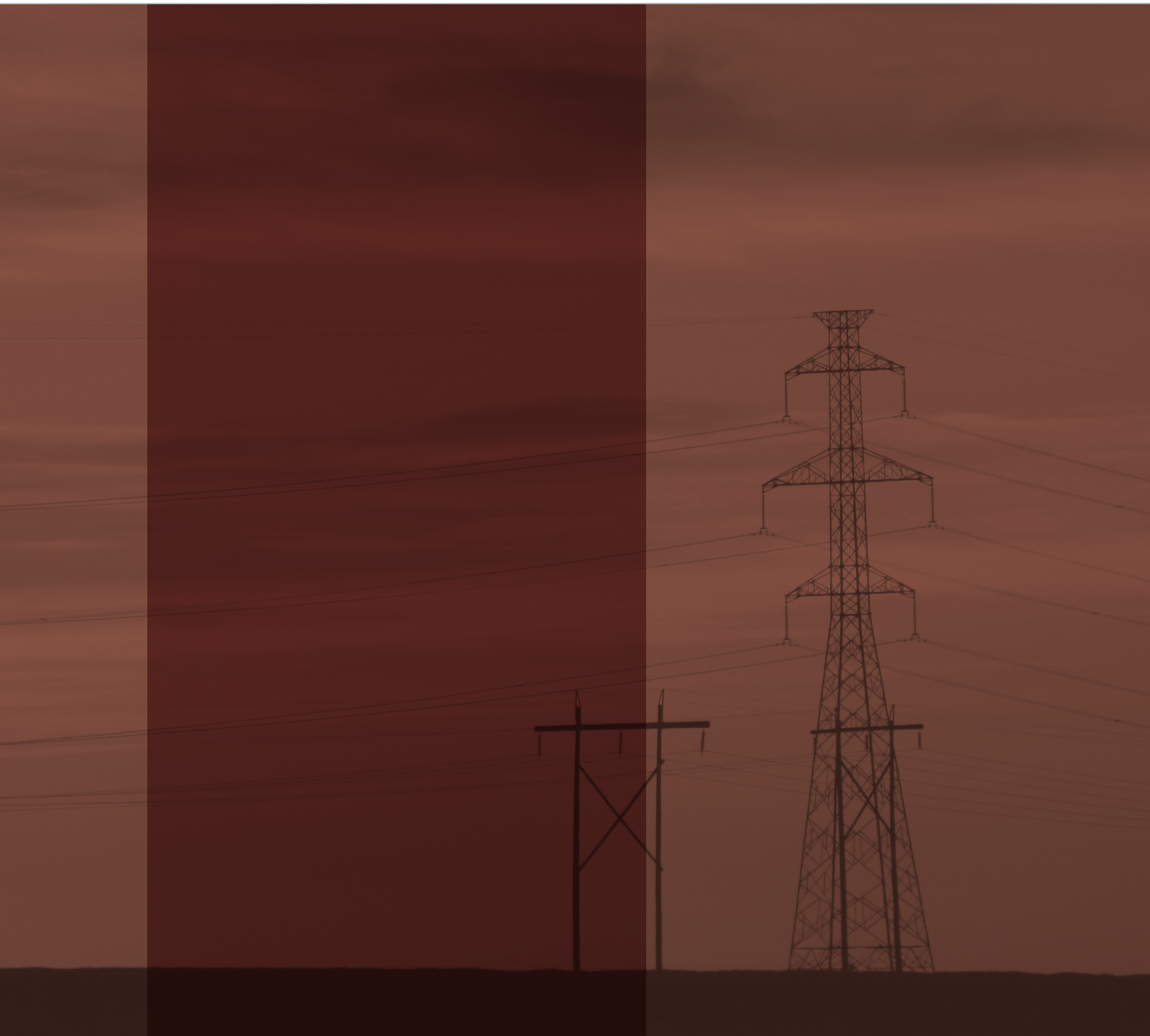
REVIEW OF THE COST STATUS OF MAJOR TRANSMISSION PROJECTS IN ALBERTA

From The Transmission Facilities Cost Monitoring Committee

DECEMBER 2013 REPORT



Industry Abbreviations Found In This Report

Alberta Electric System Operator . . . . . (AESO)

Alberta Utilities Commission . . . . . (AUC)

AltaLink Management Ltd. . . . . (AltaLink)

ATCO Electric Ltd. . . . . (ATCO)

Critical Transmission Infrastructure. . . . . (CTI)

Distribution Facility Owner . . . . . (DFO)

ENMAX Power Corporation. . . . . .(ENMAX)

EPCOR Distribution and Transmission Inc. . . . . (EDTI)

EPCOR Utilities Inc. . . . . .(EPCOR)

General Tariff Application . . . . . (GTA)

High Voltage Direct Current. . . . . .(HVDC)

In-Service Date . . . . . (ISD)

Long-Term Plan . . . . . .(LTP)

Needs Identification Document. . . . . .(NID)

Proposal to Provide Service . . . . . (PPS)

Permit and Licence . . . . . .(P&L)

TransAlta Corporation . . . . . (TransAlta)

Transmission Cost Recovery Subcommittee . . (TCRS)

Transmission Facilities Cost
Monitoring Committee . . . . . (TFCMC)

Transmission Facility Owner . . . . . (TFO)

Transportation Utility Corridor. . . . . (TUC)

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Message From the Chair

This is the sixth report from the Transmission Facilities Cost Monitoring Committee (TFCMC) to its stakeholders. The report provides a detailed and structured summary of the cost, scope and schedule information of the transmission projects monitored by the Committee on a monthly basis for the period of May 1, 2013 to October 31, 2013.

During this period, the Committee examined the progression of 17 major transmission projects, with the total cost of these projects estimated at just over $11 billion. A listing of the projects can be found in Section 1 while details for these projects are contained in Appendices B and C. The Northwest Transmission Development (Project 535) and Yellowhead Area Transmission Development (Project 671) were completed during this reporting period. The final cost for these projects came in at $731 million. At the Needs Identification Document (NID) stage, these projects were projected to cost $410.8 million.

Section 2 of this report contains several key observations made by the Committee while monitoring the progress of these 17 transmission projects. At the invitation of AltaLink, Mr. Bill Smith, a senior vice-president with Siemens, made a presentation to the Committee on the cost of the DC converter station for the North South Transmission Reinforcement Project. He suggested one of the major drivers for the cost differential – when comparing them to international projects – is the cost related to civil works. The additional information gained from his presentation was helpful in understanding part of the cost differential gap that was identified by the Committee's expert consultant even though there is a substantial cost differential left unexplained. The Committee, however, noted that the Alberta Utilities Commission (AUC) through its AltaLink General Tariff Application (GTA) decision found the converter station costs to be reasonable (see Section 4).

During this report period, the Committee also learned of a few other project cost increases due to increasing labour costs in our province. While labour cost increases in the provincial economy are uncontrollable, the Committee is encouraged by the signs of collaboration between the transmission facility owners (TFOs) and the Alberta Electric System Operator (AESO) to adjust project in-service dates (ISD) in order to mitigate labour availability pressures, and by the AESO's initiative to review transmission line design criteria. These types of actions should lead to cost optimization even in an environment of high labour costs. Some of the ratepayers, who are also members of the TFCMC, participated vigorously in the GTA proceedings during this period. The Committee welcomes the decisions recently issued by the AUC and intends to learn from these decisions in order to be more effective in our cost monitoring approach.

Through the TFCMC's work in monitoring transmission project costs, it has identified many opportunities to control costs. Since its inception, the Committee has made recommendations to take advantage of these opportunities. Section 3 provides an update on the status of all previous recommendations. The Committee is heartened by the proactive responses from the AESO and Alberta Energy. The AESO's continuing work in enhancing the benchmarking database and in strengthening Rule 9.1 in the areas of cost estimates, cost reporting and procurement are just some examples of their positive responses to the Committee's recommendations. In a letter to the Committee dated July 22, 2013, the Minister of Energy stated, "my announcement on January 29, 2013 on increased scrutiny of transmission costs was in part informed by the work of the TFCMC."

Section 4 contains the Committee's conclusions and recommendation for this period. To improve transparency and accountability of project cost management, the Committee believes it is reasonable for the TFOs to seek approval from the AESO – after a project has been approved by the Regulator – only for changes to the ISD and/or changes in scope and the resulting cost impact. All other changes should be evaluated through regulatory proceedings.

Since its inception, the Committee has had two independent members appointed by the Minister of Energy. The appointments were for a three-year term, which expired on December 14, 2013. The Committee held an in-camera discussion, chaired by Colette Chekerda, resulting in a recommendation to the Minister of Energy to reappoint Mr. Al Snyder and Mr. Henry Yip as independent members of the TFCMC. It further recommended that Mr. Yip stay on as the Chair of the Committee. The Minister accepted the Committee's recommendation and appointed the two to serve on the Committee for another three years in their respective capacities.

Thank you for your continuing support. The TFCMC's next report is scheduled for the fall of 2014. Your comments to improve the 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.

Monitored Projects

The TFCMC monitored 17 projects valued at a total of $11.061 billion[1] (based solely on the current estimated costs noted in Appendix B of this report). During the period covered by this report, two of the projects – 535, Northwest Transmission Development and 671, Yellowhead Area Transmission Development – were completed and this report is expected to conclude the Committee's work on these undertakings.

The monitored projects, in alphabetical order, are:

- **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.
- **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.
- **EAST CALGARY TRANSMISSION PROJECT AND ENMAX SHEPARD ENERGY CENTRE CONNECTION (ECTP);** PROJECT 719 – To serve growing demand for electricity in the Calgary and High River planning areas and to interconnect the ENMAX Shepard Energy Centre.
- **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.
- **FOOTHILLS AREA TRANSMISSION DEVELOPMENT – EAST PROJECT (FATD);** PROJECT 1117 – To meet growing demand in South Calgary, High River and the surrounding area.
- **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 the Hanna, Sheerness and Battle River areas.
- **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[2].
- **NORTHWEST FORT MCMURRAY TRANSMISSION DEVELOPMENT (NW FMM);** PROJECT 1180 – To provide service and connect future industrial customers in areas where there are no transmission facilities northwest of Fort McMurray.
- ***COMPLETED* NORTHWEST TRANSMISSION DEVELOPMENT (NWTD);** PROJECT 535 – Transmission expansion and enhancement in northwest Alberta.

1 This figure does not include costs for Project 838 – Fort McMurray Area Transmission Bulk System Reinforcement (FMAC) – as this project falls under a competitive procurement process.

2 In late February 2012, this project received provincial government approval to proceed after previously being placed under review by the government.

- **RED DEER REGION TRANSMISSION DEVELOPMENT (RDTD);** PROJECT 813 – Transmission system reinforcements in the Red Deer area.
- ***NEW* SOUTH AND WEST OF EDMONTON TRANSMISSION DEVELOPMENT (SWEATR);** PROJECT 850 – Transmission system reinforcement to the 138 kV system south and west of the City of Edmonton.
- **SOUTHERN ALBERTA TRANSMISSION REINFORCEMENT (SATR);** PROJECT 787 – To accommodate wind generation in southern Alberta.
- ***COMPLETED* 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, it embarks on in-depth assessments of these undertakings (in the case of new projects[3]) or focuses on a more detailed analysis of existing ones and relevant issues based on the monthly reports[4] it receives.

The Committee observed the following concerns and or issues during the six-month period covered by this report.

North South Transmission Reinforcement Cost Increases

In October 2013, the Alberta Electric System Operator (AESO) received updates from AltaLink Management Ltd. (AltaLink) and ATCO Electric Ltd. (ATCO) for their respective portions of the North South Transmission Reinforcement (HVDC) Project (Project 737). AltaLink and ATCO also presented the cost increases to the TFCMC in November and December, respectively.

AltaLink projected a 17% ($211 million) increase from the original Proposal to Provide Service (PPS) for the Western Area Transmission Line (FA 963). ATCO projected a 13% ($206 million) increase from the original PPS for the Eastern Area Transmission Line (FA 961).

The increases for the Western Area Transmission Line (WATL) are due to:

- Increased rates for tower assembly;
- Right-of-Way (ROW) preparation and brushing magnitude were underestimated;
- Increased access costs including matting, snow clearing, fences, gates, roads and culverts due to the wet conditions in early 2013;
- Cost increases at both Crossings and Sunnybrook substations due to site fill requirements;
- Increases in project-management costs ($34 million) to support global procurement of line and substation materials, to manage increased complexity and to manage the splitting of the DC line construction into three segments; and
- Increases in construction-management costs ($40 million) for additional field personnel required to manage subcontractors for material handling, field coordination, environmental coordination and safety.

There is no impact on the in-service date of April 22, 2015.

The increases for the Eastern Area Transmission Line (EATL) are due to:

- Increases in competitively tendered costs for all the major material and service contracts;
- The Permit and License delay caused by the Critical Transmission Review Committee (CTRC) work, and
- An increase in project contingency, including $24 million for schedule risk should the in-service date be delayed one to four months.

Regarding the contingency amount of $24 million, the AESO's understanding is that this is a potential risk of an in-service date (ISD) delay of one to four months, and that this amount would only be earmarked as such; and will not be allocated for any other risk.

The AESO is concerned about a potential in-service date delay and advised of the consequences of not meeting the in-service date. The AESO's approval of this contingency amount is not to be interpreted as an endorsement of an in-service-date change, as the AESO expects the EATL project to be in-service by December 2014. A change in the forecasted ISD would require an additional Change Proposal.

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

4 The TFCMC continues to receive monthly reports from the AESO, which originate from the TFOs, on all projects valued at $100 million and over.

After reviewing the change proposals and information request responses from the transmission facility owners (TFOs), the AESO approved both change proposals.

In summary, the AESO noted that:

- Both increases are within the original PPS +/- 20% threshold;
- The changes do not affect the chosen alternative;
- The changes do not affect the requirements of the functional technical specification;
- Contracts were competitively tendered; and
- The AESO cannot comment on the prudency of these costs.

The TFCMC observes that the primary driver for the cost increases appears to be the changes in the labour market conditions, offset by minor reductions in material costs.

EATL and the corresponding WATL project, being built by ATCO and AltaLink respectively, combine to form the North South Transmission Reinforcement (HVDC) development, also referred to as Project 737 – the construction of two 500 kV HVDC transmission lines from the Edmonton area to the Calgary and south regions.

HVDC Converter Station Presentation

At the October 2013 meeting, both AltaLink and Siemens provided presentations on the procurement of the WATL Converter Stations.

AltaLink advised that it went to three well-known suppliers for bids, of which Siemens was selected as the winning bid. In addition, three more companies were considered but these firms advised that they would not offer solutions to North America – often, these three companies do not bid but will supply electrical components to the main suppliers. AltaLink reported that Siemens had the lowest cost commercially and was tied technically with the other two companies. AltaLink also said all three bids were within a very tight price range. The timing of the procurement allowed AltaLink to lock in the price at the best time in the market – doing so just one quarter later would have resulted in a significant price increase.

The Siemens presentation provided a perspective on what is happening in the global HVDC market.

Cost, it was said, is contingent upon market timing and global location. Global factors include primary materials (copper, structural and alloy steel), manufacturing capacity and productivity, transportation costs and exchange rate effects. Local factors include functional requirements, labour availability and productivity, site conditions and environmental requirements. Siemens advised that good timing allowed Alberta to take advantage of a beneficial situation as manufacturing (for this industrial sector) was at a low level. Siemens further advised that local factors provide the most challenges in terms of cost, and that the functional requirements for Alberta's HVDC project were not a significant cost driver. Siemens advised the TFCMC that they are having significant challenges with their civil works in Alberta and are currently working with contractors to pull resources from Ontario and Quebec.

Central East Transmission Project Cost Increases

At the September 2013 meeting, ATCO provided the TFCMC with a presentation on the Central East Transmission Development Project (P811), mainly discussing recent cost increases.

ATCO advised the TFCMC that they are experiencing an upward pressure on prices, high volatility in bids, and bidders dropping out. There is also an upward trend due to a hotter economy. On a typical project, ATCO approaches six to nine qualified bidders and generally receives three responses. ATCO stated that it looks at the possibility of staggering work internally but does not work with other TFOs on this when it comes to staging projects. They said trying to coordinate the huge number of projects TFOs work on would prove to be a daunting task.

Further, ATCO said there is more work than available resources and that EATL and WATL alone (Project 737, North South Transmission Reinforcement) are enough work to satisfy the largest contractor in North

America. ATCO also stated that contrary to what some may think, it is price sensitive and reviews options to reduce costs (such as using its own crews on salvage work). With regards to a question on the use of helicopters, ATCO said that, generally, they prefer not to use them to erect transmission towers. They prefer the conventional method of using cranes.

Hanna & Cassils-Bowmanton-Whitla Cost Comparison

TFCMC members have identified the AltaLink Cassils-Bowmanton-Whitla (CBW) project – a portion of Project 787, Southern Alberta Transmission Reinforcement – as a development that appears to have high costs. The TFCMC undertook an initial high-level analysis, with assistance from the AESO, to identify the causes of some of the costs based on circumstances unique to this project. Since the ATCO Hanna project was constructed in a similar area of Alberta with similar terrain and population densities, similar tower types and environmental challenges, a comparison with the Hanna project was considered reasonable.

The focus of the analysis was the transmission construction labour, which seemed to be one of the major drivers for cost increases, both in the Hanna and CBW projects.

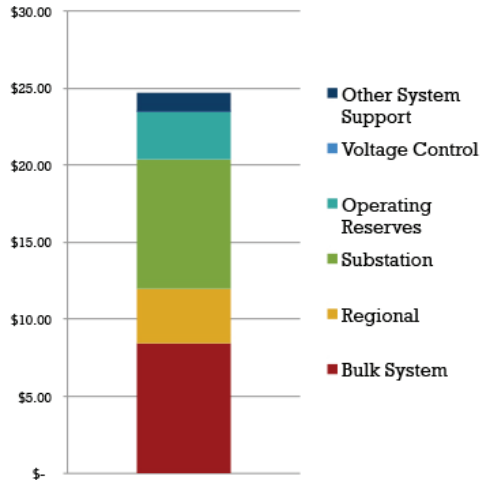
At this point in the analysis, it is premature to come to any sufficiently supported conclusions. The AESO and the TFCMC will conduct further analysis and address a number of outstanding questions, including:

- Tower design (R series, zones A to C);
- Conductor size;
- Conductor strung on one or both sides of double-circuit lines;
- Inclusion of tower development costs;
- Transmission line cross-overs;
- Transmission line length;
- Cost estimate updates;
- Construction practices (i.e., helicopters versus cranes);
- Cost of detailed engineering;
- Line and tower optimization; and
- Line routes and right-of-ways.

By the end of January 2014, the AESO will start to receive the final cost reports for both of these projects, which are required to start the analysis. A target will be to complete this analysis and publish the results for the June 2014 TFCMC report.

Transmission Cost Outlook: Implications of Projected Transmission Costs

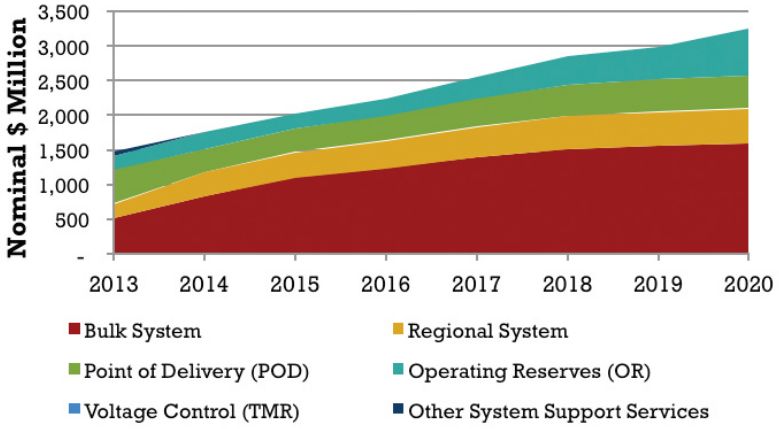
The transmission tariff, designed by the AESO, and approved by the Alberta Utilities Commission (AUC), collects the revenue requirement of the TFOs and other transmission costs. The tariff, known as Demand Transmission Service (DTS), is divided into six cost categories based on cost causation principles. The average DTS rate in 2013 is illustrated as follows:



Cost categories observed by the TFCMC include the bulk, regional and substation costs. These represent the costs to build, finance, operate and maintain transmission infrastructure in the province. The elements of operating reserves, voltage control, and other system support services reflect the costs the AESO incurs to reliably serve load and dispatch the energy market in real time.

In 2013, the AESO prepared a long-term transmission tariff cost outlook as part of their 2014–2016 General Tariff Application (GTA). The cost outlook considers forecasts for load growth, infrastructure project costs, in-service dates and the pool price.

The following chart represents the revenue requirement predicted based on these forecasts:



By 2020, Albertans can expect average transmission rates to increase from $25/MWh to approximately $41/MWh.

The cost projection is sensitive to load growth, actual project costs and timing, as well as pool prices. Customers are concerned with the cost outlook and the risk of further increases beyond the base case. Some of the cost mitigation measures currently being pursued are in the areas of onsite generation, demand response, and energy efficiency strategies.

As the TFCMC reviews the major projects, it is important for the members to understand the impact to consumers of changes in costs. If the projects were to come in at the +20% upper band of the cost estimates, the impact to consumers would be an additional $5/MWh to $6/MWh.

Line Design & Optimization Issues

In May 2013, the TFCMC requested that the AESO provide responses to specific questions regarding transmission line design and optimization with respect to the AESO's development of the Transmission Line Rules and the subsequent development of the transmission towers.

Responses to the questions were provided by the AESO with assistance from Utilitech Consulting Inc. (Mr. Carl Orde) who was the AESO's primary technical consultant in the development of the Transmission Line Rules and the subsequent development of the transmission towers. This work was undertaken with extensive TFO participation and the Rules were issued for full industry consultation prior to filing with the AUC.

A brief summary of the responses to the TFCMC's questions and the May 27, 2013 presentation to the TFCMC is as follows.

General Line Optimization Issues

The purpose of both the line and conductor optimization study as required in Rule 502.2(12) was to reflect the overall cost of transmission line facilities—both the initial capital cost and the net present value of electrical losses over the economic life of the facilities. The optimum solution is the line design having the lowest net present value (NPV) of costs. This principle has been widely used by utilities in other jurisdictions for many years, for both transmission and distribution systems.

A full line optimization study will include the cost of right-of-way and the cost of towers and foundations, as well as the cost of conductors. Options such as conductor type (ACSR, ACSR/TW, HTLS), tower types (lattice, H-frame, monopole), tower material (wood, steel, composite), and foundation type (driven pile, caisson, grillage) would be considered.

It is important to note that the purpose of the line or conductor optimization study is to identify cost differences between options examined. Those factors that do not change between options are not considered. The objective is not to produce an accurate estimate of the cost to build the project.

Regarding tower design, the AESO has developed weather-loading maps that provide the minimum loading levels within Alberta. TFOs are required to utilize tower designs that meet or exceed these requirements. The AESO worked with the TFOs to develop common tower designs (that are available to all upon request) that a TFO may utilize as they see fit. TFOs may also design new towers to address specific project requirements (typical design/testing time frame of 12 to18 months).

General Access to Line Optimization Results

After January 1, 2012, the TFOs are required to comply with the ISO Rule 502.2 and as such have prepared and submitted line optimization studies to the AESO as part of the PPS submissions where applicable. Similar to other information provided to the AESO by the TFOs, the conductor and line optimization studies would normally be considered confidential.

Roles and Responsibilities under ISO Rule 502.2

The Rules are intended to place responsibility for the optimization on the TFO as they have access to the information required to undertake the optimization study (i.e., price of conductors, weight of towers, number of tangent and angle towers, etc.). However, under special circumstances, the AESO has engaged consultants to undertake preliminary optimization studies. An example of this would be the HVDC project

where at an early stage the AESO engaged a consultant to undertake preliminary studies to better understand the project scope. The final optimization studies and tower development were then undertaken by the TFOs.

TFOs can advise the AESO should major opportunities for cost savings be identified (while meeting the basic requirements of ISO Rule 502.2, or even with minor variances to the Rule). Several requests for variances to ISO Rule 502.2 have been approved by the AESO where the requests were deemed to result in no significant impact on reliability, and produced significant cost savings.

Development of ISO Rule 502.2 and the Adoption of Tougher Design Standards

The industry workgroup that developed ISO Rule 502.2 included participation by AltaLink, ATCO, ENMAX and EPCOR. Once a draft of the Rules was developed, the AESO's rules development consultation process was followed. Comments were received and the rules were modified. A second full round of consultation was undertaken with additional comments being received. Further modifications were made and the final version was submitted to the AUC for approval. The AUC approved the Rule subsequent to receiving no comments.

The new 240 kV double-circuit tower designs reflect the assessment that the new high-capacity double-circuit lines (up to 1100 MVA per circuit) have an importance in the grid equal to that of the 500 kV lines (part of the "backbone" grid). It was agreed that the design criteria should reflect the actual weather loadings in Alberta and the design of the new 240 kV double-circuit towers should also address the following known deficiencies in the existing designs:

- The existing towers had no requirements for wet snow, or combined wet snow and wind loadings (which are the predominant form of icing in Southern Alberta);
- The existing towers had no requirement for unbalanced longitudinal loadings, or certainly nothing that would be close to current criteria as expressed in the Rule;
- The towers had no requirements for galloping, and the lines in the southern part of the province had experienced many outages due to this type of event; and
- The existing towers were not designed to allow live line maintenance.

The design criteria for the new towers addresses the deficiencies noted above, and are consistent with the criteria for similar lines in other jurisdictions. In some parts of Canada, the design criteria for lines having similar reliability expectations are more onerous than those used here.

The committee members were aware that the weight of the new 240 kV towers would be significantly higher than the weight of the existing L towers. However, it was assessed that the impact on the design of 138 kV wood pole lines and 500 kV lines would be minimal.

An important aspect of the overall economics related to design criteria is consideration of the economic impacts and cost of restoration in the event of a major line failure. In the 1986 outage event – the result of a significant winter storm – replacement towers were available from a project underway by ATCO Electric, and they agreed to "loan" the required towers to TransAlta for restoration purposes. Even then, it took several months for the line to be restored to service. It is understood that for the 2010 line failure – from a wet snow and ice storm in Southern Alberta – replacement towers were also available from another project and the restoration time was in the order of months. In the event of a major line failure where replacement towers were not readily available (the normal situation), it could easily take six to 12 months to procure the towers and restore the line to service. The cost of system constraints and overall cost to the economy would likely be very significant.

R Series Towers

The AESO has not reviewed AltaLink's GTA submission with respect to increased tower weights for the 240kV RC22A tower. The R series tangent towers for Zones A, B and C were load tested and the loads would have reflected the requirements of ISO Rule 502.2. One tower failed and the loading on the other two was stopped when it reached a predetermined value as follows:

- For the RA22A tower, there was a failure of some members at less than 100% load. These were modified and the testing continued with the wet snow and wind-loading case being increased to a level between the 120% and 125%, at which point a significant tower failure occurred.
- For the RB22A tower, the destructive load case was taken to be the ice-shedding case. The loading was increased to 125% without failure of the tower.
- For the RC22A tower, the destructive load case was taken to be the wet snow and wind-loading case. The load was increased to 125% without failure of the tower.

Following the May 27, 2013 Presentation

Since providing the above responses to the TFCMC, the AESO has initiated an industry review of ISO Rule 502.2. This workgroup included participation by AltaLink, ATCO, ENMAX, EPCOR, and the Office of the Utilities Consumer Advocate (UCA). The purpose of this workgroup is as follows:

1. Review ISO Rule 502.2 at a high level and identify if any new data is available that could lead to rule enhancements or modification;
2. Review the conductor and line optimization process, as applied by the TFOs, to confirm that the desired outcome is being achieved;
3. Identify the need for new tower families based on the AESO's area plans (smaller conductor, single conductor, guyed towers, common H frames, etc.). Given the 12 to 18 months required to design/test towers, this will allow TFOs to either pre-emptively design towers or the AESO may initiate common tower designs that would be made available to all; and
4. Determine if existing tower designs need further review (based on any changes initiated from Item 1 and upcoming need as identified in Item 3).

Any proposed changes to rules would go through the AESO's rules development consultation process. Any new tower designs initiated by the AESO would be made available to all participants.

Change Order Analysis

Members of the TFCMC expressed concerns about the number of project change proposals that were occurring on TFO projects. The impression was that the project change proposals were becoming a substantial portion of a project's total cost. The TFCMC requested a review of these change proposals to determine their overall magnitude.

AltaLink, ATCO, EDTI, and ENMAX Power Corp. projects that the TFCMC monitors were included in the review. The review did not differentiate projects by their stage of development. Consequently, any given project – when completed – may have a higher proportion of change proposals compared to the current budget, than occurs on average across all projects.

An initial analysis was conducted in September 2013 and was to be updated in January 2014 in order to determine the percentage of change proposals (in dollars) compared to the current budget (in dollars). The current percentages, aggregated by TFO and, with the caveat above, range from 10% to 14%. The TFCMC has requested that the AESO monitor these percentages semi-annually.

Transmission Line Helicoptering

The TFCMC has looked at different aspects of transmission towers and their impact on the transmission build. One aspect involved helicoptering, described as an innovative method to minimize environmental impacts and speed up construction.

An AltaLink presentation detailed how the helicopters were used to bring in transmission towers to power line construction sites on the Cassils-Bowmanton-Whitla portion of Project 787, the Southern Alberta Transmission Reinforcement (SATR).

The use of a helicopter reduces environmental impacts along the transmission line right-of-way, the TFCMC was told. Using a helicopter was also said to be a significantly faster construction technique, however, this process would not make sense in the case of a short, 10-kilometre line (or less), nor is it necessary when using wood or steel poles. It was claimed to be a good practice for lattice towers.

This helicopter process was described as quick, with a round trip between a nearby assembly yard and the tower location pegged at about five minutes. The helicopter used was a Sikorsky, equipped with an Erickson Air-Crane that can lift 25,000 pounds.

Transmission towers are taken from an assembly yard in close proximity to the actual site and the towers are in two pieces. Typically, there are 20 to 25 towers in an assembly yard. Multiple assembly yards are required and this space is rented.

While a crew is back bolting the upper section of the tower to the lower portion, which takes about five minutes, the helicopter is then putting in the next tower section.

Screw pile foundations were used exclusively on this project, and they reduce environmental impacts. There are three piles per leg of the foundations, with an average six metres of depth for the screw piles. Had the screw piles not been able to be used, AltaLink would have gone with concrete caissons. Screw pile foundations cost less than concrete caissons and are also much quicker to put in, AltaLink said.

Asked about feedback from landowners, AltaLink said anecdotal information is that they are very happy. AltaLink plans to do a more formal survey on this. AltaLink also said it plans to use helicopters wherever it can to lift towers. AltaLink is looking at using the helicopter system for the Western Alberta Transmission Line (WATL) portion of Project 737, North South Transmission Reinforcement (HVDC).

When ATCO Electric was questioned about using helicopters for tower assembly, they indicated they did not consider them to be cost effective in normal terrain. They indicated from their experience that helicopters are effectively deployed in the conductor stringing process and for tower erection in remote areas, such as mountains, where access is very difficult. ATCO Electric does not normally use helicopters for tower erection.

From the perspective of landowner impacts, when using helicopters for tower erection, considerable access to the right-of-way by heavy equipment is still required. This equipment is required to install the foundations (screw piles, caissons, etc.) and to install the stub of the tower that attaches to the foundations. Other anecdotal information from landowners (not from AltaLink) indicates that while landowners are impressed with the use of helicopters, they were concerned with the number of times AltaLink had to access the right-of-way during the project, including the number of times they installed, removed and reinstalled rig or access mats.

During AltaLink's 2013 2014 General Tariff Application, the issue of using helicopters was raised by interveners. AltaLink produced a cost estimate to demonstrate the cost effectiveness of using helicopters for tower erection. AltaLink estimated that it saved 0.5% on the Cassils to Bowmanton transmission line and 2.6% on the Bowmanton to Whitla line by using helicopters rather than cranes[5]. The details of the cost estimate were redacted and therefore could not be further evaluated. These untested cost estimates demonstrate only a marginal benefit that is likely well within the accuracy of the estimate and does not show a major cost saving by using helicopters. Interveners have the option of further reviewing the use of helicopters versus cranes in the Deferral Account process.

5 AltaLink 2013 2014 General Tariff Application, (Proceeding ID 2044) Exhibit 197.01.

Observations On New Projects

At the October meeting, the AESO provided a presentation on the new South and West of Edmonton Transmission Development Project (P850), which has recently been added to the list of projects the TFCMC monitors. The AESO advised that:

There are existing transmission constraints in the area south and west of Edmonton.

- Demand for electricity in the Edmonton region is forecast to increase by 800 MW over the next 10 years;
- Growth of 800 MW over 10 years represents a 2.7% average annual growth to the current demand of 2,127 MW;
- The electrical system in this area will not have sufficient capacity to handle this growth without a number of system developments; and
- The Needs Identification Document (NID) is estimated at $172 million; the AESO Long-Term Plan estimate was $178 million.

The AESO submitted its NID application to the AUC on December 14, 2012 (Application #1609123). Additional stakeholder communication was held in August 2013 due to swath extension required by the TFO. An AUC hearing is anticipated by the first quarter of 2014 and NID approval is anticipated by the second quarter of 2014.

AltaLink is currently working on the routing with the Facility Application (FA). Filing with the AUC is anticipated by the third quarter of 2014. The AUC FA Hearing is anticipated by the first quarter of 2015. The AUC decision on the facility proposal is anticipated by the third quarter of 2015, with the facilities in-service date anticipated by the second quarter of 2016.

Completed Projects

The following projects have been completed and are now in service. The AESO considers these projects as closed and they will no longer be reported on to the TFCMC. Where a project may have some work outstanding, the AESO will advise the TFCMC as necessary. Projects are listed alphabetically.

Northwest Alberta Transmission Development (NWTD) – Project 535

The Northwest Alberta Transmission Development identified transmission issues in three areas of the Northwest region. The project was completed and in service in May 2013. The transmission development included:

- Adding new 240/144 kV transformers;
- Adding 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.

Yellowhead Area Transmission Development (YATD) – Project 671

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

- Conversion of the 69 kV systems to 138 kV from Wabamun to Drayton Valley and Wabamun to Barrhead; and
- Reconfiguration and enhancements to the 138 kV system in the Edson-Hinton area.

All construction work and energizations are complete. AltaLink will complete its project close out report, including final costs, by mid-February 2014.

3. Results to Date: Status of Previous TFCMC Recommendations

Previously, the TFCMC has issued five semi-annual reports containing 10 recommendations – all with the goal of enhancing the management of transmission costs in Alberta. Of these recommendations, eight were directed to the Alberta Electric System Operator (AESO) and two have been made to Alberta Energy.

Instead of issuing additional recommendations, the TFCMC's last report (June 2013) contained a list of its Top 5 transmission priorities. This list came about as Alberta Energy initiated a review of its transmission cost management policy. An update on the status of that endeavour is also included in this section.

Recommendations to the Alberta Electric System Operator

As noted in previous editions of the TFCMC's semi-annual report, the AESO has been proactive in its response to recommendations made by the Committee. It has adopted a number of the recommendations made by the TFCMC and it is moving forward on implementing others. The TFCMC continues to be encouraged by this as well as the overall direction and response that the AESO has taken in regards to these recommendations.

Recommendations already implemented:

- **JUNE 2011 REPORT, RECOMMENDATION NUMBER 1:** 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, RECOMMENDATION NUMBER 2:** 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, RECOMMENDATION NUMBER 4:** That the AESO enhance compliance of the material procurement provisions of Rule 9.1.

Recommendations in the process of being implemented:

- **JUNE 2011 REPORT, RECOMMENDATION NUMBER 3:** That the AESO develop a transmission cost benchmarking competency and database;
- **JUNE 2011 REPORT, RECOMMENDATION NUMBER 6:** Initiate a review process on the current framework for cost accountability;
- **JUNE 2012 REPORT, RECOMMENDATION NUMBER 1:** That for each Direct Assigned Capital project estimated to cost in excess of $100 million[6] 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.
- **DECEMBER 2012 REPORT, RECOMMENDATION NUMBER 1:** The AESO, with assistance from TFCMC consultants, undertake a case study concerning the cost changes for Project 671 – from the NID through to the PPS and the authorized budget – and this should include lessons learned from the Yellowhead project and lessons about reporting under ISO Rule 9.1 (Compliance Monitoring).

6 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.

The remaining AESO recommendation:

The AESO has expanded the following recommendation into the broader context of the TFCMC's earlier cost accountability recommendation. The AESO's goal is to coordinate with the Alberta Utilities Commission on the development of a reporting protocol with respect to the treatment of transmission project costs.

- **DECEMBER 2011 REPORT, RECOMMENDATION NUMBER 2:** That for each Direct Assigned project, the AESO provide to the Alberta Utilities Commission a summary of the scope changes authorized by the AESO for that project including the following:
  - V. The AESO's assessment on whether each scope change was needed;
  - VI. A summary of the alternatives available to meet each scope change;
  - VII. The AESO's assessment on whether the alternative recommended by the TFO to address each needed scope change was the most appropriate alternative; and
  - VIII. The AESO's assessment on whether the cost of each scope change as estimated by the TFO was reasonable.

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.

AESO Cost Accountability Recommendation: ISO Rule Section 9.1 Consultation Update

The AESO intends to recommence its stakeholder consultation on Rule 9.1 in early 2014, after Alberta Energy has completed its stakeholder consultation on its Transmission Cost Management policy initiatives. Changes to Rule 9.1 are expected to be developed and filed with the AUC by the end 2014.

Based on the recommendations from the Transmission Facilities Cost Monitoring Committee's June 2011 Report, the AESO began a review of the cost accountability framework in November 2011.

AESO Transmission Cost Accountability Recommendation: Reporting and Oversight Protocol

The AESO is currently participating in Alberta Energy's Transmission Cost Management policy stakeholder consultation. Consultation will include the following four cost initiatives:

- Approved cost estimate;
- Cost oversight manager;
- Competitive Process project criteria; and
- Cost reporting enhancements.

Stakeholder consultation concluded at the end of December 2013. New legislation regarding Transmission Cost Management is expected to be tabled in the government's spring session.

AESO Cost Benchmarking Recommendation Update

In March 2013, the AESO published the first release of the Alberta transmission cost benchmarking document on its website: AESO Position Paper – Reasonable Assessment of Transmission Cost Using Benchmarking Methodology (Benchmarking Document). It consists of a main paper and four appendices.

Since then, the AESO has received several data and analysis requests from different stakeholders on transmission cost benchmarking. The AESO continues to update the benchmarking database and related analysis with revised project cost information, and plans to update the benchmarking document twice a year. Interactive analysis software has now been implemented allowing stakeholders to access transmission cost benchmarking data and to do their own analysis.

The AESO published the links of several interactive dashboards for transmission cost benchmarking data and analysis on its website on July 31, 2013. A video was also posted to demonstrate how to use the interactive dashboards. The following dashboards are online and ready for use:

- Project overall cost estimate breakdown;
- Project summary component cost percentage chart;
- Transmission line facility unit cost estimate;
- 138/144 kV substation facility unit cost estimate;
- 240 kV substation facility unit cost estimate; and
- Substation major equipment unit cost estimate:
  - Transformer;
  - Circuit breaker, and
  - Capacitor bank.

Stakeholders are being encouraged to contact the AESO when dealing with significant data outliers as it will help to improve both data accuracy and the quality of the transmission benchmarking database and analysis.

This initiative is based on a recommendation from the TFCMC, in its June 2011 Semi Annual Report, to develop a cost benchmarking database that 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.

Recommendations to the Provincial Government

The TFCMC has directed two recommendations to the Alberta Energy through its semi-annual reports. One[7] of the two, ***Recommendation Number 5*** in the June 2011 Report, was considered premature by the Department given the implementation of the other recommendations from the same semi-annual report.

The TFCMC made a second recommendation for the Department to consider. This one, ***Recommendation Number 1*** in the December 2011 Report, reads as follows:

- 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.

The Minister, in a letter to the Committee, advised that Alberta Energy would consider this recommendation as it reviews potential amendments to the Transmission Regulation. The review was still underway at the time of this report.

Top 5 Transmission Priorities: Transmission Cost Management Policy Update

As noted in the June 2013 semi-annual report, the TFCMC created a Top 5 list of transmission priorities based upon a request from Alberta Energy as part of its transmission cost management policy review. The provincial government initiative was put in place to seek advice from leaders in the electricity sector as Alberta Energy moves to address the concerns arising out of increasing transmission costs.

In brief, the TFCMC's recommendations[8] for action on transmission costs, which have previously been forwarded to Alberta Energy as part of it review, are summarized as follows:

7 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.

8 To see the TFCMC's Top 5 Transmission Priorities in their entirety, please consult the TFCMC's June 2013 semi-annual report.

1. Transparency, consistency and accuracy in developing cost estimates;
2. Joint TFO cost reduction practices;
3. Incentive and penalty mechanisms;
4. Project prioritization; and
5. Competitive bidding for all major transmission projects.

In January 2013, in response to stakeholder concerns, the Minister of Energy announced a number of initiatives aimed at improving the management of transmission costs. Alberta Energy's Electricity Policy Branch commenced the Transmission Cost Management Policy Development to provide confidence to ratepayers that future transmission expenditures are cost effective and prudent. In support of this process, Alberta Energy engaged an external consultant - MNP LLP - to facilitate a series of multi-stakeholder working sessions. Participating stakeholders included representatives from groups within the electricity industry, including TFOs, regulatory agencies, Alberta Energy, the Office of the Utilities Consumer Advocate, as well as generator and customer associations.

The consultations with electricity stakeholders occurred over seven sessions throughout the fall of 2013 and focused on gathering input regarding the benefits, alternatives, risks and implications of a range of initiatives so as to enable better policy development. Specifically centering on the following four initiatives, a key priority of the sessions was to develop policies that could be operationalized effectively:

- **APPROVED COST ESTIMATE (ACE):** a regulation amendment to enable the Alberta Utilities Commission (AUC) to approve a cost estimate on transmission projects;
- **EXPANDED COMPETITIVE PROCESS (CP):** a regulation amendment to define the future major transmission projects that will be subject to the current Alberta Electric System Operator (AESO) competitive process;
- **IMPROVED COST REPORTING:** a regulation amendment to enable the AUC and the AESO to implement enhanced and more efficient cost reporting requirements for the TFOs; and,
- **COST OVERSIGHT MANAGEMENT FUNCTION (COM):** establish a cost-oversight management function for peer review and comment on transmission project costs during all phases of a project. The current approach is to implement a pilot program to evaluate the effectiveness of this initiative.

The key objectives of these initiatives are to achieve greater transparency of transmission costs, to ensure that the project costs are reasonable, and to implement measures that would provide confidence to all parties.

Stakeholders contributed to the development of the frameworks for the ACE, COM, and Improved Cost Reporting initiatives, as well as a definition for the projects that could be launched into the currently approved AESO competitive process.

It is the Committee's understanding that Alberta Energy is working towards developing a coherent, holistic, and coordinated policy package to propose regulatory amendments on these initiatives. Alberta Energy is of the view that the stakeholder sessions have been crucial to achieving this objective. In the coming months, Alberta Energy will work towards developing regulatory amendments for the ACE, COM and Improved Cost Reporting initiatives, and they will also be evaluating as to when the CP definition change should be enacted. Additionally two sub-groups have been formed, each consisting of stakeholder groups, to focus on the implementation of the ACE and the COM. The AESO will also resume its Rule 9.1 consultations, which were postponed for the duration of the stakeholder consultations, concentrating on improving cost reporting. These improvements will ultimately be implemented through AESO rule changes.

It should be noted that the ACE and COM initiatives will not cover all transmission projects in Alberta. The current intent is to apply these initiatives to upcoming projects over a specific dollar amount. As such, some ratepayer stakeholders have communicated to the government that it is vital to have other mechanisms in place to monitor, report on and examine the prudence of transmission project costs in the province.

4. TFCMC Conclusions & Recommendations

This section provides a look at the conclusions the TFCMC has reached during the period covered by this report and a glimpse into the impact of its work, along with the Committee's newest recommendation, which is aimed at improving the transparency of the project cost management process.

Status of the TFCMC's Concerns With Respect to the HVDC Converter Stations Cost

In a presentation to the TFCMC (see also page 10, HVDC Converter Station Presentation), AltaLink Management Ltd. (AltaLink) and Siemens officials discussed projected costs for the WATL HVDC converter stations. The purpose was to rationalize the significant variance of the WATL converter station costs with those of other similar projects occurring in the world today.

The projected cost of the two converter stations on the WATL project, with a 1000 MW carrying capacity, has been established as $495 million. This does include a significant AC switchyard with an estimated cost of $135 million, thus the project component directly related to the DC stations is $360 million ($495 million minus $135 million). This value compares to a benchmark figure of $180 million to $200 million for similarly configured projects worldwide.

Siemens did explain that the unit costs of the equipment supplied for WATL were comparable to other global projects with similar specifications. Materials such as steel and copper have been priced in line with the global commodities prices. Since most equipment is sourced in Germany, freight costs for the WATL project are not a significant variance from comparable projects. The only remaining factor to explain the variation in costs would appear to be the civil works – including the project's labour component.

Typically, civil works on converter station projects account for approximately 20% of the total cost. In the WATL case in Alberta, civil works account for more than 45% of the costs. The question remaining is whether it is possible that rates for labour and equipment in Alberta for civil works are twice the worldwide average.

The Committee's view is based on the analysis of publicly available information and inputs from consultants who are knowledgeable and have expertise in this area. Our expert, Dr. Mohamed Rashwan, was retained by a ratepayer group in the AltaLink General Tariff Application (GTA) but was unable to sign the associated onerous confidentiality undertaking and as such did not have access to the confidential module of the hearing.

In its decision, the Alberta Utilities Commission (AUC) found AltaLink's forecast cost for the WATL HVDC converter stations "to be reasonable and to be representative of market value". The AUC noted that it expects the actual cost will be reviewed as part of a future Direct Assign Capital Deferral Account (DACDA) hearing and that more details regarding the actual cost will be available in the public realm at that time.

EATL and the corresponding WATL project, being built by ATCO and AltaLink respectively, combine to form the North South Transmission Reinforcement (HVDC) development, also referred to as Project 737 – the construction of two 500 kV HVDC transmission lines from the Edmonton area to the Calgary and south regions.

The TFCMC's Work and the Regulatory Forum

A key role of the TFCMC is to review records that relate to the cost, scope, schedule and variances of Alberta transmission facility projects forecast to cost more than $100 million. As a part of that process, the TFCMC reviews information provided by the transmission facility owners (TFOs), the AESO and others. This information is considered public when provided to the TFCMC and can be used by members of the TFCMC during GTAs and deferral account applications of the TFOs.

The TFCMC does not get involved in the GTAs of TFOs as this is outside of its mandate. However, in 2012 and 2013, three members of the TFCMC – the Consumers' Coalition of Alberta (CCA), the Industrial Power Consumers Association of Alberta (IPCAA) and the Alberta Direct Connect Consumers Association (ADC) – were active in the 2013-2014 GTAs of both ATCO Electric (ATCO) and AltaLink regarding capital expenditures. The TFCMC is encouraged that its work has been a contributing factor that has enabled these groups to play a stronger role in the regulatory process.

The involvement of the CCA, IPCAA and ADC was conducted under a coalition referred to as the Ratepayer Group. The Ratepayer Group filed extensive evidence in these two proceedings, and relied, in part, upon information provided to the TFCMC. Information relied upon included the TFO monthly reports and presentations to the TFCMC by the TFOs, the AESO and others. The TFCMC's efforts to obtain strategic and practical insights into cost, scope, schedules and variances proved of considerable value in the regulatory process.

The AUC has rendered decisions on both of these GTAs and their associated deferral account applications. A significant number of recommendations of the Ratepayer Group were adopted by the AUC and are reflected in the following items[9]:

1. **Revenue Requirements:** In the ATCO proceeding, the AUC reduced a number of forecast amounts, including contractor escalation, Eastern Alberta Transmission Line (EATL) forecasts of capital and additions, Hanna labour costs, and contingency levels. ATCO's compliance filing shows an overall reduction in the revenue requirement of $58 million in 2013 and $97 million in 2014, compared to the originally filed amounts.[10]

   In the AltaLink proceeding, the impact of capital related recommendations on revenue requirements was relatively small. In their recently filed Compliance filing, AltaLink indicates an overall revenue requirement reduction of only $19 million in 2013 and $34 million in 2014, compared to their originally filed amounts.[11]

2. **Cost Audits:** In the ATCO proceeding, the AUC directed an audit of the Hanna Regional Transmission Development with a forecast capital cost in excess of $740 million.[12] In the AltaLink proceeding, the Ratepayer Group filed extensive evidence challenging the prudence of portions of the substantial cost overruns on the Southwest Project (Pincher Creek – Lethbridge area). The AUC directed an audit on a portion of this project as it was "concerned that some of AltaLink's decisions and actions … may not demonstrate prudent actions."[13]

3. **Project Priorities and Work Levelling:** In the ATCO proceeding, the AUC adopted Ratepayer Group recommendations on project priorities and work leveling.[14] In the AltaLink proceeding, the AUC determined that "AltaLink should work with the AESO to assess the need to achieve in-service dates" and relied on Ratepayer Group evidence "to support the AUC finding that a re-examination is warranted of the need to achieve targeted in-service dates at virtually any cost."[15]

4. T**ransmission Tower and Line Design:** In both proceedings, the Ratepayer Group raised concerns about the design and implementation of new towers and ISO Rule 502.2 on various projects.

   In the ATCO proceeding, the AUC found that TFOs "have a duty to make recommendations to the AESO that reflect the interests of customers and avoid needless expenditures"[16] and "if it is determined that ATCO Electric has applied ISO Rule 502.2 to projects prematurely or improperly, ATCO Electric will have to demonstrate the prudence of its actions before those project costs will be permitted to be included in its rate base."[17]

   In the AltaLink proceeding, the AUC agreed with Ratepayer Group concerns about the high cost differential between R-series lattice structures and H-Frame structures,[18] and concluded that the potential for certain designs to require larger and more costly foundations should be a matter for consideration in the design and selection of transmission towers for future projects.[19]

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9 This is not an exhaustive list, but rather is indicative of key areas reviewed in the GTAs.

10 ATCO Electric 2013 2014 GTA Compliance Filing, Proceeding ID 2904, Exhibit 33.05

11 AltaLink 2013 2014 GTA Compliance Filing, Proceeding ID 3024, Exhibit 2.00, Summary of Changes to Revenue Requirement, Jan 15, 2014 and AltaLink 2013-2014 GTA, Proceeding ID 2044, Exhibit 3.00, page 1-4, Table 1.2-1

12 AUC Decision 2013-358, para. 819

13 AUC Decision 2013-407, para. 569-577

14 AUC Decision 2013-358, para. 387-388

15 AUC Decision 2013-407, para. 439

16 AUC Decision 2013-358, para. 391

17 AUC Decision 2013-358, para. 801

18 AUC Decision 2013-407, para. 495

19 AUC Decision 2013-407, para. 498

The AUC also noted that the Ratepayer Group "had presented persuasive evidence that the revised wet snow loading requirements set out in ISO Rule 502.2 have affected the economics of using twin bundled conductors" and that additional [excess] structural capabilities "could potentially be avoided with single conductors."[20] The AUC indicated it was "considering the engagement of an independent expert to ensure that ratepayer interests are taken into account in decisions about standard designs."[21]

5. **Competitive Process and Risk Reward Model:** In the AltaLink proceeding, the AUC found the competitive process to procure engineering, procurement, and construction management (EPCM) services was not fair, returning the rates for these services to a two times labour multiplier.[22] The AUC also denied the risk and reward model and ordered AltaLink to remove any impact of the model in its compliance filing.[23]
6. **Minimum Filing Requirements:** In the ATCO proceeding, the AUC adopted Ratepayer Group recommendations on Minimum Filing Requirements.[24] AltaLink was also directed to use similar Minimum Filing Requirements to those recommended by the Ratepayer Group in AltaLink's next deferral account application and to file that application separately from their GTA.[25]

Many of these matters are of continuing interest to the TFCMC and will be monitored within the TFCMC mandate.

Yellowhead Transmission Development Case Study

Following a presentation by AltaLink in January 2013 on the Yellowhead Area Transmission Development Project cost increases, the TFCMC felt more information was needed to explain the cost increases and estimate accuracy – as noted in the TFCMC's June 2013 Semi-Annual Report. As such, the AESO agreed to work with AltaLink on a case study. The results were presented at the September 2013 TFCMC meeting.

Overview

In 2012, AltaLink submitted a $15.4-million change proposal – related to the Hinton/Edson area – to the AESO for approval. The AESO processed this change proposal in October 2012. The AESO clarified in a letter to AltaLink that its approval is based upon the AESO's review of the project scope and potential impact to system reliability; and that the AESO provides no comments or approval as to whether these costs are prudent.

Some of the highlights of the cost increases on the Yellowhead project included:

- The Hinton-Edson sub-project including 90 kilometres of 745L rebuild had significant complexities including a one-winter timeframe for construction instead of the planned two due to delayed permit and license (P&L), a customer requirement for no extended outages, an interdependency with the Distribution Facility Owner (DFO) under-build, and salvaging preceding the rebuild;
- Winter construction was followed by very wet spring conditions;
- In terms of whether to proceed with work or delay until the following winter, estimates showed it would cost $18.5 million to delay and $15.4 million to continue with construction; and
- The AESO agreed that the project needed to move forward and waiting for another winter construction season was not an option.

20 AUC Decision 2013-407, para. 503

21 AUC Decision 2013-407, para. 507

22 AUC Decision 2013-407, para. 730-734

23 AUC Decision 2013-407, para. 751-759

24 AUC Decision 2013-358, para. 1077-1096

25 AUC Decision 2013-407, para. 1359-1363

Lessons Learned

Some of the lessons learned from the analysis were that the AESO needs to be clear in its correspondence back to the TFOs on what it is accepting or rejecting concerning change orders, i.e., cost and technical requirements of the Functions Specification, etc. The AESO also needs to have the TFOs explain what portion of contingency is being used, if any, when requesting approval of change orders.

With regards to cost estimates, the cost estimate for this project increased from $88 million at the NID stage to $126 million at the Proposal to Provide Service (PPS) stage and was completed with a final forecast of $141 million. The Committee learned that:

- NID estimates[26] are prepared using historical data from similar projects and that no site visits are made to determine land conditions. As a result, limited information or scope is known at this time of the project.
- PPS estimates are developed with TFOs on the ground; however, limited engineering is performed at this point and land access is still an unknown.

Through the ISO Rules 9.1 Working Group, it was determined that a standard process for estimating be adopted (AACE). However, it may be unrealistic to have more precise estimates at the time of the NID given that routing is not known, there is limited access to land, and the scope of the project is not finalized at this time. The AESO may request TFOs to provide more accurate estimates, however, this would require more time and cost. This discussion will continue in the Rule 9.1 Working Group meeting once they reconvene, which is expected in early 2014 once Alberta Energy completes its stakeholder consultation on its Transmission Cost Management policy initiatives.

With regards to lessons learned and improvement opportunities, the AESO:

- Has made changes to internal business practices around change management as a result of this case study;
- Is clear on what is being accepted or rejected with regards to documentation on change proposals;
- Requests additional information on utilization of contingency before it processes any change proposals; and
- May notify the AUC of any concerns or issues it has with respect to the costs of the project (Electric Utility Act – Transmission Regulation 25.5).

Change management will be discussed in the Rule 9.1 Working Group discussions and will be a topic for Alberta Energy's Cost Oversight Management discussions.

AltaLink Responses to Cost Increases

AltaLink provided the following responses to the AESO questions in support of the TFCMC case study.

Additional rig mat rental not identified in the PPS

The Yellowhead Area (Hinton-Edson) Transmission Development project experienced a number of issues, which are outlined below, that required additional access mats not identified in the PPS estimate.

- The project area contains large amounts of natural gas and crude oil exploration, development and transportation facilities. In order to cross or parallel pipelines and other oil and gas facilities, AltaLink will generally be required by the facility owner to enter into a crossing or proximity agreement. A standard clause of these agreements is that AltaLink will provide access matting for access to and along the proposed right-of-way where crossing third party underground facilities. Due to the large amount of oil and gas infrastructure in the area of the project, a significant number of access mats were required to cross these facilities. Due to the warm winter and the significantly above average wet spring, as further described below, this access matting was left in place for longer than planned.

26 The preparation of estimates for this project pre-dated a number of 'estimate improvement' initiatives undertaken by the TFOs.

- Delays in receiving P&L and project interdependencies on the local DFO prevented the winter construction that was the basis of the project's PPS estimate and execution plan. Because the existing transmission line needed to be salvaged prior to the construction of the new line, the DFO was required to relocate their existing under-build. The DFO ran into permitting delays during their construction execution, which significantly impacted the ability to complete construction of the transmission line during the remaining winter season.

However, due to operational system risks to AltaLink's customer (the DFO) and the DFO's customers (i.e., town of Hinton and the Obed Mine on a radial feed), there were requirements from the DFO and the local government to complete the 745L rebuild as soon as possible. Therefore, additional construction activities were required during the spring, summer and fall. For construction in non-frozen conditions, additional access mats were required to ensure compliance with Alberta Environment and Sustainable Resource Development (AESRD) regulations as outlined in AltaLink's Letter of Authorization. The unseasonably warm winter (lack of frozen ground conditions) and the significantly above-average rainfall in the spring increased the requirement for access mats along the right-of-way for access and construction. AltaLink worked proactively with AESRD to clarify requirements and attempted to minimize costs, but the use of additional matting was unavoidable.

Additional transmission line subcontractor costs related to construction delays and execution required for environmental mitigation

The additional environmental mitigations that AltaLink undertook to remain compliant with the AESRD Letter of Authorization and to strive towards the earliest in-service date – discussed above – resulted in additional costs for transmission line subcontractors. These additional costs fall into two broad categories:

- Environmental Mitigations: the extreme wet weather encountered during the spring of 2012 required additional access mat costs to comply with AESRD requirements. These costs came in two forms:
  - Access mats that were stranded in place with no means of removal without violating the AESRD Letter of Authorization, i.e., more environmental damage would have occurred by removing the mats; and
  - Additional access mats required to complete the scope of work and comply with the AESRD regulations.
- Environmental Mitigations Delays: the extreme wet weather encountered during the spring of 2012 caused a number of work stoppages and construction delays as AltaLink attempted to comply with AESRD requirements and evaluate both options.

AltaLink reviewed the costs and schedule ramifications associated with the use of access mats and continuing with construction, compared to the costs and schedule ramifications of suspending construction until frozen ground conditions. That evaluation determined that the lowest cost alternative was to continue with construction and use the additional access mats. The details of the cost comparison were shared with the AESO on August 21, 2012 and with the TFCMC on January 18, 2013. This alternative also met the requests of our key stakeholders: AESRD for environmental protection and the DFO for operational risk mitigation.

Additional Engineering, Procurement, and Construction Management (EPCM) costs required to manage the environmental mitigation; including AC pipeline mitigation work

During consultation with industry stakeholders on this project, several pipeline operators expressed concerns with induction impacts on their pipelines resulting from the proposed transmission line project. It is standard industry practice for the TFO to pay the reasonable costs of an AC mitigation study and the design and installation of any mitigation imposed by the proposed transmission line project. These study and mitigation commitments were included in the Facility Application that was provided to the AUC on August 5, 2010, and was approved by the AUC on April 29, 2011.

The impetus for both the AC mitigation studies and any possible mitigation scope of work is public safety; AltaLink strives to ensure that our transmission line infrastructure poses the least possible risk to public safety. With regards to pipeline infrastructure, this primarily takes two forms: the reduction of risks on pipeline infrastructure and the elimination of any additional corrosion potential.

For the Yellowhead Area (Hinton Edson) Development, four pipeline companies were identified in the Facility Application as having the potential for mitigation scope. Through subsequent consultation and engineering, it was determined that three of those pipeline companies would require additional pipeline AC/DC mitigation studies to determine the specific mitigation scope required for this development. Since the pipeline infrastructure is the responsibility of the pipeline owner, and they are the only entity capable of completing work on their pipelines, the pipeline owners complete their own mitigation studies using data supplied by both the AESO (functional specification) and AltaLink. AltaLink then reviewed the pipeline owner-developed mitigation studies to ensure reasonableness of the proposed mitigation. In some cases, AltaLink sought the assistance of an independent third party to review mitigation studies if the proposed scope appeared extensive or non-standard.

Recommendations

The primary goal of this recommendation is to improve the transparency and accountability of project cost management by refining the Alberta Electric System Operator's (AESO) Change Order approval process.

Currently, transmission project cost estimates are prepared by the TFOs without any constraints from the AESO aside from in-service dates and the scope of the projects.

The Committee believes it is reasonable for the TFOs to seek approval from the AESO for changes to in-service dates and/or changes in scope after a project has been approved by the AUC and the resulting cost impact.

But TFOs should be accountable to the Regulator for their cost estimates if there is no change to the in-service date or project scope. When a transmission project is approved, the associated cost estimate includes two elements to accommodate future uncertainty inherent in cost estimates:

- A dollar amount is included for price increase volatility: escalation;
- A dollar amount is included to accommodate known unknowns: contingency;

Given that these allowances are already built into the overall cost estimate of a project, it is imperative that any cost change proposals should be subjected to rigorous regulatory scrutiny. The committed project in-service date and scope must be honoured even if the proposed cost changes were to be disallowed by the Regulator.

1. The Committee recommends that the AESO take the necessary steps to change the relevant rules so that it is clear that it will only review change orders for scope and in-service date changes.

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 Commerc**e 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 A**lberta 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. Their representative on the TFCMC is **Dwight Oliver, a Past Director for AAMDC District 2.**

Alberta Chambers of Commerce (ACC)

The ACC is a federation of 126 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. Their 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. Their 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. Their representative on the TFCMC is **Kelly Yagelniski, AESO's Director, Transmission Program 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. Their representative on the TFCMC is **Dan Astner, AFREA 2nd Vice President.**

Alberta Urban Municipalities Association (AUMA)

The AUMA represents Alberta's 272 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. Their representative on the TFCMC is **Andre Chabot, AUMA Director, Cities Over 500,000.**

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. Their representative on the TFCMC is **Richard Truscott, the CFIB's Director of Provincial Affairs, 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. Their 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. Their 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. Their representative on the TFCMC is **Vittoria Bellissimo, IPCAA's Executive Director.**

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 a 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 the AESO and the Transmission Facility Owners (TFOs) for further illumination on the reasons for the variances.

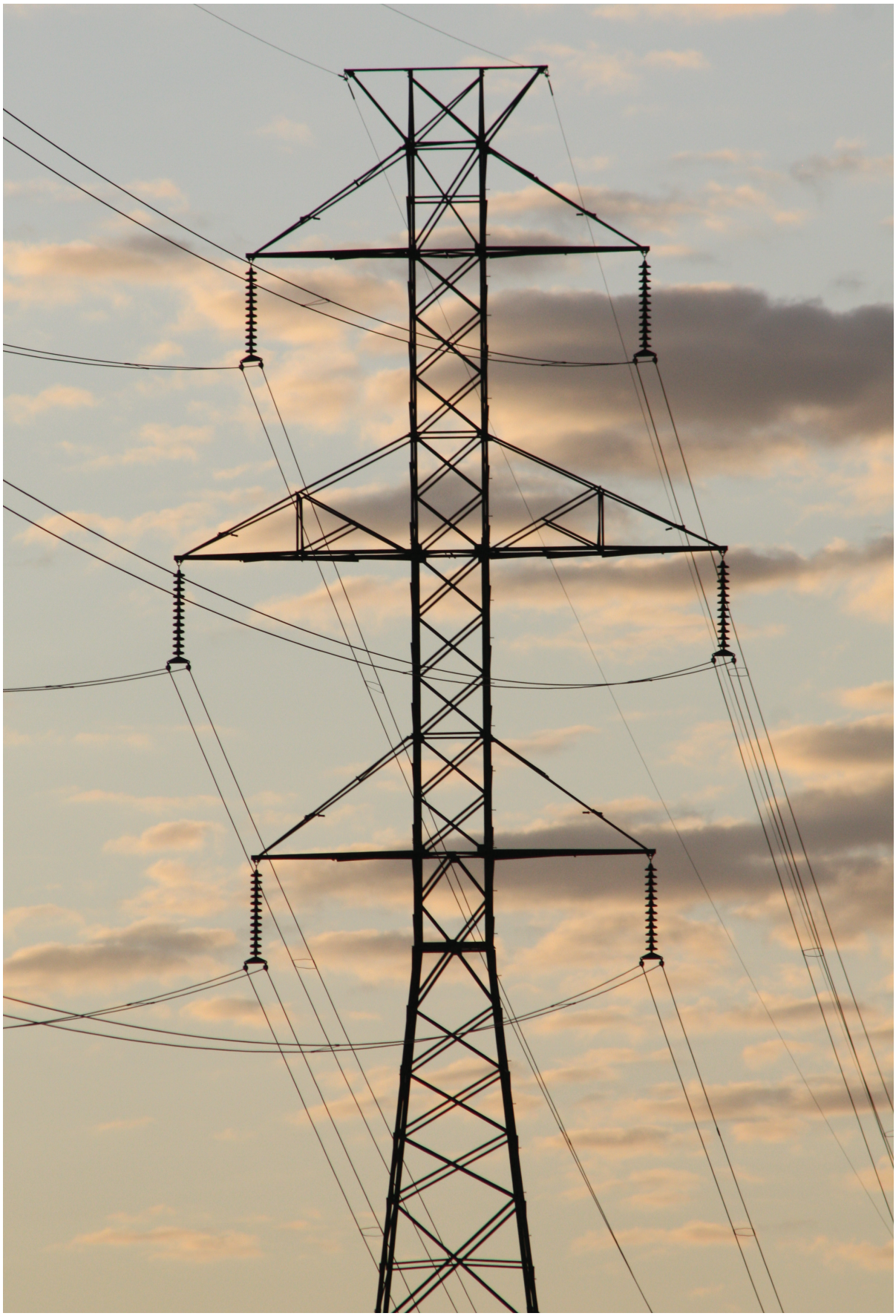
Each calendar year, the TFCMC is required to provide at least two reports to the member organizations represented on the committee as well as at least one report to the Ministers of Energy and Service Alberta. The reports summarize the records it reviews and the status of the transmission facility projects.

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 Alberta Energy; she also serves as the Committee's technical writer.

The TFCMC will also form subcommittees from time to time to facilitate the workings of the Committee. There were two 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. Evan Bahry 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.



Appendix B: The Transmission Projects At A Glance

Facility Applications for each project are sorted by the forecast or actual in-service date (ISD). The Facility Application number column in each project's initial chart is provided as an easy reference to its location on the accompanying map.

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, will support oilsands development, local demand in the Heartland area, and strengthen the entire provincial network. The Industrial Heartland region includes parts of Sturgeon, Strathcona and Lamont counties.

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).

FACILITY APPLICATION NAME	FACILITY APPLICATION NUMBER	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
Heartland 12S Ellerslie 89S and 1054L/1061L	2	Heartland 500 kV substation and 22 kilometres of 240 kV lines to tie in the existing system	December 4, 2013
500 kV 1206L/1212L	1	Sixty-five kilometres of 500 kV double-circuit line from Ellerslie to Heartland substation	December 7, 2013

THE TRANSMISSION FACILITY OWNER(S): AltaLink Management Ltd. (AltaLink) and EPCOR Distribution & Transmission Inc.(EDTI).

PROJECT COST:

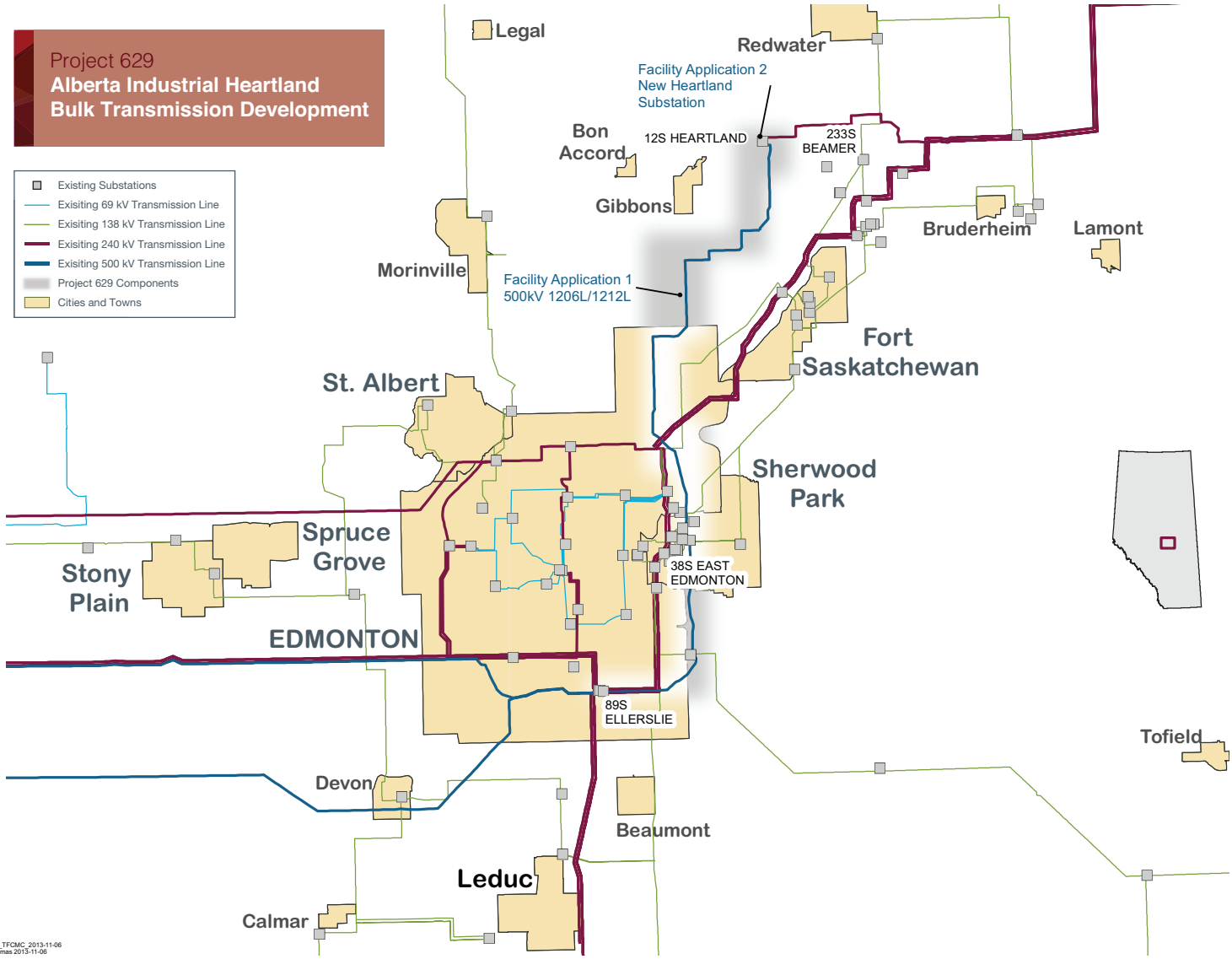
TRANSMISSION PROJECT	AESO LONG-TERM TRANSMISSION PLAN (FILED JUNE 2012) ESTIMATED COST	CURRENT ESTIMATED COST
Alberta Industrial Heartland Bulk Transmission Development	**$537 Million** (2011$ without escalation)	**$589 Million** (ISD$ with escalation)[27]

CURRENT STATUS: The Alberta Utilities Commission (AUC) approved the Alberta Industrial Heartland Bulk Transmission Development project in November 2011. The approved east route for the line skirts the city of Edmonton to the south and east and travels through an existing Transportation/Utility Corridor (TUC) for roughly half the line's length.

27 Current estimated cost is the Authorized Budget, as per the information provided in the Cost Committee Monthly Summary at the TFCMC's October 2013 meeting; it is based upon the TFO's August 2013 monthly project progress report.

On October 29, 2013, AltaLink advised the AESO that the 240/500 kV transformers for the project failed testing; thus, the in-service date (ISD) of December 2013 is not attainable. AltaLink presented an option to energize the 500 kV line at 240 kV as an interim solution. This option does not require the 240/500 kV transformers to be energized. On November 6, 2013, the AESO accepted the AltaLink proposed option of $4.9 million (specifically $4,917,547) and Heartland was energized at 240kV on December 28, 2013. The estimated energization for Heartland at 500 kV is July 31, 2014.

On December 10, 2013 the AESO also accepted an AltaLink change proposal for $12.5 million (specifically $12,568,409), which was a result of increased labour costs since the original Proposal to Provide Service (PPS) was submitted. The current authorized budget for Heartland is $606 million. By the end of December 2013, AltaLink spent $653 million on the project. The AESO has requested that AltaLink advise it on these additional costs and or submit a change proposal.



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 for pipelines moving oilsands production, and 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, compels the substantial rebuild of the 138 kV and 144 kV systems, and the 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 conversion of three existing 72/25 kV substations to 144/25 kV; a new 240 kV switching station in the Cold Lake area, 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 line from the existing Wainwright 51S to the existing Edgerton 899S; a new 144 kV capacitor bank at Vermilion 710S; the addition of one 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 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 at Bourque to the existing Marguerite Lake 826S.

FACILITY APPLICATION NAME	FACILITY APPLICATION NUMBER	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
Heisler Area Upgrades	6	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	July 11, 2013
Line Clearance Mitigations	9	Restore ratings of existing 144 kV lines by mitigating line clearances	July 11, 2013
Vermilion 710S Substation Upgrade	5	Addition of 144 kV–25 VAr 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)	September 15, 2013
Cold Lake Area Reinforcements (Except Bonnyville to Bourque)	1	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)	October 1, 2013
St. Paul Area Upgrades – Watt Lake, 7LA92	3	New 144/25 kV Watt Lake and new 144 kV line from Watt Lake to existing 7L92	November 1, 2013

FACILITY APPLICATION NAME	FACILITY APPLICATION NUMBER	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
Kitscoty Area Upgrades	7	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	December 1, 2013
St. Paul Area Upgrades – St. Paul 707S, Whitby Lake 819S & 7L139/7L70	4	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/out configuration	August 1, 2014
Cold Lake Area Reinforcements – Bonnyville	2	New 240 kV double-circuit line (one side strung) from new 144 kV switching station to existing Bonnyville 700S, initially energized at 144 kV	December 1, 2014
7L749 Replacement	8	Rebuild existing 749L/7L749 from Metiskow 648S to Lloydminster 716S	March 1, 2015[28]
Provost & Wainwright Area Upgrades	10	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	June 1, 2015[29]
7L50 Rebuild	11	Rebuild the existing 138/144-kV transmission line 7L50 from Battle River 757S substation (SW 29-40-15-W4) to Buffalo Creek 526S substation (4-12-48-9-W4) using one 477 kcmil ACSR conductor per phase	October 9, 2015
Cold Lake Reinforcement (2017) – 240kV Cold Lake	12	Build a new 240 kV double-circuit line (one side strung) from Bourque 970S substation to Marguerite Lake 826S substation using two 795 kcmil ACSR conductors per phase. This transmission line is to be initially operated at 144 kV	December 1, 2017

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

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)	**$378 Million** (ISD$ with escalation for Stage 1)

CURRENT STATUS: The AUC approved the Central East Transmission Development Needs Identification

28 In the June 2013 TFCMC Report, it was noted that this item was cancelled. This facility will be cancelled pending the AESO filing a NID amendment in early April 2014 with the AUC and will be officially cancelled when the AUC approves the NID amendment.

29 In the June 2013 TFCMC Report, it was noted that this item was cancelled. The outcome of the 2012-2017 AESO Long Term Plan indicates that the 704L/403L at Wainwright 51S is still required; hence, the cancellation has been lifted. The TFO is developing a public consultation for this facility.

Document (NID) in February 2011. The project will be developed in two stages.

For Stage 1, ATCO plans to file a total of 13 Facility Applications. To date, ATCO has filed 11 Facility Applications and received AUC approval for the nine listed below.

- 7L587 from Marguerite Lake to Wolf Lake;
- 144kV developments in the Cold Lake area (forecast in-service December 2013);
- Bonnyville substation reconfiguration and 7/9L146 line from Bonnyville to Bourque;
- Heisler substation (in-service);
- Kitscoty substation;
- Whitby Lake substation;
- Watt Lake substation;
- 7L701 clearance mitigation;
- 7L53 and 7L117 clearance mitigation; and
- Vermillion upgrades (in-service).

ATCO is moving through the construction phase of these facilities.

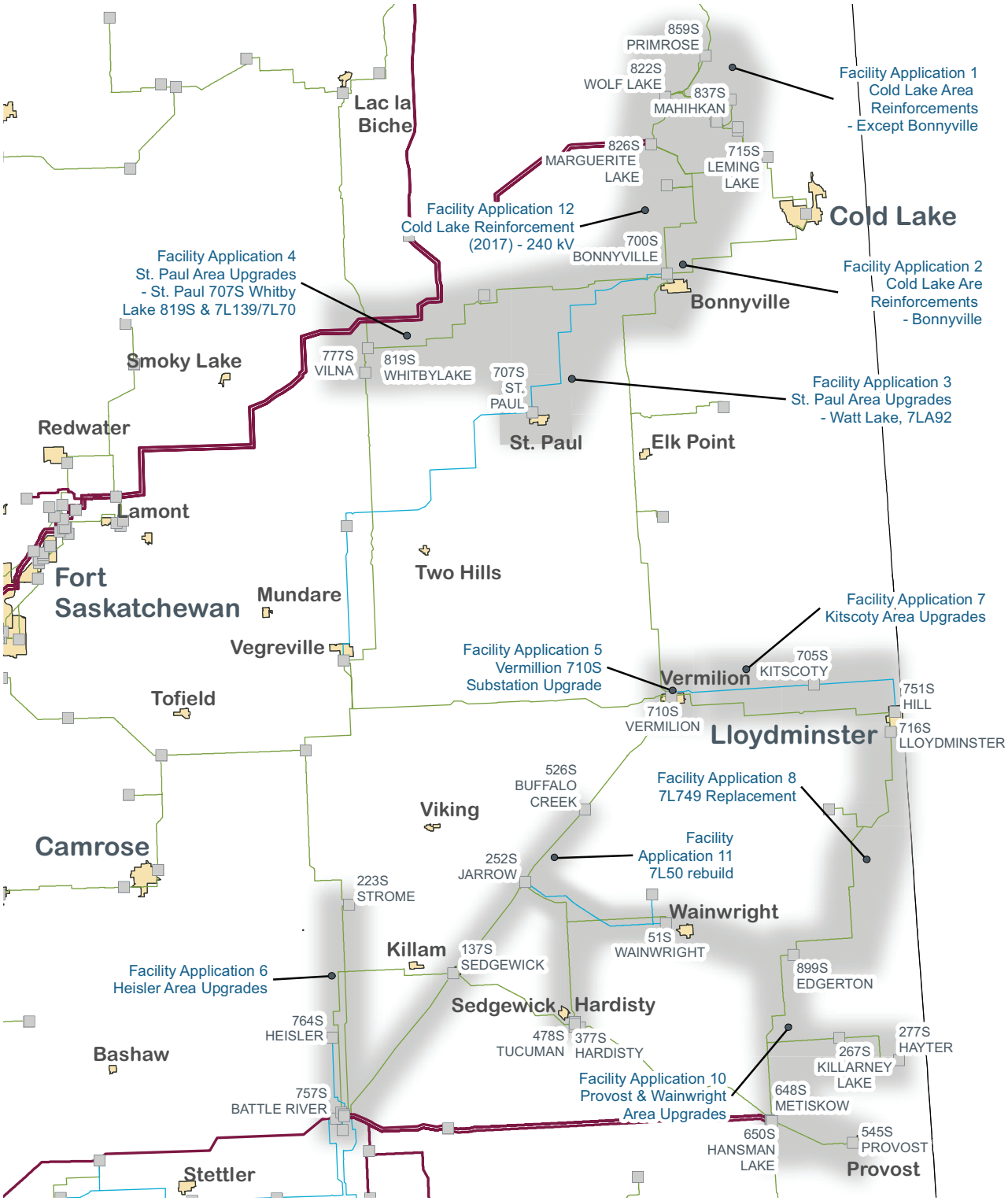
ATCO issued Change Proposals in June 2013 totaling $93.8 million. The cost increases are similar in all Change Proposals; attributed to higher labour cost, including management costs due to risks not identified during the PPS stage.

Further, the AESO is carrying out the Central Region System Study and has determined that the following facilities, as approved as part of the Central East NID, are no longer required:

- 7L50 line;
- 7L749 line;
- Wainwright area system upgrade; and
- A 240 KV line between Bourque and Marguerite Lake to be energized at 144 KV (Stage 2 by 2017).

Since both AltaLink and ATCO share the scope of work on 7L50 and 7L749, the AESO requested that both TFOs stop any activity related to these developments.

AltaLink has commenced developing a Facility Application to build approximately 25 km of single-circuit line from Wainwright 51S to 704L/408L to re-arrange the connection at Wainwright 51S from a single-circuit tap-off to an in-and-out configuration.



Project 811
Central East Area Transmission Development

- Existing Substations
- Exisiting 69 kV Transmission Line
- Exisiting 138 kV Transmission Line
- Exisiting 240 kV Transmission Line
- Project 811 Components
- Cities and Towns

811_TFCMC_2013-11-06
cthomas 2013-11-07

3. **CHRISTINA LAKE AREA 240 KV TRANSMISSION DEVELOPMENT (CHL);** PROJECT 1101 – Reinforcing transmission facilities for oilsands developments and enhanced reliability to existing oilsands operations

THE PROJECT:[30] Significant 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 Ipiatik 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 NUMBER	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
Black Spruce substation and 240 kV lines	1	Black Spruce substation and interconnecting 240 kV lines	July 10, 2013
Pike substation and 240 kV lines	2	Pike substation and interconnecting 240 kV lines to Black Spruce	June 30, 2014
Pike to Ipiatik to Heart Lake and 240 kV lines and modifications to Christina Lake 723S	3	New Ipiatik substation, new 240 kV line from Pike to Ipiatik to Heart Lake substation and modifications to Christina Lake 723S	June 30, 2015
Heart Lake expansion	4	Expand Heart Lake sub for the termination of 9L930 in/out and the new 240 kV line to Ipiatik	September 18, 2015

THE TRANSMISSION FACILITY OWNER(S): AltaLink and ATCO.

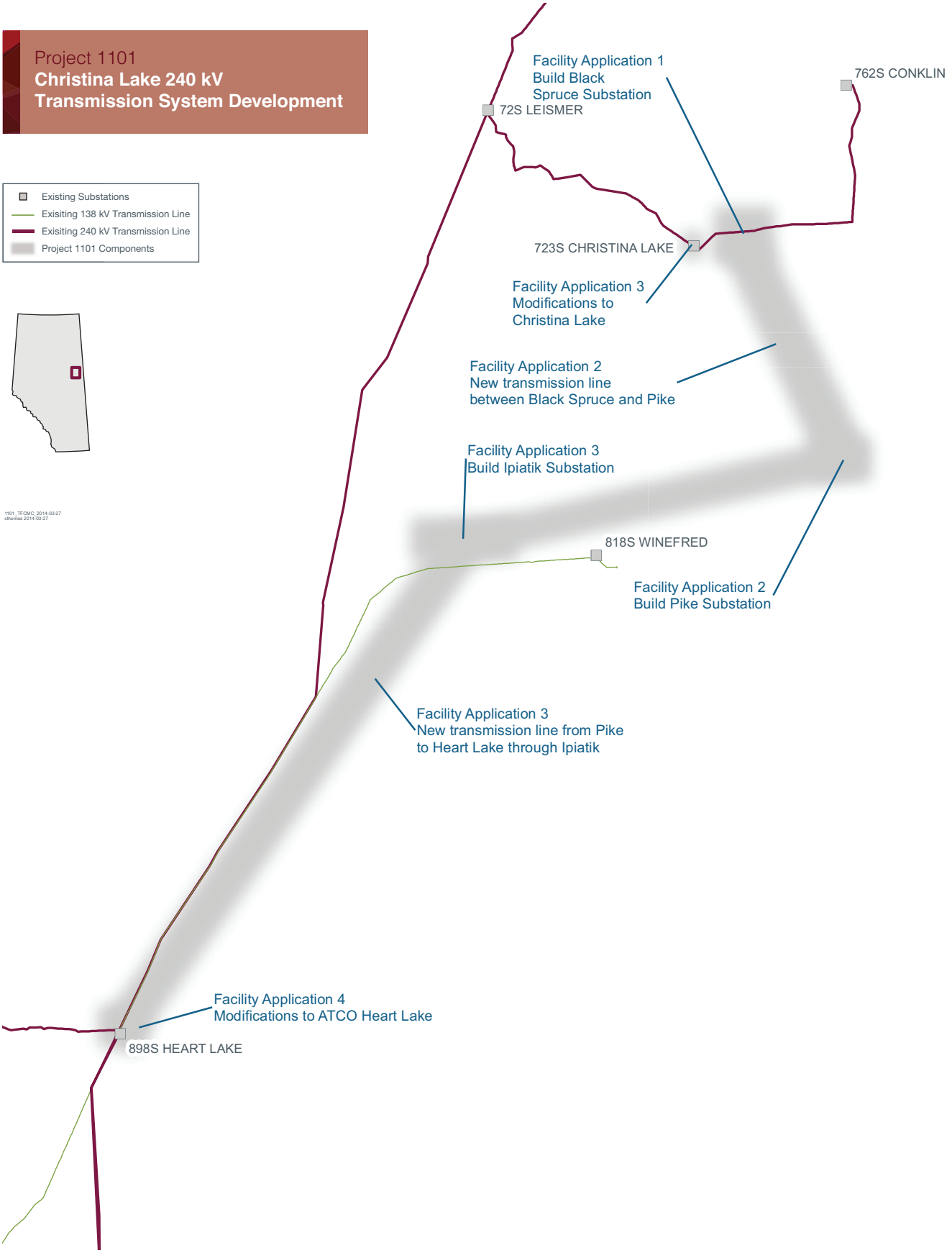
PROJECT COST:

TRANSMISSION PROJECT	AESO LONG-TERM TRANSMISSION PLAN (FILED JUNE 2012) ESTIMATED COST	CURRENT ESTIMATED COST
Christina Lake Area 240 kV Transmission Development	**$358 Million** (2011$ without escalation)	**$440 Million** (ISD$ with escalation)

CURRENT STATUS: The NID was approved by the AUC on April 24, 2012. The Black Spruce substation was energized on July 11, 2013. The Permit & License (P&L) for Pike was received on June 28, 2013. The Facility Application for the Ipiatik development was filed on March 28, 2013. ATCO filed the Heart Lake Facility Application on October 10, 2013.

Various Change Proposals totaling $13.4 million were approved by the AESO in July 2013. In general, the cost increases were due to increases in actual costs greater than what was estimated in the PPS. All ISO procurement rules were followed.

30 The Christina Lake Area 240 kV Transmission Development and the Heart Lake expansion project identified in the AESO's Long-term Transmission Plan (filed June 2012) were combined into one NID.


Project 1101
Christina Lake 240 kV
Transmission System Development
Existing Substations
Exisiting 138 kV Transmission Line
Exisiting 240 kV Transmission Line
Project 1101 Components
1101_TFCMC_2014-03-27
cthomas 2014-03-27
Facility Application 1
Build Black
Spruce Substation
72S LEISMER
762S CONKLIN
723S CHRISTINA LAKE
Facility Application 3
Modifications to
Christina Lake
Facility Application 2
New transmission line
between Black Spruce and Pike
Facility Application 3
Build Ipiatik Substation
818S WINEFRED
Facility Application 2
Build Pike Substation
Facility Application 3
New transmission line from Pike
to Heart Lake through Ipiatik
Facility Application 4
Modifications to ATCO Heart Lake
898S HEART LAKE

4. **EAST CALGARY 240 KV AND 138 KV TRANSMISSION SYSTEM UPGRADES AND THE ENMAX SHEPARD ENERGY CENTRE CONNECTION (ECTP);** PROJECT 719 – To serve growing demand for electricity in the Calgary and High River planning areas and to interconnect the ENMAX Shepard Energy Centre.

THE PROJECT: The East Calgary Transmission Project and the ENMAX Shepard Energy Centre Connection is required to serve growing demand for electricity in the Calgary and High River planning areas, enable future generation facilities to reliably connect to the system, and maintain system reliability. The project is combined with the ENMAX Shepard Energy Centre Connection development to connect the new 850 MW combined cycle generation facility via a new substation, to be called ENMAX No. 25, to the existing transmission system.

THE COMPONENTS: Modifications to existing East Calgary 5S and ENMAX No. 2 substations (including the addition of one 240/138 kV – 240/320/400 MVA transformer); a new 138 kV transmission line between ENMAX No. 23 and ENMAX No. 2; a new 138 kV transmission line between Janet 74S and ENMAX No. 23; modifications to the existing 240 kV double-circuit towers (to maintain the connection between Janet 74S and East Calgary 5S); removal of line terminations at East Calgary 5S and Janet 74S; new 240 kV double-circuit 240 kV transmission line (985L/1003L) from Janet 74S to ENMAX No. 25; addition of a 240 kV switching station (ENMAX No. 25) for connection to the transmission system and Shepard Energy Centre; addition of a second 240/138 kV – 240/320/400 MVA transformer at East Calgary 5S.

FACILITY APPLICATION NAME	FACILITY APPLICATION NUMBER	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
East Calgary 240 kV and 138 kV transmission system upgrades and Shepard Energy Centre Connection (AltaLink Facility Application)	1	Rebuild East Calgary 5S substation; upgrade AltaLink-owned infrastructure from structure 26 to Janet 74S; build D/C 240 kV transmission line between Janet 74S and ENMAX No. 25 substations, replace existing transformer at East Calgary 5S	June 30, 2015
East Calgary 240 kV and 138 kV transmission system upgrades and Shepard Energy Centre Connection (ENMAX Facility Application)	2	Modifications to existing ENMAX No. 2 and No. 23 substations, addition of new ENMAX No. 25 substation	June 30, 2015

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

PROJECT COST:

TRANSMISSION PROJECT	AESO LONG-TERM TRANSMISSION PLAN (FILED JUNE 2012) ESTIMATED COST	CURRENT ESTIMATED COST
East Calgary 240 kV and 138 kV Transmission System Upgrades and ENMAX Shepard Energy Centre Connection	***$711 Million**[31] (2011$ without escalation) *entire FATD plan	***$132 Million** (includes escalation and AFUDC) *ECTP and Shepard Energy Centre PPS only

CURRENT STATUS: The AESO filed the NID with the AUC on May 10, 2011. Subsequently, ENMAX and AltaLink filed Facility Applications with the AUC on June 10, 2011, and June 27, 2011, respectively. The AUC approved the development and issued P&L on November 1, 2012.

The Shepard Energy Centre interconnection and components of the East Calgary Transmission Project were energized in September 2013. The remaining facilities for the transmission system upgrade are scheduled to be completed by January 2015.

The AESO has received Change Proposals for $13.8 million from AltaLink for schedule delays and cost increases resulting from delay in regulatory approval, changing market conditions, a temporary bypass required for 916L/917L and necessary upgrades to the East Calgary 5S substation to address footprint or space requirements due to equipment, fire and safety requirements. Additional information and clarification from the TFO has been received and the AESO is currently processing the Change Proposals for approval.

In addition to the AltaLink cost increase, a Change Proposal for $9.3 million has been processed and approved by the AESO to ENMAX for increased costs resulting from delay in regulatory approval, changing market conditions and estimate refinement as per the +/- 10 PPS estimate.

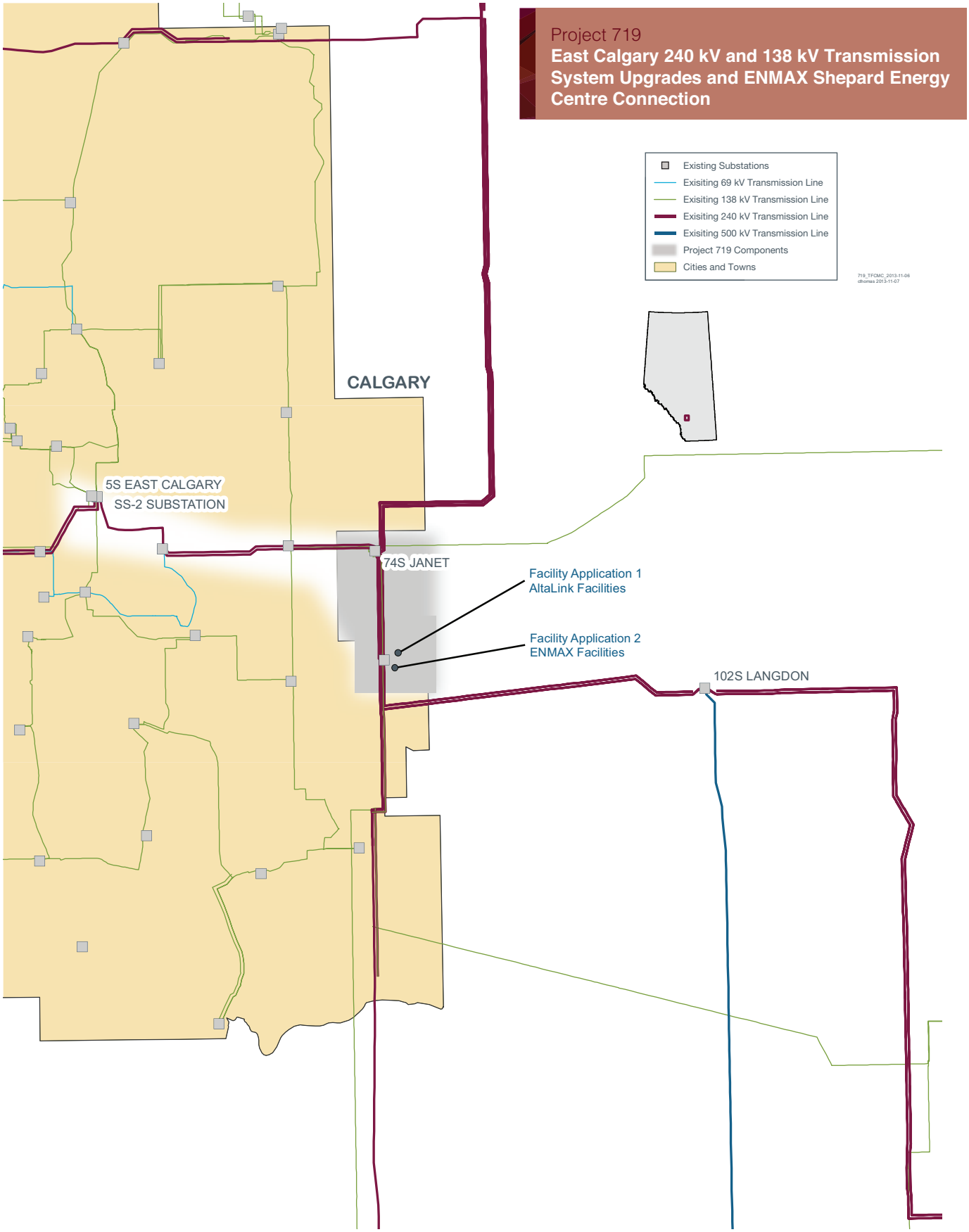
31 The AESO's Long-Term Transmission Plan identified the need for the Foothills Area Transmission Development. The East Calgary 240 kV and 138 kV transmission system upgrades are one of four components of the overall Foothills Area Transmission Development. The four components of the Foothills Area Transmission Development are:

a) East Calgary 240 kV and 138 kV transmission system upgrades and Shepard Energy Centre Connection;

b) Foothills Area Transmission Development – East Region;

c) Third 138 kV circuit from ENMAX No. 65 to existing ENMAX No. 54 and 41; and

d) Foothills Area Transmission Development - West Region.


Project 719
East Calgary 240 kV and 138 kV Transmission System Upgrades and ENMAX Shepard Energy Centre Connection
Existing Substations
Exisiting 69 kV Transmission Line
Exisiting 138 kV Transmission Line
Exisiting 240 kV Transmission Line
Exisiting 500 kV Transmission Line
Project 719 Components
Cities and Towns
CALGARY
5S EAST CALGARY
SS-2 SUBSTATION
74S JANET
Facility Application 1
AltaLink Facilities
Facility Application 2
ENMAX Facilities
102S LANGDON

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 regional 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 and East Edmonton to Nisku, and from East Edmonton to the Fort Saskatchewan area are weak during peak load conditions, and voltage violations occur in those two areas due to weak system support.

FACILITY APPLICATION NAME	FACILITY APPLICATION NUMBER	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
AltaLink 908L, 909L Restring	5	Restring four km of 908L and 909L outside Sundance 310P substation (first four km of the lines); 908L is renumbered to 1045L	March 20, 2011
EPCOR Jasper, Petrolia	6	Upgrade bus work and protections	June 14, 2011
EPCOR 1044EL, 1045EL	3	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)	February 29, 2012
ATCO Phase Shifter	7	Add 600 MVA phase shifting transformer at Livock 939S	August 20, 2013
AltaLink Rebuild 240 kV 904L (1043L) TransAlta 902L, 1043L Reterminate 909L at Sundance	1, 2 3, 8	Delegate the work to AltaLink for re-termination of the existing 240 kV 909L at Sundance 310P (Ellerslie 89S to Sundance 310P); rebuild approximately 50 km of the existing 240 kV line 904L between Jackfish Lake 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 2014
AltaLink 902L	4	Restring eight km of 902L at each line end; Wabamun 19S and Sundance 310P substations	February 3, 2014

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 lines, and the installation of a special protection scheme for multiple contingencies to ensure system reliability in the area. Additionally, a 240 kV phase shifter transformer will be installed at Livock 939S in the Fort McMurray area.

THE TRANSMISSION FACILITY OWNER(S): AltaLink, EDTI and ATCO.

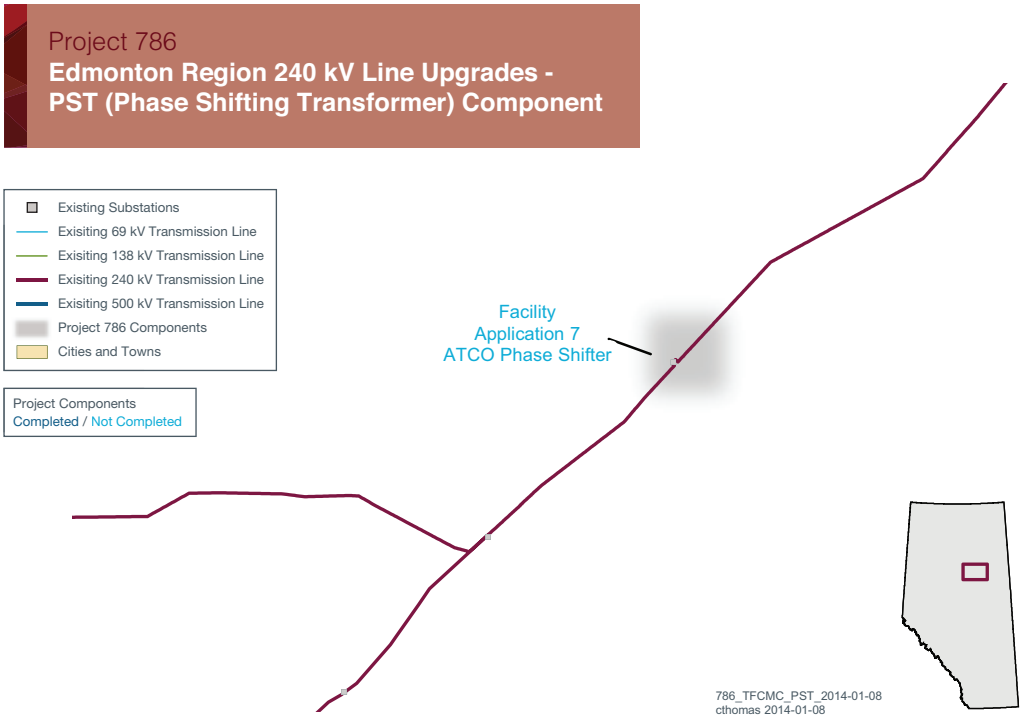
PROJECT COST:

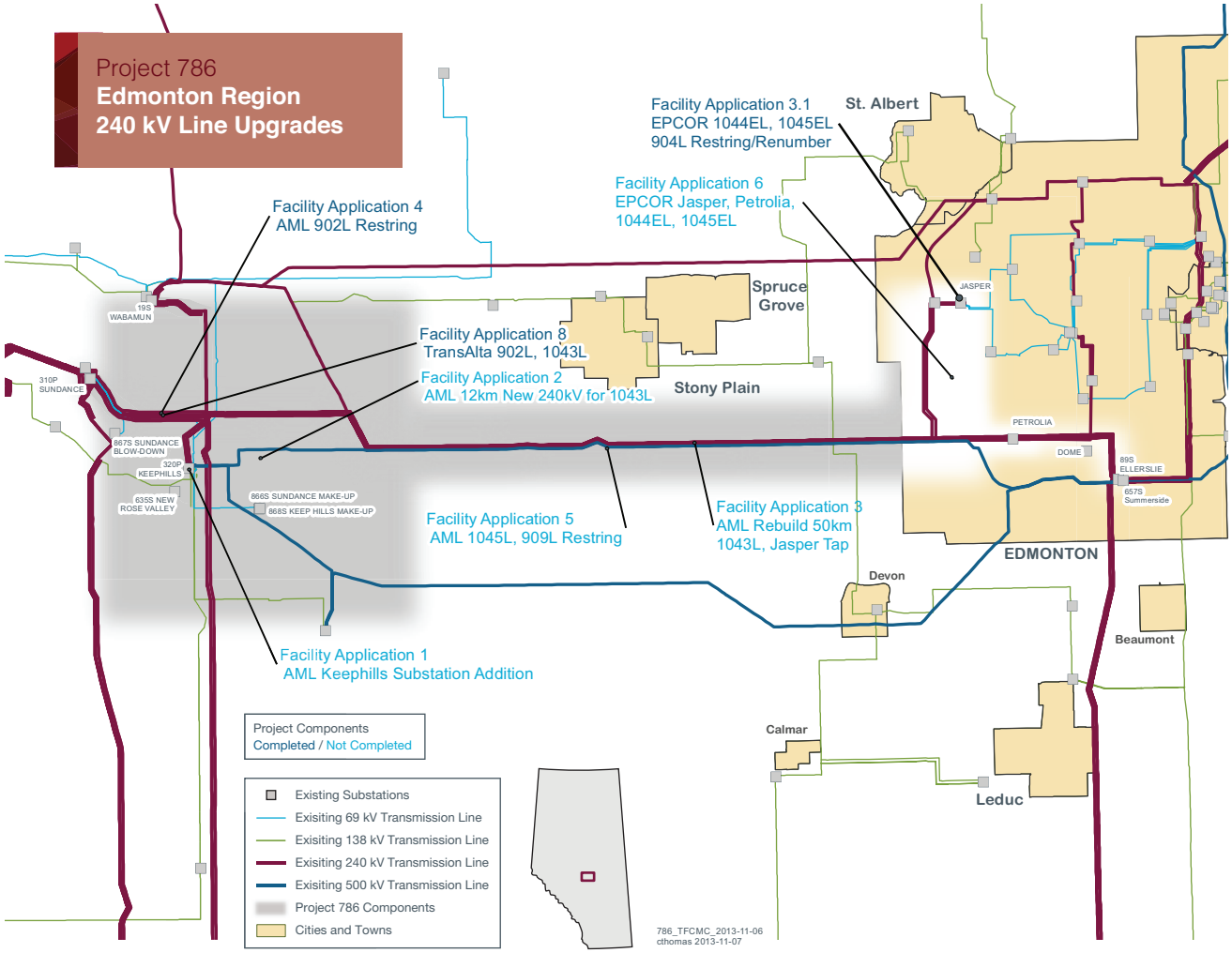
TRANSMISSION PROJECT	AESO LONG-TERM TRANSMISSION PLAN (FILED JUNE 2012) ESTIMATED COST	CURRENT ESTIMATED COST
Edmonton Region 240 kV Line Upgrades	**$153 Million** (2011$ without escalation)	**$178 Million** (ISD$ with escalation)

CURRENT STATUS: All aspects of this project, with the exception of 1043L, are in service.

AltaLink received P&L for the 904L rebuild (renamed to 1043L) on September 30, 2011, and plans to complete the work in early 2015. The construction required to complete a small portion of the 1043L transmission line has been delayed due to land access issues. An ISD for the 1043L transmission line and re-termination of 909L cannot be determined at this time, but stakeholders will be advised of next steps once new information is available. For the purposes of TFCMC reporting, this project is closed. Once work commences on 1043L, the AESO will advise the TFCMC of its progress.

In June 2013, the AESO approved a Change Proposal for $4.1 million in regards to the Livock phase shifter component of the project, which was in the final construction and commissioning stage. The forecast cost increase was due mainly to increases in site grading costs and substation foundation costs as a result of poor ground conditions, rig matting costs due to wet site conditions, and camp cost due to large increases in camp rates.




Project 786
Edmonton Region
240 kV Line Upgrades
Facility Application 3.1
EPCOR 1044EL, 1045EL
904L Restring/Renumber
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 240kV 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
Project Components
Completed / Not Completed
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
786_TFCMC_2013-11-06
cthomas 2013-11-07

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[32]: This project was originally listed as Critical Transmission Infrastructure (CTI) in the AESO 2012 Long-Term Transmission Plan. The proposed development includes a new 240/138 kV substation, to be called ENMAX No. 65 substation (located east of 88 Street SE, Calgary, and north of Highway 22X), a short double-circuit 138 kV transmission line that ties into an existing 138 kV transmission line and a double-circuit 240 kV transmission line from existing 911L to connect into the existing transmission system. The substation is required to improve capacity and reliability in response to both current and future demand for electricity in southeast Calgary.

THE COMPONENTS: The proposed development includes a new 240/138 kV substation comprising two 400 MVA 240-138 kV autotransformers; four 240 kV circuit breakers; four 138 kV circuit breakers; and approximately one km of 138 kV and 240 kV transmission lines to interconnect into the existing system.

FACILITY APPLICATION NAME	FACILITY APPLICATION NUMBER	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
New 240/138 kV Substation (named ENMAX SS 65)	1	New ENMAX No. 65 Substation and about one km of 138 kV transmission line to connect the new substation to the existing transmission system	September 30, 2013
ENMAX No. 65 Substation interconnection 2	2	Addition of double-circuit line from existing 911L to create an in/out configuration into the new ENMAX No. 65 Substation	September 30, 2013

THE TRANSMISSION FACILITY OWNER(S): ENMAX and AltaLink.

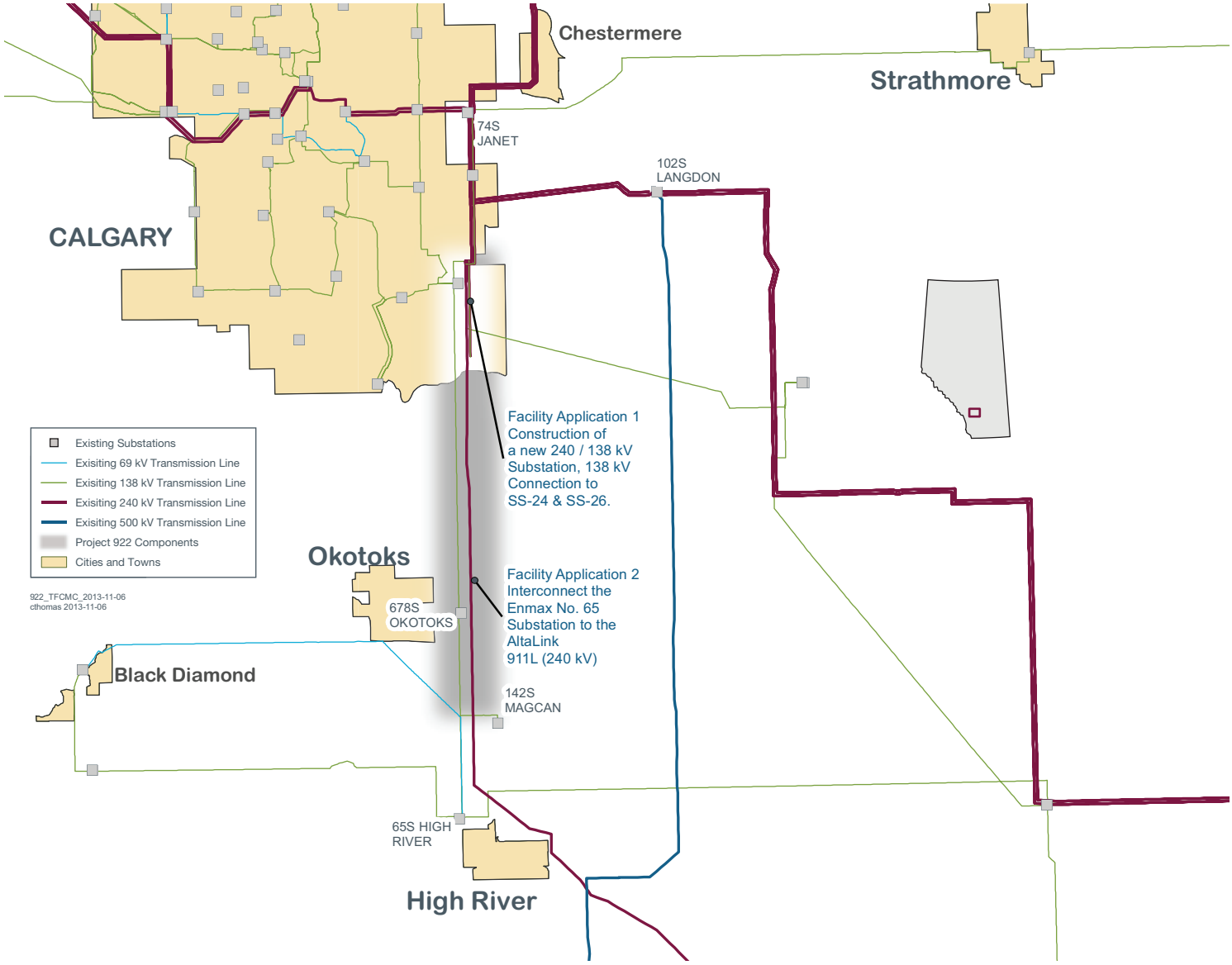
PROJECT COST:

TRANSMISSION PROJECT	AESO LONG-TERM TRANSMISSION PLAN (FILED JUNE 2012) ESTIMATED COST	CURRENT ESTIMATED COST
ENMAX No. 65 Substation	**$37 Million** (2011$ without escalation)	**$39 Million** (ISD$ with escalation)

CURRENT STATUS: On November 3, 2011 the AUC approved the Facility Application and issued P&L for the project. Construction on the project started in April 2012 and it was energized on September 30, 2013.

32 The TFCMC is monitoring Project 922, ENMAX No. 65 Substation. While the current value of the project is below the $100-million TFCMC threshold, the original project initially came in above the threshold and as such continues to be monitored by the Committee.

Project 922
ENMAX No. 65 Substation



7. **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 arise 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 areas, enable new generation facilities to connect, and maintain system reliability. It 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 recently completed 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 new ENMAX SS-65 substation to the new ENMAX SS-25 substation; and the de-energization of sections of existing transmission lines.

The 138 kV scope consists of 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.

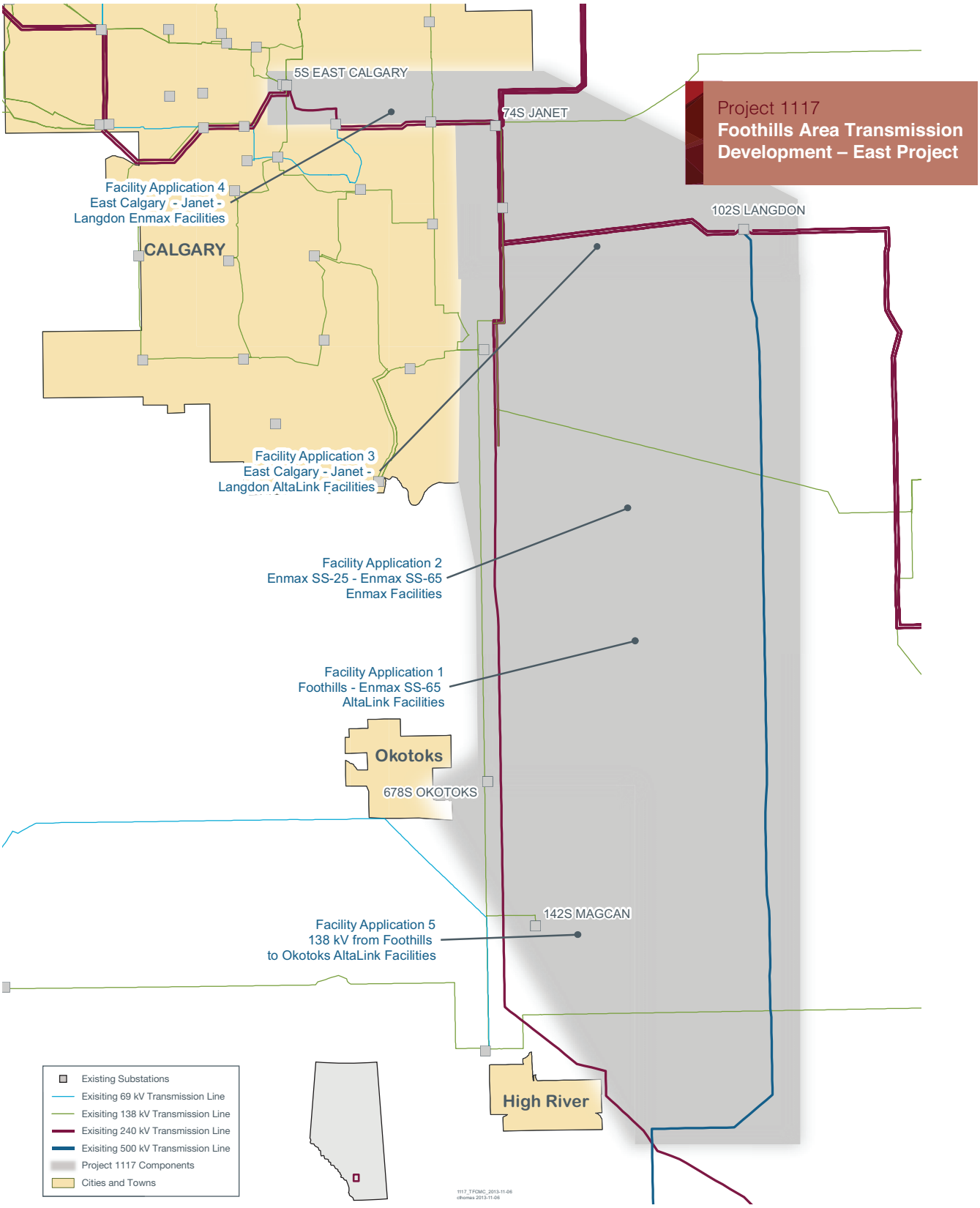
FACILITY APPLICATION NAME	FACILITY APPLICATION NUMBER	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
Foothills 138 kV Project	5, 3	Addition of two 240/138 kV transformers at Foothills 237S; construction of approximately 14 km of double-circuit 138 kV transmission line from Foothills 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	May 12, 2015
ENMAX No.25 substation 240 kV line additions and ENMAX No.65 substation 240 kV line additions	2	Interconnection of two new AltaLink 240 kV transmission lines at ENMAX SS-25, and termination of three new AltaLink 240 kV transmission lines at ENMAX SS-65	May 25, 2015
North Foothills Transmission Project	1	Construction of Foothills 235S 240/138 kV switching station, and construction of approximately 52 km of double-circuit 240 kV transmission line from Foothills 237S to ENMAX SS-65	July 30, 2015
Langdon to Janet Project	3, 4	Construction of approximately 18 km of double-circuit 240 kV 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	July 30, 2015

THE TRANSMISSION FACILITY OWNER(S): AltaLink and ENMAX.

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	***$417 Million** (ISD$ with escalation *FATD East PPS only

CURRENT STATUS: The AESO filed its NID with the AUC in July 2012. AltaLink and ENMAX filed the Facility Applications in July 2012. The AUC held a hearing in May 2013. The AUC approved the NID and Facility Application on October 7, 2013. Construction started in the fall of 2013.


Project 1117
Foothills Area Transmission Development – East Project
5S EAST CALGARY
74S JANET
102S LANGDON
CALGARY
Facility Application 4
East Calgary - Janet -
Langdon Enmax Facilities
Facility Application 3
East Calgary - Janet -
Langdon AltaLink Facilities
Facility Application 2
Enmax SS-25 - Enmax SS-65
Enmax Facilities
Facility Application 1
Foothills - Enmax SS-65
AltaLink Facilities
Okotoks
678S OKOTOKS
142S MAGCAN
Facility Application 5
138 kV from Foothills
to Okotoks AltaLink Facilities
High River
Existing Substations
Exisiting 69 kV Transmission Line
Exisiting 138 kV Transmission Line
Exisiting 240 kV Transmission Line
Exisiting 500 kV Transmission Line
Project 1117 Components
Cities and Towns

8. **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 NUMBER[33]	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, referred to as the West 500 kV line	2019
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, referred to as the East 500 kV line	2020

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

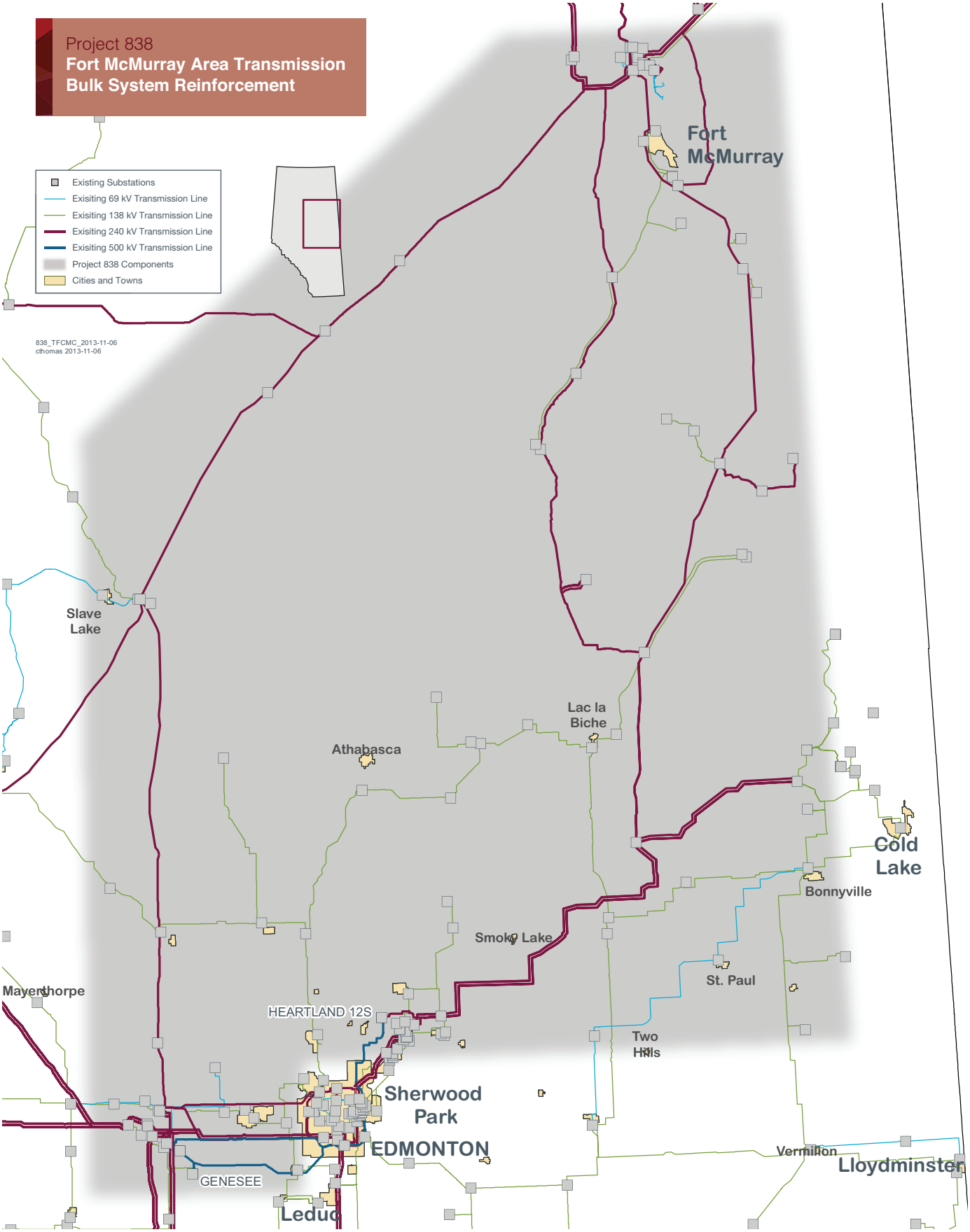
PROJECT COST:

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 AESO's Competitive Process was approved by the AUC on February 14, 2013, with certain conditions.

Request for Expressions of Interest (REOI) closed on June 19, 2013, with 30 companies expressing interest in the project. Request for Qualifications (RFQ) began on July 29 with evaluations to be completed in early January 2014. The Request for Proposal (RFP) will commence in early January 2014 with the five RFQ respondents who will be shortlisted. The AESO will select a winning company in December 2014. The target in-service date for the project is 2019.

33 At the moment, there are no facility numbers for this project as an RFP is pending.


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
838_TFCMC_2013-11-06
cthomas 2013-11-06
Fort McMurray
Slave Lake
Lac la Biche
Athabasca
Cold Lake
Bonnyville
Smoky Lake
St. Paul
Mayerthorpe
HEARTLAND 12S
Two Hills
Sherwood Park
EDMONTON
Vermilion
Lloydminster
GENESEE
Leduc

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

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 double-circuit 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 VAr 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 VAr static var compensator, and various local area 138 kV and 144 kV enhancements.

FACILITY APPLICATION NAME	FACILITY APPLICATION NUMBER	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
Battle River 757S Capacitor Bank addition	2	Battle River 757S–72 kV Capacitor Bank addition; 144 kV circuit breaker and substation alterations	October 3, 2011
Youngstown 772S Capacitor Bank addition	1	Youngstown 772S–Capacitor Bank addition; 144 kV breaker and communication tower	October 6, 2011
144 kV Capacitor Bank and Circuit Breaker additions at Three Hills substation 770S	13	Three Hills 770S 144 kV Capacitor Bank addition; 144 kV circuit breaker and substation alterations	December 13, 2011
Rowley 768S–Michichi–Three Hills 144 kV DC Line 7L25	18	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
Hardisty 377S substation Capacitor Bank	21	138 kV Capacitor Bank addition at Hardisty 377S substation and other associated work	June 28, 2012
Hansman Lake 650S substation SVC addition	22	Addition of a -100/+200 VAr SVC at Hansman Lake 650S	October 5, 2012

FACILITY APPLICATION NAME	FACILITY APPLICATION NUMBER	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
Heatburg 948S–Three Hills–Nevis 144 kV D/C Line 7L16/7L159	17	New 144/25 kV Heatburg 948S substation; new double-circuit 144 kV transmission line from Heatburg 948S to existing 7L16; modification of 7L16 to create an in/out configuration to Heatburg 948S and alterations at existing substations	January 25, 2013
Oakland 946S 240 kV S/S combined with Anderson–Oakland line	7	New double-circuit 240 kV transmission line (designated as 9L70/9L97) from Anderson 801S to Oakland 946S, Oakland 946S substation and related alterations	March 25, 2013
Stettler 769S–Nevis 768S 144 kV S/C Line 7L143	19	New single-circuit 144 kV transmission line from Nevis 766S to Stettler 769S; alterations to Nevis 766S and alterations to Stettler 769S	April 21, 2013
Coyote Lake 963S 240 kV S/S combined with Oakland–-Coyote line	9	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	May 17, 2013
New Lanfine 240/144 kV substation	3	New 240/144 kV substation designated Lanfine 959S	May 20, 2013
Oakland–Lanfine 240 kV S/C line 9L924	8	New double-circuit 240 kV transmission line (one side strung) designated 9L24, from Oakland 946S to Lanfine 959S and alterations to Oakland 946S	May 21, 2013
Pemukan 932S 240 kV substation	11	New 240/144 kV substation designated Pemukan 932S	June 1, 2013
New Lanfine-Pemukan 240 kV S/C Line 9L46	12	New double-circuit 240 kV transmission line (one side strung) designated 9L46, from Pemukan 932S to Lanfine 959S and alterations to Lanfine 959S	June 1, 2013
Relocate 7L98 Oyen 767S–Lanfine 959S	6	Decommission and salvage of transmission line 7L98 and 7LA98	June 1, 2013
Relocate 7L79 line from Monitor 774S–Pemukan 932S	16	Re-termination of existing 7L70 from Monitor 774S to Pemukan 932S and alterations to Pemukan 932S	June 12, 2013
Pemukan 932S–Monitor 774S 144 kV S/C Line 7L127	15	Double-circuit 144 kV line (one side energized) from Pemukan 932S to Monitor 774S	June 15, 2013
Coyote Lake 963S–Michichi Creek 802S 144 kV SC Line 7L128	10	New single-circuit transmission line designated as 7L128 from Michichi Creek 802S to Coyote Lake 963S and alterations to existing Michichi Creek 802S	July 12, 2013

FACILITY APPLICATION NAME	FACILITY APPLICATION NUMBER	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
Lanfine-Oyen 144 kV S/C Line 7L132	5	Double-circuit 144 kV line (one side energized) from Lanfine 959S to Oyen 767S	July 15, 2013
Hansman Lake-Pemukan 240 kV S/C Line 9L966	14	New double-circuit 240 kV transmission line (one side strung) designated 9L966, from Pemukan 932S to AltaLink's service territory and alterations to Pemukan 932S	August 21, 2013
New 240 kV line 966L from Pemukan 932S–Hansman Lake 650S	23	New double-circuit 240 kV transmission line (one side strung) designated 966L, from Hansman Lake 650S to ATCO's service territory and alterations to Hansman Lake 650S	August 21, 2013
Nilrem 574S combined with D/C 240 kV 953L –1047L and Tucuman 478S combined with D/C 138 kV 679L–-680L	20	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	August 30, 2013
New 240 kV line 1060L from Ware Junction 132S–West Brooks 28S	24	New single-circuit 240 kV transmission line (designated 1053L) from Ware Junction 132S to Cassils 324S; alterations to Ware Junction 132S and alteration to Cassils 324S	November 15, 2013
Lanfine 959S 200 VAr SVC	4	Addition of a -100/+200 VAr SVC at Lanfine 959S	December 3, 2013

THE TRANSMISSION FACILITY OWNER(S): AltaLink and ATCO.

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)	**$969 Million** (ISD$ with escalation)

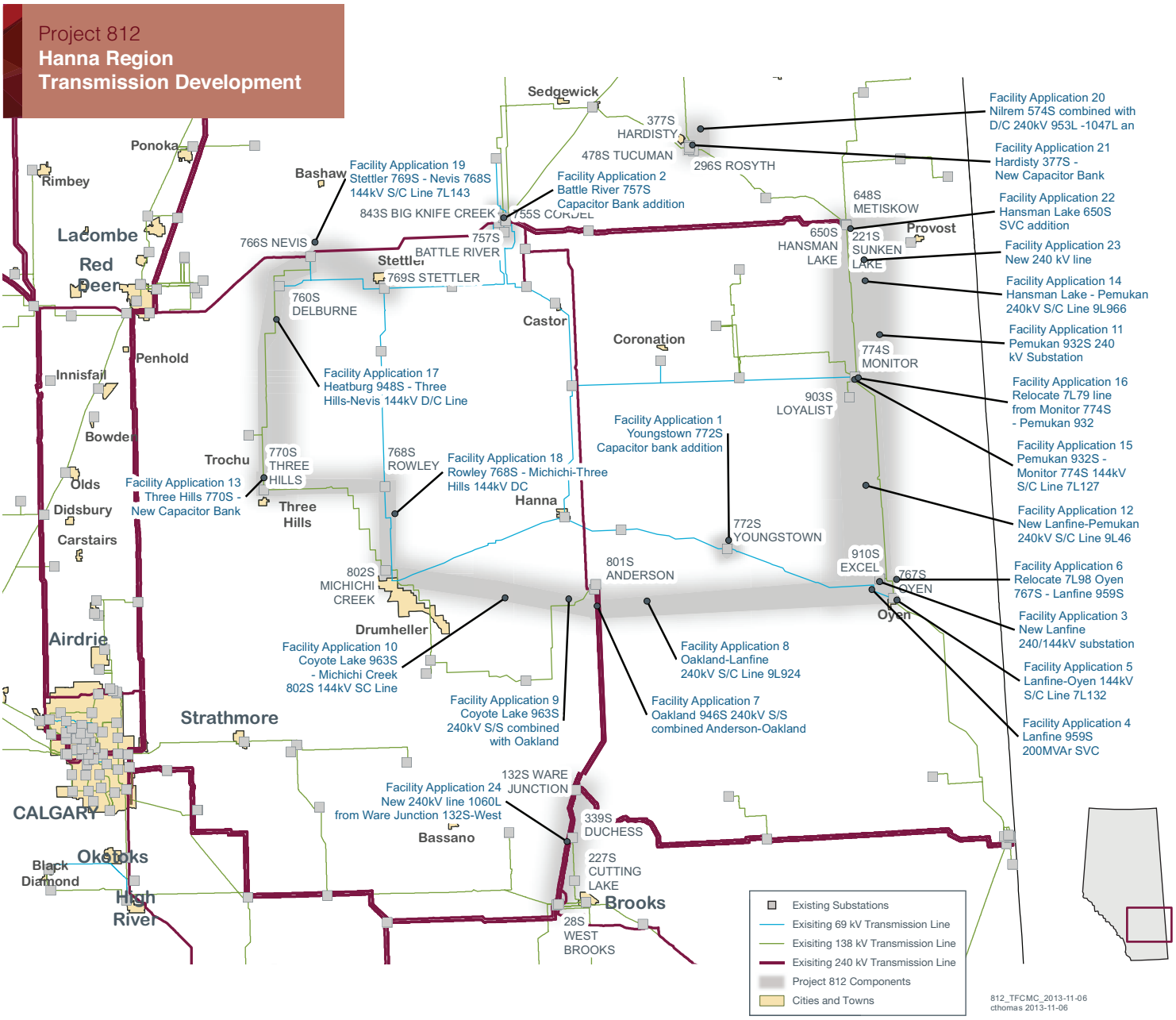
CURRENT STATUS: The Hanna Region Transmission Development NID was approved April 29, 2010. All Facilities Applications related to Stage 1 of the project have been approved by the AUC with the last Facility Application for the Heatburg 948S and Three Hills-Nevis 144 kV D/C transmission line being approved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

Change Proposals totalling $73.8 million were submitted to the AESO in February 2013 and approved by the AESO in May 2013. The increases in costs within these Change Proposals were due mainly to schedule delays; increased ROW scope (reflecting more onerous ROW conditions and associated environmental mitigations compared to those identified at the time of the original PPS); and changes in labour market conditions, which have become evident since the original PPS estimates in 2009/2010. Increased costs for Nilrem were also a result of the AUC decision to approve a portion of the preferred and alternate routes.

The AESO received another Change Proposal for $8.2 million. This Change Proposal covers multiple cost increases from the +/-10 until the end of construction. The increased costs are due to labour market conditions, unseasonably wet ROW conditions and costs to resolve these issues during construction. The AESO has requested additional information from AltaLink and will process the Change Proposal once this information is received.

The 138 kV and 240 kV Energizations for the Hansman Lake, Pemukan, Tucuman and Nilrem facilities were energized at the end of August 2013; while the new 240 kV line from Ware Junction to 132S Cassils was energized on November 29. FA 4 Lanfine SVC is scheduled for energization in February 2014. This is the last scope of work to be completed for the Hanna program.

The AESO is currently working on Stage 2 of the Hanna project; the NID identifies that this development is required by 2017.



10. 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 (one side strung) from Kearl Lake to Salt Creek, the 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 NUMBER	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
North Fort McMurray Transmission Development	1	Double-circuit 240 kV line (one side strung) 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	November 29, 2013

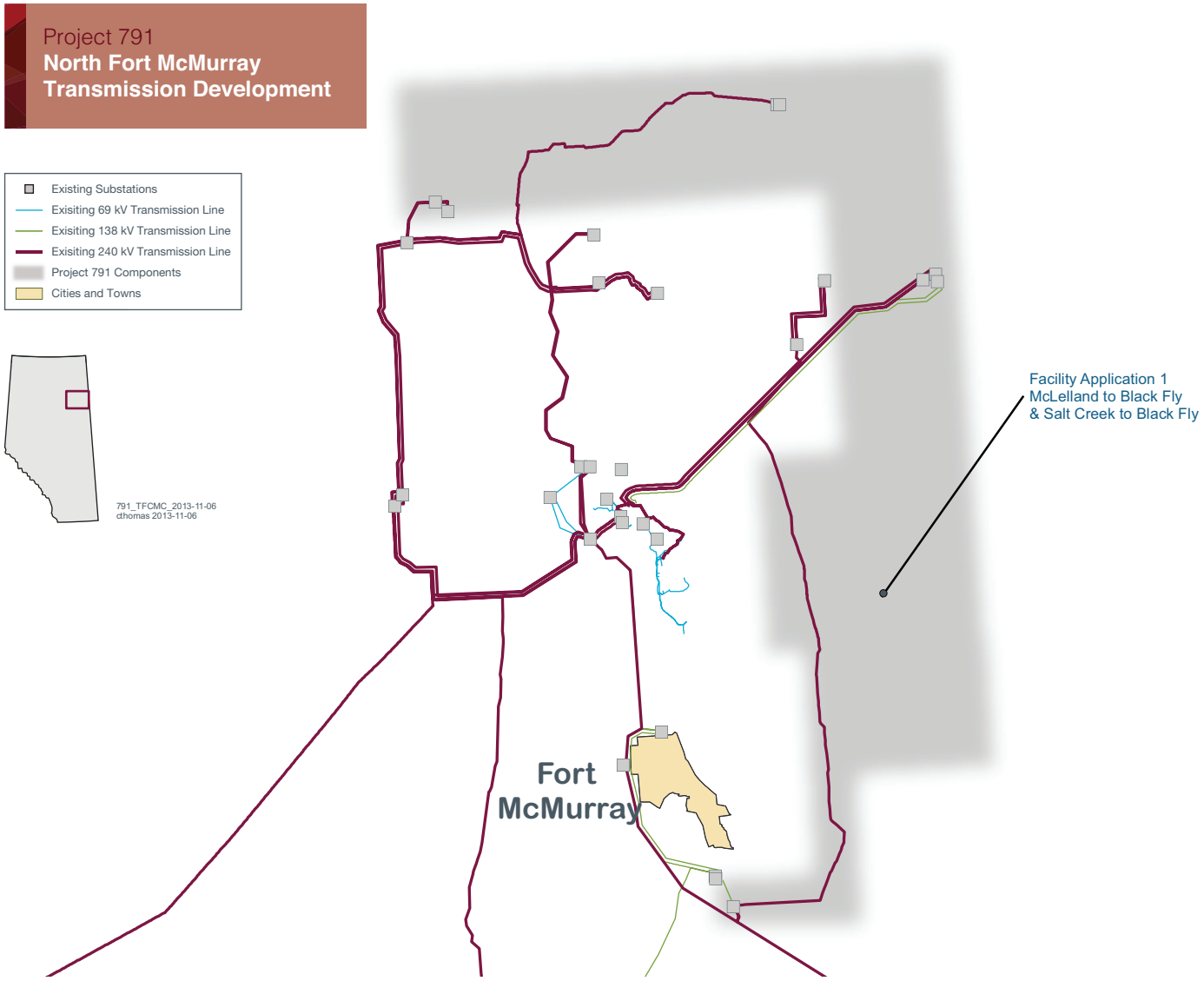
THE TRANSMISSION FACILITY OWNER(S): ATCO.

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)	**$357 Million** (ISD$ with escalation)

CURRENT STATUS: The North Fort McMurray NID was approved June 24, 2011. On July 28, 2011, the AUC approved the south portion of the Facility Application and on December 23, 2011, it 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 north part of the project, Black Fly Substation, 9L69 from Black Fly to McLelland and McLelland substation, was energized on December 11, 2013.

A Change Proposal was provided to the AESO in March 2013 by ATCO Electric for $28.8 million. The change was signed off by the AESO in June 2013. The increase in costs were due mainly to the unusually warm temperatures and an early spring thaw, which required maintaining an ice bridge across the Athabasca River; scheduling 24-hour shifts to take advantage of nighttime temperatures and the extensive use of rig mats. Excessive rainfall causing flooding at the Blackfly substation caused delays in construction and required extensive dewatering and grading to mitigate erosion at the substation and along the access road. Actual geotechnical conditions were worse than anticipated.


Project 791
North Fort McMurray
Transmission Development
Existing Substations
Exisiting 69 kV Transmission Line
Exisiting 138 kV Transmission Line
Exisiting 240 kV Transmission Line
Project 791 Components
Cities and Towns
791_TFCMC_2013-11-06
dthomas 2013-11-06
Fort
McMurray
Facility Application 1
McLelland to Black Fly
& Salt Creek to Black Fly

11. 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 two new lines will be 500 kV high-voltage direct current (HVDC) technology and will be built to transfer up to 1000 MW of power each. Each line and converter station can be upgradable to 2000 MW at a future date. For each line, two 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 NUMBER	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
Eastern Alberta Transmission Line Project Facility Application – AltaLink	3	Application to construct and operate an interface for the EATL Converter Stations	August 7, 2014
Eastern Alberta Transmission Line Project Facility Application – ATCO	2	Application to construct and operate a high-voltage DC line from Heartland to West Brook	December 15, 2014
Western Alberta Transmission Line Project Facility Application – AltaLink	1	Application to construct and operate a high-voltage DC line from Genesee to Langdon	April 2015

THE TRANSMISSION FACILITY OWNER(S): AltaLink is the designated TFO to build the Western Alberta Transmission Line (WATL) and ATCO is the designated TFO to 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)	**$1.655 Billion** (ISD$ with escalation)
North South Transmission Reinforcement – WATL	**$1.329 Billion** (2011$ without escalation)	**$1.457 Billio**n (ISD$ with escalation)

CURRENT STATUS: The AUC public hearing for ATCO's EATL application closed August 20, 2012. The AUC issued P&L on November 15, 2012, for Facility Applications from ATCO, AltaLink and EPCOR. The EATL ISD is scheduled for December 15, 2014.

For EATL, on March 28, 2013, the AESO issued a stop-work direction to EPCOR when it determined the scope of work previously directed to EPCOR was no longer required. On April 25, 2013, the AESO approved a cost increase Change Proposal of $4 million submitted by AltaLink as a result of change in the Remedial Action Scheme. Construction for this project has started and is ongoing.

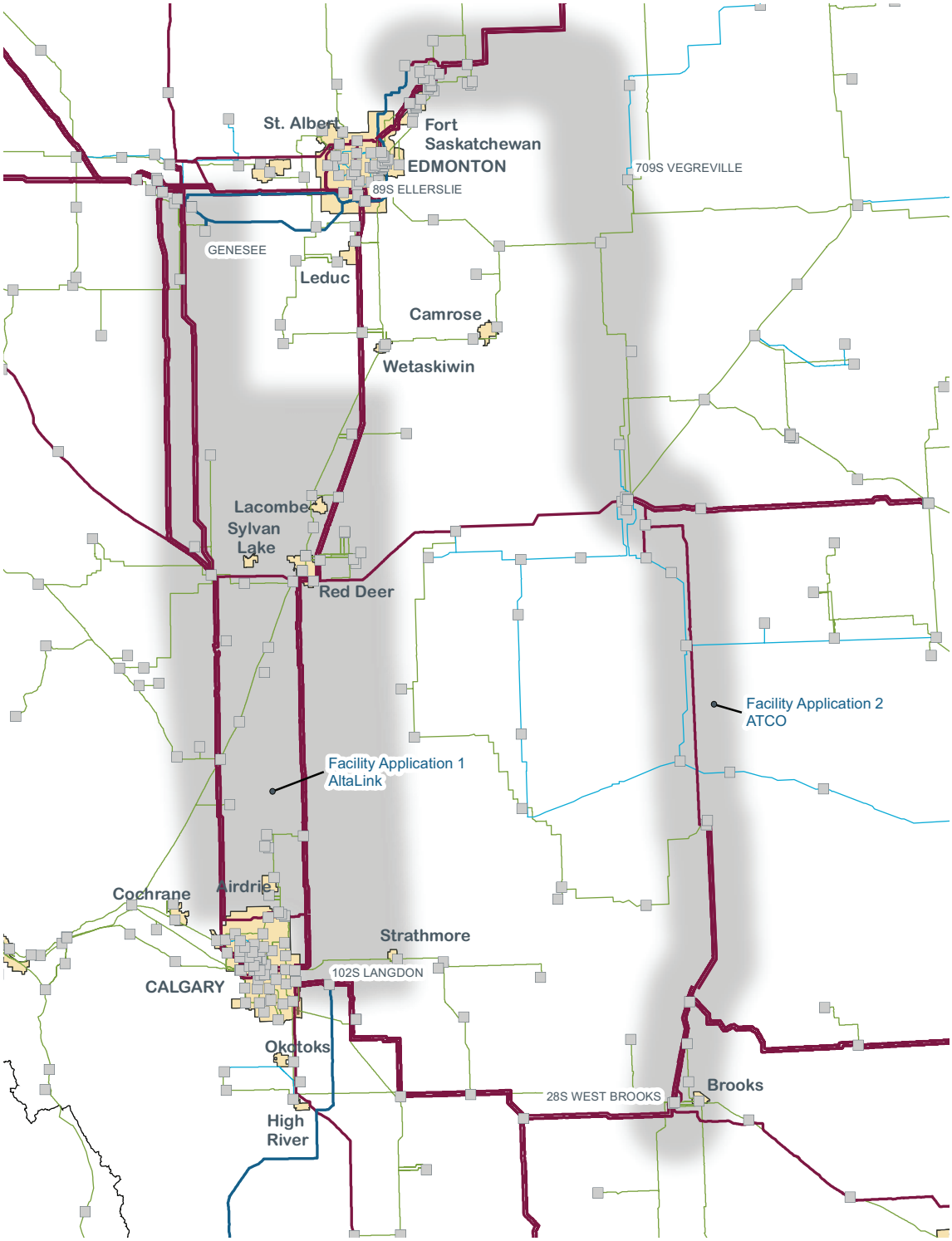
The AUC public hearing for AltaLink's WATL application closed on September 10, 2012. P&L was issued on December 6, 2012. The WATL ISD is scheduled for early 2015.

On August 23, 2013, the AESO received ATCO's updated +/- 10% PPS estimate for the EATL project. The estimate is 13% ($206 million) higher than the original PPS and is within the original PPS +/- 20% threshold. In addition, on September 10, 2013, the AESO received a corresponding Change Proposal for the same $206 million. The increases were a result of hikes in competitively tendered costs for all of the major material and service contracts, and a result of the P&L delay from the Critical Transmission Review Committee. ATCO indicated that all contracts were competitively tendered. As part of the AESO's review, the AESO issued a number of Information Requests to ATCO. On October 24, 2013, ATCO provided the AESO with a presentation and was available for questions on their Information Request responses. The AESO raised a concern with the estimate and will process the Change Proposal shortly after it has been addressed.

On October 8, 2013, the AESO received AltaLink's updated +/- 10% PPS estimate for the WATL project. The estimate is 14% ($211million) higher than the original PPS plus additional approved Change Proposals (Authorized Budget), and is within the original PPS +/- 20% threshold. In addition, the AESO received a corresponding Change Proposal for the same $211 million. The Change Proposal is for cost increases due to the changes in labour market conditions, increased ROW effort and complexity (brushing, matting and environmental mitigation) and additional costs at Temporary Bennett. AltaLink has advised that the lowest price contractors were selected. AltaLink also reports that there is no schedule impact; the ISD remains April 2015.

On October 10, 2013, the AESO received AltaLink's updated +/- 10% PPS estimate for the EATL interface. The estimate is 56% ($33 million) higher than the original PPS; and is not within the original PPS +/- 20% threshold. The Change Proposal is for cost increases due to increased complexity for the transmission line modifications, spring construction conditions and the market conditions on construction labour costs. According to AltaLink, construction costs were bid as per AESO rules and the lowest bidders were selected. The original assumption was a 32-month construction duration with an ISD of December 2014; and construction assumed to start in April 2012. However, due to regulatory delays and approval, the construction duration is only 17 months; with construction having started in March 2013. The AESO has reviewed that Change Proposal and has requested additional information from AltaLink before the AESO processes the Change Proposal completely.

Project 737
North South Transmission Reinforcement



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dthomas 2013-11-07

12. NORTHWEST FORT MCMURRAY TRANSMISSION DEVELOPMENT (NW FMM); PROJECT 1180 – To provide service and connect future industrial customers in areas where there are no transmission facilities northwest of Fort McMurray.

THE PROJECT: The Northwest (of) Fort McMurray 240 kV Transmission Development includes a 240 kV looped system extending west from existing transmission facilities between the Dover 888S and Joslyn 849S substations, including the addition of two new 240 kV substations. This expansion of the transmission system will serve developing (electricity intensive) industrial growth as oilsands extraction facilities and related industrial developments are proceeding into areas where there are currently no transmission facilities to provide service, and connect future industrial customers.

THE COMPONENTS: A new 240 kV switching substation (Birchwood Creek 960S-NW FMM South); existing 9L57 line in/out at Birchwood Creek 960S; new 240 kV switching station (Ells River 2079S-NW FMM North); 9L08 Joslyn to Dover line in/out at Ells River 2079S (approximately 50 km of 240 kV double-circuit line, designated as 9L08/9L76); approximately 80 km of 240 kV double-circuit line (9L95), between Ells River 2079S and Birchwood Creek 960S.

FACILITY APPLICATION NAME	FACILITY APPLICATION NUMBER	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
Birchwood Creek substation and 9L57 in/out.	1	Birchwood Creek: new 240 kV switching substation; existing 9L57 line in/out at Birchwood Creek	October 30, 2014
Ells River substation, 9L76 and 9L08, in/out 240 kV double-circuit line from existing 9L08 to Ells River substation	2	9L08, Joslyn to Dover line in/out at Ells River (approximately 50 km of 240 kV double-circuit line)	April 15, 2015

THE TRANSMISSION FACILITY OWNER(S): ATCO.

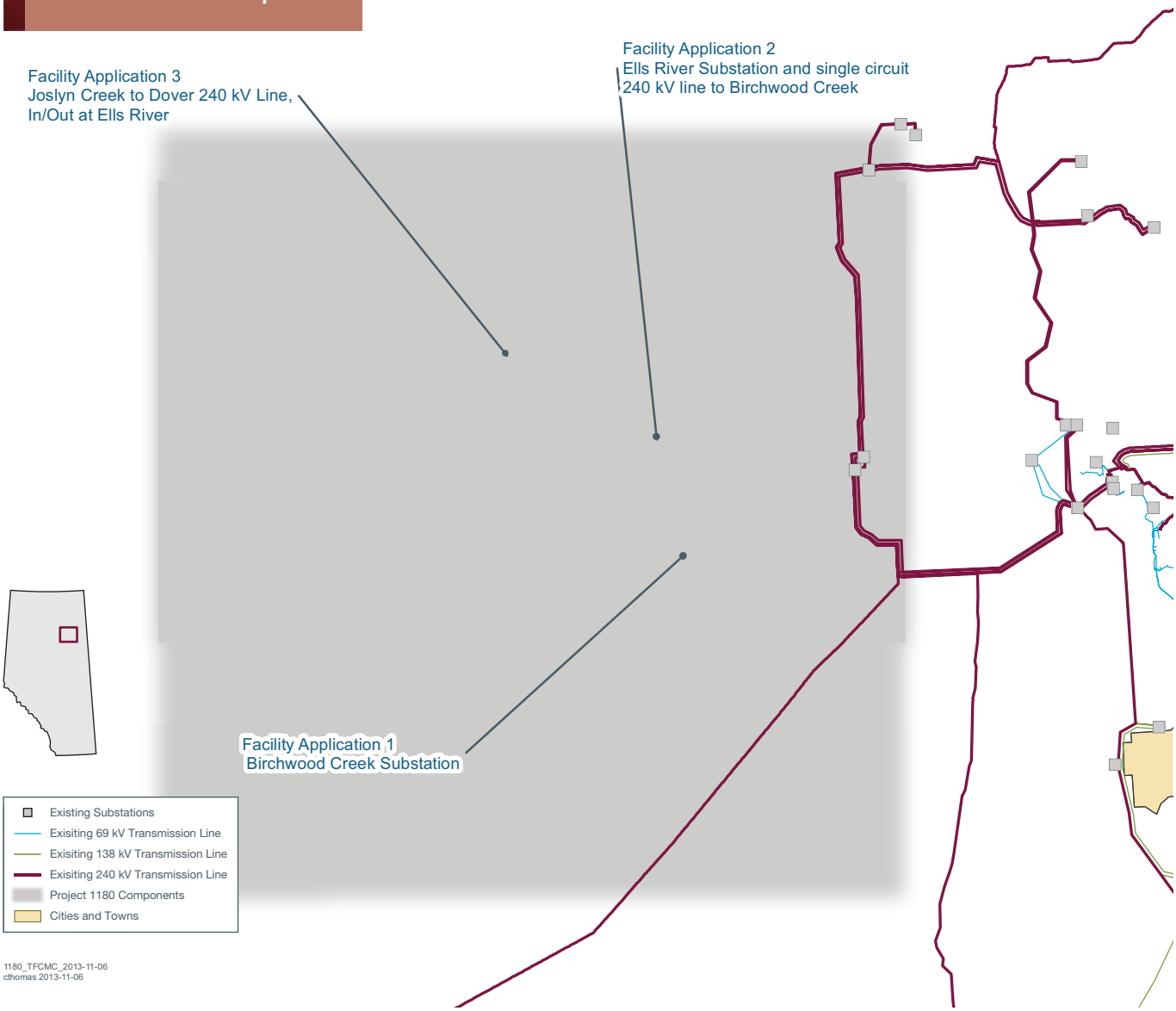
PROJECT COST:

TRANSMISSION PROJECT	AESO LONG-TERM TRANSMISSION PLAN (FILED JUNE 2012) ESTIMATED COST	CURRENT ESTIMATED COST
Northwest Fort McMurray 240 kV Transmission Development	**$342 Million** (2011$ without escalation)[34]	**$371 Million** (ISD$ with escalation)

CURRENT STATUS: On June 18, 2012, the AUC approved the NID for the Northwest Fort McMurray 240 kV Transmission Development. The project will be developed in three stages. The Facility Application for Stage 1, Birchwood Creek, was filed on October 25, 2013. The Facility Application for the Ells River stage is expected to be filed in the second quarter of 2014 and the Facility Application for 9L95 in the fourth quarter of 2014.

34 Referenced as the "240 kV double-circuit line from Livock to Joslyn Creek" in the Long-Term Transmission Plan filed in June 2012.

Project 1180
Northwest Fort McMurray Transmission Development



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

THE PROJECT[35]: 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.

FACILITY APPLICATION NAME	FACILITY APPLICATION NUMBER	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
9L15 240 kV Wesley Creek 834S 240 kV single-circuit line	1	9L15 energized Wesley Creek to Brintnell 876S, two 300 MVA transformers at Wesley Creek	March 19, 2010
Little Smoky 813S-install +/-100 VAr SVC and two 144 kV breakers	8	Little Smoky 813S +/-100 VAr SVC and two 144 kV VAr Static VAr Compensator and breakers	March 31, 2010
High Level 786S +/- 30 VAr SVC	4	High Level +/- 30 VAr Static VAr Compensator	June 30, 2010
7L131/7L106 – 144 kV D/C line CTs Wesley Creek to Meikle 905S	2	Double-circuit 144 kV line from Wesley Creek to new Meikle 905S station	September 29, 2010
7L133 -144 kV S/C line Sulphur Point 828S to High Level 786S	3	Single-circuit 144 kV line from Sulphur Point 828S to High Level 786S	March 19, 2011
Arcenciel 930S +/-30 VAr	7	Arcenciel 930S +/-30 VAr Static VAr Compensator	September 7, 2011
7L113-144 kV S/C line Ring Creek 853S to New Arcenciel 930S	5	Single-circuit 144 kV line from Ring Creek to new Arcenciel 930S substation and one – 30 VAr Capacitor Bank at Arcenciel	December 19, 2011
Arcenciel 930S -30/+50 VAr synchronous condenser	6	Arcenciel 930S -30/+50 VAr synchronous condenser	May 31, 2013

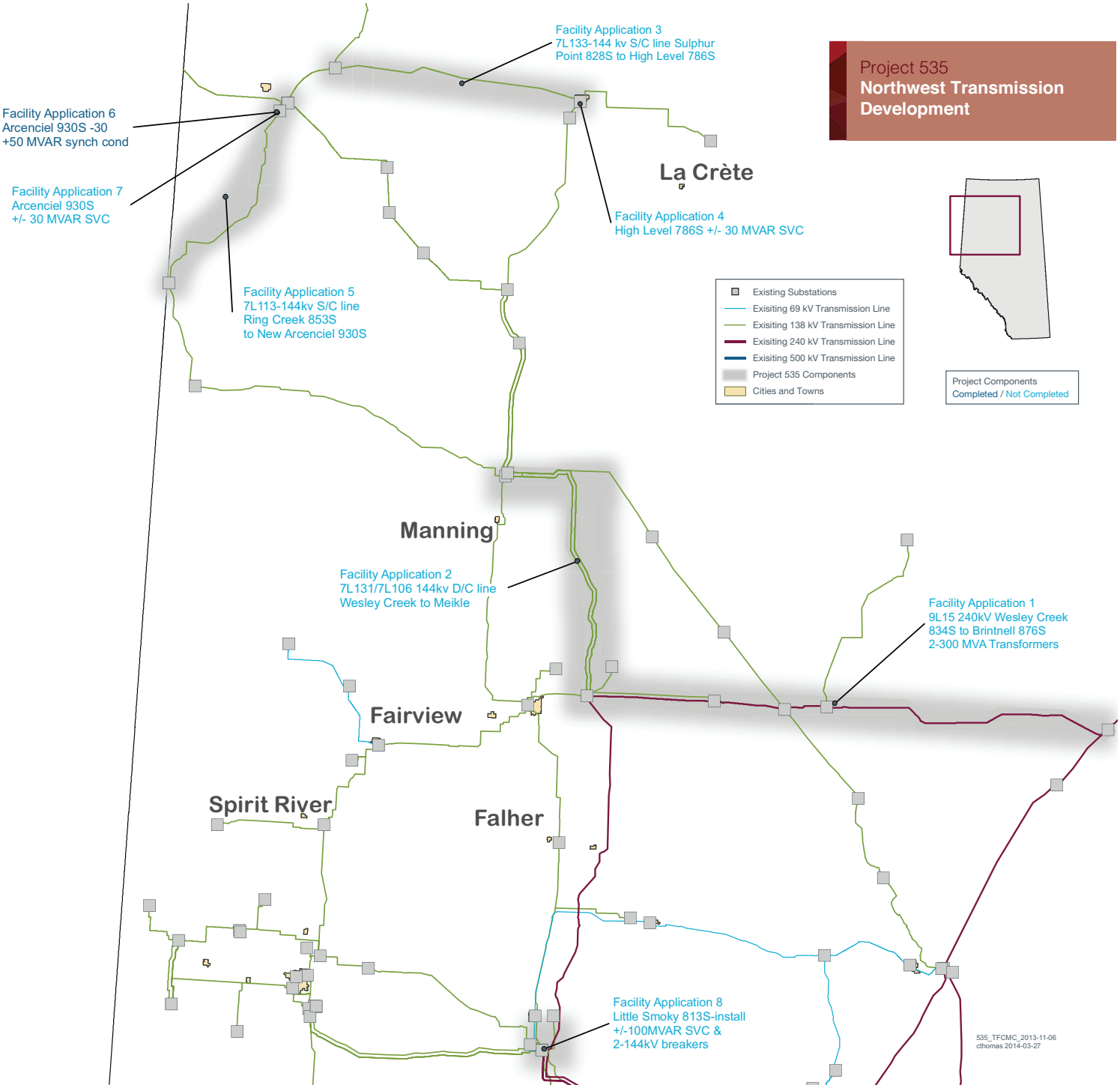
THE TRANSMISSION FACILITY OWNER(S): ATCO.

PROJECT COST:

TRANSMISSION PROJECT	AESO LONG-TERM TRANSMISSION PLAN (FILED JUNE 2012) ESTIMATED COST	CURRENT ESTIMATED COST
Northwest Transmission Development	**Not estimated in last Long-Term Transmission Plan**	**$583 Million** (ISD$ with escalation)

CURRENT STATUS: The Northwest Transmission Development was completed and in service in May 2013. This project is closed and will no longer be reported to the TFCMC.

35 This project was not included in the AESO's Long-Term Transmission Plan (filed June 2012) as it was expected to be completed at the time of publication. The revised ISD for this project was May 2013.


Project 535
Northwest Transmission Development
Facility Application 3
7L133-144 kv S/C line Sulphur Point 828S to High Level 786S
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
Facility Application 5
7L113-144kv S/C line
Ring Creek 853S
to New Arcenciel 930S
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
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
2-300 MVA Transformers
Fairview
Spirit River
Falher
Facility Application 8
Little Smoky 813S-install
+/-100MVAR SVC &
2-144kV breakers
535_TFCMC_2013-11-06
cthomas 2014-03-27

14. RED DEER REGION TRANSMISSION DEVELOPMENT (RDTD); 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[36]: 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 only component left for Stage 2 of the project is building a third 138 kV line from Gaetz to Joffre.

FACILITY APPLICATION NAME	FACILITY APPLICATION NUMBER	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
Red Deer Area Transmission Development Stage 1 – Brownfield	1	Split 768L and 778L; 240/138 kV transformer at Benalto 17S; Capacitor Banks at Joffre 535S, Prentiss 276S and Ellis 332S	November 29, 2013
Red Deer Area Transmission Development Stage 1 – Rebuilds	2	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	December 26, 2014
Red Deer Area Transmission Development Stage 2 – Rebuild 166L	4	Rebuild 166L from Didsbury 152S to Harmattan 256S	June 26, 2015
Red Deer Area Transmission Development Stage 1 – Greenfields	3	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	July 10, 2015
Red Deer Area Transmission Development Stage I – Salvage	5	Salvage 80L from Ponoka 331S to West Lacombe 958S; salvage 80L from Red Deer 63S to Innisfail 214S to Olds 55S; salvage 716L from Wetaskiwin 40S to Ponoka 331S	November 7, 2017

THE TRANSMISSION FACILITY OWNER(S): AltaLink.

PROJECT COST:

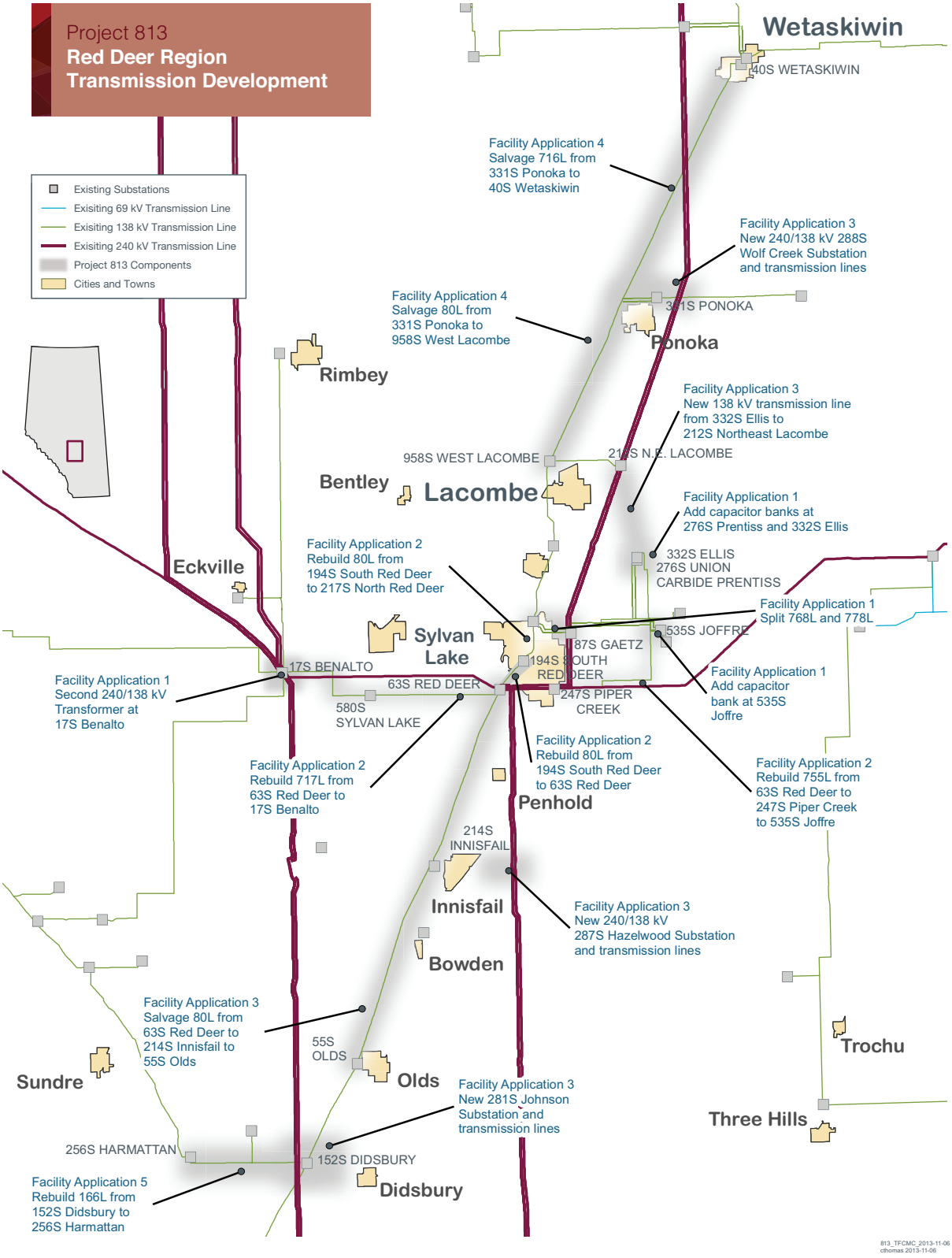
TRANSMISSION PROJECT	AESO LONG-TERM TRANSMISSION PLAN (FILED JUNE 2012) ESTIMATED COST	CURRENT ESTIMATED COST
Red Deer Region Transmission Development	**$204 Million** (2011$ without escalation)	**$356 Million** (ISD$ with escalation)

36 Revisions have been made to the information in this project's Components chart. As such, please use this information going forward.

CURRENT STATUS: AltaLink filed the first Facility Application for Brownfield on September 26, 2011, and received approval on September 27, 2012. AltaLink filed Facility Application Rebuilds and Facility Application Greenfields in June 2013. Stage 2 development related to the rebuild of 166L will be advanced to 2014 to facilitate the connection of a generation facility in the Harmattan area.

The AESO approved a Change Proposal in June for $5.4 million due to a delay in P&L, constructions bids coming in significantly higher than assumed in the PPS, additional requirements to meet demands of working in customer facilities, and the relocation of a water line.

In July, the AESO approved another Change Proposal for $5.8 million to cover an extension in the project timeline by 11 additional months in order to resolve environmental and siting revisions on 755L and incorporate stakeholder feedback.


Project 813
Red Deer Region
Transmission Development
Existing Substations
Exisiting 69 kV Transmission Line
Exisiting 138 kV Transmission Line
Exisiting 240 kV Transmission Line
Project 813 Components
Cities and Towns
Wetaskiwin
40S WETASKIWIN
Facility Application 4
Salvage 716L from
331S Ponoka to
40S Wetaskiwin
Facility Application 3
New 240/138 kV 288S
Wolf Creek Substation
and transmission lines
Facility Application 4
Salvage 80L from
331S Ponoka to
958S West Lacombe
331S PONOKA
Ponoka
Rimbey
Facility Application 3
New 138 kV transmission line
from 332S Ellis to
212S Northeast Lacombe
958S WEST LACOMBE
212S N.E. LACOMBE
Bentley
Lacombe
Facility Application 1
Add capacitor banks at
276S Prentiss and 332S Ellis
Facility Application 2
Rebuild 80L from
194S South Red Deer
to 217S North Red Deer
332S ELLIS
276S UNION
CARBIDE PRENTISS
Eckville
Facility Application 1
Split 768L and 778L
535S JOFFRE
Sylvan
Lake
187S GAETZ
194S SOUTH
RED DEER
17S BENALTO
63S RED DEER
247S PIPER
CREEK
Facility Application 1
Second 240/138 kV
Transformer at
17S Benalto
580S
SYLVAN LAKE
Facility Application 1
Add capacitor
bank at 535S
Joffre
Facility Application 2
Rebuild 80L from
194S South Red Deer
to 63S Red Deer
Facility Application 2
Rebuild 717L from
63S Red Deer to
17S Benalto
Facility Application 2
Rebuild 755L from
63S Red Deer to
247S Piper Creek
to 535S Joffre
Penhold
214S
INNISFAIL
Innisfail
Facility Application 3
New 240/138 kV
287S Hazelwood Substation
and transmission lines
Bowden
Facility Application 3
Salvage 80L from
63S Red Deer to
214S Innisfail to
55S Olds
55S
OLDS
Trochu
Sundre
Olds
Facility Application 3
New 281S Johnson
Substation and
transmission lines
Three Hills
256S HARMATTAN
152S DIDSBURY
Facility Application 5
Rebuild 166L from
152S Didsbury to
256S Harmattan
Didsbury
813_TFCMC_2013-11-06
clhomas 2013-11-06

15. *NEW* SOUTH AND WEST OF EDMONTON TRANSMISSION DEVELOPMENT (SWEATR); PROJECT 850 – Transmission system reinforcement to the 138 kV system south and west of the City of Edmonton.

THE PROJECT: In preparation of the South and West Edmonton Plan, the AESO considered the specific needs and timing of existing and future transmission facilities in the South and West Edmonton area. There is insufficient transmission capacity in the South and West Edmonton area and transmission developments are required to provide the needed capacity to meet future load growth.

South and West Edmonton Transmission Development will add two new 240/138 kV source substations, one south of the town of Stony Plain and one close to the Nisku 149S substation; reconfigure the 138 kV network in the vicinity of the Cooking Lake 522S substation; rebuild portions of the 138 kV transmission lines, and modify existing substations in the area. These developments are expected to be in service by the first quarter of 2017.

THE COMPONENTS: The list for the South and West of Edmonton Transmission System Development[37] is as follows: a new 240/138 kV Harry Smith substation; a new Saunders Lake substation; a new 138 kV line from 780L to Cooking Lake and reconfiguration; one 138 kV 27 MVAr capacitor bank at Leduc 325S; existing 138 kV Lines reconfiguration.

FACILITY APPLICATION NAME	FACILITY APPLICATION NUMBER	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
New Harry Smith Substation	1	New 240/138kV Harry Smith 367S substation including two 240/138 kV 400 MVA transformers, modifications to Acheson 305S, Stony Plain 434S and Keephills 320P substations, and two new 240 kV Lines and three new 138 kV lines	December 2016
New Saunders Lake Substation	2	New Saunders Lake 289S substation including two 240/138 kV 400 MVA transformers, modifications to Nisku 149S, Wetaskiwin 40S and Ellerslie 89S, four 240 kV lines, two 138 kV lines, and rebuild 780L and 858L between Nisku and Saunders Lake	December 2016
New 138 kV Line from 780L to Cooking Lake and Reconfiguration	3	Two new 138 kV circuits, 780L to Cooking Lake 522S, augmentation of Cooking Lake 522S Substation (upgrades existing bus, addition of circuit breakers with isolating switches)	December 2016
Re-terminate 914L at Saunders Lake and Up-rate 910L and 723L	4	Operate 133L line from Wabamun 19S to 234L tap normally open (operating condition)	December 2016
New Capacitor Bank at Leduc 325S	5	One 138 kV 27 MVAr capacitor bank at Leduc 325S	April 2017

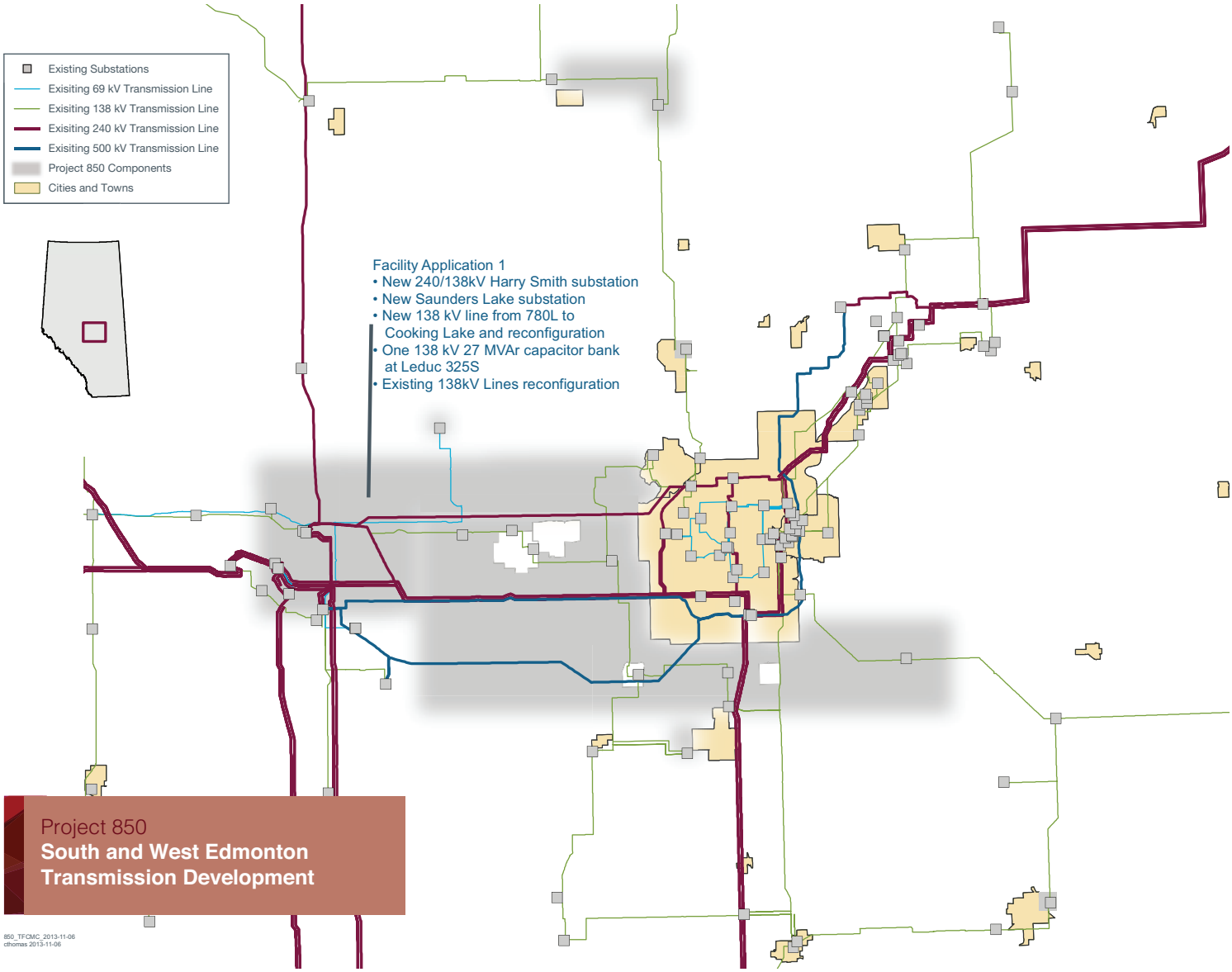
THE TRANSMISSION FACILITY OWNER(S): AltaLink.

PROJECT COST:

TRANSMISSION PROJECT	AESO LONG-TERM TRANSMISSION PLAN (FILED JUNE 2012) ESTIMATED COST	CURRENT ESTIMATED COST
South and West of Edmonton Transmission Development	**$152 Million** (2012$)	**$172 Million** (ISD$ with escalation)

37 The AESO's NID for this project has not yet been approved by the AUC; approval is expected in June 2014.

CURRENT STATUS: This is a new project. The AESO filed NID Application 1609123 with the AUC on December 14, 2012. The NID is being reviewed by the AUC with expected approval by June 2014. The AESO and AltaLink are currently preparing for AUC hearings to be held in March 2014. AltaLink is expected to file their Facility Applications in mid-to-late 2014.



16. 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.

Stage 1: Planned to reinforce the 240 kV system in the Fort MacLeod and the Brooks–Medicine Hat corridor.

Stage 2: Planned to reinforce the 240 kV and 138 kV systems in the Glenwood, Lethbridge, Blackie and City of Medicine Hat areas, including a 240 kV system loop connection to the 500 kV Langdon–Cranbrook line.

Stage 3: Interconnect the Ware Junction–Langdon area via a 240 kV line.

FACILITY APPLICATION NAME	FACILITY APPLICATION NUMBER	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
Milo Junction Switching Station	2	Build a switching station at Milo Junction	November 1, 2011
PST Addition at Russell 632S	3	Phase shifting transformer and new Russell substation	April 25, 2012
Cassils to East Medicine Hat	4	240 kV lines from Cassils to new Bowmanton	November 12, 2013
Ware Junction substation upgrade	13	933L line in/out at Ware Junction	November 15, 2013
East Medicine Hat to Whitla 240 kV Transmission Line	5	240 kV lines from Bowmanton to new Whitla	March 31, 2014
Medicine Hat Area 138 kV Line Development	6	138 kV system upgrades in the Medicine Hat area	May 22, 2015
Blackie Area 138 kV upgrade	11	138 kV system upgrade in the Blackie area	July 15, 2015
Cypress Reactive Power Addition	12	Reactive power addition at Cypress substation	July 20, 2015
911L Line Replacement	1	Build new 240 kV lines from Foothills substation to Windy Flats substation	September 22, 2015
240 kV Line from Etzikom Coulee to Goose Lake	9	240 kV line from new Journault substation to Goose Lake substation	January 1, 2017
Etzikom Coulee S/S and 240 kV line to MATL S/S	8	240 kV line from new Journault to Picture Butte (formerly called MATL) substation	May 15, 2017
Etzikom Coulee S/S to Whitla 240 kV Line	10	240 kV line from Journault to Whitla substation	May 15, 2017
240 kV lines from Goose Lake to Crowsnest/Chapel Rock substation	7	240 kV Line from Goose Lake to new Chapel Rock 500 kV substation	July 29, 2017

THE TRANSMISSION FACILITY OWNER(S): AltaLink.

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)	**$2.82 Billion**[38] (ISD$ with escalation)

CURRENT STATUS: On December 30, 2008, the AESO applied to the AUC for approval of a NID for transmission reinforcement in Southern Alberta (SATR NID). AUC Approval No. U2009-340 was issued to the AESO on September 17, 2009.

On December 7, 2009, the AESO filed the finalized milestones and monitoring process with the AUC pursuant to their direction in Decision 2009-126 (SATR NID). AUC Approval No. U2010-264 was issued to the AESO on July 19, 2010.

On December 14, 2012, the AESO filed the Goose Lake to Chapel Rock Amendment to the AUC SATR Approval No. U2011-115.

The Milo Junction Switching Station and phase-shifting transformer addition at Russell substation are in service.

The upgrades to the Ware Junction substation are in service.

The Cassils–Bowmanton and Bowmanton–Whitla components of this development are currently under construction.

The AESO filed the Medicine Hat area Amendment to the AUC SATR NID Approval No. U20111-115 on May 11, 2012. AltaLink filed a Facility Application for the Medicine Hat area development on December 3, 2012. The AUC posted Notice of Application on April 22, 2013. The NID amendment was approved August 22, 2013 and the Facility Application was approved on October 18, 2013.

AltaLink is preparing the PPS and Facility Applications for the Blackie Area 138 kV upgrade and plans to file the Facility Application in February 2014.

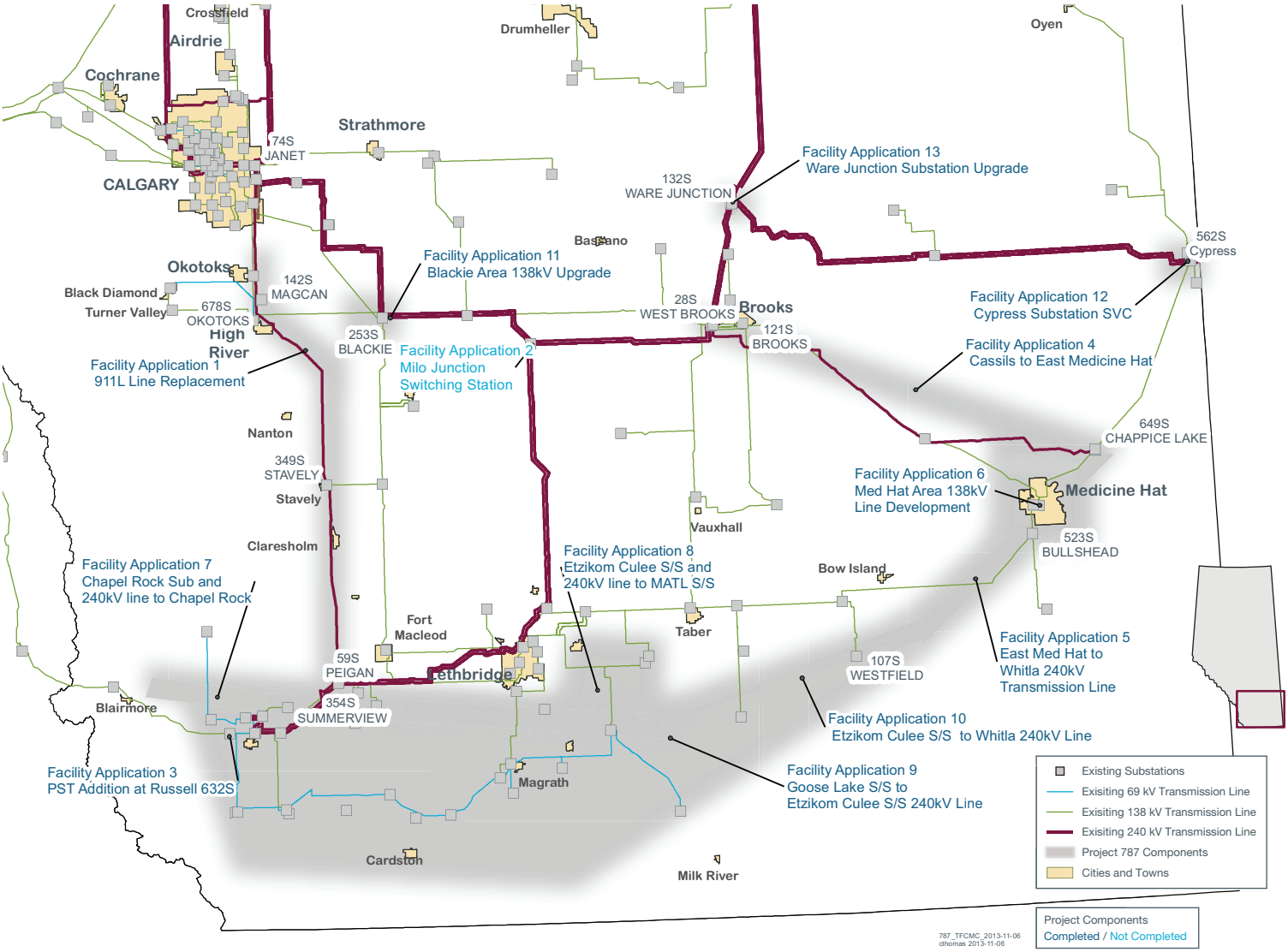
The 911L Line Replacement component of this development received Facility Application approval on October 7, 2013.

The Reactive power addition at Cypress substation has been delayed until the AESO updates the Southern Alberta Reactive Power Studies, which were completed on December 9, 2013. The Functional Spec was expected to be completed in January 2014, with a NID amendment and FA to be filed in the fall of 2014.

The AESO has received the PPS for Etzikom Coulee S/S and 240 kV line to MATL S/S and Etzikom Coulee S/S to Whitla 240 kV Line developments. AltaLink is preparing the PPS for the Goose Lake S/S to Etzikom Coulee S/S 240 kV Line development. All three of these SATR components have been temporarily put on hold while the AESO conducts an analysis related to its intertie restoration initiative, which may affect the timing of the three planned SATR components. The AESO has also requested that AltaLink delay filing its Facility Applications with the AUC for these SATR components until mid-to-late 2014.

38 For Facility Applications 7 to 12, the AESO has not yet received PPS estimates from the TFO. As such, these costs are not included in the PPS estimate total of $1.25 billion.

Project 787
Southern Alberta Transmission Reinforcement



17. ***COMPLETED* YELLOWHEAD AREA TRANSMISSION DEVELOPMENT (YATD);** PROJECT 671 – To improve reliability in the Drayton Valley, Edson 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 region.

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

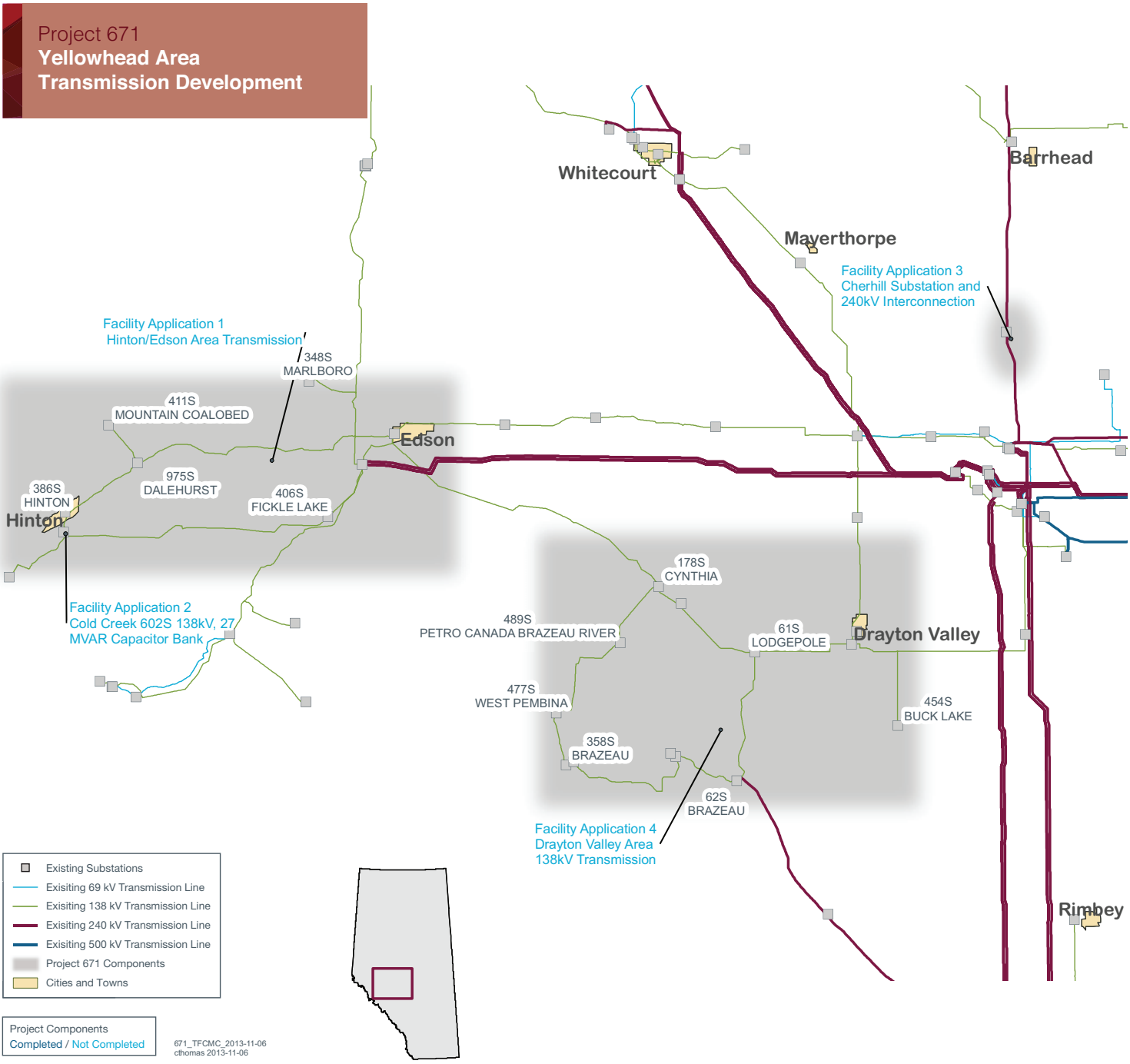
FACILITY APPLICATION NAME	FACILITY APPLICATION NUMBER	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
Cold Creek 602S 138 kV, 27 VAr Capacitor Bank	2	Cold Creek 602S 138 kV, 27 VAr Capacitor Bank	February 9, 2011
Drayton Valley Area 138 kV Transmission	4	Drayton Valley area 138 kV transmission development and cap bank installations	December 21, 2011
Cherhill Substation and 240 kV interconnection	3	Cherhill substation and 240 kV interconnection	April 2, 2012
Hinton/Edson Area Transmission	1	Hinton/Edson area 138 kV transmission upgrades	October 31, 2012

THE TRANSMISSION FACILITY OWNER(S): AltaLink.

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)	**$148 Million** (ISD$ with escalation)

CURRENT STATUS: All construction work and energizations are complete. AltaLink will complete its project close out report, including final costs, by mid-February 2014.


Project 671
Yellowhead Area
Transmission Development
Whitecourt
Barrhead
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
489S
PETRO CANADA BRAZEAU RIVER
61S
LODGEPOLE
Drayton Valley
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
Project Components
Completed / Not Completed
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Appendix C: Previously Monitored Projects

Since the TFCMC began its deliberations, the Committee has monitored a total of 18 different transmission projects. To date, three of the projects have been completed and for the purpose of TFCMC reporting are considered closed. Those undertakings, and their final costs, are below. Projects are listed alphabetically.

NORTHWEST TRANSMISSION DEVELOPMENT (NWTD); PROJECT 535 – Transmission expansion and enhancement in northwest Alberta.

FINAL PROJECT COST: $583 million | AESO 2012 LTP Estimated Cost: Not Estimated[39] | Removed from monitoring: TFCMC December 2013 Report

SOUTHERN ALBERTA TRANSMISSION DEVELOPMENT (SATD); PROJECT 416 – Transmission development in Goose Lake-Peigan and North Lethbridge region.

FINAL PROJECT COST: $238 million | AESO 2011 LTP Estimated Cost: $91 million | Removed from monitoring: TFCMC June 2013 Report

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.

EXPECTED FINAL PROJECT COST: $148 million[40] | AESO 2012 LTP Estimated Cost: $123 million | Removed from monitoring: TFCMC December 2013 Report

39 In the June 2011 TFCMC Report it was reported that the need for this project was recognized in March 2006 and the need approval was granted in August 2006 with the total project scope envisioned at $262 million. However, due to project scope changes, the value increased to $463 million. In the December 2011 TFCMC Report, the PPS estimated cost was $508 million (ISD$ with escalation but that did not include project 603, the Arcenciel synchronous condenser).

40 The figure of $148 million is the most current figure available at the time of this report. AltaLink will complete its project close out report, including final costs, by mid-February 2014.

Appendix D: TFCMC Working Documents

The TFCMC receives reports and cost summary updates, on a monthly basis, in order to 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.

Project Cost Reporting for TFCMC, Project 629: Alberta Industrial Heartland Bulk Transmission Development (HBTD); October 2013 Meeting

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 : 2013 / Oct
Month of TFO Report : 2013 / Aug

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	Nov 1,2011	Dec 7,2013	$580.69	$8.46	$589.15
2	Heartland 12S Ellerslie 89S and 1054L/1061L (Formerly P1066)	Sep 27,2010	Nov 1,2011	Dec 4,2013			
				Total:	$580.7	$8.46	$589.2

Project Comments:

Project Cost Reporting for TFCMC, Project 719: ENMAX Shepard Energy Centre (ECTP); October 2013 Meeting

Cost Committee Monthly Summary

Project 719: ENMAX Shepard Energy Centre

Project Description:
850 MW Generation Facility and Associated ENMAX No. 25 Substation - includes system work at East calgary, Janet and associated transmission upgrades.

Month of TFCMC Meeting : 2013 / Oct
Month of TFO Report : 2013 / Aug

NID Application				
Filing Date	Approval Date	TFO	NID Estimate w/ AFUDC	w/o AFUDC
10-May-11	Nov 01, 2012	AML - 1	$37.1	$34.4
		AML - 2	$33.7	$31.2
		ENMAX	$65.55	$63.14
		Total	$136.3	$128.8

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	FA1 - AltaLink Facilities	Jun 27,2011	Nov 8,2012	Jun 30,2015	$70.77	-$5.07	$65.70
2	FA2 - Enmax Facilities	Jun 10,2011	Nov 8,2012	Jun 30,2015	$65.55	$1.30	$66.85
				Total:	$136.32	-$3.78	$132.54

Project Comments:

Changes from Last Month:

Energization of the Shepard Energy Centre interconnection (ENMAX No. 25 substation to 911L) completed September 30, 2013.

FA#1
• Pending AltaLink change proposals received on June 28, 2013 totally $13.7 million are under final review by the AESO.

FA#2
• Inquiry sent to TFO regarding variance on Authorized Changes total.

Project Cost Reporting for TFCMC, Project 737: North South Transmission Reinforcement (HVDC) – Eastern Alberta Transmission Line; October 2013 Meeting

Cost Committee Monthly Summary

Project 737: North South Transmission Reinforcement - EATL

Project Description:
Construction of a +- 500KV bipolar HVDC transmission line from the vicinity of Heartland substation to the vicinity of West Brook substation. Initial development will be a monopole with at least 1000 MW transfer capacity.

Month of TFCMC Meeting : 2013 / Oct
Month of TFO Report : 2013 / Aug

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	Nov 15,2012	Dec 15,2014	$1,598.76	-$2.55	$1,596.20
3	Facility Application 3 - AltaLink East DC Facilities (Currently known to TFO as P961)	May 1,2011	Nov 15,2012	Dec 15,2014	$39.35	$19.68	$59.03
4	Facility Application 4 - EPCOR East DC Facilities (Currently known to TFO as P961)	Mar 30,2011	Nov 15,2012		$0.12	-$0.11	$0.01
				Total:	$1,638.23	$17.01	$1,655.24

Project Comments:

• Received Change Proposal from ATCO for $206 M and review in process including a meeting with ATCO.
• AESO has received 180 day PPS updated estimate from ATCO but not from AltaLink on the interconnections.

Project Cost Reporting for TFCMC, Project 737: North South Transmission Reinforcement (HVDC) – Western Alberta Transmission Line; October 2013 Meeting

Cost Committee Monthly Summary

Project 737: North South Transmission Reinforcement - WATL

Project Description:

Construction of a 500kV HVDC transmission line from the vicinity of the Genesee substation to the vincinity of the Langdon substation. Initial development will be a monopole with 1000 MW transfer capacity.

Month of TFCMC Meeting : 2013 / Oct
Report for the Month of : 2013 / Aug

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
2	Facility Application 2 - AltaLink West DC Facilities (Currently known to TFO as P962)	Mar 1,2011	Dec 6,2012	Apr 22,2015	$1,420.19	$37.69	$1,457.88
				Total:	$1,420.19	$37.69	$1,457.88

Project Comments:

- AltaLink to provide the180 Day PPS update early October.

Project Cost Reporting for TFCMC, Project 786: Edmonton Region 240 kV Line Upgrades (ERLU); October 2013 Meeting

Cost Committee Monthly Summary

Project 786: Edmonton Region 240 kV Line Upgrades

Project Description:

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

Month of TFCMC Meeting : 2013 / Oct
Report for the Month of : 2013 / Aug

NID Application				
Filing Date	Approval Date	TFO	NID Estimate w/ AFUDC	w/o AFUDC
26-Aug-08	Feb 24, 2009	AML	$77.3	$72.6
		EPCOR	$9.5	$9.0
		ATCO	$38.68	$35.81
		TransAlta		
		Total	$125.4	$117.4

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	$12.66	$114.01
2	AML Rebuild 240kV 904L (1043L)	Jul 28,2010	Aug 12,2011	Feb 3,2014			
4	AML 902L Restring & 909L Retermination **(Formerly P1057)**	Aug 5,2011	Oct 31,2012	Feb 3,2014			
5	AML 908L, 909L Restring **(Formerly P1058)**	Sep 13,2009	Feb 10,2010	Mar 20,2011			
6	Epoch Jasper, Petrolia (Formerly P955)	Apr 15,2010	Jun 16,2010	Jun 14,2011	$4.55	$2.60	$7.15
3	EPCOR 1044EL, 1045EL **(Formerly P955)**	Oct 15,2010	Aug 12,2011	Feb 29,2012	$7.97		$7.97
7	ATCO Phase Shifter **(Formerly P957)**	Sep 14,2009	Mar 25,2010	Aug 20,2013	$31.51	$8.00	$39.51
8	TransAlta 902L, 1043L **(Formerly P959)**	Aug 5,2011	Oct 31,2012	Feb 3,2014	$9.65		$9.65
				Total:	$155.0	$23.3	$178.3

Project Comments:

- FA 2, 4 and 8 are all associated with 1043L. The work on 1043L is delayed because of land access negotiations.

Project Cost Reporting for TFCMC, Project 787: Southern Alberta Transmission Reinforcement (SATR); October 2013 Meeting

Cost Committee Monthly Summary

Project 787: Southern Alberta Transmission Reinforcement

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

Month of TFCMC Meeting : 2013 / Oct
Month of TFO Report : 2013 / Aug

NID Application				
Filing Date	Approval Date	TFO	NID Estimated w/ AFUDC	w/o AFUDC
30-Dec-08	Sep 17, 2009	Stage I	$829.7	$829.7
		Stage II	$722.1	$722.1
		Stage III	$279.1	$279.1
		AFUDC & Escalation in NID	$1,612.0	$1,486.0
		Total	$3,442.9	$3,316.9

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	911L Line Replacement (Formerly P882)	Sep 25,2012	Nov 11,2013	Sep 22,2015	$440.17	-$29.58	$410.59
2	Milo Junction Switching Station (Formerly P883)	Dec 21,2009	Aug 5,2010	Nov 1,2011	$29.70	$0.47	$30.17
3	PST Addition at Russell 632S (Formerly P884)	Aug 27,2010	Jan 12,2011	Apr 25,2012	$17.21	-$0.08	$17.13
4	Cassils to Bowmanton (Formerly P886)	Jul 27,2010	Jun 8,2011	Nov 12,2013	$407.91	-$48.54	$359.37
5	Bowmanton to Whitla 240kV Transmission Line (Formerly P887)	Jul 27,2010	Jun 8,2011	Mar 31,2014	$352.75	-$42.21	$310.54
6	Med Hat Area 138kV Line Development (Formerly P888)	Dec 3,2012	Dec 15,2013	May 22,2015	$120.28	-$4.36	$115.92
7	Goose Lake to Chapel Rock 240 kV Line (Formerly P1034)	Oct 14,2014	Nov 15,2015	Jul 29,2017			
8	Etzikom Coulee S/S and 240kV line to Picture Butte S/S (Formerly P1035)	May 29,2014	May 29,2015	May 15,2017			
9	Goose Lake S/S to Etzikom Coulee S/S 240kV Line (Formerly P1036)	Feb 28,2014	Mar 28,2015	Jan 1,2017			
10	Etzikom Coulee S/S to Whitla 240kV Line (Formerly P1037)	May 23,2014	May 25,2015	May 15,2017			
11	Blackie Area 138kV Upgrade (Formerly P1038)	Feb 17,2014	Aug 1,2014	Jul 15,2015			
12	Reactive Power Addition to Cypress 562S (Formerly P1039)	Jul 18,2014	Dec 22,2014	Jul 20,2015			
13	Ware Junction Substation Upgrade (Formerly P1040)	Apr 5,2011	Feb 6,2012	Nov 15,2013	$6.13	$0.47	$6.61
					$1,374.16	-$123.83	$1,250.32

Project Comments:
Changes:

#13: Change Proposal approved.

Project Cost Reporting for TFCMC, Project 791: North Fort McMurray Transmission Development (NFMD); October 2013 Meeting

Cost Committee Monthly Summary

Project 791: North Ft McMurray Transmission Development

Project Description:
North Ft McMurray Transmission Development

Month of Reporting : 2013 / Oct
Report for the Month of : 2013 / Aug

NID Application				
Filing Date	Approval Date	TFO	NID Estimated w/ AFUDC	w/o AFUDC
12-Aug-10	Jun 24, 2011	ATCO	$237.4	$214.9
		Total	$237.4	$214.9

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	North Fort McMurray 240 kV Transmission Development	Sep 10,2010	Jul 28,2011	Nov 29,2013	$237.4	$119.8	$357.2
				Total:	$237.4	$119.8	$357.2

Project Comments:
• In service date delayed because of McLelland substation construction delays

Project Cost Reporting for TFCMC, Project 811: Central East Area Transmission Development (CETD); October 2013 Meeting

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

Month of TFCMC Meeting : 2013 / Oct
Report for the Month of : 2013 / Aug

NID Application				
Filing Date	Approval Date	TFO	NID Estimated Cost	w/o AFUDC
17-May-10	Feb 10, 2011	Stage-1 ATCO	$166.4	$160.6
		Stage-1 AML	$143.8	$133.5
		Stage-2 ATCO	$60.10	$57.99
		Escalation in NID	$60.70	$60.70
		Total	$431.0	$412.8

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	FA 1 - Cold Lake Area Reinforcements - No Bonnyville Substation	Mar 7,2012	Dec 13,2012	Oct 1,2013	$141.08	$54.83	$195.92
2	FA 2 - Cold Lake Area Reinforcements - Bonnyville Substation Only	Apr 27,2012	Aug 1,2013	Dec 1,2014			
3	FA 3 - St. Paul Area Upgrades - Watt Lake, 7LA92	Dec 23,2011	Mar 1,2013	Nov 1,2013	$50.85	$27.80	$78.65
4	FA 4 - St. Paul Area Upgrades - St. Paul 707S, 7L139/7L70	Jul 19,2012	Oct 1,2013	Aug 1,2014			
5	FA 5 - Vermillion 710S Substation Upgrade	Oct 24,2011	May 16,2012	Aug 1,2013	$6.70	$2.92	$9.62
6	FA 6 - Heisler Area Upgrades	Dec 23,2011	Feb 27,2012	Jul 11,2013	$31.48	$14.69	$46.17
7	FA 7 - Kitscoty Area Upgrades	Jun 13,2012	May 9,2013	Dec 1,2013			
8	FA 8 - 7L749 Replacement **(Cancelled)**	Jul 1,2013	Aug 1,2014	Mar 1,2015	$34.20		$34.20
9	FA 9 - 7L701 Line Clearance Mitigation (Letter Of Enquiry)	Oct 24,2011	Feb 27,2012	Jul 11,2013	$13.28		$13.28
10	FA 10 - Provost & Wainwright Area Upgrades	Sep 6,2013	Mar 21,2014	Jun 1,2015			
11	FA 11 - 7L50 Rebuild **(Cancelled)**	Nov 1,2013	May 16,2014	Oct 9,2015			
12	FA 12 - Cold Lake Reinforcement (2017) - 240kV	Sep 7,2015	Mar 21,2016	Dec 1,2017			
				Total:	**$277.59**	**$100.24**	**$377.83**

Project Comments:

Project Cost Reporting for TFCMC, Project 812: Hanna Region Transmission Development (HATD); October 2013 Meeting

Cost Committee Monthly Summary

Project 812: Hanna Region Transmission Development

Project Description:
Transmission development in Hanna, Sheerness and Battle River

Month of TFCMC Meeting : 2013 / Oct
Month of TFO Report : 2013 / Aug

NID Application				
Filing Date	Approval Date	TFO	NID Estimated Cost	w/o AFUDC
14-Aug-09	Apr 29, 2010	AML	$228.1	$211.6
		ATCO	$643.9	$600.7
		Escalation in NID	$110.7	$110.7
		Total	$982.7	$922.9

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	Youngstown 772S Capacitor bank addition (Formerly P977)	Aug 9,2010	Nov 15,2010	Oct 6,2011	$6.29	-$0.36	$5.93
2	Battle River 757S Capacitor Bank addition (Formerly P978)	Aug 9,2010	Aug 27,2010	Oct 3,2011	$3.00	-$0.17	$2.83
3	New Lanfine 240/144kV substation (Formerly P979)	Dec 21,2010	May 8,2012	May 20,2013	$38.75	-$2.20	$36.54
4	Lanfine 959S 200MVAr SVC (Formerly P980)	Mar 4,2011	May 8,2012	Dec 3,2013	$39.36	-$2.24	$37.12
5	Lanfine-Oyen 144kV S/C Line 7L132 (Formerly P982)	Mar 21,2011	May 8,2012	Jul 15,2013	$15.62	-$0.89	$14.73
6	Relocate 7L98 Oyen 767S - Lanfine 959S (Formerly P995)	Mar 21,2011	Dec 22,2011	Jun 1,2013	$12.77	-$0.73	$12.04
7	Oakland 946S 240kV S/S combined with Anderson-Oakland line (Formerly P996)	Nov 25,2010	May 8,2012	Mar 25,2013	$45.47	-$1.72	$43.75
8	Oakland-Lanfine 240kV S/C Line 9L924 (Formerly P998)	Dec 21,2010	May 8,2012	May 21,2013	$119.93	-$3.05	$116.88
9	Coyote Lake 963S 240kV S/S combined with Oakland-Coyote line (Formerly P999)	Feb 7,2011	May 8,2012	May 17,2013	$77.80	-$4.42	$73.38
10	Coyote Lake 963S - Michichi Creek 802S 144kV SC Line 7L128 (Formerly P1000)	Apr 8,2011	May 8,2012	Jul 12,2013	$39.25	-$2.23	$37.02
11	Pemukan 932S 240 kV Substation (Formerly P1001)	Jan 24,2011	May 8,2012	Jun 1,2013	$32.49	-$1.85	$30.64
12	New Lanfine-Pemukan 240kV S/C Line 9L46 (Formerly P1003)	Mar 3,2011	May 8,2012	Jun 1,2013	$97.24	-$5.15	$92.09
13	Facility Application 13 - 144kV Capacitor Bank and Circuit Breaker Additions at Three Hills Substation 770S (Formerly P1022)	Oct 8,2010	Dec 23,2010	Dec 13,2011	$27.04	-$1.54	$25.50
18	Rowley 768S - Michichi-Three Hills 144kV DC Line 7L25 (Formerly P1022)	Nov 15,2010	May 17,2011	Jun 1,2012			

Project Cost Reporting for TFCMC, Project 813: Red Deer Region Transmission Development (RDTD); October 2013 Meeting

Cost Committee Monthly Summary

Project 813: Red Deer Area Transmission Development

Project Description:

P813 - 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 : 2013 / Oct

Month of TFO Report : 2013 / Aug

NID Application				
Filing Date	Approval Date	TFO / Stage	NID Estimated w/ AFUDC	w/o AFUDC
20-Jul-11	Apr 10, 2012	AML Stage 1	$207.8	$196.4
		AML Stage 2	$15.0	$14.1
		Total	$222.8	$210.6

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	Sep 27,2012	Nov 29,2013	$20.72	$10.28	$31.00
2	Red Deer Area Transmission Development Stage I - Rebuilds & Greenfields	Jun 18,2013	Jun 27,2014	Dec 26,2014	$316.784	$5.53	$322.32
4	RDATD Facility Application 4 - 166L Rebuild	Aug 23,2013	Nov 25,2013	Jun 26,2015			
5	RDATD Stage II 2017 Facilities	Oct 25,2016	May 9,2017	Nov 7,2017			
3	RDATD Facility Application 3 - Salvage	Dec 13,2013	Jan 9,2015	Jul 10,2015		$3.07	$3.07
				Total:	$337.5	$18.89	$356.4

Project Comments:

- ISD's for FA#1 expected to be fall 2013 as a result of AML not obtaining plant outages and a result of other construction delays.
- FA#2 was combined as one submission to the AUC for Line Rebuilds and Greenfields. For future TFO reports, the current FA#2 and FA#3 costs will be combined into one FA#2. New FA#3 will be "Salvage" costs.
- FA#4 filing of FA has been delayed by TFO's regulatory review process. Expected to be filed in October 2013.

Project Cost Reporting for TFCMC, Project 850: South and West of Edmonton Transmission Development (SWEATR); October 2013 Meeting

Cost Committee Monthly Summary

Project 850: South and West of Edmonton Transmission Development

Project Description:

Area south and west of EdmontonTransmission Development
Sequential Filing
Formerly Leduc/Parkland/Wetaskiwin Area Upgrade

Month of TFCMC Meeting : 2013 / Oct

Month of TFO Report : 2013 / Aug

NID Application				
Filing Date	Approval Date	TFO / Stage	NID Estimated w/ AFUDC	w/o AFUDC
14-Dec-12		P850 Total	$172.2	$172.2
		Total	$172.2	$172.2

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 - Harry Smith Sub	Jul 18,2014	Jan 30,2015	Dec 30,2016			
2	Facility Application 2 - New Saunders Lake 240/138kV Substation Development	Aug 8,2014	Feb 20,2015	Jan 20,2017			
4	Facility Application 4 - Re-terminate 914L at Saunders Lake & Up-rate 910L, 914L & 723L	Aug 8,2014	Feb 20,2015	Jan 20,2017			
5	Facility Application 5 - New Capacitor Bank at Leduc 325S	Nov 14,2014	May 29,2015	Apr 28,2017			
3	Facility Application 3 - New 138kV Line from 780L to Cooking Lake and Reconfiguration	Aug 8,2014	Feb 20,2015	Jan 20,2017			
				Total:			

Project Comments:

- PPS and FA Filing is pending.

Project Cost Reporting for TFCMC, Project 922: ENMAX No. 65 Substation (ESCS); October 2013 Meeting

Cost Committee Monthly Summary

Project 922: ENMAX No. 65 Substation

Project Description:
New 240 kV / 138 kV substation in south Calgary and associated transmission facilities

Month of TFCMC Meeting : 2013 / Oct
Month of TFO Report : 2013 / Aug

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	Sep 30,2013	$31.14		$31.14
2	AML- No. 65 I/C to 911L	Feb 16,2011	Nov 3,2011	Sep 30,2013	$6.90	$0.65	$7.56
				Total:	$38.0	$0.65	$38.7

Project Comments:
Changes from last month:

FA 1 and 2
• Energization completed on September 30, 2013.

Project Cost Reporting for TFCMC, Project 1101: Christina Lake Area Development (CHL); October 2013 Meeting

Cost Committee Monthly Summary

Project 1101: Christina Lake Area Development

Project Description:
Christina Lake Area Development

Month of TFCMC Meeting : 2013 / Oct
Month of TFO Report : 2013 / Aug

NID Application				
Filing Date	Approval Date	TFO / Stage	NID Estimated w/ AFUDC	w/o AFUDC
20-Oct-11	Apr 24, 2012	AML	$394.9	$360.0
		ATCO	$11.7	$11.7
		Total	$406.6	$371.7

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 - CHL1 Black Spruce 154S	Jul 23,2012	Dec 24,2012	Jul 10,2013	$19.96	$11.77	$31.73
2	Facility Application 2 - Black Spruce 154S to Pike 170S	Jan 18,2013	Jun 28,2013	Jun 30,2014	$116.15	$2.57	$118.72
3	Facility Application 3 - Pike 170S to Ipiatik Lake 167S	Mar 28,2013	Dec 27,2013	Jun 30,2015	$256.74	$7.20	$263.94
4	Facility Application 4 - ATCO Heart Lake 898S	Oct 10,2013	Jul 10,2014	Sep 18,2015	$26.05		$26.05
				Total:	$418.9	$21.5	$440.4

Project Comments:
• AFUDC was included in the NID estimates - AFUDC is not included in the PPS estimates
• Ipiatik Lake FA 3 - FA filed
FA 4 Heart Lake PPS has been accepted Notice to File issued

Project Cost Reporting for TFCMC, Project 1117: Foothills Area Transmission Development – East Calgary Development (FATD); October 2013 Meeting

Cost Committee Monthly Summary

Project 1117: FATD - East Calgary Development

Project Description:

Project 1117 - East Calgary Development, including:

-New 240kV line(s) from Foothills 237S to Enmax 65S
-Re-energization of 850L from 65S to 102S
-Salvage 727L from 850L junction to Janet 74S

Month of Reporting : 2013 / Oct
Report for the Month of : 2013 / Aug

NID Application				
Filing Date	Approval Date	TFO	NID Estimate w/ AFUDC	w/o AFUDC
July 5, 2012	Oct 7,2013	AltaLink	$439	$414
		ENMAX	$4	$3
		Total	$443	$417

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 - Foothills-Enmax 65S AltaLink Facilities	Jul 13,2012	Oct 7,2013	Jul 30,2015	$247.94	-$15.99	$231.95
2	Facility Application 2 - Foothills-Enmax 65S Enmax Facilities	Jul 13,2012	Oct 7,2013	May 25,2015	$4.29		$4.29
3	Facility Application 3 - East Calgary-Janet-Langdon AltaLink Facilities	Jul 16,2012	Oct 7,2013	Jul 30,2015	$81.98	-$5.43	$76.55
4	Facilty Application 4 - East Calgary-Janet-Langdon AltaLink Enmax Facilities	Jul 13,2012	Oct 7,2013	May 25,2015	$22.66		$22.66
5	Facility Application 5 - 138kV from 237S to Okotoks AltaLink Facilities	Jul 16,2012	Oct 7,2013	May 12,2015	$86.59	-$4.73	$81.85
				Total:	$443.5	-$26.1	$417.3

Project Comments:

Changes from last month:

• AUC approved NID and FA's on October 7, 2013.

Project Cost Reporting for TFCMC, Project 1180: Northwest Fort McMurray Transmission Development (NW FMM); October 2013 Meeting

Cost Committee Monthly Summary

Project 1180: NW Ft McMurray Transmission Development

Project Description:

NW Ft Mac Transmission Development

Month of TFCMC Meeting : 2013 / Oct
Month of TFO Report : 2013 / Aug

NID Application				
Filing Date	Approval Date	TFO / Stage	NID Estimated Cost	w/o AFUDC
10-Nov-11	Jun 19, 2012	Stage I	$21.0	$21.0
		Stage II	$156.1	$156.1
		Stage III	$189.19	$189.19
		Total	$366.3	$366.3

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 - Birchwood Creek/9L95/Ells River	Jun 5,2013	Nov 20,2013	Oct 30,2014	$175.12		
2	Facility Application 2 - Ells River/9L08/9L76	Jun 5,2013	Nov 20,2013	Apr 15,2015	$195.69		
				Total:	$370.8		

Project Comments:

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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 December 2013 Report.

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

March 5, 2014

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

Henry,

AltaLink has now had the opportunity to review the TFCMC's sixth semi-annual Transmission Cost Monitoring Committee Report. AltaLink continues to be supportive of industry dialog regarding industry practices which determine how transmission projects are built.

AltaLink is of the view that the recommendations set forth at paragraph 30 are fundamentally flawed.

The AESO's role, in part, is to review the reasonableness of project costs through project execution through change notices and monthly reporting. The suggestion that project costs can be somehow "fixed" at the PPS stage is inconsistent with historical practises but, further, fails to appreciate the challenges that may be encountered in the consultation, siting, regulatory hearing process and construction of major transmission projects. The AESO has an ongoing role, as it reviews change orders, to reaffirm as system planner that the project is required as it assesses changes to costs. The TFOs are subject to the directions of the AESO and it is again flawed to suggest that the AESO be limited to simply reviewing changes in scope and ISDs.

The TFCMC's recommendation will result in a significant increase in the risk profile of TFOs. Recommendations cannot and should not be advanced in a vacuum with a sole focus on costs to the exclusion of all other relevant factors. The suggestions that a TFO should be subjected to all risk of increased costs post the issuance of a PPS will result in a very significant increase in the risk assessment of the utility and inevitably will impact the cost of capital.

If there is to be a change to the rules, they cannot be done retroactively. If changes are to be made, they must be accomplished through a full consultative process that involves all stakeholders. AESO rules are subject to review and oversight by the AUC and, given the gravity of the changes being apparently recommended, this process should be followed.

AltaLink would be supportive of an examination of the current rules for project cost estimation. Alberta now has the experience of the significant delays and challenges in siting and constructing major transmission lines. In AltaLink's view, this experience informs and guides the development of a workable rule for the estimation of projects, especially when there may be significant delays between the PPS and actual construction.

The Alberta Energy Initiatives workshop recommended that if costs are to have a soft cap, that should occur 180 days post the granting of permit and license. This recommendation recognizes that only after the transmission project is approved and costs are firmed up through competitive processes is it reasonable to impose a soft cap. This recommendation is logical and recognizes the experiences in this

Transmission Facility Owners Responses

ALTALINK

Province in the consultation, siting, approval and cost assessment of major transmission development. AltaLink considers that the recommendation contained in the Sixth Report to be diametrically opposed to the recommendation of the industry working group.

The reference to escalation factors and the project contingencies cannot capture the risk of procedural delays for contentious projects. This is why the industry working group has recommended the approved cost estimate (ACE) occur 180 days after permit and license.

AltaLink is concerned that the TFCMC's proposed recommendations do not align with the initiatives discussed at the Transmission Cost Management Policy Development Workshops hosted by Alberta Energy in 2013. First, the recommendations imply that the only factor to be considered to optimize project delivery is cost. There is no sensitivity to the statutory framework within which the AESO and TFOs operate. TFOs are obligated to comply with mandatory directions for the construction of much needed transmission infrastructure.

Given the significant stakeholder engagement in the Alberta Energy initiatives, AltaLink would recommend that the TFCMC allow the AE initiatives to be implemented and align its recommendation to support the recommendations of the industry groups participating in AE forum. In particular, the Approved Cost Estimate (ACE) and Cost Oversight Manager (COM) function, should address many of the TFCMC concerns.

AltaLink's additional comments on other sections of the report are set forth below:

Section 2 of your report, *TFCMC Observations to Date*, summarizes observations regarding a wide variety of topics reviewed by the Committee since the TFCMC's last report. Of note, the cost of the HVDC converter stations has been discussed once again.

AltaLink has previously commented in prior semi-annual Transmission Cost Monitoring Committee Reports concerning the challenges of benchmarking transmission projects across jurisdictions as there are significant cost drivers that impact the cost of building transmission projects. Mr. Bill Smith, Senior Vice President of Siemens answered all of the cost differential concerns when he presented to the TFCMC. The price of the converters is based on supply and demand factors at the time of the bid and is based on the location of the converter installation. As many other construction projects across all industry sectors in the province have discovered, Alberta is an expensive place to source construction labor. This should not be a surprise to anyone. The primary reason for the difference in price is Alberta based labour rates. There was nothing substantial left to explain as this Report to the extent it remains unchanged would otherwise indicate. The Alberta Utilities Commission ("Commission") in Decision 2013-407 (page 90), also found AltaLink's forecast for the WATL HVDC converter stations to be reasonable for revenue requirement purposes.

Also in Section 2 of the Report, North South Transmission Reinforcement Cost Increases, it should be noted that unit rate increases for the WATL project tower assembly are the outcome of competitively tendered contracts.

Transmission Facility Owners Responses

ALTALINK

In section 2 of the report, Transmission Line Helicoptering, the TFCMC comments that the helicopter cost estimate provided in the 2013 /2014 AltaLink General Tariff Application (GTA) for the Cassils to Bowmanton and Bowmanton to Whitla projects were untested. We disagree. The estimates were tested through the GTA process as the commission and the intervener had full opportunity to question the information. The redacted information was commercially sensitive information and although not visible supported the conclusion of the analysis. What was demonstrated was that helicopters were not a more expensive solution. The choice of construction methodology was a prudent choice. Both helicopter tower erection and crane erection are effective methods of erection.

Respectfully, it is AltaLink's view that it is not within the TFCMC's mandate to opine on whether long standing AUC confidentiality requirements of the Commission are "onerous" or otherwise.

Furthermore as reflected in Section 4, the report incorrectly characterizes the Commission's decision on AltaLink's competitive procurement process from the 2013/2014 AltaLink GTA. The AUC did not direct AltaLink to return to the old rates. The AUC directed AltaLink to use the old rates for the purposes of forecasting its revenue and advised that the new rates would be tested through the deferral account process. This is a significant distinction and the AUC comments are captured below for clarity:

> "**For purposes of forecasting the capital expenditures** related to those projects allocated to SNC-ATP and B&M pursuant to the new relationship agreements, AltaLink is directed to use the same rates as above, namely, the two times labour multiplier and other approved mark-ups". (p732, highlight added)

In addition, the actual EPC costs incurred by AltaLink will be included in future DACDA proceedings. AltaLink remains confident that these costs will be determined to be prudently incurred.

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

Johanne Picard-Thompson
SVP Projects, AltaLink

.cc Jerry Mossing, VP AESO

Transmission Facility Owners Responses

2000 – 10423 101 St NW, Edmonton, AB
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March 3, 2014

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

Dear Mr. Yip,

RE: TFCMC December 2013 Report

EDTI appreciates the opportunity to comment on the December 2013 Report from the Transmission Facilities Cost Monitoring Committee ("TFCMC" or the "Committee"). EDTI remains 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 – TFCMC Conclusions & Recommendations, and in particular the subsection describing the TFCMC's Recommendations. EDTI is concerned that the recommendations proposed by the TFCMC are not aligned with the initiatives discussed at the Transmission Cost Management Policy Development Workshops hosted by Alberta Energy ("AE") in 2013. EDTI believes that we, as an industry, should allow AE to continue working with stakeholders (the AESO, the AUC, TFOs, consumer advocacy groups, and generator and customer associations) to implement the initiatives that have been discussed and proposed through those workshops, and that other recommendations being proposed take into consideration those discussions and proposed initiatives.

To illustrate, one of the initiatives AE has proposed is the creation of an approved cost estimate ("ACE") that would be subject to AUC approval to increase confidence in both the reasonableness of transmission costs incurred and in the potential reduction of project cost reviews during tariff and Direct Assign Capital Deferral Account proceedings. Amended ACE estimates would also be subject to AUC approval. Contrary to AE's proposed ACE, the Committee proposes that the AESO review and approve changes in cost estimates. Further, the AESO does not have the authority or jurisdiction to approve the prudence of transmission costs incurred, which the TFCMC recommendation appears to imply.

EDTI will continue to support the Committee's and AE's efforts to improve accountability for transmission projects in Alberta. If you have any questions about EDTI's comments, please do not hesitate to contact me at 780.441.7111.

Regards,

Jay Baraniecki
Director, EDTI Regulatory Affairs

- 1 -

Transmission Facility Owners Responses

ATCO Electric

March 6, 2014

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 – December 2013 Report

Thank you for the opportunity to review and comment on the Transmission Facilities Cost Monitoring Committee's (TFCMC) sixth report dated December 2013.

As mentioned in our comments on the TFCMC's June 2013 report, ATCO Electric (ATCO) remains committed to cooperating with all interested parties and working on a collaborative basis to help the TFCMC achieve its mandated objectives. ATCO is, however, concerned with some of the comments contained in the following sections of the report:

- **Section 4, TFCMC Conclusions and Recommendations (p. 30)**

  "TFOs should be accountable to the Regulator for their cost estimates if there is no change to the in-service date or project scope….it is imperative that any cost change proposals should be subjected to rigorous regulatory scrutiny. The committed project in-service date and scope must be honoured even if the proposed cost changes were to be disallowed by the Regulator."

  "The Committee recommends that the AESO take the necessary steps to change the relevant rules so that it is clear that it will only review change orders for scope and in-service date changes."

Although escalation and contingency amounts are included in cost estimates, it is not reasonable to assume those amounts can accommodate all possible unforseen or uncontrollable circumstances and the total cost impact they might have.

Ultimately, all costs are subject to review by the Regulator to assess prudency, but the AESO's role, as stated in Section 25(1) of the *Transmission Regulation*, is to make rules to ensure that the cost estimates prepared by a TFO are reasonable for the purpose of transmission system planning

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Transmission Facility Owners Responses

ATCO Electric

decisions. If the recommendation is implemented, the AESO will not be in a position to revisit its mandated in-service date and scope of work, and assess the impact on cost estimates, as and when unforeseen or uncontrollable events materialize during the project lifecycle. This recommendation assumes that the risk and impact of such decisions on costs will have to be managed and borne solely by the TFO and could materially impact the business risks faced by the TFO. Therefore, a re-assessment could be required for the rate of return earned by TFOs to ensure that this rate is fair and reflects, among other things, the additional business risks associated with the proposed change.

This recommendation should be reviewed more thoroughly in light of DOE cost management initiatives, which give authority to the AUC to approve cost estimates.

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

Dennis A. DeChamplain, C.A.
Senior Vice President, Finance and Regulatory

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DECEMBER 2013 REPORT

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