



# AESO 2013 Long-term Transmission Plan



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## 1.0 Executive Summary

The *2013 Long-term Transmission Plan* (2013 LTP or Plan) is the Alberta Electric System Operator's (AESO) vision of how Alberta's electric transmission system needs to be developed to secure continued provincial economic growth over the next 20 years, specifically out to 2032. Transmission infrastructure remains a key component in enabling Alberta's \$312 billion economy by providing the safe, reliable, and efficient delivery of wholesale electrical energy throughout the province.

The safe and reliable delivery of electricity is essential to ensuring Alberta's long-term growth and continued standard of living. Beyond the physical aspects of transmission infrastructure, the 2013 LTP explores the interdependencies of maintaining a competitive electricity market, serving growing demand, facilitating long-term adequacy of generation, and incorporating new and emerging renewable generation technologies.

Transmission builds are typically long lead time endeavours subject to substantial regulatory, environmental and stakeholder review. Transmission infrastructure, once built, provides long service life of 40 or more years and must accommodate both near-term and long-term needs. The Alberta Interconnected Electric System (AIES) must operate as part of a larger North American interconnected system, and must be planned accordingly to comply with North American standards and practices.



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The Plan provides the latest comprehensive evaluation of the transmission system, satisfies Alberta Reliability Standards (ARS), and incorporates the most recent forecasts of load, generation and overall economic activity in Alberta. The Plan identifies and recommends transmission solutions to address existing and anticipated constraints and performance issues throughout the transmission system. This enables load and generation customers to connect to the grid, thereby ensuring the AIES continues to meet the province's current and future electricity needs.

The comprehensive regional transmission plans that serve to form part of the Plan identify specific projects and take into account key metrics such as technology, planning need dates, projected in-service dates and staging, where practical. In order to develop a robust plan over a 20-year study period, the AESO models and presents details in three distinct time intervals: near term (to 2017); medium term (2018 to 2022); and long term (2023 to 2032).

This Plan is supplemented by complementary publications such as the annually produced *24-Month Reliability Outlook*, annual *Alberta Reliability Standards (ARS) Compliance Report*, the bi-annual *Review of the Cost Status of Major Transmission Projects in Alberta*, and the *Transmission Projects Quarterly Report*. These publications periodically track and publish updates to key inputs to the Plan, reflect adjustments to project scope, and communicate the progress of projects or initiatives contained in the LTP. In addition, in June 2013 the AESO introduced the *Long-term Plan Progress Report* that provided updates to the progression of transmission projects identified in the 2012 LTP. The AESO is committed to continuing this practice by publishing Progress Reports to the 2013 LTP and future Plans.

The AESO is guided by the Province of Alberta's *Electric Utilities Act*<sup>1</sup> (EUA), the *Transmission Regulation*<sup>2</sup> (T-Reg), and public policy such as the direction articulated in the 2003 *Transmission Development Policy*<sup>3</sup>. The AESO is mandated to plan a transmission system that is free of constraint<sup>4</sup>, satisfies Alberta reliability standards, and is in the public interest.

Ensuring transmission facilities are available to accommodate forecast load and generation, as well as planning for an unconstrained system, provides the certainty generation investors need to invest in the Alberta electricity market. Further, it gives those in other industries the confidence to do business in the province, knowing that power will be there when they need it. Alberta's future prosperity depends upon a reliable transmission system and a competitive electricity market.

When planned transmission facilities are deferred or delayed beyond identified need dates, the AESO designs and implements system operation protocols and market products or rules as short-term mitigation strategies aimed at addressing these delays. These solutions serve as bridging mechanisms to enable reliable system operation until new transmission facilities can be constructed.

New to the 2013 LTP is the introduction of the AESO's Competitive Process (CP). The AESO was directed by the Government of Alberta<sup>5</sup> to develop a new procurement process to select an organization to develop, design, build, finance, own, operate and maintain new major transmission infrastructure in the province. The Fort McMurray West 500 kV Transmission Project is the first transmission project to be subject to CP.



AESO file photograph.

<sup>1</sup> SA 2003, C.E-5.1

<sup>2</sup> A/R 86/2007

<sup>3</sup> Alberta Energy, *Transmission Development: The Right Path for Alberta*, Nov. 2003

<sup>4</sup> See s. S.15(1)(e) of the T-Reg for a full listing of requirements for the LTP

<sup>5</sup> See s. 24.2(1) of the T-Reg regarding Competitive Process



## 1.1 ASSUMPTIONS AND INPUTS

Since filing the 2012 LTP in June 2012, the AESO has completed the *2012 Long-term Outlook* (2012 LTO), a comprehensive forecast reflecting the latest provincial economic growth numbers, adjusted load and generation forecasts and incorporating the most recent customer connection requests. This information was further updated in the *2012 Long-term Outlook Update* (2012 LTOU). Both publications are available on the AESO's website at [www.aeso.ca](http://www.aeso.ca). These reports serve as significant inputs to the transmission assessment modeling and ultimately the refreshing of the Plan.

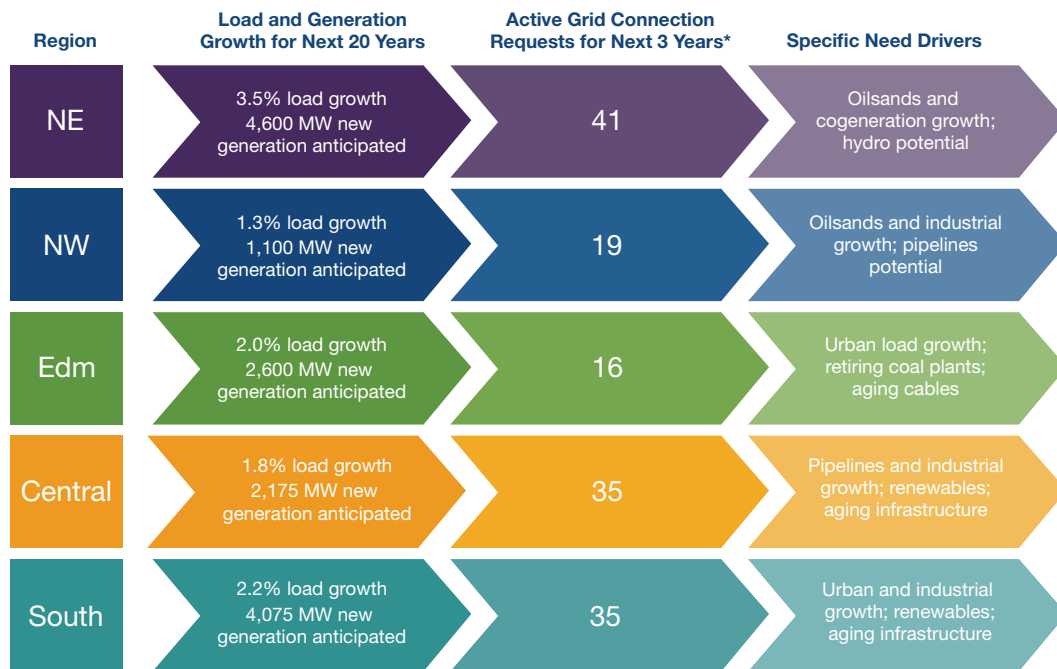
Strong investment in the oilsands and associated development is expected to continue to drive Alberta's economy and create 2.5 per cent average annual growth until 2032—the strongest provincial GDP growth in Canada. Translated to total electricity energy forecast across industrial (including oilsands), commercial, and residential sectors, the AESO anticipates overall Alberta Internal Load (AIL) to grow at an average annual rate of 2.4 per cent until 2032. Similarly, AIL peak is expected to grow at an average annual rate of 2.4 per cent for the same 20-year period.

The AESO incorporates input and analysis in the development of its load and generation forecasts using third party experts such as The Conference Board of Canada, the Canadian Association of Petroleum Producers, and IHS Global Insights, as well as the latest customer connection requests. Of note, the AESO is currently managing over 200 connection requests for load and generation facilities.

Generation investment is expected to keep pace in response to this anticipated load growth. The investment in future generation supply is determined by market participants who assume the risk and reward of building generation. Beyond the need to serve expanding load over the 20-year period of the Plan, opportunities for new generation facilities will also be driven by significant coal plant retirements. The generation mix in Alberta continues to shift from a predominantly coal-based fleet to a natural gas-based fleet, with the majority of future generation additions expected to come from gas-fired combined cycle and cogeneration. Additional wind generation, small scale renewables and the potential for future hydro generation is also anticipated.

The AESO continually works with stakeholders to monitor changes to the key inputs to our forecast of both load and generation. The 2013 LTP embodies the practice of continuous improvement at the AESO. The Plan is designed to be comprehensive and flexible in order to reflect the complexities and dependencies of project development, and to accommodate the variability of industries and business cycles.

The AESO's transmission planning processes are purposefully staged and flexible to accommodate changes in the forecast demand and generation. Each of the AESO's five planning regions present distinct load and generation profiles, connection requests and specific need drivers.

**Figure 1.1-1: Regional Diversity Drives Flexible Planning**

\* As of January 31, 2014

The AESO continues to evolve the Plan content by providing information on integral elements such as system operations and performance, telecommunications, market design and operations, project prioritization and competitive process. Collectively, these serve to increase the comprehensive nature of the Plan.

## 1.2 KEY HIGHLIGHTS OF THE 2013 LTP

- Provides a high-level summary of proposed transmission infrastructure solutions detailed in the AESO's newly established 20-year comprehensive regional transmission plans.
- Provides a 20-year blueprint, out to 2032, for transmission infrastructure builds in response to the needs identified from the 2012 LTO.
- Significant stakeholder engagement occurs in all processes required to prepare the 2013 LTP.
- Strong provincial economic growth (2.4 per cent average annual GDP to 2032) continues to drive load growth and subsequently customer connection requests (2.4 per cent average annual growth to 2032).
- Alberta economic growth is principally driven by oilsands expansion; northeast is the fastest growing region.
- Significant generation additions (more than 6,000 MW of new generation by 2022) are required to respond to growing demand and replacement of retiring coal generation.
- The forecast incorporates expected coal generation retirements and anticipates new generation replacements to be predominantly natural gas-fired. Diversity of generation mix continues to grow with gas, wind, cogeneration, small scale renewables and potentially future hydro.
- The 2013 LTP represents 37 transmission projects proposed out to 2017; of these, approximately \$7.5 billion (2013 dollars) represents committed project dollars already approved by the AUC, while approximately \$4.1 billion (2013 dollars) represents planning stage projects which have not received regulatory approval.
- Alberta is currently in a very active transmission infrastructure build cycle, with nine approved transmission projects representing approximately \$5.3 billion (2013 dollars) currently under construction.
- The AESO is proceeding with a competitive process that is open to competitors across the globe—a unique approach in Canada—to develop, design, build, finance, own, operate and maintain new transmission infrastructure for the province.
- Telecommunication infrastructure analysis and planning are an integral element of the larger transmission planning process, where telecommunication costs typically make up three to six per cent of a transmission upgrade or expansion project.
- Recognizing the inherent degree of uncertainty and to ensure plans are both flexible and responsive, the regional transmission plans anticipate both preferred and alternative solutions.
- All planned transmission projects will be subject to a two-stage regulatory approval process.

## 2.0 Introduction

Electricity is an essential part of our daily lives. Albertans, whether at work, home, or at play, have come to expect steady delivery of electricity that is affordable, reliable and sustainable. The Alberta bulk transmission system is essential infrastructure linking generation facilities to load entities, transporting electricity in a safe, reliable and efficient manner, and facilitating the connection of an ever expanding and diverse mix of load and generation facilities.

Alberta, much like the rest of North America, is undergoing a significant transmission infrastructure build, one which is expected to remain quite active over the next five to ten years. The Conference Board of Canada estimates, that on average, over \$15 billion per year for the next 20 years needs to be invested in Canada's electrical system.

The Alberta Electric System Operator (AESO) has a legislated mandate to ensure the interconnected transmission system is operated in a safe, reliable and economic manner, and to plan the transmission system to meet the demand for electricity now and in the future. This mandate is defined in the *Electric Utilities Act* (EUA), which requires the AESO to assess the current and future needs of market participants and to plan for the construction of transmission infrastructure in advance of need. The *Transmission Regulation* provides additional clarity about this responsibility. It requires the AESO to make assumptions about future load growth, anticipate generation changes, assess market conditions, determine requirements for ancillary services, plan for telecommunication networks, and integrate these assumptions into a transmission plan. The AESO is obligated to act in the public interest in developing transmission system plans.



Stock photograph.

The AESO is required through legislation<sup>6</sup> to prepare and maintain a transmission system plan for at least the next 20 years. The *2013 Long-term Transmission Plan (2013 LTP or Plan)* identifies those planned transmission system enhancements and expansions that the AESO has determined, through its transmission system planning process, are needed to meet the needs of Alberta over a 20-year planning horizon. The transmission system plan must be updated periodically, but at least once every 24 months, and filed for information with the Alberta Utilities Commission (AUC) and the Minister of Energy.

The 2013 LTP provides a holistic and comprehensive synopsis of planned transmission system and market design solutions over the 20-year horizon. The 2013 LTP identifies what transmission infrastructure needs to be built so that the Alberta Interconnected Electric System (AIES) continues to meet the province's current and future electricity needs. The Plan sets out the blueprint to mitigate identified system constraints or limitations, to connect new customers to the grid, and specifically identify and recommend when and where the transmission system needs to be expanded or reinforced.

A large part of the AESO's role is planning effective and prudent transmission system expansions to serve new generation development and demand growth, generally referred to as customer connections. The knowledge and information gathered from stakeholders and market participants in the forecast stage is critical to ensuring the province's transmission system is upgraded in anticipation of customer needs. The AESO uses this information to identify the best wires solutions to strengthen the electricity grid.

Advancement of the projects identified in the 2013 LTP is subject to regulatory and legislative processes, which provide opportunities for direct stakeholder and public input. Stakeholder and public engagement remain essential components in preparing the Plan.

The AESO's system planning activities do not stop with the publication of a particular version of the Plan. Continuous planning and evaluation is essential to ensure the development of a robust, flexible and efficient transmission system. A comprehensive planning process involves a rigorous analysis of a variety of public policy, economic and transmission alternatives, as well as consideration of defined sensitivities. Economic inputs provide forecasts of future demand for electricity and the anticipated generation development to meet that demand. Forecasting scenarios are utilized by transmission planning to address a broad range of uncertainties in evaluating the need for transmission projects and establishing need dates, staging and prioritization of projects.

The Plan is not static. It must respond and adapt to changes in assumptions of future conditions and circumstances should significant changes to the economy, government policy or regulation occur. The AESO regularly reviews inputs to the Plan to determine if circumstances warrant a significant change. Should new information become available, the Plan is updated accordingly. Recognizing the possibility of such change, and in a continuous effort to provide greater transparency and frequent progress information on the approved and active transmission projects, three publications are now available to stakeholders:

<sup>6</sup> T-Reg s.10

- Consistent with ISO Rules, each quarter the AESO posts the *AESO Transmission System Projects—Quarterly Report (QTP)* report on [www.aeso.ca](http://www.aeso.ca). This report serves as a status update for transmission projects currently underway.
- The Transmission Facilities Cost Monitoring Committee (TFCMC) produces a report titled *Review of the Cost Status of Major Transmission Projects in Alberta*. This report, introduced in June 2011 and updated and published every six months, provides visibility to and rationale for changes to transmission projects beyond the Needs Identification Document (NID) stage with cost estimates greater than \$100 million. The TFCMC's reports are posted on the Government of Alberta's Department of Energy website at [www.energy.alberta.ca](http://www.energy.alberta.ca) and on several TFCMC member websites.
- The AESO's [2012 LTP Progress Report](#), introduced in June 2013, provides information relating to the progression of all the Plan projects, including those projects not captured in either the QTP or TFCMC reports—essentially those projects in the planning (i.e., pre-NID) stage. The Progress Report provides a holistic summary of the progress of all major projects and initiatives referenced in the Plan, regardless of their stage.

These three publications are complementary to each other, and collectively serve to provide periodic reporting to stakeholders on the status and progression of the projects and initiatives identified in the Plan.

To anticipate what future transmission reinforcement is needed, the AESO considers a broad range of factors such as:

- Alberta's economic outlook
- Load and generation forecasts
- Potential intertie energy flows
- Customer load and generation connection requests
- Transmission system asset condition and performance
- Geographic diversity of transmission facilities
- Efficient use of rights-of-way
- Transmission system efficiency and operational flexibility

The AESO's planning team, consisting of transmission planning engineers and economists, analyzes electricity consumption patterns in every area of the province and integrates data from many sources to determine where electricity demand will grow. They also anticipate the type and location of generation required to meet that demand across a range of scenarios, and ultimately determine the additional transmission infrastructure that will be required.

The AESO also researches historical energy intensities for the industrial, oilsands, residential, farm and commercial sectors to adjust for future load patterns. In addition,





AESO file photograph.

an emphasis on customer, stakeholder, market participant and public consultation helps the AESO incorporate the most current information to identify overall system needs. This includes ongoing research into oilsands development, industrial processes, cogeneration requirements and other end-use studies. Information is updated through third party experts and through direct conversation with industry players, government agencies, transmission facility owners (TFOs) and distribution facility owners (DFOs). Determination of need is then established utilizing extensive modeling and analysis, ultimately identifying both preferred and alternative transmission infrastructure solutions.

The projects identified in the 2013 LTP will help deliver the power Albertans need, facilitate the reliability of the provincial transmission system, and improve the efficiency of the transmission system. At the same time, transmission projects will remove existing transmission constraints on generation of all forms, including renewable sources such as wind, hydro and biomass, as well as intertie capacity. This will ensure electricity can move from where it is produced to where Albertans need it. These solutions also facilitate non-discriminatory system access service to customers while ensuring the electricity market remains fair, efficient and openly competitive.

The 2013 LTP provides a high level summary of planned transmission activities and discusses project details in three distinct time periods: the near term (to 2017); medium term (2018 to 2022); and long term (2023 to 2032). Detailed transmission regional plans are available for all five of the planning regions and will be available on the AESO website in 2014.

Fundamental to the planned projects are the inclusion of key project metrics such as project description, project stage, planned need date and anticipated in-service date (ISD). Near-term cost estimates are defined in two categories; firstly, for those projects that have already been approved by the AUC; and secondly, those projects yet to undergo regulatory

review and receive approval from the AUC. The plan recognizes the degree of uncertainty inherent in estimating project costs beyond the near term as there is potential for projects to be modified, cancelled or delayed depending on changes to certain inputs, including the timing and nature of proposed customer development projects. The accuracy of each of these estimates is dependent on the stage of each specific project.

New to the 2013 LTP is the introduction of the AESO's Competitive Process (CP). The AESO was directed by the Government of Alberta<sup>7</sup> to develop a new procurement process to select an organization to develop, design, build, finance, own, operate and maintain new major transmission infrastructure in the province. The Fort McMurray West 500 kV Transmission Project is the first infrastructure project to be subject to CP.

In addition, the 2013 LTP addresses the opportunity, role and value of bulk system inter-regional transmission infrastructure that enables connection of transmission to other jurisdictions outside Alberta. Per the legislative direction outlined in the T-Reg<sup>8</sup>, restoring the import and export transmission capability of the existing interties to their designed path ratings continues to be a focus for the AESO. Alberta continues to be a net importer of electrical energy, a trend expected to continue into the near future. The dynamics associated with the recent addition and energization of the Montana Alberta Tie-Line (MATL) in September 2013 is represented in our transmission project plans.

System operations, telecommunications, market rules, market operations, and requisite AESO initiatives are also discussed in the 2013 LTP. These elements serve to complement and enhance the integrity and performance of both the physical transmission infrastructure and the market. The evolution and development of these aspects of the AESO's mandate are closely linked to how transmission infrastructure development is expected to unfold.



Stock photograph.

<sup>7</sup> See s. 24.2(1) of the T-Reg regarding Competitive Process

<sup>8</sup> See s.16(1) of the T-Reg

The 2013 LTP takes a comprehensive approach to planning a robust transmission system. At the same time, this approach provides confidence for all power generators, including those who want to build more renewable and low-emission power generating facilities. It also provides confidence to industry investors, commercial ventures, and Alberta communities that the reliable, competitive electricity they depend on will be available to support their current and future plans.

The following sections of the 2013 LTP provide background, set context and define the planning process undertaken by the AESO. The 2013 LTP provides the most current assessment of future transmission infrastructure needs across the 20-year planning horizon, and addresses those complementary elements directly linked to maintaining and operating a safe, reliable and secure transmission system.

The development and execution of the 2013 LTP will serve to provide Albertans with continued access to safe, reliable and affordable electricity. Alberta's future prosperity will be secured by having a reliable transmission system, adequate generation resources, timely investment in infrastructure and a competitive electricity market.



Photo courtesy of AltaLink.

## 3.0 Background

The AESO was created through legislation in June 2003 as an amalgamation of the Power Pool of Alberta and the Transmission Administrator. Its mandate is to plan and operate the transmission system in a safe, reliable and economic manner, as well as to operate and facilitate the wholesale electricity market in a manner that is fair, efficient and openly competitive (FEOC). The AESO is a not-for-profit organization that acts in the public interest and by legislation cannot own any transmission, distribution or generation assets. The duties and responsibilities of the AESO are defined in the Province of Alberta's *Electric Utilities Act* (EUA) and the *Transmission Regulation* (T-Reg). The AESO is governed by an independent board comprised of individuals appointed by the Minister of Energy. The AESO Board currently consists of eight individuals offering a diverse background in finance, business, electricity, oil and gas, energy management, regulatory affairs and technology. The Board's governance strategy is founded on balancing the interests of a diverse set of stakeholders, while at the same time, fulfilling the AESO's mandate to plan and operate a safe, reliable transmission system to meet the needs of Albertans.

The key duties and responsibilities of the AESO are to:

- Ensure the safe, reliable and economic operation of the Alberta Interconnected Electric System (AIES).
- Operate the power pool and facilitate the electricity market in a manner that is fair, efficient and openly competitive.
- Provide transmission system access service via a tariff.
- Manage and recover the costs associated with line losses and ancillary services.
- Determine the future requirements of the AIES, develop transmission plans over long-term horizons that identify the transmission system enhancements needed to meet those requirements, and make the necessary arrangements to implement those enhancements.
- Develop and implement a fair and open competitive process to determine the successful proponent who will develop, design, build, finance, own, operate, and maintain new major transmission infrastructure in Alberta.
- Prepare and maintain a transmission system plan that anticipates, for at least the next 20 years, system conditions and requirements. Additionally, the AESO must plan a transmission system that is available in advance of need. These legislative provisions mean that the AESO must take a long-term view, adjusting for short-term changes and focusing on directional system requirements to meet the long-term vision for electrical infrastructure in Alberta.



The 2013 LTP must take into account technical considerations, reliability standards and operating and planning criteria that provide for reliability and a well-functioning electricity market. In addition, other factors such as government policies, forecast load growth, generation development, technological advances and environmental impacts are considered.

### **3.1 OBJECTIVES OF THE 2013 LTP**

The primary objective of the Plan is to identify transmission infrastructure projects to accommodate long-term growth and secure Alberta's economic future. Another objective is to restore the import/export transmission capability of the existing interties to their path ratings. The implementation of these infrastructure projects in a proactive fashion reduces investment uncertainty regarding transmission access for both generators and load customers while supporting an unconstrained, competitive market.

The T-Reg informs, to a large extent, what the AESO views as the objectives of the 2013 LTP. These include. As part of its duties under section 10(1) of the T-Reg, the AESO must:

- (a) prepare and maintain a transmission system plan that projects, for at least the next 20 years,
  - (i) the forecast load on the interconnected electric system, including exports of electricity,
  - (ii) the anticipated generation capacity, including appropriate reserves and imports of electricity required to meet the forecast load,
  - (iii) the timing and location of future generation additions, including areas of renewable or low emission generation,
  - (iv) the transmission facilities required to meet the forecast load, imports and exports of electricity and anticipated generation capacity, including appropriate reserves and facilities to serve areas of renewable or low emission generation, in a timely and efficient way,
  - (v) the transmission facilities required to provide for the efficient and reliable access to jurisdictions outside Alberta.

As part of its duties under Section 8 of the T-Reg, the AESO:

- (a) must anticipate future demand for electricity, generation capacity and appropriate reserves required to meet the forecast load so that transmission facilities can be planned to be available in a timely manner to accommodate the forecast load and new generation capacity,
- (b) must make assumptions about future load growth, the timing and location of future generation additions, including areas of renewable or low emission generation, and other related assumptions to support transmission system planning,
- (c) must make an assessment of the transmission facilities required to provide for the efficient and reliable access to jurisdictions outside Alberta, and
- (d) may, if the ISO considers it necessary to do so, make an assessment of the contribution of a proposed transmission facility to any of the following:
  - (i) improving transmission system reliability;
  - (ii) a robust competitive market;
  - (iii) improving transmission system efficiency;
  - (iv) improving operational flexibility;
  - (v) maintaining options for long term development of the transmission system.

The T-Reg provides some latitude for exemptions to these objectives and the consideration of non-wires solutions as options in very limited circumstances; however, the objectives of the 2013 LTP are clearly defined. Non-wires solutions are typically viewed as temporary mitigation actions employed when the physical transmission recommendation will be deferred or delayed. Typical non-wires solutions include certain market and operational products and services (i.e., transmission must-run (TMR), remedial action schemes (RAS) and congestion management (TCM)) used to directly support the safe, reliable and efficient operation of the transmission system. Independent System Operator (ISO) rules also include a comprehensive real-time transmission congestion management section to manage any transmission constraints as they occur.

The AESO plans the transmission system to be compliant with Alberta Reliability Standards<sup>9</sup> (ARS). Although the 2013 LTP provides a 20-year assessment, to comply with Alberta Reliability Standards the AESO must demonstrate the transmission system is planned in the 10-year horizon such that:

<sup>9</sup> <http://www.aeso.ca/rulesprocedures/17006.html>



- It can be operated to accommodate forecast load and generation scenarios without interruptions when all transmission facilities are in service (TPL-001)
- It can be operated to accommodate forecast load and generation without interruptions following the loss of a single element (TPL-002)
- When system simulations indicate an inability to meet the above requirements, the AESO must develop transmission enhancements to achieve the required performance (TPL-001 and TPL-002)
- It can be operated to accommodate forecast load with controlled load interruption or removal of generation following the loss of two or more elements (TPL-003)
- It has been evaluated for the risks of extreme events (TPL-004)

The AESO operates the AES to stay within acceptable limits during normal conditions, to perform acceptably after credible contingencies, to limit the impact and scope of instability and cascading outages when they occur, to ensure facilities are protected from unacceptable damage by operating them within facility ratings, and to restore system integrity promptly if it is lost. The system must supply the aggregate electric power and energy requirements of electricity consumers, taking into account scheduled and reasonably expected unscheduled outages of system components. These criteria define how the system is planned to operate reliably and safely.

The 2013 LTP provides a high-level summary of the proposed telecommunication infrastructure solutions detailed in the AESO's *Telecommunication Long-term Plan*.



AESO file photograph.

Section 1 of the EJA defines transmission facilities and the transmission system to include telecommunications as follows:

- (bbb) “transmission facility” means an arrangement of conductors and transformation equipment that transmits electricity from the high voltage terminal of the generation transformer to the low voltage terminal of the step-down transformer operating phase-to-phase at a nominal high voltage level of more than 25,000 volts to a nominal low voltage level of 25,000 volts or less, and includes:
- (i) transmission lines energized in excess of 25,000 volts,
  - (ii) insulating and supporting structures,
  - (iii) substations, transformers and switchgear,
  - (iv) operational, telecommunication and control devices,
  - (v) all property of any kind used for the purpose of, or in connection with, the operation of the transmission facility, including all equipment in a substation used to transmit electric energy.
- (ccc) “transmission system” means all transmission facilities that are part of the interconnected electric system.

### 3.2 LONG-TERM PLANNING PROCESS

In order to capture and respond to evolving system conditions, the AESO collects information and evaluates inputs and needs for the transmission system in three distinct time periods: the near term (to 2017); medium term (2018 to 2022); and long term (2023 to 2032). Comprehensive forecasts and regional transmission plans are developed for the full 20-year period.

The validation of key inputs and conditions, the required analysis, the results, and ultimately the Plan itself are not static. The transmission planning process is continuous and involves frequent evaluation of assumptions and proposed transmission solutions. Coupled with the AESO’s regulatory obligation to file an updated version of the Plan with the AUC and the Minister of Energy at least once every 24 months and make it publicly available, the AESO regularly reviews inputs, performs analysis and updates elements of the Plan when circumstances warrant.

The 2013 LTP builds on previous long-term plans, incorporating the most current information available on Alberta’s economic outlook, projected load growth and anticipated generation expansion and diversity.

Figure 3.2-1 reflects the high-level process of how the Plan is prepared and filed. This process is consistent in the evaluation and determination of need for transmission infrastructure and ensuring a FEOC market.

Figure 3.2-1: AESO's 24-Month Planning Process



### 3.3 TRANSMISSION DEVELOPMENT IN ALBERTA

The AESO is charged with the responsibility of planning for an unconstrained system and ensuring adequate transmission facilities are available to accommodate forecast load and generation. In Alberta's deregulated, single price, wholesale electricity market, this means that transmission plans must allow all generators to have equal opportunity to fully compete in the market and allow all loads to withdraw power whenever and wherever it is required. Insufficient transmission capacity should not be a factor that hinders economic development decisions, nor determines winners or losers in the wholesale electricity market. In fact, transmission infrastructure should serve to secure Alberta's economic future. Only a robust, open, non-discriminatory transmission system can achieve these objectives.

Throughout North America, there are a number of electricity delivery models ranging from localized delivery systems within a municipal service territory or industrial system, to fully integrated grids over large balancing authorities. While localized delivery systems may offer efficiencies due to integrated systems and balances of load and generation, there are greater economies of scale available in larger market systems. Transmission is critical to securing the benefits of large-scale integrated grid models. The transmission development recommendations in the 2013 LTP address a 20-year horizon and leverage the economies of scale for building large-scale transmission now to support the existing system today and in the future. There are significant economic and regulatory efficiencies to be gained from sizing facilities for anticipated demand 20 years into the future. This approach avoids having to repeatedly expand existing transmission corridors or create new corridors to add incremental capacity to the system to meet demand growth over time. Building in advance of need leverages the economies of scale that recognizes transmission infrastructure has an investment lifespan of more than 40 years.

Decisions made by those investing in new sources of generation are based in part on having the confidence that they can transmit the electricity they generate to the market and ultimately to consumers. For business and industry, decisions on whether to locate in Alberta or to expand existing operations require reasonable assurance of access to an adequate supply of electricity at reasonably predictable and stable future prices. The availability of a robust transmission system provides investors and generation developers with confidence that they will be able to connect to the grid and provide their electricity to the market.

Transmission development plans also recognize that Alberta is connected to the North American electricity grid. Transmission interties connecting Alberta to neighbouring systems are an essential part of a reliable electricity system and a competitive market. Interties provide the ability to import power into Alberta when economically viable, and serve as an additional source of supply. Since 2001 Alberta has been, and for the foreseeable future will continue to be, a net importer of electrical power. In periods where excess generation supply beyond the needs of Albertans is available, generators can export power to adjacent jurisdictions. Albertans benefit from these interties by gaining access to potentially lower-priced electricity and obtaining greater diversity of supply.

The value of transmission has been studied and quantified in markets throughout the world and is typically based on several key elements:

- Value associated with reliable service—sometimes measured as the value of lost load.
- The avoided cost of transmission losses as transmission improvements are put in place.
- The value of supporting a competitive generation market – usually assessed against some measure of local market power.
- The avoided cost of temporary solutions such as having to run more expensive local generation or curtailing lower-cost generation.
- The enabling of expansion and connection opportunities for fuel-diverse generation resources, particularly essential to increasing the addition of diverse renewable generation facilities.
- Insurance against contingencies during abnormal system conditions such as fuel supply disruption, extended loss or outage of a baseload power plant, or prolonged weather-related events resulting in the failure of a critical transmission line in the AIES.

Transmission value is created by investing in backbone infrastructure today that is designed to link regional hubs, relieve congestion, satisfy operational and reliability objectives internally and across other balancing authorities, and accommodate large-scale growth in the province. Albertans have come to rely on electricity that is affordable, reliable and sustainable; so much so, that it is frequently viewed as an essential service that must be available at all times. These expectations are consistent across all consumer groups from industrial, commercial, agriculture and residential. Just as *“electricity is the backbone*

*of Canada's energy system, powering our economy as well as our homes, offices and lifestyles,<sup>10</sup>* so too is the transmission system that delivers that electricity.

Consistent with many jurisdictions across North America, Alberta in the late 1980s and through the 1990s experienced relatively flat investment, and even *under-investment* in some locations, in transmission infrastructure builds. Progress is now being made as transmission projects assessed and identified in previous AESO long-term plans continue to advance through the regulatory and stakeholder process through to completion. Even so, over the planning horizon, Alberta is facing a significant need for new capital investment to maintain, renew, sustain and expand the transmission grid.

The long lead time and economic life associated with transmission projects results in an asymmetric risk profile for transmission development where the impact of building insufficient transmission capacity far outweighs the impact of building surplus transmission capacity. In looking out over the 20-year time horizon, demand growth is expected to remain strong and the transmission system must evolve in anticipation of this demand. Fundamental to that response, Alberta is moving from a 240 kV backbone system to a 500 kV backbone system. This will enable efficient system operation for decades to come and allow Alberta industry to keep pace with global demand for its resources.

### **3.3.1 Connecting to the Grid**

The AESO's customer connection process facilitates customer connections to the AIES. The AESO monitors this process to ensure that all customers seeking connection to the AIES are provided open and fair access. The AESO engages customers directly, facilitates the process and seeks stakeholder input on how best to accommodate continuous improvement to both process and cycle times.

The primary objectives of the process are to ensure:

- Efficient progression of projects
- Fair and non-discriminatory treatment of market participants
- Fair and efficient management of AESO and TFO work resources
- Fair assignment of connection remedial action schemes in constrained areas

Fundamental to the process is a formal stage/gate approach and the creation and management of a connection queue for all new connections. Key activities take place in each stage and projects must meet all of the requirements within each stage to complete the corresponding gate for that stage.

<sup>10</sup> Canadian Electricity Association, *Power for the Future: Electricity's Role in a Canadian Energy Strategy*, July 2013

The stage gates are defined as:

- Stage 0: Identify Project
- Stage 1: Connection Study Scope
- Stage 2: Connection Proposal
- Stage 3: NID & Facility Application
- Stage 4: File Application & AUC Approval
- Stage 5: Construction
- Stage 6: Energization

This connection process serves to facilitate project management and is an essential component when establishing, validating and modifying the AESO's forecast of load and generation.

Details of the AESO's [Connection Process](#) and connection study guidelines can be found on the AESO website.

### **3.3.2 Telecommunication Network Development**

A reliable transmission system requires a reliable telecommunication network. As such the AESO includes telecommunication system planning in its long-term transmission plans. A formal telecommunication plan is prepared and refreshed annually and is based on the same 20-year planning period as the 2013 LTP. The AESO completes a comprehensive evaluation of the existing telecommunication infrastructure and establishes a plan for future growth, one that aligns with the transmission infrastructure projects identified in the 2013 LTP.

The technology considerations essential to the effective design and operation of a robust grid are incomplete without consideration of the sophisticated telecommunication infrastructure that overlays the entire system. The current focus on enhancing existing system controls as well as the monitoring, protection and reporting functions means that the role, application and comprehensive planning of telecommunication infrastructure needs to be linked to the physical transmission being proposed.

The AIES utility telecommunication networks owned and operated by TFOs are used for the delivery of teleprotection signals, operational data, Supervisory Control and Data Acquisition (SCADA) data, voice and mobile radio communications. Alberta's electric transmission system relies on this province-wide, utility owned and operated communications network for its reliable, efficient, and safe operation.

The operation of the transmission system requires a functional and effective telecommunication network where the design and performance of the communications system will contribute to the ability of the system to meet Alberta Reliability Standards (ARS). The telecommunication plan provides a blueprint for how Alberta's aging microwave telecommunication systems will be replaced and/or modified with more advanced and durable fibre optic technology. Despite the advantages of deploying fibre optics, it is envisioned that the existing microwave systems will continue to be utilized, maintained, and



expanded where economics and practicality dictate that microwave technology is the most appropriate solution. In certain areas of the province, the microwave system will continue to be used as it is more cost effective.

The general objectives of the *Telecommunication Long-term Plan* are as follows:

- Provide a highly reliable telecommunication network
- Support ongoing system growth including applications for smart grid in the future
- Meet latency requirements and high security standards
- Seek efficient overall operating costs for Alberta ratepayers

The *Telecommunication Long-term Plan* supports and complements the 2013 LTP by defining needed telecommunication infrastructure requirements in response to the transmission infrastructure projects identified in the five regional transmission plans. It identifies how the utility telecommunication network should evolve and grow to support these projects proposed in the 2013 LTP.

There are five key highlights within the *Telecommunication Long-term Plan*:

1. Fibre optic (OPGW-optical ground wire) deployment continues on all 240 kV and 500 kV lines. Deployment on 138 kV lines will be reviewed on a per-project basis.
2. Expanding customer interconnections (generation facility owners) are driving the need for new 138 kV teleprotection services.
3. Shared use of the TFO-based telecommunication networks is progressing where practical, optimizing both infrastructure and operational functionality.
4. The Mobile Radio System planning requires review and industry consultation with federal and provincial emergency agencies, addressing technical considerations and opportunities to leverage infrastructure.
5. There will be a significant OPGW backbone in place by 2022, based on the transmission projects proposed in the 2013 LTP.

The following factors have been considered in the development of the *Telecommunication Long-term Plan*:

- Network development and capacity planning follows transmission system development that relies on, among other things, forecasts of load growth and future generation additions. The AESO recognizes that many factors affect load and generation growth, and that the actual load in the future could be higher or lower than forecast, which may impact the actual requirements for the telecommunication networks.
- A long-term horizon is required for planning purposes to ensure the telecommunication networks put in place today will be able to handle growth in network traffic arising from such applications as synchrophasors, video surveillance, possible smart grid data and other applications not in wide-scale use at this time, including SCADA-over-IP and substation automation.

Adoption and deployment of smart grid applications and services will complement the development of a robust, competitive market for electricity. While the extent and timing of such deployment is uncertain, the *Telecommunication Long-term Plan* takes into account the potential for widespread deployment of applications such as advanced metering infrastructure (AMI), demand response (DR), distribution automation (DA), and others related to the smart grid concept.

Telecommunication costs typically make up three to six per cent of a transmission system upgrade or expansion. The estimated costs to implement the projects identified in the 2013 LTP already have a telecommunication component embedded within the project cost estimates. In addition, any costs and scope of distinct standalone telecommunication projects needed to enhance the overall bulk system are identified, and consistent with all transmission infrastructure projects, are subject to regulatory review prior to proceeding.



AESO file photograph.

The following conceptual projects are telecommunication-specific projects that are identified as being required over the next 10 years and are not associated with any specific transmission upgrade identified in the AESO's 2013 LTP. Project scope and cost are yet to be determined and will be subject to regulatory review prior to proceeding:

1. Whitecourt Swan Hills Planning Area Telecom Upgrade
2. Brooks – Milo Fibre Installation
3. Mobile Radio Upgrade – System upgrade project to use the Industry Canada 700 MHz band in conjunction with Public Safety
4. AESO – Northwestern Energy – MATL Telecommunication Emergency Voice and Data Deployment
5. Alberta-B.C. Interconnection Telecommunication Upgrade

Over time and as the transmission system is upgraded as identified in the 2013 LTP, the Alberta utility telecommunication network will be established accordingly. Details of the planned telecommunication developments can be found in the *Telecommunication Long-term Plan* expected to be released in conjunction with the AESO's *Regional Transmission Plans* in the first quarter of 2014.

### 3.3.3 Interties

Alberta is one of the least interconnected jurisdictions in North America, and since 2001 has been a net importer of electricity. Net imports from B.C. more than doubled in 2011 and 2012 compared to historical 2009 and 2010 levels. This was mainly due to a dramatic increase in the price spread between Alberta and Mid-Columbia. Prices have decreased in the neighbouring Pacific Northwest market due to surplus renewable energy, mainly hydro. At the same time, Alberta experienced a temporary loss of baseload coal-fired generation further contributing to the price spread. Going forward, imports should decline as the supply situation in Alberta improves and hydro flows in the northwest return to normal.

The AESO continues to work on advancing the intertie framework including:

- Restoring the existing interties to their rated capacity.
- Enabling imports and exports of new interties up to their rated capacity.
- Developing market rules and any required tariff changes to support a sustainable intertie framework, including considerations of market seams.
- Developing criteria the AESO would use to determine whether or when it would actively advocate for the development of future interties outside of a merchant developer framework.
- Defining and implementing the processes and planning required to interconnect future merchant interties. This work will continue to leverage the learnings from the recent Montana-Alberta Tie Line (MATL) interconnection initiative which facilitated the interconnection of the newest intertie to the Alberta system in September 2013.

The intertie planning and restoration initiative is focused on the transmission evaluation and planning assessments required to ensure existing interties are restored to their original design capacity, while recently added interties are also able to transfer up to their design capacity. Power flows on existing interties are included in the development of detailed regional transmission plans, summaries of which can be found in the Transmission Results section of this document.

Progress on this initiative has included the introduction of Load Shed Services for Imports (LSSi) aimed at increasing import capacity into the Alberta system. Work is progressing on studies to determine intertie transfer limits based on anticipated future system conditions. These studies will identify potential mechanisms for increasing these transfer limits. Next steps include completing a joint study with BC Hydro to further define potential mitigation mechanisms, and updating operational transmission studies to reflect new system conditions now that MATL is operational. Further information on this initiative can be found on the AESO's website.

The assessment of interties is complex from technical, utilization, market impact and multi-jurisdictional perspectives. Significant lead time is required to evaluate need, technology options, size, location and costs, and to manage the multi-jurisdictional process required to permit such facilities. In the medium term the analysis will focus on the potential for MATL to increase its capacity from 300 to 600 MW. To the extent further merchant intertie lines are advanced, the AESO will perform the analysis required to accommodate and support these initiatives.

### **3.3.4 Transmission Project Cost Estimates**

The 2013 LTP provides a high-level summary of planned transmission activities and discusses project details in three distinct time periods: the near term (to 2017); medium term (2018 to 2022); and long term (2023 to 2032). Detailed regional transmission plans are available for all five of the planning regions and will be available on the AESO website in the first quarter of 2014.

Fundamental to the planned projects are the inclusion of key project metrics such as project description, project stage, planned need date and anticipated in-service date (ISD). Near-term cost estimates are defined in two categories; firstly, for those projects that have already been approved by the Alberta Utilities Commission (AUC); and secondly, those projects yet to undergo regulatory review and receive approval from the AUC. The plan recognizes the degree of uncertainty inherent in estimating project costs beyond the near term as there is potential for projects to be modified, cancelled or delayed depending on changes to certain inputs, including the timing and nature of proposed customer development projects. The accuracy of each of these estimates is dependent on the stage of each specific project. Cost estimates are defined in constant 2013 dollars.

The 2013 LTP represents 37 transmission projects proposed out to 2017; of these, approximately \$7.5 billion (2013 dollars) represents committed project dollars already approved by the AUC, while approximately \$4.1 billion (2013 dollars) represents planning stage projects that have not received regulatory approval.

Projects are generally categorized in three distinct stages; essentially planning through to construction and ultimately completion. The stages are:

#### **Planning stage**

This is typically the early conceptual stage where specifications are established on general characteristics or functional specifications such as line length and voltage level. The level of estimating accuracy is +/- 50 per cent.

#### **Needs Identification Document (NID) stage**

This is the first formal level of regulatory examination of the AESO's proposed project development, subject to AUC approval and stakeholder review and comment. This stage provides greater project granularity and the level of estimating accuracy is +/- 30 per cent.

#### **Facilities Application (FA) stage**

This stage typically follows NID approval and assignment or awarding of a project to the appropriate TFO. A facility application is prepared and submitted to the AUC for review and approval, and is subject to stakeholder review in a public hearing process where a more detailed proposal including refined costs and possible rights-of-way options is presented.

The FA stage is further divided to separate the early FA application projects from those projects currently under construction; frequently referred to as the Proposal to Provide Service (PPS) stage. The level of estimating accuracy is +20 per cent to -10 per cent.

Project cost estimates are developed in accordance with ISO Rule 9.1<sup>11</sup> and AUC Rule 007<sup>12</sup>.

The Alberta *Transmission Regulation* requires the AESO to make rules or establish practices to ensure that project cost estimates prepared by a TFO or other party are reasonable for the purpose of making transmission planning decisions. ISO Rule 9.1 describes requirements associated with development of a transmission project including, but not limited to, preparation of project scope documents, cost estimates and schedule documents, and administration of scope changes. These rules are further augmented by tools that include cost reporting templates and scope change documents. The AESO has also developed a benchmarking database to provide transparency of transmission costs and to help assess the reasonableness of cost estimates prepared by a TFO or other entity. This cost data is useful to the AESO, the AUC and stakeholders in order to perform analysis such as cost trending, identification of cost improvement opportunities, and final cost reconciliation.

The cost estimates for projects in the planning stage are developed based on the early stages of project definition and the preliminary conceptual design of the project. Estimates are prepared based on high-level functional specifications provided by the AESO. These estimates are further validated by the benchmark data that the AESO continually updates based on data from recent projects in Alberta. Planning cost estimates are established based on characteristics of the projects (such as line length and voltage level) rather than specific bid or tender prices or estimates provided by TFOs.

<sup>11</sup> [http://www.aeso.ca/downloads/Section\\_9\\_Transmission\\_-\\_ISO\\_Rules\\_-\\_March\\_28\\_2012.pdf](http://www.aeso.ca/downloads/Section_9_Transmission_-_ISO_Rules_-_March_28_2012.pdf)

<sup>12</sup> <http://www.auc.ab.ca/acts-regulations-and-auc-rules/rules/Pages/Rule007.aspx>

The cost estimates for projects in the NID stage or FA stage (i.e., projects for which a NID or FA have been filed) are more refined than planning level estimates, as they reflect more advanced project definitions and scope. The cost estimates typically represent quotes or bids for supply of specific equipment, commodities or services. The cost estimate of a transmission project is affected by various factors such as the time and year of construction, geography of the terrain, population density along the route (urban versus rural), geotechnical conditions, type of construction (lattice versus monopole, underground versus overhead etc.), voltage levels, types and number of conductors, number of circuits, technology, environmental requirements, labour availability, local regulations and weather effects during construction. These factors, however, do not have the same degree of impact on each project.

A number of planning and process approaches are taken by the AESO to ensure the reasonableness and prudence of the projects proposed in the Plan. The AESO seeks opportunities to adjust project prioritization, employ project staging, and define milestone development when appropriate.

### **3.3.5 Competitive Process**

New to the 2013 LTP is the introduction of the AESO's Competitive Process (CP). The AESO was directed by the Government of Alberta to develop a new procurement process to select an organization to develop, design, build, finance, own, operate and maintain new major transmission infrastructure in the province. The Fort McMurray West 500 kV Transmission Project is the first infrastructure project to be subject to CP.

Electric transmission infrastructure development in Alberta has generally and historically occurred through the AESO's direct assignment of transmission projects to incumbent transmission utilities based on traditional service territories. The incumbent transmission utilities operate and are paid under a cost-of-service model in which their prudently incurred costs are recovered in a tariff approved by the AUC. The incumbent transmission utilities are required, under legislation, to make their electric transmission facilities exclusively available to the AESO.

In December 2008, the Government of Alberta introduced the *Provincial Energy Strategy* (PES), a comprehensive plan for Alberta's energy future. The strategy noted the importance of electricity as a "facilitator of prosperity" and a key contributor to economic development in Alberta. To aid in implementing the PES, amendments to the *Electric Utilities Act* resulted in legislated "needs approval" (Bill 50)<sup>13</sup> for certain substantial upgrades to the Alberta transmission system referred to as "critical transmission infrastructure" (CTI). Subsequently, as a result of the Critical Transmission Review Committee's review and recommendations in early 2012, Bill 8<sup>14</sup> was passed repealing Bill 50, essentially stating that all planned transmission infrastructure builds will be subject to the full NID and FA regulatory hearing process.

<sup>13</sup> Bill 50, *Electric Statutes Amendment Act*, 2nd Session, 27th Legislature, Alberta, 2009.

<sup>14</sup> Bill 8, *Electric Statutes Amendment Act*, 1st Session, 28th Legislature, Alberta, 2012.



In furtherance of the development of critical transmission infrastructure, on September 30, 2010 and on September 6, 2012, the Government of Alberta amended the *Transmission Regulation* to provide, among other things, that:

- (a) the AESO develop a competitive process to determine the person who is eligible to apply for the construction and operation of certain critical transmission facilities, and
- (b) the AESO obtain the AUC's approval of the competitive process prior to implementing it.

The AESO's objectives for the Competitive Process are to:

- Minimize life cycle costs through the use of competitive pricing
- Create opportunity for maximum innovation throughout the life cycle of the facilities
- Allocate risk to most efficiently and effectively reduce costs and mitigate risk
- Foster efficient investment, operation and maintenance of assets across the life cycle of the facilities
- Ensure facilities are designed to meet standards for performance and ensure the reliable operation of the Alberta Interconnected Electric System
- Consider obligations typically assumed by the incumbent transmission facility owner

The AESO submitted its Competitive Process application to the AUC in September 2011 and the AUC approved it on February 14, 2013.



Stock photograph.

The AESO is introducing competition into Alberta's electricity transmission industry with the new Competitive Process being employed for the Fort McMurray West 500 kV Transmission Project. The AESO expects to identify the successful proponent in January 2015.

**Table 3.3.5-1: Competitive Process Timeline for the Fort McMurray West 500 kV Transmission Project**

AUC Decision on the Competitive Process	February 2013
Request for Expressions of Interest stage	May 9 to June 19, 2013
Request for Qualifications stage opens	July 29, 2013
Request for Qualifications submissions deadline	October 11, 2013
Short-listed respondents invited to participate in Request For Proposals stage	Week of December 16, 2013
Request for Proposals stage	December 2013 – December 2014

Additional information on the AESO's Competitive Process and the Fort McMurray West 500 kV Transmission Project can be found at [www.aeso.ca/cp](http://www.aeso.ca/cp)

### 3.3.6 Managing Uncertainty

Long-term transmission planning is inherently uncertain given the time horizons involved, the diversity of generation that may or may not be built, the importance of locational siting and the critical importance of timing. Transmission investment decisions must anticipate need decades into the future because transmission infrastructure has an investment lifespan of 40 or more years, and new developments typically require five to eight years to plan and build. In addition to reliability requirements, transmission plans must consider trends in economic development, population growth, technological advancement and environmental regulation, as well as trends in neighbouring jurisdictions, in order to arrive at robust solutions that stand the test of time. In Alberta's deregulated market, transmission planning is characterized by additional uncertainty because the timing and location of new generation additions and retirements are private investment decisions made independently of the AESO.

Given the large number of variables involved, accurate and complete forecasting of load and generation growth over the long economic life of transmission assets is challenging. Decisions must be made through the use of scenario analysis to arrive at plans that can adapt to a broad range of potential future outcomes. This is why the planning process is reviewed and updated on a regular basis. Essential to the planning process, the AESO prepares a comprehensive refresh of the forecast a minimum of once every 24 months, with a supplemental review or update once every 12 months. These are made publicly available to all stakeholders and can be found on the AESO's website at [www.aeso.ca](http://www.aeso.ca). The most recent versions are the *2012 Long-term Outlook* (2012 LTO) published July 2012 and the *2012 Long-term Outlook Update* (2012 LTOU) published February 2013.

With the large number of variables that must be considered, the AESO's transmission plans must be flexible so that the configuration of the system does not constrain future economic development. In recognition of this uncertainty, the 2003 *Transmission Development Policy* provides direction to the AESO to be proactive in its planning and build transmission

in advance of need. The use of project staging enables prudent timing of transmission developments ensuring consumers receive maximum value from transmission investments, by timing the construction of incremental phases of projects to align investment with anticipated need dates.

As policies evolve and fuel source preferences change over time, adequate transmission capacity facilitates changes in the generation fleet as investors and generation developers choose new types and locations of generation based on the availability of new fuels. Wind and hydro power provide low cost, carbon-free energy that complements thermal sources such as natural gas and coal. A diverse mix of generation sources provides economic, environmental and supply security benefits, and the ability to connect such diversity is a key objective of the *Transmission Development Policy* and, subsequently, is reflected in AESO's transmission planning.

If forecasts for load and generation evolve more slowly than predicted, the AESO believes it is a reasonable assumption that loads and generation will only be delayed, eventually catching up to where the transmission can be fully utilized. If future expectations of need turn out to have underestimated the amount of transmission capacity required, the negative consequences of not having transmission capacity available are much greater, as economic development may actually be deferred or reduced due to a lack of sufficient transmission capacity. Increased constraint undermines the efficiency of the wholesale market, increases the delivered cost of power to consumers, reduces the competitiveness of generators and potentially discourages the entry of new market participants. System inefficiency intensifies with increased line loading, which results in greater system losses and expanded reliance on non-wires solutions to compensate for inadequate transmission capacity in constrained areas. The sum of these consequences is incremental system costs with the ultimate penalty being reduced system reliability.

In determining the appropriate size of incremental transmission additions, the most effective hedge against future uncertainty is to plan for the most likely demand and generation growth forecast and test with sensitivities. This will ensure sufficient capacity margin and minimize the significant consequences associated with insufficient transmission capacity. The AESO takes a measured approach to determine solutions that are practical, prudent and cost effective. Consideration for staging projects, defining milestones and identifying non-wires temporary solutions are employed where appropriate. This follows the direction of the T-Reg, Part 3, *Transmission System Criteria and Reliability Standards*.

### 3.4 KEY INPUTS TO THE 2013 LTP

The following section discusses key components of the Plan which serve to reinforce the end-to-end planning process, influence proposed solutions and establish an integrated and flexible long-term transmission plan.

#### 3.4.1 Stakeholder Consultation

Stakeholder consultation with industry, the general public, elected officials, special interest groups and others provides the AESO with a broad perspective and valuable input used to improve the reasonableness of the forecast and ultimately the transmission planning results. Annually, the AESO carries out extensive consultation in many locations throughout Alberta on various proposals to develop the transmission system. This consultation includes the exploration of geographic options, potential technologies and environmental and social considerations. Stakeholders continue to be engaged through various methods and their input helps form the transmission system development identified in the 2013 LTP. Significant conversations with third parties, industry players, municipalities, regional groups, and load and generation connection customers have occurred to further update the 2013 LTP.

Stakeholders are generally identified as:

- Market participants
- Rate payers (residents, occupants, landowners and businesses)
- Industry groups
- Connection customers
- First Nations and Métis
- Advocacy and environmental groups
- Distribution facility owners
- Transmission facility owners
- Elected and administrative government officials at local, municipal and provincial levels



AESO file photograph.

## ***The AESO's Stakeholder Engagement Principles***

### ***Roles and participation in decision-making***

- The AESO makes decisions, proposing solutions and the timing of those solutions
- The AESO uses the experience and expertise of stakeholders to improve the quality and implementation of decisions
- The AESO determines the level of consultation needed on an issue, based on the perceived significance and impact on stakeholders and the time available
- All stakeholders have the right to comment on the AESO's plans, decisions and actions

### ***The process of making decisions***

- All potential proposals progress through consistently defined stages from problem identification to implementation and review
- The AESO's consultation process and rationale for decisions are transparent

### ***Informing stakeholders***

- All stakeholders have the right to be informed of the AESO's direction, plans, status of issues and decisions in a timely manner
- The AESO communicates a consistent position on a proposal, including potential changes, that resolves perspectives across the AESO's functions

### ***Continuous improvement***

- The AESO measures the success of its engagement process and the effectiveness of resulting recommendations to improve its future performance

The AESO employs a variety of methods to notify, consult and engage stakeholders including mailings, newspaper and radio ads, news releases, website postings, meetings and presentations, correspondence, industry sessions and open houses.

Throughout 2012 and 2013 the AESO's transmission planning team also directly engaged TFOs, DFOs, counties and municipalities to provide updates on transmission projects planned or active in their jurisdictions, and to seek input aimed at further identifying regional need. In addition, the AESO is an active participant in *Alberta Land Stewardship Act* (ALSA) regional plans and Comprehensive Regional Infrastructure Sustainability Plans (CRISP).

Stakeholder engagement opportunities are also available through the NID consultation process, the FA consultation process, and frequent engagement with stakeholders regarding changes to market rules and tariffs.

From 2012 to 2013, over 1,225 stakeholders and members of the general public participated in 34 open houses and group meetings as part of various transmission system development consultation processes. Meetings with 95 municipalities across the province were also conducted over the same time period.

### 3.4.2 Economic, Social and Environmental Considerations

The AESO conducts a high-level land use impact assessment which considers factors such as population density, agriculture, proximity to future load and generation locations, alignment with existing rights-of-way<sup>15</sup> and environmentally sensitive areas. Public safety in the planning, design, construction, location and operation of transmission infrastructure is always a paramount consideration in all aspects of transmission projects.

The land impact assessment process allows the AESO to consider potential land impacts associated with transmission development. The assessment process is driven by the major aspects of AUC Rule 007, Section 6, NID 12. The AESO examines agricultural impact, residential impact, environmental impact, electrical considerations, visual impact and special constraints. Associated with each major aspect are several specific considerations, as specified in AUC Rule 007<sup>16</sup>. However, not all considerations (e.g., noise and TV interference, visual impact of tree removal, etc.) can be assessed in detail until the facility application stage of a project when the legal owner of the transmission facility finalizes more detailed route and structure location, and detailed design. The land impact assessment at the planning stage focuses on the conceptual aspects and considerations that can be described using information currently available.

Information obtained through a route determination process provides data that can be used to represent potential routes for this assessment. At this stage, land impacts are typically considered in a qualitative manner for alternative comparison purposes. The availability of data derived from siting work on previous projects provides the opportunity to compare transmission alternatives. Any routes or route segments used in this analysis are intended to be viewed as representative routes for the purposes of this high-level analysis and are not intended to predetermine the location of any routes that may be identified through future siting work.

Route options have differing and offsetting impacts. For example, routes with low residential impact may have higher environmental impacts. The factors used for comparison generally consist of:

#### ***Agricultural Impact***

Agricultural impact refers to the potential effects on farming activities carried out on rural lands which include raising livestock, cultivation of crops, and other commercial operations.

#### ***Residential Impact***

The potential for reducing residential impact is an important consideration in the development of routing for transmission lines. The residences identified along with the proximity of urban areas are used as a general indication of the potential residential impact associated with the proposed alternatives during the land impact assessment stage.

#### ***Specific Environmental Concerns***

Major surface water bodies, important bird areas, wetlands, parks, protected areas, environmentally sensitive areas and native vegetation are considered as potential indicators

<sup>15</sup> As required in s.15.1(2) of the T-Reg

<sup>16</sup> <http://www.auc.ab.ca/acts-regulations-and-auc-rules/rules/Pages/Rule007.aspx>



of environmental impact as part of the land impact assessment. It is expected that effects on these features can be avoided or reduced at the FA stage when additional assessment work occurs and more detailed information becomes available.

### **Visual Impacts**

Visual impacts are generally considered social impacts and are closely associated with residential impacts, as they are typically influenced by similar factors. In addition to residents, individuals who do not reside close to a transmission line but who regularly use the area, such as recreational users or people who travel through the area, may experience visual impacts. There are some general assumptions regarding visual impacts that can be made for overhead transmission lines, such as:

- The closer a line is to a residence, the more likely a visual impact will be perceived
- The higher the residential density, the more likely a visual impact will be perceived
- Transmission lines paralleling existing developed linear corridors are more likely to have a lower visual impact than a greenfield route
- Transmission lines near parks, natural areas or recreational areas may be viewed as creating a higher visual impact

Beyond the specific environmental concerns identified previously, environmental considerations are part of the 2013 LTP in two other ways. First, the current and expected environmental policy will influence the type and location of generation facilities built in the future, which directly influences the need for transmission. Secondly, environmental policies influence the type and location of electrical load that may develop in the future.



Stock photograph.

The AESO considers environmental impacts in choosing general transmission study areas and the technology to be employed. The assessment of economic, social, and environmental impacts are specifically included as part of project NID filings which may be evaluated in a hearing process in front of the AUC. The siting and routing of transmission facilities incorporates these three considerations through the FA process, allowing for direct public and stakeholder input.

### **ALSA Regional Plans**

Section 16.1 of the *Electric Utilities Act*<sup>17</sup> directs the AESO to carry out its duties in accordance with *Alberta Land Stewardship Act* (ALSA) regional plans. In carrying out its mandate under this Act and other enactments, the AESO must act in accordance with any applicable ALSA regional plan.

In its transmission planning, the AESO participates in ALSA regional planning activities and takes into account the objectives and outcomes of each of the ALSA regional plans as they apply in each planning region and system project. These considerations are an important component of the AESO's planning process that ensures alignment with provincial energy development policy objectives.

In all cases, transmission projects are evaluated after taking economic, social and environmental impacts, among other factors, into consideration.

### **3.4.3 Alberta's Wholesale Electricity Market**

The Alberta wholesale electricity market is designed as a real time, energy-only equilibrium market, or power pool. This means that suppliers are paid one single, hourly pool price for only the energy they deliver, not simply for building capacity. The single pool price model requires effective price signals for long-term investment, for consumption response and for response from other markets. Additionally, this market model relies on an unconstrained transmission design to ensure that the pool price reflects the price of electrical energy available at any given time.

There are no transmission rights in Alberta. Instead, there is an injection-withdrawal system where transmission access is assigned in a non-discriminatory manner upon dispatch in the energy market. Transmission is paid for at a "postage stamp" rate, with no differentiation based on location—meaning it does not matter where the electricity is produced or used. At present, there are areas of transmission congestion that can occur and, at times, pose a challenge to the efficient dispatch of supply to meet demand.

Alberta's electricity market design provides choice to consumers, incents generators and load to build in Alberta, and provides viable access to other markets for both import and export opportunities. Transmission is required to serve both consumers and generators in the delivery of electricity, and also to connect new and varying generation fuel types wherever they are located. Simply put, transmission development must address both reliability and market objectives. As noted in Alberta government policy and confirmed by the T-Reg, an unconstrained transmission system is critical to ensuring an effective and efficient electricity market for all.

<sup>17</sup> S.A. 2003, Chapter E-5.1

The 2013 LTP is based on assumptions that generation will be unencumbered, allowing investment opportunities in new generation facilities. It also reflects market rules which support the connection of various fuel types and establishes a framework for effective transmission interties. Accordingly, the AESO continues to support market evolution to encourage generation and load development in the province.

The following wholesale electricity market priorities are consistent with baseline assumptions built into the 2013 LTP. They support an evolving competitive market for electricity while responding to a growing economy.

- Integration of wind resources including rule development for forecasting wind, wind power management and potential dispatch of wind assets
- Creation of market-based products to help restore the capability of interties to rated capacities
- Development of demand participation products
- Development of framework details for participation of interties in the Alberta market including tariff design, capacity allocation rules and design to consider integration of future interties and merchant lines
- Implementation of congestion management rules and procedures to address real-time constraints
- Provision of consistent and transparent system access business practices and connection process

The AESO develops and facilitates Alberta's hourly competitive wholesale electricity market, establishing and implementing market rules that assure a predictable market structure and provide a reliable price signal for producers, consumers and investors. This price signal is critical for private companies making investment decisions that ultimately will ensure an adequate supply of electricity for Albertans for many years to come.

Historic and recent market performance is provided in the *Annual Market Statistics* report, posted on [www.aeso.ca](http://www.aeso.ca)

#### **3.4.4 Ancillary services**

Ancillary services are services required to reliably operate the AIES and to support the competitive market, in addition to physical transmission plans. One of the critical considerations of a sustainable transmission plan is the need to minimize dependency and cost of ancillary services by removing system constraints. The AESO recognizes that as more variable resources are integrated into the system, the need for ancillary services will likely increase. The AESO continues to assess this requirement and will include the results of the ongoing analysis as part of future updates of the LTP.

With the current transmission system often operating at or near its limits during peak conditions, until planned transmission is built, the system is reliant on operational tools and some ancillary services. As new transmission facilities are built and energized, the reliance on some ancillary services will be reduced. New transmission builds also serve to address

the occasional generation or load constraints that can occur in certain areas of Alberta when transmission facilities are taken out of service, whether for planned maintenance or forced outages, such as during weather events.

When the system experiences constraints or operational disturbances, the AESO relies on the procurement and use of ancillary services, and the development and implementation of operational procedures to alleviate the problem. The AESO also continues to rely on coordination of planned outages to minimize supply adequacy issues. System controller training and procedures are developed and implemented to support ongoing monitoring and response alternatives to challenging system conditions.

Ancillary services used to support reliability include:

- **Transmission must-run service** – supplied by a generator that is required to be online and operating at specific levels in parts of the system where local transmission capacity is insufficient to meet local demand; in effect acting as a temporary substitute for transmission.
- **Regulating reserve** – available output from a generator that can be dispatched, and is responsive to automatic generation control, to provide the power needed to address the lag period between balancing supply and demand (as generators catch up to increasing or decreasing load).
- **Contingency reserve** – available output from a generator that can be dispatched, or load that can be reduced, to restore the balance of supply and demand of electricity following a contingency or unforeseen event on the system. Contingency reserve is further categorized as either spinning reserve (immediate generator response) or supplemental reserve (10-minute response from generation or load).
- **Black start service** – supplied by generators that are able to start their generation facility with no outside source of power. In the event of a system-wide blackout, black start providers are called upon to re-energize the transmission system by providing start-up power to generators who cannot self-start.
- **Load shed scheme service** – supplied by electricity consumers (load) who have agreed with the AESO to be automatically curtailed in order to instantly reduce demand in the event of an unexpected problem that threatens the balance of supply and demand of electricity on the system. There is also a manual trip option available for certain circumstances.

In accordance with the T-Reg, load customers pay for the costs of ancillary services, including operating reserve. The mechanism the AESO uses to recover these costs from load customers is its tariff, which is filed for approval with the AUC. In the tariff, costs for ancillary services are identified in the rate component applicable to load customers and broken out in the following charges:

- The operating reserve charge recovers costs associated with regulating and contingency reserves and black-start services. This charge makes up the largest part of ancillary services costs recovered.
- The voltage control charge recovers costs associated with the provision of transmission must-run services.
- The other system support services charge recovers costs associated with other ancillary services.

The procurement and use of ancillary services will continue to be critical to ensuring the physical transmission system remains safe, reliable and able to respond to customer connection needs. These services supplement the available capacity and operational protocols that are part of effectively operating the grid 24 hours a day, seven days a week. By planning transmission infrastructure appropriately, the reliance on and need to procure some ancillary services will diminish over time.

For more information on ancillary services, refer to the [Ancillary Services Manual](#) posted on [www.aeso.ca](http://www.aeso.ca)

### **3.4.5 Transmission Constraints Management (TCM)**

The transmission system must be free of constraints for the underlying market model to function effectively. Transmission constraints can interfere with the flow of electricity from one part of the system to another or alter the normal dispatch of the energy market merit order, restricting market participants' access to the market and impacting market prices. The AESO's approach to constraint management must ensure transmission access and contribute to a stable investment climate in order to maintain investor confidence.

The AESO must actively manage transmission system constraints as they occur, take appropriate operational action to maintain system reliability, and optimize the use of existing transmission.

Reliability criteria are applied in planning studies to identify potential constraints and provide warnings of real-time potential or actual constraints. AESO monitoring and control systems detect constraints that system controllers must mitigate using established protocols and procedures.

The T-Reg obligates the AESO to make rules and establish practices to manage transmission constraints that may arise from time to time. The AESO has been consulting on constraints management with industry since the T-Reg became law in 2004. During those discussions, the AESO has been guided by the principles and recommendations of both the 2003 *Transmission Development Policy* and the 2005 *Electricity Policy* framework.

Recently the AUC has ruled on a challenge to the Transmission Constraints Rule 302.1 (TCM rule). The AUC has set out specific principles to be followed by the AESO in revising this rule. In response, the AESO has begun a process to engage market participants in the development of a new TCM rule that will meet these AUC principles. While the new TCM rule is being developed, the AUC has ruled that the existing TCM rule is to be used to manage transmission constraints.



The AESO manages, and will continue to manage congestion effectively by using practices and procedures such as regional operating procedures and remedial action schemes. These measures maximize the use of the existing system and help minimize congestion events. The AESO operates the system in a manner that ensures reliability criteria and reliability standards are met.

In addition, the AESO will continue to develop and implement Information Documents (IDs) to describe the management of constraints in specific regions. These IDs will be aligned with and based on the TCM rule.

In executing the transmission project plans defined within the 2013 LTP, there are times where the defined need date may not be met for numerous regulatory, logistical and project management reasons. It is during these periods when effective constraint management is essential to ensure Alberta's electricity market remains fair, efficient and openly competitive. Alberta's wholesale market design utilizes a single clearing price for all power regardless of the location from which power is delivered. To support this design, transmission must be available to all supply and load customers in a non-discriminatory manner and with sufficient capacity to ensure neither load nor generation is constrained. This is necessary to eliminate geographical pricing advantages caused by transmission congestion, and it exposes every generator to full competition from every other generator in the system. This encourages all generators to consider their marginal production costs in their energy offers in order to increase their chance of being dispatched ahead of their competitors. In turn, this provides consumers the lowest delivered cost of power. The full benefits of the competitive wholesale market can, therefore, only be realized with an unconstrained transmission system.

Another congestion management tool is transmission must-run (TMR). In areas where load is not sufficiently supported by the transmission system, the AESO must contract for the



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right to use local generation to meet local demand. The use of generators in this manner often results in the dispatch of more expensive generators to meet demand than would be the case if sufficient transmission capacity was available. The use of TMR contracts has been greatly reduced as transmission infrastructure has been built, such as in the northwestern part of Alberta. A significant reduction in contracted TMR occurred from 2011 to 2012. In 2012 the costs of contracted TMR were around \$3.7 million, and costs for 2013 are expected to be approximately \$2.5 million. No new TMR contracts are anticipated in 2014.

The AESO regularly monitors the impact of transmission constraints on the market and undertakes annual stakeholder reviews to discuss regional constraint issues. Please refer to the AESO's [24-Month Reliability Outlook \(2013-2014\)](#) for historical constraint information on the AESO's website.

### **3.4.6 AESO System Operations**

The function of an AESO system controller is much like an air traffic controller, using sophisticated data capture and analysis tools to monitor, analyze and direct the safe and reliable operation of the AIES 24 hours per day, seven days a week. This is accomplished using control systems that provide real-time visibility of power grid conditions and allow for contingency analysis in the event of transmission system element failures.

In addition to balancing supply and demand in real time, system controllers are responsible for all outage coordination, short-term and long-term operational planning, and working collaboratively with transmission facility owners and Emergency Management Alberta on system restoration activities to ensure that, in the event of a major disruption to service, normal operations can be quickly restored with minimal disruption to all Albertans.

Over the last decade, demands on provincial transmission infrastructure have increased significantly due to the growth in system load and the expansion of generating facilities—facilities that are now more diverse in type and geographic location. The significant increase of wind production and the growth of cogeneration in the north introduces unique operational challenges to the system. These types of generation facilities can be intermittent in nature and operate in a manner that is not highly controllable; wind power is generated when the wind blows and cogeneration facilities are designed and operated to meet industrial process needs rather than power system requirements. The variability of generation production challenges transmission operations and will continue to do so. Further reinforcement of the bulk and regional transmission systems will allow for greater diversity of total generation available on the system, and will ultimately better accommodate these types of intermittent generation sources.

The AESO manages the grid and system constraints through the effective execution of approved policies and procedures to ensure consistency and effective implementation of market rules. However, as the complexity and demand on the system increases, it has become evident that additional staff, information systems and technologies are needed to ensure visibility and proactive mitigation of potential system overloads. The AESO initiated a significant upgrade to its Energy Management System (EMS) in 2007 with the first stage completed in 2009, second stage in 2011, and the most recent enhancements implemented in 2013. In response to an ever evolving electric grid, the AESO will continue to respond

and upgrade its Energy Management System as required, integrating these new technology solutions into daily operations.

The EMS provides greater situational awareness and contingency analysis options to system controllers and their support teams, allowing for transmission capacity to be maximized while maintaining a safe and reliable operating condition. The need for custom tools are assessed, developed and implemented for the control room to monitor and manage the growing diversity and variability of new generation resources within the province. This allows the system to connect and absorb a greater volume of renewable resources than would otherwise have been possible in the past. The recent addition of the MATL inertia in September 2013 further increased the complexity of monitoring and managing fluctuating transfer capacity into and out of Alberta. New operating policies, procedures and protocols were designed and are now in place to enable this addition.

Also in 2013, AESO System Operations undertook two additional major initiatives. Firstly, the design, build and move into a new Back-up Control Centre that houses a secondary data centre and control room for use in the event that the Primary System Control and Data Centre require evacuation. Secondly, the AESO prepared to take on new responsibilities by assuming all Reliability Coordinator functions from the Western Electricity Coordinating Council (WECC) for the province of Alberta. Transition activities, including informing affected external entities, have been completed and the AESO assumed full responsibility of the role effective January 1, 2014.

Effective operation of the grid directly supports Alberta's fair, efficient and openly competitive market structure. As the size and complexity of Alberta's power system grows, AESO System Operations continue to evolve and employ the most appropriate technologies to maintain a safe, reliable and efficient system and operate a FEOC market.

#### **3.4.7 AESO Tariff**

The AESO applies to the Alberta Utilities Commission (AUC) for approval of the ISO tariff under Section 30 of the *Electric Utilities Act*. The tariff sets out the rates to be charged for, and terms and conditions that apply to, system access service provided by the AESO. The AESO typically submits a comprehensive tariff application for approval every two to three years. The AESO may also file tariff updates, deferral account reconciliations, and other applications on specific aspects of the tariff when warranted.

The 2014 tariff application was filed with the AUC July 17, 2013 and is expected, subject to AUC review and through a public proceeding, to result in rates that will become effective in 2014. Included as part of the tariff application is a Transmission Cost Causation Study that considers both existing transmission facilities costs and future planned transmission cost estimates identified in the 2013 LTP.

Transmission facility owners, including both owners of existing regulated transmission facilities and of future facilities resulting from a competitive process, will build, own, operate and maintain the projects proposed in the 2013 LTP, once regulatory approval has been received. The AESO pays owners for the use of their facilities and recovers those costs through regulated rates charged for system access service. Payments to the AESO for system access service are included in the transmission charges on bills for electric service paid by all end-use consumers, whether industrial, commercial, and residential or farm.

The total cost of all transmission projects, once approved by the AUC and ultimately constructed, is recovered over the life of the transmission facilities, which typically last 40 or more years. Not all projects are built at the same time and the impact of the projects in the 2013 LTP on customer rates will occur gradually as they are formally approved and placed in service over the years out to 2032.

The transmission projects in the 2013 LTP will have other impacts on the costs of electric service. In some cases, new transmission projects will reduce existing operating and maintenance costs associated with older transmission facilities that are scheduled to be removed or replaced. Additional capacity resulting from new projects will allow flexibility in operation and permit optimal management of the transmission system. New projects will improve the efficiency of the transmission system and reduce system losses and their associated costs. The transmission projects will also reduce costs resulting from transmission system constraint that can prevent the operation of the most economical generation available at any given time.

It is challenging to accurately determine the rate impact of these transmission projects, given the various factors mentioned above and the potential changes to project cost estimates and timing. Transmission rate impact analysis considers the project cost estimates and timing of anticipated in-service dates (ISDs). To provide frequent up-to-date information to stakeholders beyond that contained in the filed 2013 LTP, and to assist stakeholders in understanding how the cost of transmission projects impact their electricity bills, the AESO has developed and makes available a rate impact model in Microsoft Excel format on our website. This Transmission Rate Impact Projection workbook<sup>18</sup> is updated regularly, and the current version is available on the website.

<sup>18</sup> <http://www.aeso.ca> > Transmission > Transmission Costs

## 4.0 Forecast

The AESO's forecast is prepared in accordance with the EUA and T-Reg. As per Section 8 of the T-Reg, the AESO:

- (a) must anticipate future demand for electricity, generation capacity and appropriate reserves required to meet the forecast load so that transmission facilities can be planned to be available in a timely manner to accommodate the forecast load and new generation capacity,
- (b) must make assumptions about future load growth, the timing and location of future generation additions, including areas of renewable or low emission generation, and other related assumptions to support transmission system planning,
- (c) must make an assessment of the transmission facilities required to provide for the efficient and reliable access to jurisdictions outside Alberta, and
- (d) may, if the ISO considers it necessary to do so, make an assessment of the contribution of a proposed transmission facility to any of the following:
  - i) improving transmission system reliability;
  - ii) a robust competitive market;
  - iii) improving transmission system efficiency;
  - iv) improving operational flexibility;
  - v) maintaining options for long term development of the transmission system.

Building on previous long-term plans, the 2013 LTP is reflective of any material changes to Alberta's economic outlook, load growth and generation expansion and diversity. The updated forecast continues to emphasize the need for additional transmission development—particularly in the near and medium term—in response to the continued growth in Alberta's economy.

The 2013 LTP transmission recommendations are evaluated using the *2012 Long-term Outlook* (2012 LTO) as a key input. This includes views on Alberta's expected economic growth and anticipated future demand and energy requirements over the next 20 years, along with the projected generation capacity to meet those requirements. The 2012 LTO, published to the AESO's website July 2012, was prepared with significant consultation with industry experts, both load and generation entities, policy makers and distribution facility owners (DFOs).

Recognizing the long lead times required in performing transmission analysis, and in an effort to remain as accurate and current as possible, the 2012 LTO was formally reviewed and updated with findings published to the AESO website February 2013 in the form of the *2012 Long-term Outlook Update* (2012 LTOU). The bulk of the 2012 LTO assumptions remain valid. The only major adjustment required is the adoption of the final federal coal-fired regulation which replaces the previous Alternative Coal Legislation scenario.

Using the 2012 LTO and 2012 LTOU assumptions, the existing transmission system is assessed under various load conditions (winter peak, summer peak, and summer light) as well as for various generation conditions (variations of in-merit dispatch, seasonal fluctuations and levels for variable generation). Finally, the system is assessed using various intertie assumptions (maximum flows for import and export, economic flows and no flows).

The planning process is complex and takes into account multiple input assumptions, all with varying degrees of uncertainty, which culminate in the running of numerous scenarios, sensitivities and stress tests. It is further complicated by the fact that Alberta is a large interconnected system where the location of either new load or generation can create consequences in other parts of the system.

#### **4.1 FORECAST PROCESS**

Establishing a credible Alberta load forecast is an essential first step in ultimately performing the required analysis to determine the need for future transmission facilities. Economic indicators such as Alberta gross domestic product, population growth, oilsands production, and seasonal weather impacts are key inputs into the energy load forecast.

The AESO uses these inputs to create a forecast of future load and generation expectations. The AESO creates a reasonable outlook of future generation capacity to evaluate the transmission system requirements. Creating the generation forecast includes determining the future supply gap by considering load growth and future generator retirements in the province. It also includes assessing which generation technologies and resources are expected to be developed within the wholesale market to ensure an adequate supply to meet future load. The generation forecast incorporates historical trends as well as project-specific proposals of new capacity, including the proposed location of such facilities.

The 2012 LTO describes the methodology, assumptions and results which serve as key inputs to the AESO's long-term transmission planning process, and ultimately the publication of the 2013 LTP results. The 2012 LTOU is a higher-level update intended to test the key elements of the 2012 LTO and identify any material changes that may need to be adjusted. Both the 2012 LTO and 2012 LTOU are used as inputs into many AESO core functions.

The LTO provides a 20-year peak demand and electricity consumption forecast and a generation capacity projection for Alberta. The load forecast is created using a wide variety of inputs, including an economic growth forecast from The Conference Board of Canada, an oilsands production forecast, population projections and other variables. The load forecast is analyzed by customer sector with regional adjustments based on historical results and project-driven growth expectations. The generation forecast is created from an assessment of the economics and availability of generation resources in the province.

Recognizing forecasts are continually subject to change, and therefore contain levels of uncertainty, the AESO's 2012 LTO incorporates the use of five scenarios, established by identifying key drivers deemed to be of high impact or importance to the forecast.

These scenarios are:

- Low Oilsands Growth
- Environmental
- High Cogeneration
- Low Cogeneration
- Alternative Coal Legislation

In September 2012, the Canadian federal government adopted the final version of its *Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations*<sup>19</sup>. The AESO's Alternative Coal Legislation scenario was created to assess variations in the proposed coal legislation. However, the final version of the legislation results in coal retirements that land between the retirement dates outlined in the 2012 LTO and the Alternative Coal Legislation scenario. With this uncertainty removed, the AESO has dropped the original Alternative Coal Legislation scenario (2012 LTO) to capture the impact of the final version of the new regulations in the 2012 LTOU, and address the impact in the AESO transmission planning models.

Consideration of these scenarios allows the AESO to test the transmission system, evaluate impacts, and propose solutions, should these scenarios unfold. They also enable the AESO to assess future market and operational impacts.

The forecasting process benefits from continuous review and improvement, building on the success and accuracy of the AESO's previous comprehensive forecasts. In 2012 the forecasting process was more closely integrated, aligning the economic outlook, load forecast and the generation projection. Other improvements included increased stakeholder consultation, and an independent third-party review by ITRON Inc. of the forecast energy consumption sector models. Other key considerations such as overall economic growth trends, legislative evolution, technology development, energy efficiency, publicly announced projects, relative generation technology costs, and the impact of Alberta's market signals are also considered in finalizing the forecast.

The forecast process begins with the Economic Outlook, which is derived from The Conference Board of Canada's annual long-term provincial economic forecast.<sup>20</sup> This forecast is verified against other third-party forecasts for reasonability and accuracy. It provides a 20-year view of the economy and is therefore designed to capture long-term trends such as demographic and economic shifts rather than short-term events. The AESO works with The Conference Board of Canada to gain in-depth understanding of the economic drivers and risks inherent in the forecast.

<sup>19</sup> Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations SOR/2012-167

<sup>20</sup> <http://www.conferenceboard.ca> > Services > Reports and Recordings > Provincial Long-Term Economic Trends Service

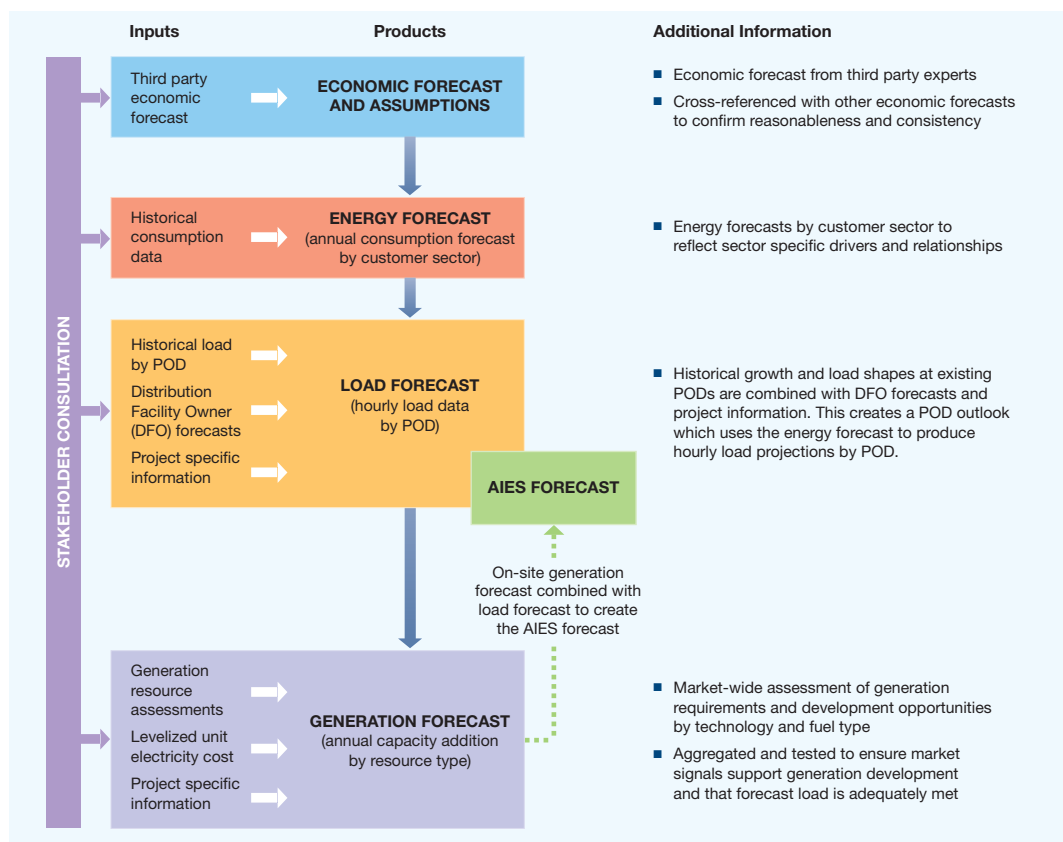


The Economic Outlook is used as a key input to forecast electricity consumption, or energy, using the economic drivers specific to five customer sectors:

- Industrial (without Oilsands)
- Oilsands
- Commercial
- Residential
- Farm

Figure 4.1-1 depicts the high-level process used to establish the 2012 LTO.

**Figure 4.1-1: Long-term Forecasting Process**





Stock photograph.

The oil sands sector is separated from the industrial (without oil sands) sector due to its importance to the Alberta economy, its unique electricity needs and its continued rapid demand growth rate. The energy forecast is then combined with point-of-delivery (POD) load shapes to produce an hourly load forecast by POD. The POD-level data is informed by historical data, publicly available information such as the AESO Connection Queue and Project List,<sup>21</sup> as well as external discussions with individual stakeholders, market participants, third-party experts, DFOs and others. In the longer term, there is naturally more uncertainty and less available information with respect to future electricity needs. Therefore, the forecast relies heavily on the trending of the long-term economic outlook.

The forecast load is compared against current installed generation and expected future retirements to assess the amount of incremental generation needed to reliably serve growing demand. Generation technologies and costs are assessed to determine what resources are expected to be developed in response to wholesale market signals to supply future electricity load. In a process similar to that of the load forecast, the generation forecast is informed in the near term by the AESO Connection Queue and Project List, as well as by external discussions with stakeholders, market participants, third-party experts, and other sources. In the longer term, the forecast relies more heavily on expected long-term trends in generation development such as relative fuel costs and expected technology developments.

There are key risks and uncertainties inherent in any long-term forecast, and these uncertainties increase the further out the forecast extends in time. The AESO addresses these risks and uncertainties through the use of scenario and sensitivity analysis.

<sup>21</sup> <http://www.aeso.ca> > Connections > Connection Queue

### 4.1.2 Stakeholder Consultation and Engagement Activities

Stakeholder consultation with the industry, general public, elected officials, special interest groups and others provides the AESO with a broad perspective and valuable input used to improve the reasonableness of the forecast and ultimately the transmission planning results. As an essential part of developing the 2012 LTO and 2012 LTOU, the AESO held individual meetings with a large number of market participants and other interested parties throughout late 2011, 2012 and 2013. These meetings focused on gathering information for the forecast, such as project details, corporate forecasts, market outlooks, and general expectations for future load and generation in Alberta.

The following organizations contributed to our forecasting activities and the AESO is grateful for the guidance, input and comments from the individuals representing these companies. Their guidance is not in any way an endorsement of the accuracy or validity of the 2012 LTO.

- Acciona Wind Energy Canada
- Alberta Energy Regulator  
(formerly Energy Resources  
Conservation Board)
- Alberta Wind Energy Corporation
- ATCO Power
- ATCO Electric
- Athabasca Oilsands Ltd.
- Benign Energy Canada II Inc.
- Canadian Association of  
Petroleum Producers
- Canadian Natural Resources  
Limited
- Capital Power Corporation
- Cenovus Energy Inc.
- City of Lethbridge
- City of Medicine Hat
- City of Red Deer
- Dover Operating Corp.
- Enbridge Pipelines
- Enel Green Power Canada Inc.  
EPCOR Utilities Inc.
- ENMAX Corporation
- FortisAlberta Inc.
- Greengate Power Corporation
- Maxim Power Corp.
- NaturEner Energy Canada Inc.
- Nexen Inc.
- Shear Wind Inc.
- Statoil Canada Ltd.
- Syncrude Canada Ltd.
- TransAlta Corporation

### 4.1.3 Policy and Regulatory Drivers

Existing and evolving policy and regulation are key drivers in the determination of forecasts and ultimately transmission plans, market dynamics and system operations. The applicable key policies considered in the development of the Plan are described in this section.

The 2013 LTP, through the use of the 2012 LTO, considers policy and regulations currently in force or proposed at the time of writing. However, it is recognized that unanticipated policies and regulations could have a large impact on the economy, load, and generation in Alberta. Therefore, the 2012 LTO scenarios provide flexibility for evaluating possible new initiatives and policies. Specifics of these scenarios that test variations to these assumptions are presented in detail in the 2012 LTO and 2012 LTOU.

### ***Oilsands Development***

The 2012 LTO implicitly assumes that the federal and provincial governments will continue to develop policies that support future oilsands development. An example of this commitment is the *Comprehensive Regional Infrastructure Sustainability Plan*<sup>22</sup> (CRISP), which establishes a long-term blueprint for future infrastructure development in the Athabasca oilsands area based on anticipated production rates and associated population growth. In addition, the 2012 Alberta Budget<sup>23</sup> clearly indicates the provincial government's expectation that oilsands production will increase and continue to provide increasing revenue to the province.<sup>24</sup>

Given the policy direction outlined above, the 2012 LTO does not anticipate a decline in growth in oilsands development. Environmental concerns, market accessibility, slowing of global oil demand and other factors that might limit oilsands development are considered in one of the scenarios presented.

### ***Climate Change Policy***

Environmental policy has been evolving for decades. Jurisdictions are taking varying approaches and there is no aligned direction for future environmental regulation for the continent. Coming out of the 2009 recession, one consistent theme to all policies was the fostering of economic recovery. In regards to future electricity consumption and generation in Alberta, the applicable federal and provincial climate change policies are discussed in the following sections. There is uncertainty regarding future policies as well as further renewable incentives, federal level air pollutant policy, demand side programs for conservation and efficiency, and focused technology development.

Given the uncertainty of these future policies, the 2012 LTO only considers the continuation and implementation of current and proposed policies, and does not assume the emergence of new policies. However, as new policy direction could significantly impact the 2012 LTO by changing electricity consumption and generation patterns, a scenario was developed to quantify the impacts of a strong shift in environmental policy.

To that end, the Environmental scenario examines a future in which both load and generation will be affected by comprehensive environmental and energy policies. This scenario takes direction from initiatives by the Government of Alberta such as the *Provincial Energy Strategy*.

### ***Federal Climate Change Policy***

Over the past decade, the federal government has considered different programs aimed at reducing greenhouse gas (GHG) emissions. While emission targets have been in place since the Kyoto Accord, few comprehensive policies have been implemented at a federal level. The degree of interdependence between the Canadian economy and the energy sector makes GHG reduction a complex task. Most climate change strategies implemented in different parts of the world involve putting a price on carbon, either through cap-and-trade initiatives or carbon taxes. At time of writing, the Canadian federal government has signaled

<sup>22</sup> <http://www.energy.alberta> > Key Initiatives > Oil Sands Sustainable Development Secretariat > Comprehensive Regional Infrastructure Sustainability Plan

<sup>23</sup> Released February 24, 2012

<sup>24</sup> Alberta Government Fiscal Plan 2012-15: Revenue

that it favours a control policy regulating emissions at source over a carbon tax or cap-and-trade system.

The draft coal-fired generation policy published in the *Canada Gazette*<sup>25</sup> in August 2011, entitled *Federal Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations*, was a first step toward implementing this direction. The draft regulation required physical compliance, set useful end-of-life of facilities at 45 years of operation, and defined a strict emission performance standard and a July 2015 effective policy date. Under this draft legislation, currently installed coal capacity was expected to retire at the end of useful life as compliance with the proposed emission standard would be prohibitively expensive. The Canadian federal government subsequently released its final version, *Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations*<sup>26</sup> in September 2012.

The AESO's Alternative Coal Legislation scenario was created to assess variations in the proposed coal legislation. However, the final version of the legislation will likely result in coal retirement dates that are between the dates outlined in the 2012 LTO and those of the Alternative Coal Legislation scenario. With this uncertainty removed, the AESO has dropped the Alternative Coal Legislation scenario and the 2012 LTOU incorporates the final version of the new regulations. The key difference between the draft and the final regulation is the length of "useful life" which was adjusted from 45 years to up to 50 years. This change has lengthened the life of coal-fired generation in the 2012 LTOU and results in fewer retirements during the first 10-year time period. Coal-fired generation retirements in this time period are similar to those identified in the Alternative Coal Legislation scenario. Total retirements in the 20-year timeframe remain similar, as some coal-fired units are required to retire before the 50-year useful life.

The federal ecoENERGY for Renewable Power program was launched in April 2007 to encourage the generation of electricity from renewable energy sources such as wind, low-impact hydro, biomass, photovoltaic and geothermal energy. The program provided a production subsidy of \$10/MWh for the first 10 years of operation for approved projects. The program supported the development of eight projects<sup>27</sup> in Alberta, for a total of 477 MW. Almost all the projects constructed in Alberta under the ecoENERGY program were wind energy projects, with the exception of one biomass project. At time of writing, there is no indication that this program will be extended, nor indications that other such wide-reaching programs will be developed and implemented.

Currently, there are no federal policies directly affecting electricity consumption. Indirect policies including improving building codes and building retrofit programs such as the ecoENERGY Retrofit program that expired June 2012 are generally offset by the trend towards larger residential and commercial buildings and smaller household size. The AESO's long-term energy models implicitly assume that current energy efficiency trends will generally continue.

<sup>25</sup> <http://www.gazette.gc.ca/rp-pr/p1/2011/2011-08-27/html/reg1-eng.html>

<sup>26</sup> Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations SOR/2012-167

<sup>27</sup> <http://www.ecoaction.gc.ca/ecoenergy-ecoenergie/power-electricite/contribution-eng.cfm>

### ***Provincial Climate Change Policy***

Large greenhouse gas (GHG) emitters in Alberta have been complying with the *Alberta Specified Gas Emitters Regulation*<sup>28</sup> (SGER) since 2007. SGER sets emission reduction requirements for large emitters, which are defined as sites emitting more than 100,000 tonnes of CO<sub>2</sub> per year, and is applicable to coal and large gas-fired generators. The regulation also creates an offset market for renewable electricity. The offset value for a renewable project is the project's environmental attributes, which are sold separately from the power.

Under SGER, large emitters must annually reduce emissions 12 per cent from their established baseline targets. In addition to physical compliance to meet reductions, they can purchase technology credits, or offsets, valued at \$15/tonne, which are worth approximately C\$8 to C\$10 per MWh from renewable sources within Alberta. The current scheme is due to be reviewed in 2014. The 2012 LTO assumes that SGER will continue in some form past this sunset date to provide support for renewable generation and to send a market signal to reduce GHG emissions. This assumption is aligned with the policy direction outlined in the *Provincial Energy Strategy*.

Going forward, it is expected that coal-fired generation will be subject to SGER until the more stringent federal performance standard is enacted, thereby superseding SGER requirements. Gas-fired generation will be subject to SGER until a replacement policy is created at the federal level.

At present, there are no programs at the provincial level designed to specifically promote electricity efficiency or demand side management.



AESO file photograph.

<sup>28</sup> <http://www.environment.alberta.ca> > Climate Change > Regulating Greenhouse Gas Emissions



### **Cross Border Climate Change Policy Influence**

In some U.S. states such as California, the establishment of a Renewable Portfolio Standard (RPS) has created a market for offsets for renewable energy. The RPS mechanism places an obligation on electricity suppliers to produce or procure a specified fraction of their electricity from renewable energy sources. There are limited opportunities to sell Alberta-based offsets to neighbouring jurisdictions with RPS requirements such as California. Generally, regulators prefer to support renewable projects within their own jurisdictions in order to support domestic jobs and industry. Other policy initiatives such as feed-in tariffs and carbon taxes are not currently under consideration in Alberta.

#### **4.1.4 Other Forecast Considerations**

In addition to scenario development, several forecast considerations were assessed and analyzed further, both quantitatively and qualitatively. The topics listed in Table 4.1.4-1 were identified as important considerations for further research and analysis in order to better understand their impact to the future load and generation. These considerations were included in the *2012 Long-term Outlook* and scenarios where appropriate. The AESO will continue to track these developments and adjust future long-term outlooks and scenarios as required.

**Table 4.1.4–1: Other Forecast Considerations**

<b>Load</b>	<b>Generation</b>
<b>Demand Side Management</b> <ul style="list-style-type: none"> <li>■ Energy efficiency</li> <li>■ Demand response</li> </ul> <b>Electric Vehicles</b>	<b>Other generation Technologies</b> <ul style="list-style-type: none"> <li>■ Geothermal</li> <li>■ Distributed generation</li> <li>■ Microgeneration</li> <li>■ Nuclear</li> <li>■ Energy storage</li> <li>■ Solar</li> <li>■ Hydro</li> </ul>
<b>Oilsands</b> <ul style="list-style-type: none"> <li>■ Alternative extraction technologies</li> <li>■ Electric intensities and efficiencies</li> <li>■ Upgrading capacity</li> </ul>	<b>Carbon Capture and Storage</b>

## 5.0 Forecast Results

The 2012 LTO and 2012 LTOU confirm expectations that the province will see continued economic growth driven by oilsands investment and related development. There are near-term risks to this growth, such as crude oil pipeline constraints, though the outlook over the next two decades is for continued development due to significant capital expenditures and a strong outlook for oil demand.

The expected economic growth accompanying oilsands development continues to drive energy and load growth in Alberta. Since the publication of the 2012 LTO, many oilsands projects have moved their regulatory and development processes forward. As a result, stronger oilsands development and corresponding higher load growth are anticipated mainly in the northeast region of the province.

The generation forecast matches the strong oilsands development and also incorporates finalized federal regulations on coal-fired generation. Combined-cycle generation remains the dominant technology to replace coal-fired retirements and meet new load growth. Wind facility additions have been reduced and the timing of development have been adjusted as a result of stakeholder consultation, which indicated current short-term market conditions are less supportive of project development.

The 2012 LTO and the 2012 LTOU forecast average annual Alberta Internal Load<sup>29</sup> (AIL) growth of 2.5 to 2.7 per cent to 2032, principally due to acceleration of oilsands projects and stronger oilsands production in the later years of the 20-year forecast period. This load growth, as well as the impact of the final federal coal-fired regulation, is reflected in the generation outlook.



Photo courtesy of ENMAX Energy.

<sup>29</sup> AIL is the sum total electricity consumption including behind-the-fence, the City of Medicine Hat, and losses (transmission and distribution).

Highlights from the 2012 LTO and 2012 LTOU comparison are best summarized as:

- Continued Alberta economic growth fuelled by oilsands development
- Rising demand from emerging markets continues to pressure oil prices upwards, while the availability of new supply resources keeps a ceiling on North American natural gas prices
- Long-run electricity demand growth will be driven by oilsands development and economic growth
- Coal generation will be significantly reduced over the next 20 years
- Generation in Alberta will shift to a cleaner emissions based fleet with additions primarily of natural gas and wind
- 2012 LTO scenarios remain valid for analyzing load and generation uncertainty, illustrating flexibility and forward thinking in the AESO's forecasting process

## 5.1 ECONOMIC OUTLOOK

The energy and load forecasts are derived using the long-term economic outlook forecast by The Conference Board of Canada. While there are continued risks to the global economy, the long-term forecast sees continued economic growth with strong demand for natural resources such as crude oil.

The western provinces will post the strongest provincial economic growth in Canada over the long term. It is anticipated this growth will be driven by global demand for primary commodities such as petroleum and mineral and non-metallic, mineral-related products. Overall, Canadian real gross domestic product (GDP) will advance at an average annual pace of 2.1 per cent to 2032, up 0.1 per cent from the initial 2012 LTO projection.

Alberta's economy is forecast to be the fastest growing in Canada with an average annual GDP growth rate of 2.7 per cent until 2032, up marginally when compared to the 2.4 per cent growth rate forecast in the initial 2012 LTO. It is expected this growth will continue to be driven by strong oilsands development. While there are near-term risks to this growth such as labour constraints and rising costs, the outlook over the next two decades is for ongoing development due to significant capital expenditures and strong oil demand. Principally, strong investment in the oilsands and associated development is expected to continue to drive Alberta's economy. This economic outlook serves as the foundation of the 2012 LTO and underpins both the load and generation outlooks.

From 2010 to 2013, AIL peak demand grew by an average of 304 megawatts (MW) (2.9 per cent) per year, increasing from 10,226 MW to 11,139 MW (an overall increase of 8.9 per cent). From 2010 to 2012, electricity consumption grew by an average of 2.6 per cent per year from 71,723 gigawatt hours (GWh) to 75,574 GWh. Over 2011 and 2012, load growth has been relatively strong in Alberta with average load increasing by 2.6 per cent and 2.4 per cent respectively. 2013 had the strongest growth in five years at 2.8 per cent, keeping right on track with the AESO's 20-year projection of 2.6 per cent annual growth.

Looking forward, the AESO is projecting continued strong energy and load growth, with peak demand growing annually at a rate of 3.1 per cent to 2022, and an overall forecast of

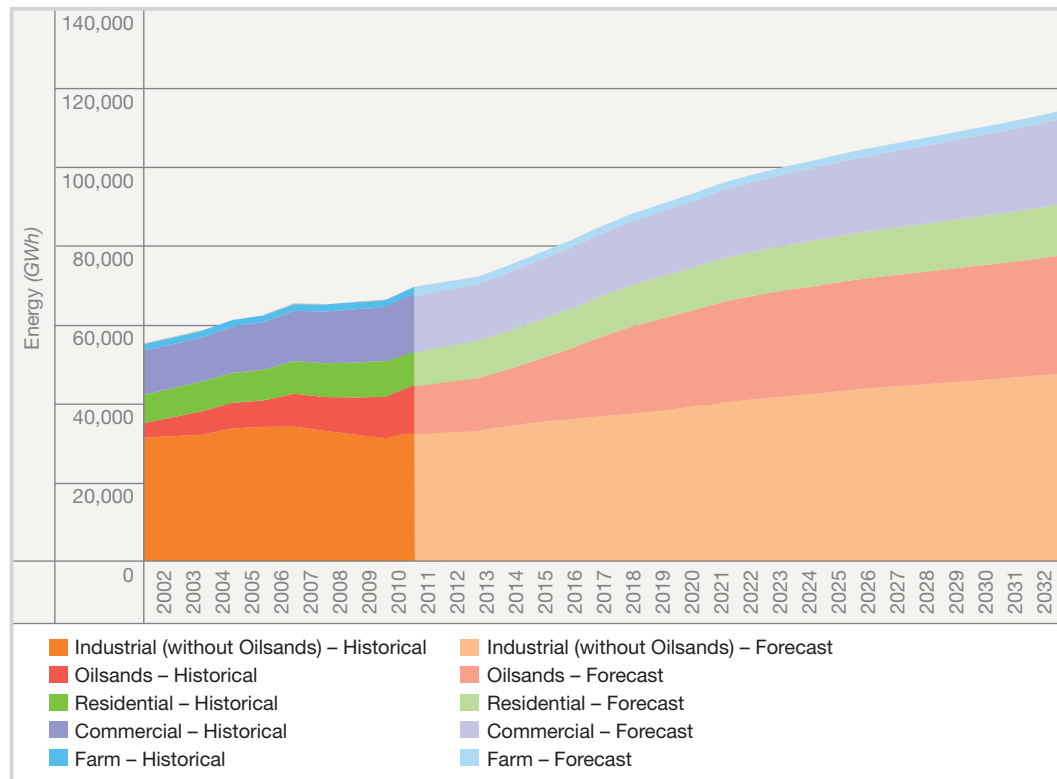
2.4 to 2.6 per cent average annual growth to 2032. Overall, long-run fundamentals remain robust with investment in oilsands development and associated industries expected to continue to drive strong economic and load growth over the next decade.

The AESO continues to recognize future uncertainty surrounding its forecast. Near-term risks could potentially impact oilsands development and corresponding load growth. Through the use of scenarios, including the Low Oilsands and the Environmental scenarios, the AESO continues to monitor, model, and quantify the potential impacts from future uncertainty.

## 5.2 CUSTOMER SECTOR ANALYSIS

The AESO analyzes and forecasts electricity consumption by customer sector: industrial (without oilsands), oilsands, commercial, residential, and farm. Each sector is modeled using key economic and demographic drivers.

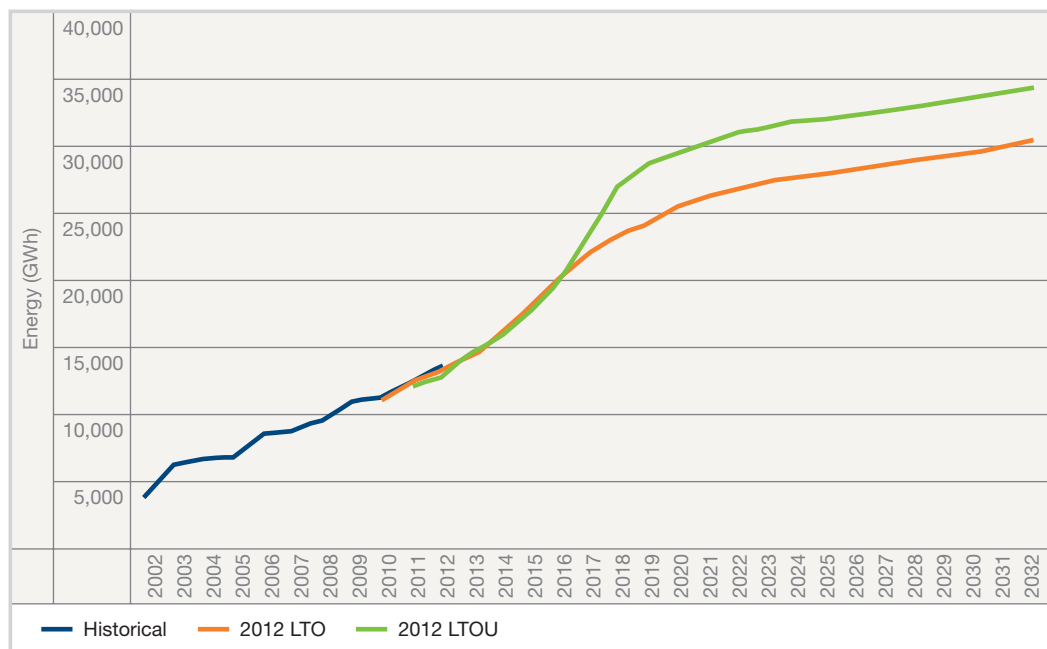
**Figure 5.2-1: Total Customer Sector Energy Outlook**



Source: AESO, ERCB

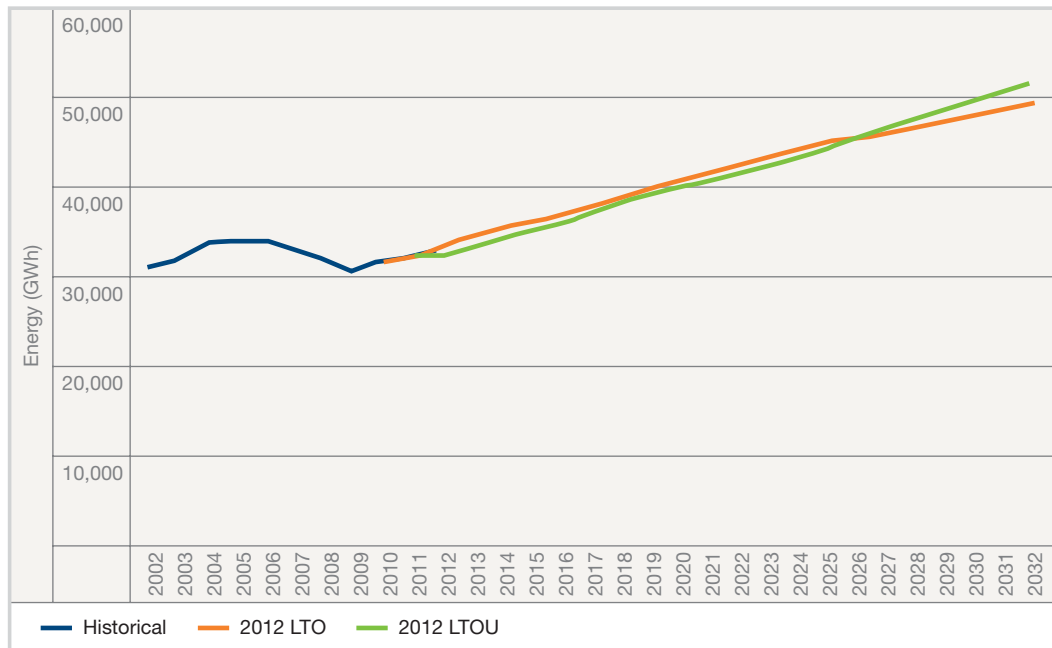
In the last two years many oilsands projects have moved their regulatory and development projects forward. This is reflected in the 2012 LTOU with an accelerated forecast of oilsands projects anticipated in the 2017 to 2019 timeframe. Oilsands electricity consumption is expected to grow rapidly, especially in the near and medium terms of the forecast. Oilsands electricity consumption is expected to grow at an average annual rate of 10.3 per cent until 2017, 7.6 per cent until 2022, and 4.7 per cent until 2032. The most recent 2012 LTOU indicates that the 4.7 per cent average annual growth rate until 2032 could in fact rise to as high as 5.7 per cent. In 2012, the oilsands sector grew from 12,142 GWh in 2011 to 13,364 GWh in 2012, an increase of 10 per cent. The 2012 LTO estimated 2012 oilsands energy of 13,331 GWh while the 2012 LTOU estimated 2012 oilsands energy of 12,886 GWh. The oilsands sector also grew 9.1 per cent in 2011.

**Figure 5.2-2: Oilsands Forecast**



The industrial (without oilsands) sector electricity consumption is expected to grow at an average annual rate of 2.0 to 2.2 per cent to 2032. The forecast for this sector reflects the changing trends of industrial demand. While some industrial subsectors, especially those associated with oilsands development such as pipelines and metals manufacturing are expected to grow, other industrial subsectors are not expected to be significant sources of growth. By incorporating third-party economic forecasts of key industrial subsectors that drive electricity consumption, the AESO's forecast reflects independent expectations of industry development, competitiveness and growth.

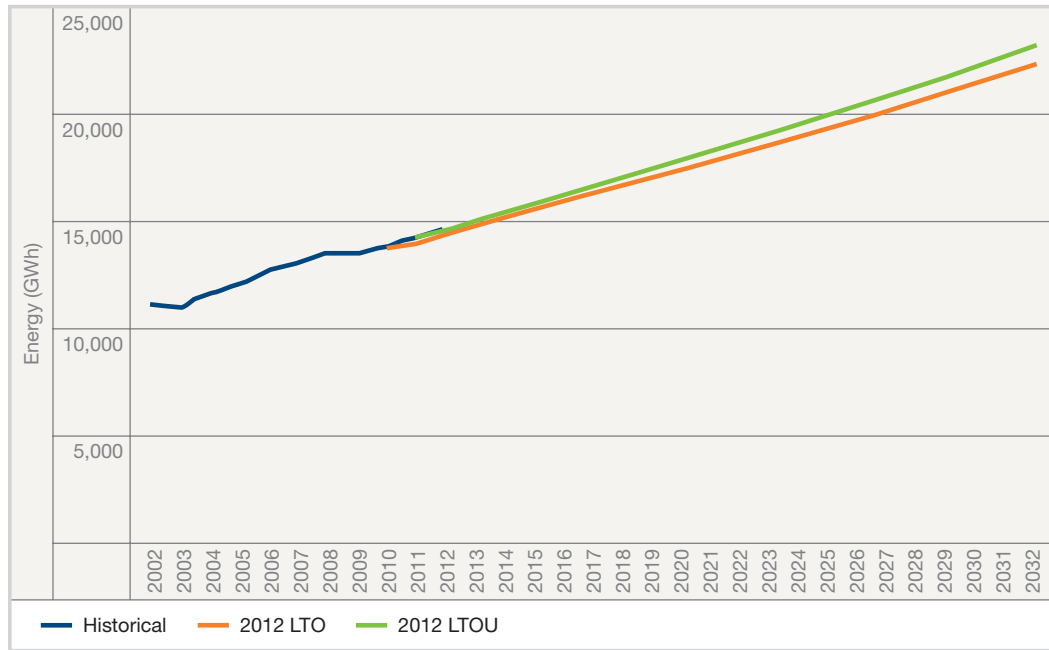
**Figure 5.2-3: Industrial (without Oilsands) Forecast**





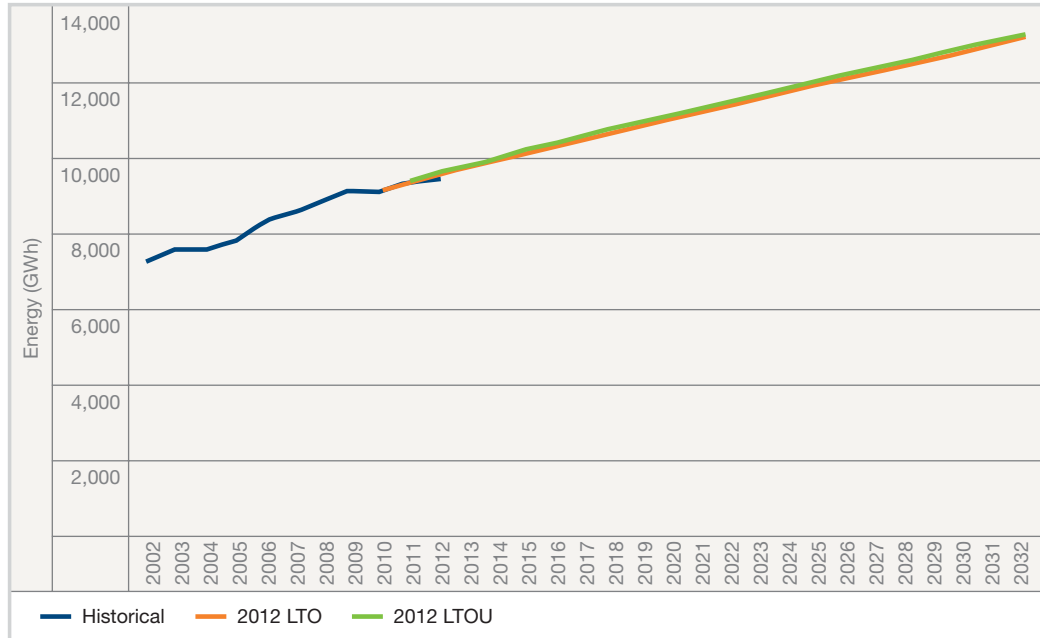
The commercial sector electricity consumption is expected to grow at an average annual rate of 2.2 to 2.3 per cent to 2032, which is generally in line with overall economic growth.

**Figure 5.2-4: Commercial Forecast**



Residential sector electricity consumption is forecast to grow at an average annual growth rate of 1.7 per cent to 2032, and is driven by growth in population and personal disposable income.

**Figure 5.2-5: Residential Forecast**



Future load considerations noted by the AESO are changing trends in demand response, conservation and energy efficiency, as well as environmental costs. Future policy changes may have an impact on Alberta's energy producing sectors including how electricity is used to meet environmental requirements. The AESO will continue to monitor the development of distributed generation offsetting grid load, as well as how electricity is used in a variety of residential, commercial, industrial and oilsands sites.

### 5.3 CHANGING GENERATION MIX

The actual amount of future generation supply is determined by market participants who assume the risk and reward of building generation in Alberta. In determining the amount and timing of expected generation additions, both forecast generation retirements and load are considered. In the 2012 LTO, assumptions regarding generation retirements and load growth have been adjusted to reflect updated information.

In Alberta, over 3,000 MW of generation capacity has been added to the system since 2008. These additions have come from a variety of technologies including coal-fired (686 MW), gas-fired (1,633 MW), wind (597 MW) and other technologies (107 MW). During the same period, approximately 550 MW of existing generation retired. The largest retirements have been the 279 MW Wabamun Unit 4 coal-fired units and the 209 MW gas-fired Rosedale facility.

At the end of 2012, total generation capacity in the province was 14,404 MW. Approximately 44 per cent of this total was coal-fired, 40 per cent gas-fired, six per cent hydro, eight per cent wind, with other technologies comprising the remainder.

While existing generation is sufficient to meet the current demand, the AESO monitors the ability of generation to meet forecast load in the two to five year time period through the quarterly publication of the *Long Term Adequacy Metrics* (LTA) report. There are four key metrics produced in the report. They include a list of proposed generations and retirement projects, annual reserve margin, daily supply cushion and the supply adequacy shortfall value. If the analysis indicates a potential LTA issue may develop, the rule indicates the ISO may take steps to address the concerns. Further, the LTA metrics are intended to provide information to stakeholders that will facilitate their assessment of the LTA. The AESO does not plan generation build for the province, so the LTA report provides stakeholders information to assist with investment decisions in Alberta's energy market.

Current analysis indicates that existing and future generation assets will be available to serve Alberta load requirements and there are no supply adequacy concerns.

The future generation mix in Alberta is expected to shift with baseload coal being replaced by natural gas, and the majority of generation additions to come from gas-fired combined cycle and cogeneration facilities, and renewables such as wind and biomass. This shift is a result of a combination of both retirements of existing coal units and additions from large baseload natural gas units. Wind generation is expected to continue to expand into other geographic areas beyond southern Alberta.

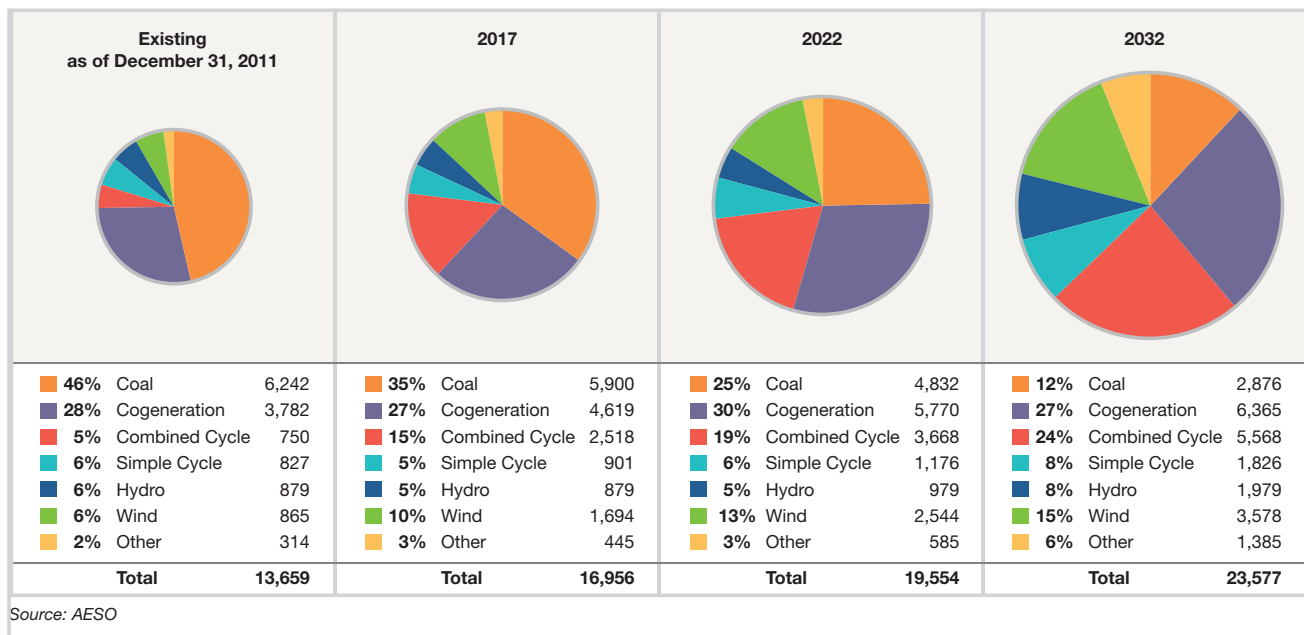
Based on the 2012 LTO, the installed generation capacity of 14,404 MW at the end of 2012 is expected to grow to approximately 19,600 MW by 2022 and 23,600 MW by 2032. Growth in combined cycle generation is expected due to low natural gas prices and a lower greenhouse gas (GHG) emission profile. Combined-cycle capacity will see a large increase from the current five per cent of installed capacity to 19 per cent in 2022 and 24 per cent in 2032.

Cogeneration additions are primarily driven by strong growth in the oilsands and the efficiencies offered by this technology. However, the proportion of this technology as a percentage of total installed capacity will remain similar to the current level of 29 per cent, moving to 30 per cent in 2022 and 27 per cent in 2032.

Forecast growth in wind facilities continues to be strong as Alberta has excellent wind resources. Wind capacity is expected to increase from the current eight per cent of installed capacity (1,088 MW) to 13 per cent in 2022 (2,544 MW) and 15 per cent in 2032 (3,578 MW), representing a tripling of capacity from the current installed wind generation today. The 2013 LTP has inherent flexibility to accommodate changes in generation fleet fuel mixes as it changes in the future.

The generation forecast incorporated the current \$15 per tonne carbon technology credit as it exists in the *Alberta Specified Gas Emitters Regulation (SGER)*<sup>30</sup>. The federal coal legislation incorporated into the forecast has resulted in no future development of conventional coal in Alberta. It is expected that carbon capture and storage technology will continue to develop and that any future coal generation will have this technology developed within the plant. By the end of the forecast period in the 2012 LTO, coal generation will have declined to only 12 per cent of the installed capacity in Alberta, while wind capacity in the province is projected to exceed coal by almost 25 per cent by 2032.

**Figure 5.3.5–1: Generation Outlook – Installed Capacity (MW)**



<sup>30</sup> <http://www.environment.alberta.ca> > Climate Change > Regulating Greenhouse Gas Emissions

## 5.4 SUMMARIZED 2012 LTO FORECAST RESULTS BY REGION

### 5.4.1 South

The South is the most populous of the AESO's five planning regions with approximately 1.65 million people or about 45 per cent of Alberta's population. Most of this population is concentrated in the Calgary area and is associated with residential and commercial demand; however, the region also includes some significant industrial loads. Overall, the South Region represents approximately 27 per cent of AIL Peak.

South Planning Region	
	Forecast Winter Peak Load (AIL)
2012 Actual	2,870 MW
Near term	3,510 MW
Medium term	3,936 MW
Long term	4,678 MW

### 5.4.2 Central

The Central Region contains about 352,000 people or about 10 per cent of Alberta's population, but accounts for approximately 15 per cent of AIL peak. The Central Region's population is mainly concentrated in the Red Deer area. The Red Deer area also contains fairly significant industrial load related to chemical and other manufacturing. In addition, there is significant pipeline load, especially in the eastern portion of the region. Two major export pipelines, Keystone XL and Energy East, are also planning to run along the east side of the Central Region.

Central Planning Region	
	Forecast Winter Peak Load (AIL)
2012 Actual	1,547 MW
Near term	1,836 MW
Medium term	2,039 MW
Long term	2,322 MW

### 5.4.3 Edmonton

The Edmonton Region contains the city of Edmonton as well as surrounding communities. It contains the second largest population of the AESO's planning regions with about 1.2 million people or about 34 per cent of the total population. It also contains the most significant amount of generation capacity, primarily located in the Wabamun area. The Edmonton Region accounts for 20 per cent of AIL peak. Much of this is residential and commercial load associated with the city of Edmonton. However, there is also a significant amount of industrial load including demand from Refinery Row as well as other manufacturing and pipeline load.

Edmonton Planning Region	
	Forecast Winter Peak Load (AIL)
2012 Actual	2,134 MW
Near term	2,506 MW
Medium term	2,785 MW
Long term	3,252 MW

#### 5.4.4 Northwest

The Northwest Region is characterized by low population, a relatively high proportion of industrial load, low growth in recent years and a respectable amount of potential future oilsands development in the Peace River area. Over the past 10 years, load growth in the Northwest has been the slowest of any of the regions with an average annual peak load growth rate of 1.2 per cent. Of the five AESO planning regions, the Northwest has the lowest population with approximately 172,000 people or less than 5 per cent of Alberta's population. However, this region accounts for approximately 12 per cent of AIL peak.

Northwest Planning Region	
	Forecast Winter Peak Load (AIL)
2012 Actual	1,233 MW
Near term	1,249 MW
Medium term	1,376 MW
Long term	1,563 MW

#### 5.4.5 Northeast

The Northeast Region is characterized by a relatively sparse population but contains significant amounts of industrial load and cogeneration. It is also the fastest growing region in terms of load as new oilsands and other industrial project activities connect to the AIES. Overall, the population in the Northeast is relatively low at approximately 240,000 or about 6.5 per cent of the province's total population. However, despite the relatively low population, the Northeast Region represents approximately 26 per cent of AIL peak.

Northeast Planning Region	
	Forecast Winter Peak Load (AIL)
2012 Actual	2,747 MW
Near term	3,933 MW
Medium term	4,685 MW
Long term	5,454 MW



## 5.5 INPUTTING FORECAST DATA TO TRANSMISSION PLANNING

Once the updated load and generation forecasts have been established, these inputs are fed into the transmission planning models to create base case models, planning scenarios and sensitivities, and to define stress test cases. This analysis determines both short-term and long-term system impacts and ultimately the assessment of transmission need to match the updated forecasts. The 2012 Planning Base Case Suite published to the AESO website in January 2012 is based on data from the 2012 LTO. The 2012 LTO and 2012 LTOU results continue to support ongoing connection studies, regional plans and future long-term plan publications.



AESO file photograph.

## 6.0 Transmission Planning

The AESO uses a comprehensive and continuous transmission system planning process based on detailed engineering evaluations of Alberta's transmission system over a 20-year planning horizon. The process involves three major steps:

- Need Assessment
- Alternative Screening
- Alternative Recommendation

Key inputs to the planning process include forecasts and assumptions regarding load growth and potential generation development and retirements, North American industry accepted reliability criteria and standards, government policy and regulation, infrastructure life-cycle requirements, operational requirements, capital costs, and environmental and social considerations.

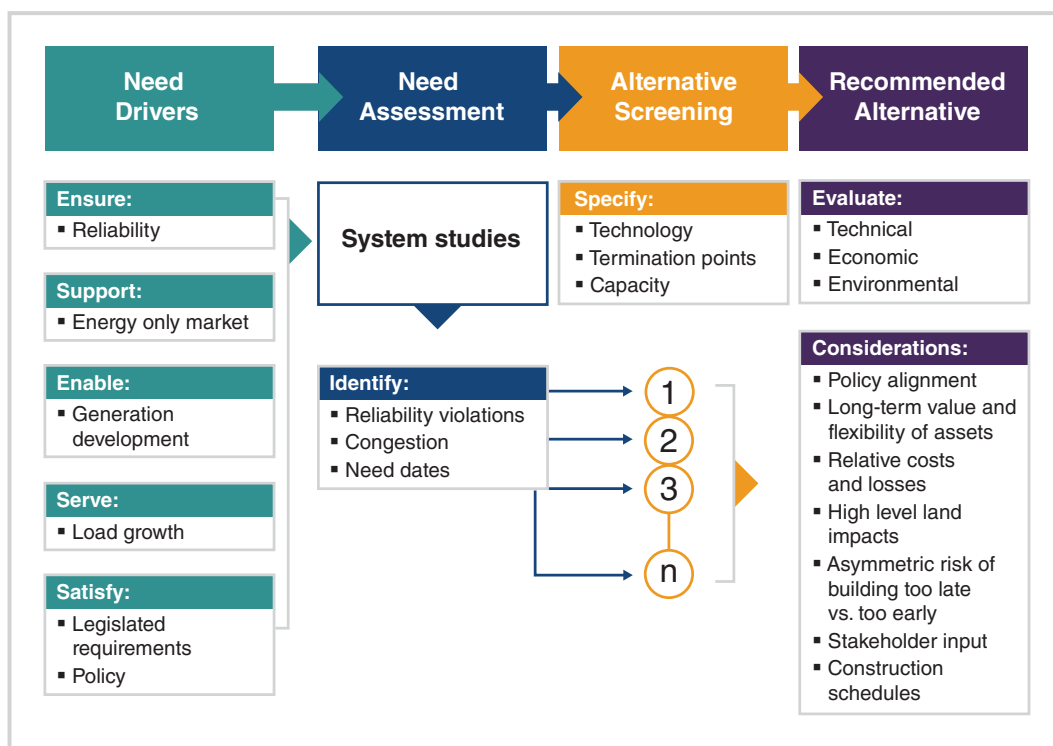
Some of the specific factors considered in the development of the 2013 LTP include the following:

- Continued strong load growth in Alberta as identified in the AESO's forecast
- Continued development and diversity of generation facilities, including new wind sites, new gas-fired generation, large hydro, and expansion of cogeneration operations
- Coal plant retirements in recognition of federal environmental policy, which will result in possible replacement with new gas-fired generation facilities
- The need to satisfy all Alberta Reliability Standards (ARS)
- Maintaining options for the long-term development of the transmission system
- Improving operational flexibility and system efficiency
- The inclusion of previously planned and approved inter-regional bulk system projects by their respective in-service dates
- The integration of the new Montana-Alberta Tie Line (MATL) merchant transmission onto the grid and the AESO's continuing work on restoring the existing interties to their design capacity
- Recognition of the supporting interim non-wires solutions, operational protocols and market products which support transmission infrastructure when required
- Interties to other jurisdictions
- A high-level land impact assessment and environmental considerations

The fundamental need for transmission system developments and regional upgrades described in previous AESO long-term transmission plans continues and the 2013 LTP provides the latest comprehensive update of the required transmission system enhancements for each planning region over the 20-year planning horizon.

Figure 6.0-1 provides an overview of the three-step planning process. The AESO begins with need assessment studies that identify the need for transmission under the scenarios identified in the load and generation forecasts. Once the AESO identifies the need for transmission enhancements, it then identifies and screens several transmission system alternatives to meet the needs. From these alternatives, the AESO identifies a suite of recommended alternatives from which plans are developed to meet the needs under the forecast scenarios. These steps are further elaborated below.

**Figure 6.0-1: Transmission System Planning Components**



## 6.1 NEED ASSESSMENT

The AESO's forecast provides assumptions on the magnitude, type, approximate location and timing of anticipated connections which ultimately serve to define the required transmission system enhancements and their respective need dates. It is also necessary to determine the need for transmission system development sufficiently in advance of when it is needed in order to ensure that future transmission facilities are available in a timely manner to accommodate the forecast load and generation requests.

Uncertainty with respect to timing and location of load and generation developments is a primary consideration in transmission system planning. Scenarios comprised of different sets of planning assumptions allow planners to consider the implications of uncertainty in a controlled and consistent manner. Through the use of scenarios, the AESO can develop plans to accommodate a range of potential future conditions, rather than a single future trajectory. Scenario consideration also allows for a more complete assessment of risks and identification of possible mitigations such as identifying milestones, triggers and off-ramps that allow development plans to be adjusted in the future as new information emerges.

Generally, it is the identification of future occurrences of Alberta Reliability Standards (ARS) violations and system constraints under forecast loading that determines the need for, and timing of, future transmission system enhancements. It is the location and magnitude of new loads and sources of generation that drives the need for transmission system expansion. Large bulk system transmission system expansions are generally driven by the need to increase transfer capability between regions.

In addition to reliability assessments, the AESO considers other factors that may require the building of new transmission facilities. For example, transmission facilities that are reaching the end of their useful life will need to be replaced. This presents an opportunity to consider higher capacity (possibly higher voltage) facilities, or even reconfiguration of the system. Losses are another driver for replacing existing facilities with higher capacity, more efficient facilities.

## 6.2 ALTERNATIVE DEVELOPMENT AND SCREENING

Once the AESO has determined the need for transmission enhancements, it can begin developing alternatives to meet those needs. The AESO performs an assessment of thermal loading, voltage and dynamic stability, as well as testing of ARS requirements to verify that the alternatives are technically feasible.

In addition to the reliability evaluations, the AESO gives consideration to existing system facilities, technology risk, project staging, high-level capital and operating cost, alignment with legislation and government policy, land use, and stakeholder input. Alternatives to be considered include reconfiguring parts of the system, changes in voltages and new transmission technologies.

The AESO screens alternatives to develop a final set of alternatives to be used in developing transmission plans for each scenario. The AESO then uses this resulting set of feasible alternatives to formulate transmission development concepts that are subjected to further assessments to identify recommended transmission system plans.

### 6.3 TRANSMISSION PLAN ASSESSMENT AND RECOMMENDATION

Once the AESO has reduced the alternatives to a final list for further consideration, regional transmission plans are developed based on synergies identified for the selected alternatives. Synergies between various needs may allow for a group of enhancements to cover multiple needs. The alternatives are combined into transmission system plans for each planning region based on needs in each area. In developing the plans, AESO transmission planners look for synergies between alternatives that meet differing needs for the various scenarios.

The AESO then tests the regional plans for robustness. The ultimate goal is to develop one overall transmission system plan that is capable of accommodating a variety of uncertainties over the planning horizon. The AESO assesses each regional plan against a set of technical, economic, operational, social and environmental considerations across multiple future scenarios. The AESO assesses the regional plans against the following:

- The technical requirements of ARS including thermal loading, voltage stability and dynamic stability to ensure a full characterization of performance capabilities for each alternative
- The capital costs of the alternatives
- The high-level potential land use impacts of the alternatives, alignment with existing corridors, and proximity to environmentally sensitive areas
- The options for long-term development and expansion provided by each alternative
- The operational flexibility and efficiency provided by each alternative
- Alignment with regulation and policy objectives

The AESO recommends the suite of alternatives in each region that represents the best trade-off across the range of considerations. To prudently address uncertainty, the planning process includes establishment of milestones and triggers to ensure transmission developments are implemented in a timely manner.

A selected transmission system plan includes a portfolio of transmission projects that can be implemented as certain milestones are met, or it may involve the identification of several phases of a single project that can be staged as necessary. To further manage uncertainty, the AESO endeavours to obtain approval of transmission system enhancements well in advance of need. However, the AESO closely manages facility development through the issuance of directions to the legal owners of transmission facilities, and issues them as necessary to ensure that facilities are placed into service in a timely manner.

The recommendations of proposed transmission infrastructure projects, along with the description of the need for each, are discussed in Section 7.0 – Transmission Results and Plan.

## **6.4 ROLE AND DEVELOPMENT OF MILESTONES**

Where the AESO is reasonably specific that certain expansions or enhancements will be required in the future, milestones may be identified to allow for staging of the enhancements.

The creation of milestones assists the AESO in managing uncertainty associated with changing economic and market conditions. The AESO is continually monitoring market conditions, reporting on changes, revising and updating system studies, and amending estimated in-service dates as conditions change.

### **6.4.1 Background**

Given the expected future growth of Alberta's economy, it is necessary to expand the transmission system in order to sustain a reliable supply of electricity and ensure an unconstrained transmission system. It is the responsibility of the AESO to ensure that transmission capacity is in place to meet the forecast needs of Alberta so that economic growth and development are not compromised.

The development of milestones is important to allow for the continued evaluation of timing or staging of transmission projects. To ensure that transmission is developed in a timely manner and to meet future infrastructure needs, it is important to identify and monitor milestones that may affect the timing requirement of the proposed transmission enhancement projects.

### **6.4.2 Use of Milestones**

The uncertainty associated with load and generation additions is reflected in the scenarios and sensitivities that the AESO studies to determine transmission enhancement requirements. Establishing milestones allows the AESO to adapt its proposed solutions to the scenario that ultimately manifests in the future. Accordingly, the AESO bases milestones related to the staging of transmission enhancements on the determination of incremental need under each scenario to ensure transmission development is in place to meet forecast need.

To accomplish this, the AESO may initiate transmission preconstruction activities as a first step. These preconstruction activities include such items as planning studies, engineering, siting and right-of-way acquisition.

### **6.4.3 Development of Milestones**

The AESO bases the timing for submitting a NID, the timing of a TFO's submission of a facility application, and the commencement of construction activities, on the combination of elements and consideration of risks under various scenarios. Load and generation scenarios indicate need dates for the incremental staging of various transmission enhancements. As these scenarios manifest, the AESO conducts analysis of key elements to determine changes to project in-service dates and ensure enhancements are in place ahead of need.

#### ***Technical requirements***

The technical analysis is intended to ensure compliance with ARS. The analysis is based on thermal loading, voltage stability, dynamic stability analysis and system operating limits.



### ***Market Impact***

This includes assessment of transmission system access for incremental generation and load, and potential for transmission congestion under various normal and abnormal operating conditions. The market impact evaluation includes assessment of the system operating limits which are a measure of congestion that requires generating units to be run out-of-merit.

### ***Economic Analysis***

The economic analysis uses the present value method and is based on planned capital investment for projects as well as consideration of system losses. Escalation of material and labour costs become part of the economic analysis. If an overall reduction to the present value over the life of the project can be achieved by advancing a project's in-service date, the AESO may recommend advancement.

### ***Development Risk***

This includes assessment of development risks due to externalities such as those related to regulatory processes, unanticipated siting issues and possible delays in related projects. Availability of material and labour can also impact the development of a project.

### ***Market Participant Connections***

The AESO expects that actual construction is staged to align with load increases and generating unit connections. There are a number of milestone dates in a generation or major load project schedule including: approval of provincial and federal environmental impact assessments, award of engineering and prime contractor contracts, order of major equipment, delivery of major equipment, ground breaking and site mobilization, and construction power to the site. The AESO identifies suitable generation or load project milestones that trigger transmission construction and assure a continuing match of timelines between the generation or load projects and the related transmission projects.

#### **6.4.4 Monitoring**

Successful development of transmission system projects is enabled by the identification of appropriate milestones. The AESO expects that development of projects is proactive, with transmission development being completed before the need for transmission occurs. The AESO monitors generation and major load projects to determine when they have reached the milestones that trigger the construction of the required transmission system facilities.

The AESO assesses milestones for the associated facility application to ensure the project is still needed in the timeframe originally determined. Once the AUC approves the facility application, milestones are reassessed before commencement of construction. The AESO bases its monitoring process on the same key indicators that are updated annually as part of the forecast models.

The AESO performs technical and market studies on an annual basis to determine if there are any changes to the desired need date or in-service date. The AESO also performs economic analysis and development risk assessment on an annual basis to ensure that there are no changes to these factors.

The transmission system projects recommended in the 2013 LTP include the identification of several key project-related metrics. In completing its analysis, evaluation and determination of need, the AESO determines the in-service dates of transmission facility projects to meet forecast need, and defines project cost estimates. The most prominent drivers requiring mitigation or response are customer connection requests, system capacity deficiencies, operating limit restrictions and system reliability concerns. Specific to these drivers, the common elements to be addressed are system reliability, reduction or removal of constraints, voltage fluctuation, frequency excursion, thermal line loading, reduced line losses, reduced dependency on non-wires short-term solutions, and the ability to fulfill load and generation connection requests.

The 2013 LTP provides a high-level summary of planned transmission infrastructure projects anticipated to 2032. Greater specifics, including full project scope and technical details of the planned transmission infrastructure projects, are provided in the AESO's comprehensive regional transmission plans which will be published on the AESO website in the first quarter of 2014.

## **6.5 PLANNING TRANSMISSION TO MEET ALBERTA RELIABILITY STANDARDS**

In planning the Alberta transmission system, the AESO must meet the performance requirements of applicable Alberta Reliability Standards<sup>31</sup>. Any planning study being performed on the AIES, including connection studies, must comply with these reliability standards. This section provides a summary of the requirements under *TPL-001-AB-0*, *TPL-002-AB-0*, *TPL-003-AB-0* and *TPL-004-AB-0*. The purpose of these Alberta Reliability Standards is to ensure that the transmission system is planned to meet certain performance requirements under a defined set of system conditions and contingencies.

The following are the primary applicable standards Alberta Reliability Standards:

- TPL-001-AB-0, System Performance Under Normal Conditions
- TPL-002-AB-0, System Performance Following Loss of a Single Bulk Electric System Element
- TPL-003-AB-0, System Performance Following Loss of Two or More Bulk Electric System Elements
- TPL-004-AB-0, System Performance Following Extreme Bulk Electric System Events
- FAC-001-AB-0, Facility Connection Requirements
- FAC-010-AB-2.1, System Operating Limits for the Planning Horizon
- FAC-014-AB-2, Establish and Communicate System Operating Limits

<sup>31</sup> <http://www.aeso.ca/rulesprocedures/17006.html>

It is generally accepted in Alberta and other jurisdictions that it is not feasible or practical to plan the addition of transmission facilities to accommodate all types of contingency events under all system conditions. Within Alberta Reliability Standards, the acceptable performance of the transmission system under various contingency conditions is identified in Appendix 1 of the TPL reliability standards. The AESO is required to:

- Assess the transmission system under pre-determined critical system conditions, considering the contingency events listed in the reliability standards as Categories A through D, each of which recognize a decreasing probability of occurrence and are accompanied by a decreasing performance requirement
- Put a plan in place to ensure that the transmission system continues to operate reliably

For Category A through C contingencies, the AESO is required to provide corrective action plans to achieve the required system performance.

The AESO must demonstrate through assessment that the transmission system is planned in the near term, the medium term and the long term so that it can accommodate forecast load and generation without interruptions when all transmission facilities are in service, and following loss of a single element (TPL-001 and TPL-002). When system simulations indicate an inability to meet the above requirements, the AESO must develop transmission enhancements to achieve the required performance.

The AESO must also demonstrate through assessment that the transmission system is planned so that it can accommodate forecast load with controlled load interruption or removal of generation following the loss of two or more elements (TPL-003). It must also be evaluated for the risk of system performance following extreme events (TPL-004).

The planning assessments upon which the 2013 LTP are based satisfy the requirements of applicable Alberta Reliability Standards.

## 7.0 Transmission Results and Plan

The 2013 LTP identifies and recommends transmission solutions to address existing and anticipated constraints and performance violations throughout the transmission system. This enables load and generation customers to connect to the grid, thereby ensuring the Alberta Interconnected Electric System (AIES) continues to meet the province's current and future electricity needs.

The bulk transmission system is the integrated system of transmission lines and substations that delivers electric power from major generating facilities to load centres. The bulk system also delivers power to, and receives power from, neighboring jurisdictions. The bulk transmission system generally includes 500 kilovolt (kV) and 240 kV transmission lines and substations.

The AESO's comprehensive regional transmission plans identify specific projects and take into account key metrics such as technology, planning need dates, projected in-service dates and staging, where practical and prudent. In order to develop a robust plan over a 20-year study period, the AESO models and presents details in three distinct time intervals: near term (to 2017); medium term (2018 to 2022); and long term (2023 to 2032).

It is important to recognize that transmission builds are typically long lead time endeavours subject to substantial regulatory, environmental and stakeholder review. Transmission infrastructure, once built, provides long service life of 40 or more years. The AIES must operate as part of a larger North American interconnected transmission system.



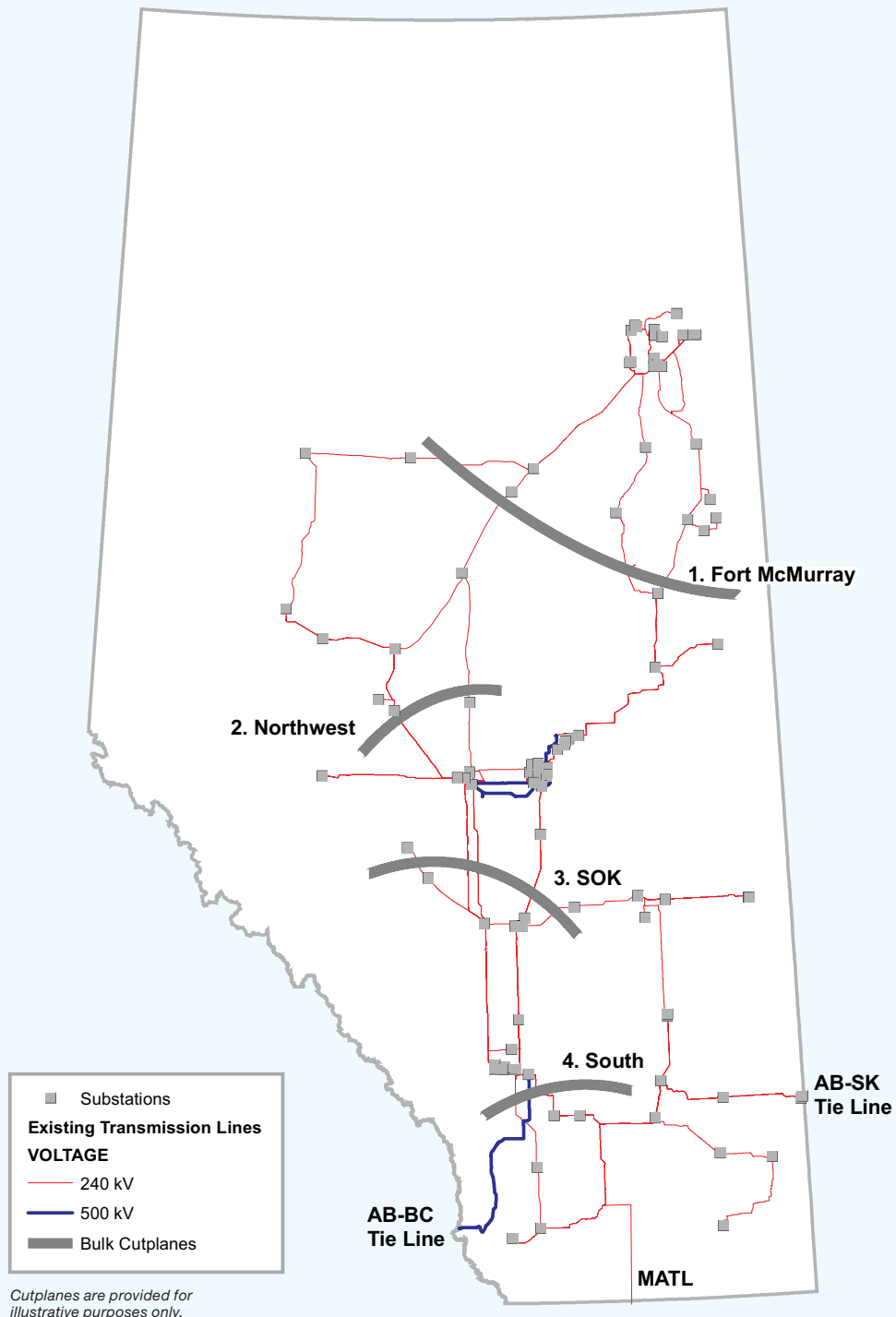
Photo courtesy of AltaLink

## 7.1 ESTABLISHED TRANSMISSION FLOW CUTPLANES

Cutplanes, also known as transmission system paths, are often used to aid bulk transmission planning and operations. These cutplanes combine the loading on groups of transmission lines that connect two regions within the bulk system. Within Alberta, there are four major cutplanes used to study the bulk transmission system, as shown in Figure 7.1-1.

1. **Fort McMurray cutplane** – Currently, the Fort McMurray area connects to the AIES system through four long 240 kV transmission lines. Two of these lines, 9L07 and 9L990 are connected to the Edmonton area transmission system via the Fort Saskatchewan area, 9L56 is connected to the Wabamun area via the High Prairie area, and 9L15 is connected to the Peace River area. All these lines combined together are referred to as the Fort McMurray cutplane.
2. **Northwest cutplane** – There are currently three 240 kV lines between the Wabamun Lake area and the northwest area. These three lines, plus a number of 138 kV lines, interconnect the Wabamun Lake area with the northwest area and are referred to as the Northwest (NW) cutplane.
3. **South of Keephills-Ellerslie-Genesee 240 kV (SOK) cutplane** – There are currently six 240 kV transmission lines between Edmonton and the Red Deer area. In addition, two 240 kV lines—one from Brazeau power plant to Benalto and another from Red Deer substation to the Hanna area—also contribute flows to this cutplane. All eight lines are collectively called the SOK cutplane.
4. **South cutplane** – There are currently three 240 kV lines between the south area and the Calgary area. These lines, plus a number of 138 kV lines, interconnect the south area with the Calgary area and are referred to as the South cutplane. In addition, the South cutplane includes the 500 kV line from B.C. to Calgary.

Figure 7.1-1: Existing Bulk Transmission System, Major Cutplanes and Interties





Besides the four cutplanes internal to Alberta, there are now three interties to other jurisdictions that are considered part of the bulk system, as shown in Figure 7.1-1.

**Alberta to B.C. intertie** – There are currently one 500 kV and two 138 kV lines between Alberta and B.C. These three transmission lines collectively constitute the intertie to B.C. Through this intertie, Alberta is connected to the B.C. system and on through to the transmission systems in the U.S. Pacific Northwest and the rest of the systems comprising the Western Interconnection of North America.

**Alberta to Saskatchewan intertie** – Alberta is connected to the Western Interconnection and Saskatchewan is part of the Eastern Interconnection. The Eastern and Western Interconnections are not synchronously connected and are joined together via high voltage direct current (HVDC) back-to-back (i.e., asynchronous) links at various points in Canada and the U.S. The Alberta-Saskatchewan intertie comprises an HVDC facility, known as the McNeill converter station, located near Empress, Alberta. The converter station is connected via a 138 kV transmission line to the Alberta system and a 230 kV line to Swift Current, Saskatchewan. This intertie provides Alberta access to the electricity markets in the Eastern Interconnection through Saskatchewan and Manitoba and the U.S. Midwest, and similarly provides entities in these jurisdictions with access to the Alberta market.

**Montana to Alberta merchant intertie (MATL)** – This path consists of a 230 kV merchant line connecting MATL substation near Lethbridge, Alberta to Marias-Great Falls substation near Great Falls, Montana. This merchant intertie is predominantly used to import wind-generated power from Montana into Alberta.

## **7.2 STATUS OF APPROVED AND ACTIVE MAJOR BULK TRANSMISSION SYSTEM PROJECTS**

The bulk transmission system is essential to overall system reliability, forming the backbone that delivers bulk power to load centres, integrates and connects the transmission regional infrastructure, connects new and existing generation and enables transfer capacity between neighboring jurisdictions, supporting both import and export transactions.

The need for these projects was presented in the AESO's 2012 LTP and therefore is not reiterated here for the sake of brevity. The following section describes the current status of approved and active major bulk transmission system projects.

### 7.2.1 Edmonton to Calgary Transmission System Reinforcement

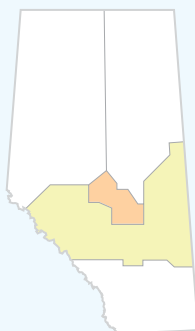
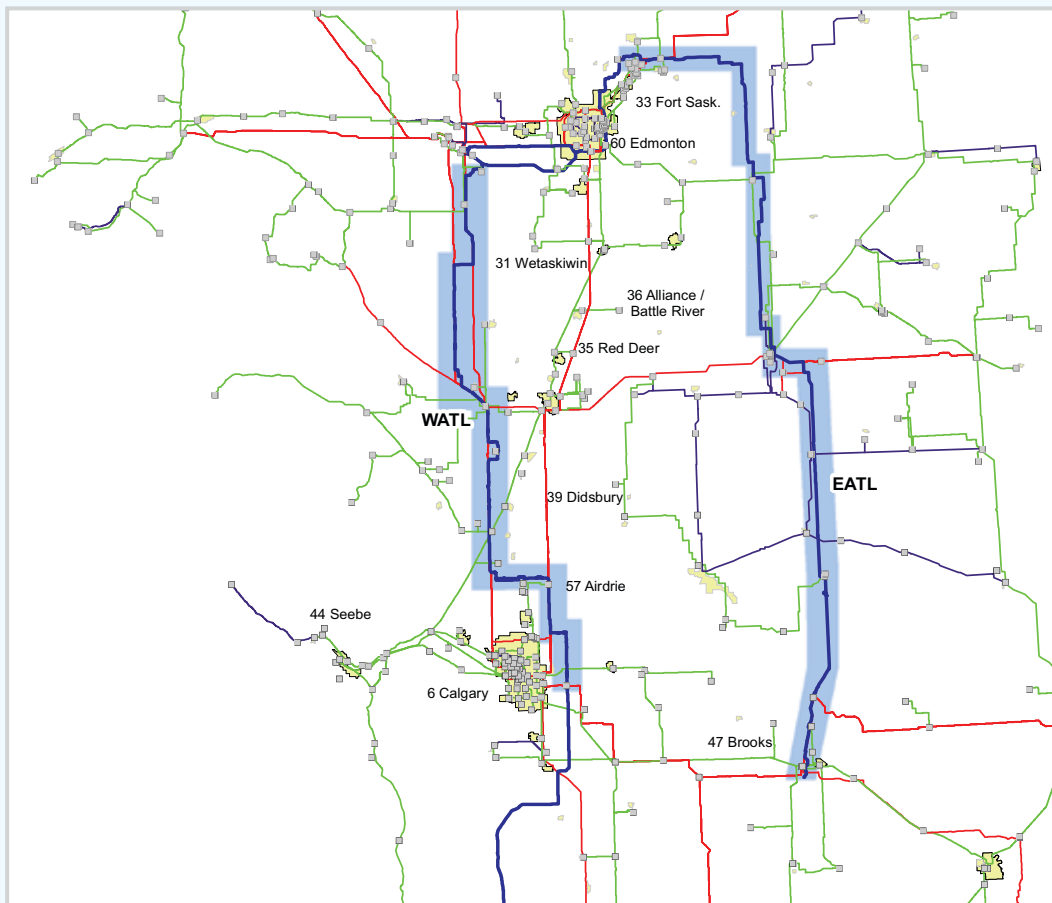
The North-South Transmission Reinforcement Project consists of two  $\pm 500$  kV HVDC high-capacity lines between Edmonton and Calgary. The Eastern Alberta Transmission Line (EATL) is located on the east side of the province, connecting the Heartland hub northeast of Edmonton to a southern hub in the Brooks area. The Western Alberta Transmission Line (WATL) will be located on the west centre portion of the province, connecting the Wabamun Lake hub west of Edmonton to the Calgary area hub near Langdon. Each line will initially be designed for 1,000 MW capacity with provision for expansion to 2,000 MW in the future. The AESO's recent planning assessments indicate that expansion is not required prior to 2032, based on the latest assumptions.

The AUC issued approval to ATCO Electric Ltd. (ATCO) to develop EATL, and to AltaLink Management Limited (AltaLink) to develop WATL. On November 15, 2012, ATCO received Permit & Licenses (P&L) for EATL and on December 6, 2012 AltaLink received P&Ls for WATL. Subsequently, construction activities began in December 2012 and continue to progress to meet the planned in-service dates of December 2014 for EATL and April 2015 for WATL.



Photo courtesy of ATCO Electric.

**Figure 7.2.1-1: Edmonton to Calgary Transmission System Reinforcement**



**Edmonton to Calgary Transmission System Reinforcement**

- ISD for EATL: December 2014
- ISD for WATL: April 2015
- Two 500 kV HVDC lines (1,000 MW each)
  - East-Heartland to Brooks (EATL)
  - West-Genesee to Langdon (WATL)
- Expandable to 2,000 MW each
- Required to:
  - Address reliability issues
  - Improve efficiency
  - Accommodate long-term growth
  - Support energy market

*Map is for illustrative purposes only and does not represent actual terminations or routes*

### 7.2.2 Heartland Transmission System Reinforcement

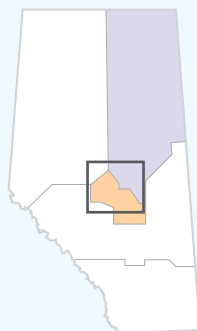
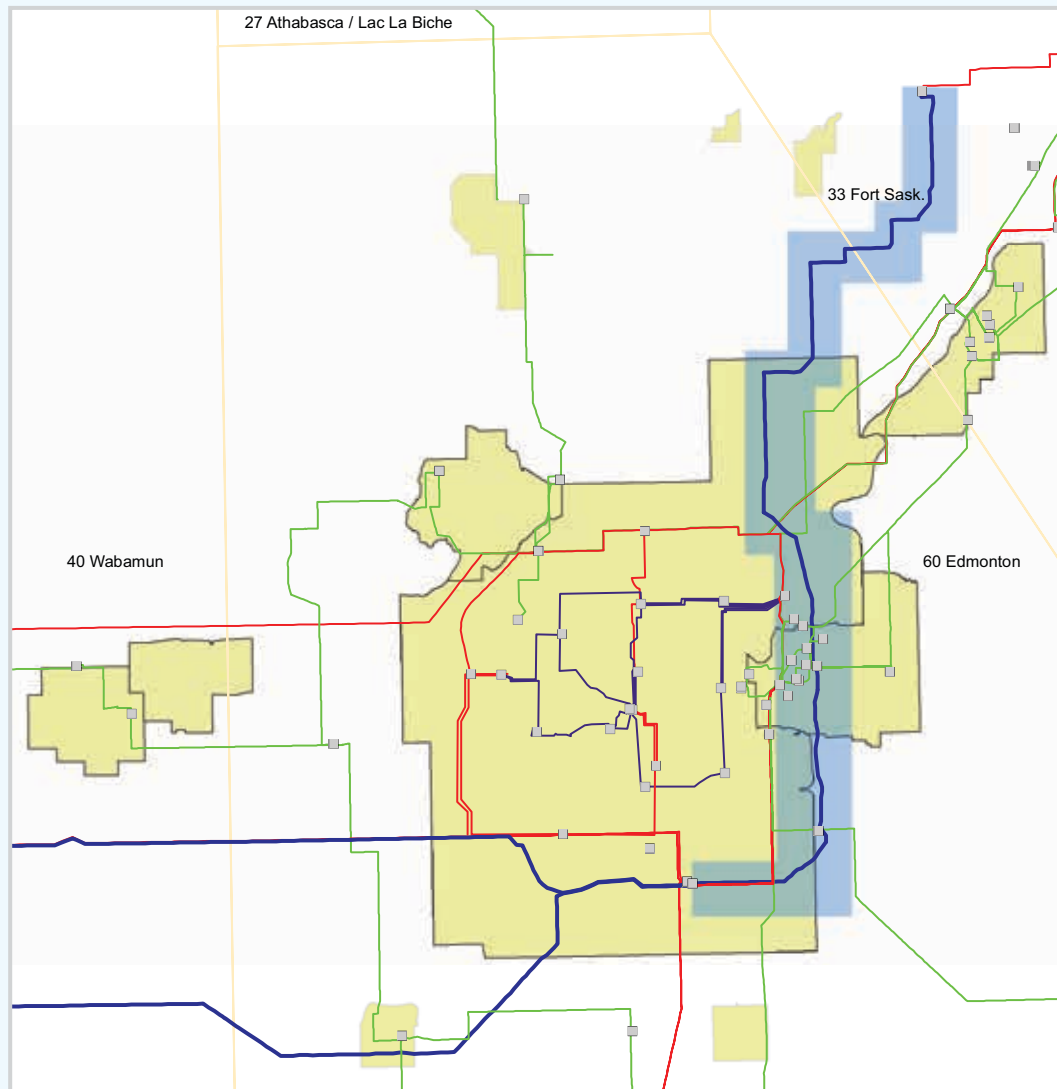
The existing transmission system into the Northeast Region and Heartland area is constrained. The northeast is currently supplied by a double-circuit 240 kV line from Edmonton through Fort Saskatchewan, and a single-circuit 240 kV line from Wabamun to the Fort McMurray area. Reinforcement of the transmission system between the Edmonton and Heartland areas is required to avoid system reliability issues for both the Heartland area and the Fort McMurray area.

Currently, interim technical measures in the form of operating procedures are required to ensure reliable supply to the northeast. Continued constraints and congestion will slow oilsands and bitumen upgrading development in Alberta. Adding high capacity 500 kV lines into the area will facilitate investment decisions by oilsands developers. These decisions not only relate to potential load growth in the area, but can also facilitate increased cogeneration opportunities by allowing excess electric generation at these sites to connect to the transmission system, providing new generation sources for the Alberta grid.

The specific facilities recommended for the transmission reinforcement between the Edmonton and Heartland areas is a 500 kV double-circuit line from the existing Ellerslie substation in south Edmonton to a new substation in the industrial Heartland area. This will strengthen transmission into the area and will provide a strong source for an eventual 500 kV line into the Northeast Region. This transmission enhancement not only reinforces the system between Edmonton and the northeast, but also provides a termination point for the proposed east HVDC line. The configuration of this 500 kV double-circuit line is described in the *Electric Utilities Act* as follows:

- One double-circuit 500 kV alternating current transmission facility connecting to the 500 kV transmission system on the south side of the city of Edmonton and to a new substation to be built in the Gibbons-Redwater region

**Figure 7.2.2-1: Heartland Transmission System Reinforcement**



**Heartland Transmission System Reinforcement**

- 2014 ISD
- Double-circuit 500 kV from Ellerslie to Heartland
- Required to:
  - Supply northeast load
  - Interconnect east HVDC
  - Supply Heartland load

### 7.2.3 Fort McMurray Transmission System Reinforcements

As with the transmission reinforcements required into the Heartland area, transmission reinforcement into the Fort McMurray area is driven by oilsands development.

The Fort McMurray area is unique from a planning perspective as it has a significant number of large industrial customers. These customers will be contracting both demand transmission service (DTS) and supply transmission service (STS) with varying degrees of usage to supply process requirements and for electric supply reliability. Planning for a transmission system that is capable of handling the simple sum of all contracted DTS and STS will result in overly large capital investments. On the other hand, not planning for a broad enough range of DTS and STS requirements can result in constraints and possible violation of the AESO's reliability criteria. The solution is to find the most probable load and supply scenarios that the Fort McMurray region will experience over the planning horizon and plan accordingly, taking into account associated uncertainties.

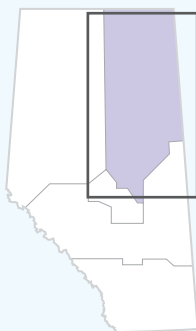
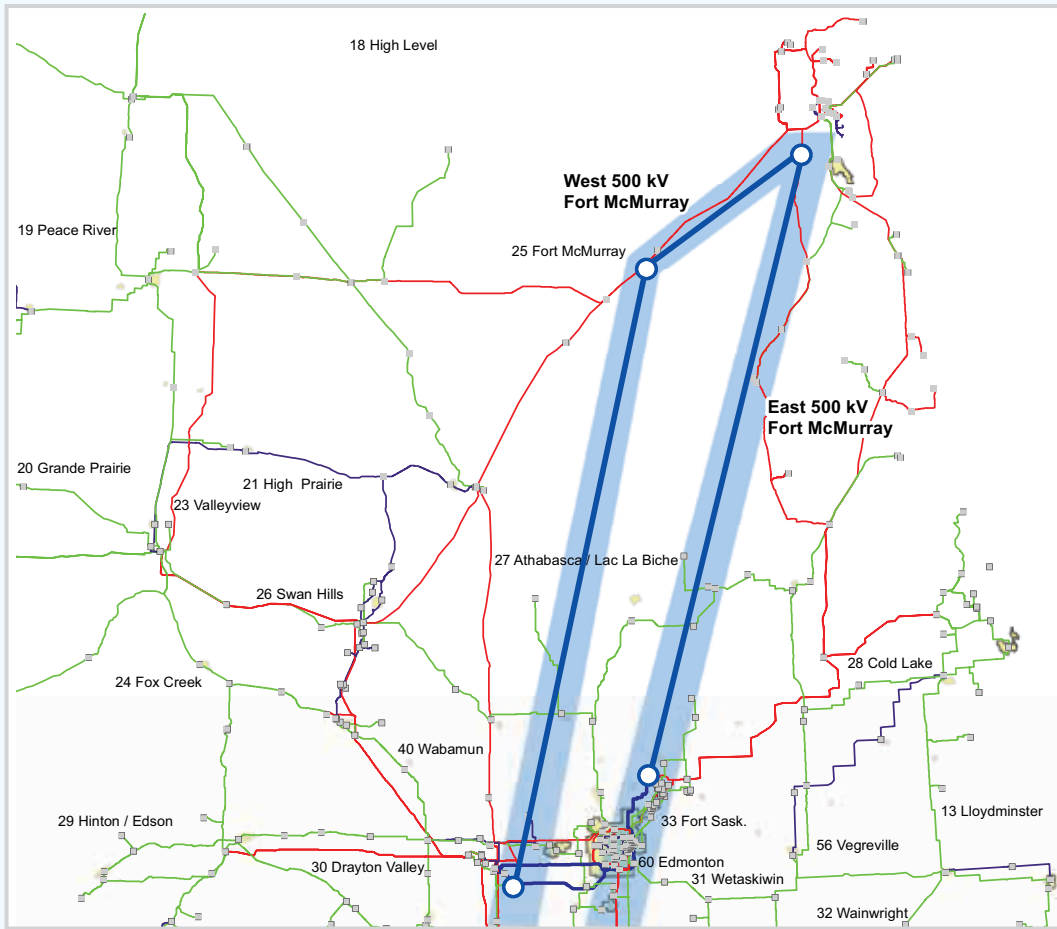
The specific facilities recommended for this reinforcement are a 500 kV AC line referred to as Fort McMurray West 500 kV Line from the Sunnybrook substation near the Genesee generating station to a new 500 kV substation in the Fort McMurray area (Stage 1), and a 500 kV AC line referred to as Fort McMurray East 500 kV Line from the new Heartland substation to the new Fort McMurray 500 kV substation (Stage 2). The Fort McMurray West 500 kV Line will be connected at the existing Livock substation near Brintnell 876S substation. Both of these lines will be developed through the Competitive Process. Work on the West 500 kV line is in progress under this process. The configuration of these lines is described in the *Electric Utilities Act* as follows:

- (a) A transmission line from a new substation to be built in the Thickwood Hills, approximately 25 kilometres (km) west of the Fort McMurray Urban Service Area, to a substation at or in the vicinity of the existing Brintnell 876S substation.
- (b) A transmission line at or in the vicinity of the existing Brintnell 876S substation to a substation in the vicinity of the existing Keephills-Genesee generating units.
- (c) A transmission line located east of the facilities described in clauses a) and b) and geographically separated from those facilities for the purposes of ensuring reliability of the transmission system, from a new substation to be built in the Gibbons-Redwater region, to a new substation to be built in the Thickwood Hills area, approximately 25 km west of the Fort McMurray Urban Service Area.

It has been realized under the Competitive Process that the earliest the Fort McMurray West 500 kV Line (Stage 1) can be completed is by the 2019/20 timeframe. The in-service date of Stage 2 is determined to be sometime after 2020.



**Figure 7.2.3-1: Fort McMurray Transmission System Reinforcements**



**Stage 1: Fort McMurray West 500 kV**

- 2019–2020 ISD
- Sunnybrook - Livock - Thickwood Hills 500 kV
- Required for northeast load

**Stage 2: Fort McMurray East 500 kV**

- Post-2020 ISD
- Heartland - Thickwood Hills 500 kV
- Required for northeast load

*Map is for illustrative purposes only and does not represent actual terminations or routes*

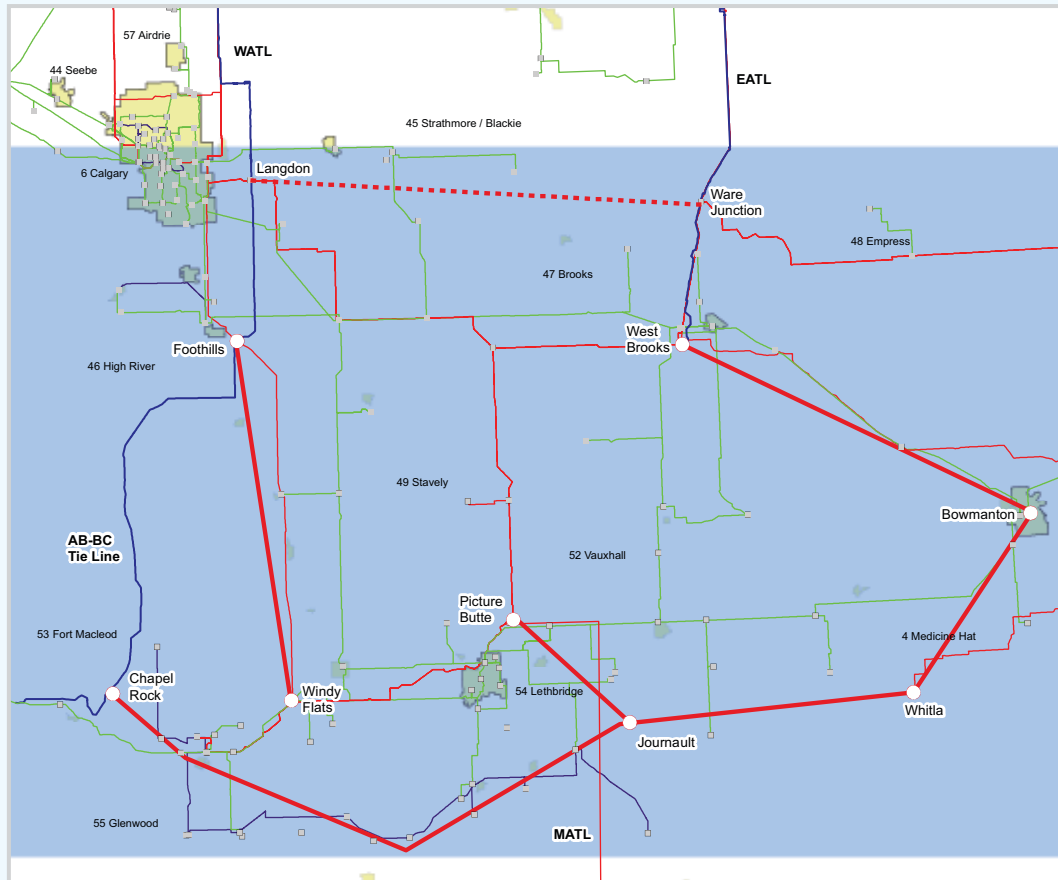
#### **7.2.4 Southern Alberta Transmission Reinforcement (SATR)**

The AESO identified the need for transmission development in southern Alberta in the SATR NID, which was approved by the AUC on September 8, 2009<sup>32</sup>. The need for SATR is primarily driven by forecast wind generation and the limited capability of the transmission system to deliver additional generation on a firm basis to the AIES. SATR was approved to be developed in three stages in accordance with specified construction milestones. Since AUC approval, the following components of the SATR developments have been energized and operational: Milo switching station, Ware junction substation upgrade, phase shifter at Russell substation, Cassils to Bowmanton 240 kV line. The remaining projects in Stages 1 and 2 are at various stages of development.

The AESO's recent planning evaluations found that with the development of the EATL and WATL HVDC lines, the third stage of SATR, between Ware Junction and Langdon, is no longer required. The primary reason for this is that the HVDC lines, primarily EATL, provide an adequate transfer path for the high levels of wind development forecast in southern Alberta, making the third stage redundant. As a result of these findings, the AESO submitted an amendment to the SATR NID to the AUC on December 13, 2013 for the cancellation of the third stage of the SATR project.

<sup>32</sup> Decision 2009-126, Approval No. U2009-340; subsequent amendments have resulted in the current Approval No. U2013-460

**Figure 7.2.4-1: Southern Alberta Transmission Reinforcement (SATR)**



**Southern Alberta Transmission Reinforcement (SATR)**

- 2011–2017 ISD
- Extensive 240 kV looped system and tie to 500 kV line
- Required to integrate renewable and gas-fired generation

*Map is for illustrative purposes only and does not represent actual terminations or routes*

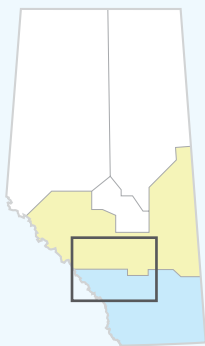
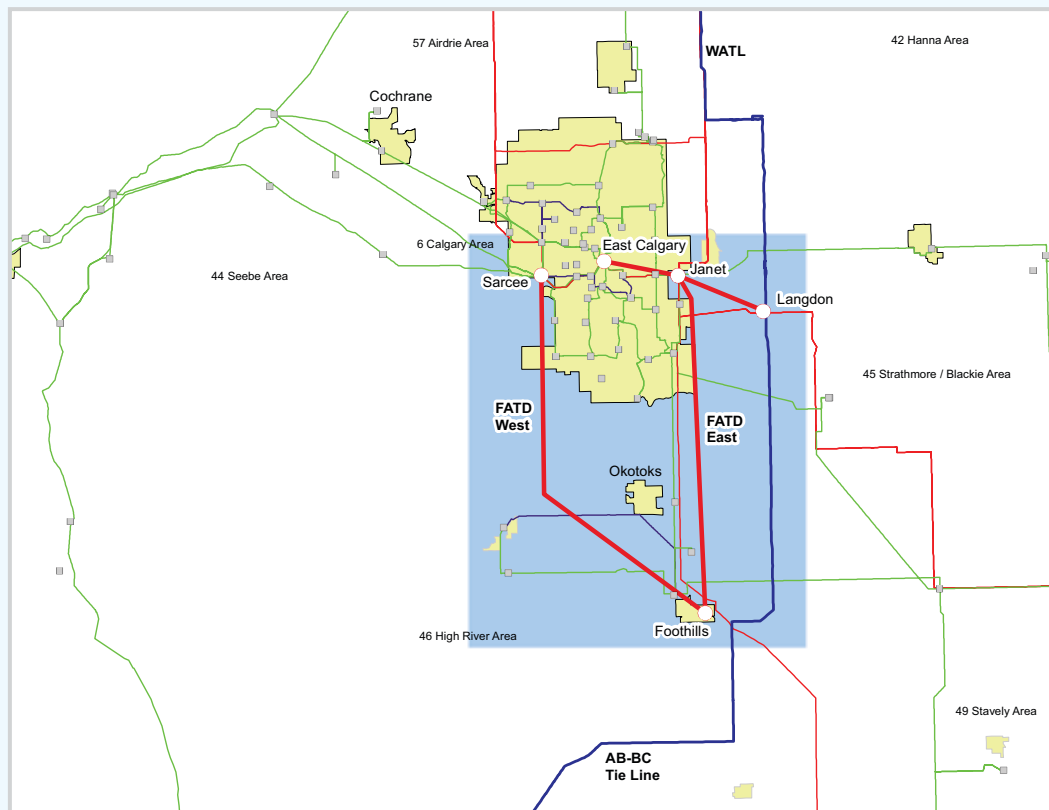
### **7.2.5 Foothills Area Transmission Development (FATD)**

In addition to the 240 kV looped system in the south, the FATD project is an integral part of the system required to move wind energy to the load centres of the Foothills and greater Calgary areas. This project includes a 240/138 kV substation near High River, 138 kV transmission system enhancements in the High River and Okotoks areas, and two double-circuit 240 kV lines from Foothills into Calgary, one to the east side of the city and the other to the west side. The project is planned to be developed in stages over time.

In addition to integrating wind energy, the Foothills area development provides other benefits by creating a system that will accommodate gas-fired generation in and near the city of Calgary, as well as mitigating local transmission constraints within the city to facilitate future load growth.

Generation development, both wind in the south and gas-fired generation in and around Calgary, can impact the FATD project. The AESO's recent planning evaluations determined that the west 240 kV line, from Foothills substation to Sarcee substation, can be deferred until approximately 2022, based on the latest assumptions. The FATD project, which includes only the east 240 kV line and the 240/138 kV substation near High River, was approved by the AUC on October 7, 2013. The AESO will submit a NID for the west 240 kV line at an appropriate future date.

**Figure 7.2.5-1: Foothills Area Transmission Development (FATD)**



**Foothills Area Transmission Development (FATD)**

- 2014–2017 ISD
- 240/138 kV substation south of Calgary
- 138 kV enhancements in High River and Okotoks areas
- 240 kV line east into Calgary and other 240 kV enhancements
- Required for reliability, load and to integrate renewable and gas-fired generation
- Application for west 240 kV line to be submitted at a future date

*Map is for illustrative purposes only and does not represent actual terminations or routes*

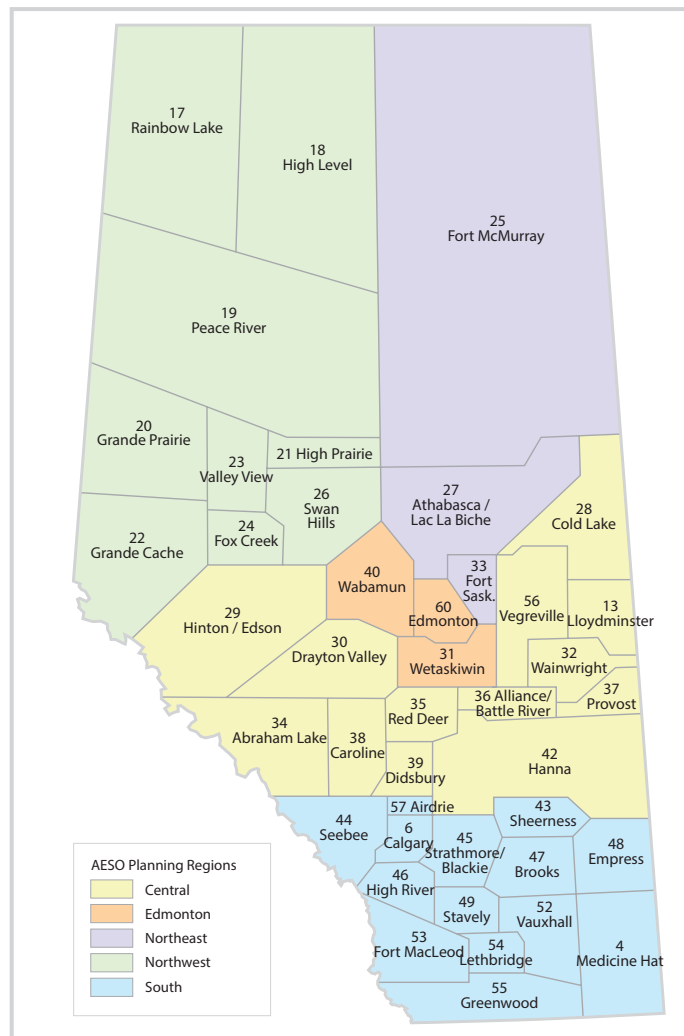
### 7.3 REGIONAL TRANSMISSION SYSTEM PLANS

The AESO divides the province into five major geographic regions for planning purposes:

- South Region
- Central Region
- Northwest Region
- Northeast Region
- Edmonton Region

The planning regions are further divided into smaller planning areas to facilitate detailed engineering evaluations of the transmission system in specific areas of each region. The regional and area designations are based on the unique load and generation characteristics of the various parts of the province. The following sections describe the need assessment results and the proposed transmission system enhancements to satisfy the forecast of load and generation to 2032 for each planning region.

**Figure 7.3–1: Transmission Planning Regions and Areas**





### 7.3.2 South Planning Region Overview

The South Region is bounded by the British Columbia, Saskatchewan and U.S. borders and the AESO's Central Region to the north. The city of Calgary is the major population centre in the region. Other population centres include High River, Airdrie, Lethbridge, Brooks and Medicine Hat. Population in this region makes up over 40 per cent of the Alberta's total population, chiefly due to the city of Calgary and nearby urban centres. As of the 2011 census, Calgary had a population of about 1.1 million, making it the largest city in Alberta. Employment by industry varies both by population density and sub-region. Agriculture accounts for 19 per cent of employment in the southwest area and approximately 10 per cent in each of the central and southeast areas of the region. Retail trade is the largest industry in the Calgary area followed closely by professional/scientific/technical services, health services and construction. Resource production, primarily conventional oil and gas, accounts for 10 per cent of the southeast area employment and also underlies other industries such as retail trade and professional/scientific/technical services.<sup>33</sup>

The diverse geography in the South Region—including mountains, forests, prairie and rivers—is reflected in the varied land use. Approximately 40 per cent of the region's land area is native grassland; over 60 per cent of land in the South Region is privately owned. Land use is a mix of agriculture (cropland) and livestock, resource production (oil, gas, wind power), urban, and tourism and recreation. Human activity in the region has resulted in conversion of native landscapes and the largest number of species at risk in Alberta.<sup>34</sup>

#### *Power Generation and Electric Load in the South Region*

The major electrical load centres in the South Region include Calgary and surrounding area, Medicine Hat, Brooks, Lethbridge and the Empress industrial area. Electricity demand in the South Region has historically peaked in the winter, although the summer peak load is approaching winter levels chiefly due to growing air-conditioning and irrigation load growth.

The region's load, which is about 30 per cent of the province's peak, is forecast to grow at about 3 per cent over the next 10 years and about 2 per cent over the next 20 years. This load growth comes mainly from general growth in the industrial, residential and commercial sectors, and considers some pipeline expansion near Empress. Major urban centres account for much of the electricity demand in the region. The city of Calgary alone accounts for nearly 54 per cent of the South Region peak load and approximately 16 per cent of Alberta's total load requirement. Calgary is expected to experience continued increasing demand for electricity as the population continues to grow. The AESO has between 15 and 20 active requests for load connections or increases in the South Region at any given time.

The region currently contains about 3,000 MW of Alberta's total installed generation capacity, made up of a mix of coal, natural gas, hydro and wind. Approximately 80 per cent of Alberta's 1,100 MW of installed wind generation capacity is located in the South planning region with considerable potential for growth. The current AESO forecast shows over 3,500 MW of installed wind capacity by 2032.

<sup>33</sup> <http://eae.alberta.ca/economic-development/regional-development/regional-map.aspx>

<sup>34</sup> Profile of the South Saskatchewan Region, Government of Alberta, <https://landuse.alberta.ca/LandUse%20Documents/>

The retirement of Sheerness unit #1 and Sheerness unit #2 will result in a decrease of about 780 MW of generation capacity in the South Region, or approximately 25 per cent by 2032. However, new generation is currently under development and additional generation is planned over the next several years. The approximately 860 MW combined-cycle ENMAX Shepard Energy Centre in southeast Calgary is under construction with a target in-service date of 2015, and the approximately 180 MW gas-fired Bonnybrook Energy Centre has been approved for construction with an anticipated in-service date of 2016. In addition, there are two other connection requests: the 120 MW gas-fired Bow Ark Energy Queenstown Power Plant near Queenstown, Alberta planned for 2015, and the approximately 350 MW TransCanada Energy Saddlebrook Power Station, which is planned for 2017.

According to the AESO connection queue as of October 2013, the AESO currently has active connection requests from approximately 20 wind-aggregated generating facilities with a combined installed capacity of approximately 2,500 MW, of which about 75 per cent are in the south. These connection requests, which are in various stages of the AESO connection process, are generally located in the Pincher Creek, Lethbridge and Medicine Hat areas of the region.

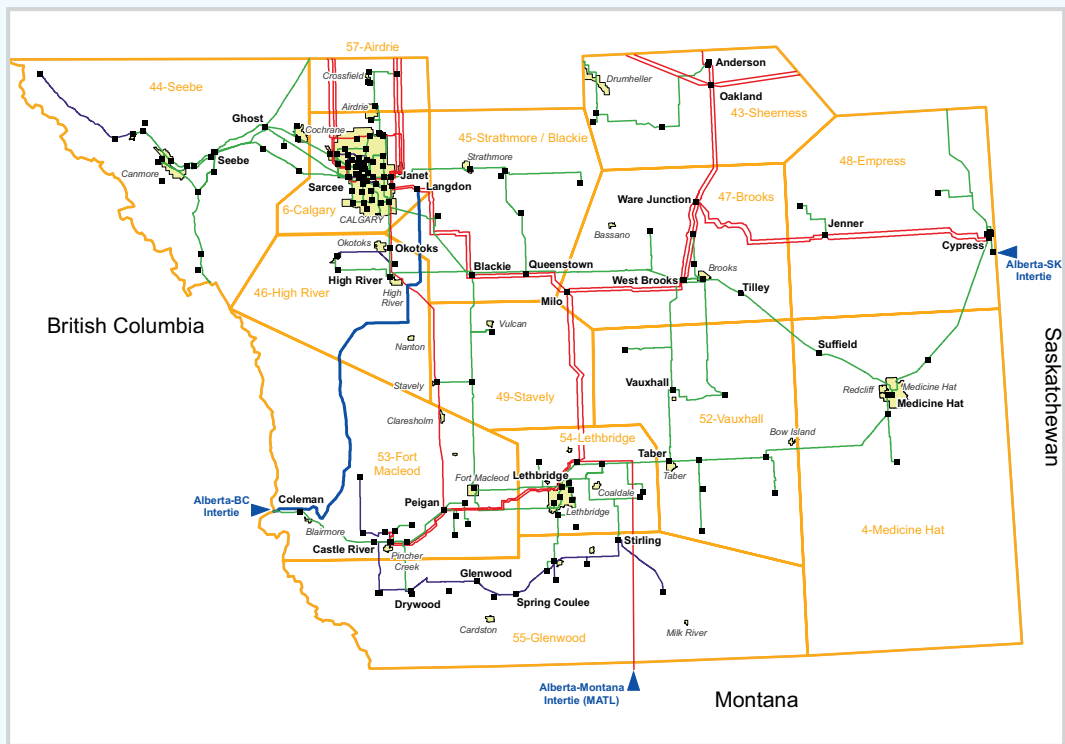
#### ***Existing Transmission System***

The South Region contains 14 AESO planning areas: Calgary (6), Medicine Hat (4), Sheerness (43), Seebe (44), Strathmore/Blackie (45), High River (46), Brooks (47), Empress (48), Stavely (49), Vauxhall (52), Fort MacLeod (53), Lethbridge (54), Glenwood (55), and Airdrie (57). The existing transmission system in the South Region consists of approximately 320 km of 500 kV; 2,500 km of 240 kV; 2,900 km of 138 kV and 450 km of 69 kV lines.

Load in the South Region is predominantly served from an extensive 138 kV transmission network supplied by a regional 240 kV network that connects the main load centres of the South Region with regional generation sources. The region also contains a small number of 69 kV facilities, including south of Lethbridge and within Banff National Park. These are generally older transmission facilities serving less densely populated areas. The existing Calgary transmission system has four main 240 kV supply stations: Sarcee in the west side of the city; East Calgary in the south centre; Janet on the east side; and Beddington in the north. The underlying transmission system within the city of Calgary is composed of 138 kV and 69 kV circuits delivering power to load-serving substations.

The regional 240 kV network is served by the existing six north-to-south 240 kV transmission lines that terminate near and in Calgary, one of the major transmission hubs in the AIES. It also includes the SATR project, which is under development and consists of several 240 kV circuits designed to collect geographically dispersed wind generation sources and move the power they generate into the load centres. Figures 7.3.2-1 and 7.3.2-2 illustrate the existing South Region and Calgary transmission systems.

Figure 7.3.2-1: Existing South Region Transmission System



**South Planning Region**

	Forecast Winter Peak Load (AIL)
2012 Actual	2,870 MW
Near term	3,510 MW
Medium term	3,936 MW
Long term	4,678 MW



### Major Transmission Projects Approved and/or Under Construction

Since 2007, the AESO has focused on planning, seeking approval for, and implementing transmission developments to reinforce and expand the 240 kV transmission network in the South Region to accommodate wind as well as other sources of generation. By 2017, four significant new transmission facilities are expected to be in service:

- Southern Alberta Transmission Reinforcement (SATR) consisting of several 240 kV circuits required to move wind energy through and out of the South Region
- East Calgary Transmission Plan - Shepard (ECTP-Shepard) consisting of 240 kV enhancements on the east side of Calgary to initially integrate the 860 MW Shepard generating station
- Foothills Area Transmission Development - East (FATD-East) consisting of a new 240/138 kV Foothills substation near High River and 240 kV enhancements into Calgary to integrate new generation from local sources as well as wind from the south
- Fidler 240/138 kV substation required to integrate wind generation north of the town of Pincher Creek

In addition, the Eastern Alberta Transmission Line (EATL) and Western Alberta Transmission Line (WATL) are two 500 kV HVDC lines being developed to increase transmission capacity between the north and south parts of the province, alleviating existing north-south transmission system constraints.

The South Region transmission system also includes Alberta's three interties with other jurisdictions. Figure 7.3.2-1 shows the general location of the three interties and Table 7.3.2-1 provides a description and the WECC Path ratings for each intertie.

**Table 7.3.2-1: WECC Path Ratings**

WECC Path	Interconnecting Jurisdictions	Description	Transfer Limits
Path 1	Alberta – British Columbia	Consists of 3 lines: Langdon-Cranbrook 500 kV Pocaterra-Fording Coal tap 138 kV Coleman-Natal 138 kV	AB to BC – 1,000 MW BC to AB – 1,200 MW
Path 2	Alberta – Saskatchewan	Consists of McNeil back-to-back DC converter station operated at 42.2 kV	AB to SK – 150 MW SK to AB – 150 MW
Path 83 MATL	Alberta – Montana	Consists of MATL 230 kV merchant line connecting MATL substation near Lethbridge, AB to Marias-Great Falls substation near Great Falls, MT	AB to MT – 325 MW MT to AB – 300 MW

### ***South Region Load and Generation Balance***

Power has historically flowed into the South Region from the rest of the AIES, even though peak load in the region is less than installed generating capacity. The amount of power flowing into the region depends in part on the output of the region's wind generation at any given time.

The proportion of the energy supply produced by wind-generating facilities located in the South Region is expected to increase gradually over the planning horizon. During certain wind conditions, coupled with an increase in gas-fired generation, the South Region will have a surplus of power to deliver to the rest of Alberta and/or to export to B.C., Saskatchewan, and Montana via the interties.

### ***Planning Considerations for the South Region***

Significant transmission expansion and reinforcement will have already taken place in the region by 2017, yet a number of planning challenges remain in the South Region, including: uncertainty in timing, location, and size of generation development over the planning horizon; intertie restoration; reliably serving growing load in urban areas; and replacement of aging infrastructure.

One of the primary objectives of the long-term regional plans is to develop transmission system enhancements that remove system constraints under normal operating conditions (when all elements are in service) and single contingencies. These constraints are currently managed by operational procedures that include remedial action schemes (RASs). RASs have become common in the south and are typically required to facilitate the reliable connection of wind generation facilities in the Pincher Creek and Glenwood areas. There are about 10 RASs employed in the South Region for normal operations or single contingency outages.

Calgary has unique challenges in that dense urban development makes adding new transmission facilities a formidable task. The existing 69 kV facilities will eventually be replaced with more efficient 138 kV facilities, but finding corridors for new transmission or even re-using existing rights-of-way can be problematic due to physical constraints. While underground lines are an option in more densely developed areas, these lines bring with them a higher (five to seven times) cost.

The need for the approved Stage 3 of the Southern Alberta Transmission Reinforcement (SATR), which consists of a double-circuit 240 kV line from Ware Junction north of Brooks to Calgary, was recently re-evaluated. This evaluation determined that the approved development is no longer required because the planned EATL and WATL lines provide the same functionality that this proposed development was planned to provide. As a result, the AESO has amended the SATR NID to cancel Stage 3, and it was not considered as part of the future transmission system in the need assessments for this long-term plan.

It was also assumed that the Alberta-B.C. intertie would be fully restored to its rated capacity of 1,200 MW for import and 1,000 MW for export by 2017. The intertie is currently constrained to about 800 MW in each direction. The regional assessments also considered, as a sensitivity, an increase in the capacity of the MATL line from 300 MW to 600 MW by 2032.

### 7.3.3 South Region Need Assessment and Transmission Plans

The primary driver for future transmission system development in the South Region is load growth in and around urban centres. Previously, the integration of major new generation sources (predominantly wind) across the region was the primary driver; however, with the transmission projects currently under development, most of the generation additions can be accommodated.

In general, the need assessment studies confirm that following the completion of SATR Stages 1 and 2 and other transmission projects currently in development, the transmission system within the region has been adequately strengthened to accommodate increasing wind generation and elimination of RASs over the duration of the planning horizon. In order that the transmission plans account for both the geographical and magnitude uncertainty associated with wind development, the AESO's planning evaluations considered the 2012 LTO Environmental scenario as well as different geographic distributions of wind development based on wind developers' past and current connection applications.

While the transmission reinforcements that are currently in development will allow for anticipated generation to connect to the system, the transmission system operating at 138 kV and below will experience a variety of constraints beginning as early as 2017 due to load increase, which will increase over the planning horizon. Consequently, the need for future transmission development in the region is primarily confined to 138 kV and lower voltage levels. The constraints are not region-wide and are limited to the following groupings of one or more of these planning areas:

- Vauxhall, Empress and Medicine Hat Areas
- Glenwood Area
- Lethbridge Area
- Strathmore/Blackie and High River Areas
- Seebe Area
- Fort McLeod Area
- Calgary and Airdrie Areas

Figures 7.3.3-2 and 7.3.3-1 show the constraints by study year that were identified in the needs assessment studies for the larger South Region and for Calgary and the surrounding area. Constraints may be overloaded facilities and/or voltage violations.



Figure 7.3.3-1: Need Assessment Results for South Region

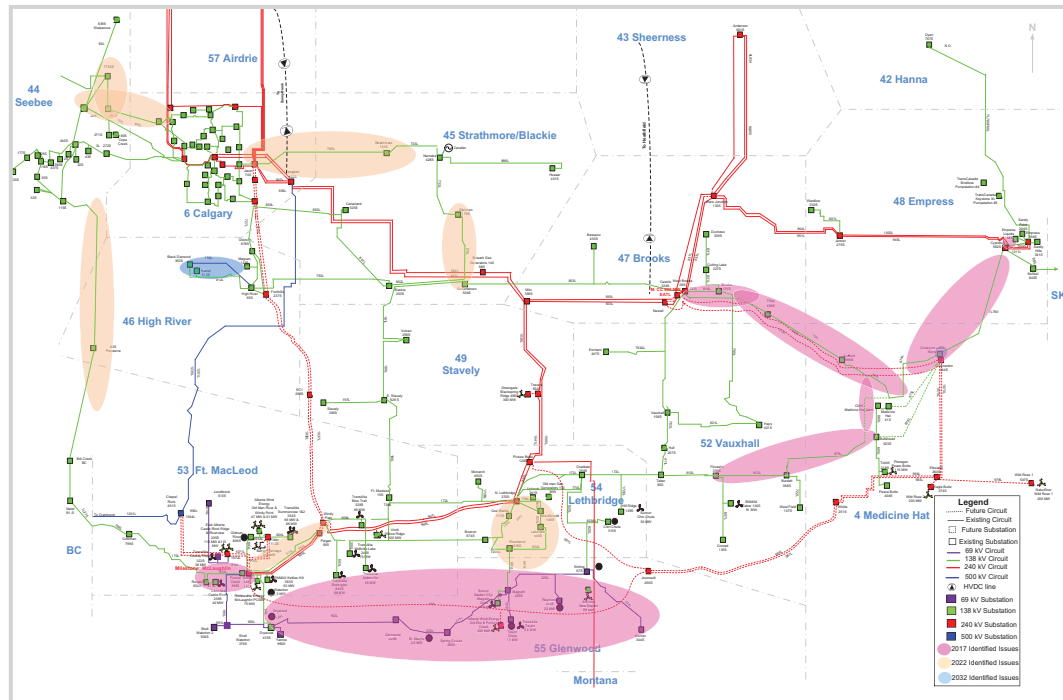
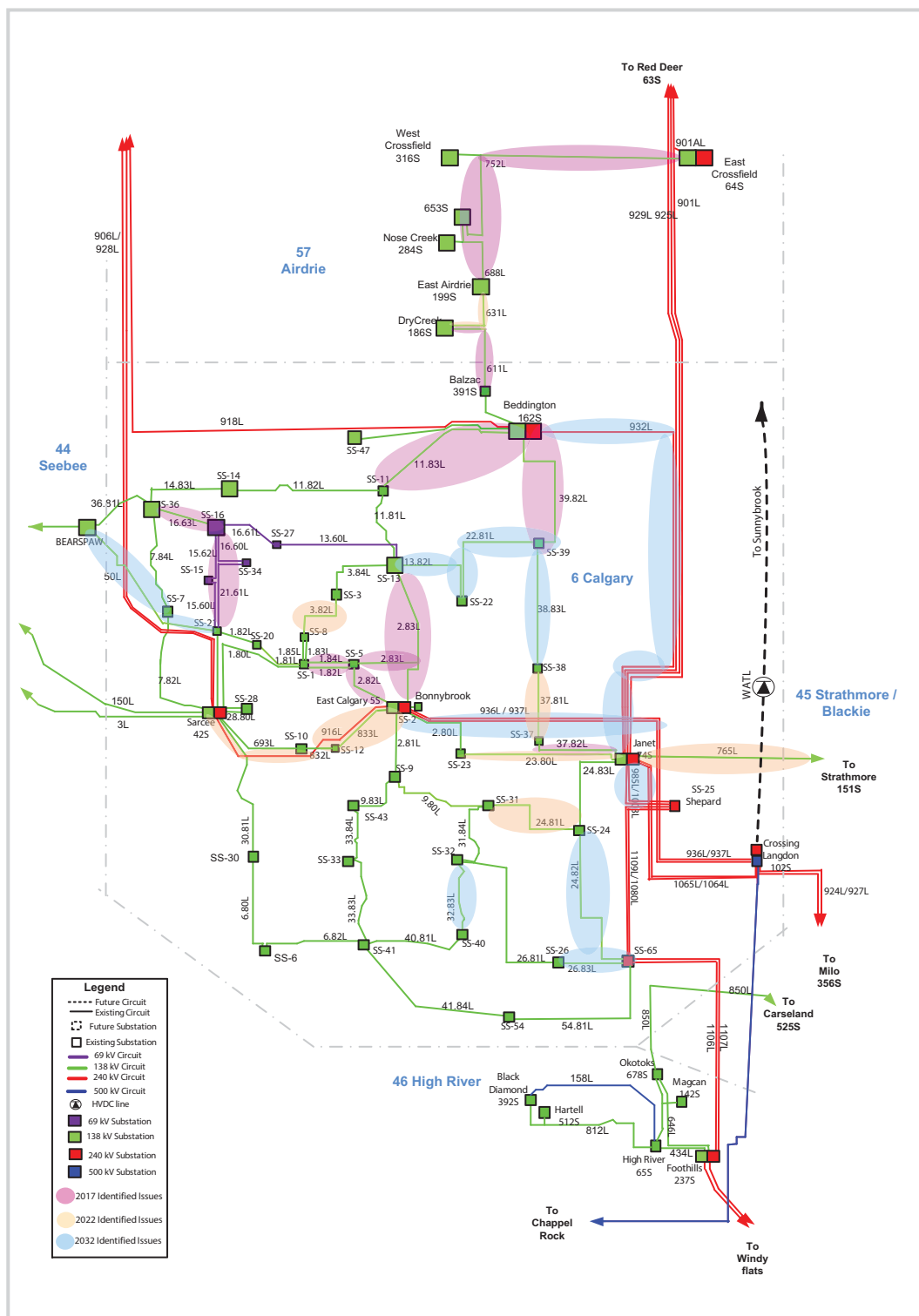


Figure 7.3.3-2: Need Assessment Results for Calgary and Airdrie Areas



The following sections summarize the South Region constraints and describe the AESO plans to address these constraints within the planning horizon.

#### ***Vauxhall, Empress and Medicine Hat Areas***

These three planning areas are connected by an existing 138 kV network, which by 2017 will be served by three 240 kV source substations at West Brooks, Bowmanton and North Lethbridge.

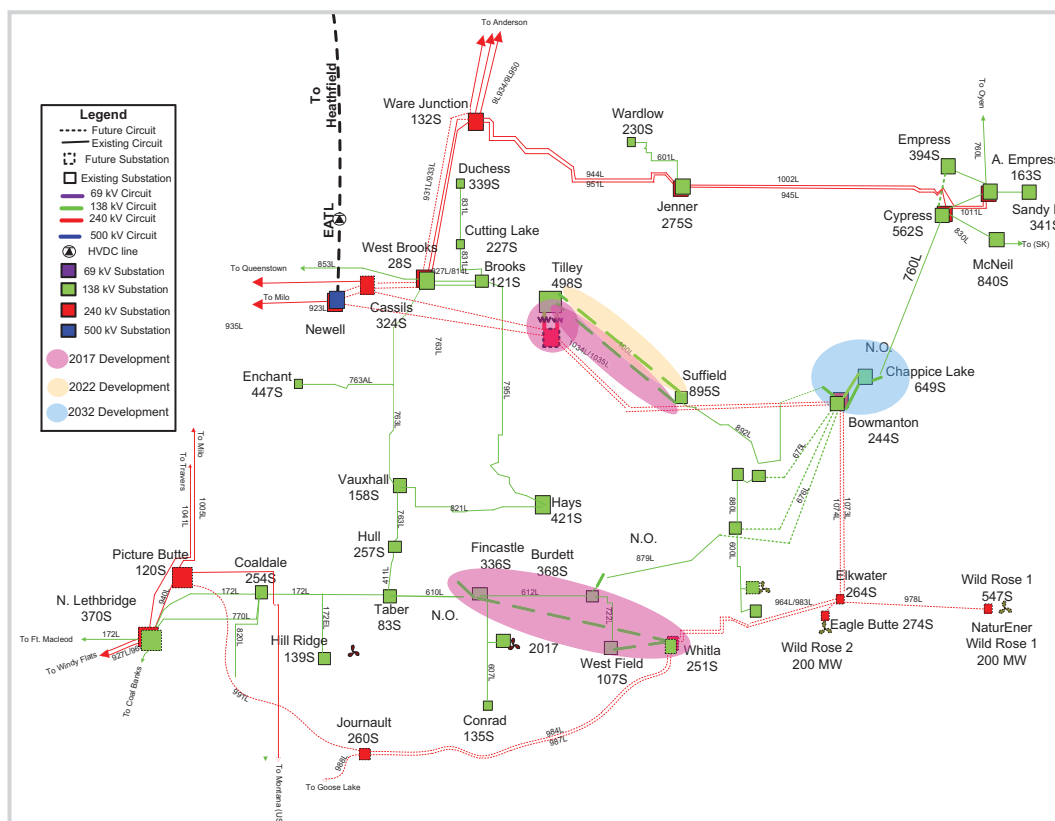
Parts of the existing 138 kV transmission system in these three planning areas are nearing capacity to serve new loads. Consequently, as early as 2017, the areas experience overloads, with an increasing risk of voltage collapse during certain single contingencies. As load grows in these areas, the severity, frequency and distribution of line overloads increases, and voltage violations arise under an increasing number of studied scenarios over the long term.

The locations of the constraints suggest the need for new 240 kV sources in the vicinity of the town of Tilley to serve growing loads in the Suffield and Tilley areas due to oil and gas developments. A new 240 kV source is also required in the vicinity of Whitla to meet load growth south and west of Medicine Hat. Associated 138 kV line upgrades will also be required.

**Table 7.3.3-2: Vauxhall, Empress and Medicine Hat Areas – LTP Summary**

<b>Timeframe</b>	<b>Development</b>
Near term	Establish a new 240/138 kV source substation near Tilley Increase 138 kV transmission line capacity to the existing Suffield substation Add a new 240/138 kV source substation near Whitla Increase 138 kV transmission line capacity between Whitla and both Fincastle and West Field substations Increase 138 kV transmission line capacity between Cypress and Empress
Medium term	Increase 138 kV transmission line capacity between Tilley area 240/138 kV source substation above, and Suffield substation
Long term	Reconfigure 138 kV system around Chappice Lake substation

**Figure 7.3.3-3: Vauxhall, Empress and Medicine Hat Areas – Long-term Transmission Plan**



Map is for illustrative purposes only and does not represent actual terminations or routes

**Glenwood Area**

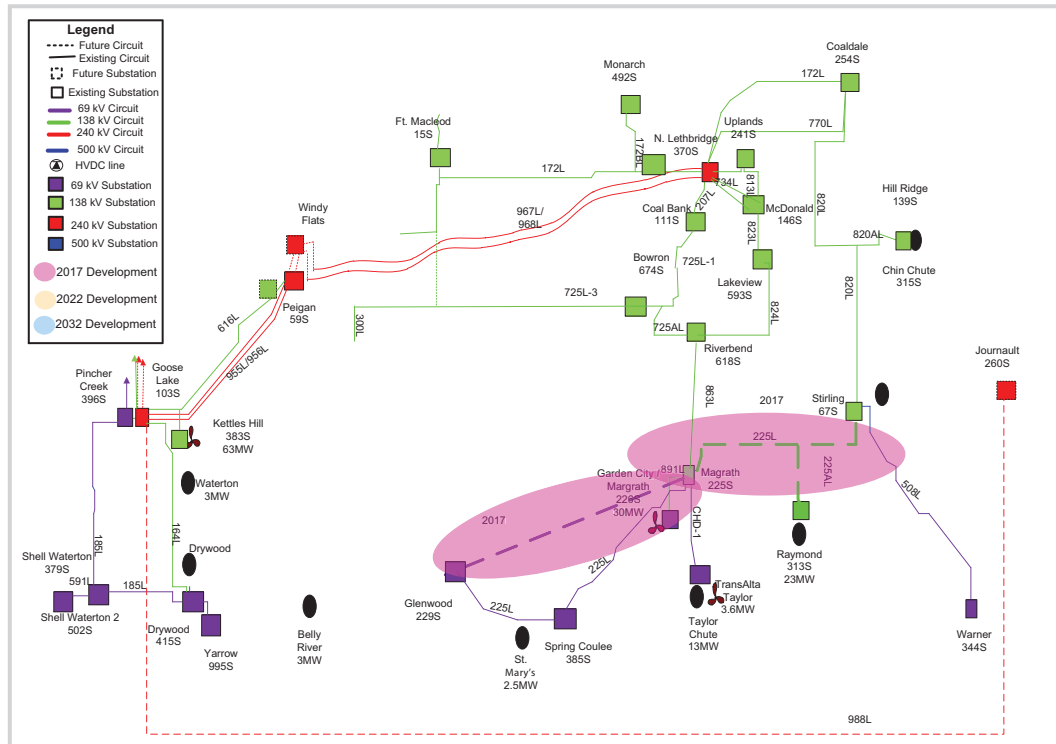
Much of this planning area is served by an aging 69 kV network. A number of small hydro and wind generators are connected to the 69 kV network. Thermal overloads and voltage violations under single contingencies start appearing in 2017 and become increasingly severe over the planning horizon. Also, the 69 kV low capacity lines from the Pincher Creek area to the area south of Lethbridge can become overloaded under the high B.C. import or export conditions studied.

These issues can be overcome by breaking the larger 69 kV loop into two smaller loops and replacing parts of the 69 kV system with 138 kV lines. Any new 69 kV lines would be constructed to 138 kV standards to allow for future conversion to the higher voltage if and when required by future load increases.

**Table 7.3.3-3: Glenwood Area – LTP Summary**

Timeframe	Development
Near term	Add 138 kV transmission line capacity between Sterling, Raymond and Magrath substations to replace the existing 69 kV lines
	Add a new line constructed at 138 kV and operated at 69 kV between Magrath and Glenwood substations and remove the 69 kV line between Glenwood and Drywood substations
Medium term	No developments required at this time
Long term	No developments required at this time

**Figure 7.3.3-4: Glenwood Area – Long-term Transmission Plan**



Map is for illustrative purposes only and does not represent actual terminations or routes

**Lethbridge Area**

This planning area includes the city of Lethbridge and surrounding rural area. The load in this area is forecast to grow steadily with the winter peak load projected to grow at an average annual rate of approximately 3.6 per cent over the next 10-year period (2012–2022) and then drop to about 1.7 per cent per year over the following 10-year period (2023–2032). The growth is due primarily to a population increase in the Lethbridge area and associated commercial and industrial development.

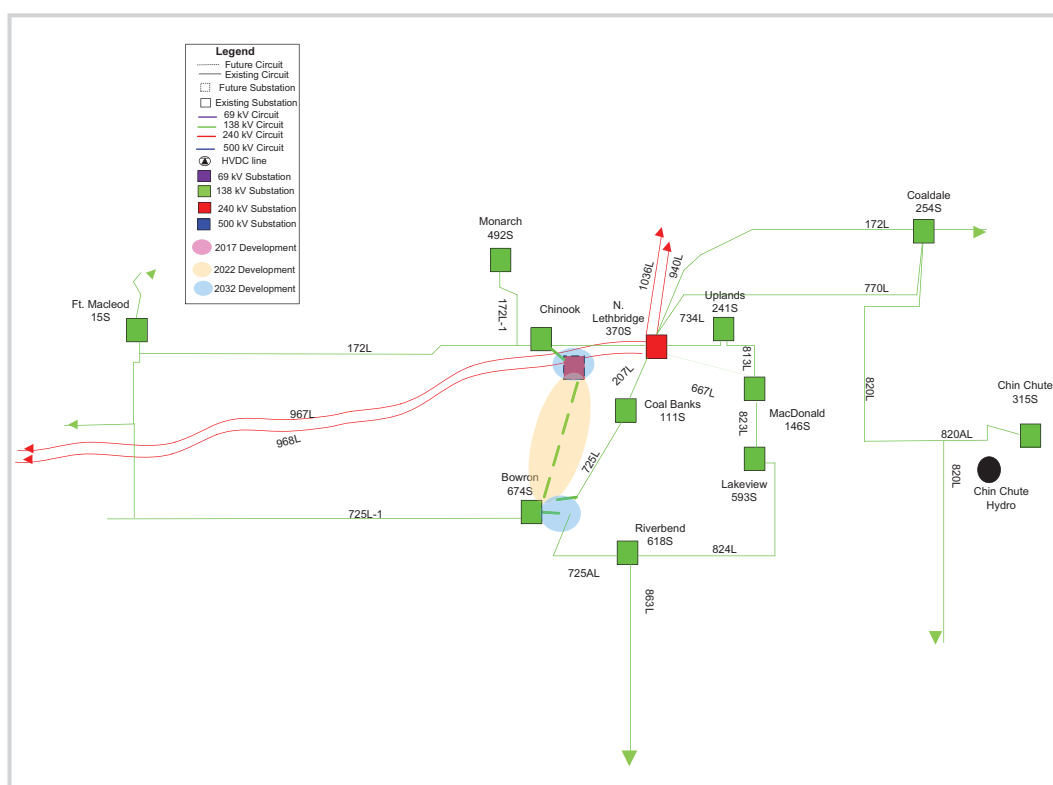
No criteria violations were observed in the area in the 2017 study year. However, by 2022, studies indicate that transformation capacity needs to be added at or near the North Lethbridge substation to accommodate forecast load growth in the city of Lethbridge and surrounding area. The area generally has strong voltage performance over the study period, with the exception of the Chinook substation on the west side of Lethbridge which experiences voltage violations in the 2023-2032 time period.

The overload and voltage violations can be mitigated by adding a new 240/138 kV source on the west side of Lethbridge where the city is anticipating most of its new growth to occur, and reconfiguring part of the Lethbridge 138 kV system.

**Table 7.3.3-4: Lethbridge Area – LTP Summary**

Timeframe	Development
Near term	No developments required at this time
Medium term	Add a new 240/138 kV source substation near west Lethbridge and upgrade associated 138 kV transmission line capacity to existing Bowron substation
Long term	Add 138 kV transmission line capacity between new source substation above to Chinook substation  Reconfigure existing 138 kV lines near Bowron to connect to Coal Banks and Riverbend substations, respectively

**Figure 7.3.3-5: Lethbridge Area – Long-term Transmission Plan**



Map is for illustrative purposes only and does not represent actual terminations or routes

**Strathmore, Blackie and High River Areas**

The area surrounding Calgary is seeing pockets of load growth that could be in the tens of megawatts in the next five to ten years.

Currently, two 138 kV lines, one from Janet substation to Strathmore substation and one from Blackie to Gleichen substations supply Strathmore area load. Studies have determined that by 2022, with one unit at the Cavalier power plant out of service, the area will experience thermal and voltage criteria violations under a number of single contingencies. By the 2018–2022 period, the existing Janet to Strathmore line will have insufficient capacity to transfer any new power generation out of the area. Further, it is forecast that by 2032, gas-fired generation will be developed near Queenstown which will exacerbate the overload conditions.

Loading on the 69 kV line from High River substation to Black Diamond substation will exceed its thermal rating in the 2023 to 2032 period and will need to be upgraded.

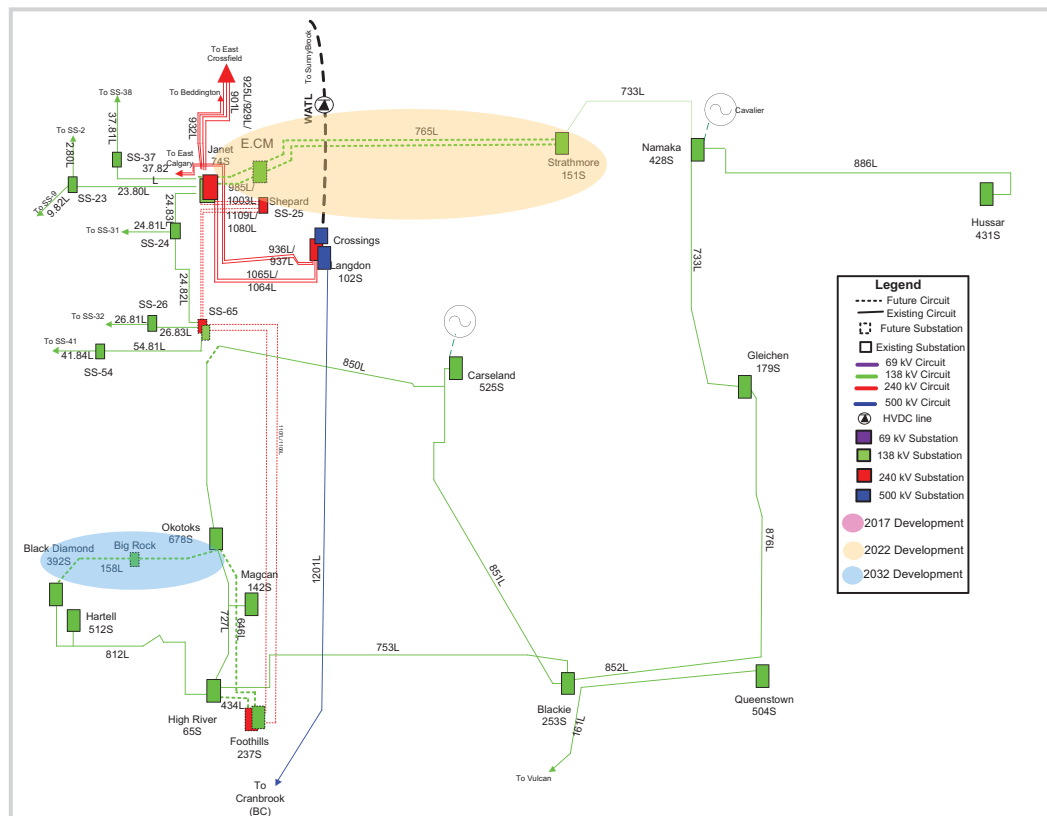
The issues above can be resolved with the addition of 138 kV circuits. Increasing line capacity to Strathmore, tied in with a potential new substation near Chestermere, will alleviate overloads in that area.

Replacing part of the 69 kV loop west of High River/Okotoks with 138 kV will alleviate the voltage violations in that area.

**Table 7.3.3-5: Strathmore, Blackie and High River Areas – LTP Summary**

Timeframe	Development
Near term	138 kV transmission line protection upgrade
Medium term	Add a second 138 kV transmission line between Janet and Strathmore substations
Long term	Add 138 kV transmission line between Black Diamond and Okotoks substations The existing 69 kV 13L/158L High River 65S to Black Diamond 392S is no longer required for purposes of transmission

**Figure 7.3.3-6: Strathmore, Blackie and High River Areas – Long-term Transmission Plan**



Map is for illustrative purposes only and does not represent actual terminations or routes



### Seebe Area

The Seebe area lies west of Calgary and extends to the foothills of Alberta. This area contains a number of small hydro plants which are connected to the existing 138 kV network. This area also has the Alberta terminus for the 138 kV Pocaterra-Fording Coal line that makes up part of the WECC Path 1 intertie between Alberta and B.C.

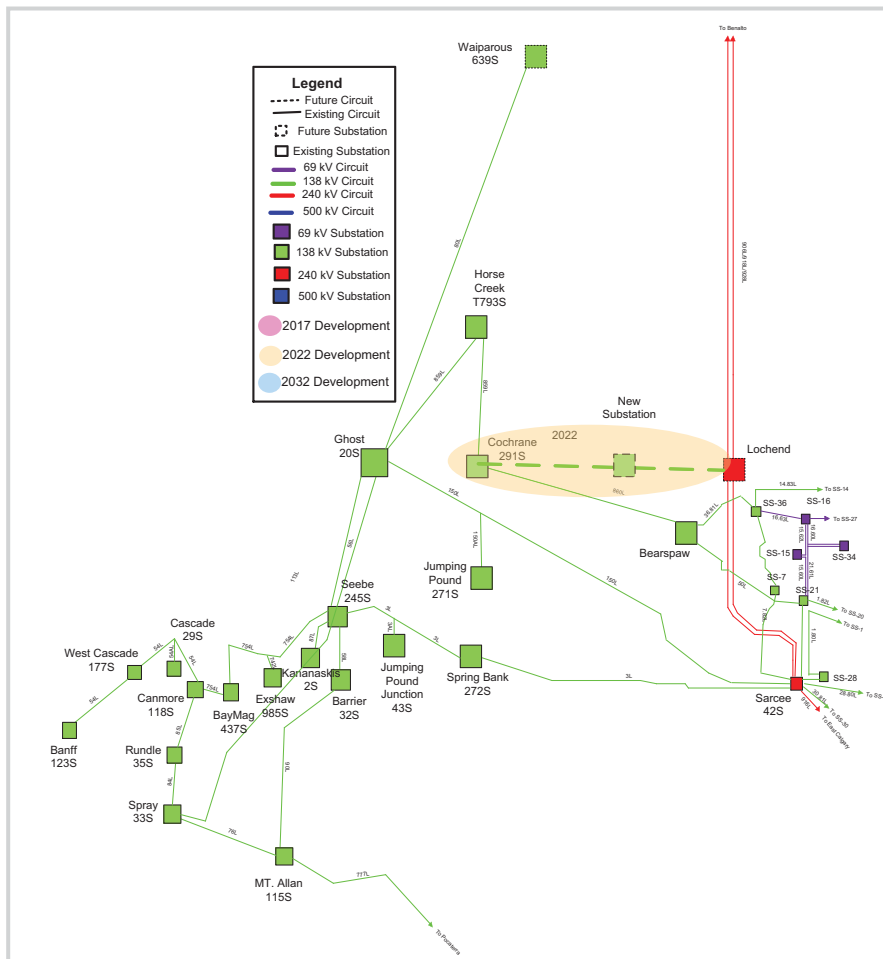
No performance violations were observed in the 2017 to 2022 time period.

In the 2032 time period, overloads appeared under single contingency outages on 138 kV lines from Ghost generating station to Cochrane and on to Calgary.

**Table 7.3.3-6: Seebe Area – Long-term Plan Summary**

Timeframe	Development
Near term	No developments required at this time
Medium term	Add 138 kV transmission line capacity between existing Cochrane substation and new 240/138 kV source substation to be located on the existing 240 kV lines from Benalto substation to Sarcee substation (identified in the Calgary and Airdrie area plan)
Long term	No developments required at this time

**Figure 7.3.3-7: Seebe Area – Long-term Transmission Plan**



Map is for illustrative purposes only and does not represent actual terminations or routes

### **Fort McLeod area**

The studies showed that with the completion of SATR (Stages 1 and 2) and the EATL and WATL HVDC lines, southern Alberta will have ample capacity for transferring power from existing and future wind generators and other generation sources in the south to load centres in Calgary and northern Alberta. The only issue is in the Fort McLeod area where the local 138 kV line from Goose Lake substation to Peigan substation and the 69 kV line from Pincher Creek substation to Shell Waterton substation will experience overloads under several single contingency outages. These overloads occur in the 2014–17 period.

As a sensitivity, studies were conducted assuming high import and high wind output. Under these conditions, the Goose Lake to Windy Flats 240 kV path becomes overloaded for the outage of the 500 kV line from Chapel Rock substation to Langdon substation.

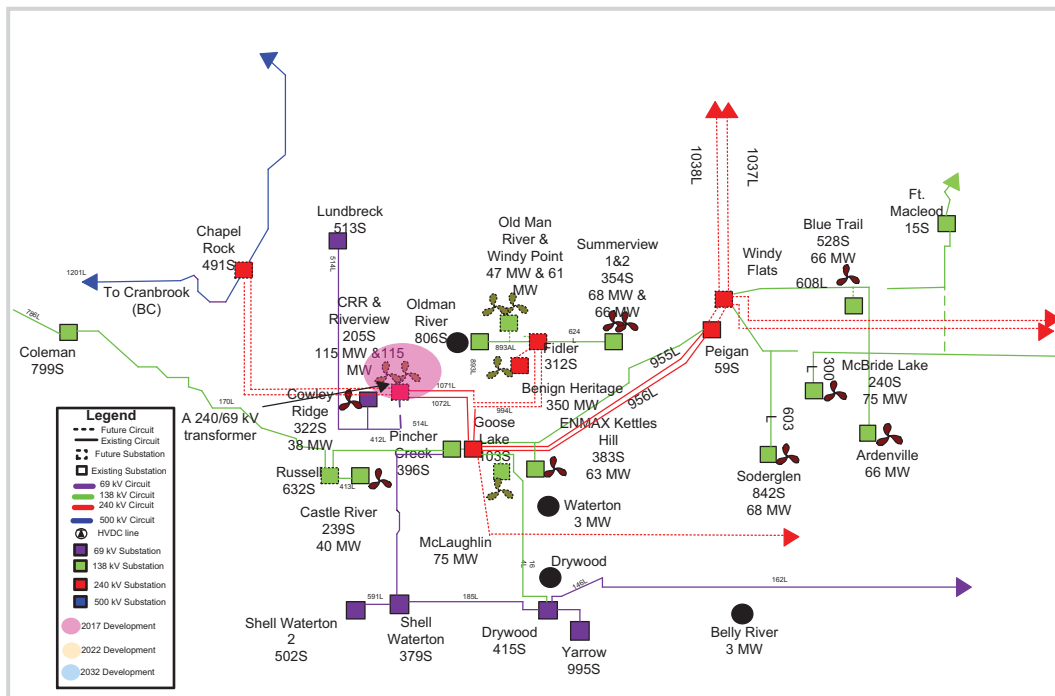
The overload issue on the 138 kV and 69 kV systems can be resolved by re-terminating the Pincher Creek—Lundbreck 69 kV line at the Castle Rock Ridge 240/138 kV substation and decommissioning the Pincher Creek to Castle Rock Ridge portion of the 69 kV line.

A condition where there is high import and high wind generation at the same time is uncommon. Hence, the proposed mitigation for this condition is to add dynamic transmission line rating equipment to the 240 kV Goose Lake—Windy Flats lines.

**Table 7.3.3–7: Fort McLeod Area – LTP Summary**

<b>Timeframe</b>	<b>Development</b>
<b>Near term</b>	Re-terminate the 69 kV line between Pincher Creek and Lundbreck substations at Castle Rock Ridge substation and add 240/69 kV transformation at that substation
<b>Medium term</b>	Install Dynamic Line Rating on the 240 kV lines from Goose Lake to Peigan to Windy Flats substations
<b>Long term</b>	No developments required at this time

Figure 7.3.3–8: Fort McLeod Area – Long-term Transmission Plan



Map is for illustrative purposes only and does not represent actual terminations or routes

### Calgary and Airdrie Areas

The assessment results generally identify the need for transmission development in five specific areas of the existing Calgary transmission system as well as the Airdrie area. The Airdrie area is served by a low-capacity 138 kV transmission line between East Crossfield and Beddington substations.

#### Downtown Calgary 138 kV network

The Calgary downtown loads are currently supplied through three substations: SS-1 in the downtown core, SS-5 in the east side of downtown, and SS-8 on the west side of downtown. Increasingly severe thermal overloads on the existing 138 kV lines feeding the downtown load will occur as early as 2015.

#### North Calgary 69 kV network

Thermal overloads are identified on the existing 69 kV system in north Calgary as early as 2015. The north 69 kV network will require upgrades and/or additional infrastructure in order to meet reliability criteria. As well, this is an aging system that will need capital maintenance work in the near future.

#### North Calgary 138 kV system

Thermal overloads under single contingency conditions will occur in the north Calgary 138 kV network sourcing from Beddington substation and Janet substation over the next 20 years. Without system upgrades, the use of RAS and operational procedures will need to increase in frequency and will become more complicated with growing load until system reliability is no longer able to be maintained.

***South Calgary 138 kV system***

Thermal overloads were observed on the 138 kV lines in the south Calgary network including the lines coming out of the south Calgary 240/138 kV source substation SS-65 under high wind and high local generation conditions in the 2023–2032 time frame. The south 138 kV network will require additional infrastructure in order to meet reliability criteria.

***Calgary 240 kV system and above***

Thermal overloads were observed on the 240 kV lines that supply substations within the City of Calgary due to increasing local Calgary generation along with wind generation in southern Alberta.

***Airdrie Area***

Under single element outages, thermal overloads were observed on almost all the 138 kV lines in the Airdrie area beginning as early as 2015. The overloads are currently managed through operational measures and will become increasingly severe and frequent as load and generation conditions change. Without system upgrades, generation in the Airdrie area could be curtailed under certain system conditions and the load cannot be supplied reliably.

***Summary***

Extensive transmission enhancements are required throughout the Calgary and Airdrie areas over the next 20 years to meet system reliability requirements:

- The downtown Calgary issues can be resolved by adding a 240 kV supply into the downtown area in the 2014–2017 timeframe with additional 240 kV reinforcement in the beyond-2022 timeframe
- The north Calgary 69 kV system will be upgraded to a 138 kV system in the 2014–2017 timeframe
- Overloads on the north Calgary 138 kV system will be mitigated by adding 138 kV lines to the north Calgary 138 kV network (from SS-47 to SS-36 and from SS-22 to SS-23) in the 2014–2017 timeframe.
- In the medium term (2018–2022) a new 240/138 kV source substation will be required in northwest Calgary to supply the northwest area of the city
- 240 kV transmission supply into Calgary will be reinforced with the addition of a 240 kV double-circuit line from the Foothills substation south of Calgary to the Sarcee substation in southwest Calgary in the 2022 timeframe
- The Airdrie area issues can be mitigated by breaking up the current large single 138 kV loop into two small loops and increasing the capacity of the 138 kV lines between the East Crossfield substation and the Beddington substation

These enhancements are listed in Table 7.3.3-8 and shown in Figure 7.3.3-11.

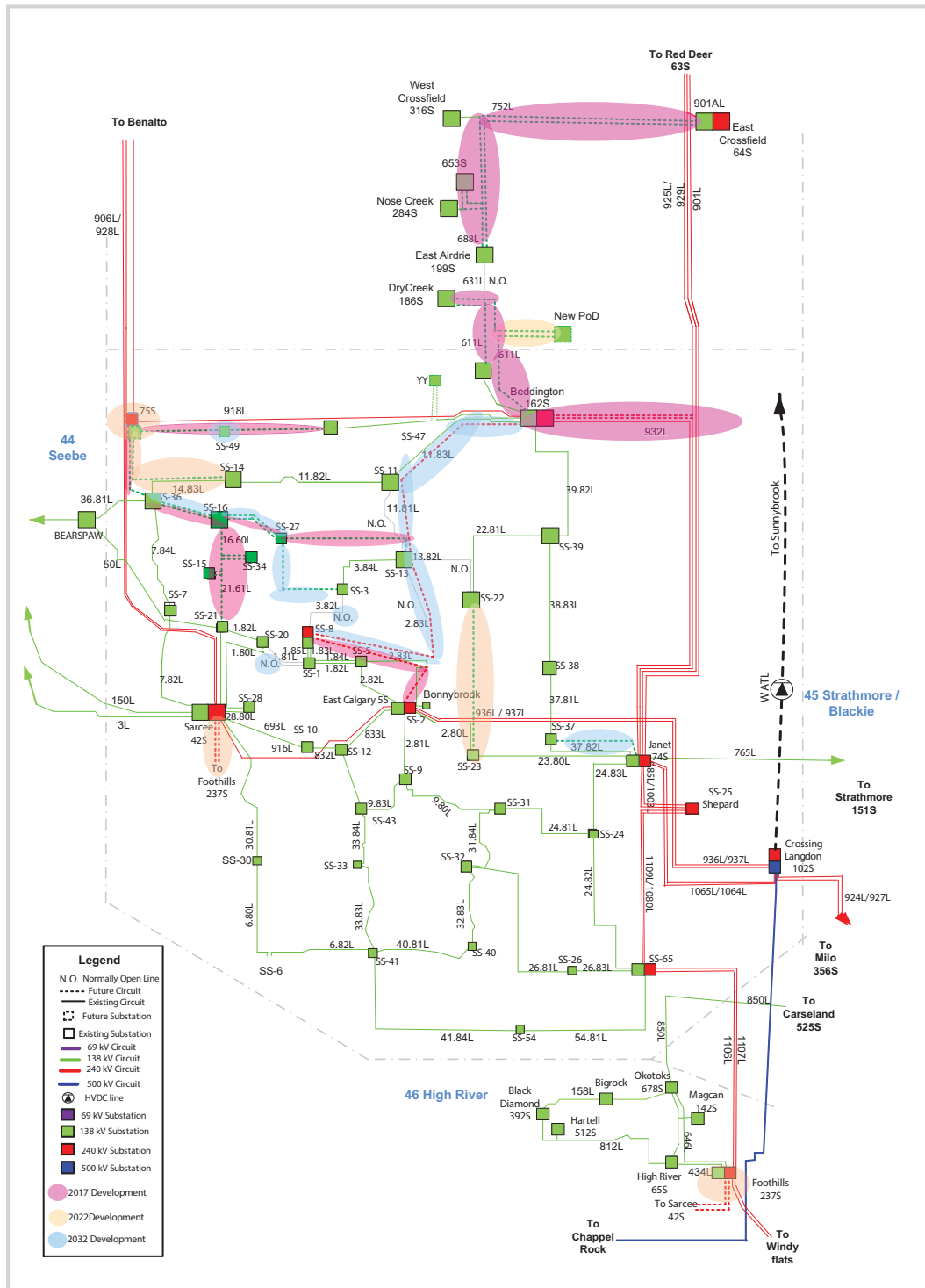
**Table 7.3.3–8: Calgary and Airdrie Area – Long-term Plan Summary**

<b>Timeframe</b>	<b>Calgary Development</b>
<b>Near term</b>	<p>Upgrade existing 138 kV substation SS-8 to 240/138 kV, and add 240 kV transmission line from East Calgary substation to new 240/138 kV substation</p> <p>Replace existing aging 69 kV network with 138 kV transmission network</p> <p>Add 138 kV transmission line between SS-47 and SS-36</p> <p>Add 138 kV transmission line between SS-22 and SS-23</p> <p>Cutting in-out of one of the 240 kV Red Deer–Janet lines to increase supply to Beddington substation</p>
<b>Medium term</b>	<p>Add 240/138 kV source substation in the vicinity of NW Calgary and associated 138 kV transmission line capacity to SS-47, SS-36 and SS-14 substations</p> <p>Add 240 kV transmission line capacity between Foothills and Sarcee substations</p>
<b>Long term</b>	<p>Add 240 kV transmission line capacity between Beddington and the new SS-8 240/138 kV substations</p> <p>Add 138 kV line between SS-27 and SS-3 in the northwest and N.O. 138 kV line 3.82L between SS-3 and SS-8</p> <p>Add 138 kV line between Janet and SS-37 substations</p> <p>Add VAR support devices in north Calgary</p>
<b>Timeframe</b>	<b>Airdrie Development</b>
<b>Near term</b>	<p>Add 240/138 kV transformation capacity at East Crossfield substation and convert existing 901AL Tap to an in-out configuration at East Crossfield</p> <p>Increase 138 kV transmission line capacity for 752L from East Crossfield to West Crossfield Tap to Summit substation; 688L from Summit to Summit tap to East Airdrie substation; and 611L from Dry Creek substation to Balzac substations</p> <p>Add 138 kV lines between East Crossfield and East Airdrie<sup>35</sup> and between Dry Creek and Beddington</p>
<b>Medium term</b>	<p>Add 138 kV transmission lines between new PoD and new 138 kV line between Dry Creek and Beddington<sup>36</sup></p>
<b>Long term</b>	<p>No developments required at this time</p>

<sup>35</sup> As per feedback from TFO, this development could be built as double-circuit with existing 752L and 688L.

<sup>36</sup> The connection of new PoD depends on the timing and location of this new substation.

Figure 7.3.3-9: Calgary and Airdrie Area – Preferred Plan



Map is for illustrative purposes only and does not represent actual terminations or routes

### **7.3.4 Central Planning Region Overview**

The Central Region spans the province east to west between Edmonton and Calgary. The region includes the Cold Lake, Lloydminster, and Hanna areas in the east and Caroline, Hinton, Edson and Drayton Valley in the west and Red Deer and Didsbury in the south. The Central Region has a diverse profile which includes large rural areas interspersed with oilsands and conventional oil developments. The city of Red Deer and surrounding area is the major population centre in the Central Region.

#### ***Power Generation and Electrical Load in the Central Region***

The major load centres in this region are the cities of Red Deer and Lloydminster and the towns of Vermilion, Cold Lake, Vegreville, Hanna, Wainwright, Provost, Hinton, Drayton Valley, Innisfail and Didsbury. The major industrial loads consist of oilsands developments in the Cold Lake area, pipeline loads along the eastern part of the region from Cold Lake to Hanna and Empress, and manufacturing in the Joffre ethylene plant. The load growth in this region is driven primarily by oilsands development and pipeline expansion. The east side of the Central region is a major path for pipelines between Edmonton and the Northeast Region, as well as to other markets. The increase in load in the region is partly a function of the planned expansion in this pipeline corridor. The AESO has about 25 active requests for load connection in the Central Region at any given time, most of which are pipeline or pipeline-related loads in the east half of the Region.

Existing power generation in the region is made up of fossil fuel—coal, gas-fired combined cycle and cogeneration, and renewable resources in the form of hydro and wind power. Approximately 700 MW of coal-fired generation capacity (Battle River units 3 and 4 by 2022 and Battle River unit 5 in 2032) will be retired over the next 20 years. It is anticipated that new generation will replace these retirements. Anticipated generation facilities include gas-fired units in the western part of the region and wind projects in the east.

Currently, proposed and operating wind projects in the region have a total capacity of approximately 800 MW. In addition to these wind projects, there is one proposed 80 MW cogeneration project in the Cold Lake Area and one proposed 95 MW gas turbine project in the Didsbury area. Although there is only one cogeneration project proposed for the Cold Lake Area at this time, the potential exists for additional cogeneration projects associated with oilsands development. In addition, the existing Battle River site could potentially be re-used for developing a large scale combined-cycle power plant following the retirement of Battle River units by 2032.

#### ***Existing Transmission System***

The AESO planning areas in this region include Cold Lake (28), Vegreville (56), Lloydminster (13), Wainwright (32), Red Deer (35), Didsbury Area (39), Hanna (42), Alliance/Battle River (36), Provost (37), Caroline (38), Hinton/Edson(29) and Drayton Valley (30). The transmission system in this region extends as far as Hinton/Edson and Abraham Lake in the west and as far as Cold Lake and Lloydminster in the east.

The six 240 kV lines that function as the system backbone between the Edmonton Region and the South Region run through the Central Region and are connected into the Central Region at two source substations near the city of Red Deer. Local area loads are supplied by 138 kV and 144 kV systems. The transmission system includes some 72 kV lines and substations that serve loads in the eastern part of the Central Region.



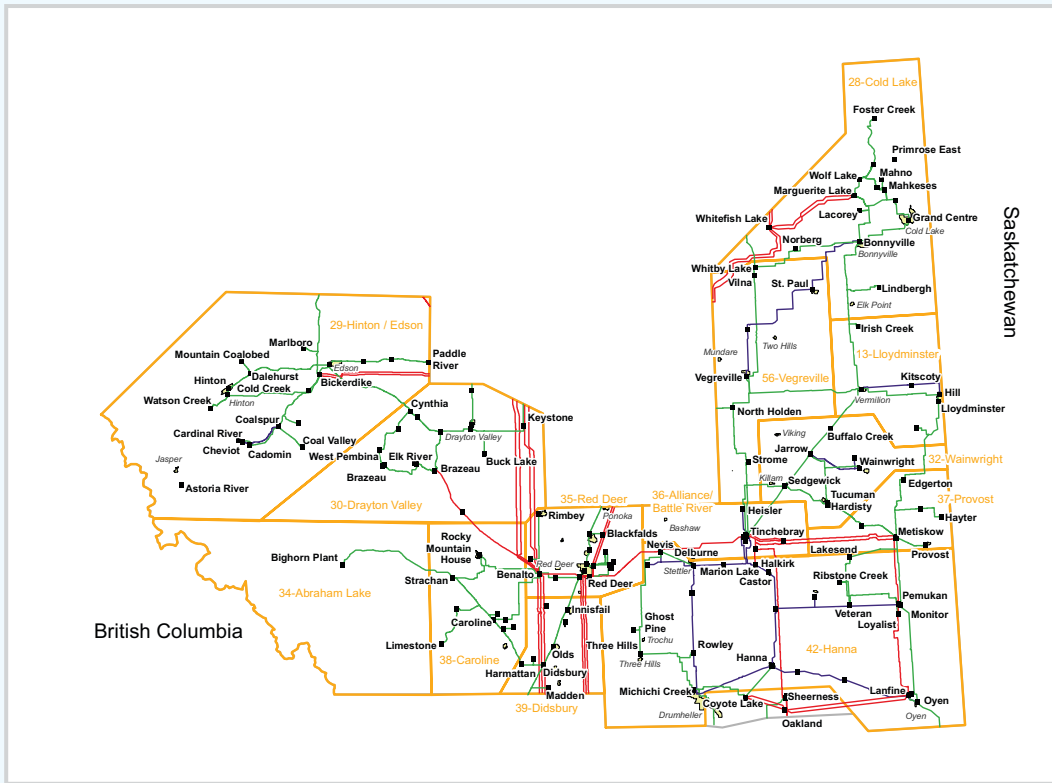
In addition to the facilities mentioned above, the new 500 kV north-south HVDC transmission lines between Edmonton and Calgary (EATL and WATL) will pass through the Central Region to carry power between the Edmonton Region and the South Region.

#### ***Major Transmission Facilities Approved and/or Under Construction***

The AESO has received approval of the need for several transmission developments intended to reinforce the transmission facilities in the Central Region. These include:

- Central East Transmission Development (CETD) consisting of several 138/144 kV enhancements in the Wainwright and Lloydminster areas to serve increasing load and generation, and 240 kV and 144 kV enhancements in the Cold Lake area to serve oilsands expansions. Parts of this development are under construction.
- Hanna Region Transmission Development (HRTD) consisting of a 240 kV loop from the Sheerness area to Hansman Lake to supply increasing pipeline loads in the area as well as integrate new wind generation. This development is under construction and is expected to enter service in 2017.
- Red Deer Area Transmission Development (RATD) consisting of new 240/138 kV substations near Ponoka, Innisfail and Didsbury and 138 kV enhancements to meet growing loads in the QE2 Highway corridor. Some of these reinforcements have been commissioned and are in service, and the remaining developments are moving through facility application filing and regulatory processes.
- The existing Central Region transmission system with those developments approved and scheduled to be in service by 2017 is shown in Figure 7.3.3-1.

Figure 7.3.4-1: Existing Central Transmission System



**Central Planning Region**

	Forecast Winter Peak Load (AIL)
2012 Actual	1,547 MW
Near term	1,836 MW
Medium term	2,039 MW
Long term	2,322 MW

### **Central Region Load and Generation Balance**

The Central Region imports energy from the rest of the AIES even though the peak load in the region is less than the installed generation capacity. Current generation capacity in the region is about 1,850 MW whereas the load is about 1,600 MW. The region has historically imported about 30 per cent of its energy requirement due mostly to the variable nature of the two hydro generating plants in the region: Big Horn (120 MW) and Brazeau (350 MW).

### **Planning Considerations for the Central Region**

Many of the above developments are expected to be in place by 2017. However, due to substantial changes in forecast assumptions and system conditions, especially those related to proposed wind generation connections on the east side of the region, the AESO has reassessed the need for approved facilities in the Wainwright, Provost, and Lloydminster areas that were included in the approved Central East Transmission Development (CETD)<sup>37</sup> as part of the regional plan assessments.

#### **7.3.5 Central Region Need Assessment and Transmission Plans**

The primary drivers for future transmission development in the Central Region are oilsands development in the Cold Lake area, potential pipelines and wind generation on the east side, and other generation throughout the region. Although loads in the QE2 Highway corridor will continue to grow faster than the Alberta average, the expected completion of Red Deer Area Transmission Development (RATD) will be adequate to serve the forecast load over the planning horizon.

One of the primary objectives of the long-term regional plans is to develop transmission system enhancements that eliminate existing system constraints currently managed by operational procedures that include Remedial Action Schemes (RASs). A review of the existing central region transmission system indicates that there exist a number of RASs and operational procedures in place due to a lack of adequate transmission facilities. Some of these RASs and operational measures were necessitated to facilitate interconnection of wind generation in the Central East area. It is worth noting that stability RAS at the Sheerness generating station will no longer be required with the completion of Hanna Region Transmission Development.

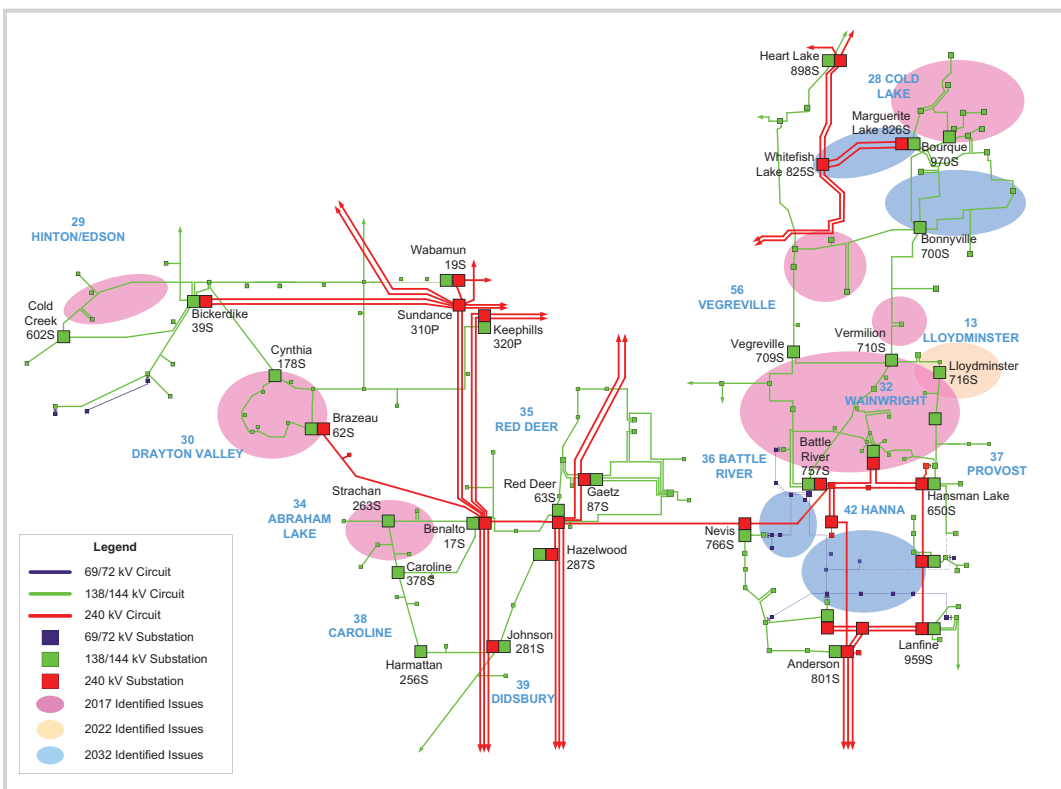
<sup>37</sup> AUC Decision 2011-048 and NID Approval No. U2011-57

Since the Central Region load growth rates as well as anticipated generator connections vary from one planning area to another, the need for reinforcements vary accordingly from one planning area to another. For the most part, the need assessment findings and subsequent transmission developments are contained within individual areas. The one exception is the Central East area of the region where the need and transmission development span five AESO planning areas. The following areas have been identified as requiring transmission enhancements in the 20-year planning horizon:

- Central East Area (consisting of the AESO planning areas of Alliance/Battle River, Provost, Wainwright, Lloydminster and Vegreville)
- Cold Lake Area
- Caroline Area
- Drayton Valley Area
- Hinton/Edson Area
- Hanna Area

Figure 7.3.5-1 illustrates the areas with identified need for transmission developments by study year. The need for developments is driven by overloaded facilities, voltage limit violations or aging infrastructure that needs to be replaced or upgraded.

**Figure 7.3.5-1: Need Assessment Results for Central Region**



### Central East Area

The five areas that constitute the Central East area are connected by an existing 138/144 kV network which is supplied from three 240 kV source substations on the southern edge: the Cordell substation near Battle River, the Nilrem substation near Hardisty and the Hansman Lake substation near Provost.

Subsequent to the approval of CETD, the magnitude and location of proposed wind generation on the east side of the Central Region has changed significantly from about 300 MW located near Provost in CETD to about 800 MW spread between Vermilion in the north and Hanna in the south. Of the 800 MW, 320 MW are now in operation and the remainder is forecast to be energized by 2017.

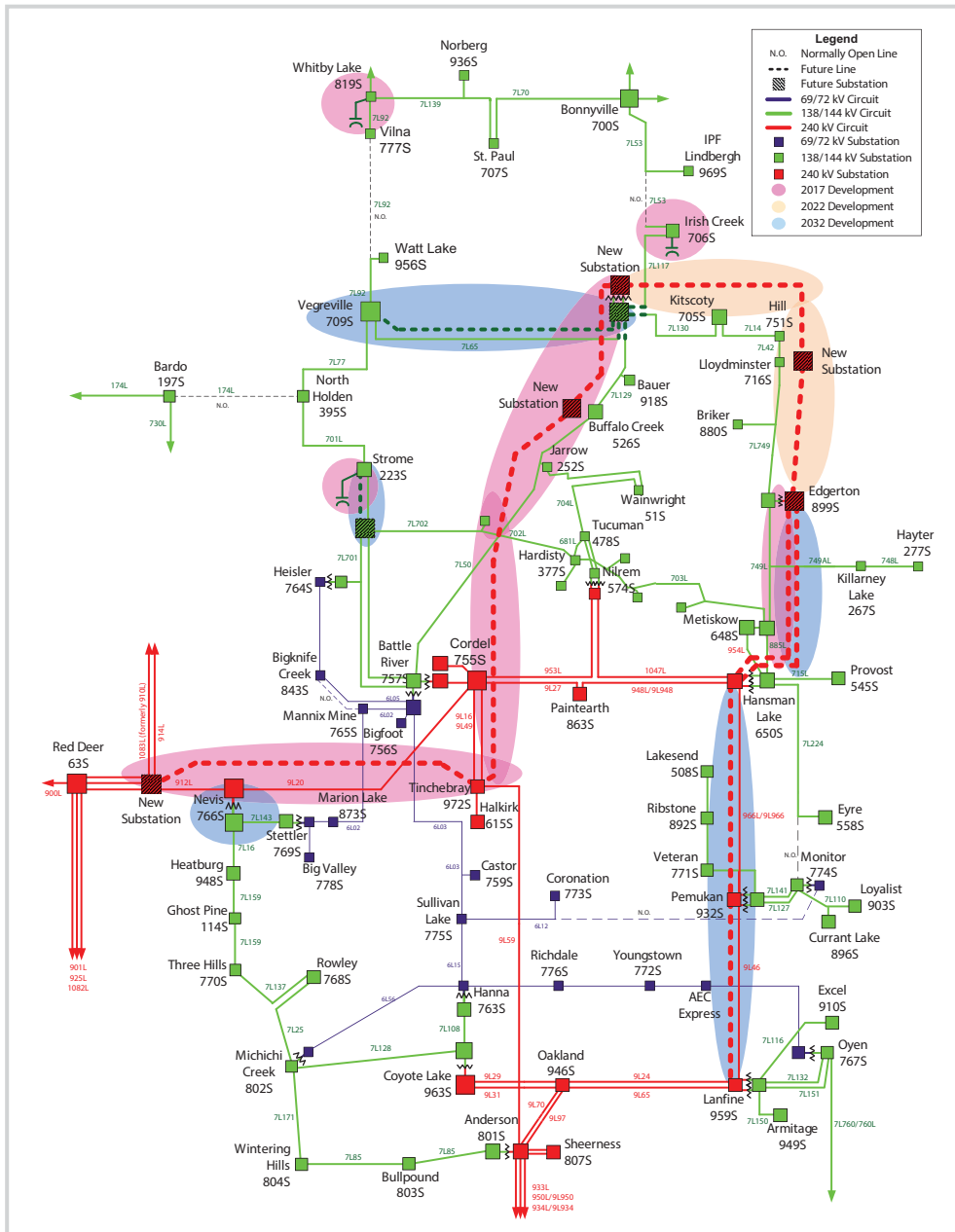
Growth in wind generation development will continue to increase power transfers out of the Central East area. The underlying 138/144 kV transmission system north of Alliance/ Battle River and Provost planning areas will be increasingly congested under an outage of the 240 kV line between Battle River, Nevis, and Red Deer substations, which is currently the only path for power transfer between the Central East and Red Deer areas. In order to connect wind projects in this area, RASs have been implemented to mitigate congestion under single contingencies. The planning studies indicated that constraints occur in 2017 which will increase in severity over the planning horizon due to load growth and the addition of new generation facilities.

The AESO has developed a suite of 144 kV and 240 kV system enhancements over the planning horizon to address the system needs in the Central East area. In addition to the enhancements described below, underlying flows on the 138 kV and 144 kV system can be managed by separating Central East from Cold Lake and Wetaskiwin areas by opening the lines between these areas.

**Table 7.3.5-1: Central East Area – LTP Summary**

Timeframe	Development
Near term	Add 240 kV transmission line capacity between: Red Deer and Tinchebray substations Tinchebray and Vermilion substations Hansman Lake and Edgerton substations Add three new 240 kV substations in the vicinity of city of Red Deer, Buffalo Creek and Vermilion substations Add voltage support devices at Irish Creek, Strome, and Whitby Lake substations
Medium term	Add a new 240 kV substation near Lloydminster Add 240 kV transmission line capacity between Edgerton and Vermilion substations, through Lloydminster substation
Long term	Add voltage support devices at Vegreville substation Add 144 kV transmission line capacity between Vermilion and Vegreville substations Add 144 kV switching substation in the vicinity of Strome substation, and associated 144 kV transmission line capacity to Strome Add 240 kV transmission line capacity between Edgerton, Hansman Lake, and Lanfine substations Increase 240/144 kV transformation capacity at Nevis

Figure 7.3.5-2: Central East Area – Long-term Transmission Plan



Map is for illustrative purposes only and does not represent actual terminations or routes

**Cold Lake Area**

The Cold Lake area continues to see load and generation additions related to oilsands development. These additions result in local area congestion as a result of the weak electrical connection to the rest of the Alberta transmission system.

Low voltages are observed in this area by 2017 when cogeneration plants that are connected radially to the system are taken out of service due to a radial line outage resulting in reactive power deficiency in the system. Low voltages are also seen under single contingencies other than for the loss of generation. These low voltages continue to spread throughout the Cold Lake area in the latter part of the planning horizon.

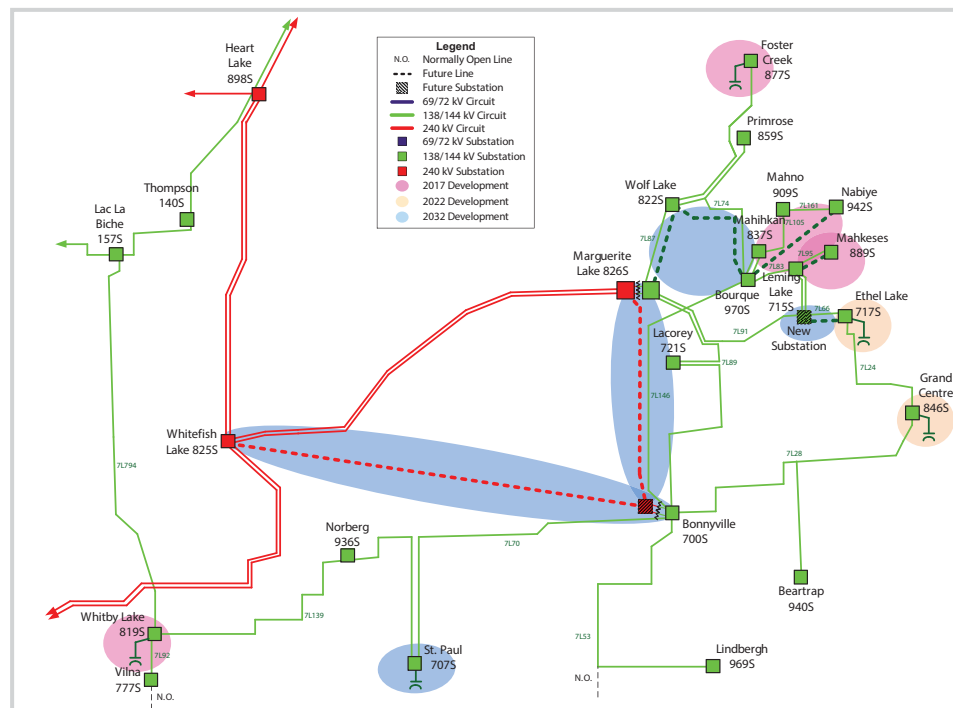
In addition to the low voltages, a number of 144 kV lines in the Cold Lake area that lie to the east and south of Marguerite Lake will be overloaded under a number of single element outages post-2022. It was also found that one of the two transformers at Marguerite Lake will be overloaded when the other is taken out of service.

As a result, the existing transmission system in the Cold Lake area is inadequate to facilitate forecast load and generation expected in the area, and 144 kV and 240 kV transmission system reinforcements are required over the planning horizon.

**Table 7.3.5-2: Cold Lake Area – LTP Summary**

Timeframe	Developments
Near term	144 kV voltage support at Foster Creek substation Add 144 kV transmission line capacity between Nabiye and Bourque substations, and between Mahkeses and Leming Lake substations
Medium term	Add voltage support devices at Ethel Lake and Grand Centre substations
Long term	Add 240 kV transmission line capacity between Whitefish Lake, Bonnyville and Marguerite Lake substations Add 240/144 kV transformation capacity at Bonnyville substation Add 144 kV transmission line capacity between Marguerite Lake, Wolf Lake and Bourque substations Add a 144 kV substation south of Leming Lake, and associated 144 kV transmission line capacity to Ethel Lake substation Add voltage support devices at Marguerite Lake and St. Paul substations

**Figure 7.3.5-3: Cold Lake Area – Long-term Transmission Plan**



Map is for illustrative purposes only and does not represent actual terminations or routes



### Caroline Area

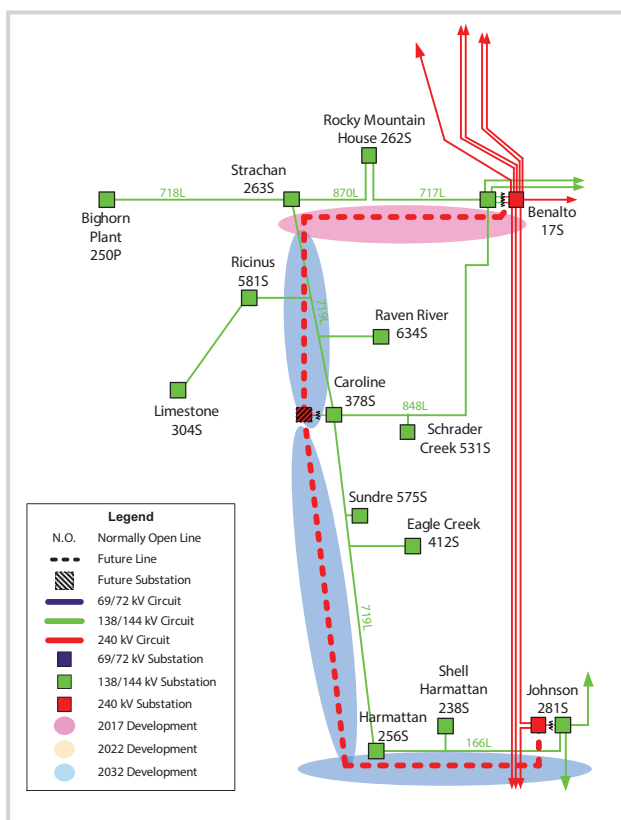
The load growth in this area is projected to be modest; however, this area has a number of gas processing facilities and has potential for gas-fired generation development. The transfer capability of the existing system (i.e., the 138 kV loop from Strachan substation to the Harmattan substation) to move power to the load centres outside this area is limited. Consequently, access to the grid for new generators will be constrained unless the system is upgraded in this area.

In the near term, additional transmission capacity is required to move energy from a proposed generator southwest of Rocky Mountain House. Additional transmission in the form of a 240 kV loop may be required in the longer term, depending on future generation development.

**Table 7.3.5-3: Caroline Area – Long-term Transmission Plan**

Timeframe	Developments
Near term	Add 240 kV transmission line capacity between Strachan and Benalto substations, operated initially at 138 kV
Medium term	No developments required at this time
Long term	Convert the new Strachan-Benalto line (above) to 240 kV operation Add 240 kV transmission line capacity between Strachan, Caroline, Harmattan and Johnson substations Add 240/138 kV transformation capacity at Caroline substation

**Figure 7.3.5-4: Caroline Area – Long-term Transmission Plan**



Map is for illustrative purposes only and does not represent actual terminations or routes

### Drayton Valley Area

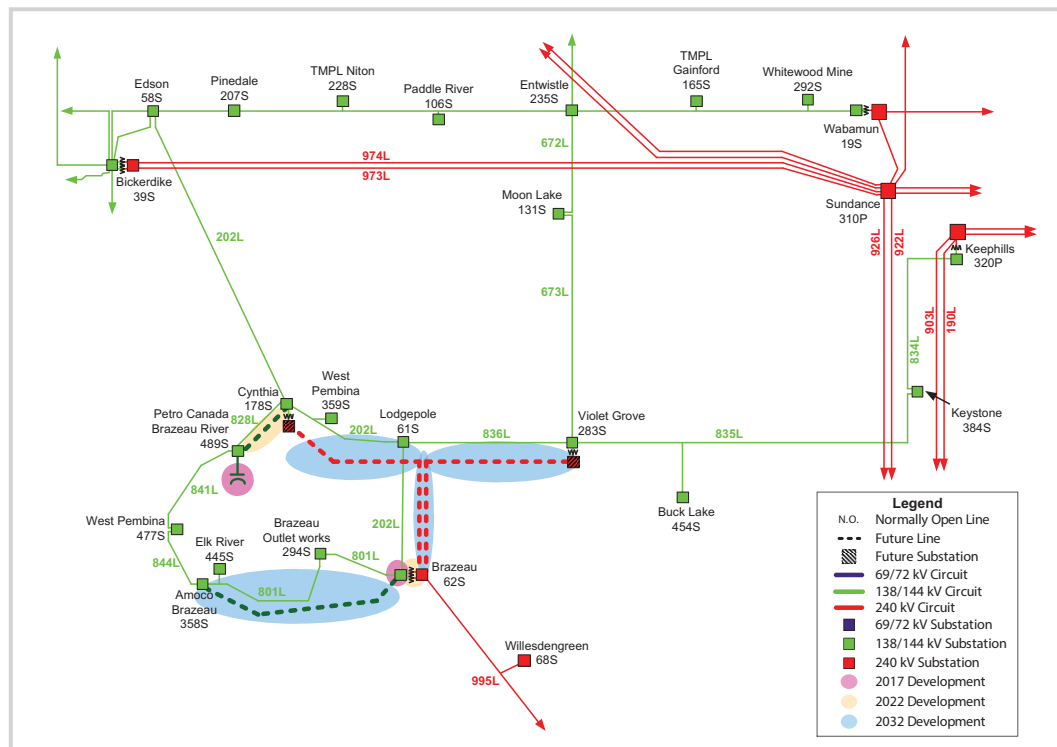
The Drayton Valley Area has potential for large loads related to oil and gas development over the planning horizon, with some uncertainty regarding the magnitude and timing of these developments. Low voltages were observed by 2017 at a number of 138 kV substations along the 138 kV loop from Cynthia-West Pembina-Brazeau-Lodge Pole; however, in the long term, overloads do occur on several 138 kV lines.

The near-term voltage problems can be resolved with the addition of voltage support in the form of capacitors at various substations. Longer-term transmission system enhancements include additional 138 kV and 240 kV lines and their timing will depend on the development of oil and gas loads in the area.

**Table 7.3.5-4: Drayton Valley Area – LTP Summary**

Timeframe	Developments
Near term	Add voltage support devices at Brazeau River substation
Medium term	Add 138 kV transmission line capacity between Cynthia and Brazeau River substations Add 240/138 kV transformation capacity at Brazeau
Long term	Add 138 kV transmission line capacity between Brazeau and Amoco Brazeau substations Add 240 kV transmission line capacity between Brazeau, Cynthia, and Violet Grove substations Add 240/138 kV transformation capacity at Cynthia and Violet Grove substations

**Figure 7.3.5-5: Drayton Valley Area – Long-term Transmission Plan**



Map is for illustrative purposes only and does not represent actual terminations or routes

### Hinton/Edson Area

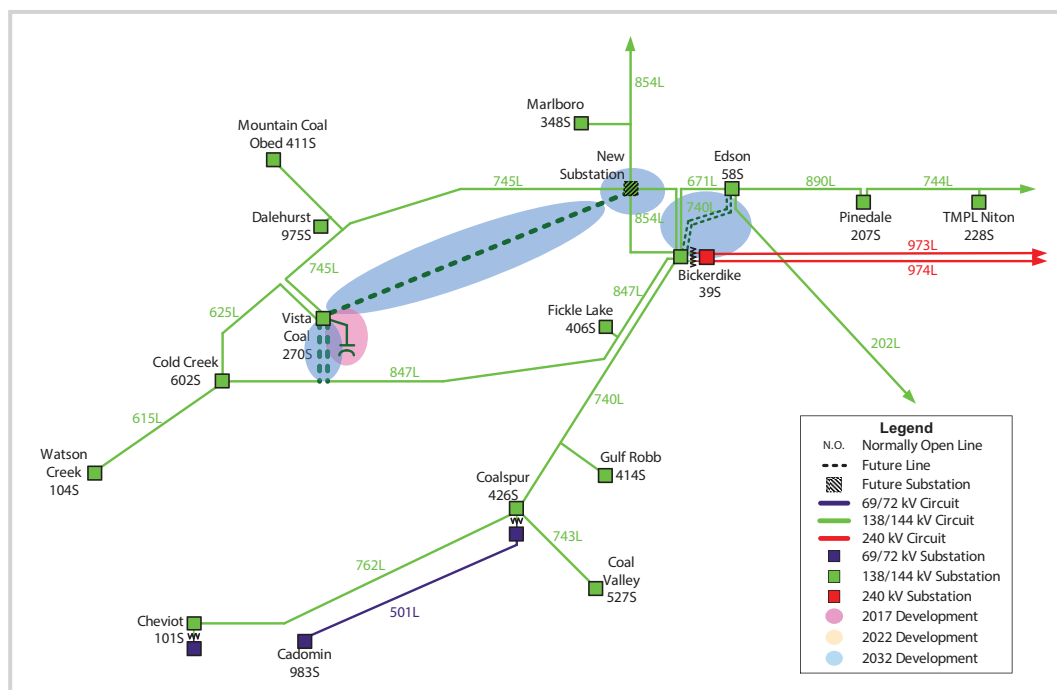
In the near term, low voltages are observed in the Cold Creek, Vista Coal and Edson substation areas due to load growth. Over the longer term, the loading of the 138 kV lines north and west of Bickerdike substation is anticipated to increase with the increased load growth in the area.

The near-term voltage issues can be resolved with the addition of capacitors. The longer-term solutions require additional 138 kV lines, the timing of which will depend on the timing and location of future load growth.

**Table 7.3.5-5: Hinton/Edson Area – LTP Summary**

Timeframe	Developments
Near term	Add voltage support at Vista Coal substation
Medium term	No developments required at this time
Long term	Add 138 kV transmission line between Vista Coal substation tapping the Cold Creek-Fickle Lake line Increase 138 kV transmission line capacity between Bickerdike and Edson substations Add a new 138 kV switching substation on the lines that intersect west of Edson Add 138 kV transmission line between Vista Coal substation and the new 138 kV switching station

**Figure 7.3.5-6: Hinton/Edson Area – Long-term Transmission Plan**



Map is for illustrative purposes only and does not represent actual terminations or routes

### Hanna Area

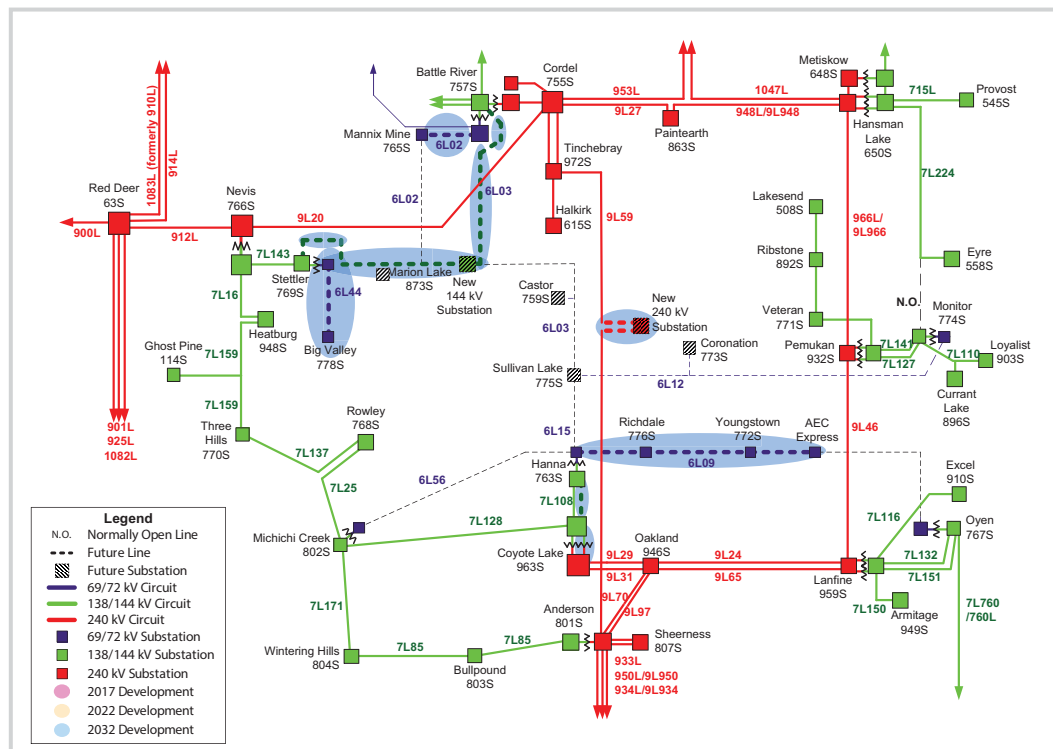
The approved Hanna Area Transmission Development (HATD) project will provide adequate transmission capacity to serve pipeline loads and integrate wind generation in the area. However, several rural communities in the Hanna area are served by an aging 72 kV system that is reaching the end of its useful life.

Parts of the 72 kV system will be replaced with 144 kV lines, as well as a 240 kV substation to serve local area loads. These enhancements are required in the long term.

**Table 7.3.5-6: Hanna Area – LTP Summary**

Timeframe	Developments
Near term	No developments needed at this time
Medium term	No developments needed at this time
Long term	<p>Add 144 kV transmission line between Stettler and Battle River substation to replace the existing 72 kV line</p> <p>Add a new 240 kV load serving substation between Tinchebray and Anderson substations</p> <p>Increase 240/144 kV transformation capacity at Coyote Lake substation</p> <p>Add 144 kV transmission line capacity between Hanna and Coyote Lake substations</p> <p>Add 144 kV transmission line capacity between Mannix Mine and Battle River, Stettler and Big Valley substations, and Hanna and Youngstown substations to replace 72 kV lines</p>

**Figure 7.3.5-7: Hanna Area – 72 kV Long-term Replacement Plan**



Map is for illustrative purposes only and does not represent actual terminations or routes

### **7.3.6 Northwest Planning Region Overview**

The Northwest Region is a geographically large region, bordered by the Northeast Region to the east, the Hinton and Wabamun planning areas to the south, B.C. to the west, and the Northwest Territories in the north. It comprises nine planning areas from Rainbow Lake and High Level in the north to Fox Creek and Swan Hills in the south. Population density in the region is sparse and the region's main population centre is the city of Grande Prairie. The Northwest Region represents approximately one-third of the area of the province but only about one-tenth of total electrical load.

The economy of this region is diverse with forestry, oil and gas, mining, agriculture and oilsands all part of the economic makeup of the area. Recent oilsands developments near Peace River are driving both load and generation increases.

#### ***Power Generation and Electrical Load in the Northwest Region***

The Northwest Region is sparsely populated which is reflected in the electrical load. The current load in the region is about 1,050 MW and industrial loads such as forestry and conventional oil and gas are found throughout the region. The peak load in this region is about 10 per cent of the total AIES load. The region currently has about 900 MW of generation which consists of mostly gas-fired generation with some biomass generation. The 150 MW H.R. Milner coal-fired generator that is also in the Northwest area is expected to be retired by 2020 when it reaches end of life.

A low to moderate rate of load growth is predicted for the northwest, with an annual rate of approximately 1.3 per cent. Load growth in the northwest is expected to be attributable mainly to forestry and oil and gas development. Oilsands development is starting to show up in the area generally east and north of the town of Peace River. The Shell Carmon Creek in situ project is about 35 km northeast of the town of Peace River and is expected to produce 80,000 barrels per day (bbl/d) of bitumen by 2017. This equates to about 70 MW of load. Several other oilsands developers also have projects in the area that are in the demonstration stages.

Potential future generation in the Northwest Region is diverse and includes gas-fired, biomass, hydro and cogeneration. The largest proposed generation project is a cogeneration facility connected to the Shell Carmon Creek oilsands development which is near the existing Wesley Creek substation. The first phase of Carmon Creek will include a 690 MW cogeneration facility. There is potential for an additional 690 MW to be developed at the site when Shell expands Carmon Creek to 160,000 bbl/d. Other possible generation additions include a 200 MW gas-fired generator north of the town of Peace River, the Dunvegan hydro power development of 100 MW on the Peace River, and a 45 MW biomass generator in the High Level area. This unit may, however, operate at reduced capacity between 2020 and 2030. There is potential for a total of 600 MW new combined-cycle generation development near this facility.

### ***Existing Transmission System***

The Northwest Region is comprised of nine AESO planning areas: Rainbow Lake (17), High Level (18), Peace River (19), Grande Prairie (20), High Prairie (21), Grande Cache (22), Valleyview (23), Fox Creek (24), and Swan Hills (26).

The northwest transmission system consists of an extensive 138 kV network that is supplied by a 240 kV loop connecting Louise Creek, Little Smoky, Wesley Creek, Brintnell, and Mitsue. The Northwest Region is connected to the Edmonton Region by a double-circuit 240 kV line from Louise Creek to Sagitawah to Sundance and a 240 kV line from Mitsue to Sundance. At Brintnell, the 240 kV transmission lines to Wesley Creek and to Mitsue connect the northwest and the northeast. There are about 500 km of older 72 kV lines still in service in the Slave Lake/High Prairie and Hines Creek areas.

### ***Major Transmission Projects Approved and/or Under Construction***

There are no major transmission developments approved or under construction in the Northwest Region at this time. The only transmission development in the region that is under construction is the conversion of parts of the High Prairie/Slave Lake 72 kV system to 144 kV.

Figure 7.3.6-1 shows the existing transmission system in the Northwest Region.





### ***Northwest Region Load and Generation Balance***

While the peak load and generation in the Northwest Region is roughly in balance—peak load is just over 1,000 MW while the installed generation capacity is just under 1,000 MW—about half of the generation is gas-fired peaking units and, thus, the region is a net importer of electric energy. However, with expected moderate load growth and the possible addition of 1,000 MW or more of generation, the Northwest Region could become a net exporter of electric energy.

### ***Planning Considerations for the Northwest Region***

Forecast load increases are not as significant a factor in planning the system in this region compared with other regions, given the forecast growth of about 1.3 per cent. There is a potential for some load increases in the Peace River Oil Sand area east and north of the town of Peace River; however, this load increase will likely be offset by local area cogeneration.

The town of Fort Nelson, B.C. is currently connected to the AIES in the vicinity of Rainbow Lake and draws up to 38.5 MW of load, affecting flow into the area. There is no increase anticipated to this load over the planning horizon in the Northwest Region plan.

There is a high degree of uncertainty regarding future generation in the Northwest. The possible addition of generation over the planning horizon ranges from as low as 375 MW to as high as 2,000 MW. As a result, system planning in the northwest considered three generation development scenarios for the region.

### ***Low Generation Development***

This scenario is based on the 2012 LTO except that in the 2012 LTO, the Swan Hills facility was included in the forecast, and this project has since been cancelled. However, the planned generation at Swan Hills (375 MW) was modeled near Wesley Creek representing possible generation additions at Carmon Creek and/or Whitetail (north of Peace River). Other generation includes the 45 MW Mustus biomass generator near High Level and the 100 MW Dunvegan hydro project on the Peace River. Also, the 150 MW H.R. Milner coal-fired generator is assumed to be retired before 2020.

### ***Expected Generation Development***

In the Expected Generation Development scenario, Carmon Creek is built to its full 690 MW capacity and the Whitetail generation of 200 MW is added before 2022, replacing the generic 375 MW generator assumed in the Low Generation scenario. Other generation is the same as the low scenario.

### ***High Generation Development***

The High Generation Development scenario includes all of the generation in the Expected Generation scenario with the addition of a second 690 MW generator at Carmon Creek.

## **7.3.7 Northwest Region Need Assessment and Transmission Plans**

Even though the load growth in this region is relatively small, under the Low Generation scenario there is inadequate transfer-in capability from the rest of the AIES; whereas under the Expected and High Generation scenarios, the added generation is subject to constraints including transfer out of the region. In addition, there are some local pockets of load-related

transmission enhancements needed regardless of the generation scenario, Grande Prairie being the most significant.

Thermal loading and voltage violations were observed in the region on all three networks—72 kV, 144 kV, and 240 kV—beginning as early as 2017. Violations are generally more severe and widespread under Expected and High Generation scenarios and grow in severity over the study horizon. The need for transmission development has been identified in certain planning areas within the region:

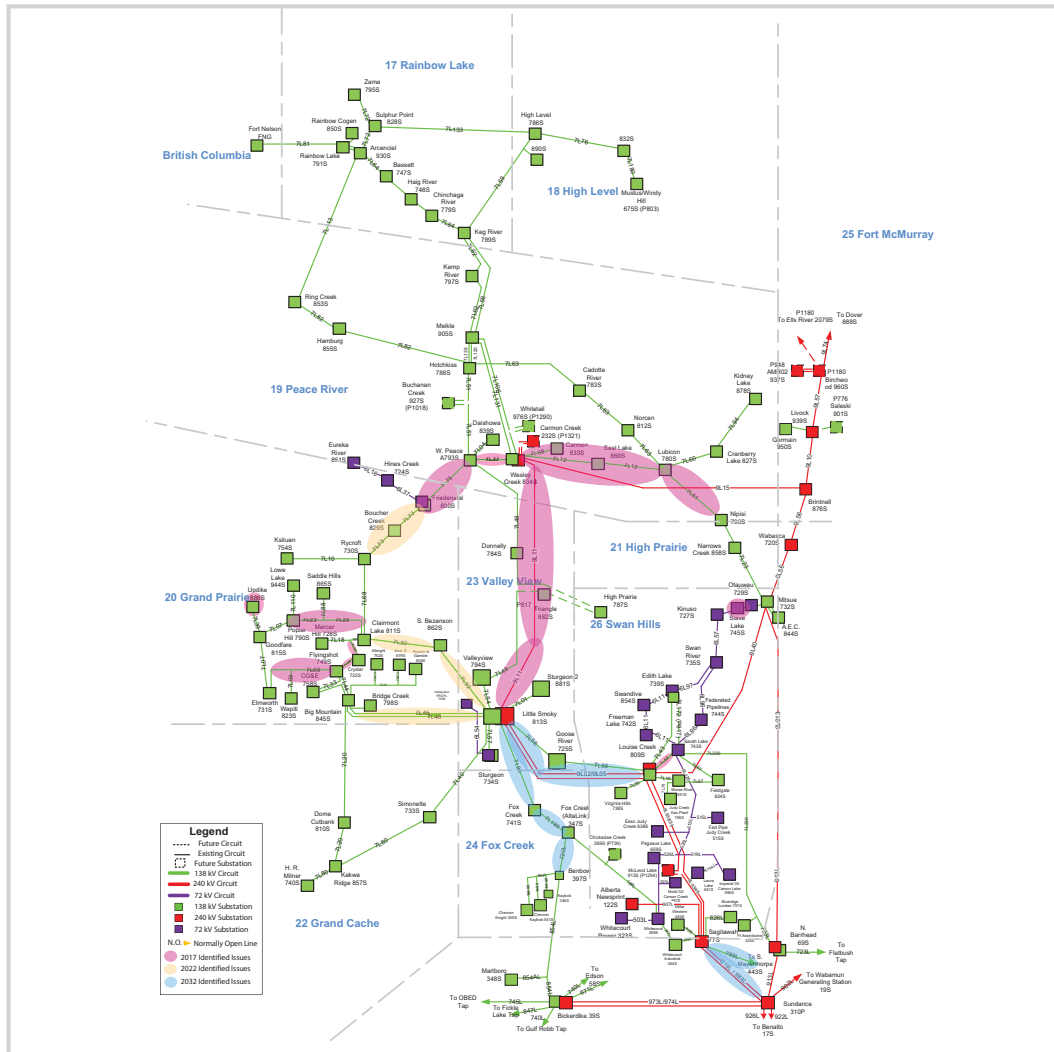
- Valleyview and Fox Creek Areas
- Swan Hills and High Prairie Areas
- Grande Prairie Area
- Peace River Area

In addition to the area issues, the transfer-in and transfer-out issues under the various generation scenarios require enhancements in the Valleyview/Fox Creek areas.

The elements of the Northwest Region transmission system that experience criteria violations under Low and Expected Generation scenarios over the planning horizon are illustrated in Figures 7.3.7-1 and 7.3.7-2 respectively. Under the High Generation scenario, there are severe system constraints throughout the area. Given that constraints under the High Generation scenario are system-wide, a figure was not included here.



**Figure 7.3.7-2: Need Assessment Results for Northwest Region (Expected Generation Development Scenario)**



**Valleyview and Fox Creek Areas**

Under the Low Generation scenario in the Northwest Region, an outage to one of the Sundance-Sagitawah 240 kV lines will overload not only the other Sundance-Sagitawah line but also the 240 kV line from Sundance to Barrhead, the underlying 138 kV line between Mayorthorpe and Sagitawah and 138 kV lines in the Fox Creek area.

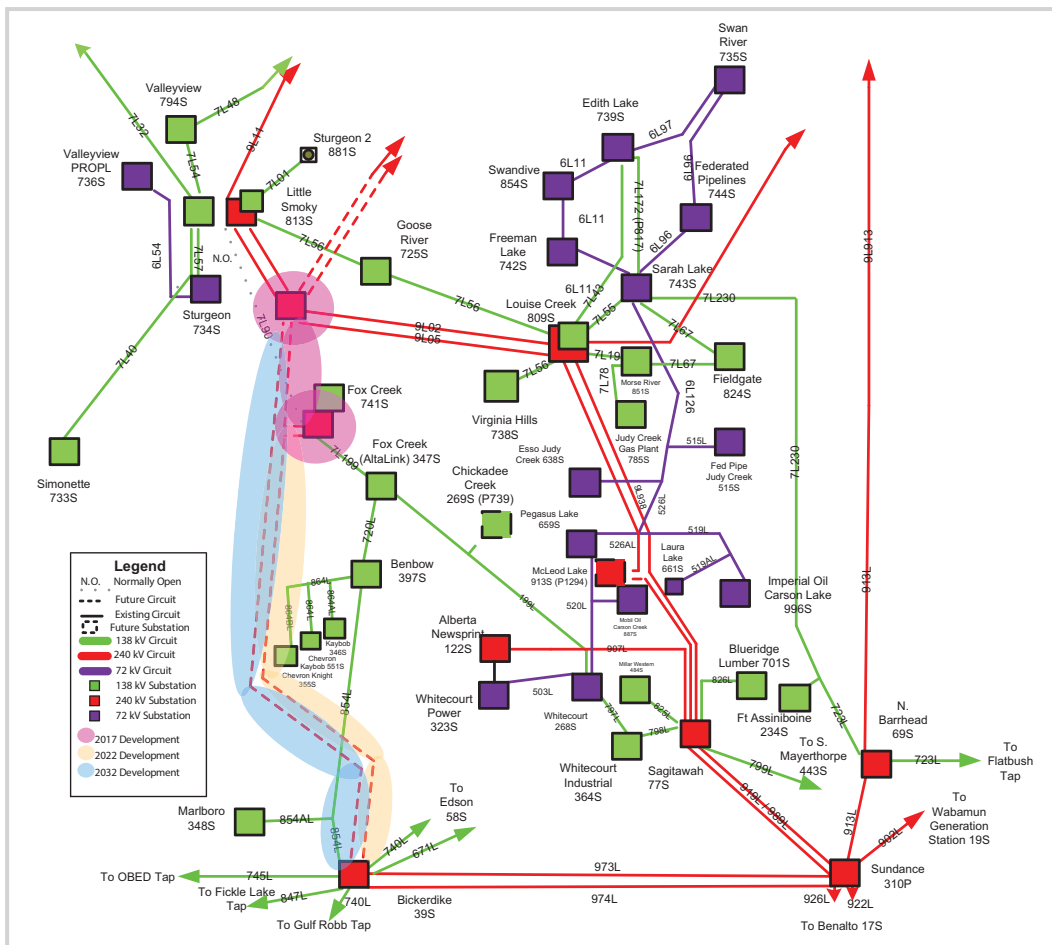
In the Expected Generation scenario, the region is expected to exceed its transfer-out capability before 2032, with overloads of the underlying 138 kV network caused by outage of a 240 kV line on the path from Little Smoky to Louise Creek to Sagitawah and to Sundance.

These transfer-in and transfer-out limits can be mitigated by adding additional 240 kV lines into the area from Bickerdike substation near Edson, and by reconfiguring the 144 kV lines near Fox Creek to reduce underlying flows on that system.

**Table 7.3.7-1: Valleyview and Fox Creek Areas – LTP Summary**

Timeframe	Development
Near term	Build a new 240 kV switching station near Little Smoky substation due to insufficient space to expand existing Little Smoky substation and cut the existing Louise Creek-Little Smoky 240 kV lines into the new switching station  Expand Fox Creek 741S to include 240/144 kV transformation  Add new 240 kV transmission line from the new switching station to Fox Creek, double-circuit construction with one-side strung
Medium term	Build new 240 kV transmission line from Fox Creek to Bickerdike substations, double-circuit construction with one-side strung
Long term	Add 240 kV transmission line capacity from the new switching station to Bickerdike, bypassing Fox Creek by stringing the second side of the double-circuit structures

**Figure 7.3.7-3: Valleyview and Fox Creek Areas – Long-term Transmission Plan**



Map is for illustrative purposes only and does not represent actual terminations or routes

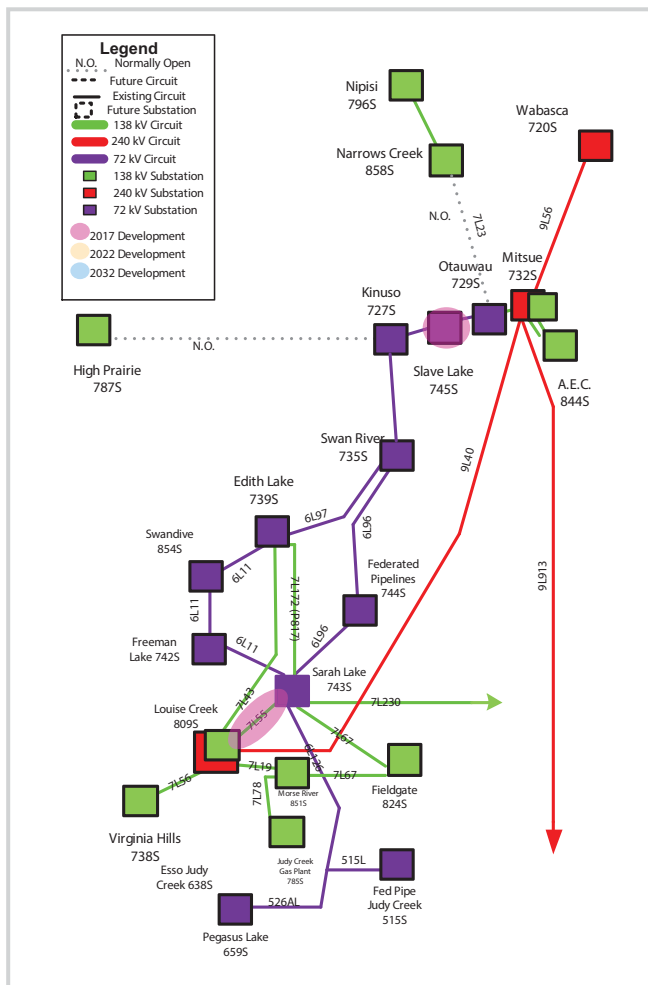
### Swan Hills and High Prairie Areas

Minor localized issues exist in the Swans Hills area. An outage of the 144 kV line from Louise Creek to Morse River will cause overloading of the 144 kV line from Louise Creek to Sarah Lake. In addition, loss of the 144 kV transformer or line feeding Otauwau will cause low voltage at Otauwau and Slave Lake substations. The need for transmission development in this area is limited to the near term.

**Table 7.3.7-2: Swan Hills and High Prairie Areas – LTP Summary**

Timeframe	Development
Near term	Increase capacity on the existing 240 kV transmission line 1046L from Sundance to Cherhill  Increase 144 kV transmission line capacity of the existing 7L55 from Louise Creek to Sarah Lake  Add voltage support at Slave Lake
Medium term	No developments needed at this time
Long term	No developments needed at this time

**Figure 7.3.7-4: Swan Hills and High Prairie Areas – Long-term Transmission Plan**



Map is for illustrative purposes only and does not represent actual terminations or routes

### Grande Prairie Area

There are major voltage and stability issues in the Grande Prairie area beginning as early as 2017. There are existing constraints on the Lowe Lake and Poplar Hill generators near Grande Prairie due to stability issues under single contingencies that prevent them from operating at full capacity. Also, operating procedures for the area currently require out-of-merit generation dispatch for low voltages under certain system conditions. In addition to the stability issue, there are several overload and voltage violations for various contingencies into and within the Grande Prairie area. In addition to local area issues, the loss of the double-circuit 144 kV lines that supply Grand Prairie from the Little Smoky substation will cause low voltages in the Grande Prairie area as well as thermal overloading of transmission lines which could require a significant amount of load to be shed in Grande Prairie. These stability and voltage issues are the result of the loads and generation in and around Grande Prairie growing beyond the capability of a 144 kV system to supply the area.

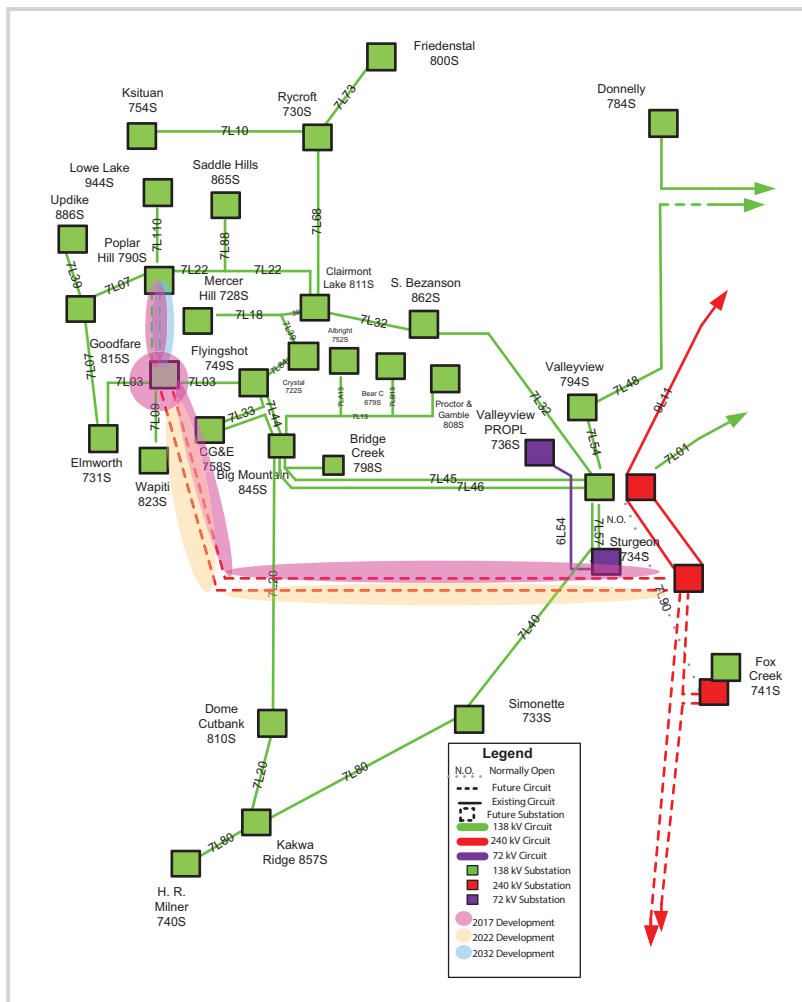
A 240 kV solution is required to provide reliable supply into Grande Prairie. As well, local area 144 kV enhancements are required to mitigate the local area overloads. There is also potential for the development of a 600 MW combined-cycle facility in the vicinity of the existing H.R. Milner generating station. The recommended 240 kV transmission developments for the region can accommodate this additional capacity.

**Table 7.3.7-3: Grande Prairie and Area – LTP Summary**

Timeframe	Development
Near term	<p>Add a new 240/144 kV source substation around Wapiti Junction</p> <p>Add a 240 kV transmission line between the new source substation and Little Smoky substation, double-circuit with one-side strung</p> <p>Connect the existing 144 kV lines from Elmworth, Wapiti and Flyingshot into the new source substation</p> <p>Add 144 kV transmission line from the new source substation to Poplar Hill substation</p>
Medium term	<p>Add transmission line capacity between Little Smoky to the new substation by stringing the second circuit on the double-circuit structures</p> <p>Add transformation capacity at the new substation</p>
Long term	<p>Add 144 kV transmission line capacity between the new substation and Poplar Hill substation</p>



**Figure 7.3.7-5: Grande Prairie and Grande Cache Areas – Long-term Transmission Plan**



Map is for illustrative purposes only and does not represent actual terminations or routes

**Peace River Area**

Under the Expected Generation scenario, generator additions near Wesley Creek will result in widespread thermal overloading of the 144 kV system for single contingency outages of the 240 kV transmission lines south and east from the substation. The forecast amount of generation connected at or near Wesley Creek ranges from about 1,000 MW in the Expected scenario to about 1,700 MW in the High Generation scenario.

In addition to the generation forecast at Wesley Creek, anticipated loads in the Seal Lake area east of Peace River will exceed the capacity of the local 144 kV system.

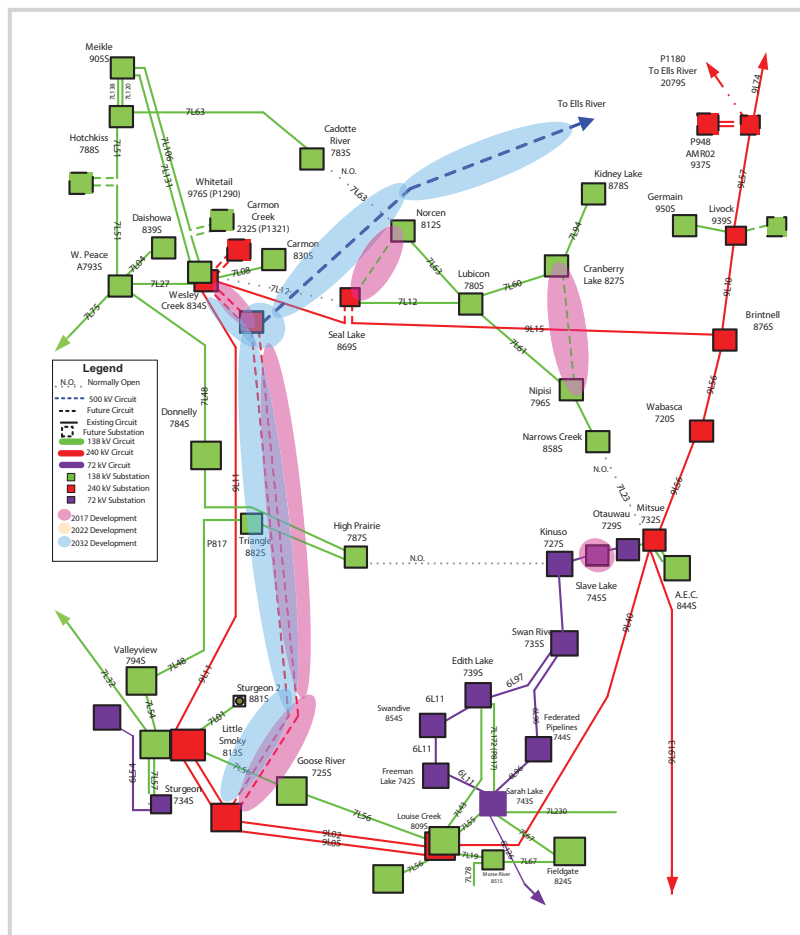
The addition of 240 kV lines from Wesley Creek substation south to Little Smoky substation will be required to move the local generation out of the area. As mentioned in the Valleyview and Fox Creek areas discussion above, the transmission enhancements between Little Smoky, Fox Creek and Bickerdike will also be required to move the added generation out of the region.

Assuming that the second 690 MW generation facility is added near Wesley Creek substation in the long term, further transmission development in the form of a 500 kV line east to the Fort McMurray area will be required.

**Peace River Area – LTP Summary**

Timeframe	Development
Near term	<p>Add 240 kV transmission line capacity from Wesley Creek to Little Smoky substation, double-circuit one-side strung</p> <p>Add a 240/138 kV substation near Seal Lake connecting into the 240 kV line between Wesley Creek and Brintnell substations</p> <p>Add 144 kV transmission lines between Seal Lake and Norcen substations and Cranberry Lake and Nipisi substations</p>
Medium term	No developments needed at this time
Long term	<p>Add 240 kV transmission line capacity between Wesley Creek and Little Smoky substations by stringing the second side of the double-circuit structures</p> <p>Add 500 kV transmission line capacity between Wesley Creek to Ells River substations</p> <p>Expand Wesley Creek substation to accommodate the 500/240 kV components</p>

**Figure 7.3.7-6: Peace River Area – Long-term Transmission Plan**



Map is for illustrative purposes only and does not represent actual terminations or routes

### **7.3.8 Northeast Planning Region Overview**

#### ***Northeast Planning Region Overview***

The Northeast Region includes the area between the Saskatchewan border in the east to the 5th meridian (approximately half way across the province of Alberta) in the west, and from approximately Edmonton in the south to the Northwest Territories border in the north. The economy of this region is driven by oilsands development which spans from Christina Lake in the south to Fort McMurray and beyond in the north. This region includes the Lower Athabasca Region (as defined in the Alberta Land Use Framework) which contains about 80 per cent of the oilsands resources in the province. Development in the oilsands industry in this region has a significant impact on the provincial economy.

#### ***Power Generation and Electrical Load in the Northeast Region***

Load growth in the Northeast Region is primarily driven by continuous development in the oilsands sector. The majority of the electrical load and generation in the region is located at oilsands sites surrounding the Fort McMurray area. This region is unique as it has significant behind-the-fence (BTF) load and generation connected to the grid as industrial systems.

The Northeast Region is expected to experience the greatest load growth of all the regions over the next 10 years due in large part to the expansion of the oilsands and secondary industries in the municipalities in the region. The current load in the Northeast Region is predominantly industrial, had a peak of 2,747 MW, and was about 28 per cent of the 2012 AIL. Load in the region is expected to grow by about 5.5 per cent in the next 10 years, reducing to about 3.5 per cent after that. The load in this region is growing at about twice the average rate for the province.

Generation in the region is predominantly gas-fired generation at oilsands sites. There is currently about 3,000 MW of generation capacity in the area, accounting for about 20 per cent of Alberta's total installed generation capacity. Through the continuing development of cogeneration at oilsands sites, generation capacity in the region is expected to increase to over 5,000 MW by 2022 and 7,500 MW by 2032. However, there is considerable uncertainty surrounding the amount of cogeneration the industry will develop with their oilsands operations.

The load in this region is supplied mainly by generation from within the region and currently this region is a net exporter of electric energy to the AIES. However, there are times of the year when the Northeast Region imports electric power from the rest of the grid. Over the planning horizon, the AESO anticipates that this region will become a significant net importer of electric energy from the AIES.

### ***Existing Northeast Transmission System***

The AESO planning areas in this region include Fort McMurray (25), Athabasca/Lac la Biche (27) and Fort Saskatchewan (33).

The Northeast Region is connected to the rest of the AIES by a network of 240 kV transmission as shown in Figure 7.3.8-1. A local 138 kV network serves loads in the Athabasca and Fort Saskatchewan areas and several 144 kV networks connect loads as well as BTF facilities in the Fort McMurray area.

### ***Major Transmission Projects Approved and/or Under Construction***

Three 500 kV transmission developments that connect the Northeast Region with the rest of the AIES have been approved and are in different stages of the development process:

- A double-circuit 500 kV AC line from Ellerslie substation in the Edmonton area to a new Heartland substation in the Fort Saskatchewan area. This project is under construction and is projected to be in service by July 2014.
- A 500 kV HVDC line (EATL) that will connect the converter station in the vicinity of the Heartland substation to a converter station in the vicinity of Brooks in the South Region. This project is under construction and is expected to be in service by December 2014.
- A 500 kV AC line referred to as Fort McMurray West 500 kV Line that will connect Sunnybrook substation near the Genesee generating station to the new Thickwood Hills substation near Fort McMurray. This project is being developed through the Competitive Process and is anticipated to be in service by 2019.

Furthermore, a 500 kV AC line referred to as Fort McMurray East 500 kV Line will connect Heartland 12S in the Fort Saskatchewan area to the new Thickwood Hills station 951S in the Fort McMurray area where the West 500 kV line is planned to be connected. This project will also be managed through the Competitive Process. The competition for this project is expected to commence in 2015.

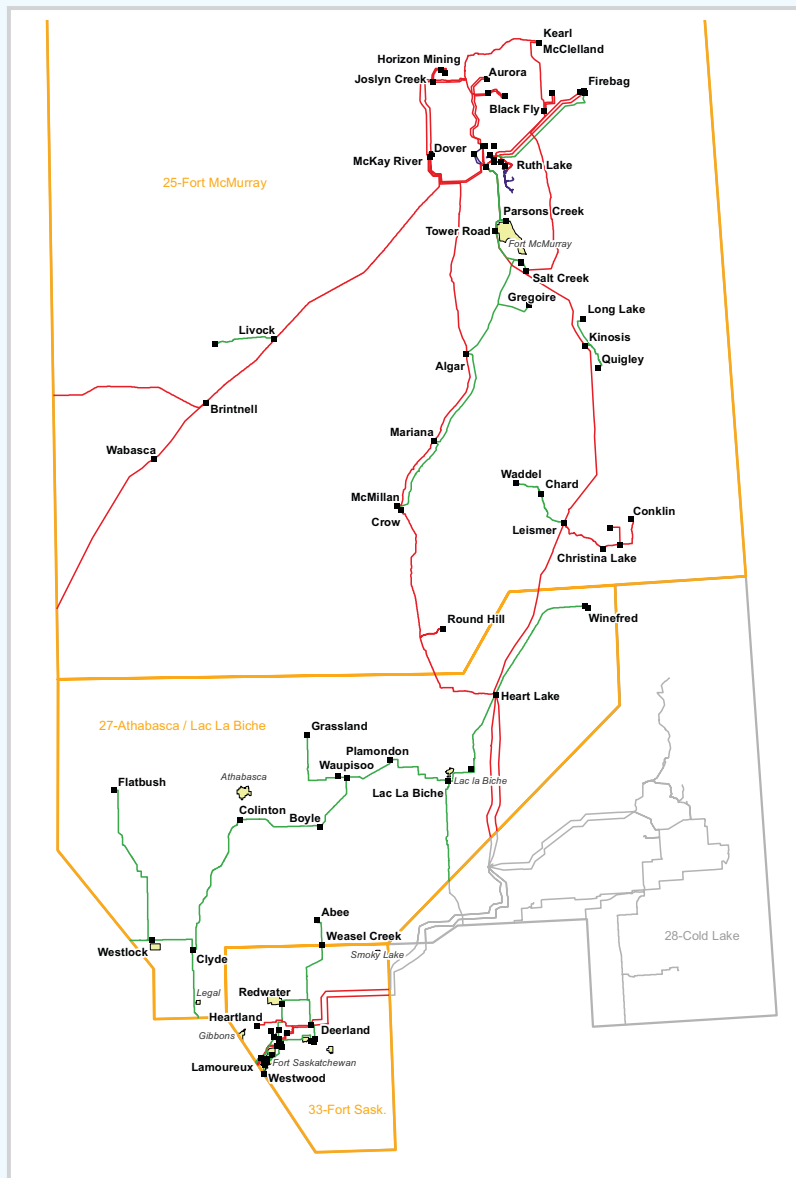
In addition to these major 500 kV developments, there are several 240 kV transmission developments being undertaken in the region, including:

- The Thickwood Hills 240 kV Transmission Development and Reactive Power Reinforcement to improve reliability north of Fort McMurray.
- North Fort McMurray Transmission Development that includes a new 240 kV transmission line from Salt Creek substation south of the Urban Service Area of Fort McMurray to the Blackfly substation and onto the Kearl substation north and east of Fort McMurray to serve new loads.
- Northwest of Fort McMurray 240 kV Transmission System Development which is a new 240 kV transmission line from the existing 240 kV lines north and west of Fort McMurray to the new Ells River substation and onto the new Birchwood Creek substation (generally referred to as the Dover West oilsands) to serve loads in that area.
- The Dawes 240/144 kV substation which will reinforce the existing 144 kV transmission system south of the Urban Service Area of Fort McMurray to provide reliability to existing and new loads.
- Kettle River substation which is a new 240/144 kV substation to serve as a point of supply to industrial loads southeast of the Urban Service Area of Fort McMurray.
- Christina Lake Area 240 kV Transmission System Development that connects three new 240/144 kV substations in the Christina Lake area to the existing Heart Lake substation via a new 240 kV transmission line to serve new oilsands loads in the area.

The above developments are expected to enter service prior to 2017 and therefore were assumed to be in place for the 2013 LTP analysis.

Figure 7.3.8-1 shows the existing transmission network in the Northeast Region.

**Figure 7.3.8-1: Existing Northeast Region Transmission System**



**Northeast Planning Region**

	Forecast Winter Peak Load (ALL)
2012 Actual	2,747 MW
Near term	3,933 MW
Medium term	4,685 MW
Long term	5,454 MW

### **Fort McMurray Area Load and Generation Balance**

Since load in the Fort McMurray Area is largely industrial and related to oilsands extraction processes, it has a high load factor and the load profile generally has a weak correlation with rest of the AIES load.

The majority of the generation units in the area are gas turbine-based cogeneration run as baseload units as needed by the industrial processes, and they are non-price sensitive. In spite of these load and generation characteristics, no strong correlation has been observed historically between the area load and generation on a region-wide basis.

This planning region has power transfers both into and out of the area. The transfers in are typically in the summer and transfers out are typically in the winter. This is in part due to gas turbine output varying with ambient temperature; as ambient air temperature increases, gas turbine units have a lower output. In addition, the available generation capacity is also reduced as a result of planned outages which typically occur in the summer months. Historically, the number of units offline simultaneously in the area ranged from zero to nine, with an average of four units simultaneously offline.

### **Planning Considerations for the Northeast Region**

The need for transmission development in the Northeast is directly linked to the development of oilsands projects. These developments result in large (50–200 MW) load increases over relatively short timeframes, and can have associated cogeneration. It is forecast that net load growth will increase and consequently the transfer-in requirement will also increase over the planning horizon. Uncertainty associated with the development of oilsands technologies such as Thermal Assisted Gravity Drainage (TAGD) and Steam Assisted Gravity Drainage (SAGD) affects transmission development in this area. TAGD could result in a significant load increase in the Fort McMurray area.

The Northeast Region is also the location of the proposed 1,000 MW Slave River hydro project near the Alberta-Northwest Territories border.

The Lower Athabasca Regional Plan (LARP), developed under the Alberta Land-use Framework, provides guidance to provincial and local decision-makers regarding land-use management for the region. The LARP implementation plan includes, among other things, conservation areas, ecosystems and recreation and tourism needs that must be considered when developing linear infrastructure such as electrical transmission lines.

### **7.3.9 Northeast Region Need Assessment and Transmission Plans**

The primary drivers for future system development in the Northeast Region are load and generation growth associated with oilsands development. Location and magnitude of these developments will trigger various transmission enhancements.

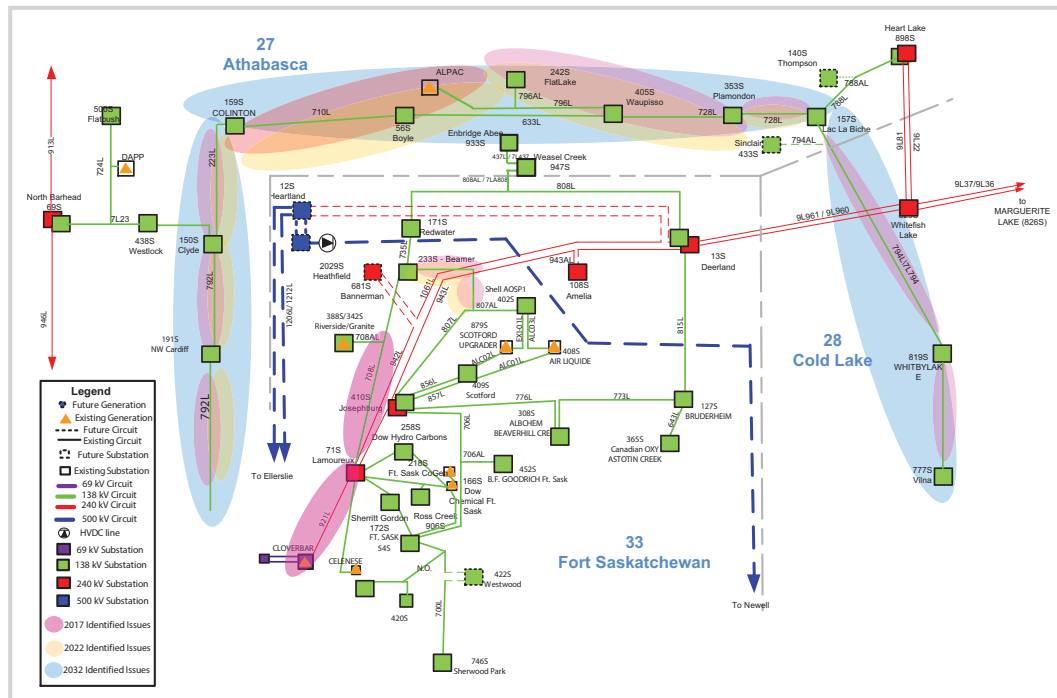
In general, the need assessment studies confirm that the Fort McMurray West and East 500 kV lines are required to remove constraints on the bulk system between the northeast and the rest of the AIES. The local area 240 kV and 138/144 kV systems also experience a variety of constraints as early as 2017. These local constraints can be separated into the AESO planning areas that constitute the Northeast Region.

Figures 7.3.9-1 and 7.3.9-2 shows the identified need for the Northeast Region transmission system enhancements by study year.





**Figure 7.3.9–2: Athabasca and Fort Saskatchewan Areas – Transmission Need Assessment Summary**



**Fort McMurray Area**

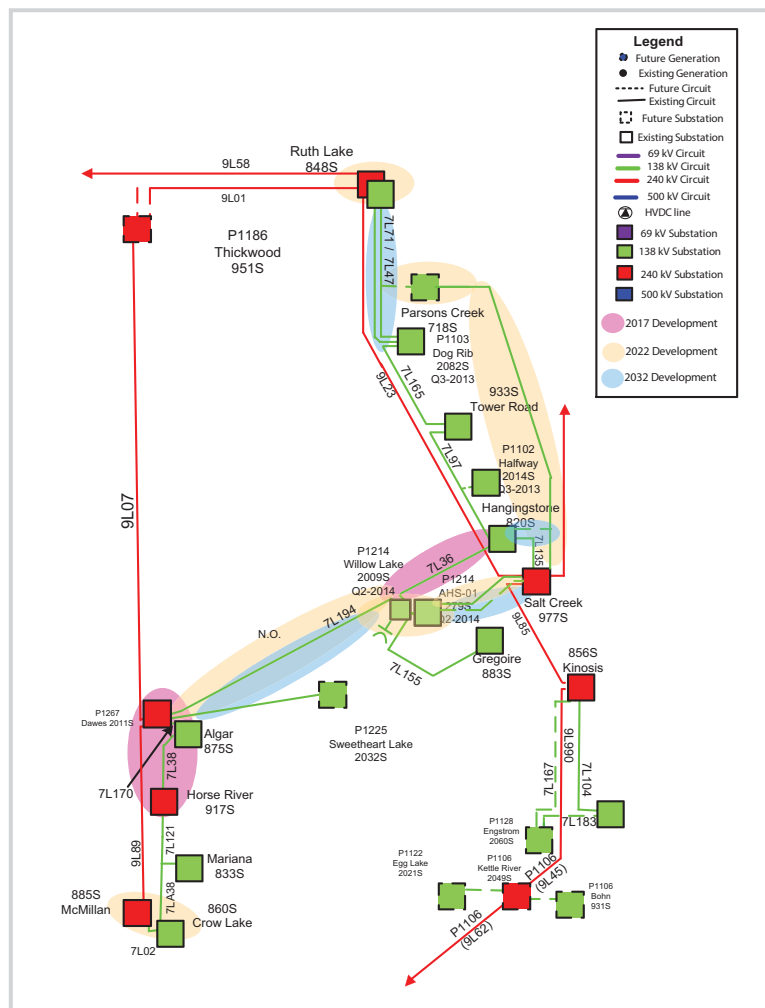
In the Fort McMurray area, a 144 kV system between McMillan, Salt Creek and Ruth Lake feeds the local industrial loads and urban loads in Fort McMurray. No generation is forecast to be connected on this 144 kV network. The load on this network is expected to undergo rapid growth in the next 20 years as oilsands loads in the area are connected.

These load increases will require enhancements to the 144 kV system as well as upgrades at various 240/144 kV supply substations.

**Table 7.3.9-1: Fort McMurray Area – LTP Summary**

Timeframe	Development
Near term	Add 240/144 kV transformation capacity at Dawes substation Increase 144 kV transmission line capacity between Algar and Dawes substations Restore 144 kV transmission line capacity between Hanging Stone and Willow Lake substations
Medium term	Add 240/144 kV transformation capacity at Ruth Lake, Salt Creek and McMillan substations Increase 144 kV transmission line capacity of various lines by restoring transmission line ratings to their conductor ratings Add voltage support at Willow Lake substation
Long term	Increase 144 kV line capacity between Ruth Lake and Parsons Creek substations Increase 144 kV transmission line capacity of various lines by restoring transmission line ratings to their conductor ratings

**Figure 7.3.9-3: Fort McMurray Area – Long-term Transmission Plan**



Map is for illustrative purposes only and does not represent actual terminations or routes

Sensitivity studies were conducted for various, possibly significant changes to the base assumptions. These included an oil sands technology shift to TAGD which would be highly electricity intensive, possible large generation in the northwest that could serve load increases in the northeast, and the possibility of the Slave River hydro project proceeding. These developments would require the development of a major 500 kV transmission system to connect these loads and generation to the rest of the AIES.

**Table 7.3.9–2: Preferred Plan for Northeast 500 kV System Additions**

Timeframe	Development
Long term	<p><b>TAGD Development:</b></p> <ul style="list-style-type: none"> <li>Build a new 500/240 kV TAGD substation near Ells River substation</li> <li>Build a new 500 kV single-circuit transmission line from Livock substation to the new TAGD substation</li> <li>Add a 500/240 kV transformer at Livock</li> <li>Local area 240 kV transmission enhancements</li> </ul> <p><b>Northwest – Northeast Link:</b></p> <ul style="list-style-type: none"> <li>Build a new 500 kV transmission line from Wesley Creek to the new TAGD substation</li> </ul> <p><b>Slave River Hydro:</b></p> <ul style="list-style-type: none"> <li>Build a 500 kV single-circuit transmission line from Slave River Hydro to Thickwood Hills substation</li> <li>Build a 500 kV single-circuit transmission line from Slave River Hydro to the new TAGD substation</li> </ul>



### Athabasca Area

In the Athabasca area, all loads are connected on the 138 kV network and are fed from the following sources:

- Heart Lake 240/138 kV substation
- North Barrhead 240/138 kV substation
- NW Calder 240/138 kV substation
- Lac la Biche to Whitby Lake 138 kV line

Outages of any of the following elements would isolate the load from one or more sources and lead to voltage and/or thermal violations:

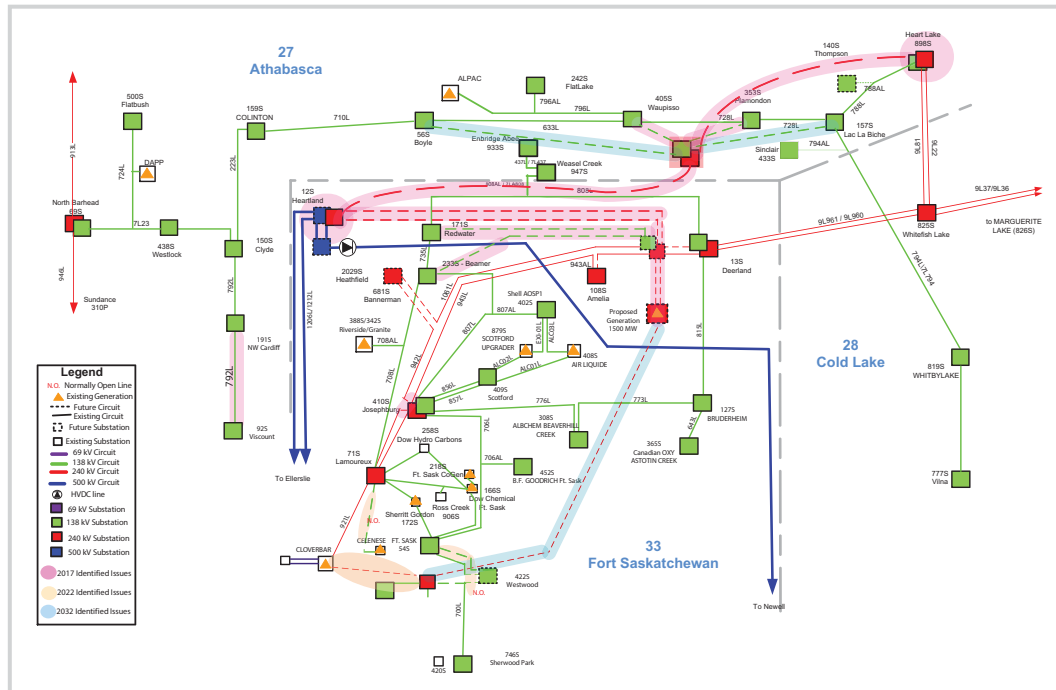
- Plamondon–Lac la Biche 138 kV line
- Clyde–Colinton 138 kV line
- Lac la Biche–Thompson–Heart Lake 138 kV line
- Heart Lake 240/138 kV transformer

The 138 kV transmission system in this area is near its capacity due to continuing load additions. Over the next 10 years, more pipeline pumping loads are expected that will cause both voltage and thermal violations throughout the local system.

**Table 7.3.9–3: Athabasca Area – LTP Summary**

Timeframe	Development
Near term	<p>Add a new 240/138 kV source substation between Plamondon and Waupisso substations</p> <p>Add a new 240 kV transmission line from the new substation to Heart Lake substation and to Heartland substation</p> <p>Add a 138 kV transmission line to Waupisso substation from the new 240/138 kV source substation</p> <p>Add a 138 kV transmission line to Plamondon substation from the new 240/138 kV source substation</p>
Medium term	No developments needed at this time
Long term	Add new 138 kV transmission lines from the new 240 kV source substation to both Boyle and Lac la Biche substations

**Figure 7.3.9-5: Athabasca and Fort Saskatchewan Areas – Long-term Transmission Plan**



Map is for illustrative purposes only and does not represent actual terminations or routes

**Fort Saskatchewan Area**

The Fort Saskatchewan area is experiencing rapid growth in the oil and gas sector. There are several industrial developments currently under study or under construction that would significantly increase loading on the system. Significant thermal overloads were observed for single-contingency outages on the 138 kV system by 2017.

There is a need to reconfigure the 240 kV system in the Fort Saskatchewan area to provide increased operational flexibility. The first project consists of cutting one of the 240 kV circuits in and out at Josephburg substation and restoring the line capacity on three of the 240 kV circuits. The second project includes a 240 kV transmission extension from the Heartland 500/240 kV substation.

**Table 7.3.9-4: Fort Saskatchewan Area – LTP Summary**

Timeframe	Development
Near term	Add a new 240/138 kV source substation between Deerland and Heartland substations
	Add a 138 kV transmission line to both Red Water and Beamer substations from the new source substation
	Increase 500/240 kV transformation capacity at Heartland substation
	Reinforce 240 kV supply to Josephburg substation
Medium term	Increase 138 kV transmission line capacity between Fort Saskatchewan and Westwood substations
Long term	Increase transmission line capacity between the proposed large generation site and a new East Edmonton substation

### **7.3.10 Edmonton Planning Region Overview**

The Edmonton Region is a relatively small region compared to the other four provincial planning regions. It is located in the centre of Alberta and covers an area that includes Lake Wabamun, Edmonton and Wetaskiwin. It is bordered in the south, east and west by the Central Region and in the north by the Northeast and Northwest Regions.

The population of this region is around 30 per cent of the total Alberta population, primarily within the city of Edmonton urban area and surrounding communities. The region has a large oil refining industrial area on the east side of the city of Edmonton. The Nisku industrial park is south of the city between Edmonton and Leduc, and the Edmonton International Airport is in the same area. The area further south is primarily farmland, as is the area west of the city.

#### ***Power Generation and Electric Load in the Edmonton Region***

The Edmonton Region is a winter peaking region, with load dominated by the residential and commercial load centre of the city of Edmonton and the large industrial area on the east side of the city. Edmonton is the second largest urban centre in Alberta, and is approximately 20 per cent of the total AIES load. Load in the Edmonton Region is expected to grow at about 2.5 per cent over the next 10 years and about 2 per cent over 20 years.

The Edmonton Region is also the major generation centre in the province. The Wabamun area contains most of the coal-fired generation and over 30 per cent of the total generation in the province of Alberta. Existing generation in this area includes the three large (800 - 1,500 MW) Genesee, Sundance and Keephills coal-fired plants and the Clover Bar 250 MW simple-cycle natural gas-fired plant which is within the city boundaries. Coal-fired capacity in the Wabamun area totals 4,650 MW. The aging coal-fired generators in the area are expected to retire once they reach their end of life as defined in federal law.

Future generation that is forecast for this region is primarily expected to be comprised of combined-cycle gas-fired power plants replacing the generation capacity in the Wabamun area as coal-fired units are retired from service. The AESO receives about 10 load requests for new or expanded substations each year, and one or two generator requests.

#### ***Existing Transmission System***

The Edmonton Region includes the city of Edmonton (60), Wabamun (40) and Wetaskiwin (31) planning areas. Owing to the large concentration of generation sources, the Edmonton Region is the central hub for the provincial transmission network connecting the north and south AIES with transmission lines that includes 500 kV and 240 kV, and in the near future will include 500 kV HVDC.

The current Edmonton Region system is comprised of transmission networks that operate at 500 kV, 240 kV, 138 kV and 69/72 kV nominal voltages. The transmission system in this region consists of approximately 150 km of 500 kV lines, 1,300 km of 240 kV lines, 1,000 km of 138 kV lines and 200 km of 72 kV lines. A 500 kV loop between Wabamun and Edmonton feeds power from the coal-fired plants in Wabamun to the southeast corner of the city. The 240 kV system transmits power from the coal-fired power plants into and around the city of Edmonton, to the Northwest Region, to western parts of the Central Region and to the



South Region. The 138 kV system feeds loads in the areas outside of the city of Edmonton as well as the east industrial area. The 72 kV system is wholly within the city of Edmonton and is dedicated to serving loads within the city.

### ***Major Transmission Facilities Approved and/or Under Construction in the Edmonton Region***

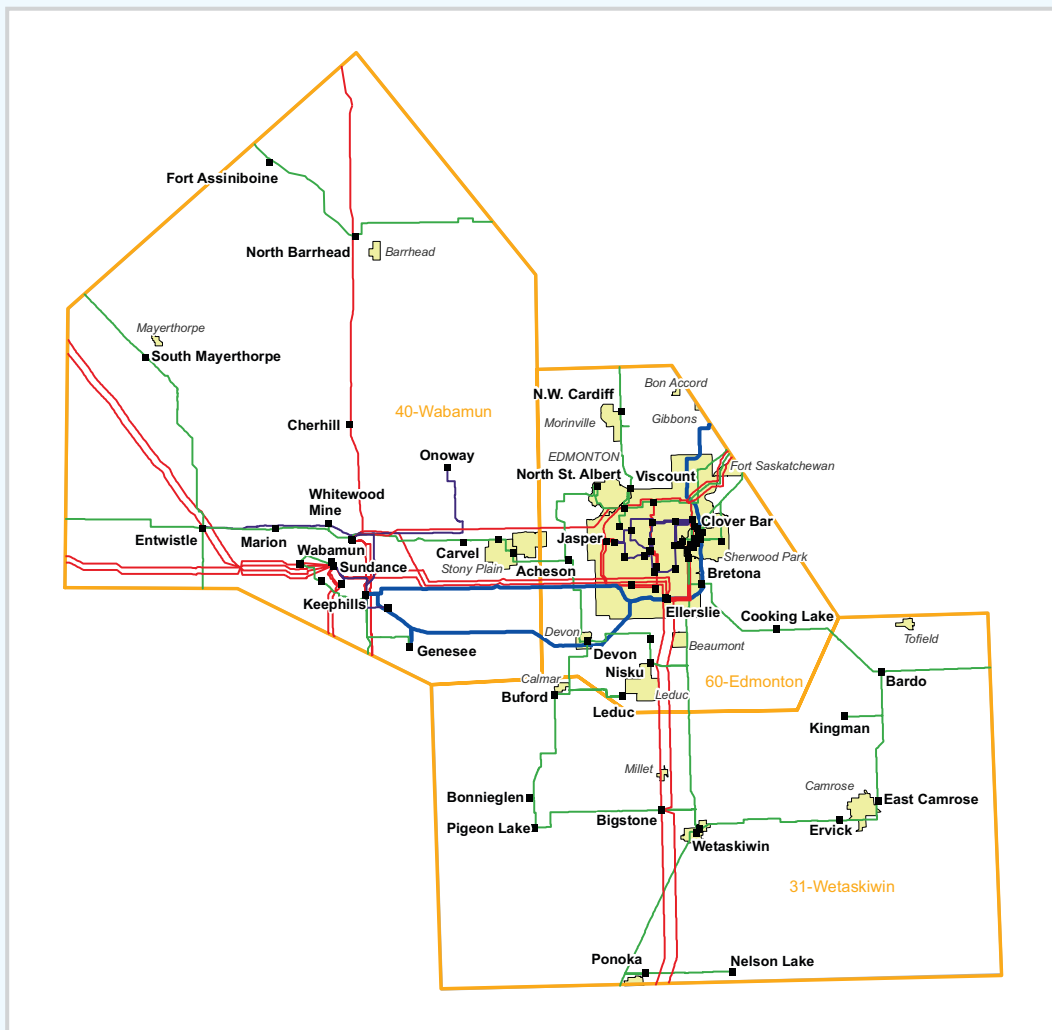
In recent years, the AESO has received approval of the need for five major transmission system developments within or terminating in the Edmonton Region. These developments include:

- Heartland 500 kV double-circuit line from south Edmonton to the Heartland industrial area near Fort Saskatchewan to supply anticipated upgraders in that area as well as being a terminus for a future line to the northeast.
- The Western Alberta Transmission Line (WATL) which is a 500 kV HVDC line from the Wabamun area to Calgary to alleviate constraints on the existing 240 kV transmission system between the Edmonton Region and the South Region.
- The Eastern Alberta Transmission Line (EATL) which is a 500 kV HVDC line from the Heartland area to the Brooks area also to alleviate constraints on the existing 240 kV transmission system between the Edmonton Region and the South Region.
- A 500 kV AC line from the Lake Wabamun area to the Fort McMurray area to supply increasing oilsands loads, and provide an outlet for generation in the northeast area of the province.
- A second 500 kV AC line to the Fort McMurray area but originating in the Heartland area also to serve increasing oilsands loads and generation in the northeast area of the province.

These major transmission developments are in various states of execution. The Heartland development and the two HVDC lines are under construction and will enter service in the 2014 to 2015 timeframe. The two 500 kV AC lines to the northeast will utilize the AESO's Competitive Process.

Figure 7.3.10-1 shows the existing Edmonton Region transmission system.

Figure 7.3.10-1: Existing Edmonton Region Transmission System



**Edmonton Planning Region**

	Forecast Winter Peak Load (AIL)
2012 Actual	2,134 MW
Near term	2,506 MW
Medium term	2,785 MW
Long term	3,252 MW

### ***Edmonton Region Load and Generation Balance***

The Edmonton Region is a net exporter of energy to the rest of the province. The total generation is about 4,950 MW compared to a regional load of about 2,140 MW (2010/11 winter peak). There is no intermittent (wind or hydro) generation in the region, and since the majority of the generation is baseload coal-fired, the region exports energy continually to the other regions of the province.

### ***Planning Considerations in the Edmonton Region***

Transmission capacity out of the Edmonton Region will be significantly increased when the two HVDC lines to the south and the two 500 kV AC lines to the northeast enter service over the coming years. As a result, the transmission system that transfers power out of the Edmonton Region will be adequate for the planning horizon. The future transmission issues that need to be resolved in the region are mainly within the city of Edmonton and surrounding area, and between the Wabamun generators and the Edmonton load centre.

The city of Edmonton distribution networks are supplied through an older system of 72 kV transmission lines fed from various source substations. This 72 kV transmission network is operated in a radial fashion; the distribution substations that supply local loads are each supplied by one 72 kV line with a second open line available if the main supply line is taken out of service. When the main supply line is taken or forced out of service, there is a temporary disruption to load while the substation is switched to the back-up line. This is unlike most of the transmission networks on the Alberta system, which are looped and therefore more reliable. Looped networks include two lines of supply to a distribution substation so that an outage to one line will not result in the loss of the substation or the load it serves. An additional challenge in the city of Edmonton is that the existing 72 kV system is mostly comprised of underground cables that are reaching the end of their service lives and will need to be replaced.

The area to the south and west of Edmonton requires additions to the transmission system in order to reduce flows on the underlying 138 kV network and to serve load increases south and west of Edmonton. A NID for the South and West of Edmonton project has been filed with the AUC for approval. The transmission facilities added under this project will alleviate most of the issues in this area.

The east side of Edmonton is seeing load growth due to industrial as well as residential and commercial growth. This load increase will likely require transmission upgrades east of the city of Edmonton.

### **7.3.11 Edmonton Region Need Assessment and Transmission Plans**

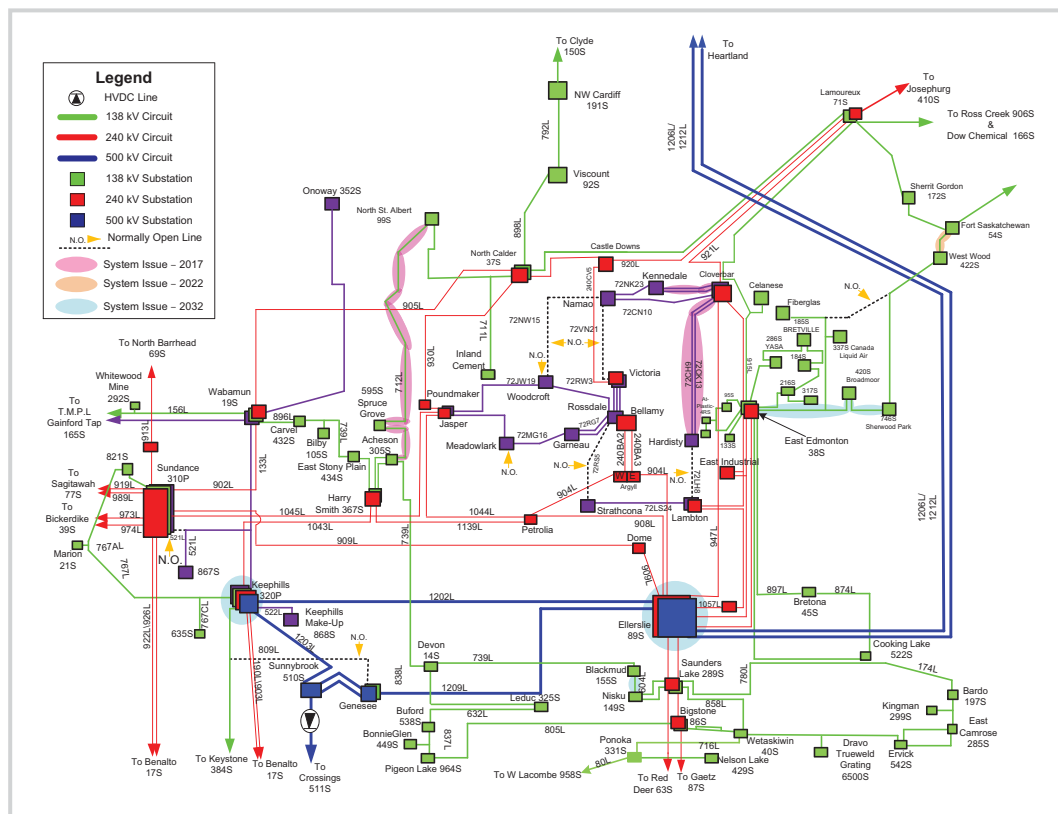
The primary drivers of the need for transmission development in the Edmonton Region are associated with steady load growth, potential large generation additions in the Wabamun area and age-related equipment conditions particularly associated with the city of Edmonton 72 kV network, as described above. Studies have identified the need for transmission development within the Edmonton planning area and between Wabamun and Edmonton. However, no need for transmission development has been identified in the Wetaskiwin planning area over the planning horizon.

Given the unique nature of the transmission systems in and around the city of Edmonton, the Edmonton planning area has been divided into three sub-areas for the purposes of need assessment. In addition, the transmission required to move power between Wabamun and Edmonton has been assessed. The areas where the need for transmission system enhancement or expansion has been identified include the following:

- City of Edmonton 72 kV Sub-area
- East of Edmonton Sub-area
- South of Edmonton Sub-area
- West of Edmonton Sub-area

Figure 7.3.11-1 depicts the results of the AESO’s need assessment for the Edmonton Region over the planning horizon. The identified transmission constraints are those that need to be addressed through transmission system development.

**Figure 7.3.11-1: Need Assessment Results for Edmonton Region**



### **City of Edmonton 72 kV Sub-area**

EPCOR has recently completed a system equipment condition assessment which indicated several of the existing 72 kV underground cables and equipment are considered to be approaching end of life. Several of the underground cables have been de-rated in thermal capacity due to deteriorating condition which has reduced the capacity of the network to supply increasing load. As such, load is approaching or has exceeded the capability of the existing 72 kV system, and increasing load will only further exacerbate capacity constraints in the future. The specific issues on the 72 kV system are:

- Garneau substation is fed by two 72 kV underground cables radially from Rosssdale substation; if one circuit is out, the other will be overloaded. In addition, part of the load at Meadowlark substation is fed from Garneau by a 72 kV circuit between Garneau and Meadowlark.
- When any of the cables between Cloverbar and Kennedale substations are out of service, or the Cloverbar and Namao substations is out of service, the Cloverbar-Kennedale-Namao loop has overloads.
- Clover Bar substation feeds Hardisty substation radially by two cables. When one cable is out of service, the other cable overloads.
- Based on EPCOR's condition assessment, the cables from Jasper substation to both Woodcroft and Meadowlark substations will need to be replaced in the 2014–2017 timeframe.
- EPCOR's condition assessment also identified the underground cables between Victoria and Rosssdale substations need to be replaced. This is an increasingly physically congested area with substantial new property development and re-development taking place.

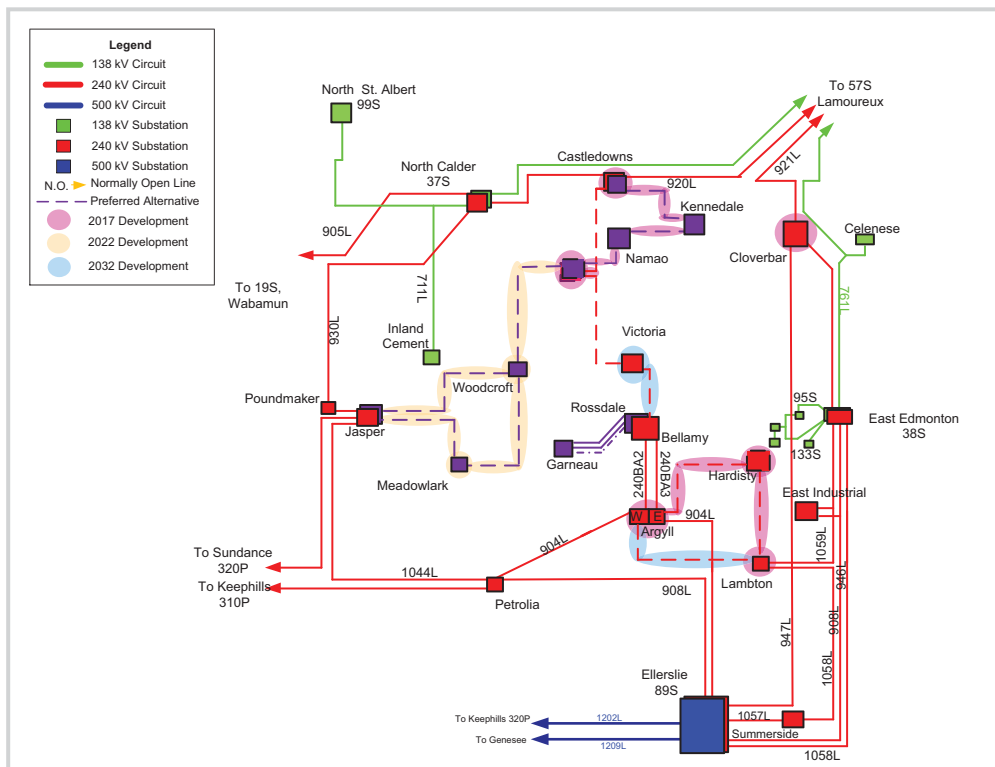
Reconfiguration of the 72 kV system in Edmonton to a closed loop system will improve reliability to the load substations and will remove two river crossings from Clover Bar to Kennedale.

Table 7.3.11-1 and Figure 7.3.11-2 provide the preferred plan for the 72 kV Edmonton network.

**Table 7.3.11-1: City of Edmonton 72 kV Preferred Alternative**

Timeframe	Development
Near term	New 240/72 kV source substation cutting in-out of the cable between Castle Downs and Victoria
	New 72 kV line from the new source substation to Namao
	Upgraded 72 kV cable from Namao to Kennedale
	New 72 kV cable from Kennedale to Castle Downs
	Two new 240/15 kV transformers at Hardisty
	New 240 kV cable from Hardisty to Lambton
	New 240 kV cable from Hardisty to Argyll
Medium term	Close the 72 kV busses at Woodcroft and Meadowlark
	Rebuild 72 kV cable from Jasper to Woodcroft
	Rebuild 72 kV cable from Jasper to Meadowlark
	New 72 kV cable from Woodcroft to Meadowlark
	New 72 kV cable from Woodcroft to the new 240/72 kV substation (identified above)
Long term	New 240 kV cable from Lambton to Argyll
	New 240 kV cable from Victoria to Bellamy
	Conversion of Victoria to serve load from 240 kV not 72 kV

**Figure 7.3.11-2: Edmonton 72 kV Long-term Transmission Plan**



Map is for illustrative purposes only and does not represent actual terminations or routes

**East of Edmonton Sub-area**

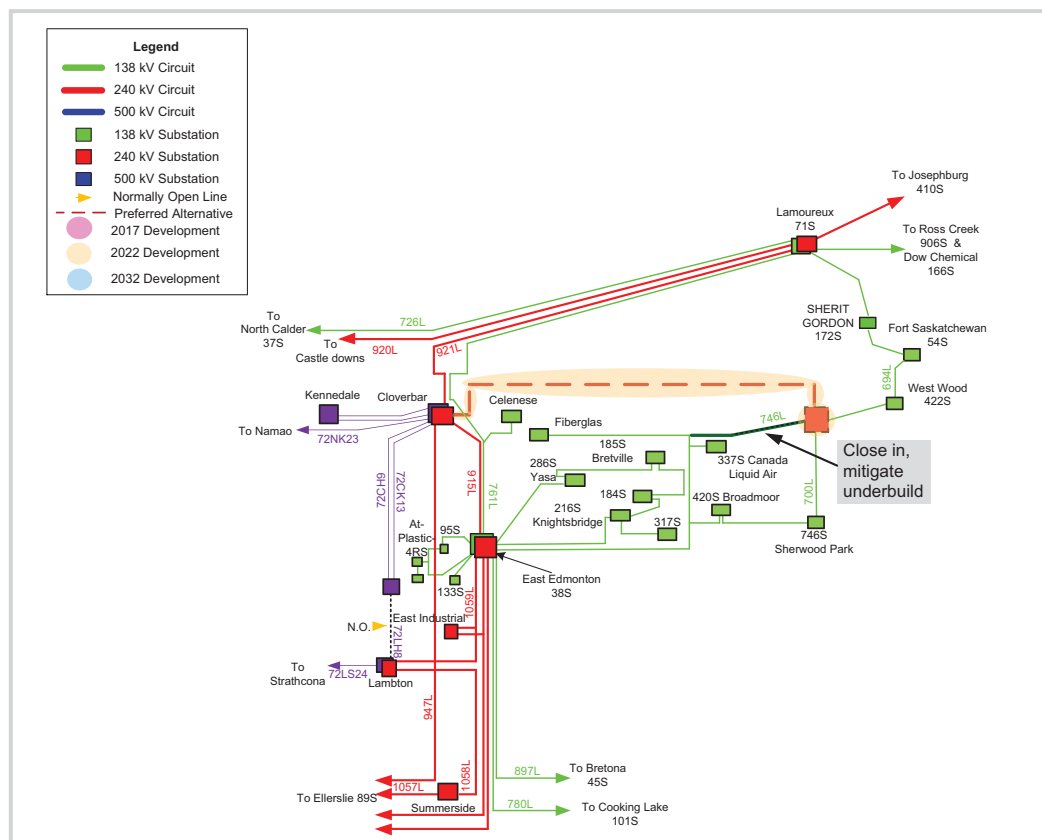
The industrial area to the east of the city of Edmonton is served by an existing 138 kV system fed primarily from the 38S, East Edmonton 240/138 kV substation. The area is also connected by a single 138 kV line to the Fort Saskatchewan area at 71S, Lamoureux substation. Single outages in the area (East Edmonton transformers or 138 kV lines) results in 138 kV overloads as the source in Fort Saskatchewan back feeds to the east Edmonton area. This problem does not occur until the 2017–2022 timeframe.

Studies indicate that the overload issues on the 138 kV network can be resolved by adding a new 240/138 kV substation northeast of Edmonton where two 138 kV lines intersect. The planned transmission developments are shown in Table 7.3.11-2 and Figure 7.3.11-3.

**Table 7.3.11-2: East of Edmonton – LTP Summary**

Timeframe	Development
Near term	No developments proposed at this time
Medium term	New 240/138 kV source substation between Sherwood Park and Fort Saskatchewan A 240 kV transmission line from Clover Bar to the new substation
Long term	No developments proposed at this time

**Figure 7.3.11-3: East of Edmonton – Long-term Transmission Plan**



Map is for illustrative purposes only and does not represent actual terminations or routes

### South of Edmonton Sub-area

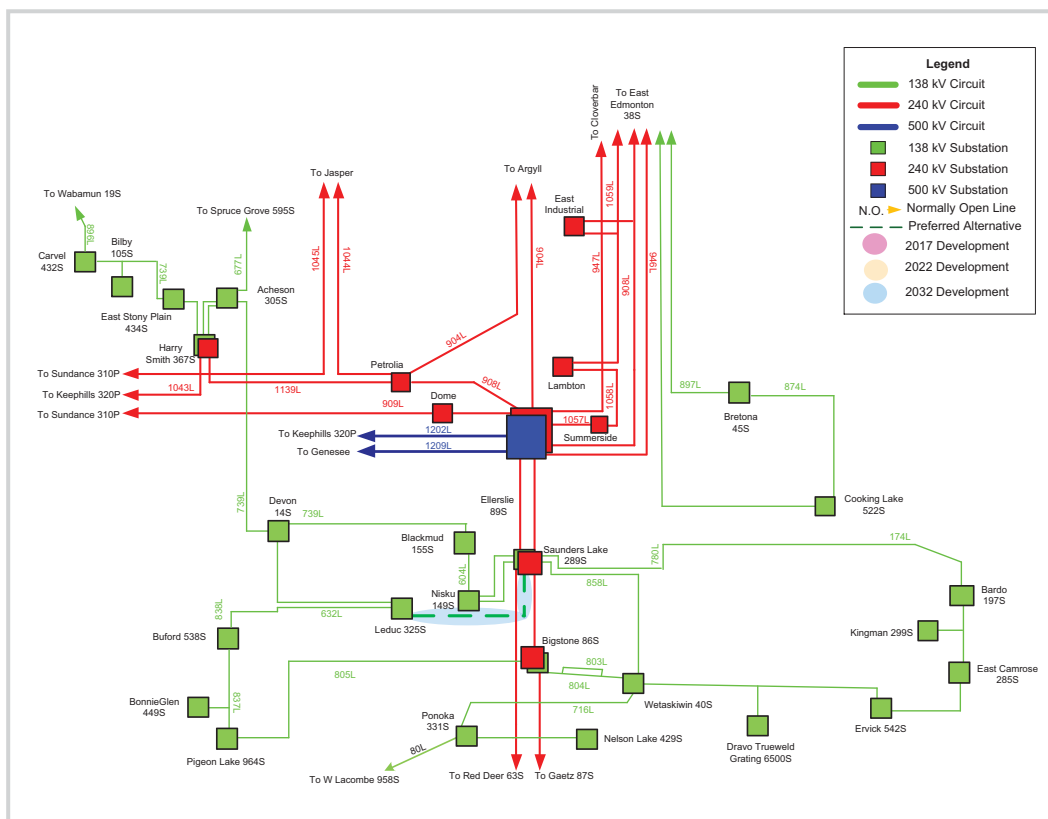
By 2017, the south of Edmonton area will be reinforced with a third source, the 289S Saunders Lake 240/138 kV substation near Leduc, proposed as part of the South and West of Edmonton Transmission Development project which is currently in the NID approval stage. With this proposed substation, this part of the system is adequate to serve load in the area until 2022. However, as load increases on the 138 kV loop, overloads are observed by 2032.

The overloads on the 138 kV system can be mitigated by adding a new 138 kV transmission circuit from the proposed Saunders Lake substation to the existing Leduc substation to separate the existing 138 kV loop into two smaller loops.

**Table 7.3.11-3: South of Edmonton – LTP Summary**

Year	Development
Near term	No developments proposed at this time
Medium term	No developments proposed at this time
Long term	Add a 138 kV transmission line between Saunders Lake and Leduc substations

**Figure 7.3.11-4: South of Edmonton – Long-term Transmission Plan**



Map is for illustrative purposes only and does not represent actual terminations or routes



### **West of Edmonton Sub-area**

With new generation forecast to develop in the Wabamun area, the capacity to the 500kV network to flow power to the city of Edmonton begins to overload with an outage of any one of the three 500/240 kV transformers. In addition, under certain contingencies, the 240 kV lines from Keephills to the city of Edmonton become highly loaded. These issues are not seen until the 2022-2032 timeframe.

In addition, power flows on 240 kV lines into Edmonton from the Wabamun area with the proposed new Harry Smith 240/138 kV source substation west of Edmonton (part of the South and West of Edmonton NID) will result in the 138 kV system becoming overloaded under certain 240 kV line outages by 2017.

The 500 kV and 240 kV system issues between Wabamun and Edmonton can be resolved by adding a 500/240 kV source substation on the approved West Fort McMurray 500 kV line with a 240 kV line to the existing North Calder 240/138 kV substation in northwest Edmonton. This enhancement is not required until the 2022-2032 timeframe and is dependent on forecast generation development in the Wabamun area.

This issue on the 138 kV system west of Edmonton can be resolved by adding a new circuit from Acheson substation to the North St. Albert substation and breaking up the parallel path from North St. Albert to Edmonton. This enhancement is required by 2017.

**Table 7.3.11-4: West of Edmonton – LTP Summary**

<b>Timeframe</b>	<b>Development</b>
<b>Near term</b>	Add 138 kV transmission line between Acheson and North St. Albert substations
<b>Medium term</b>	No developments proposed at this time
<b>Long term</b>	New 500/240 kV source substation northwest of Edmonton connecting to the proposed West Fort McMurray 500 kV line A new 240 kV transmission line from the new 500/240 kV substation to North Calder substation



## 8.0 Conclusion

The 2013 LTP proposes an integrated, comprehensive and strategic upgrade of the Alberta transmission system that meets statutory requirements, aligns with public policy and strategy respecting electricity, meets load growth, and facilitates development of Alberta's abundant natural resources for the next 20 years. Transmission infrastructure projects at both the regional and inter-regional bulk system level are planned in response to the forecast, customer connection requests, market dynamics and system operational compliance requirements.

The 2013 LTP will be updated again within two years to capture and reflect any material changes in forecast, government policy, industry, technology, and overall economic conditions in Alberta. The 2013 LTP provides efficient, reliable and prudent cost-effective solutions, and facilitates non-discriminatory system access service to customers through timely implementation of transmission system enhancements, while ensuring the electricity market remains competitive and responsive.

While the 2013 LTP is robust and flexible, there are implementation challenges. These challenges range from environmental considerations and regulatory process cycles to cost and availability of labour and materials. The AESO responds to these challenges by establishing milestones where appropriate, incorporating project staging, conducting stakeholder consultation, facilitating efficient regulatory coordination and filing, and developing competitive procurement of equipment and services. This allows consumers to receive maximum value from transmission investments by timing the construction phases of projects to align with investment and scheduled need dates.

This Plan's 20-year horizon and blueprint for the future is further refined and tested in real time through the AESO's complementary publications such as the annually produced *24-Month Reliability Outlook*, annual *Alberta Reliability Standards (ARS) Compliance Report*, the bi-annual *Review of the Cost Status of Major Transmission Projects in Alberta*, and the *Transmission Projects Quarterly Report*. These serve to periodically track and publish updates to the key inputs to the Plan, reflect adjustments to project scope, and communicate the progress of projects or initiatives contained in the LTP. In addition, in June 2013 the AESO introduced the *Long-term Plan Progress Report* which updated the progress of projects identified in the 2012 LTP. The AESO is committed to continuing this practice by publishing an update report to the 2013 LTP.

The AESO will continue to monitor key economic indicators and changes to legislation or the regulatory framework, respond to customer requests for both load and generation connections, and evaluate the requirements for upgrading the transmission system. Stakeholder consultation and engagement remains a key commitment of the AESO. Engagement with the public and with industry will continue, furthering the objectives related to establishing project milestones, employing the AESO's Competitive Process for future transmission projects and determining intertie strategies.

The AESO is committed to progressing the projects identified in the 2013 LTP through the formal regulatory process, the customer connection process and by being responsive to changes in both forecast and applicable regulatory policies.

The 2013 LTP will serve to provide confidence to Albertans that they will continue to have access to safe, reliable and affordable electric power. The province's future prosperity will be secured by having a reliable transmission system, adequate generation resources, timely investment in infrastructure and a competitive electricity market that benefits all Albertans.

# Appendix A

## Glossary of Terms

**Alberta Interconnected Electric System (AIES):** The system of interconnected transmission power lines and generators in Alberta.

**Alberta Internal Load (AIL):** The total electricity consumption including behind-the-fence (BTF) load, the City of Medicine Hat and losses (transmission and distribution).

**Alternating current (AC):** A current that flows alternately in one direction and then in the reverse direction. In North America, the standard for alternating current is 60 complete cycles each second. Cycles per second is also referred to as Hertz (Hz).

**Ancillary services:** Services necessary to support the transmission of energy from resources to loads while maintaining reliable operation of the transmission system in accordance with good utility practice.

**Behind-the-fence load (BTF) load:** Industrial load characterized by being served in whole, or in part, by on-site generation built on the host's site.

**Biomass:** Used to produce synthetic fuels or is burned in its natural state to produce energy. Biomass fuels include wood waste, peat, manure, grain by-products and food processing wastes.

**Bulk transmission system:** The integrated system of transmission lines and substations that delivers electric power from major generating stations to load centres. The bulk system, which generally includes 500 kilovolt (kV) and 240 kV transmission lines and substations, also delivers/receives power to and from adjacent control areas.

**Bus (busbar):** Electrically conductive structures in a substation to which elements such as transformers or transmission lines are connected.

**Capability:** The maximum load that a generating unit, generating station or other electrical apparatus can carry under specified conditions for a given period of time without exceeding limits of temperature and stress.

**Capacitor/capacitor bank:** A static device (sometimes referred to as static capacitors) that introduces capacitive reactance into the power system. Capacitors are used to control voltages by eliminating the voltage drop in the system caused by inductive reactive loads. If connected between conductors or between conductors and ground, they are sometimes described as shunt capacitors. If connected in series with a transmission line, they are described as series capacitors.

**Capacity:** The amount of electric power delivered or required for a generator, turbine, transformer, transmission circuit, substation or system as rated by the manufacturer.

**Carbon offset:** A financial instrument representing a reduction in greenhouse gas (GHG) emissions.

**Circuit:** A conductor or a system of conductors through which electric current flows.

**Cogeneration:** The simultaneous production of electricity and another form of useful thermal energy used for industrial, commercial, heating or cooling purposes.

**Combined cycle generation:** A system in which a gas turbine generates electricity and the waste heat is used to create steam to generate additional electricity using a steam turbine.

**Conductor:** A metallic wire or combination of wires through which electric current is intended to flow.

**Congestion:** The condition under which transactions that market participants wish to undertake are constrained by conditions on the transmission grid.

**Constraint:** A restriction on a transmission system or segment of a transmission system that may limit the ability to transmit power between various locations.

**Control area:** A defined region of the electricity grid for which supply and demand are kept in balance by the control area's system operator.

**Converter station:** A location where electric energy is converted to direct current (DC) from AC or vice versa.

**Customer sectors:** Types of electric load classified according to type of use. Four sectors commonly used are residential, commercial, farm and industrial.

**Cutplanes:** An imaginary line that cuts across the transmission lines that connect two or more areas. The loading on these lines is summed together to measure the power flow across the cutplane.

**Demand (electric):** The volume of electric energy delivered to or by a system, part of a system, or piece of equipment at a given instant or averaged over any designated period of time.

**Demand transmission service (DTS):** The service provided to loads for interconnection access to the Alberta transmission system.

**De-rate:** A reduction in a generating unit's or other piece of electric equipment's net capacity.

**Direct current (DC):** Current that flows continuously in the same direction (as opposed to AC). The current supplied from a battery is direct current.

**Dispatch:** The process by which a system operator directs the real-time operation of a supplier or a purchaser to cause a specified amount of electric energy to be provided to, or taken off, the system.

**Distributed generation:** Small-scale power sources typically connected to a distribution system at customer locations.

**Double circuit:** A line of supporting structures that carries two power circuits.

**Emission intensity:** The ratio of a specific emission (such as carbon dioxide) to a measure of energy output. For the electricity sector, emission intensity is usually expressed as emissions per megawatt hour (MWh) of electricity generated.

**Gas turbine:** See simple cycle gas turbine.

**Generating unit:** Any combination of an electrical generator physically connected to reactor(s), boiler(s), combustion or wind turbine(s) or other prime mover(s) and operated together to produce electric power.

**Geothermal energy:** Where the prime mover is a turbine driven either by steam produced from hot water or by natural steam that derives its energy from heat found in rocks or fluids at various depths beneath the surface of the Earth.

**Gigawatt (GW):** One billion watts.

**Gigawatt hour (GWh):** One billion watt hours.

**Greenfield:** Land being considered for development that has not previously been used for commercial or industrial purposes.

**Greenhouse gas (GHG) emissions:** Gases that trap the heat of the sun in the Earth's atmosphere, producing the greenhouse effect.

**Grid:** A system of interconnected power lines and generators that is operated as a unified whole to supply customers at various locations. Also known as a transmission system.

**Gross domestic product (GDP):** One of the measures of national income and output for a given country's economy. GDP is defined as the total market value of all final goods and services produced within the country in a given period of time (usually a calendar year). It is also considered as the sum of the value added at every stage of production (the intermediate stages) of all final goods and services produced within a country in a given period of time and is given a monetary value.

**Heat rate:** A measure of generating plant thermal efficiency generally expressed as units of energy input per unit of energy output.

**High voltage direct current (HVDC):** The transmission of electricity using direct current.

**Independent system operator (ISO):** A system and market operator that is independent of other market interests. In Alberta the entity that fulfils this role is the Alberta Electric System Operator.

**Interconnection or transmission interconnection:** An arrangement of electrical lines and/or transformers that provides an interconnection to the transmission system for a generator or large commercial or industrial customer.

**Intertie:** A transmission facility or facilities, usually transmission lines, that interconnect two adjacent control areas.

**Levelized unit electricity cost (LUEC):** The constant price required to cover all expenses incurred over the lifetime of a generating unit.

**Load (electric):** The electric power used by devices connected to an electric system.

**Looped system:** A system of power lines in which circuits are contiguously connected between substations and then back to the same substation.

**Megawatt (MW):** One million watts.

**Megawatt hour (MWh):** One million watt hours.

**Merchant transmission:** Transmission line(s) constructed by proponents that are not regulated utilities for the purpose of selling transmission capacity to third parties, usually generators or load customers who wish to make transactions over the merchant transmission line.

**Merit order:** In the electricity wholesale market, merit order refers to the list used to dispatch electric generation to meet demand. The lowest cost generation is dispatched first.

**Meters or metering:** Equipment that measures and registers the amount and direction of electrical quantities.

**Needs Identification Document (NID):** A document filed by the AESO with the Alberta Utilities Commission (AUC) to define the need to reinforce the transmission system to meet load growth and/or provide non-discriminatory access to interconnect new loads and generators to the system.

**Nuclear Generations:** Where heat produced in a reactor by the fissioning of nuclear fuel is used to create steam in a boiler. This steam is then used to drive a turbine, which in turn drives the electric generator.

**Offset:** See carbon offset.

**Operating reserve:** Generating capacity that is held in reserve for system operations and can be brought online within a short period of time to respond to a contingency. Operating reserve may be provided by generation that is already online (synchronized) and loaded to less than its maximum output and is available to serve customer demand almost immediately. Operating reserve may also be provided by interruptible load.

**Parallel path:** Electric power flows on all interconnected parallel paths in amounts inversely proportional to each path's resistance. This also refers to the flow of electric power on one electric system's transmission facilities resulting from scheduled electric power transfers between other electric systems.

**Peak load/demand:** The maximum power demand (load) registered by a customer or a group of customers or a system in a stated period of time. The value may be the maximum instantaneous load or, more usually, the average load over a designated interval of time such as one hour, and is normally stated in kilowatts or megawatts.

**Point-of-delivery (POD):** Point(s) for interconnection on the transmission facility owner's (TFO) system where capacity and/or energy is made available to the end-use customer.

**Power pool:** An independent, central, open-access entity that functions as a spot market, matching demand with the lowest-cost supply to establish an hourly pool price.

**Reactive power:** The component of electric power that does not provide real work but is required to provide voltage.

**Reliability:** Electric system reliability has two components: adequacy and security. Adequacy is the ability of the electric system to supply the aggregate electrical demand and energy requirements of customers at all times, taking into account scheduled and unscheduled outages of system facilities. Security is the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system facilities.



**Reliability criteria:** A set of tests against which the operation of a power system is measured to ensure acceptable performance. The AESO's reliability criteria are central to assessing the adequacy of the current and future Alberta transmission system.

**Reserve margin:** The percentage of installed capacity exceeding the expected peak demand during a specified period.

**Simple cycle:** Where a gas turbine is the prime mover in a plant. A gas turbine consists typically of an axial-flow air compressor, one or more combustion chambers where liquid or gaseous fuel is burned. The hot gases are passed to the turbine where they expand, driving the turbine that in turn drives the generator.

**Single circuit:** A transmission line where one circuit is carried on a set of structures (poles or lattice towers).

**Solar (power):** A process that produces electricity by converting solar radiation to electricity or to thermal energy to produce steam to drive a turbine.

**Static var compensator (SVC):** An electrical device for providing fast-acting reactive power compensation on electricity networks.

**Substation/switching station:** A facility where equipment is used to tie together two or more electric circuits through switches (circuit breakers). The switches are selectively arranged to permit a circuit to be disconnected or to change the electric connection between the circuits.

**Supply transmission service (STS):** The service provided to generators for interconnection access to the Alberta transmission system.

**Tap:** A point of connection along a transmission line between substations.

**Tariff (Transmissions):** The terms and conditions under which transmission services are provided, including the rates or charges that users must pay.

**Thermal overload:** A condition where the thermal limit of a piece of electrical equipment such as a conductor or transformer is exceeded.

**Transfer capability:** The measure of the ability of interconnected electric systems to move or transfer power in a reliable manner from one area to another over all transmission lines (or paths) between those areas under specified system conditions. The units of transfer capability can be expressed in megawatts.

**Transformer:** An electrical device for changing the voltage of alternating current.

**Transmission:** The movement or transfer of electric energy over an interconnected group of lines and associated equipment between points of supply and points at which it is transformed for delivery to consumers or is delivered to other electric systems. Transmission is considered to end when the energy is transformed for distribution to the consumer.

**Transmission facility owner (TFO):** The owner of the system of high voltage power lines and equipment that links generating units to large customer loads and to distribution systems.

**Transmission losses:** Energy that is lost through the process of transmitting electrical energy.

**Transmission must-run (TMR):** A generator required to operate at a minimum specified output level to maintain system reliability in the event of an outage to certain transmission system elements.

**Transmission path:** One or more transmission lines that form the transmission connection between two points on the system.

**Transmission system (electric):** An interconnected group of electric transmission lines and associated equipment for moving or transferring electric energy in bulk between points of supply and points at which it is transformed for delivery over the distribution system lines to consumers or is delivered to other electric systems.

**Voltage:** The difference of electrical potential between two points of an electrical circuit expressed in volts. It is the measurement of the potential for an electric field to cause an electric current in an electrical conductor. Depending on the amount of difference of electrical potential, it is referred to as extra low voltage, low voltage, high voltage or extra high voltage.

**Voltage stability:** Operation within acceptable voltage ranges. Normal voltage limits are defined as the operating voltage range on the interconnected system that is acceptable on a sustained basis. Emergency voltage limits are defined as the operating voltage range on the interconnected system that is acceptable for the time sufficient for system adjustments to be made following a facility outage or system disturbance.

**Voltage violation:** A measured or calculated condition where the voltage at a point on the transmission system is outside the acceptable limits as described in the criteria.

**Watt:** The unit of power equal to one joule of energy per second. It measures a rate of energy conversion. A typical household incandescent light bulb uses electrical energy at a rate of 25 to 100 watts.

**Watt hour (Wh):** An electrical energy unit of measure equal to one watt of power supplied to or taken from an electric circuit steadily for one hour.

**Western Electricity Coordinating Council (WECC):** An organization formed to coordinate and promote electric system reliability for the system that interconnects Alberta, B.C., 14 western U.S. states and part of one Mexican state.

# Appendix B

## Errata

On January 31, 2014 the AESO posted the *2013 Long-term Transmission Plan* on [www.aeso.ca](http://www.aeso.ca) and filed copies for information with both the Minister of Energy and the Alberta Utilities Commission, in accordance with the AESO's statutory obligations as defined in Section 33(1) of the *Electric Utilities Act* and sections 10(1) and 10(2) of the *Transmission Regulation*.

The following corrections are immaterial changes that were identified subsequent to January 31, 2014. Many of the changes are a result of graphic conversion issues identified at the final printing stage.

Description	Page	Section	Date
Table of Contents - numbering	TOC 2	TOC: Section 5.4.1-5.4.5	02/06/2014
Figure 3.2-1 graphic update	18	3.0 Background	02/06/2014
Section numbering	62-63	5.0: Forecast Results	02/06/2014
Figure 7.3.3-1 diagram update	95	7.0: Transmission Results and Plan	02/06/2014
Figure 7.3.3-3 diagram update	98	7.0: Transmission Results and Plan	02/06/2014
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Figure 7.3.7-1 diagram update	125	7.0: Transmission Results and Plan	02/06/2014
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Figure 7.3.11-3 diagram update	151	7.0: Transmission Results and Plan	02/06/2014
Figure 7.3.11-6 diagram update	154	7.0: Transmission Results and Plan	02/06/2014
Project number reference in body copy	25	3.3.4: Transmission Project Cost Estimates – last paragraph	03/11/2014



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