AESO 2017 Long-term Transmission Plan

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1.0 Executive summary

Executive summary

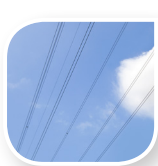
The 2017 Long-term Transmission Plan (2017 LTP) looks forward 20 years and details the transmission developments required to support the economy by providing for the safe, dependable, efficient delivery of electricity wherever and whenever it is needed.

A safe, reliable electricity system, along with a fair, efficient and openly competitive electricity market, is critical to the economic well-being and future prosperity of Alberta. The *2017 Long-term Transmission Plan* (2017 LTP) looks forward 20 years and details the transmission developments required to support the economy by providing for the safe, dependable, efficient delivery of electricity wherever and whenever it is needed.

The 2017 LTP was developed following a detailed, two-year planning cycle. Planning and implementation of well-defined transmission development increases the flexibility of the electricity system, which enables generators and load customers to act and adapt effectively in a competitive market. Developing the right transmission infrastructure at the right time also guides generation developers towards projects that optimize transmission capacity.

With unique access to credible, accurate and real-time electricity information, the AESO is the single largest source of transmission planning expertise in Alberta. The 2017 LTP presents the AESO's best possible solutions to transmission needs anticipated at the time of publication. All transmission projects undergo further review and detailed study prior to filing with the Alberta Utilities Commission for regulatory approval, and they are subject to change. Through this iterative approach, the AESO can adjust plans for transmission development as required and is prepared to adapt to economic and electric system changes that may arise.

Alberta's electricity industry is in a state of transition, due in part to changing policies and economic drivers that can affect load growth, generation development and, consequently, the transmission system development plan. This information is reflected in the *AESO 2017 Long-term Outlook* (2017 LTO), which serves as the foundation for the 2017 LTP.



Alberta's electricity industry is in a state of transition, due in part to changing policies and economic drivers that can affect load growth, generation development and, consequently, the transmission system development plan. The AESO has deliberately approached the 2017 LTP in a manner that enables responsive and adaptable system planning.

Since mid-2014, the provincial economic growth outlook has changed in response to the price of oil. Consequently, the forecast used to develop the 2017 LTO reflects a slower rate of economic growth. The AESO's forecast for Alberta is consistent with other industry outlooks, and predicts less load growth than previous AESO long-term forecasts.

The Alberta economy continues to grow, albeit more slowly, and new electricity generation will be needed. Considering that Alberta's long-term economic growth and generation profile can never be predicted with absolute certainty and can potentially develop in a number of different ways, the AESO has deliberately approached the 2017 LTP in a manner that enables responsive and adaptable system planning.

One of the most significant differences between previous long-term transmission plans and the 2017 LTP is the use of scenarios as contained in the 2017 LTO.

The five specific scenarios studied in detail in the 2017 LTP are:

- **Reference Case Scenario**–aligns with recent information and announcements pertaining to Alberta's electricity industry, including publicly announced generation changes, and serves as the AESO's base case to confidently plan the system in the near term and compare against the remaining scenarios.
- **No Coal-to-gas Conversion Scenario**–assumes no coal units slated for retirement are converted to natural gas generation.
- **New Large-hydro Generation Scenario**–assumes the addition of approximately 1,500 megawatts (MW) of hydroelectric generation in Alberta.
- **Western Integration Scenario**–assumes a new large-scale interconnection with British Columbia.
- **High Cogeneration Scenario**–assumes approximately 2,000 MW of cogeneration is added in the Fort McMurray area.

The Reference Case Scenario is the foundation of the AESO's near-term planning and allows the AESO to confidently identify transmission developments that will require approval for the next five years, defined as the near-term time horizon. The other four scenarios allow the AESO to anticipate transmission developments required under a variety of different generation assumptions over the longer term, which is the period beyond the first five years up to 20 years. Each scenario shares some commonalities with the Reference Case Scenario, but the differences allow the AESO to plan projects as necessary depending on how the future unfolds. For practical reasons, the Reference Case Scenario is treated as a base case for comparison against the others; however, the AESO remains neutral and does not take a position on the likelihood of one scenario occurring over another.

The 2017 LTP satisfies the AESO's mandate as stated in the province's *Electric Utilities Act* (EUA) and *Transmission Regulation* (T-Reg). By maintaining flexibility in its planning, the AESO is well-poised to adapt to Alberta's load and generation needs.

One of the most significant differences between previous long-term transmission plans and the 2017 LTP is the use of scenarios as contained in the 2017 Long-term Outlook (2017 LTO). The 2017 LTO's Reference Case Scenario is the foundation of the AESO's near-term planning and allows the AESO to confidently identify transmission developments that will require approval for the next five years. Four other 2017 LTO scenarios allow the AESO to anticipate transmission developments required under a variety of different generation assumptions over the longer term.

ASSUMPTIONS AND INPUTS

The AESO's 2017 LTO is a foundational input into the 2017 LTP. The 2017 LTO contains detailed forecasts with corresponding scenarios based on provincial economic growth outlooks, commodity price expectations, economic evaluations, applicable policy considerations and system access service requests.

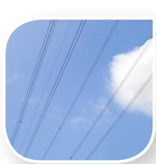
The 2017 LTO forecasts that Alberta's electricity demand will grow at an annual rate of 0.9 per cent until 2037. This is due to a trend towards smaller-scale oilsands projects, slower economic growth and energy efficiency gains over the long term.

The 2017 LTP addresses renewable generation additions and the intended phase-out of all coal-fired generation in Alberta by 2030. Together, these present a significant shift in the province's generation fleet. Moving through the LTP's forecast period, the province's generation mix will shift from 38 per cent coal and 17 per cent renewable generation to 63 per cent natural gas and 37 per cent renewable generation. Future generation investments are expected to keep pace with predicted load growth and coal-fired generation replacements, as well as renewable generation additions primarily through the Renewable Electricity Program. The AESO is committed to meeting the government's 2030 renewable generation and coal phase-out targets.

There is also potential for future hydroelectric (hydro) generation development. Another key assumption is that some generation sources such as wind and solar are not available on demand. Therefore, non-intermittent generation, such as simple-cycle or combined-cycle gas-fired generation, will still be required.

2017 LTP HIGHLIGHTS

- Provides a comprehensive vision of the transmission system developments required to meet the future needs of Alberta over the next 20 years.
  - Scenarios were used to provide a flexible transmission plan that can adjust to economic and policy changes.
  - The Reference Case Scenario was studied in detail for the near term. For the longer term, the AESO remains neutral and does not take a position on the likelihood of one scenario occurring over another.
- The 2017 LTP identifies 15 transmission developments proposed over the next five years and valued at approximately $1 billion. Regulatory approval for all identified developments is still required.
  - This plan proposes transmission system developments that will result in an average transmission rate increase of 1.8 per cent per year over the next 20 years.
- The 2017 LTP places increased focus on the evolving economy, policy changes and environmental initiatives, including renewable generation additions and the phase-out of coal-fired generation wherever possible.
- The 2017 LTP was developed with the goal of efficient utilization of existing and planned transmission systems in areas where high renewables potential exists. Previously planned transmission enhancements for renewable generation integration will be developed in a staged manner where high potential for renewable resources exist. This will follow a staged approach that incents robust competition by enabling simultaneous access in geographically diverse renewable generation areas.
- For the purposes of transmission system planning and to fulfill the requirements of the EUA and T-Reg, locations are assumed for future generation units. Each technology is assigned to locations based on the likelihood of that technology developing in a particular region. Locational considerations include utilization of existing infrastructure such as brownfield sites, available transmission capacity serving retiring generation, renewable resource areas such as strong wind and solar resource locations, planned transmission capacities, and developer information.
- The proposed transmission upgrades identified within the 2017 LTP are comprehensively planned yet flexible, and will allow the AESO to adapt to changes in transmission infrastructure needs and demand for transmission access.



The 2017 LTP places increased focus on the evolving economy, policy changes and environmental initiatives, including renewable generation additions and the phase-out of coal-fired generation wherever possible.

Near-term regional transmission plan highlights

The regional highlights below are based on the Reference Case. They summarize potential transmission system developments required over the next five years.

- **South Planning Region**
  - — The Chapel Rock–Pincher Creek Transmission System Enhancement is in the development stage and will increase system capability to integrate additional generation.
  - — The existing Alberta–British Columbia intertie is operating below its original path rating and will be restored to full capability.
- **Calgary Planning Region**
  - — Local area 138 kilovolt (kV) developments in the Calgary area and vicinity are required to mitigate local constraints on the system, as well as additional equipment to manage short-circuit levels in downtown Calgary.
  - — The Calgary Downtown Transmission Reinforcement Project is an approved new 138 kV single-circuit transmission line that accommodates load growth and addresses the risk of significant overloads on two main 138 kV transmission lines through the city's core. The expected in-service date is in Q1 2021.
- **Central Planning Region**
  - — The Provost–to–Edgerton and Nilrem–to–Vermilion Transmission Development (PENV) will address existing and forecasted load serving constraints and enable flexible local renewable integration capability in the area. No other near-term enhancements are required. The Needs Identification Document (NID) for this project is before the Alberta Utilities Commission (AUC) for approval.
  - — Inter-regional transmission developments are required to transfer surplus power from the central east area to major load centres.
- **Northwest Planning Region**
  - — Local area supply constraints impacting Grande Prairie require an additional 144 kV supply and voltage-support enhancements in that area.
  - — Transmission enhancement is required in the Fox Creek area to address local and transfer-in constraints.
- **Northeast Planning Region**
  - — Other than the Fort McMurray West 500 kV line, local transmission system enhancements in the Fort Saskatchewan and Athabasca areas and projects currently underway, no additional near-term enhancements are required.
- **Edmonton Planning Region**
  - — Load growth in the area is creating a need for local 72 kV and 138 kV enhancements.

2.0 Background and objectives

Background and objectives

The AESO is a not-for-profit corporation mandated by legislation to act in the public interest, and is prohibited from holding an interest in any transmission, distribution or generation assets.

The AESO is required by provincial legislation to operate the transmission system in a safe, reliable and economic manner and plan a transmission network that meets electricity demand today and in the future. It is governed by an independent board comprising nine members appointed by the Minister of Energy. Following the principles of sound governance, the AESO balances the interests of a wide range of stakeholders in order to fulfil its legislative mandate.

The AESO's duties and responsibilities related to transmission planning are prescribed in the Province of Alberta's *Electric Utilities Act*, *Transmission Regulation* and *Renewable Electricity Act*.

These duties include the following:

- Determine future requirements of the transmission system, develop plans that optimize the utilization of the existing transmission system, and arrange to implement any required transmission system enhancements as necessary, all in a timely and efficient manner and in accordance with the AESO's statutory obligations.
- Prepare and maintain a transmission system plan that anticipates, on a 20-year horizon, system conditions and requirements to accommodate future load growth and expected generation additions.
- Ensure the safe, reliable and economic operation of the provincial electricity grid.
- Operate the integrated transmission system, including the power pool, and facilitate the electricity market in a manner that is fair, efficient and openly competitive.
- Provide transmission access service consistent with an approved transmission tariff.
- Manage and recover the costs associated with line losses and ancillary services.
- Enable production of 30 per cent of Alberta's electric energy from renewable sources by 2030.

The AESO's transmission system planners and economists analyzed provincial electricity consumption patterns using data from a variety of sources to determine where electricity demand is likely to grow. The AESO also anticipated the type, capacity and location of generation needed to efficiently meet electricity demand, enable the coal-fired generation phase-out, and achieve renewable energy targets across a range of scenarios to determine the infrastructure that may be required.

The 2017 LTP also takes into account technical considerations, reliability standards and operating criteria that provide for system reliability and a well-functioning market. The AESO is required to update its long-term transmission plan at least every two years, and file it for information with the provincial Minister of Energy and the AUC.

STAKEHOLDER CONSULTATION AND ENGAGEMENT

The AESO engages Albertans across the province to develop the transmission system. This consultation process provides the AESO with a broad perspective and valuable input that is then used to test the logic of forecast and transmission planning results.

The AESO conducted consultation meetings with a variety of stakeholders, including specific municipalities, in Q1 2017 and Q2 2017. Engagement opportunities with other stakeholders, such as landowners and the general public, are created during the NID notification process. Stakeholder engagement regarding changes to market rules and the AESO tariff is also conducted when necessary. Stakeholder experience and expertise help improve the quality and implementation of the AESO's decisions.

ECONOMIC, SOCIAL AND ENVIRONMENTAL CONSIDERATIONS

Public interest and the effects of transmission development, from economic, environmental and social perspectives, are primary considerations in the planning, design, construction, location and operation of transmission infrastructure. The AESO considers these early in the transmission planning process. These considerations are further assessed once a transmission development plan progresses through the regulatory process part of the AESO's NID applications and are evaluated during AUC regulatory proceedings.

The AESO is not directly responsible for the detailed siting and routing of transmission developments. This process falls to transmission facility owners and the AUC. However, the AESO does consider a variety of factors when preparing an application, including high-level agricultural, residential, visual and environmental impacts.

Alberta Land Stewardship Act regional plans

When carrying out its mandate, the AESO is required by Section 16.1 of the EUA to act in accordance with applicable *Alberta Land Stewardship Act* (ALSA) plans. The AESO participates in ALSA regional planning activities as part of its regional planning, and takes the objectives and outcomes of applicable ALSA regional plans into account.

CLIMATE LEADERSHIP PLAN IMPLEMENTATION

The Government of Alberta introduced its Climate Leadership Plan (CLP) in 2015. Since then, legislation and regulatory announcements (the *Renewable Electricity Act*), and initiatives such as the Renewable Electricity Program and coal phase-out agreements have been advanced as part of the CLP. The 2017 LTP proposes transmission system developments to enable the retirement and replacement of coal-fired generation, as well as renewable generation integration targets.

CAPACITY MARKET TRANSITION

In November 2016, the Government of Alberta announced its acceptance of the AESO's recommendation to transition from an energy-only market to a new framework that includes both an energy market and a capacity market. Stakeholder engagement to determine capacity market design is under way, with the first procurement expected in 2019 and first contracts awarded in 2020/21.

The AESO's transmission planning process and recommended developments are currently considered to be applicable through the transition to a capacity market. The AESO's transmission planning is flexible, responsive and weighs economic factors alongside other considerations related to acting in the public interest.

Stakeholder engagement to determine capacity market design is under way, with the first procurement expected in 2019 and first contracts awarded in 2020/21.

FORECAST PROCESS AND METHODOLOGY

The 2017 LTO was published in July 2017 and is the AESO's most recent corporate forecast. The 2017 LTO is a key input for the 2017 LTP, and is the source for load and generation forecast assumptions. The 2017 LTO contains updated load and generation forecasts, including background, assumptions and results across several scenarios. Key elements of the 2017 LTO are outlined in this section. For additional information about the 2017 LTO, please see the 2017 LTO document at *www.aeso.ca/LTO*

The 2017 LTO development process begins with an economic outlook for the province, as economic considerations are the key driver of long-term load growth. The 2017 LTO generation forecast is based on the following assumptions:

- The system will follow a pattern of low load growth.
- Coal-fired generation will be phased out according to targets.
- Renewable generation meets the goals of the Province of Alberta's *Renewable Electricity Act.*
- A capacity market is in place.
- The characteristics of each generation technology are considered.
- Natural resources will be used when they are available.

The AESO uses market simulation tools to assist in forecasting future generation.

The AESO develops robust, comprehensive LTO forecasts using third-party information, stakeholder consultation, best practices in forecasting methodology and tools and, as the province's largest source of electricity industry expertise, a wide range of in-house experts. The 2017 LTO is designed to align with current and expected trends using the most up-to-date information. It incorporates third-party information and is validated against other credible forecasts whenever possible. The AESO consults with stakeholders including industry groups, generation developers and distribution facility owners to gather information, confirm assumptions and align outlooks.

The 2017 LTO and 2017 LTP also rely on scenarios in order to quantify and understand the effects of alternate potential outcomes.

Load

The 2017 LTO's load forecast methodology is a blend of top-down, economics-based Alberta Internal Load (AIL) peak forecasts combined with bottom-up hourly Point-of-Delivery (POD)-level load shapes. This process allows the AESO to have a POD-by-POD forecast, required as an input into transmission planning, which is aligned with an economics-driven AIL-level forecast.

In the near term, the AESO expects load growth to be in line with historic trends due to recently completed and under-construction oilsands projects, alongside improved economics in 2017 and 2018. In the longer term, once all projects under construction are complete, the AESO expects that load growth will follow a slower trend as small-scale expansions at oilsands sites and slower GDP growth become the new norm.

Overall, the 2017 LTO Reference Case Scenario load forecast is lower than the 2016 LTO Reference Case Scenario. The drop is due to changes in the economic outlook for the province, changes to energy efficiency assumptions, and adjustments made to load forecast methodology from the 2016 LTO. As a result of these changes, long-term load growth in the 2017 LTO is approximately half of that projected in the 2016 LTO Reference Case Scenario.

Generation

Generation development in the 2017 LTO scenarios is based on two main factors: ensuring demand is met, and aligning with policy directions including renewable generation additions and coal-fired generation retirements. In considering what generation types are likely to develop, the AESO reviews the characteristics of generation technologies, including costs, operating characteristics, resources availability and market behaviour, in addition to policy-driven incentives.

The various generation technologies considered in the 2017 LTO and 2017 LTP have different capabilities in terms of their ability to serve load, assist coal phase-out, and meet renewable generation targets.

These specific capabilities are explained in detail in Appendix A. Key high-level generation assumptions include:

- Emissions from coal-fired generation will be phased out by the end of 2030.
- In the Reference Case Scenario and most scenarios, approximately 2,400 MW of coal-fired generation will convert to natural gas-fired generation units by the early 2020s.
- The development of approximately 5,000 MW of renewable generation primarily supported by the REP, of which a target of approximately 600 MW will be energized and operational by December 2019 with more capacity progressively added in following years up to 2030.
- Additional renewables generation may develop outside of the REP.
- By 2030, 30 per cent of electricity produced in Alberta will come from renewable sources.
- The Alberta–British Columbia intertie capability is planned to be restored by 2022 following the intertie restoration initiative, increasing capability from the existing 800 MW to 1,200 MW of imports while maintaining an export capability of 1,000 MW.

FORECAST SCENARIOS

The 2017 LTO includes a set of scenarios which were utilized to evaluate transmission system capability and potential expansion needs over the next 20 years. The scenarios utilized in the 2017 LTP are summarized below.

Reference Case Scenario

The 2017 LTO Reference Case Scenario was applied as the base case for both the near-term and longer-term 2017 LTP assessments. In the near-term there are immaterial differences between the scenarios.

The Reference Case Scenario is consistent with information available at the time of the 2017 LTO's development. This includes announcements made by the Government of Alberta, the Government of Canada and market participants.

Key Reference Case Scenario assumptions

Retirements

The Reference Case Scenario assumes that approximately 2,400 MW of coal-fired generation capacity will be converted to natural gas-fired generation between 2021 and 2023. These units are assumed to convert to gas-fired units for 15 years before eventually retiring. The remaining coal-fired generators (approximately 3,000 MW capacity) are assumed to retire between 2019 and 2030 in order of vintage, and at a rate of no more than two units per year in order to ensure supply adequacy and reliability. Four units totalling approximately 900 MW are expected to retire before 2022.

Generation location assumptions

For the purposes of transmission system planning and to fulfil the requirements of the EUA and T-Reg, locations are assumed for future generation units. Each technology is assigned to a location based on the likelihood that it will develop in a particular region. Locational considerations include utilization of existing infrastructure such as brownfield sites, available transmission capacity serving retiring generation, renewable resource areas such as strong wind and solar resource locations, planned transmission capacities, and developer information.

Within these regions, generation units are assigned to specific locations on the transmission system where they utilize existing transmission capability, including capacity made available by retiring coal-fired generation, and locations where transmission capacity is readily available. Resource availability and generation technology are also factors in selecting future generating facility locations.

Renewable generation additions, primarily wind generation, are expected to be distributed between the South and Central planning regions, with some anticipated development in the Northwest Planning Region. The actual locations and development timelines of future renewables projects are subject to some factors that cannot be determined at this time; however, the 2017 LTO is based on reasonable assumptions as a starting point for transmission planning purposes.

Solar generation is assumed to overlap with the wind generation resources geographically located in the South and Central planning regions. Solar resources are optimal in the South Planning Region, with highly suitable resources also located in the Central Planning Region. This will facilitate sharing existing and planned transmission infrastructure between the two renewable resources.

The hydro development assumed in the Reference Case Scenario is located within the Northwest Planning Region on Peace River. Additional potential hydro resources have also been identified at some existing hydro facilities such as the Brazeau dam, as well as on other northern Alberta rivers.

Combined-cycle generation additions are assumed to primarily occur at or near brownfield coal-fired generation sites and previously identified combined-cycle project locations. Brownfield sites are assumed due to development advantages, including readily available and existing infrastructure and potentially lower development costs compared to greenfield sites.

Cogeneration development is assumed to occur within established oilsands production areas (Fort McMurray and Cold Lake).

Forecast outcomes

Firm natural gas capacity, including both coal-to-gas converted units as well as combined-cycle and simple-cycle additions, will replace coal-fired generation emissions planned to be phased out by the end of 2030, as per Government of Alberta policy.

Based on Reference Case Scenario assumptions, the forecast predicts that renewables will provide the targeted 30 per cent of energy produced in Alberta, and will represent about 36 per cent of total installed generation capacity by 2030. By 2037, approximately two-thirds of Alberta's energy will originate from renewable generation and cogeneration.

Additional details of the Reference Case Scenario, including the assumed coal-retirement schedule, can be found within the 2017 LTO data file which can be found at *www.aeso.ca/LTO*

No Coal-to-gas Conversion Scenario

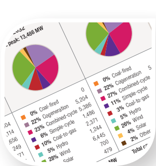
Due to a number of unspecified elements regarding federal coal and gas emissions regulations, which could affect the incentives for conversion, the 2017 LTO contains a No Coal-to-gas Conversion Scenario in which none of Alberta's coal-fired units convert to natural gas.

Assumptions

The assumptions for this scenario are nearly the same as for the Reference Case Scenario, except that there are no coal-to-gas conversions. Instead, coal-fired units are assumed to retire based on the following criteria: federal regulations and the 2030 Alberta coal phase-out date set absolute end-dates for the units; no more than two coal-fired units retire per year; and retirements occur in order of vintage (oldest units retire first). Using these criteria, most units retire in the late 2020s. Similar to the Reference Case Scenario, the combined-cycle units developed in this scenario are primarily assumed to be built at brownfield coal-fired generation sites.

Forecast

In the No Coal-to-gas Conversion Scenario, new gas-fired units would be required to replace coal-fired units as they retire. Combined-cycle and simple-cycle units are likely to be built sooner for this scenario compared with the Reference Case Scenario. However, by the end of the LTP forecast horizon (2037), the total number of combined-cycle and simple-cycle units in the two scenarios is similar because the coal-to-gas units in the Reference Case Scenario are assumed to retire by 2038.



Establishing a credible load forecast is the first step in determining the need for future transmission facilities.

New Large-hydro Generation Scenario

Initiatives such as the Regional Electricity Cooperation and Strategic Infrastructure (RECSI) program consider the effects of large-scale infrastructure projects, including large hydro generation development, in Alberta. The Large-hydro Generation Scenario considers the impact of a new, large hydro generation development in Alberta, with smaller units near existing hydro sites.

Assumptions

For the purpose of this scenario, it is assumed a new 1,000 MW run-of-river hydroelectric generation facility on Slave River will come into service well after 2030. Typically, the regulatory and construction lead times on large hydro projects are greater than a decade, which makes it unlikely that a new large hydro facility in northern Alberta can enter service before 2030. Since the project is run-of-river, it is not assumed to be able to provide its full nameplate capacity towards the assumed reserve margin.

This scenario also assumes hydro generation development of 170 MW on the North Saskatchewan River near the confluence of the Brazeau River. The development would occur in the late 2020s.

When including the 350 MW already assumed in the Reference Case Scenario with the above two projects, total new hydro generation by 2037 is 1,520 MW. Additional sensitivity was also considered with respect to a 900 MW pumped-hydro storage facility at the existing Brazeau hydro generating station.

The remaining assumptions in this scenario are the same as the Reference Case Scenario.

Forecast

The forecast for the New Large-hydro Generation Scenario is the same as for the Reference Case Scenario until the year that development of new hydro facilities is complete. The Saskatchewan River–Brazeau River 170 MW hydro development has minimal effect on overall capacity development and on renewable energy production. However, the large hydro development assumed to be online in the 2030s effectively replaces some combined-cycle additions late in the forecast horizon, based on its assumed contribution to the reserve margin.

Western Integration Scenario

The RECSI project is also considering, among other developments, a new intertie between Alberta and British Columbia. The Western Integration Scenario considers a new large intertie between the two provinces.

Assumptions

The main assumption of the Western Integration Scenario is that a new transmission line is developed between Alberta and British Columbia with a rating of approximately 1,700 MW (similar to the existing Alberta–British Columbia intertie design rating), and that this intertie comes into service by 2027.

With a second large intertie to British Columbia, the total effective transfer capability with that province could reach 1,700 MW following restoration of the existing intertie. The total Alberta transfer-in capability could reach up to approximately 2,150 MW, including the Montana–Alberta intertie and the Saskatchewan intertie. This simultaneous transfer capability allows the new intertie to fully back the existing intertie, and an outage of the existing or new intertie will not cause a trip of the other interties.

The remaining assumptions in this scenario are the same as in the Reference Case Scenario.

Forecast

The overall generation forecast for the Western Integration Scenario is not significantly different from the Reference Case Scenario. The main variation is that less simple-cycle capacity is required under the Western Integration Scenario.

High Cogeneration Scenario

New oilsands emissions limits have been introduced, accompanied by provisions for cogeneration. These provisions, or other support mechanisms, could introduce new incentives for cogeneration development that would increase the amount of cogeneration capacity at oilsands sites above levels assumed in the Reference Case Scenario. The High Cogeneration Scenario considers a larger amount of cogeneration development compared to the Reference Case Scenario.

Assumptions

Under the Reference Case Scenario, projects currently under construction plus approximately 400 MW of new cogeneration capacity are assumed to develop. In the High Cogeneration Scenario, there is approximately 1,300 MW of additional cogeneration capacity above the Reference Case Scenario, totalling 2,000 MW of new cogeneration capacity including projects under construction.

All of this additional cogeneration capacity is assumed to be retrofitted capacity that replaces standalone steam boilers. Consequently, this new cogeneration capacity is net-to-grid, meaning there is no additional oilsands load growth associated with it.

Forecast

Additional cogeneration development would displace combined-cycle and simple-cycle capacity additions assumed in the Reference Case Scenario. The High Cogeneration Scenario assumes that a large portion of additional cogeneration will come online by the early 2020s, which means that connections of new combined-cycle and simple-cycle units included in the Reference Case Scenario would be deferred.

Other LTO scenarios

The 2017 LTO contains two additional scenarios, Low Load Growth and High Coal-to-gas Conversion, which were also considered for the 2017 LTP.

However, these scenarios were not carried forward into detailed transmission assessments for the following reasons:

- The High Coal-to-gas Conversion Scenario assumes that 5,400 MW of coal-fired generation capacity converts to gas-fired generation. It has similar generation output and locations to the Reference Case Scenario.
- The Low Load Growth Scenario contains a lower average annual load growth of 0.4 per cent. In the near term, considering the shorter timeframe, the lower load growth will not have a significant impact on transmission requirements. In the longer term, transmission needs are driven mainly by generation changes.

Other considerations

There are several generation technologies in various stages of development that were considered in terms of the effect they can have over the LTP time horizon. Some technologies such as hydro-electric and solar generation have been included in the various scenarios where a significant effect was expected. The technologies below are noted as ones to watch while they evolve, and may require further assessment for future versions of the LTP.

Storage

There are many energy storage technologies, some that have existed for decades and others that are on the horizon. While the AESO closely monitors such developments, no storage capability has been factored into the development of the LTP other than as noted in the New Large-hydro Generation Scenario.

Bulk storage is being considered as a scenario for the RECSI. The RECSI's main objective is to evaluate electricity infrastructure projects in the western provinces that have potential to transition to a sustainable, non-emitting electricity generation portfolio. Funding for this study is being provided by Natural Resources Canada's Energy Innovation Program.

Geothermal

Geothermal energy is considered a renewable energy source that can generate baseload electricity. The technology extracts heat from Earth's inner layers by pumping fluids from several thousand feet below surface to an electrical generating facility. Current geothermal potential and development in Alberta is focused on abandoned oil and gas well conversions, which may have the potential to create small distribution-connected geothermal generation units.

Nuclear

As one of the world's largest producers of uranium, Canada meets nearly 15 per cent of its electricity needs through nuclear power. Nuclear power generation is a type of thermal power in which electricity is generated from steam produced by the fissioning, or splitting, of uranium atoms. Nuclear power is emission-free and provides baseload generation; however, it also produces radioactive waste which needs to be safely managed and stored. Alberta does not use nuclear generation and there are no projects on the horizon for this technology.

More details regarding all AESO scenarios can be found within the ***2017 LTO***

3.0 Transmission planning and developments

Transmission planning and developments

The AESO's transmission planning is a continuous process, based on detailed engineering evaluations of the transmission system over a 20-year planning horizon, and involves frequent examination of assumptions and proposed transmission solutions.

2017 LONG-TERM TRANSMISSION PLAN DEVELOPMENT STRATEGY

The development process for the 2017 LTP differs from previous years in response to the anticipated evolution of electricity generation and delivery in Alberta. The differences are largely driven by the Government of Alberta's goals to phase out coal-fired generation and increase electricity generation from renewable sources.

The LTP development strategy focuses on two main areas:

- Ensure that the transmission plan is flexible and adaptable to a wide variety of potential future scenarios. Make efficient use of the existing transmission system with timely addition of necessary new transmission developments.
- Provide a road map of how the Alberta transmission system will be enabled to optimally accommodate up to 5,000 MW of additional renewable electricity generation capacity by 2030.

TRANSMISSION PLANNING PROCESS

The planning process relies on a number of key inputs, forecasts and assumptions. The AESO examines load growth and potential generation development and retirements. This LTP brings a new focus on transmission developments required to meet forecast load growth, but also the shift in Alberta's generation fleet with the upcoming phase-out of coal generation as well as the 2030 renewable electricity target. As the timing and location of future generation developments have not been determined, the 2017 LTP uses scenarios outlined within the 2017 LTO to ensure transmission development plans are created to accommodate a range of potential future conditions.

OVERVIEW OF EXISTING TRANSMISSION SYSTEM

Transmission development is driven by load and generation, as the purpose of the transmission system is to move power from generators to loads. The location and density of load, and the size and location of generation, dictate the capacity, location and configuration of the transmission network required to serve the integrated system.

Current load and generation profile

The load configuration in Alberta is diverse, ranging from dense urban centres to sparse rural areas. The two major urban centres are the cities of Calgary and Edmonton, which account for about 30 per cent of the provincial electrical load. A unique feature of the Alberta load makeup is oilsands development, primarily located around Fort McMurray, representing a third major load centre. Other areas such as the South, Central and Northwest planning regions are primarily industrial and agricultural with sparse loads.

Generation development in the Alberta of the mid-to-late 1900s was primarily coal-based, with the majority (4,500 MW of 6,300 MW total) located in the Wabamun Lake area. The notable exceptions are the Battle River and Sheerness plants in the central east area of the province. As the northeast oilsands area developed, a large amount of gas-fired cogeneration was added to support the heating requirements of oilsands processing, while also generating electricity for local consumption and providing electricity to the Alberta grid.

The abundance of natural gas in the province, coupled with low prices, has resulted in the growth of gas-fired generation facilities, the largest of which is the Shepard Energy Centre, an 850 MW combined-cycle facility located east of Calgary. Alberta has a relatively small amount of hydroelectric generation (approximately 895 MW), which includes smaller plants on the Bow River and tributaries as well as the larger Big Horn and Brazeau plants in the North Saskatchewan watershed.

Renewable energy, specifically in the form of wind generation, has grown substantially over the past 10 years to a total of about 1,500 MW in the south and central east portions of the province. Alberta has significant renewable generation resources, namely wind and solar, in these areas.

Existing transmission system

The transmission system in Alberta developed in response to load and generation growth. As coal-fired generation developed in the Wabamun Lake area between the mid-1950s and mid-1990s, transmission infrastructure was needed to connect the generation to major load centres in Calgary and Edmonton. More recently, oilsands development near Fort McMurray resulted in transmission development to and within that area. Most recently, transmission developments have been put in place to integrate renewable generation from the south and central east areas of the province.

Bulk transmission system

The bulk transmission system consists of 500 kV and 240 kV lines that move large amounts of power from generation sources to load centres. A 500 kV network connects generation in the Wabamun Lake area to Edmonton and beyond, and a network consisting of six 240 kV lines connects the Wabamun Lake/Edmonton area with Calgary and the south. Two 500 kV high-voltage direct current (HVDC) lines were added in 2015 to transfer power north-to-south or south-to-north and can be operated independently.

A 240 kV network also exists between the Wabamun Lake/Edmonton area and the northwest and northeast. The northwest is primarily a load centre with flows from south-to-north, whereas the northeast is a load and generation area where flows may be in either direction.

Transmission development is driven by load and generation, as the purpose of the transmission system is to move power from generators to loads. The location and density of load, and the size and location of generation, dictate the capacity, location and configuration of the transmission network required to serve the integrated system.

Regional transmission systems

Regional transmission systems take power from the bulk system and move it to load-serving substations that serve distribution systems. Major urban centres can have concentrated systems comprising several load-serving substations in a relatively small geographic area. Alternately, regional transmission systems can be present in sparsely populated areas such as the south or central parts of the province, where there is significant distance between substations.

Interties

As part of the North American electricity grid, Alberta's interconnections with neighbouring systems are an essential component of a reliable transmission system and competitive electricity market. Alberta is one of the least interconnected system in North America. With the third-largest peak demand for electricity among all provinces in Canada at approximately 11,500 MW, our simultaneous intertie capability is approximately 10 per cent of our peak demand.

Alberta's intertie with British Columbia has an existing import capability, 800 MW of import transfer capability and connects the Alberta grid with the British Columbia Hydro grid. The Saskatchewan intertie connects Alberta to the SaskPower grid and is capable of transferring 150 MW; the Montana intertie is capable of transferring 300 MW.

Transmission system overview

The transmission system has seen needed reinforcement over the past 10 years with the development/completion of several projects:

- **Heartland 500 kV Transmission Development**–500 kV double circuit line between the Ellerslie substation and the Heartland substation to strengthen supply into the industrial zone and to the northeast.
- **North–South Transmission Reinforcement**–two 500 kV HVDC links, the Eastern Alberta Transmission Line and Western Alberta Transmission Line, connecting the North and South planning regions.
- **Southern Alberta Transmission Reinforcement**–240 kV transmission system in southern Alberta to integrate renewable generation.
- **Foothills Area Transmission Development**–240 kV and 138 kV enhancements in and south of Calgary, including a new 240/138 kV substation near High River to accommodate renewable generation in the south, as well as other Calgary area generation.
- **Hanna Region Transmission Development Phase 1**–240 and 144 kV transmission development in the Hanna, Sheerness and Battle River areas.
- **Red Deer Area Transmission Development**–240 kV and 138 kV transmission system reinforcements in the Red Deer area.
- **South and West of Edmonton**–240 kV and 138 kV transmission system enhancements.

These reinforcements will provide necessary transmission capacity to move power between the major regions for the foreseeable future. The Fort McMurray Transmission Reinforcement will also strengthen the backbone of Alberta's system.

The Fort McMurray Transmission Reinforcement consists of two 500 kV lines, one from the Wabamun Lake area (Fort McMurray West) and the second from the Fort Saskatchewan area (Fort McMurray East). The Fort McMurray West project is proceeding, with an in-service date of 2019. The Fort McMurray East project has been deferred due to the future economic outlook.

The Fort McMurray West project was awarded to Alberta PowerLine Limited in December 2014 through a competitive process. Construction started during Q3 2017. The Fort McMurray East project timing will depend on when additional cogeneration development or strong load growth occurs in the Fort McMurray area. With large cogeneration development in that area, the Fort McMurray East line will assist system operability and avoid significant generation curtailment in the Fort McMurray area for sustained transmission outage conditions.

In addition to these transmission projects, several regional transmission developments are underway or have been completed to address regional transmission needs.

TRANSMISSION SYSTEM ASSESSMENTS

The 2017 LTP assessed the transmission system in three timeframes:

- Near-term assessment (five years)–examined the transmission system on a regional basis using the Reference Case Scenario. They are detailed as there is a higher level of certainty about load and generation trends over the next five years. The following transmission developments are currently underway; planned in-service dates prior to 2022 were assumed energized:
  - — Alberta–British Columbia Intertie Restoration
  - — Thickwood Hills 240 kV Transmission Development and Reactive Power Reinforcement
  - — Fort McMurray West 500 kV Transmission Project
  - — Provost–to–Edgerton and Nilrem–to–Vermilion Transmission Development
  - — Downtown Calgary Transmission Reinforcement
- Longer-term assessment (5+ years)–examined the transmission system from a bulk, system-wide basis based on a range of future scenarios. They capture major effects of the various scenarios discussed in the Forecast section (see page 9). As such, only outages on elements at 240 kV and above were assessed and elements at 138 kV and above were monitored.
- Coal-fired generation is currently planned to be phased out by 2030. It is important that transmission system reliability, stability and performance be evaluated, and deficiencies and mitigation measures, if any, are identified early. Longer-term studies for 2032 were analyzed to capture any reliability constraints that may arise at the end of the coal phase-out timeframe.

Telecommunication network development

Alberta's province-wide, utility-owned-and-operated telecommunication network is essential to the reliable, efficient and safe operation of Alberta's transmission system. This sophisticated infrastructure overlays the transmission system and is vital to monitoring, operating and protecting the interconnected electric system, and all reporting functions.

Numerous factors are considered in telecommunication network planning and development. Generally, this follows the transmission planning process and is therefore also reliant on Alberta load and growth forecasting. Changes in future load and generation facilities can affect requirements for the telecommunication network.

To read the 2017 Telecommunication Long-term Plan visit: ***www.aeso.ca/LTP***

COAL PHASE-OUT TRANSMISSION RELIABILITY ASSESSMENT POST-2030

The AESO evaluated the potential effects on transmission reliability when all coal-fired generators retire by 2030. The key findings are described below.

Transmission reliability

Transmission reliability (also known as operational reliability) is a broad term used to describe technical or physical impacts that can influence reliability. The following describes the specific assessments undertaken by the AESO to determine possible effects.

Inertia for frequency response

Frequency response is the ability of the power system to stabilize and restore grid frequency following large, sudden mismatches between supply and load. The system currently relies on large coal-fired synchronous generators to provide the inertia (stored kinetic energy) required to provide frequency stability. An outage of the Alberta–British Columbia intertie while importing at full capacity would be the largest loss of supply on Alberta's electrical system. With no coal units online and replacement energy potentially provided mostly by renewable generation, system frequency may not recover to the minimum system-stable limit due to lack of inertia. New gas-fired generation, expected to be developed to replace coal-fired generation and meet load growth, is anticipated to provide the required inertia.

Retirement of coal-fired generation may affect the system's inertia response. However, the AESO will be closely monitoring coal retirement and replacement activity and there will be sufficient time to apply mitigation measures to any issues that may arise.

Transmission system adequacy

Transmission system adequacy is the ability of the transmission system to move electricity reliably from generation sources to loads. In the future, bulk transmission adequacy is expected to depend on the timing and locations of coal-fired unit retirements, replacement generation and renewable generation additions throughout Alberta. Studies indicated that transmission system adequacy is not a concern at this time.

It is generally expected that a large proportion of new gas-fired generation will be developed at or in close proximity to existing coal-fired plant locations to utilize available infrastructure, resources and transmission capacity. Transmission developments that are already completed and/or planned as part of this LTP will be sufficient to meet forecast load growth and integrate new renewable and gas-fired generation.

System transient stability

Transient stability is the ability of generating units on the system to recover from a major disturbance and maintain stable operation. For the 2017 LTP, transient stability was evaluated in two key areas of the system: the Lake Wabamun area and the Calgary area (the Alberta terminus of the Alberta–British Columbia intertie). System stability at both locations may be affected by the generation connected in the Lake Wabamun area. From a coal phase-out perspective, the results of the initial assessments indicate no transient stability concerns.

Short-circuit capability

Short-circuit capability is necessary to provide strong voltage support under varying system operating conditions, switching events, and for motor starting. Also, high-voltage direct current (HVDC) converters operate more reliably when short-circuit capability is higher, and are designed to operate at a minimum short-circuit capability level. Short-circuit capability is mainly provided by synchronous generators such as coal-fired thermal plants and combined-cycle plants. This initial assessment found that short-circuit levels will be adequate for motor starting after coal-fired units are retired. However, the two HVDC circuits, the Western Alberta Transmission Line and Eastern Alberta Transmission Line, will require synchronous generation in the Wabamun Lake and southeast areas in order to have sufficient short-circuit levels to operate within their design limits. It is expected that gas-fired generation development will occur at or close to existing coal-fired generation areas, or the AESO can address this through a transmission solution.

The AESO does not have concerns regarding changes to the system's short-circuit capability as coal-fired generation retires and new replacements come online. Any issues that could appear are likely to do so with sufficient time to apply mitigation measures.

Protection and control

Protection and control relates to equipment on the transmission system that is designed to isolate system elements under faulted conditions. This is necessary to protect personnel, and to safeguard equipment such as generators and transformers from harmful operating conditions. Renewable generation from wind and solar sources does not materially contribute to fault currents. Therefore, lower short-circuit levels affect protection and control coordination. Although this is a concern, mitigation can be managed by adjustments to protection and control equipment as necessary.

Transmission reliability is a broad term used to describe technical or physical impacts that can influence reliability.

Gas infrastructure

The *Alberta Gas Supply and Infrastructure Analysis* was commissioned by the AESO to understand the operation of the Alberta and western Canada natural gas systems as they relate to the development and operation of reliable, large-scale, gas-fired power generation as a replacement for coal-fired generation and back-up to intermittent resources. The report examines Alberta and western Canada, as the Alberta systems are interconnected to those in British Columbia, Saskatchewan and the United States.

The analysis concludes that there are substantial natural gas resources, a dependable delivery system and established commercial processes underpinning its operation. However, some characteristics of the natural gas system need to be monitored and managed to ensure future reliability of gas-fired power generation, especially in regions with a high concentration of such assets.

Some potential areas of assessment include:

- Regions such as Wabamun Lake could potentially have a high concentration of gas-fired generation that may depend upon a limited pipeline infrastructure for fuel supply. As the pipeline infrastructure is expanded to allow for increased demand for power generation, analysis of planned and forced pipeline outages needs to be completed with mitigation plans where significant reliability issues may arise. This may include redundant pipelines or minimizing the number of electric power generators dependent upon a single pipeline.
- The timing to develop additional pipeline infrastructure in fully-contracted delivery point regions should be reviewed to ensure reliable fuel supply on a timely basis to meet the incremental natural gas demand for electrical power generation.
- The supply of natural gas into the system is relatively inflexible over the short term (i.e., within hours), with fluctuations in demand or supply generally balanced through the use of system line pack and natural gas storage. The system was not originally designed with the capability to respond to large short-term fluctuations in natural gas demand that may evolve based on the requirements of electrical power generation (i.e., increased volatility in natural gas demand for electric power generation resulting from changes in renewable electricity production). The generation facilities may need to consider installation of on-site storage of natural gas or fuel-switching capability to ensure fully dependable operation.
- For increased long-term reliability, natural gas storage facilities within the Alberta system should be assessed (particularly withdrawal capacities) as gas-fired and renewable generation increase.
- Natural gas system operators and electric power generation developers must work together to ensure that the influx of new natural gas-fired generation does not affect regional system reliability.
- To ensure reliability of fuel supply, electricity generators should consider high-priority, high-capacity transportation services and storage contracts.

To read Alberta Gas Supply and Infrastructure Analysis visit: ***www.aeso.ca/LTP***

Renewable generation-following and system-ramping capability

Electrical output from renewable generation can change by large magnitudes over short periods of time. With the targets of adding 5,000 MW of renewable generation capacity and meeting 30 per cent of energy production from renewable generation by 2030, there is potential for renewable generation development to exceed the ability of the system to respond within its system operating limits to major renewable generation ramping events. This does not influence the phase-out of coal units but may affect the generation required to replace them, as well as ancillary services required to provide faster ramping response.

If a larger percentage of renewable generation ramps up or down quickly, other types of generators will be required to respond to maintain generation-load balance. Gas-fired generators may need to be online in order to react in time. Simple-cycle gas turbines that have short start-up times may need to be added to the system. Other solutions, such as ancillary services or ramping products, may need to be developed.

Renewable distributed energy resource assessment

It is anticipated that a portion of the future renewable generation additions required to meet Alberta's renewable target will come from distributed energy resources (DER) connected to the distribution system.

The 2017 LTO includes utility-scale (5 MW and higher) generation capacity and assumes these units will be connected at transmission voltages; however, the AESO recognizes this capacity could be connected at the distribution level at smaller sizes as well.

To date, there are approximately 470 MW of DER in Alberta. At the current volume of DER, the AESO is confident that existing requirements and practices allow for reliable management of the transmission system. In the future, however, there is potential for a much higher DER capacity to develop, which may influence the planning and operation of the transmission system.

If DER follows nearby loads, they could potentially reduce loading on the transmission system at certain times. However, large-scale DER penetration in wind and solar resource-rich regions such as the southern and the central east areas of the province would exacerbate transfer-out congestion and affect transmission capacity enhancement requirements. This is because the load level in these regions is relatively low and, with large-scale DER penetrations, transmission transfer-out capability to meet the surplus generation may become an issue. DER could also change the flow pattern on local transmission systems or further exacerbate loadings, depending on the location merits of their respective areas of connection. These changes could lead to local transmission constraints that need to be addressed through additional transmission investment or operational measures.

Depending on the nature of the DER fuel source, the DER capacity added to the Alberta electric system may not contribute to resource adequacy under peak load conditions. For example, Alberta's peak load typically occurs during winter in early evening. In the case of solar DER, they may produce electricity well below their nameplate capacity at that time of day and thus may not contribute to capacity during peak load periods in winter.

Based on the current rules, the AESO has very limited visibility or control over DER. DER below 5 MW of capacity are not currently required to participate in the day-to-day dispatch of the electricity market; hence the current rules do not require these small installations to exchange telemetered data with the AESO. At the current level of DER, the AESO can operate the interconnected electric system reliably. However, if significant DER capacity develops and makes up a larger proportion of generation capacity, additional visibility and control may be required.

At this time, the AESO anticipates continued interaction with distribution facility owners regarding the operation and control of DER when the amount of DER on the system increases. These DER facilities are connected to the facilities of distribution facility owners, and they can also influence the operation of the distribution system. Coordination between the AESO and distribution facility owners on the operation of DER is required to ensure the distribution system and transmission system can both remain reliable.

TRANSMISSION SYSTEM ASSESSMENT FOR RENEWABLE GENERATION INTEGRATION

The AESO examined the ability of the current transmission system to support Alberta's renewable generation integration target. The 2017 LTP utilizes the existing and planned transmission system efficiently in areas where high renewable generation potential exists. This approach will facilitate competition by enabling simultaneous access in geographically diverse, renewable resource-rich areas. Transmission development is planned in a staged manner to ensure it occurs at the right time and in the right place. DER and their potential impact to the transmission system was also examined.

In the assessment, new renewable generators were integrated in resource-rich areas in a way that made optimal use of existing and planned transmission capacity.

Methodology

The renewable generation integration studies focused on the South and Central planning regions, as this is where most of the wind and solar resource potential exists. The majority of historical connection applications for renewable projects received by the AESO have also been in these regions.

At present, the majority of renewable generation connection applications are also located in these areas (Figure 3.0-1).

The South and Central planning regions were further divided into three main areas; the southwest, southeast, and central east areas. These areas have the highest potential for both wind and solar resources in Alberta, as shown in Figures 3.0-2 and 3.0-3.

The southwest, southeast and central east areas have strong existing and planned collector systems to connect incremental renewable generation. However, the transfer-out system in these areas is not strong enough to integrate substantial renewable generation additions. Load levels in the south and central east areas are relatively low compared to other regions in the system, and this further contributes to generation transfer-out limitations.

The renewable generation capacity additions were connected to the strong buses (mainly 240 kV) in these areas. The existence of a strong 240 kV collector system in the central east, southeast and southwest areas of the province, along with the planned 240 kV transmission infrastructure, provides flexibility for the location of generation. The incremental generation was assigned to the buses which lead to maximized utilization of the transmission system capability for wind and solar integration. The integration capacity was evaluated so thermal constraints do not occur under system normal conditions, and are manageable under contingency conditions.

Figure 3.0-1: Existing transmission system capability and current renewable generation applications

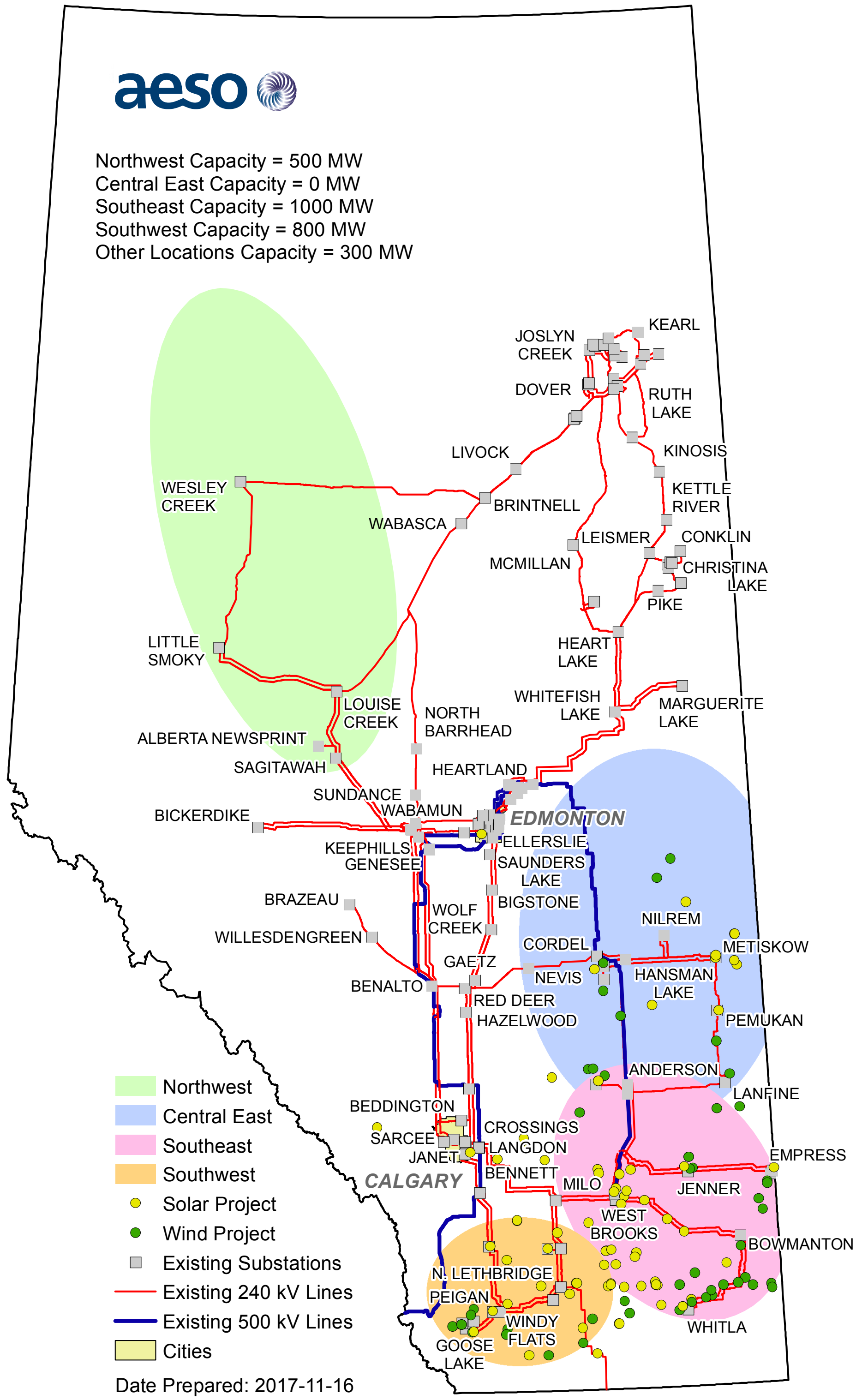


Figure 3.0-2: Alberta's wind resource potential

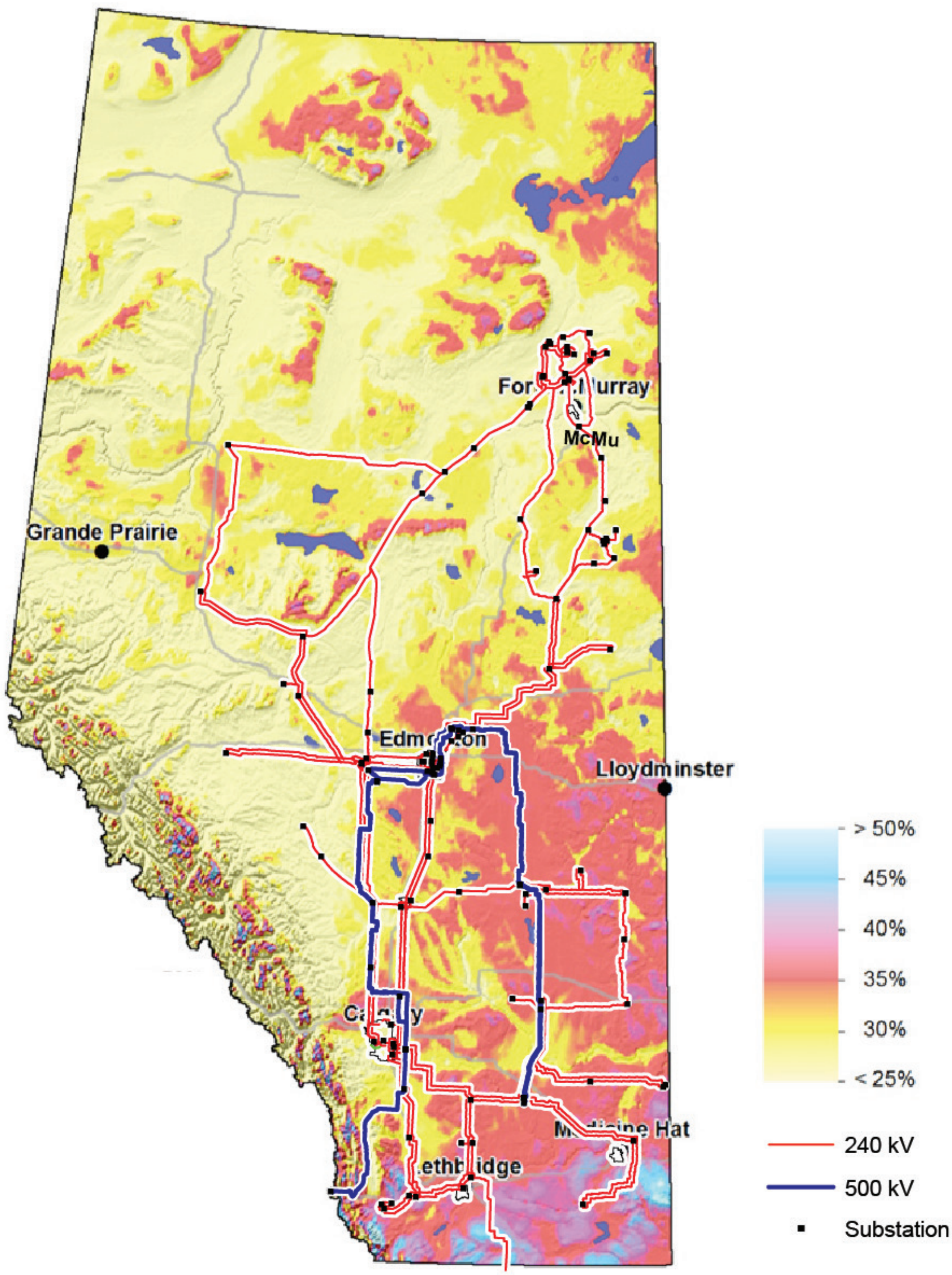
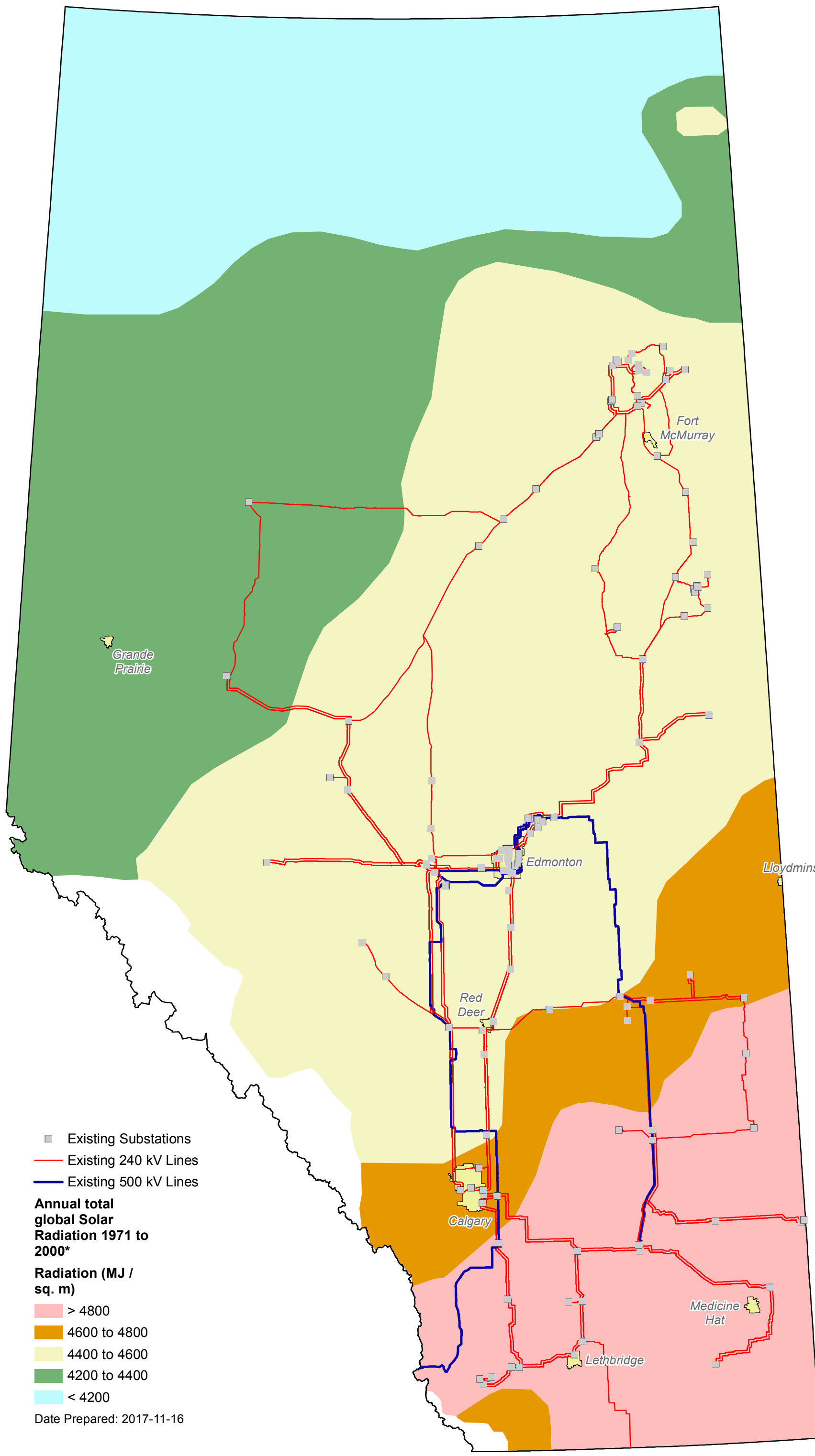


Figure 3.0-3: Alberta's solar resource potential



RENEWABLE GENERATION INTEGRATION PLAN

Alberta's current renewable electricity target–30 per cent of electricity generated using renewable resources by 2030–requires the addition of approximately 5,000 MW of renewable generation and assumes wind and solar resources are the most economical renewables that will develop. Currently, the existing transmission system has an upper-limit capacity of approximately 2,600 MW. The AESO has determined that the remaining transmission capacity needed to meet the 5,000 MW target can be met through the completion of a number of developments conceptually similar to those identified in previous long-term plans.

The integration of new renewable generation into the system includes the following considerations:

- The most resource-efficient connection of renewable generation will occur where strong, abundant renewable generation resources such as wind and solar exist. The optimal plan maximizes utilization of existing collector systems in the province's southwest, southeast, Hanna and central east regions. This includes Pincher Creek, Fort Macleod, Lethbridge, southeast Alberta along the Cassils–to–Bowmanton–to–Whitla transmission corridor and the central east region of Alberta stretching between Vegreville in the north and Cypress in the south. This will utilize the existing transmission network in the area, including the Hanna Region Transmission Development and the planned Provost–to–Edgerton and Nilrem–to–Vermilion Transmission Development.
- In the process of adding capacity to meet the 5,000 MW target, transmission planning must ensure that added transmission does not decrease capacity elsewhere.
- Optimal, cost-efficient transmission development to meet the renewable generation target will be best reached through the development of previously planned reinforcements, specifically the Chapel Rock–to–Pincher Creek area transmission development and transfer-out reinforcement transmission developments in the central east area.
- Completion of these two planned transmission developments brings total available capacity to 4,300 MW. The remaining 700 MW required to meet target can be achieved through hydroelectric generation development and increasing the allocated DER integration capacity.
- The following projects are not required for renewable capacity integration and can therefore be cancelled: Picture Butte–to–Etzikom Coulee, Etzikom Coulee–to–Whitla and Gooselake–to–Etzikom Coulee (PBEC ECW, GLEC). The existing Hanna 240 kV system and Planned PENV development will provide collector system capability instead.

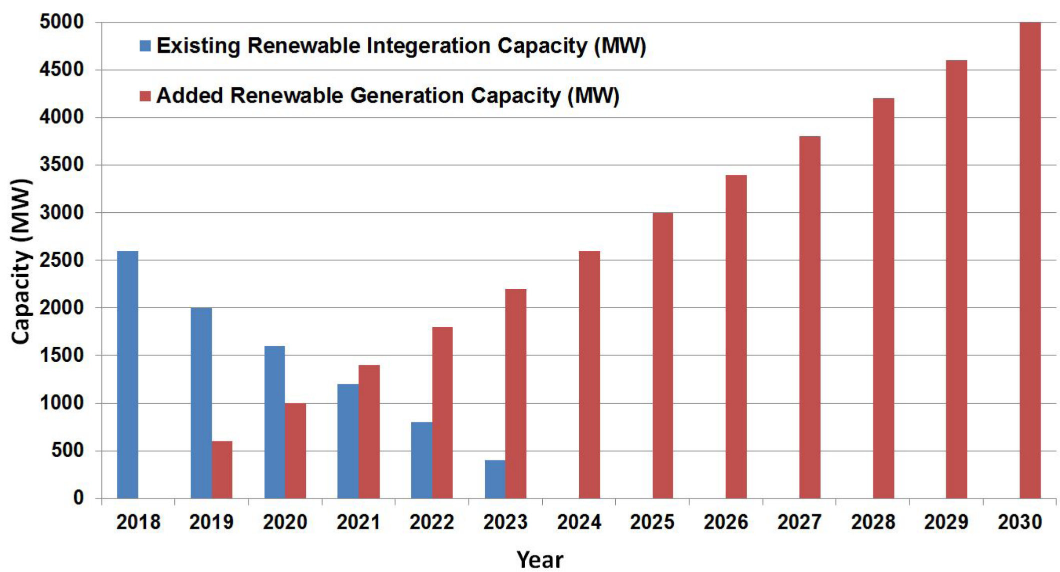
Transmission development timeline

Transmission projects, on average, require five to seven years to advance from approval to completion. To ensure that the AESO is planning optimally in order to meet currently forecast capacity requirements, construction milestones need to be set at this time and selected construction elements need to be underway within the near future.

Approximately 600 MW of incremental renewable generation will come into service through the REP by the end of 2019, followed by annual average additions of approximately 400 MW until the 5,000 MW target is reached. To meet Alberta's renewable energy target at 400 MW per year, the system will run out of capacity by 2024 or earlier. Figure 3.0-4 shows the average trend for added renewable generation capacity, assuming optimum utilization of existing transmission capacity. It also shows how the optimal integration capacity of the transmission system decreases by adding incremental generation into the system.

Therefore, transmission enhancements are required to increase the capacity of the system for renewable generation integration as transmission system capability in specific renewable-rich areas becomes utilized. Note that regional capacity is expected to be utilized at different rates.

Figure 3.0-4: Existing and assumed added renewable capacity in the transmission system



> Transmission enhancements are required to increase the capacity of the system for renewable generation integration as transmission system capability in specific renewable rich areas become utilized.

Methodology and key considerations

- The renewable generation integration studies focused on the South and Central planning regions, as this is where most of the wind and solar resource potential exists. The majority of current and historical connection applications for renewable projects received by the AESO have also been in these regions (Figure 3.0-1).
- The South and Central planning regions were further divided into three main areas; the southwest, southeast, and central east areas of the province. These areas have the highest potential for both wind and solar resources in Alberta, as shown in Figures 3.0-2 and 3.0-3.
- Strong 240 kV transmission networks currently exist that could be utilized to connect renewable energy capacity in the resource-rich areas in the southwest, southeast and central east areas. However, the transfer-out system in these areas is not strong enough to reach the target renewable generation additions.
- The existing southwest and southeast area available capacities were found to be 800 MW and 1,000 MW, respectively. The central east area cannot integrate incremental renewable generation at present without removing available capacity from another region.
- Load levels in the south and central east areas are relatively low compared to other regions in the system, and this further contributes to generation transfer-out requirements and limitations.
- The Central East Transfer-out Transmission Development and the Chapel Rock–Pincher Creek Transmission Development were determined to be the most effective transfer-out transmission projects in the central east and southwest areas. Studies showed that these two developments can increase the integration capacity in the central east and south areas by 1,000 MW and 700 MW, respectively. This brings total integration capacity to 4,300 MW from the current 2,600 MW.
- The Central East Transfer-out Transmission Development and the Chapel Rock–Pincher Creek Transmission Development add the highest level of renewable integration capacity per transmission cost out of the studied transmission development alternatives.
- The existence of a strong 240 kV collector system in the central east, southeast and southwest areas of the province, along the planned 240 kV transmission infrastructure, provides flexibility and diversity over a vast footprint in southern and central Alberta.
- The Northwest Planning Region has strong hydro potential and existing transmission capacity in the region that can be used to integrate wind, solar, hydro or geothermal generation or a mixture of these resources. The existing northwest capacity is approximately 500 MW, and an additional 300 MW of renewable generation can be added at other locations in the system.
- In assessing existing and planned transmission capacities for renewable integration, the incremental generation was assigned to the buses which lead to maximized utilization of the transmission system. The integration capacity was evaluated so thermal constraints do not occur under system-normal conditions and are manageable under contingency conditions.

Existing transmission system capability

- The 2,600 MW of available capacity is the upper limit for generation integration into the existing system. Optimal placement and maximum utilization of existing capacity was assumed for assessing available and planned capacity.
- There is existing renewable generation integration capability in the central east area. However, integration of any renewable generation in that area will reduce the total system renewable integration capacity by a factor of two, approximately. Table 3.0-7 shows the optimal simultaneous incremental renewable generation placement; the central east area's share is 0 MW. However, this does not mean there is no incremental capacity in this area. Integration of incremental generation in the central east area would be sub-optimal, leading to a reduced system-wide total capacity to integrate new renewable generation by an amount greater than that added in the central east area. Specifically, for every 100 MW of incremental renewable generation added in the central east area, the southeast area renewable generation integration capacity would be reduced by 160-190 MW. The planned transmission transfer-out reinforcement in the central east area will address this constraint.
- Potential development of DER may also utilize the capacity of the transmission system for renewable generation. If DER develops in the southwest, southeast and central east areas, they would depreciate the 1,800 MW of available transmission capacity in these regions. As load levels in these regions are low, each region will reflect surplus generation capacity. Therefore, regardless of whether renewable generation is DER or otherwise, transfer-out limitations will occur.
- The phase-out of coal-fired generation will influence the available capacity to integrate renewable generation. For example, generation replacements located near the Battle River and Sheerness coal-fired units would directly utilize the available local and transfer-out capability. This will then affect the available renewable integration capacity in the southeast and central east areas. In this assessment, the level of thermal generation replacement capacity at those plants is assumed to be approximately 1,000 MW. A relatively high generation capacity is needed in those locations to support the short-circuit levels for HVDC and reliable operation of renewable generation.
- The development of conventional generation and level of generation coincident with high renewable generation output, will impact the transmission capacity available for renewables. The Shepard Energy Centre near Calgary would directly affect the renewable generation integration capacity in the southwest area, and future generation developments in the northwest would also utilize portions of the area's available transmission capacity.
- Voltage stability challenges and operational constraints following major 240 kV path contingencies may arise. In such conditions, mitigation measures to integrate new renewable electricity generation in the presented volumes would be required to manage these constraints. For example, depending on the connection of generation, mitigation measures may be required to integrate 1,000 MW of new supply along the Cassils–Bowmanton–Whilta path in the southeast area.

Required transmission developments

After comprehensive study, two previously identified transmission developments continue to be required to meet renewable generation integration targets. These projects are the Castle Rock Ridge–to–Chapel Rock Transmission Project, approved by the AUC in 2009, and the Central East Transfer-out Transmission Development, identified in previous AESO long-term plans. The Castle Rock Ridge–to–Chapel Rock Transmission Project may be reconfigured and, as such, has been renamed as the Chapel Rock–Pincher Creek Transmission Development.

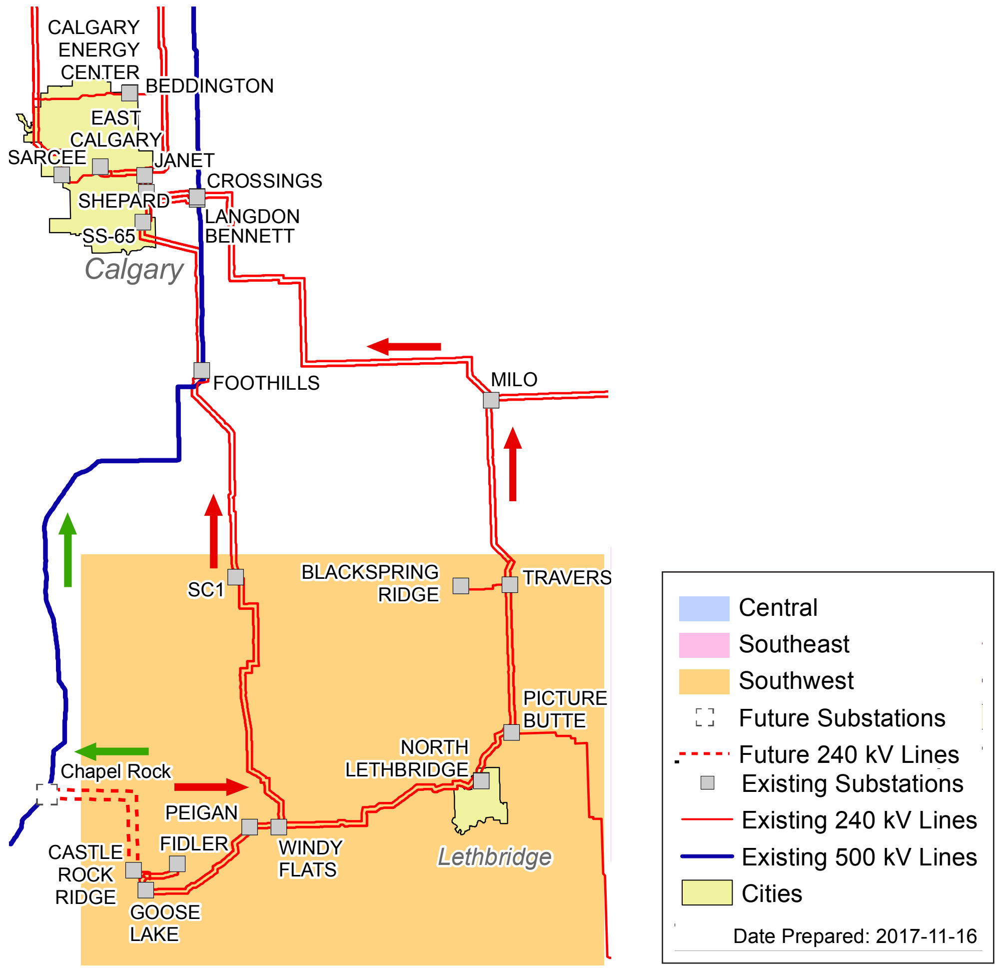
These developments will enhance the system capability to transfer power out of the areas where power is produced and deliver it to load centres. Both projects can be staged with milestones to introduce flexibility to enable incremental transfer capability to be added as renewable generation development evolves.

Chapel Rock–Pincher Creek Transmission Development

A number of transmission developments, including Foothills Area Transmission Development West and Chapel Rock–Pincher Creek Transmission Development, and the Etzikom Coulee–Whitla line (ECW), the Picture Butte–Etzikom Coulee line (PBEC), Goose Lake–Etzikom Coulee line (GLEC) developments were reviewed to evaluate the ability each would have to integrate renewable generation. Among these projects, the Chapel Rock–Pincher Creek Transmission Development allows the highest level of renewable generation integration in the southwest, further enhances transfer-out capability from the area and also contributes to the restoration of the Alberta–British Columbia intertie capability. With a goal of optimizing transmission system capability and having evaluated renewable generation requests for access, the Etzikom Coulee–Whitla line (ECW), the Picture Butte–Etzikom Coulee line (PBEC), Goose Lake–Etzikom Coulee line (GLEC) developments will be cancelled.

The Chapel Rock–Pincher Creek Transmission Development enables use of the existing 240 kV system in the Pincher Creek area, and in the greater southwest area, extending east to Lethbridge for collecting renewable generation. This development would be staged to add 700 MW of generation integration capability in the southwest by adding two new 240 kV transmission circuits approximately 40 km long between the Pincher Creek area and a new 500 kV substation to be called Chapel Rock. This short 40 km transmission development would expand the collector system in the area and enhance the transfer-out path via the new Chapel Rock substation, and consequently to the existing 1201L 500 kV transmission line in the area. This optimizes the use of three parallel paths connecting the southwest to the Calgary area load centre via the Lethbridge–Milo–Langdon, Windy Flats–Foothills and Chapel Rock–Bennett transmission paths. Figure 3.0-5 shows the location of the Chapel Rock substation and the new path created by this plan to transfer the incremental power.

Figure 3.0-5: Chapel Rock–Pincher Creek Transmission Development



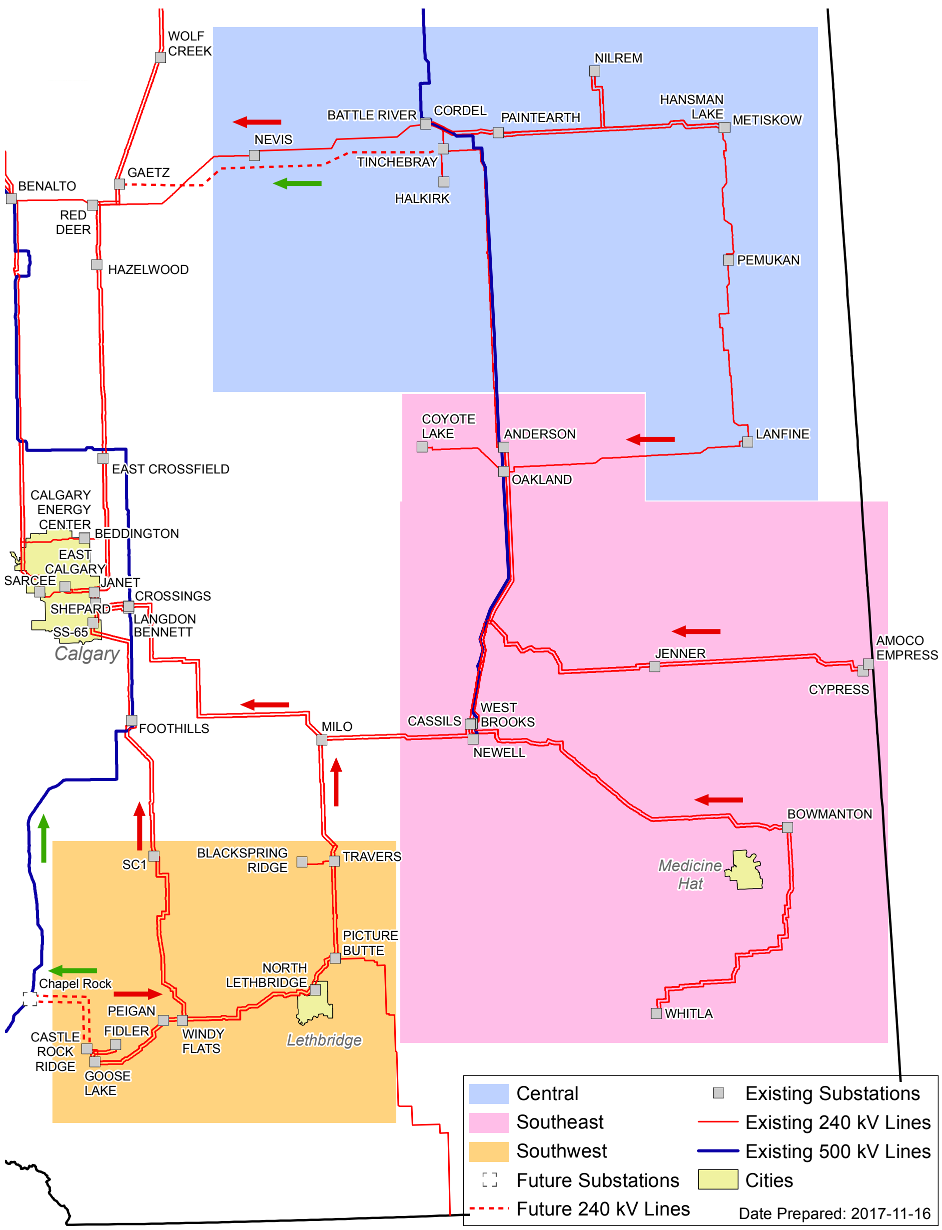
Central East Transfer-out Transmission Development

To determine an efficient transfer out of the central east area and the northern portion of the southeast region, several alternatives were considered, including Oakland–to–Langdon, Ware Junction–to–Langdon, and Central East–to–Red Deer. The Central East Transfer-out Transmission Development strengthens the existing Cordel–Nevis–Gaetz transmission path and is considered to be the most efficient enhancement to integrate incremental renewable capacity in the central east area. The specific configuration of the Central East Transfer-out Transmission Development is currently being studied in detail. One alternative includes the addition of a two staged 240 kV transmission circuits from Tinchebray to Gaetz. Another option is the addition of a single-circuit 240 kV transmission line from Tinchebray to Gaetz and a rebuilding of the existing 240 kV system from Cordel to Nevis to Red Deer for higher capacity, which may impose unacceptable challenges for system operation if sustained outages are required to rebuild the existing line.

The Central East Transfer-out Transmission Development will open up integration capacity in the central and southeast areas. This transmission development will add approximately 1,000 MW of additional integration capacity depending on the replacement capacity of existing coal-fired generation in the area. Similar to the Chapel Rock–Pincher Creek Transmission Development, the two circuits of the Central East Transfer-out Transmission Development are also planned to be added in two stages. The timing of each stage is highly dependent upon firm coal-fired generation replacement in the areas of Battle River and Sheerness areas.

The Central East Transfer-out Transmission Development would enhance transfer-out capability for both the southeast and central east areas.

Figure 3.0-6: Central East Transfer-out Transmission Development



Added transmission system capability

The total system simultaneous generation integration capacity for the combinations of the proposed system developments is presented in table 3.0-7 below.

3.0-7: System simultaneous renewable capacity by utilizing Chapel Rock–Pincher Creek Transmission Development and Central East Transfer-out Transmission Development

Central East Transfer-out Transmission Development	Chapel Rock–Pincher Creek Transmission Development	Northwest and Other Areas Capacity (MW)	South and Central East Capacity (MW)	Total Capacity (MW)
None	None	800	1,800	2,600
In service	None	800	2,800	3,600
None	In service	800	2,500	3,300
In service	In service	800	3,500	4,300

The added transmission system capability created by development of the Chapel Rock–Pincher Creek and Central East Transfer-out Transmission Developments are at least 700 MW and approximately 1,000 MW, respectively.

Total transmission integration capability for renewables after development

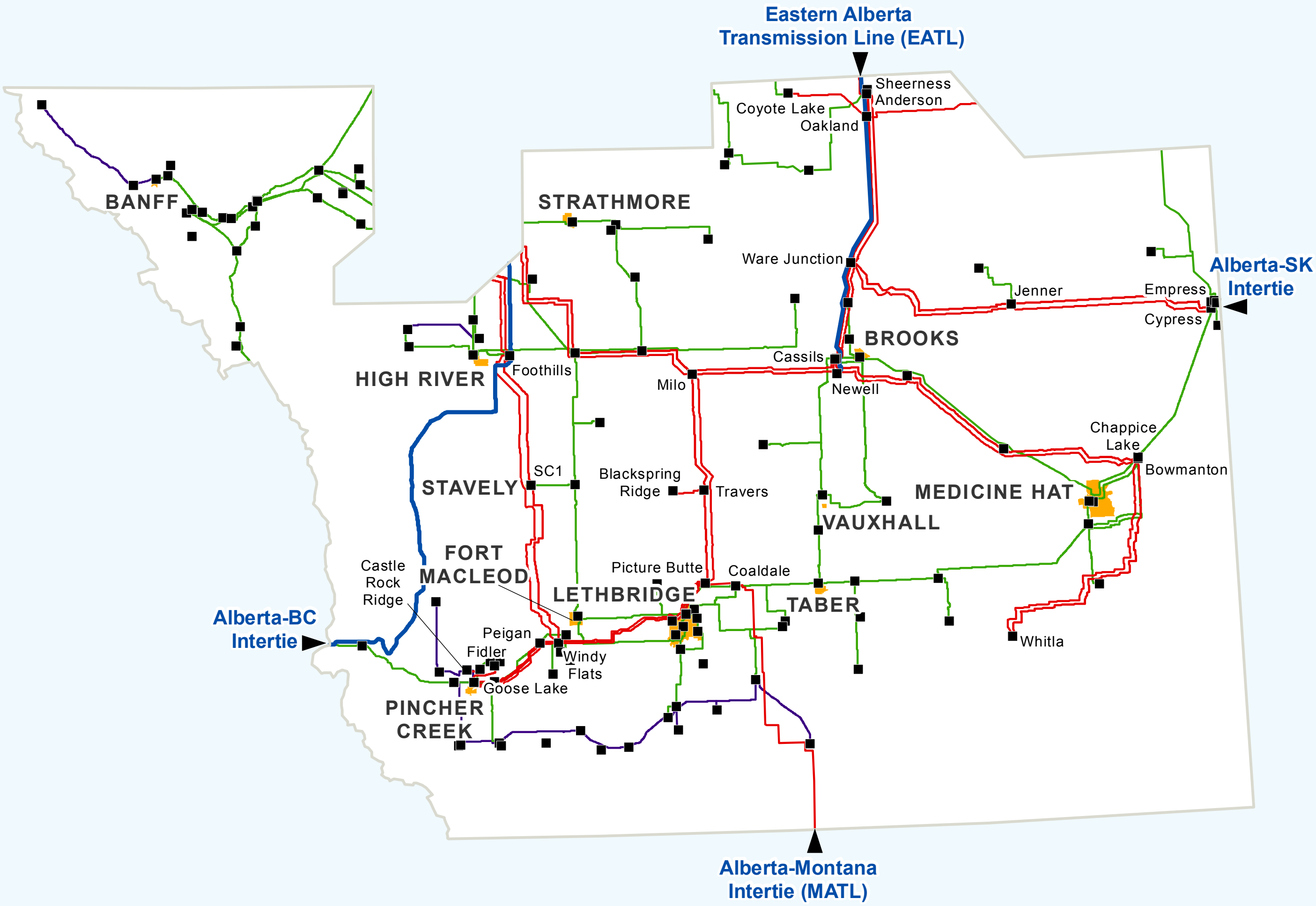
With the Chapel Rock–Pincher Creek Transmission Development and Central East Transfer-out Transmission Development, the transmission system can integrate approximately 4,300 MW of renewable energy resources. Additional renewable resources connected to the distribution system such as urban DER (close to major load centres), future hydro generation developments and other technologies are expected to contribute an additional 700 MW. Development of urban DER and hydro generation outside of the south and central east areas would enhance the existing integration capacity of the transmission system outside these two regions (i.e., other locations) from 800 MW to 1,500 MW.

Finally, it should be noted that as renewable generation developments start to energize and utilize existing transmission capability, mitigation measures may be applied to enable continuous integration of renewable generation while construction of incremental transmission developments is underway. This will ensure that transmission integration capability will stay available in a large geographically diverse footprint while incremental transmission additions underway are energized, enabling more competition and efficiency of the REP.

SOUTH PLANNING REGION

Existing transmission system

Legend
- Cities/Towns
- Substations
- 69/72 kV
- 138/144 kV
- 240 kV
- 500 kV



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REGIONAL TRANSMISSION PLANS

South Planning Region

Overview and forecast

The South Planning Region encompasses southern Alberta and includes Lethbridge, High River, Brooks, the Empress industrial area and Medicine Hat.

The region represents approximately 11 per cent of provincial electrical load. Load has remained relatively slow over the past decade but is expected to grow at a rate of 0.7 per cent annually over the next 20 years, due to population growth and residential, commercial and industrial development.

South regional reference case load and generation forecast

	Existing (MW)	2022 (MW)
Load at non-coincident peak	1,325	1,404
Coal-fired	790	790
Cogeneration	110	110
Combined-cycle gas	373	373
Simple-cycle gas	80	128
Hydro	409	409
Wind	1,185	2,384
Solar	0	200
Other	42	42

Existing transmission system

Load in the South Planning Region is primarily served through an extensive, looped 138 kV transmission network supplied by a regional 240 kV network connecting the main load centres with regional generation sources. The region also contains a small number of 69 kV facilities, including ones located south of Lethbridge and within Banff National Park.

There are existing 240 kV lines extending from the Calgary area to Brooks and Lethbridge, and a 240 kV network delivering power from the Sheerness and Battle River coal-fired generation units south to the Brooks area. The region also includes parts of the approved Southern Alberta Transmission Reinforcement (SATR) project, consisting of several 240 kV circuits designed to collect geographically dispersed renewable generation sources and move power onto the bulk transmission network. In 2015, the double-circuit 240 kV line from Windy Flats (near Fort Macleod) to Foothills and a double-circuit 240 kV line from Whitla to Medicine Hat and on to Brooks were energized, enabling additional wind development capacity in the south. The recently energized Eastern Alberta Transmission Line, a 500 kV HVDC line, terminates near Brooks and is capable of moving electric power from the north to supply loads when generation in the south is low, and to the north when generation in the south is high.

Transmission project status

- Chapel Rock–to–Castle Rock Ridge Transmission Project–The project was originally approved for a 500/240 kV substation on the 500 kV Alberta–British Columbia intertie near the proposed Chapel Rock substation, with 240 kV lines to the existing Castle Rock Ridge substation. This project is being reconfigured, will be staged, and has been renamed as the Chapel Rock–Pincher Creek Area Transmission Development.
- The following three projects that were approved as part of the SATR will be cancelled:
  — Picture Butte–to–Etzikom Coulee (PBEC) Transmission Project
  — Goose Lake–to–Etzikom Coulee (GLEC) Transmission Project
  — Etzikom Coulee–to–Whitla (ECW) Transmission Project
- Cypress Substation Voltage Support will be cancelled as it is no longer required.

Transmission plans

There were three overloads identified in the South Region: two on the 138 kV loop east of Calgary in the Strathmore–Blackie area, and one on the 138 kV line north of Medicine Hat. There were no voltage violations identified in the South Planning Region.

The following developments are required to mitigate the identified constraints:

Development	Description
Alberta–British Columbia Intertie Restoration	Enhancements that include Bennett substation transformer upgrade, clearance mitigations on the 500 kV 1201L and reactive power support to restore the transfer capability of the Alberta–British Columbia intertie
Restore Chappice Lake–to–Cypress 138 kV Line	Restore the 138 kV line from Chappice Lake substation to Cypress substation to higher capacity

The Alberta–British Columbia Intertie Restoration is an ongoing development and has been reconfirmed in this plan.

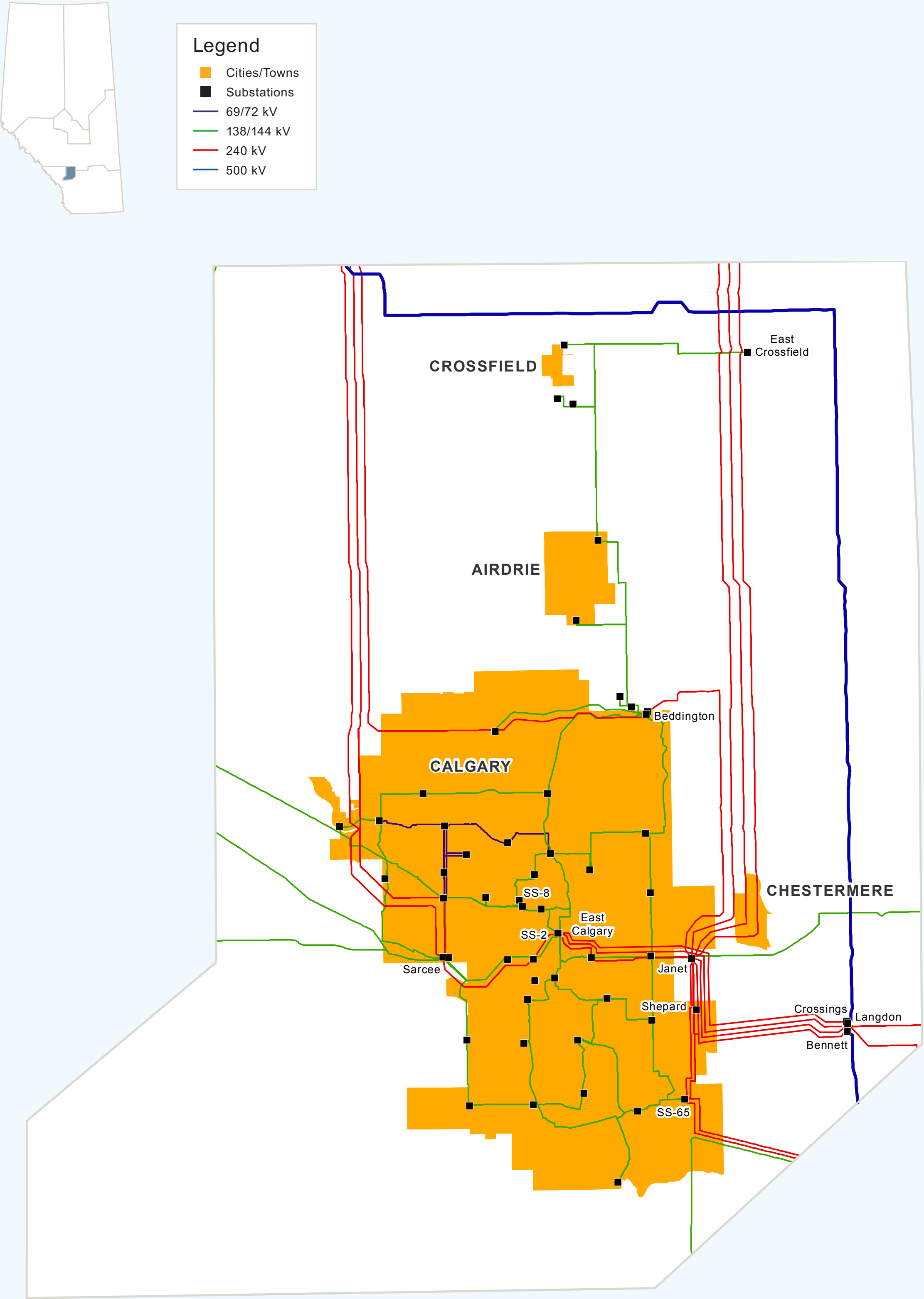
The development for the 138 kV east of Calgary to Strathmore–Blackie substation violations are covered in the Calgary Planning Region section below.

Renewables integration

In addition to the above developments, the renewables integration transmission plan confirms the need for the Chapel Rock–Pincher Creek Transmission Development to accommodate renewable energy integration in the southwest area. The construction timing for this project will depend on the pace at which renewable generation connects to the transmission system in the southwest area of the province. The AESO is working towards filing an application with the AUC to reflect the revised configuration and staging plans and milestones for the development.

CALGARY PLANNING REGION

Existing transmission system



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Calgary Planning Region

Overview and forecast

The Calgary Planning Region includes the city of Calgary, city of Airdrie and the surrounding area.

This region represents 15 per cent of provincial load. Load growth has averaged 0.7 per cent annually over the past 10 years. In the near term, Calgary's load is forecast to decline as a result of the economic downturn. Over the next 20 years however, Calgary load is forecast to grow at an average annual rate of 0.9 per cent, due to population growth and associated commercial and residential demand growth, offset by energy efficiency.

Calgary regional reference case load and generation forecast

	Existing (MW)	2022 (MW)
Load at non-coincident peak	1,737	1,691
Cogeneration	12	12
Combined-cycle	1,300	1,300
Simple-cycle	144	192

Existing transmission system

The existing transmission system in the Calgary Planning Region is designed to serve local loads and transfer power from major generation centres to Calgary and the surrounding area.

The regional 240 kV network is served by the 500 kV HVDC Western Alberta Transmission Line from the Edmonton–Wabamun Lake area and the six existing north-to-south 240 kV transmission lines that terminate near and in Calgary, one of the major transmission hubs on the grid. Calgary has five main 240 kV supply stations: Sarcee on the west side of the city, East Calgary in the south centre, Janet and SS-65 on the southeast side, and Beddington in the north. The underlying transmission system within the Calgary area consists of 138 kV and 69 kV circuits delivering power to load-serving substations.

The transmission system in and around Calgary was recently enhanced with the addition of 240 kV and 138 kV developments to integrate the Shepard Energy Centre generation facility, as well as preparing the system for additional renewable generation in the southwest area of the province.

In addition, the 500 kV Alberta–British Columbia intertie connects to the system near Langdon.

Transmission project status

- Downtown Calgary Transmission Development–a new 138 kV single circuit to interconnect ENMAX No. 2 and ENMAX No. 8 substations. The project NID is approved by the AUC and is expected to be in service in 2021.

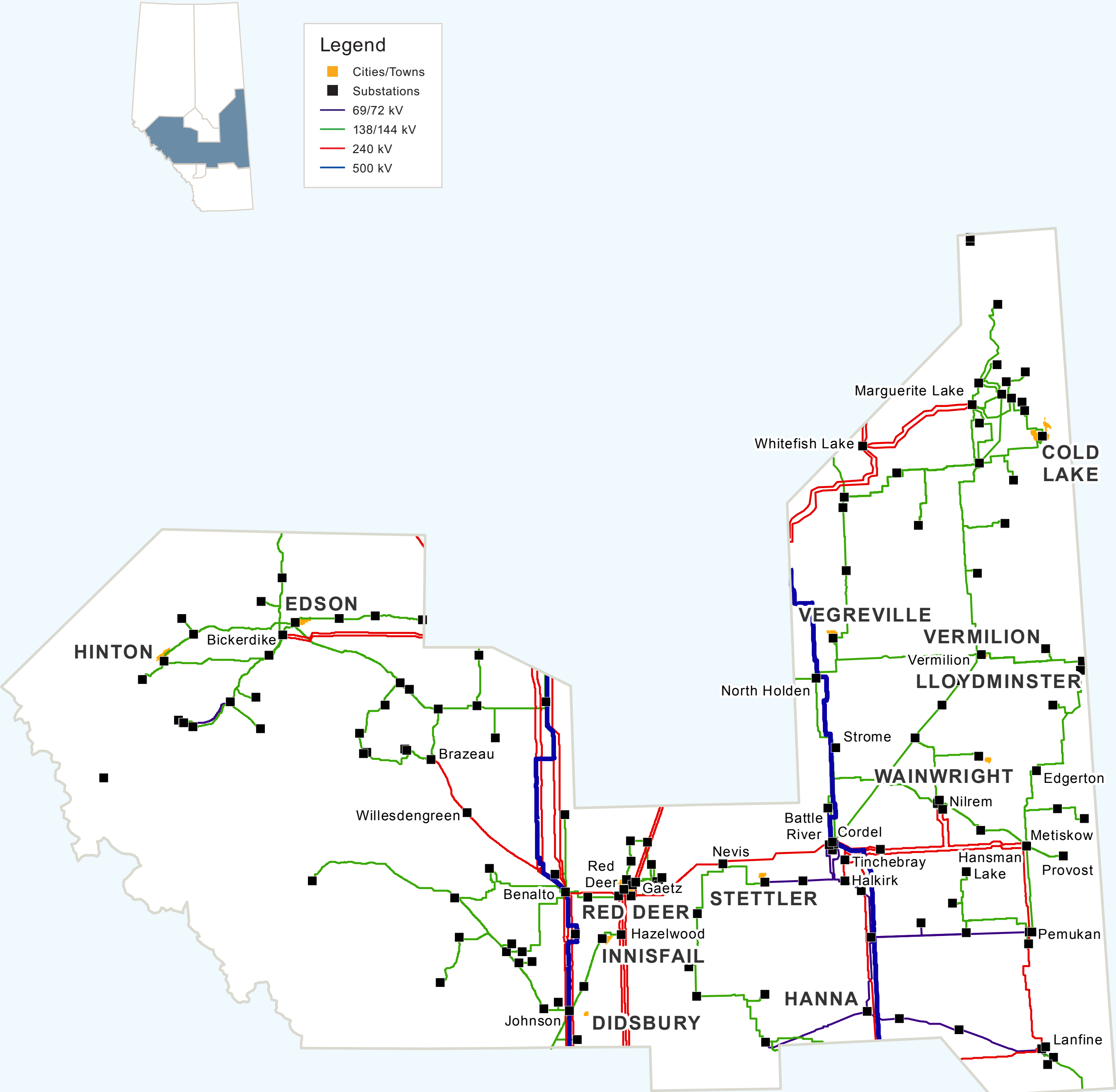
Transmission plans

The following developments were identified to mitigate thermal overloads and short-circuit capability constraints:

Development	Description
Janet–East Chestermere 138 kV enhancement	Build a new 138 kV circuit between the existing Janet and East Chestermere substations
Calgary short-circuit level mitigation	Substation equipment additions and reconfigurations to mitigate short-circuit levels in the downtown Calgary area

CENTRAL PLANNING REGION

Existing transmission system



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Central Planning Region

Overview and forecast

The Central Planning Region spans the province east-to-west between the borders of British Columbia and Saskatchewan, and north-to-south between Cold Lake and Calgary, excluding the Edmonton area. Its major population centres are the cities of Red Deer and Lloydminster. The region also includes Camrose and Wetaskiwin in the east, and Edson and Hinton in the west.

The region currently represents 19 per cent of Alberta's load. Load growth has averaged 2.0 per cent annually over the last 10 years. In the near term, load growth in the region is forecast to decline due to the economic downturn, although some areas are forecast to increase during this period. Over the next 20 years, load is forecast to grow at the average rate of 0.7 per cent annually. The forecast load growth is less than historical growth in response to revised economic growth and energy efficiency expectations. Oilsands sites in the Cold Lake area are forecast to expand, but no new large greenfield oilsands developments are assumed in the load forecast, due to an updated outlook for Alberta's oil and gas sector.

Central regional reference case load and generation forecast

	Existing (MW)	2022 (MW)
Load at non-coincident peak	2,216	2,207
Coal-fired	674	540
Cogeneration	1,145	1,174
Hydro	485	485
Wind	260	561
Other	61	61

Existing transmission system

The Central Planning Region transmission system includes six 240 kV lines that function as the system backbone between the Edmonton Planning Region and the Calgary Planning Region. These lines run through the Central Planning Region and are connected to two source substations located near the city of Red Deer that supply local load.

Local area load is supplied by looped 138 kV and 144 kV systems. The transmission system includes 72 kV lines and substations serving load in the eastern part of the Central Planning Region. The recent 240 kV development in the Hanna area serves local regional load and provides transmission access for renewable generation.

The Cold Lake area is served by a 240 kV double-circuit line and local 144 kV network to support oilsands and industrial operations. The western part of this planning region is primarily supplied by 138 kV lines serving load. The Brazeau hydroelectric plant is also located in this region.

In addition to the facilities mentioned above, the two new 500 kV north-south HVDC transmission lines carry power between North and South Planning Regions.

Transmission project status

- Hanna Region Transmission Development–The project was originally approved in two phases. Phase 1 has been completed. The need for Phase 2, which covers 240 kV and 144 kV lines along with transformers and capacitor banks in the Hanna area, is currently on hold and under review.

Transmission plans

The following development was identified to serve increasing load and generation in the area:

Development	Description
Provost–to–Edgerton and Nilrem–to–Vermilion (PENV) Transmission Development	Multiple enhancements (built to 240 kV standard but energized at 138/144 kV) in the central east area to serve increasing load and generation

PENV will address the load-serving needs in the central east area. In addition, this project will provide generation collection capability and extend the 240 kV transmission system to Vermilion and Edgerton for renewable integration. With the planned PENV development assumed energized by 2021, the only overload identified in the Central Planning Region in 2022 was on the 138 kV line from North Holden to Bardo (near Edmonton). This overload occurs under an outage of the 240 kV line that transfers out surplus power, including renewable generation from the central east area to Red Deer. There were no voltage violations identified in the Central Planning Region. For the near term, the overload can be mitigated by opening the North Holden–to–Bardo 138 kV line during an outage of the 240 kV line to Red Deer. As such, beyond the planned PENV development, no additional transmission facilities are required in the near term. In the longer term, the central east transfer-out reinforcement will address this constraint among others.

Renewables integration

The Central East Transfer-out Transmission Development is needed to increase the transfer-out capability for surplus renewable energy integration capacity, as discussed in the transmission system assessment for renewable generation integration section on page 34. The timing and staging of this development will depend on the pace at which renewable generation connects to the transmission system in the central east area. The AESO plans to file a Needs Identification Document with the AUC in order to be prepared to initiate construction of the developments once system renewable integration capacity is reached. This project will be staged, taking into account coal-fired generation retirements and replacements, and each stage will be connected to construction milestones.

Northwest Planning Region

Overview and forecast

The Northwest Planning Region occupies the northwest quarter of the province. Its largest population centre is the city of Grande Prairie.

This region has a relatively high amount of industrial load. As a result, regional load accounts for approximately 11 per cent of the total provincial load. Load growth over the past decade has averaged 0.7 per cent annually, and is expected to continue to grow at a rate of 0.7 per cent over the next 20 years.

The AESO expects future load growth in the area to be driven by growth in non-oilsands unconventional oil and gas projects and associated growth in the city of Grand Prairie.

Northwest regional reference case load and generation forecast

	Existing (MW)	2022 (MW)
Load at non-coincident peak	1,221	1,336
Coal-fired	144	0
Cogeneration	147	147
Combined-cycle gas	73	73
Simple-cycle gas	442	490
Wind	0	100
Other	227	227

Existing transmission system

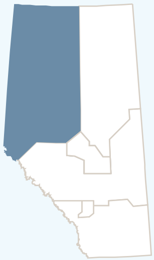
The Northwest Planning Region is primarily served by a 240 kV network that moves power into the region from generation in the Wabamun Lake area, and from cogeneration in the northeast. Local load is supplied via 144 kV networks from the Louise Creek, Little Smoky, Wesley Creek, Sagitawah, Bickerdike, Mitsue, North Barrhead and Wabamun 240 kV substations. A portion of the load in the Swan Hills, High Prairie and Peace River areas is served by 69/72 kV networks.

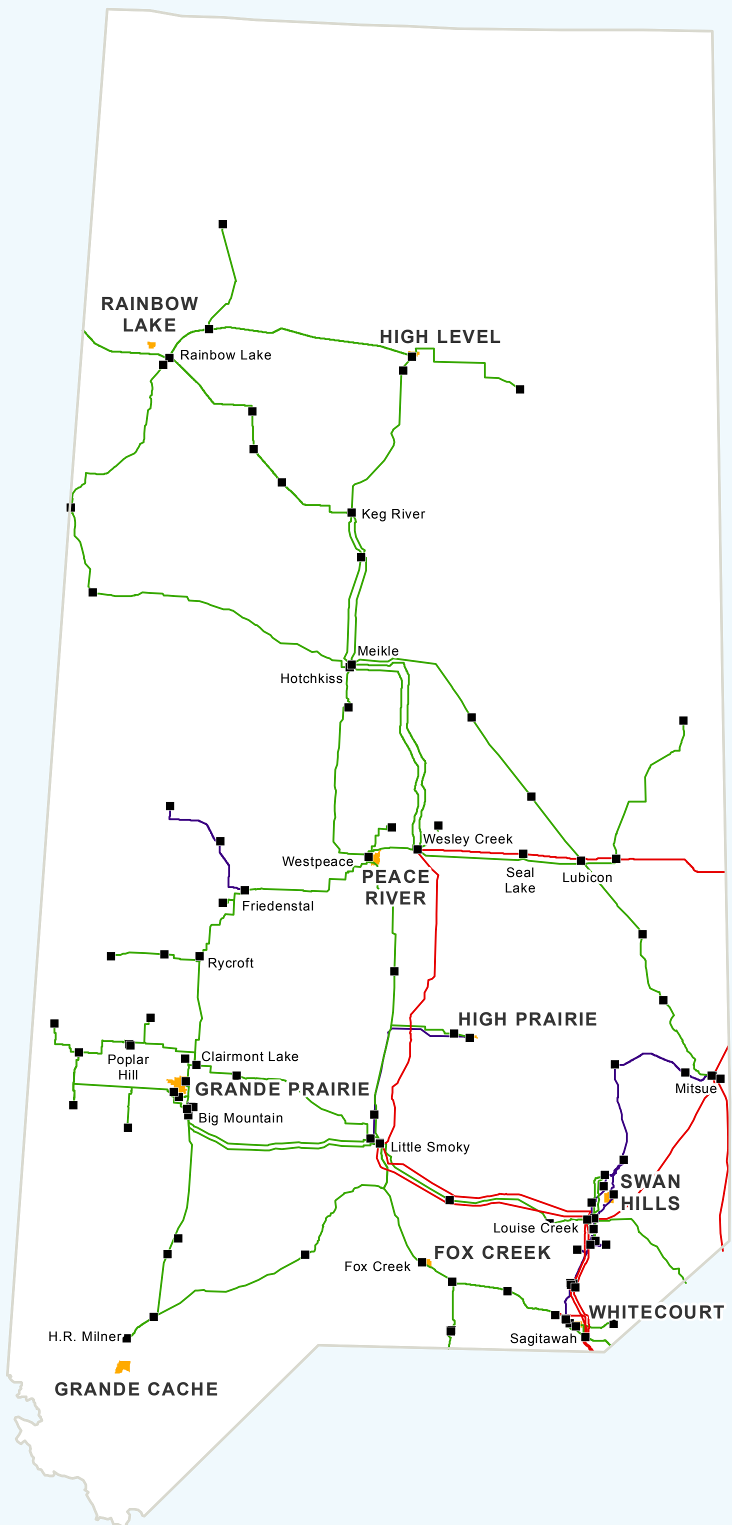
Transmission project status

Currently, there are no major projects approved or under construction in the Northwest Planning Region.

NORTHWEST PLANNING REGION

Existing transmission system





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Transmission plans

Several 138/144 kV lines in the Whitecourt–to–Fox Creek area could experience overloads for an outage to the main 240 kV lines that supply the northwest from Edmonton and the northeast. In addition, the transformers at Little Smoky are loaded to near capacity and each could overload during an outage of the other. Voltage collapse is observed in the Grande Prairie area under certain conditions.

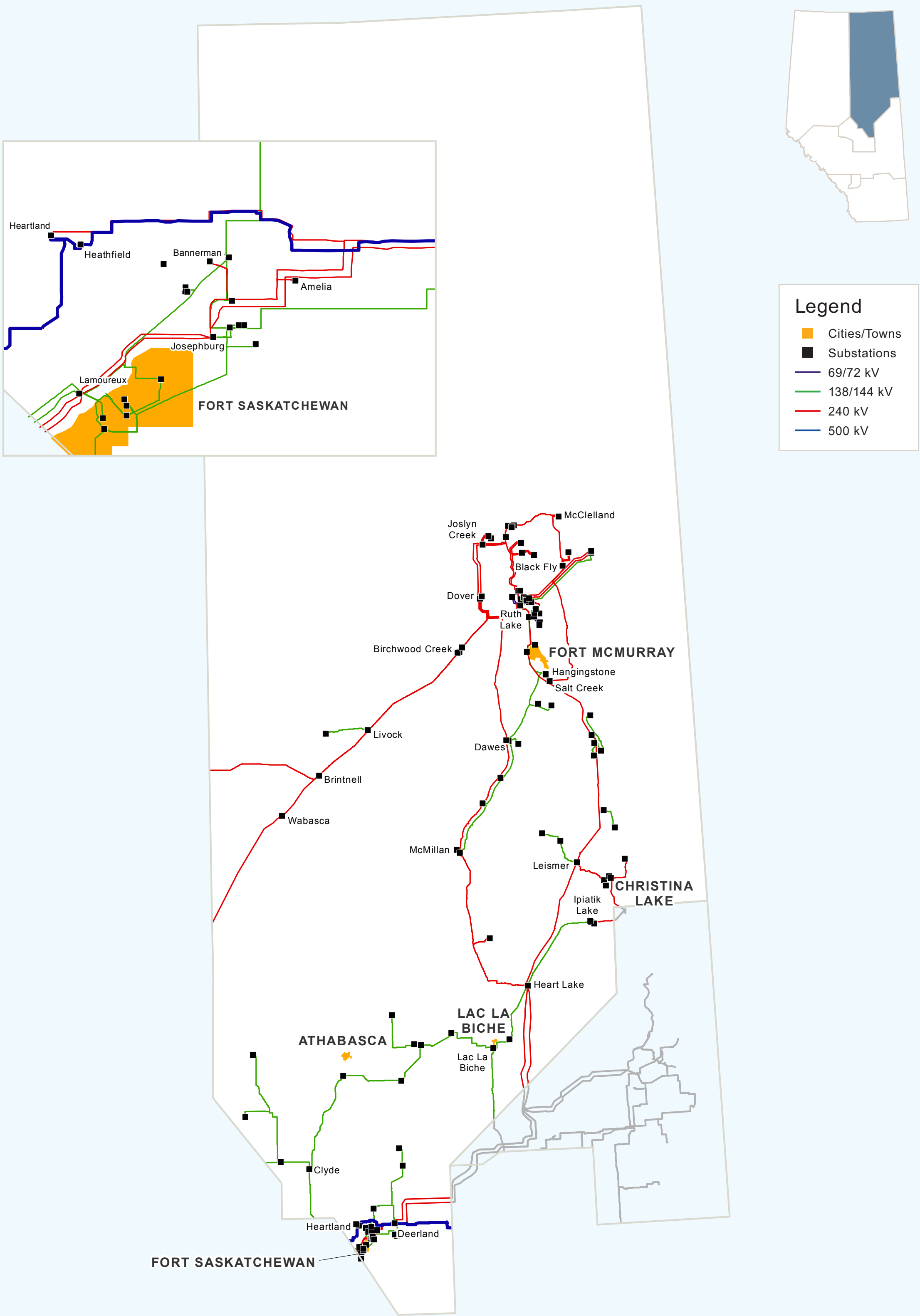
The following developments are required to mitigate the identified violations:

Development	Description
Fox Creek reinforcement	Build a 240/144 kV substation near Fox Creek Build a new single-circuit 240 kV line from Little Smoky substation to new Fox Creek substation to Bickerdike substation
Little Smoky substation – increase transformer capacity	Replace existing 240/144 kV transformers with higher capacity units (or add a third unit) at Little Smoky substation
Grande Prairie supply	Build a new 240/144 kV substation on 9L11 between Wesley Creek and Little Smoky substations Build a new single-circuit 144 kV line from new substation on 9L11 to Rycroft substation
Rycroft voltage support	Add voltage support equipment in the Rycroft area
Grande Prairie loop	Build a new 144 kV line from Clairmont Lake substation to Poplar Hill substation

Since most of the identified transmission constraints in the Northwest Planning Region are driven by transfer-in requirements to serve load, the required developments are dependent on load and generation developments. There may be opportunities to reduce the required transmission development depending on future and existing generation utilization. Depending on future generation developments in this region, some of the transfer-in driven needs may shift to transfer-out needs according to new generation capacity additions and their location. The AESO will continue to monitor generation development interest in the area and transmission must-run services may continue to be utilized as the AESO adjusts plans accordingly.

NORTHEAST PLANNING REGION

Existing transmission system



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Northeast Planning Region

Overview and forecast

The Northeast Planning Region is sparsely populated, with most residents located in the Fort McMurray area of the Regional Municipality of Wood Buffalo.

Growth in this region is driven by the oilsands industry, and the need for transmission development is directly linked to future oilsands developments. Oilsands load accounts for approximately 20 per cent of all electricity consumed in Alberta. Over the past 10 years, load in this region has shown the strongest growth of any region at an average annual rate of 4.5 per cent. Northeast Planning Region load is forecast to grow at 1.2 per cent annually over the next 20 years. A lowered oil price outlook has consequently decreased expectations for oilsands load growth.

In the next 10 years, it is expected that some baseload demand in the northeast will be met by oilsands-related cogeneration additions.

Northeast regional reference case load and generation forecast

	Existing (MW)	2022 (MW)
Load at non-coincident peak	2,897	3,301
Co-generation	3,487	3,532
Other	149	149

Existing transmission system

The Northeast Planning Region transmission system consists of a 240 kV network primarily serving large industrial operations in the Fort McMurray and Fort Saskatchewan areas. In addition, local 138/144 kV networks serve load across the planning region. Several 144 kV networks connect load and behind-the-fence facilities in the Fort McMurray area.

Transmission project status

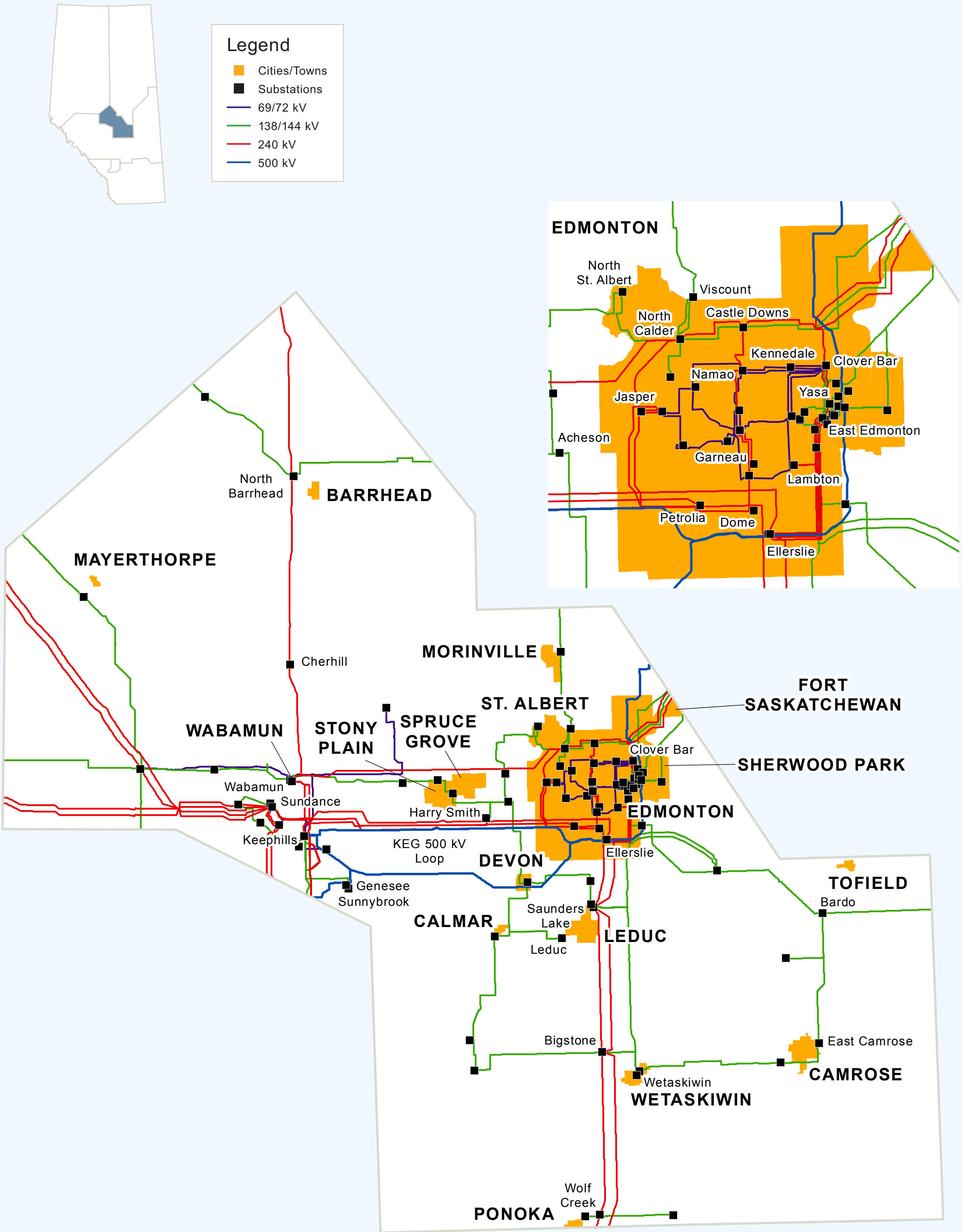
- Fort McMurray West 500 kV Transmission Project–a new 500 kV alternating current (AC) transmission line between the Sunnybrook substation in Wabamun Lake area and at the new Thickwood Hills substation southwest of Fort McMurray. The project is currently under construction and expected to be in service before 2020.
- Fort McMurray East 500 kV Transmission Project–a new 500 kV AC transmission line between the Heartland substation (northeast of Edmonton) and Thickwood Hills substation (southwest of Fort McMurray). The project is currently on hold due to lower growth forecast in the northeast region.
- Beamer–Shell 138 kV line Rebuild–approved by the AUC; however, the construction milestone which could be triggered by either load or generation development in the area has not yet been met.
- Northwest of Fort McMurray Area Transmission System Development–this 240 kV transmission development has been filed with the AUC for cancellation as the anticipated oil sands developments in the area did not materialize.

Transmission plans

With the Fort McMurray West 500 kV Transmission Project in service before 2020, no system overloads or voltage violations were observed in the near term. Therefore, no additional transmission developments were identified.

EDMONTON PLANNING REGION

Existing transmission system



View Single Line Diagrams (SLDs): ***www.aeso.ca/LTP***

Edmonton Planning Region

Overview and forecast

The Edmonton Planning Region includes the communities of Edmonton, St. Albert, Sherwood Park, Spruce Grove, Stony Plain, Leduc, Camrose plus the Wabamun Lake area.

This region represents 19 per cent of Alberta's load, which has grown at an average annual rate of 0.9 per cent over the last decade. Over the next 20 years, load is forecast to grow at a rate of 0.8 per cent annually. The bulk of this growth is expected in the Edmonton area, driven primarily by residential, commercial and industrial development. Like Calgary, load growth in Edmonton is expected to be partially offset by increases in energy efficiency.

The Edmonton Planning Region, particularly the Wabamun Lake area, is a central generation hub in the province with approximately 4,700 MW of coal-fired generation. It is expected that as coal plants retire, they will be replaced with coal-to-gas conversions and combined-cycle, gas-fired generation plants, utilizing existing transmission and natural gas infrastructure in the region.

Edmonton regional reference case load and generation forecast

	Existing (MW)	2022 (MW)
Load at non-coincident peak	2,171	2,372
Coal-fired	4,676	2,519
Gas-fired (converted from coal-fired)	0	1,581
Cogeneration	49	49
Simple-cycle gas	250	250

Existing transmission system

Containing a large concentration of generation sources, the Edmonton Planning Region is the central transmission hub for the provincial network, connecting the north and south with transmission lines operating at 500 kV and 240 kV. These bulk transmission lines transfer power from the Edmonton Planning Region to the rest of the province.

Local load in this region is served by a transmission network consisting of 500 kV, 240 kV, 138 kV and 69/72 kV lines. A 500 kV loop between Wabamun and Edmonton feeds power from coal-fired generating plants in Wabamun to the southeast corner of the city. A 72 kV system in Edmonton is dedicated to serving load within the city. This 72 kV system is currently being evaluated by the transmission facility owner, and transmission upgrades will be identified upon completion of the assessment. The 138 kV system feeds load in the areas outside of Edmonton as well as the heavy industrial area to the east.

Transmission project status

- Fort McMurray West 500 kV Transmission project — this project is connected to the Wabamun area within the Edmonton region. See the Northeast Planning Region section on page 49 for more details.

Transmission plans

There are several areas in and around Edmonton where overloads were observed on the 138 kV and 72 kV systems. This includes the northeast area of the city, where overloads are observed in the Hardisty–Kennedale area, in the east Edmonton industrial area, near the University of

Alberta (Garneau area), around the city of St. Albert and the Acheson industrial area, and north of Wabamun. No voltage violations were observed in the Edmonton area.

The following developments are required to mitigate the identified overloads:

Development	Description
Yasa– to– East Edmonton – 138kV circuit	Build a 138 kV circuit between the Yasa 286S and E Edmonton 38S substations
East Edmonton – transformer capacity increase	Replace or add new transformers at the E Edmonton 38S substation
Acheson to North St. Albert – 138 kV circuit	Build a new 138 kV circuit from the Acheson 305S substation to North St. Albert 99S substation
City of Edmonton 72 kV upgrades	Build a new 240/72 kV transformer at Castle Downs substation and a new 240/72 kV Blatchford substation near Namao Build a new 72 kV circuit from Castle Downs substation to Kennedale substation, a new 72 kV circuit from Namao substation to Kennedale substation and a new 72 kV circuit from the new Blatchford substation to Namao substation Discontinue use of 72CK12 and 72CK13 from Clover Bar substation to Kennedale substation Upgrade 72 kV circuit between Clover Bar–Hardisty substations and Garneau–Rossdale substations
North Calder– to– Viscount–rebuild of 138 kV line	Rebuild 898L from North Calder substation to Viscount substation

The plans for the Edmonton area are subject to change as the transmission facility owner (TFO) further develops a plan to replace much of its aging 72 kV transmission cables.

Near-term Development Summary

The following provides a summary of the near-term developments for all regions.

Development	Planning Region	Driver	In-Service Date	Scenario
Alberta–British Columbia Intertie Restoration	South	Intertie	2021	Under development
Restore Chappice Lake–Cypress 138 kV line	South	Generation	2022	Proposed development
Janet to East Chestermere – 138 kV enhancement	Calgary	Load	2022	Proposed development
Calgary short-circuit level mitigation	Calgary	Load / Generation	2022	Proposed development
PENV development	Central	Load / Generation	2021	Filed with AUC
Fox Creek reinforcement	Northwest	Load / Transfer-in	2022	Proposed development
Little Smoky substation – increase transformer capacity	Northwest	Load	2022	Proposed development
Grande Prairie supply	Northwest	Load / Transfer-in	2022	Proposed development
Rycroft voltage support	Northwest	Load	2020	Filed with AUC
Grande Prairie loop	Northwest	Load	2022	Proposed development
Yasa–to–East Edmonton – 138 kV circuit	Edmonton	Load	2022	Proposed development
East Edmonton – transformer capacity increase	Edmonton	Load	2022	Proposed development
Acheson–to–North St. Albert – 138 kV circuit	Edmonton	Load	2022	Proposed development
City of Edmonton – 72 kV upgrades	Edmonton	Load	2022	Proposed development
North Calder–to–Viscount – 138 kV rebuild	Edmonton	Load	2022	Proposed development

2017 Telecommunication Long-term Plan

The utility telecommunication network represents a key component of Alberta's transmission system. For the full details of the *2017 Telecommunication Long-term Plan* please refer to the AESO website *www.aeso.ca/LTP*

The utility telecommunication network carries critical telecommunication services used to protect, monitor and control the transmission system. It helps to quickly isolate faulted elements to maintain system stability, monitor transmission network integrity, protect equipment from unnecessary damage, and allows system operators to respond to changes and take corrective action as needed. Outages on the utility telecommunication network can require outages on the transmission system. These critical telecommunication services require the telecommunication network to be highly reliable and have appropriate capacity. In general, telecommunication costs represent one to five per cent of a transmission system upgrade or expansion.

The following are key benefits of the utility telecommunication network:

- Enables coordinated monitoring, control and operation of the transmission system.
- Enables larger power flows on transmission lines by facilitating faster fault-clearing times.
- Enables the connection of additional and diverse generation on existing transmission lines.
- Enables the connection of additional load on existing transmission lines.
- Provides emergency voice and data telecommunication for effective power system restoration.

The utility telecommunication network is a private network owned and operated by transmission facility owners (TFOs). Utility telecommunications =need to be highly reliable, available and functional under all operating conditions, including during severe operating conditions.

Technology and system evolution affect the utility telecommunication network. The following technological trends are and will continue affecting the network:

- Shift towards packet-based telecommunication equipment.
- Distributed energy resource (DER) growth.
- Distribution system applications that benefit the overall electrical system.
- Further leveraging of telecommunications to optimize transmission system usage.
- Utilization of the utility telecommunication network by market participants to provide required data to the AESO.

The utility telecommunication network is planned in coordination with the AESO and TFOs. A telecommunication work group is in place with the major TFOs (AltaLink, ATCO, ENMAX and EPCOR) and distribution facility owner (Fortis Alberta) in the province. As the operators and primary planners of their utility telecommunication networks, the work group supports the AESO in creation of the wider *2017 Telecommunication Long-term Plan*. The AESO's role in telecommunication planning is, at the provincial level, to lead coordinated planning between the utilities, provide long-term direction and identify inter-organizational opportunities.

In developing the *2017 Telecommunication Long-term Plan*, the AESO evaluated the current and future needs and drivers for the utility telecommunication network. The AESO helped identify telecommunication needs, and the work of the AESO's DER work group was followed in considering the future needs of the network. The *2017 Telecommunication Long-term Plan* is developed to align with long-term transmission planning, which is a major driver of new telecommunication development and opportunities.

In planning the utility telecommunication network, critical and core services remain the primary need drivers. Other services can be considered based on their benefit to the system.

The following are considered to be the critical and core telecommunication services:

- Teleprotection
- Supervisory control and data acquisition
- Inter-control centre communication protocol
- Voice communications
- Mobile land radio communications

Projects in the *2017 Telecommunication Long-term Plan* have been selected to significantly reduce both planned and unplanned outages on the telecommunication network, and therefore improve the overall reliability and availability of the transmission system. Particular focus is placed on improvements to the 500 kV and 240 kV transmission systems. As standard process, individual business cases and justification documents are still required to support execution and determine the required timing of proposed telecommunication projects.

The *2017 Telecommunication Long-term Plan* lists key projects for the near-term (five-year) and medium-term (10-year) time periods. When applicable, project alternatives are also outlined. The selected projects follow the outlined planning guidelines, and where possible, leverage existing telecommunication infrastructure.

The *2017 Telecommunication Long-term Plan* outlines planning guidelines for the following:

- Shift towards packet-based telecommunication equipment.
- Distributed energy resource (DER) growth.
- Distribution system applications that benefit the overall electrical system.
- Further leveraging of telecommunications to optimize transmission system usage.
- Utilization of the utility telecommunication network by market participants to provide required data to the AESO.

The *2017 Telecommunication Long-term Plan* outlines planning guidelines for the following:

- Secondary paths (network topology)
- Bandwidth capacity
- Fibre deployment
- Microwave radio deployment

Other telecommunication initiatives are also specified that deal with voice and data communications between utility control and operation centres, voice communications to key generators, DER communications, mobile radio system upgrades and emergency restoration planning.

Of these other telecommunication initiatives, DER communication is the least defined, with several telecommunication options. The telecommunication requirements for DER are still to be determined, and their influence on the distribution and transmission systems is being evaluated.

LONGER-TERM PLANS

The 2017 LTO identified seven scenarios that represent differing generation assumptions regarding the future of electricity supply in Alberta. Of the seven, five were studied to determine the potential effects on the transmission system. The two scenarios from the LTO that were not studied were the High Coal-to-gas Conversion and the Low Load Growth Scenario. The High Coal-to-gas Conversion Scenario will have generation dispatches that are generally similar as the Reference Case Scenario which includes partial coal-to-gas conversion assumptions, particularly in the longer term, and thus was not included in the transmission assessment. The Low Load Growth Scenario was not studied as it was not expected to have a major influence on identified transmission enhancements due to identified load-driven enhancement being captured in the near-term assessments. The longer term transmission developments will be primarily influenced by coal-fired generation retirement and the pace/magnitude at which renewable generation is added to the interconnected electric system.

The five scenarios examined are:

- Reference Case Scenario
- No Coal-to-gas Conversion Scenario
- New Large-hydro Generation Scenario
- Western Integration Scenario
- High Cogeneration Scenario

The load forecast used for all scenarios was the 2017 LTO mid-growth forecast, which anticipates a growth rate of approximately 0.9 per cent annually for the next 20 years.

Reference Case Scenario

The 2017 LTO Reference Case Scenario is consistent with recent information and announcements pertaining to Alberta's electricity industry. However, the AESO remains neutral and does not take a position on the likelihood of one scenario occurring over another. The following are the generation changes that comprise the Reference Case Scenario:

- Coal retirement:
  - H.R. Milner, Sundance 1 and 2 and Battle River Unit 3 (900 MW) retire before 2022
  - Sundance 3–6 and Keephills 1 and 2 (2,400 MW) convert to gas-fired thermal generation between 2021 and 2023
  - Remaining coal units (3,000 MW) retire between 2025 and 2030
- Renewable generation:
  - Wind–5,000 MW by 2030
  - Solar–500 MW by 2030, plus 500 MW post-2030
  - Hydro–350 MW by 2030
- Intertie: Alberta–British Columbia intertie capacity restored to original path rating of 1,200 MW import and 1,000 MW export.
- Firm gas (combined-cycle and simple-cycle) to meet load plus reserve, primarily on brownfield sites.
- Cogeneration: projects under construction, plus 400 MW by 2037.

South Planning Region and Calgary Planning Region

Under high renewable generation output conditions, power is forced towards and through the city of Calgary, resulting in overloads on 240 kV lines on the east and south sides of the city. Also, an outage of the 500 kV HVDC Eastern Alberta Transmission Line (EATL) under high south-to-north flows will result in increased power flowing toward and through Calgary, causing potential overload conditions. Overloads also occur in the Brooks and Medicine Hat areas and north of Lethbridge. These overloads occur as early as 2027. However, there are no overloads observed for low renewable output conditions.

The overloads in and around Calgary are partly due to the dispatch of combined-cycle generation within and south of Calgary. With the assumed conversion of Sundance 3–6 and Keephills 1 and 2 to gas-fired thermal plants, the efficiency is much lower than combined-cycle plants. Thus, combined-cycle generators in the south (Shepard Energy Centre area and a new plant near the Foothills substation), which have a much higher efficiency, are dispatched ahead of the converted plants.

Studies show that an outage of one of the 240 kV lines from Cassils substation to Newell substation will overload the other. This is due to the overloaded line having a rating of only 500 MVA, whereas the other line is rated at 1,000 MVA. This is a previously identified constraint and a remedial action scheme (RAS) is in place that will reduce the flow on EATL to reduce the loading under the noted outage condition. This RAS changes flows on the 500 kV HVDC lines and does not interrupt generation or load.

The following developments are required to mitigate the identified overloads:

Development	Description	In-Service Date
Chapel Rock–Pincher Creek Transmission Development	Add a new 500/240kV substation at Chapel Rock and two 240 kV lines from Chapel Rock to the Pincher Creek area	Post-2022 (Milestone Based)
Rebuild SE 138 kV circuits to higher capacity	Rebuild 138 kV lines from Bowmanton substation to Suffield substation, and from Suffield substation to Tilley substation Restore the 138 kV line from Chappice Lake substation to Cypress substation to higher capacity	Post-2022

As discussed earlier on page 33, the Chapel Rock–Pincher Creek Transmission Development has been reconfirmed in this plan and will be staged with milestones to provide flexibility in development, and to align with the pace of renewable generation additions in the southwest region.

Restoration of the 138 kV line from Chappice Lake substation to Cypress substation was also identified in the near-term horizon plans.

The local 138 kV transmission network within the city of Calgary may require additional upgrades to meet the forecast load growth and future generation additions including DER within and around Calgary. The timing and nature of these reinforcements will depend on how load and generation additions develop in the longer term, which could be different from the current and historical localized load growth pattern. These localized developments will be captured as part of the AESO's ongoing planning work and subsequent LTP updates.

Central Planning Region

As with the South and Calgary planning regions, high renewable generation results in overloads for various contingencies in this planning region. The total amount of renewable generation forecast to be added in the Central Planning Region is about 1,260 MW by 2027 and 1,960 MW by 2032. However, actual renewable generation additions will depend on actual projects proceeding to connect in the region. An outage of the 240 kV line from the central east area to Red Deer causes overloads on underlying 138/144 kV systems and the 240/144 kV transformer at Nevis substation. This is a known transfer-out capability limitation that will require mitigation as coal units are replaced and new renewable generation is added in the Central Planning Region and southeast areas of the province.

There are overloads observed on the 138 kV lines in the Battle River coal-fired generation area that could occur under low renewable generation output conditions. These overloads are the result of lack of conventional generation due to retirement of the coal-fired Battle River generation facility.

In addition, overloads were also seen on the 240 kV lines between the Oakland substation and the Anderson substation. The rating of the two lines is constrained by equipment limits at the substations, which could be increased to alleviate the identified constraint.

The following projects are required to mitigate the identified overloads:

Development	Description	In-Service Date
Tinchebray–to–Gaetz 240 kV	New single-circuit 240 kV line from Tinchebray substation to Gaetz substation	Post-2022 (2027) (Milestone Based)
Cordel–to–Red Deer–rebuild 240 kV to higher capacity	Rebuild the 240 kV line from Cordel substation to Nevis substation, and from Nevis substation to Red Deer substation to higher capacity	2032 or later (Milestone Based)

As an alternative to the rebuild of the 240 kV from Cordel substation to Red Deer substation due to a potential extended outage limitation, a third 240 kV circuit could be built from Tinchebray substation to the Red Deer area.

It is possible that transmission reinforcements between the central east and Red Deer areas could be required before 2027, depending on renewable generation developments and the coal retirement and replacement schedule in the area. Therefore, this development, including the Tinchebray–to–Gaetz line and the rebuild of the Cordel–to–Red Deer line or a third 240 kV line, will be staged with milestones to allow flexibility in development to align with pace of renewable generation additions.

Edmonton Planning Region

Lower generation in the Edmonton area, due to the conversion of coal to gas-fired units coupled with southern renewable generation flowing into the area on the 500 kV HVDC lines, could result in overloads south of Edmonton. Due to the lower efficiency of the converted coal units compared to new combined-cycle units coupled with surplus generation flowing into the area, more power is injected at the Ellerslie 500/240kV substation. This may cause overloads on the 240 kV system in the area.

A number of transmission development options were identified to address potential overloads in the Edmonton region. The transmission options could include either:

- Build a 500 kV line between Keephills substation and Sundance substation so that more power flows toward Sundance and on to north Edmonton to relieve the loading at Ellerslie.
- Add a 240 kV circuit between Ellerslie substation and Petrolia substation.
- Reconfiguration of the 240 kV system between and around the Sundance and Keephills generation plants.

The AESO will continue to monitor generation development in this region, and will be recommending the proper transmission enhancement, including any potential network reconfigurations, as generation development plans become more certain in the Lake Wabamun area.

In addition to the 240 kV overloads in south Edmonton, an overload occurs on the 138 kV line from North Calder substation to Cardiff substation for an outage of the 240 kV line from Sundance substation to Cherhill substation. This overload has been observed in previous long-term transmission plans and is not related to anticipated generation developments in the area.

The following development is required to mitigate the identified overload:

Development	Description	In-Service Date
Rebuild North Calder–to–Cardiff	Rebuild the 138 kV lines from North Calder substation to Viscount substation and from Viscount substation to Cardiff substation	Post-2022 (2027)

Northwest Planning Region

Several 240 kV lines from Fort McMurray and Lake Wabamun transfer power to the Northwest region. Underlying these circuits are 138/144 kV systems, including through the Fox Creek area. Loss of one of the 240 kV circuits will impose additional loading on the Fox Creek system. This thermal violation is influenced by the retirement of the H.R. Milner coal-fired unit near Grande Cache and reduction of economic generation output in the Grand Prairie area under high renewable output conditions.

The 144 kV line from the Wesley Creek substation to Peace River substation and on to Friedenstal substation becomes overloaded, for an outage of the 240 kV line from Wesley Creek substation to Little Smoky substation. This overload occurs when new generation comes into service and is connected to Wesley Creek, the nearest 240 kV bus. Loss of the 240 kV line will force power flow from the new plant towards Grande Prairie through the 144 kV lines, overloading them. A new supply to the Grande Prairie area will alleviate these potential overloads.

The 240/144 kV transformers at Little Smoky substation are heavily loaded under normal operating conditions (more than 75 per cent of their rating). Loss of either unit will overload the other.

The following transmission developments are required to mitigate the identified overloads:

Development	Description	In-Service Date
Fox Creek reinforcement	Build a new 240/144 kV substation near Fox Creek, add a single-circuit 240 kV line from Little Smoky substation to new Fox Creek substation to Bickerdike substation	2022
Increase transformer capacity at Little Smoky	Replace existing 240/144 kV transformers with larger units	2022
Grande Prairie supply	Build a new 240/144 kV substation on the 240 kV line between Wesley Creek and Little Smoky substations and a 144 kV line from new substation to Rycroft substation	2022

The above developments were also identified in the near-term horizon plans that assessed the system at a more detailed level. Therefore, the in-service dates are shown to be 2022 and will, as discussed previously, depend on future generation development plans in the area.

Northeast Planning Region

There were no effects to report in the Northeast Planning Region for the cases studied.

No Coal-to-gas Conversion Scenario

The No Coal-to-gas Conversion Scenario is intended to represent future generation changes, assuming that no coal-fired generation units are converted to gas-fired generation. The coal plants will instead be replaced with combined-cycle units, some of which will be located at or near the sites as well as other areas in the province. The following summarizes the assumptions, results and proposed enhancements of studies conducted for this scenario.

Transmission plan

The study results were very similar to those for the Reference Case Scenario and in consequence, the transmission plans for the two scenarios are the same. A comparison between the two scenarios is provided below.

South Planning Region and Calgary Planning Region

As with the Reference Case Scenario, overloads occur in the Brooks and Medicine Hat areas and north of Lethbridge due to wind generation additions. Overloads were also seen on 240 kV lines in the Calgary area, although not as severe and not as early as in the Reference Case Scenario.

In the Reference Case Scenario, the overloads in Calgary were partly driven by high renewable generation output but also by higher output from the Calgary area's combined-cycle plants. The Chapel Rock–Pincher Creek Transmission Development would mitigate the Calgary area overloads. In the No Coal-to-gas Conversion Scenario, the coal units in the Edmonton area are replaced with combined-cycle units that have a higher efficiency than gas-fired generation units, and are thereby dispatched along with the Calgary area combined-cycle plants, thus reducing the simultaneous output from the Calgary area units. This reduces the flows on the Calgary area transmission system from the combined-cycle units in that area, particularly during high renewable generation output conditions.

Given that the results for this scenario are similar to those of the Reference Case Scenario, the projects identified in that scenario are also required here.

Central Planning Region

The overloads in the Central Planning Region are driven primarily by renewable generation additions and not by coal-to-gas conversion. As a result, the proposed central east area enhancements for the No Coal-to-gas Conversion Scenario are the same as the Reference Case Scenario.

Edmonton Planning Region

As in the Reference Case Scenario, overloads on some of the 240 kV lines into south Edmonton occur due to renewable generation which flows toward Edmonton on the 500 kV HVDC lines, and the generation dispatch in the area. However, when the combined-cycle units are developed on the 240 kV system, these overloads are reduced.

Although the overload conditions are not as severe as in the Reference Case Scenario, the mitigation measures could be similar.

Northwest Planning Region

In the northwest, transmission constraints are driven by local area load and generation patterns that do not change between the two scenarios. As a result, the proposed northwest enhancements for this scenario are the same as in the Reference Case Scenario.

Northeast Planning Region

As in the Reference Case Scenario, no reliability violations are identified in the Northeast Planning Region.

New Large-hydro Generation Scenario

The New Large-hydro Generation Scenario represents the effect of future generation changes on the Alberta electric system when large hydroelectric generation (hydro) units come into service.

Generation forecast

Other than the addition of hydro generation plants, the generation forecast for the New Large-hydro Generation Scenario is the same as the Reference Case Scenario.

Hydro additions for this scenario include:

- 350 MW in the Northwest Planning Region (included in Reference Case Scenario)
- 170 MW in the Central Planning Region
- 1,000 MW (Slave River hydro project)

The first two projects are assumed to be in place by 2030. The Slave River Hydro Project is assumed to be in place sometime after 2030 due to the magnitude of this development. Given that the renewable generation target is 5,000 MW by 2030, and the Slave River Hydro Project is post-2030, it was assumed that the hydro additions would not displace other renewable generation sources.

Hydro generation is considered to be run-of-river and was dispatched according to historic water flow records. Run-of-river hydro generation is not typically dispatched outside the seasonal flows other than for emergencies, as there is insufficient storage to sustain higher dispatch levels. Dispatching lower than the seasonal flows will result in spilled energy.

Transmission plan

Hydro generation would not displace other renewable sources from a dispatch perspective, but would displace some gas-fired generation. As a result, the studies for this scenario, and consequently the transmission plans, were substantially the same as those for the Reference Case Scenario for all but the Central and Northeast planning regions. The following discusses the effects of hydro additions in those regions.

Central Planning Region

A new hydro facility in the central west area of the province is assumed to be located near the existing Brazeau plant and would connect to the existing Brazeau substation. This would increase the maximum generation at that location to 520 MW. The current transmission system in the Brazeau area is not sufficient to integrate this amount of generation, and a 240 kV development would be required. Furthermore, the existing 240 kV line from Brazeau to Benalto is currently rated at 333 Mega Volt Amperes (MVA) and could become overloaded with the addition of 170 MW of hydro. The above rating is due to an equipment limitation, whereas the conductor rating is 481 MW. Although the equipment limit could be removed, additional line restoration may be needed to integrate the additional output at the Brazeau hydro site. Thermal overloads were also observed on a local 138 kV line from Brazeau substation to Lodgepole substation.

The following development is required to mitigate the identified overloads:

Development	Description	In-Service Date
Brazeau area upgrades	Build a single-circuit 240 kV line from Brazeau substation to Benalto substation Rebuild 138 kV line from Brazeau substation to Lodgepole substation (line 202L) to a higher capacity Remove current transformer limitations and carry out needed line restoration and/or rebuilds to 481 MVA on 240 kV line from Brazeau substation to Willesden Green substation and replace existing 240/138 kV transformers at Brazeau substation with higher-capacity units	2030 (Aligns with hydro development timing)

The above transmission enhancements will accommodate up to 350 MW of additional generation connected to the Brazeau substation. All other constraints and transmission solutions identified for the Central Planning Region are the same as stated in the Reference Case Scenario.

Northeast Planning Region

Slave River hydro generation, with a capacity of 1,000 MW, is assumed to come into service after 2030. Two 500 kV single-circuit transmission lines of approximately 350 km each are required to connect the hydro units to the system at Thickwood Hills substation.

No reliability violations were observed in the Northeast Planning Region with the Slave River Hydro Project in service. The addition of the Fort McMurray West 500 kV line provides sufficient transmission capacity to move hydro generation to load centres in the south. Although the Fort McMurray East 500 kV line under this scenario could be delayed beyond the longer-term horizon, the Northeast system will be operated at marginal capability limits. Also, without Fort McMurray East an extended outage of the Fort McMurray West line could result in significant generation curtailment due to lack of transmission capacity needed to move energy from cogeneration facilities to the rest of the system under transmission outage conditions.

Pumped-hydro storage

TransAlta Corporation recently announced the development of pumped-hydro storage at its existing Brazeau hydro facility, and expects to begin stakeholder consultation in the near future. The project will expand the Brazeau hydro facility by up to 900 MW and store water for generation. During low demand, water will be pumped from a lower reservoir into an upper reservoir. Water flows from the upper reservoir down to the lower reservoir to generate power during high demand.

Currently, the existing Brazeau hydro generation is transferred into the grid via a single 240 kV circuit from Brazeau substation to Benalto substation (in the Red Deer area). There are also two 138 kV circuits which transfer generated power to the Drayton Valley area. Major overloads can occur on a local 138 kV line from Brazeau substation to Lodgepole substation (119 MVA capacity) under loss of the 240 kV circuit. Currently, a remedial action scheme is installed in the Brazeau substation which limits the generation dispatch of the hydro units to 210 MW for an outage of the 240 kV Brazeau–to–Benalto line. Moreover, the existing rating of the 240 kV circuit is 333 MVA, which is significantly lower than the total capacity of 1,250 MW with both existing generation and the pumped-hydro generation. Therefore adding 900 MW of pumped storage would require significant transmission system enhancements.

In order to integrate a 900 MW pumped-storage facility into the transmission system, two 500 kV circuits would be required from Brazeau to the 500 kV system in the Wabamun Lake area.

The first option would be to connect these two circuits to the Sundance substation. This plan would require that the existing 500 kV system in the Lake Wabamun area be expanded to Sundance as there is currently no 500 kV system at that location. Transferring the incremental power from Brazeau to the Edmonton area can also facilitate coal retirement in the Lake Wabamun area since it provides replacement generation and will support load in the Edmonton area. However, space and routing limitations will need to be considered in developing the needed transmission development plan under this scenario.

A second option is to connect these two 500 kV circuits to the existing 500 kV system in the Keephills substation area. This option, however, requires additional transmission enhancements in the Edmonton area. This option would force power to flow into Ellerslie substation (in south Edmonton), which is already anticipated to be congested under the Reference Case Scenario.

A third alternative would be construction of a new 500/240 kV substation between Sundance and Keephills substations. This new substation would include connecting to 240 kV lines from Sundance in an in/out arrangement. This third alternative plan will alleviate the concerns in the first and second proposed plans, which simultaneously expand the 500 kV system to Sundance and add a new transfer-out system in the Lake Wabamun area.

Conclusions

The addition of 1,500 MW of hydro to the Alberta system does not directly affect transmission development needs outside of the local areas.

- The Slave River Hydro Project will require two new 500 kV lines (each approximately 350 km in length) to connect that project to the grid at the Thickwood Hills substation.
- The addition of 170 MW at Brazeau requires a second 240 kV line to the Benalto substation, upgrade of the existing 240 kV line and a minor 138 kV upgrade near Brazeau.
- A 900 MW pumped-hydro storage facility at Brazeau would require two 500 kV lines to the Lake Wabamun area near Sundance substation, with a connection to the 240 kV lines between Sundance substation and Keephills substation.

Western Integration Scenario

The Western Integration Scenario represents the effect of changes on the Alberta electric system when a large intertie is added. This scenario stems from the Regional Electricity Cooperation and Strategic Infrastructure (RECSI) initiative. As such, and considering the long-lead timeline requirements, it only examines one year, 2032, and only addresses effects on the system caused by a new intertie.

Two candidates for the location of a new intertie between Alberta and British Columbia were assessed: a northern route and a southern route. The northern route would connect the Wesley Creek substation in northwestern Alberta with the Stonybrook substation at the Site C hydro-generation project on the Peace River in northern British Columbia. The southern route would parallel the existing intertie from the proposed Chapel Rock substation in southwestern Alberta to a substation in Cranbrook, British Columbia Each option requires system reinforcements in British Columbia and/or Alberta in addition to the intertie itself.

Generation forecast

All generation assumptions are the same as the Reference Case Scenario.

Transmission plan

Various export and import conditions were tested to determine the effects of adding a second intertie between Alberta and British Columbia to the Alberta transmission system. Conditions included the extremes of 1,600 MW of export from Alberta to British Columbia with 300 MW of export from Alberta to Montana, to 1,700 MW of import from British Columbia to Alberta and 300 MW of import from Montana to Alberta.

The following summarizes the effects that each intertie option would have on the system. Only those violations related to the interties are discussed here. Other issues related to generation additions, such as enhancements required to move wind generation from the South Planning Region and central east area, are not included here. Those issues and enhancements would be the same as for the Reference Case Scenario.

Northern intertie

The initial results with the northern intertie connected into Wesley Creek substation show that without further transmission developments in the northwest, the Alberta system would experience voltage collapse from the loss of the existing Alberta–British Columbia intertie between Cranbrook and Chapel Rock substation. A new 500 kV line from Wesley Creek substation to Livock substation and series compensation on the planned lines would be required to mitigate the voltage collapse.

Southern intertie

In the southern intertie cases, the Chapel Rock Transmission Development, including two 240 kV lines from Chapel Rock substation to the Pincher Creek area, was assumed to be in place. The southern intertie did not result in any major overloads and thus no enhancements are recommended for this option.

High Cogeneration Scenario

The High Cogeneration Scenario represents the effect of future generation changes on the Alberta electric system if a large amount of cogeneration is added along with an incremental 5,000 MW of renewable energy.

Generation forecast

The primary change is the addition of new cogeneration in Alberta, which was assumed to be 1,725 MW higher than the Reference Case Scenario capacity additions of 405 MW by 2037. The majority of that amount is in the Northeast Planning Region, with only 90 MW added in the Cold Lake area of the Central Planning Region. This increased cogeneration would reflect a reduction in combined-cycle additions by about 1,365 MW, and simple-cycle additions by about 335 MW. There were no reductions to renewable generation additions compared to the Reference Case Scenario.

In this scenario, there will be instances when there is low load combined with high renewable generation output and high cogeneration output. This could result in challenges in system and market operations.

Transmission plan

The studies for this scenario, and consequently the transmission plans, were substantially the same as those for the Reference Case Scenario for all but the Northeast Planning Region.

Northeast Planning Region

High cogeneration in the Northeast Planning Region results in lower generation in the Northwest Planning Region and Edmonton Planning Region. As a result, significant power flows from the northeast to Edmonton and the northwest.

There are two paths from the Northeast to Northwest planning regions: the 240 kV system from Dover substation to Brintnell substation and the 138 kV system in the Athabasca area from Lac La Biche substation to North Barrhead substation. The 240 kV line from Dover substation to Birchwood Creek substation will overload under loss of the Fort McMurray West 500 kV line from Thickwood substation to Livock substation. Also, loss of the 240 kV transmission line from Dover substation to Birchwood Creek substation will overload the underlying 138 kV system in the Athabasca area. In addition to these effects resulting from flows between the northeast and the northwest, a local area constraint also occurs near Fort Saskatchewan. Loss of the 240 kV circuit between the Josephburg and Lamoureux substations will overload the underlying 138 kV system.

The following developments were identified to mitigate the overloads:

Development	Description	In-Service Date
Rebuild Dover–to–Birchwood Creek	Rebuild the 240 kV Dover–to–Birchwood Creek line to a higher capacity	Post-2022 (2027)
Athabasca enhancements	Build a new 240/138 kV source substation between Heart Lake and Heartland substation Build a new 240 kV transmission line from the new substation to Heart Lake and Heartland substation Add 138 kV transmission lines from the new substation to Lac La Biche, Boyle and Waupisoo substations	Post-2022 (2027)
Fort Saskatchewan enhancements	Rebuild the 138 kV line from Josephburg substation to Fort Saskatchewan substation for higher capacity	Post-2022 (2027)

Implementing the above projects could delay the need for the Fort McMurray East 500 kV line to beyond the longer-term horizon. However, under this scenario, even with the above developments in place, the Northeast system will be operated at marginal capability limits and, depending on generation development in the area, the Fort McMurray East line may be required sooner. Also, without Fort McMurray East an extended outage of the Fort McMurray West line could result in significant generation curtailment due to lack of transmission capacity needed to move energy from cogeneration facilities to the rest of the system under transmission outage conditions.

View Single Line Diagrams (SLDs): ***www.aeso.ca/LTP***

4.0 Conclusions

Conclusions

The proposed transmission developments for the Reference Scenario are also required in all other scenarios.

The proposed transmission developments that are based on load drivers are mainly for near-term. This includes proposed developments in the Northwest, Edmonton and Calgary planning regions. For the Northwest region, future generation developments could impact proposed transmission developments, and the AESO will continue to monitor the region to ensure timely development of needed transmission infrastructure to maintain reliability. In addition, the planning assessments showed that the coal phase-out in the Wabamun area may introduce potential local transmission constraints, which would require system enhancements, reconfigurations or upgrades. However, due to the uncertainties in the future generation development in the area, the AESO will continue to monitor and adjust its transmission plans as needed.

The following developments will enable integration of additional generation in renewable resource-rich areas of the southern and central east regions:

- The Chapel Rock–Pincher Creek Transmission Development, which includes a 500/240 kV substation and two 240 kV lines.
- A 240 kV line from the central east area to the Red Deer area and upgrade of the existing 240 kV line between them.

These two developments will need to be advanced depending on renewables development in the southwest and central east areas. These reinforcements will be staged with construction milestones to provide flexibility in development timing to align with the pace of renewables additions.

Reconfiguration of generation in the Lake Wabamun area may drive new transmission enhancements. Due to the lower efficiency of the converted coal units compared to new combined-cycle units coupled with surplus generation flowing into the area, more power is injected at the Ellerslie 500/240 kV substation. Depending on the amount and type of generation capacity replacement in the area, overloading of the 240 kV circuits from Ellerslie into south Edmonton may develop and require further mitigation.

The dispatch patterns for the expected generation changes and additions noted above also result in overloads of the 138 kV system that parallels the 240 kV supply system into the Northwest Planning Region. A new 240 kV supply from Bickerdike substation to Little Smoky substation via Fox Creek substation will alleviate the 138 kV overloads. This issue and the proposed new facilities were also seen in the near-term horizon plans.

There are three local area developments that are load-driven in the longer term for the Reference Case Scenario. In the Edmonton Planning Region, the rebuild of the North Calder–to–Cardiff 138 kV line is needed to serve increased loads in the Athabasca area. In the Grande Prairie area, the Grande Prairie supply and transformer capacity increase at Little Smoky substation developments are known load-driven projects and have been seen in previous long-term transmission plans.

Conclusions

The addition of 1,725 MW of cogeneration to the Alberta system influences the flows between the Northeast and Northwest planning regions and as a result, overloads are observed on the transfer paths between the two. An upgrade will be required between Dover substation and Birchwood Creek substation, and a major upgrade will be required in the Athabasca area. In addition, a local area upgrade is required in the Fort Saskatchewan area.

The Fort McMurray East 500 kV line, which was a designated critical transmission infrastructure project, has been put on hold pending further studies. Depending on load and generation development in the Northeast Planning Region, it may be necessary to advance this project due to operational challenges resulting from surplus generation capacity.

The proposed transmission developments for the Reference Scenario are also required in all other scenarios. In addition, for the New Large-hydro Generation Scenario, developments are proposed in the Northeast region to integrate the potential Slave River hydro generation plant and also in the Central region to integrate generation near Brazeau. The Western Integration Scenario requires a 500 kV line from the Northwest region to Northeast region for the northern intertie option. The High Cogeneration Scenario requires developments in the Northeast region in Athabasca, Fort Saskatchewan and Fort McMurray areas.

The following provides a summary of the longer-term developments for all regions:

Development	Planning Region	Driver	In-Service Date	Scenario
Chapel Rock–Pincher Creek	South	Renewables Integration	Post-2022	All
Rebuild South-East 138 kV circuits to higher capacity	South	Renewables Integration	Post-2022	All
Tinchebary–to–Gaetz, 240 kV	Central	Renewables Integration	Post-2022	All
Rebuild Cordel–to–Red Deer 240 kV to higher capacity	Central	Renewables Integration	Post-2032	All
Rebuild North Calder–to–Cardiff	Edmonton	Load	Post-2022	All
Fox Creek reinforcement	Northwest	Load / Transfer-in	2022	All
Little Smoky substation – increase transformer capacity	Northwest	Load	2022	All
Grande Prairie supply	Northwest	Load / Transfer-in	2022	All
Brazeau Area upgrades	Central	Hydro development	2030	New Large-hydro Generation
Two 500 kV lines for Slave River hydro development	Northeast	Hydro development	Post-2030	New Large-hydro Generation
500 kV line Wesley Creek–to–Livock	Northwest	Intertie development	Post-2030	Western Integration
Rebuild Dover–to–Birchwood Creek	Northeast	Cogeneration	Post-2022	High Cogeneration
Athabasca enhancements	Northeast	Cogeneration	Post-2022	High Cogeneration
Fort Saskatchewan enhancements	Northeast	Cogeneration	Post-2022	High Cogeneration

5.0 Appendices

Appendices

APPENDIX A

Effects of generation capacity factors on renewables targets, serving load, and coal phase-out

Background and purpose

Current and anticipated generation technologies have varying characteristics, with corresponding market and transmission requirement consequences. The purpose of this section is to summarize the differences between generation technology types and the related influences on renewable generation targets, serving load and assisting coal phase-out. These characteristics were considered in the 2017 LTO generation forecast development, and the resulting generation forecast which was a key input into 2017 LTP assessments. The content of this section is intended to assist 2017 LTP development in terms of considering how generation characteristics may affect transmission assessments.

Intermittent (non-firm) versus non-intermittent (firm) generation technologies

At a high level, generation technologies can be separated into two main categories distinguished by their ability to provide power when called upon or when required, typically at system peak conditions. It is usually renewable technologies, including wind, solar and run-of-river hydro, which are considered to be intermittent. The intermittency of these technologies means other technology types are necessary to ensure demand is met, regardless of how many intermittent resources are developed.

Non-intermittent technologies such as coal and natural gas are typically considered to be “firm” and capable of providing power when called upon and serving demand, especially at peak load conditions. A major consequence of these differences in technologies is that non-intermittent technologies are necessary to replace coal-fired units, which are mandated to retire by the end of 2030. The ability of non-intermittent technologies to replace coal and meet demand is discussed, along with other considerations, in the Technology Types and Key Characteristics section below.

Alberta renewable generation targets

The *Renewable Electricity Act* (REA) requires that 30 per cent of electricity produced in Alberta, on an annual basis, generated by renewable technologies by 2030. As part of the REA, the AESO is tasked with introducing a Renewable Electricity Program (REP) which will utilize a series of auctions to procure up to 5,000 MW of renewable capacity. Due to specific generation technology characteristics, different forms of renewable generation will contribute varying amounts of energy towards the 30 per cent target. The ability of the various forms of renewable technologies to help meet the 30 per cent target is discussed below in the Technology Types and Key Characteristics section.

Technology types and key characteristics

Natural gas technologies

The 2017 LTO anticipates that demand will grow while coal-fired capacity progresses to full retirement by 2030. Of the non-intermittent technologies with sufficient resources in Alberta and the ability to develop by 2030, natural gas technologies are the most likely to proceed. There are several types of natural gas technologies, including simple-cycle, combined-cycle, coal-to-gas conversion and cogeneration.

Simple-cycle

Simple-cycle units refer to natural gas turbine or reciprocating engine technologies without waste heat capture technology. These units are often fast-ramping and less efficient than combined-cycle natural gas technologies. Modern simple-cycle units can achieve full output 10 minutes after a start. They are commonly at or near the top of the merit order and often fulfil the role of providing reserves or peaking capability. This ability means the technology is able to help facilitate coal phase-out and renewable generation integration. As wind and solar resources ramp up and down, simple-cycle technologies can follow the ramping to ensure load is served.

Being at the top of the merit order means these units are usually dispatched less frequently than other technologies and therefore have lower capacity factors (average output as a ratio of maximum capability). Another common feature of the technology is that simple-cycle units are often smaller than other gas technology types, and typically have a higher degree of flexibility in terms of where they can locate within the province.

Simple-cycle units can operate in parallel, independently, thereby creating flexibility in unit-specific operation. This also makes simple-cycle technology one of the more difficult technologies to forecast on a regional or area basis. Generally, simple-cycle natural gas units will exhibit high capacity factors in times of low reserve margin, and low capacity factors during times of high reserve margin. Simple-cycle units usually do not bid below their variable cost, and hence they are not frequently dispatched when lower-cost combined-cycle, intermittent or baseload generation is available.

Combined-cycle

Combined-cycle units will normally have one or more gas turbines with heat-recovery steam generators and a single steam turbine, operating in sequence. The efficiencies of these units are usually higher than simple-cycle technology because of the heat recovery and subsequent generation from the steam turbine. However, the steam cycle reduces operational flexibility and ramping capability due to metallurgical constraints within the heat recovery equipment. The steam generator requires two to six hours to cycle from idle to full steam. As a result, the gas turbine must be ramped more slowly than it would otherwise be capable of in simple-cycle mode to maintain the reliability of a combined-cycle unit.

In Alberta, one unique operation incorporates an auxiliary boiler to keep the Rankine cycle warm during times of dormancy. The Cavalier 2-on-1 combined-cycle plant can ramp more quickly than its sister plant, the Balzac Energy Centre, as a result of this configuration.

Combined-cycle facilities are usually larger than simple-cycle units. Their size, efficiency, and reduced flexibility means they are usually well-suited for baseload or mid-merit order operation and therefore may often have higher capacity factors than simple-cycle units. Combined-cycle units are also well-suited for coal replacement and serving load. Often, a combined-cycle plant will operate at the minimum stable level during low-priced periods, when subsequently higher-price periods are anticipated.

By maintaining generation during such periods, a combined-cycle facility may ramp to full output when market prices dictate profitability. With the anticipated addition of intermittent renewable generation in Alberta, it is expected that the real-time energy market price will fluctuate more significantly compared to previous years. This changes the expected realized price for combined-cycle units and alters the incentives for combined-cycle configurations. Specifically, it is expected that future combined-cycle units will be more flexible than certain existing combined-cycle units in order to ramp up and down more frequently as intermittent renewable generation ramps up and down in the future.

From a fuel availability perspective, combined-cycle units have a relatively high degree of flexibility in terms of where they can locate. Alberta has substantial natural gas pipeline infrastructure throughout the province, which either has available capacity today or can provide capacity with relatively easy upgrades. However, fuel availability is not the only locational consideration. Water usage and discharge are also important considerations when siting combined-cycle units. The steam cycle is condensed via cooling towers, which are operated via water-cooling, air-cooling or a hybrid of the two technologies. Water cooling is more efficient than air cooling from an energy use perspective, since air cooling requires very large fans with significant electrical loads. However, water cooling produces large plumes and consumes significant volumes of water, which constrains generation to areas that have available water sources. Notably, all of the existing combined-cycle units in Alberta use water cooling for the condenser.

Other considerations such as land costs, available transmission and community acceptance can also influence location decisions. Notably, there are considerable advantages to locating at brownfield coal sites. Locating at existing sites can reduce costs and regulatory requirements, and often achieve community acceptance more readily than at greenfield sites. Consequently, the 2017 LTO assumes most combined-cycle development will occur at brownfield coal sites.

Coal-to-gas conversion

It remains to be seen exactly how coal-to-gas converted units will operate since no Alberta coal-fired units have ever converted to natural gas. The capital costs to convert are relatively low since most of the Rankine cycle infrastructure does not change. However, coal-to-gas units are significantly less efficient, and have higher variable operating costs, than other gas generation technologies.

This lower efficiency means there is an incentive for these units to operate less frequently, and only when market prices rise high enough to cover variable costs. This would suggest it may be likely that coal-to-gas units will operate with lower capacity factors than previous coal power plants. The slow ramping nature of these units may influence how they participate in the electricity market. Since these units cannot quickly respond to price spikes, they may be required to operate at minimum levels in order to respond quickly to price signals. The more coal units that convert, however, the more frequently coal-to-gas units will be dispatched and the higher their capacity factors will be. While many of their operating characteristics are unknown, coal-to-gas units are expected to be able to provide firm generation capacity and serve demand.

A key consideration of coal-to-gas converted units is their ramping capability. Since it is expected these units will utilize the same steam boilers, turbines and other related equipment as the existing coal facilities, there are limits to how quickly the steam cycle can be safely superheated, which may limit ramping capability, likely resulting in ramp rates similar to existing coal facilities.

Cogeneration

Cogeneration technology involves the coincidental production of electricity and thermal energy. The majority of cogeneration in Alberta is related to oilsands production, which requires large amounts of steam used in the steam-assisted gravitational drainage process. By using gas turbines to generate the steam instead of boilers, electricity can be produced. The steam needs of these sites typically determine the amount of cogenerated power, effectively making electricity a byproduct of oilsands production processes.

Due to the efficiencies of cogeneration processes, the cost to produce electricity from cogeneration is typically quite low compared to other natural gas-fired technologies. Since most oilsands operations are 24/7, cogeneration is usually a baseload technology with high capacity factors. A key difference between cogeneration and other gas-fired technologies is that since the electricity produced is effectively an industrial byproduct, its operational characteristics, especially total output, are more related to the underlying industrial process than to electricity market conditions. Since cogeneration is the integration of electricity production with other energy production, its location potential is limited and will likely develop mainly in oilsands-producing areas such as Fort McMurray and Cold Lake.

Renewable generation

Hydroelectric generation

Hydro generation varies by type of facility and can be either run-of-river or hydro with reservoir technologies. The difference is that hydro with reservoir technologies (storage) have the ability to store water and energy for a prolonged period compared to run-of-river technology.

Run-of-river hydro generation

Run-of-river hydro facilities can be either small or large. Their key characteristic is a limited ability to store water; therefore, their output tends to be subject to the underlying flows and volumes of the river on which they are built, as well as the size of the facility. Run-of-river units may be able to have high capacity factors if they are small and the river has sufficiently high flows, or in cases where the river is regulated through an upstream dam. Capacity factors of larger run-of-river units are more related to seasonal river flows, with maximum production during the freshet season. Consequently, capacity factors of run-of-river projects can vary greatly depending on individual project siting and environmental characteristics. The seasonal output variation of run-of-river projects also means their ability to assist with coal phase-out is limited. The 2017 LTO assumes run-of-river hydro can contribute 50 per cent of its capacity towards meeting system peak.

Run-of-river hydro facilities are also unlikely to make strong contributions towards renewable generation targets. Either the facilities will have relatively low capacity factors due to seasonal river flows, or the facilities will be small if they have high capacity factors. In either case, their contribution towards the 30 per cent renewable generation target by 2030 is unlikely to be large. Furthermore, the larger the facility, the more environmental impacts and costs it will have, which reduces the chances of being in service by 2030.

Hydro with large reservoir

Large, dammed hydro projects are capable of storing significant volumes of water and generating electricity on demand. Large hydro sites are limited to advantageous topography along major rivers. As such, the scope for large-scale dammed hydro in Alberta is limited to a few key rivers and specific sites.

The variable production cost of dammed hydro is very low, as most expenses are fixed. Capacity factors can be constrained by downstream flow requirements and other regulations regarding water flow. Dammed hydro projects can respond very quickly, and increase or decrease generation by controlling the intake gates. Hydro with storage is capable of providing firm output, meaning it can likely help serve demand, including at times of system peak. However, it is unlikely that storage hydro will be able to help facilitate with coal phase-out or with meeting renewable generation targets.

While there are sufficient hydro sites within the province with the potential for enough capacity to replace coal, it is highly unlikely that any these sites can be developed by 2030 due to the substantial regulatory requirements and costs associated with large hydro projects.

Wind

Wind electricity is intermittent, based on prevailing weather. Typical capacity factors for wind generation facilities are 30–40 per cent in favourable locations in Alberta, and there is a strong correlation between localized wind facilities. Generally, when wind generation is available in Alberta, several facilities produce simultaneously and the prevailing pool price is depressed by the abundance of zero-bid energy entering the market.

This is a result of the strong concentration of wind facilities in southwestern Alberta. As projects throughout the southeast and central east portions of the province develop, a more diverse generation profile is anticipated.

Seasonally, wind generation tends to peak during winter and tail off in summer. Due to the intermittency of wind resources, it is not assumed to be capable of providing power at times of peak demand, and therefore is unable to replace coal units.

Solar

Alberta's latitude enables a large amount of solar radiation throughout summer, with a very small amount available during winter. This is directly related to solar exposure, as the sun rises and sets at different times throughout the seasons. An 18 per cent capacity factor, annually, can be expected at favourable solar sites in southern Alberta. As latitude increases toward the north of the province, capacity factors decline. Cloud cover and other occlusions will reduce output at solar facilities.

Although solar generation is intermittent, it is relatively predictable due to its daily and annual patterns. It is likely that solar resources will be able to help meet summer peaks; however, Alberta's winter peaks occur in the evening when the sun is not shining, and therefore, solar is not expected to assist with either meeting peak demand or coal phase-out.

The capacity factor of solar is approximately half that of wind, meaning twice the amount of installed solar capacity is required to achieve the same energy output as wind, megawatt for megawatt. In consequence, significantly more solar resources would be required to meet Alberta's renewable generation targets compared to wind. This characteristic was an important consideration in the 2017 LTO's assumption that the majority of the 5,000 MW of REP-supported renewable generation will be wind.

6.0 Glossary of terms

Glossary of terms

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

Alberta Utilities Commission (AUC): The provincial body accountable for regulating the utilities sector, natural gas and electricity markets.

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 based on consumption (for loads) and dispatch (for suppliers).

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

Brownfield: Land previously or currently used for industrial or certain commercial purposes.

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 device used to control voltages by eliminating a voltage drop in the system.

Capacity: The amount of electric power delivered or required for a generator, turbine, transformer, transmission circuit, substation or system as rated by the manufacturer.

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: 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.

Congestion: The condition under which transactions that electricity 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.

Distributed energy resources (DER): Electrical generation and storage performed by a variety of small, grid-connected devices, generally with capacities of 10 MW or less and located close to the load they serve.

Distribution facility owner (DFO): Entities that own and operate distribution lines, the portion of the Alberta electrical system operating at 25 kilovolts (25,000 volts) or less. These distribution lines provide service to most consumers, except for some very large industries that are directly connected to the transmission grid.

Gas turbine: See simple-cycle.

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.

Greenfield: Land being considered for development that has not previously been used for commercial or industrial purposes.

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.

High voltage direct current (HVDC): The transmission of electricity using direct current.

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, which interconnect two adjacent electric systems and allow power to be imported and exported.

Load (electric): The electric power used by devices connected to an electric system.

Load factor: A measure of the average load, in kilowatts, supplied during a given period. It is generally used to determine the total amount of energy that would have been used if a given customer's maximum load was sustained over an extended period of time and, through comparison, show what percentage of potential load was actually used.

Looped system (loop): A system of power lines in which circuits are contiguously connected between substations and then back to the same substation.

Megawatt (MW): An electrical capacity unit of measure equal to one million watts of power supply, demand, flow or capacity.

Merit order: In the wholesale electricity market, merit order refers to the list used to dispatch electricity generation to meet demand. The lowest-cost generation is dispatched first.

Needs Identification Document (NID): A document filed by the AESO with the 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.

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.

Peaking capacity: The capacity of generating equipment normally reserved for operation during hours of the highest daily, weekly, or seasonal loads. Some generating equipment may be operated at certain times as peaking capacity, and at other times to serve loads on an around-the-clock basis.

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: The combined adequacy and security of an electric system. 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.

Reserve: See "operating reserve"

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 consisting typically of 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.

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.

Tarrif (transmission): 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 transfer of electricity over a group of interconnected 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 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 system (electric): An interconnected group of electric transmission lines and associated equipment for moving or transferring electricity 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.

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