1212L (Formerly P629)	Sep 27,2010	Oct 20,2011	Sep 30,2013	$580.69	$41.18	$621.87
2	Heartland 12S Ellerslie 89S and 1054L/1061L (Formerly P1066)	Sep 27,2010	Nov 1,2011	Sep 30,2013			
				Total:	$580.7	$41.18	$621.9

Project Comments:

• All cost numbers are in Million$
• PPS and authorized budget change a result of salvage being included in estimate
In service date and cost change due to AUC direction on tower type and route.

Project Cost Reporting for TFCMC, Project 671: Yellowhead Area Transmission Development (YATD); April 2012

Cost Committee Monthly Summary

Project 671: Yellowhead Area Transmission Development

Project Description:

Yellowhead Area Transmission Development - all NID work completed under P671

Month of TFCMC Meeting : 2012 / Apr
Report for the Month of : 2012 / Feb

NID Application			
Filing Date	Approval Date	TFO / Stage	NID Estimated Cost
09-Jun-09	May 12, 2010	AML	$87.8
		Total	$87.8

Facility					Costs		
Facility Application Number	Facility Application Name	Facility Application Filing Date	Facility Application Approval Date	Overall Facility In Service Date	PPS Estimated Cost	Authorized Cost Changes	Authorized Budget
1	Hinton/Edson Area Transmission (Formerly P909)	Aug 5,2010	Apr 29,2011	May 30,2012	$51.36		$51.36
2	Cold Creek 602S 138kV, 27 MVAR Capacitor Bank (Formerly P910)	Jul 8,2010	Aug 16,2010	Feb 9,2011	$2.25		$2.25
3	Cherhill Substation and 240kV Interconnection (Formerly P911)	Jul 26,2010	Apr 21,2011	Apr 2,2012	$30.50	$0.01	$30.51
4	Drayton Valley Area 138kV Transmission (Formerly P912)	Jul 30,2010	Apr 27,2011	Dec 21,2011	$41.86	$1.21	$43.07
				Total:	$126.0	$1.22	$127.2

Project Comments:

• All cost numbers are in Million$ FA 3 ISD for Cherhill energized Apr 2/2012. FA 1 Hinton/Edson moved back to May 31/2012

Project Cost Reporting for TFCMC, Project 737: North South Transmission Reinforcement (HVDC); April 2012

Cost Committee Monthly Summary

Project 737: North South Transmission Reinforcement

Project Description:
Construction of two 500kV HVDC transmission lines. Initial development will be two monopoles with at least 1000 MW transfer capacity each.

Month of TFCMC Meeting : 2012 / Apr
Report for the Month of : 2012 / Feb

NID Application			
Filing Date	Approval Date	TFO / Stage	NID Estimated Cost
CTI			
		Total	

Facility					Costs		
Facility Application Number	Facility Application Name	Facility Application Filing Date	Facility Application Approval Date	Overall Facility In Service Date	PPS Estimated Cost	Authorized Cost Changes	Authorized Budget
1	Facility Application 1 - ATCO East DC Facilities (Currently known to TFO as P961)	Mar 29,2011	Jan 15,2013	Dec 15,2014	$1,775.76		$1,775.76
2	Facility Application 2 - West (Currently known to TFO as P962)	Mar 1,2011	Oct 9,2012	Apr 22,2015	$1,542.19		$1,542.19
3	Facility Application 3 - AltaLink East DC Facilities (Currently known to TFO as P961)	May 1,2011	Jan 15,2013	Dec 15,2014	$42.55		$42.55
4	Facility Application 4 - EPCOR East DC Facilities (Currently known to TFO as P961)	Mar 30,2011	Jan 15,2013	Dec 15,2014	$0.12		$0.12
				Total:	$3,360.61		$3,360.61

Project Comments:
- All cost numbers are in Million$
- ISDs update from TFOs as a result of CTRC review on the HVDC lines

Project Cost Reporting for TFCMC, Project 786: Edmonton Region 240 kV Line Upgrades (ERLU); April 2012

Cost Committee Monthly Summary

Project 786: Edmonton Region 240kV Line Upgrades

Project Description:
Upgrade 240kV transmission lines in Edmonton area; add one 240kV phase shifter at Dover substation

Month of TFCMC Meeting : 2012 / Apr
Report for the Month of : 2012 / Feb

NID Application			
Filing Date	Approval Date	TFO	NID Estimated Cost
26-Aug-08	Feb 24, 2009	AML	$77.26
		EPCOR	$9.47
		ATCO	$38.68
		TransAlta	
		Total	$125.41

Facility					Costs		
Facility Application Number	Facility Application Name	Facility Application Filing Date	Facility Application Approval Date	Overall Facility In Service Date	PPS Estimated Cost	Authorized Cost Changes	Authorized Budget
1	AML Keephills Substation Addition **(Formerly P953)**	Nov 6,2009	Mar 19,2010	Jul 31,2010	$101.35	$10.59	$111.93
2	AML Rebuild 240kV 904L (1043L)	Jul 28,2010	Aug 12,2011	Jan 29,2013			
4	AML 902L Restring & 909L Retermination **(Formerly P1057)**	Aug 5,2011	Jan 11,2012	Mar 5,2013			
5	AML 908L, 909L Restring **(Formerly P1058)**	Sep 13,2009	Feb 10,2010	Mar 20,2011			
6	EPCOR Jasper, Petrolia **(Formerly P955)**	Apr 15,2010	Jun 16,2010	Jun 14,2011	$4.55	$2.01	$6.56
3	EPCOR 1044EL, 1045EL **(Formerly P955)**	Oct 15,2010	Aug 12,2011	Oct 13,2011	$7.97		$7.97
7	ATCO Phase Shifter **(Formerly P957)**	Jun 24,2011	Jul 14,2011	[redacted]	$29.34		$29.34
8	TransAlta 902L, 1043L **(Formerly P959)**	Jun 30,2010	Jan 27,2011	Mar 5,2012	$9.65		$9.65
				Total:	$152.85	$12.60	$165.46

Project Comments:
- All cost numbers are in Million$

Project Cost Reporting for TFCMC, Project 787: Southern Alberta Transmission Reinforcement (SATR); April 2012

Cost Committee Monthly Summary

Project 787: Southern Alberta Transmission Reinforcement

Project Description:
Re-enforcement of transmission system in Southern Alberta

NID Application			
Filing Date	Approval Date	TFO	NID Estimated Cost
30-Dec-08	Sep 17, 2009	Stage I	$830
		Stage II	$722
		Stage III	$279
		AFUDC & Escala	$1,612
		Total	$3,443

Month of Reporting : 2012 / Apr
Report for the Month of : 2012 / Feb

Facility					Costs		
Facility Application Number	Facility Application Name	Facility Application Filing Date	Facility Application Approval Date	Overall Facility In Service Date	PPS Estimated Cost	Authorized Cost Changes	Authorized Budget
1	New Windy Flats and 240kV line (SFTP) (Formerly P882)	Dec 2,2011	Mar 7,2013	Dec 17,2014	$436.38		$436.38
2	Milo Junction Switching Station (Formerly P883)	Dec 21,2009	Aug 5,2010	Oct 31,2011	$29.70		$29.70
3	PST Addition at Russell 632S (Formerly P884)	Aug 27,2010	Jan 12,2011	Dec 20,2011	$17.21		$17.21
4	Cassils to Bowmanton (Formerly P886)	Jul 27,2010	Jun 8,2011	Mar 25,2014	$407.91		$407.91
5	Bowmanton to Whitla 240kV Transmission Line (Formerly P887)	Jul 27,2010	Jun 8,2011	Mar 31,2014	$352.75		$352.75
6	Med Hat Area 138kV Line Development (Formerly P888)	Mar 30,2012	Feb 4,2013	May 26,2014	$120.28		$120.28
7	Chapel Rock Sub and 240kV line to Fidler (Formerly P1034)	Aug 25,2013	Jul 22,2014	Aug 16,2015			
8	Etzikom Culee S/S and 240kV line to Picture Butte S/S (Formerly P1035)	May 31,2012	Jun 30,2013	Apr 27,2015			
9	Goose Lake S/S to Etzikom Culee S/S 240kV Line (Formerly P1036)	Jun 28,2013	Jul 31,2014	Sep 30,2016			
10	Etzikom Culee S/S to Whitla 240kV Line (Formerly P1037)	Mar 23,2012	Apr 18,2013	Jan 22,2015			
11	Blackie Area 138kV Upgrade (Formerly P1038)	May 15,2012	Jan 15,2013	Nov 30,2013			
12	Cypress Substation SVC (Formerly P1039)	Jan 18,2012	Mar 14,2012	Feb 24,2014			
13	Ware Junction Substation Upgrade (Formerly P1040)	Apr 5,2011	May 9,2012	Jul 15,2013	$6.13		$6.13
					$1,364.23		$1,364.23

Project Cost Reporting for TFCMC, Project 791: North Fort McMurray Transmission Development (NFMD); April 2012

Cost Committee Monthly Summary

Project 791: North Ft McMurray Transmission Development

Project Description:
North Ft McMurray Transmission Development

NID Application			
Filing Date	Approval Date	TFO	NID Estimated Cost
12-Aug-10	Jun 24, 2011	ATCO	$237.44
		Total	$237.44

Month of TFCMC Meeting : 2012 / Apr
Report for the Month of : 2012 / Feb

Facility					Costs		
Facility Application Number	Facility Application Name	Facility Application Filing Date	Facility Application Approval Date	Overall Facility In Service Date	PPS Estimated Cost	Authorized Cost Changes	Authorized Budget
1	North Fort McMurray 240 kV Transmission Development	Sep 10,2010	Jul 28,2011	Apr 1,2013	$237.44	$90.96	$328.40

Project Cost Reporting for TFCMC, Project 811: Central East Area Transmission Development (CETD); April 2012

Cost Committee Monthly Summary

Project 811: Central East Area Transmission Development

Project Description:

Transmission Development in Waiwright, Lloydminster, Provost, Vegreville Alliance/Battle River and Cold Lake

NID Application			
Filing Date	**Approval Date**	**TFO**	**NID Estimated Cost**
17-May-10	Feb 10, 2011	Stage-1 ATCO	$166.41
		Stage-1 AML	$143.76
		Stage-2 ATCO	$60.14
		Escalation in NID	$60.68
		Total	$431.0

Month of TFCMC Meeting : 2012 / Apr

Report for the Month of : 2012 / Feb

Facility					Costs		
Facility Application Number	**Facility Application Name**	**Facility Application Filing Date**	**Facility Application Approval Date**	**Overall Facility In Service Date**	**PPS Estimated Cost**	**Authorized Cost Changes**	**Authorized Budget**
1	FA 1 - Cold Lake Area Reinforcements - Except Bonnyville	Feb 28,2012	Aug 1,2012	Mar 1,2013	$139.57		
2	FA 2 - Cold Lake Area Reinforcements - Bonnyville	May 15,2012	Dec 1,2012	Aug 1,2013			
3	FA 3 - St. Paul Area Upgrades - Watt Lake, 7LA92	Dec 15,2011	Jul 1,2012	Dec 1,2012	$50.85		
4	FA 4 - St. Paul Area Upgrades - St. Paul 707S, Whitby Lake 819S & 7L139/7L70	Feb 28,2012	Dec 1,2012	Oct 1,2013			
5	FA 5 - Vermillion 710S Substation Upgrade	Oct 24, 0211	Jun 13,2012	Oct 1,2012	$6.70		
6	FA 6 - Heisler Area Upgrades	Dec 23,2011	Feb 28,2012	Nov 1,2012	$33.51		
7	FA 7 - Kitscoty Area Upgrades	May 15,2012	Dec 1,2012	Jul 1,2013			
8	FA 8 - 7L749 Replacement	Jul 2,2012	Apr 1,2013	Jan 1,2014	$33.17		
9	FA 9 - Double Circuit Line Clearance Mitigations (Letter Of Enquiry)	Oct 24, 0211	Jun 13,2012	Dec 31,2012	$13.28		
10	FA 10 - Provost & Wainwright Area Upgrades	Aug 8,2012	Jun 20,2013	Sep 1,2014			
11	FA 11 - 7L50 Rebuild	Oct 19,2015	May 2,2016	Dec 1,2017			
12	FA 12 - Cold Lake Reinforcement (2017) - 240kV	Sep 7,2015	Mar 21,2016	Dec 1,2017			
				Total:	**$277.1**		

Project Comments:

• All cost numbers are in Million$. Facility Application and anticipated dates are elaborated as per the current project status. ISD's and $ values are unchanged.

Project Cost Reporting for TFCMC, Project 813: Red Deer Region Transmission Development (RDTD); April 2012

Cost Committee Monthly Summary

Project 813: Red Deer Area Transmission Development

Project Description:

Transmission system development that consists of new 240/138 kV substation developments, additions to existing substations, new 138 kV transmission line developments, 138 kV transmission line rebuilds and discontinued operation of existing 138 kV transmission lines

Month of TFCMC Meeting : 2012 / Apr
Report for the Month of : 2012 / Feb

NID Application			
Filing Date	Approval Date	TFO / Stage	NID Estimated Cost
20-Jul-11	Jul 12, 2012	AML Stage 1	$207.9
		AML Stage 2	$15.0
		Total	$222.9

Facility					Costs		
Facility Application Number	Facility Application Name	Facility Application Filing Date	Facility Application Approval Date	Overall Facility In Service Date	PPS Estimated Cost	Authorized Cost Changes	Authorized Budget
1	Red Deer Area Transmission Development Stage I - Brownfield	Sep 26,2011	Jul 23,2012	May 15,2013	$20.72		
2	Red Deer Area Transmission Development Stage I - Rebuilds	Jun 13,2012	Jul 19,2013	Mar 24,2014			
3	Red Deer Area Transmission Development Stage I - New Builds	May 31,2012	May 7,2013	Jun 16,2014			
4	Red Deer Area Transmission Development Stage I - 80L Salvage	May 30,2013	Aug 30,2013	Dec 19,2014			
5	Red Deer Area Transmission Development Stage I - 716L Salvage	May 30,2013	Aug 30,2013	Dec 19,2014			
6	Red Deer Area Transmission Development Stage II	Aug 19,2016	Mar 3,2017	Dec 8,2017			
				Total:	**$20.7**		

Project Comments:

- All cost numbers are in Million$
- The NID was re-filed by Regulatory in July resulting in a change to the NID filing date.
- AML adjusted their schedules and removed some float that was in the previous schedules
- An additional Faciltiy Application was added for Development #16 (was orginally part of FA4), because 716L crosses through land that may take longer approval. Mitgates the delay of FA4.
- The AUC announced the hearing for June 2012, with an anticipated approval in Sept/Oct 2012. This has pushed the FA Approval and ISD for FA #1 out to 2013
- The ISD date for FA #4 and #5 pushed to winter 2014 because salvage on cross country land best done during the winter when ground frozen and not in crop season.
- AUC Hearing set for June 2012, NID approval Sept 2012 and FA#1 approval pushed to Oct 2012, delayed FA#1 ISD to May 2013
- AESO has recieved change proposal related to FA#1 and AESO is in the process of reviewing and ultimately a decision regarding these changes.
- AML PPS delivery got delayed, therfore FA#3 Filing date slipped by a month
- No interveners submitted any evidence to AUC, AESO sent letter to AUC asking for NID Approval. NID could be approved earlier than July 2012.

Project Cost Reporting for TFCMC, Project 922: ENMAX No. 65 Substation (ESCS); April 2012

Cost Committee Monthly Summary

Project 922: ENMAX No. 65 Substation

Project Description:

New 240kV / 13k kV substation in south Calgary and associated transmission facilities

Month of TFCMC Meeting : 2012 / Apr
Report for the Month of : 2012 / Feb

NID Application			
Filing Date	Approval Date	TFO / Stage	NID Estimated Cost
CTI	CTI		
		Total	

Facility					Costs		
Facility Application Number	Facility Application Name	Facility Application Filing Date	Facility Application Approval Date	Overall Facility In Service Date	PPS Estimated Cost	Authorized Cost Changes	Authorized Budget
1	New 240/138 kV Substation	Dec 17,2010	Nov 3,2011	Jul 3,2013	$31.14		
2	ENMAX No. 65 I/C to 911L	Feb 16,2011	Nov 3,2011	Jul 3,2013	$6.90		
				Total:	**$38.0**		

Project Comments:

- All cost numbers are in Million$

Appendix E

Transmission Facility Owners Responses

Under the TFCMC's mandate, the Committee shall allow Transmission Facility Owners (TFOs) to review and provide written comments on any report produced that references a TFO or a project a TFO is developing. The following responses were received in regards to the June 2012 Report.

ALTALINK | 2611– 3rd Avenue SE, Calgary, Alberta T2A 7W7 | www.altalink.ca

August 31, 2012

Henry Yip, Chair
Transmission Cost Monitoring Committee
Email:hcyip@teleus.net

Henry,

Thank you for the opportunity to comment on your third semi-annual Transmission Cost Monitoring Committee Report. AltaLink continues to be supportive of providing greater transparency to the industry practices which determine how transmission projects are built.

Section 2 of your report, *TFCMC Observations to Date*, requires clarification. In particular, your summary of project 787 (Southern Alberta Transmission Reinforcement) suggests that several Stage 2 projects and all Stage 3 do not have authorized budgets. It is not clear what is meant by the term "authorized budget". All stage 2 projects are currently active and are progressing under direction from the AESO. Stage 3 projects are on hold pending direction from the AESO to proceed. Also, your reports states that TFCMC has observed that in comparison to the original NID, the cost of Cassils to Bowmanton (CB) and Bowmanton to Whitla (BW) has increased substantially. The main driver for the cost increase, however, is not mentioned. It should be noted that the NID estimate for SATR was prepared in 2008. The PPS estimate was prepared in 2010. The main driver for the variance between the estimates is escalation.

In Section 4, *AESO Cost Benchmarking Recommendation Update*, the report mentions that the AESO has explained that 60% of the costs of a project estimate are termed hard costs and include material, labour and land. The balance (40%) of the estimate has been characterized by the AESO as soft costs and includes project management, contingency and escalation. This definition of soft costs or indirect cost would not be consistent with project management practices. Contingency and escalation are not soft costs. Both contingency and escalation are associated with market discipline and competitive pricing and relate directly to labour or material so should therefore be considered hard costs. In general, indirect costs vary depending on the type of project between 20 to 25% of the estimate.

Section 5, *TFCMC Conclusions and Recommendations*, of the report highlights observations made by the committee on tower weights based on information provided by AltaLink for the CBW project. The context to the comparison noted by AltaLink for the difference in weight between the SW Project towers and the CBW towers is however not captured. In explaining one of the drivers for the cost variance between the NID and PPS, AltaLink explained that changes in the estimate assumptions for tower weight were a contributing factor to the variance. The weight difference was driven specifically as a result of meeting the requirements

Transmission Facility Owners Responses

ALTALINK

of the functional specification which identified a larger conductor, new environmental loading criteria and an increased return period. To illustrate the impact of the functional specification we offered a comparison to the cost for the SW project, which was designed and built to different function specifications and design criteria which were established prior to the development and approval of Rule 502.2 and are the basis for the NID estimate. Furthermore, it should be noted that the AESO certified the CB/BW projects as meeting the functional specification, thus the design of the CBW towers are appropriate for the project.

In the section of the TFCMC report, *Enhancing TFCMC Cost Monitoring/Future TFCMC Future Considerations,* several references are made to verifying the feasibility and/or prudence of the design. With due respect to the Committee, this is well outside the mandate of the committee. Although it is appreciated that some of these factors may impact project cost, it should be noted that the AESO's functional specifications dictate the design. In addition, material, equipment and labour are competitively bid in the market and are subject to market forces of the day. The mandate of the TFCMC is specifically to "monitor" project costs, not to "validate" project design.

Overall, AltaLink continues to be supportive of the general TFCMC recommendations to improve and clarify the Cost Accountability Framework. We look forward to participating in the AESO industry working groups to review and improve AESO rules 9.1.3 and 9.1.5.

Thank you again for the opportunity to comment on your report. If you have any questions relative to these comments, please don't hesitate to call me at 403-267-6133.

Regards,

Johanne Picard-Thompson
SVP Projects, AltaLink

.cc Jerry Mossing , VP AESO

Transmission Facility Owners Responses

ATCO Electric

August 31, 2012

Henry Yip
Chair, Transmission Facilities Cost Monitoring Committee
1701 TD Tower
10088 – 102 Avenue
Edmonton, AB T5J 2Z1

Dear Sir:

Subject: Review of the Cost Status of Major Transmission Projects in Alberta – June 2012 Report

Thank you for the opportunity to review and comment on the Transmission Facility Cost Monitoring Committee's (TFCMC) third report dated June 2012.

As mentioned in our comments to the December 2011 draft report, ATCO Electric (ATCO) remains committed to cooperating with all interested parties to further the understanding of "Cost Accountability" within our industry.

Please contact me directly at 780-420-7434 if you have any questions or require any clarification to the comments included herein.

Yours sincerely,
ATCO ELECTRIC

Original signed by

Dennis A. DeChamplain, C.A.
Vice President, Controller

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Transmission Facility Owners Responses

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August 31, 2012

Henry Yip, Chair
Transmission Facilities Cost Monitoring Committee
Email: hcyip@telus.net

RE: **TFCMC June 2012 Report**

Dear Mr. Yip,

EDTI appreciates the opportunity to comment on the June 2012 Report from the Transmission Facilities Cost Monitoring Committee. EDTI continues to be supportive of the committee and its efforts to understand Alberta transmission infrastructure projects and the various factors that can impact the cost, scope and schedule of these projects.

EDTI has reviewed the report with specific attention to Section 4: Results to Date Status of Previous TFCMC Recommendations and Section 5: Conclusions and Recommendations. EDTI has the following comments:

EDTI notes that in comments made in relation the AESO Cost Benchmarking Recommendation that the report characterizes 40% of transmission project costs as being related to soft costs. This 40% figure appears to classify contingency and escalation as soft costs. EDTI disagrees with this classification. Escalation and contingency are part of the hard costs of delivery of transmission projects and should be classified as such. Escalation and contingency are directly related to the hard costs of labour, material and land acquisition costs that are identified in the report as being dependent on market discipline and competitive pricing.

EDTI is actively participating in the AESO's process initiated in response to the TFCMC's recommendations related to cost accountability and believes that this is an appropriate forum in which to initiate a review and discussion of this subject. EDTI will continue to provide its comments on these matters through the AESO's consultation processes. However, EDTI would like to reiterate that it is beyond the AESO's jurisdiction to review the prudence of transmission costs.

EDTI is also particularly concerned with the discussion in the report found under the heading "Tower Weights". It appears that the Committee is seeking and reporting on information related to technical specifications and technology choice. These decisions are made in the early stages of a projects definition, consistent with ISO Rules and should not be revisited when reviewing cost variances. As noted in the report, the TFCMC's mandate clearly states:

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> …the starting point for the TFCMC when reviewing cost variances is the estimate in place when a project is approved by an Order in Council for Critical Transmission Infrastructure (CTI) projects, or the estimate in place with the Needs Identification Document (NID) is approved by the Alberta Utilities Commission (AUC). The TFCMC, therefore, does not review any of the projects from an initial prudence, need, technology choice or staging perspective. [TFCMC June 2012 Report, page 21, paragraph 1]

EDTI's submits that the TFCMC's reviews of these aspects of a project is well outside of this mandate and does not agree with the Committee's comments that it intends to explore these aspects further in the future.

If you have any questions, please do not hesitate to contact me at 780.441.7154.

Regards,

John Elford
Director, EDTI Regulatory Affairs

JUNE 2012 REPORT

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