

# AESO 2017 Long-term Outlook



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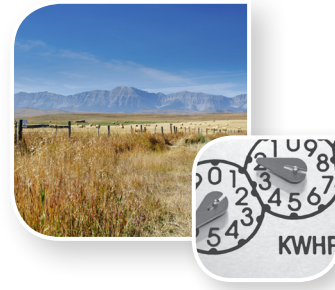
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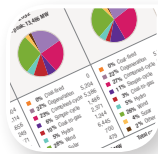
# 1.0 Executive summary



*The Alberta Electric System Operator (AESO) 2017 Long-term Outlook (2017 LTO) describes Alberta's expected electricity demand over the next 20 years, as well as the expected generation capacity needed to meet that demand.*

The AESO's 2017 LTO is a forecast used as one of many inputs to guide the AESO in planning Alberta's transmission system. It describes the factors that drive load growth and generation development in Alberta and the assumptions the AESO has made to understand the impacts. Alberta's electricity industry is in a state of transition, due in part to changing policies and economic drivers that can significantly impact load growth and development of generation. Since mid-2014, the outlook for economic growth within the province has been revised downward in response to changes in the price outlook for crude oil. This downward revision of oil prices and economic growth for Alberta is consistent with industry outlooks, and results in lower anticipated load growth compared to previous AESO long-term outlooks. Methodology adjustments and energy efficiency assumptions further reduce the outlook for load growth.

The 2017 LTO aligns with the Government of Alberta's Climate Leadership Plan (CLP) wherever possible; however, there remain a number of possible policy-driven outcomes which the 2017 LTO assesses through the use of scenarios. The 2017 LTO assesses both undetermined policy and economic outcomes through the use of scenarios that are further outlined in the following sections.



- > The 2017 LTO generation forecast is based on the load growth outlook, policy considerations including the CLP and forthcoming capacity market, generation technology, and resource availability.

## 1.1 SCENARIO DEVELOPMENT

The 2017 LTO is built upon a Reference Case, a Low Load-growth Scenario and five generation scenarios that use the Reference Case load-growth, allowing the AESO to quantify and assess the outcomes of potential future impacts that are presently unknown.

The five generation scenarios are:

- High Coal-to-gas Conversion Scenario (5,400 megawatts (MW) of coal capacity converts to natural gas).
- No Coal-to-gas Conversion Scenario (no coal capacity converts to natural gas).
- New Large-scale Hydro Generation Scenario (hydroelectric development, including large-scale development, in northern Alberta).
- Western Integration Scenario (new large-scale interconnection with British Columbia).
- High Cogeneration Scenario (higher amounts of cogeneration development).

These scenarios enable the AESO to quantify and assess the outcomes of a variety of different potential future impacts. The AESO considers all scenarios and uses its Reference Case as its primary corporate forecast, or base case, and other scenarios are compared to it. If other scenarios become more likely, the AESO may adopt one as its main forecast.

In all scenarios, the AESO anticipates load growth over the long term to be lower than the 2016 LTO forecast, due mostly to lower anticipated economic growth, load forecast modelling adjustments, and energy efficiency assumptions.

The AESO continually reviews its forecasts as economic, policy and other influential drivers evolve. In order to align the latest information with its studied forecasts, the AESO will consider alternate load and/or generation assumptions when appropriate. Further, the AESO will provide updates to align with the latest information when needed.

## 1.2 BUILDING THE 2017 LONG-TERM OUTLOOK (LTO)

The 2017 LTO development process begins with an economic outlook for the province, as economic considerations are the key driver of long-run provincial load growth. The 2017 LTO generation forecast is based on the load growth outlook, policy considerations including the CLP and the forthcoming capacity market<sup>1</sup>, generation technology, and resource availability. Additionally, the AESO uses market simulation tools to assist in determining the likely future generation outlook.

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 body 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 relies on third-party information and is validated against other credible forecasters whenever possible. The AESO consults with stakeholders including industry groups, generation developers and distribution facility owners in order to gather information, confirm assumptions, and align outlooks.

The AESO continually strives to improve its forecasts and forecast processes and welcomes feedback.

<sup>1</sup> On Nov. 23, 2016, the Government of Alberta announced its endorsement of the AESO's recommendation to transition from an energy-only market to a new framework that includes an energy market and a capacity market. More information can be found at [www.aeso.ca/market/capacity-market-transition/](http://www.aeso.ca/market/capacity-market-transition/)

### 1.3 KEY HIGHLIGHTS OF THE 2017 LTO

- The Reference Case represents the AESO's corporate forecast for future long-term load growth and generation development.
- The Reference Case load forecast reflects a significant revision downward compared to the 2016 LTO in response to revised economic growth expectations, load forecast modelling adjustments, and energy efficiency assumptions.
  - Load is forecast to grow at an average annual rate of 0.9 per cent until 2037.
- The Reference Case generation forecast is aligned with recent policy including the CLP, the forthcoming capacity market, and recent industry announcements. These assumptions include:
  - All coal-fired generation will retire by the end of 2030.
  - The Renewable Electricity Program (REP) will support approximately 5,000 MW of renewable generation development, 400 MW of which will be energized and operational by December 2019.
  - Additional renewables will develop outside of the REP.
  - By 2030, 30 per cent of electricity produced in Alberta will come from renewable sources.
  - The Alberta–B.C. intertie capability will be restored following the intertie restoration initiative, increasing capability to 1,200 MW of imports and 1,000 MW of exports.
  - Approximately 2,400 MW of coal-fired generation will convert to natural gas-fired units in the early 2020s.
- 13,900 MW of new capacity is forecast to be developed by 2037 (this excludes CTG conversions).
- Peak demand is forecast to grow from 11,458 MW in 2016 to 13,947 MW in 2037.
- Six additional scenarios (one load, five generation) were developed to capture key known uncertainties in load and generation. These scenarios are:
  - Low Load-growth Scenario (0.4 per cent average annual load growth to 2037).
  - High Coal-to-gas Conversion Scenario (5,400 MW of coal capacity conversion).
  - No Coal-to-gas Conversion Scenario (no coal capacity conversion).
  - New Large-scale Hydro Generation Scenario (hydroelectric development, including large-scale development, in northern Alberta).
  - Western Integration Scenario (new large-scale interconnection with British Columbia).
  - High Cogeneration Scenario (higher amounts of cogeneration development).
- The 2017 LTO assesses both undetermined policy and economic outcomes through the use of scenarios.
- The creation and tracking of scenarios allows a better understanding of future potential outcomes and proactively addresses risks to the Reference Case.

# 2.0 Background



*The 2017 LTO will be used as the foundation for the AESO's next Long-term Transmission Plan, which will set out the AESO's current evaluation of Alberta's transmission system.*

The 2017 LTO is a key input into the AESO's *Long-term Transmission Plan* which will describe how the AESO will continue to provide reliable and non-discriminatory system access service and the timely implementation of transmission system expansions and enhancements.

The load and generation forecasts within the 2017 LTO are also an input to Needs Identification Document (NID) filings submitted by the AESO to the Alberta Utilities Commission, and are used to support transmission connection studies that are conducted in response to the system access service requests proposed by market participants.

While the 2017 LTO will be an input to transmission planning and NID filings, the AESO carefully reviews the load and generation assumptions for every system NID as part of its planning process. If the load and generation assumptions of a particular project are found to not reflect the latest expectations, the AESO may consider refinements to the load and generation forecasts used for the purposes of a NID or abbreviated NID. This is to ensure that only the needed transmission reinforcements are developed using the latest forecast information for the area under consideration.

The 2017 LTO is prepared in accordance with the AESO's duties as outlined in the Province of Alberta's *Electric Utilities Act* (EUA)<sup>2</sup> and the *Transmission Regulation* (T-Reg).<sup>3</sup>

Forecast direction, in part, is drawn from the Part 2 of T-Reg which states the AESO, in planning the transmission system:

- Must anticipate future demand for electricity, generation capacity and appropriate reserves required to meet the forecast load so that transmission facilities can be planned to be available in a timely manner to accommodate the forecast load and new generation capacity.
- Must make assumptions about future load growth, the timing and location of future generation additions, including areas of renewable or low-emission generation, and other related assumptions to support transmission system planning.

<sup>2</sup> [www.qp.alberta.ca/documents/Acts/E05P1.pdf](http://www.qp.alberta.ca/documents/Acts/E05P1.pdf)

<sup>3</sup> [www.qp.alberta.ca/documents/Regs/2007\\_086.pdf](http://www.qp.alberta.ca/documents/Regs/2007_086.pdf)



In addition, the *Long-term Transmission Plan* must include, accounting for at least the next 20 years, the following projections:

- The forecast load on the interconnected electric system, including exports of electricity.
- The anticipated generation capacity, including appropriate reserves and imports of electricity required to meet the forecast load.
- The timing and location of future generation additions, including areas of renewable or low-emission generation.

Alberta's electricity industry, technologies and economy are dynamic and constantly evolving. To ensure the 2017 LTO aligns with current and expected trends, the AESO continually monitors relevant industry developments that may affect future load growth and generation development.

These industry-impacting developments include:

- Changes to Alberta's economy, including key drivers such as the crude oil, natural gas, and oilsands industries, as well as financial and commodity market conditions.
- Provincial, federal and international policies and regulations concerning economic development, the environment and the electricity industry in Alberta.
- Technological changes, including generation technologies, costs and resources availability, energy efficiency and other demand-side management initiatives.
- Announced, applied-for, approved, under-construction, and existing oilsands, industrial, generation and other projects.
- Regional factors, including both specific and potential sources of load and generation changes.

In particular, there are two recent major policy changes which impact the future of the electricity industry in Alberta. These include the Government of Alberta's Climate Leadership Plan and the introduction of a capacity market.



- > To ensure the 2017 LTO aligns with current and expected trends, the AESO continually monitors relevant industry developments that may affect future load growth and generation development.

## **2.1 CLIMATE LEADERSHIP PLAN AND CAPACITY MARKET IMPLEMENTATION**

### **2.1.1 Climate Leadership Plan**

Load and generation development are both influenced by government policies. In particular, the Alberta government's Climate Leadership Plan (CLP) plays a strong role in influencing the 2017 LTO. Since the CLP's announcement in November 2015, legislative, regulatory, and other initiatives such as the Renewable Electricity Program and coal phase-out agreements have advanced the CLP. However, additional potential policy initiatives are still pending, introducing uncertainty into the forecast. To assess the impacts of some of these possible policy initiatives, the 2017 LTO contains a set of scenarios which examine an array of potential developments. This scenario-based approach, along with scenario narratives, assumptions and results, are described in further detail throughout this document.

### **2.1.2 Move to a capacity and energy market**

On Nov. 23, 2016, the Government of Alberta announced its endorsement 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<sup>4</sup>. A capacity market is a market-based structure with two separate markets, one for the provision of capacity, which is the ability to produce energy, and one for the actual production and delivery of energy. In this structure, generators receive payments for both providing capacity and producing energy. The purpose of the capacity market is to ensure there will be an adequate supply of electricity to meet the province's demand.

The details of the new market are yet to be determined and implemented and, depending on how the capacity market is designed, it can be expected to impact the future of load and generation within Alberta. The 2017 LTO makes assumptions regarding load and generation development in consideration of the future capacity market. The 2017 LTO aligns with typical features of capacity markets through the use of a target reserve margin in the calculation of future generation requirements to meet demand. While a target reserve margin is used in the 2017 LTO, details of the capacity market, including provisions regarding a reserve margin, are yet to be determined.

### **2.1.3 Other uncertainties**

Alberta's electricity industry is currently in a state of transition as a capacity market is developed and implemented, as the AESO implements the REP, and as coal-fired generation is phased out. Furthermore, additional uncertainty exists due to potential, but yet-to-be-determined additional policy programs that could impact the province's electricity supply mix. To quantify these sources of uncertainty and ensure that the AESO understands their potential impact, a scenario-based approach was adopted for the 2017 LTO.

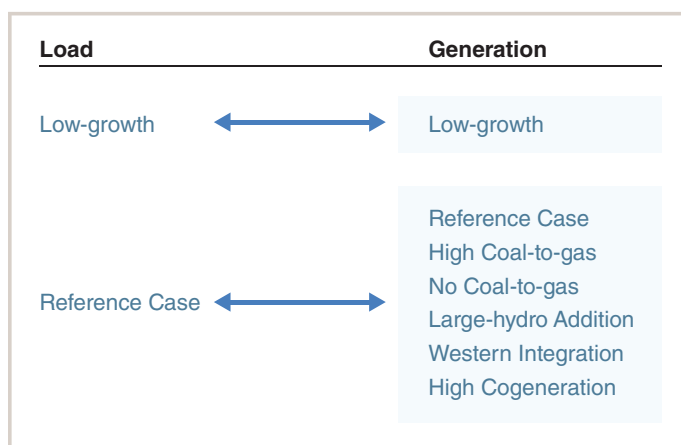
<sup>4</sup> [www.aeso.ca/market/capacity-market-transition/](http://www.aeso.ca/market/capacity-market-transition/)

## 2.2 2017 LTO METHODOLOGY

### 2.2.1 Scenario-based analysis

The 2017 LTO is structured around a set of two load scenarios with five generation scenarios (see Figure 1). Scenarios allow the AESO to test uncertainties by making specific assumptions about particular developments or outcomes in order to answer “what if?” questions. The 2017 LTO scenarios address specific and targeted sources of uncertainty individually in order to understand their impacts in isolation from other sources of uncertainty. Scenario details including background, assumptions, and results are presented in Section 6.0.

**FIGURE 1: Scenario overview**



### 2.2.2 2017 LTO Reference Case Scenario

The 2017 LTO Reference Case Scenario is consistent with recent information and announcements pertaining to Alberta’s electricity industry. However, due to ongoing policy discussions which could cause further impacts, the AESO remains neutral towards the outcome of any given scenario. The AESO considers all potential scenarios until they can be ruled out, depending on the use and anticipated scenario impacts. This is despite the adoption of the Reference Case as its main corporate outlook.

### 2.2.3 Multiple outcomes

Within any given scenario, assumptions were made in order to model the impacts. However, there may be alternate assumptions that could be reasonably made with regard to any specific scenario. Where applicable, these scenario-specific uncertainties are described with the Generation Forecast Scenarios, Section 6.0. The scenario-specific uncertainties are not explicitly explored in the 2017 LTO, but will be assessed and considered by the AESO through other initiatives as required.

## 3.0 Policy drivers and assumptions

### 3.1 ENVIRONMENTAL POLICY DRIVERS AND ASSUMPTIONS

Environmental laws and policies affect the economics and incentives of market participants, impacting the future of electricity demand and supply in Alberta. While both supply and demand can be affected by environmental laws and policies, this section primarily focuses on those laws and policies, both in place and pending, that will affect future generation development.

### 3.2 COAL REGULATIONS

At the federal level, the *Reduction of Carbon Dioxide Emissions from Coal-Fired Generation of Electricity Regulations* (Federal Coal Regulation)<sup>5</sup> under the *Canadian Environmental Protection Act 1999* sets out standards for new and existing coal-fired units.

Under the Federal Coal Regulation, new coal-fired generation facilities, as well as those at the end of their useful life, are required to meet a performance standard matching the carbon dioxide emission intensity of natural gas combined-cycle technology at a fixed rate of 420 tonnes per gigawatt hour. As per the Federal Coal Regulation, coal-fired units reach their end-of-useful-life date at up to 50 years, at which time they must meet the performance standard.

The main impact of the Federal Coal Regulation is to limit the useful life of Alberta's coal-fired units. Of the 18 coal-fired units currently operating in Alberta, 12 are required to meet the performance standard or retire before 2030. The Federal Coal Regulation is currently being reviewed by the Government of Canada. The details of this review are discussed in Section 3.4.1.

#### 3.2.1 Coal phase-out

As part of the CLP, the Government of Alberta will phase out all coal-fired emissions by Dec. 31, 2030.<sup>6</sup> Due to the high costs associated with coal-fired emissions abatement measures, it is assumed that coal phase-out means coal-fired generation units will be required to retire or cease using coal as a fuel source by the end of 2030. Under the Federal Coal Regulation, 12 of Alberta's 18 coal-fired units are already required to reduce emission intensities to that of gas units by 2030. Therefore, Alberta's coal phase-out primarily affects the remaining six coal-fired units. The owners of these six units reached an arrangement with the Government of Alberta to end coal-fired emissions at the six units on or before Dec. 31, 2030.

### 3.3 OTHER REGULATIONS, FRAMEWORKS AND POLICIES

This section of the 2017 LTO summarizes current Alberta provincial legislation and regulations which affect the future of Alberta's electricity industry.

<sup>5</sup> [www.ec.gc.ca/cc/default.asp?lang=En&n=C94FABDA-1](http://www.ec.gc.ca/cc/default.asp?lang=En&n=C94FABDA-1)

<sup>6</sup> [www.alberta.ca/release.cfm?xID=44889F421601C-0FF7-A694-74BB243C058EE588](http://www.alberta.ca/release.cfm?xID=44889F421601C-0FF7-A694-74BB243C058EE588)

### 3.3.1 Renewable Electricity Program (REP)

The new *Renewable Electricity Act* sets out a requirement that at least 30 per cent of electric energy produced in Alberta, measured on an annual basis, will be produced from renewable energy sources by 2030. The *Renewable Electricity Act* also establishes the REP. The REP is intended to encourage the development of 5,000 MW of new renewable electricity generation capacity connected to the Alberta grid between now and 2030. The AESO is responsible for implementing and administering the program through a series of competitions that will incent the development of renewable electricity generation through the purchase of renewable attributes.

Additional information on the REP can be found on the AESO's website.<sup>7</sup>

### 3.3.2 Specified Gas Emitters Regulation/output-based allocation

Large industrial emitters will continue to be subject to the *Specified Gas Emitters Regulation*<sup>8</sup> framework until the end of 2017, when the province will transition to an output-based allocation approach.

The output-based allocation system is not yet law and is currently under consultation; however, under the proposed system, it is anticipated that a facility would receive performance credits if its greenhouse gas emissions are less than the amount freely permitted. If its emissions are above the amount freely permitted, it is anticipated that it will be required to take one or more of the following actions<sup>9</sup> to bring the facility into compliance:

- Make improvements at the facility to reduce emissions intensity.
- Use emission performance credits generated at facilities that achieve more than the required reductions.
- Purchase Alberta-based carbon offset credits.
- Contribute to Alberta's Climate Change and Emissions Management Fund.

The Climate Change Advisory Panel (the Panel) recommended, for electricity generation, that output-based allocations<sup>10</sup> would be based on a "good-as-best-gas" generation standard, which specifies the product benchmark as the least emissions-intensive, natural gas-fired generation system in Alberta. The Panel proposed that output-based allocations be reduced at a pre-determined annual rate, called the tightening or ramping rate, (one to two per cent) to drive reductions in emissions. A set of assumptions consistent with the Panel recommendation report were made to estimate the future carbon compliance costs for the various generation technologies.

### 3.3.3 Micro-generation

On Dec. 21, 2016, the Alberta government released changes to the *Micro-generation Regulation*, which is the regulation that sets out requirements for small-scale renewable and alternative energy sources.<sup>11</sup> At a high level, the major changes include allowing micro-generating systems to serve adjacent sites and increasing the size limit from one MW to five MW. As well, the expiry date and review requirements of the *Micro-generation Regulation* have been removed. These changes increase flexibility and opportunities for micro-generation facilities. It is likely that additional

<sup>7</sup> [www.aeso.ca/market/renewable-electricity-program/](http://www.aeso.ca/market/renewable-electricity-program/)

<sup>8</sup> [www.aep.alberta.ca/climate-change/guidelines-legislation/specified-gas-emitters-regulation/](http://www.aep.alberta.ca/climate-change/guidelines-legislation/specified-gas-emitters-regulation/)

<sup>9</sup> [www.alberta.ca/output-based-allocation-engagement.aspx](http://www.alberta.ca/output-based-allocation-engagement.aspx)

<sup>10</sup> [www.alberta.ca/documents/climate/Output-Based-Allocation-System-Discussion-Document.pdf](http://www.alberta.ca/documents/climate/Output-Based-Allocation-System-Discussion-Document.pdf)

<sup>11</sup> [www.qp.alberta.ca/documents/Regs/2008\\_027.pdf](http://www.qp.alberta.ca/documents/Regs/2008_027.pdf)

smaller renewable and alternative generation additions will occur under the revised *Micro-generation Regulation*. However, the renewable generation capacity additions included in the 2017 LTO are assumed, for modelling purposes, to be mainly utility-scale.

### 3.3.4 Energy efficiency

On Jan. 23, 2017, the Alberta Energy Efficiency Advisory Panel<sup>12</sup> released its formal recommendations to the government. The recommendations regard the long-term vision, goals, initial programs, and other initiatives for Energy Efficiency Alberta (EEA) to undertake as part of its duty as the Crown agency responsible for supporting energy efficiency. This panel recommended several energy efficiency and community generation incentives and programs, including residential and business installation, and rebates for low-cost energy efficient products and photovoltaic solar incentives.

EEA is a new Government of Alberta agency with a mandate to raise awareness of energy use and promote, design, and deliver programs and other activities related to energy efficiency, conservation and the development of micro-generation and small-scale energy systems in Alberta. EEA is already implementing a number of the programs recommended by the panel. The 2017 LTO Reference Case accounts for anticipated energy efficiency impacts, which are discussed in further detail in Section 5.2.2.

### 3.3.5 Alberta Infrastructure solar request for proposal

In May 2017, the Government of Alberta issued a request for proposals<sup>13</sup> (RFP) to provide advice on the potential cost and best approach for procuring solar power for half of provincial government operations. The intent is to replace two existing green energy contracts that expire by the end of 2017 with solar power. The total consumption for the two contracts is 135,000 MWh per year which is approximately equivalent to 80 MW of solar capacity. A third green-energy contract expires in December 2024. The 2017 LTO Reference Case and scenarios contain solar additions which are consistent with the Government of Alberta's solar RFP. Additional details of these assumptions are discussed in Section 6.1.

### 3.3.6 Other renewables programs

In addition to the aforementioned programs, there are a number of other smaller renewables support programs in Alberta fostering development in the residential, municipal, community and Aboriginal sectors, including school boards. These various programs are intended to support smaller-scale and community-scale renewables and alternative generation resources. The Reference Case and other scenarios include renewables generation additions. While the 2017 LTO assumes these generation additions will be utility-scale, it is likely that some of the anticipated renewable generation additions will be smaller scale.

## 3.4 POTENTIAL POLICY CHANGES

In addition to the aforementioned current regulations, legislation, and programs, there are a number of federal and provincial initiatives and policies which are being considered and may also be implemented.

<sup>12</sup> [www.encyalberta.ca/about/](http://www.encyalberta.ca/about/)

<sup>13</sup> [www.alberta.ca/release.cfm?xID=43547099523a4-f51b-7dbc-5867889fe042019a](http://www.alberta.ca/release.cfm?xID=43547099523a4-f51b-7dbc-5867889fe042019a)

### 3.4.1 Federal policy on coal-fired and gas-fired electricity emissions

The Government of Canada announced that it intends to amend the *Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations* to phase out traditional coal-fired electricity by 2030. Along with the amendments, the government intends to create a corresponding gas-fired electricity emission regulation, which as of December 2016, would set emission limits for modified boiler units converted from coal to natural gas, to apply for 15 years or until 2045, whichever comes first, after which an emissions requirement of 420 t/GWh would apply.

The proposed amendments and new regulation are currently being reviewed by government and industry. Environment and Climate Change Canada has announced its intention to publish proposed regulations in the *Canada Gazette*,<sup>14</sup> Part I at the end of 2017, with final regulations to be published at the end of 2018. It has also been announced that the amendments will come into force in 2026, with regulatory requirements for natural gas-fired electricity generation to come into force in 2020.

Since the amendments to the Federal Coal Regulation are still in the consultation phase, there remains uncertainty regarding the final form of the amendments. This uncertainty means it is unclear how the amendments will impact coal retirement and coal-to-gas conversions. Due to this uncertainty, the 2017 LTO contains scenarios which explore alternate assumptions regarding coal-to-gas conversions.

### 3.4.2 Regional Electricity Cooperation and Strategic Infrastructure Initiative (RECSI)

The RECSI study is funded by Natural Resource Canada's Energy Innovation Program<sup>15</sup>, and its objective is to evaluate and rank the most promising electricity infrastructure projects in the four western provinces (British Columbia, Alberta, Saskatchewan, and Manitoba) and the Northwest Territories with the potential to assist Alberta and Saskatchewan transition to a sustainable, non-emitting electricity generation portfolio.

Two of the projects being considered under the RECSI that could alter the outlook for future generation are large-scale hydroelectric (hydro) development in Alberta and a new intertie between Alberta and British Columbia.

Due to the possible impacts from these projects along with their current uncertainty, the 2017 LTO contains a scenario which considers new large-scale hydro development, and another scenario which considers the new intertie, called the Western Integration Scenario.

### 3.4.3 Cogeneration provisions

The *Oil Sands Emissions Limit Act*<sup>16</sup> introduces limits to oilsands emissions of 100 megatonnes (Mt) per year. Under the act, cogeneration emissions attributable to the electric energy portion of the total energy generated or produced by cogeneration is excluded from the 100 Mt emissions cap. The act also permits government to make regulations prescribing a method for determining the oilsands emissions allocated to cogeneration (Section 3(d)).

The introduction of the emissions cap with exemptions for cogeneration alters the incentives for cogeneration development. Given the proposed federal and provincial policy related to gas-fired generation, output based allocations, and oilsands emissions, it is presently unclear exactly how the change in incentives will alter the outlook for cogeneration. Therefore, the 2017 LTO contains a scenario which considers significantly higher oilsands cogeneration development compared to the reference case.

<sup>14</sup> [www.gazette.gc.ca/rp-pr/p1/2016/2016-12-17/html/notice-avis-eng.php](http://www.gazette.gc.ca/rp-pr/p1/2016/2016-12-17/html/notice-avis-eng.php)

<sup>15</sup> [www.aeso.ca/market/market-updates/regional-electricity-cooperation-and-strategic-infrastructure-initiative-recsi/](http://www.aeso.ca/market/market-updates/regional-electricity-cooperation-and-strategic-infrastructure-initiative-recsi/)

<sup>16</sup> [www.qp.alberta.ca/documents/Acts/O07p5.pdf](http://www.qp.alberta.ca/documents/Acts/O07p5.pdf)

# 4.0 Economic drivers and assumptions

## 4.1 ECONOMIC CONSIDERATIONS

A key factor affecting electricity demand in Alberta over the long term is economic growth. This section discusses the economic considerations and assumptions underpinning the 2017 LTO's Reference Case load forecast.

The outlook for Alberta's economy has changed since mid-2014, when oil prices decreased from approximately U.S. \$100/barrel to under \$50/barrel at the time of the 2017 LTO publication. This shift in oil prices, resulting from increased global oil production, has altered the outlook for the Alberta crude oil industry and the provincial economy.

The reduction of global oil prices has prompted oil producers to reduce costs. Cost reductions in American shale oil basins have unleashed significant new supply, which is expected to keep global oil prices from climbing to pre-2014 levels. Over the past two years, third-party forecasters have reduced their long-run oil price expectations in reaction to the resilience of American tight oil production, OPEC instability, non-OPEC production growth, and the fact that global oil stocks remain high.

Alberta's economy is highly correlated with oil prices due to the size of its oil industry, especially the oilsands. Lower current and anticipated oil prices mean oilsands projects are less profitable. It is no longer expected that large greenfield oilsands projects will drive strong oilsands production and corresponding economic growth. Instead, it is now anticipated that with reduced expectations for oil price increases, oilsands development will continue to expand but at a more modest pace. Instead of the large greenfield projects previously anticipated, it is expected that smaller brownfield expansions will be the new norm for the industry. These smaller brownfield projects require significantly less capital investment, are quicker to build and scale, require lower oil prices to be profitable, and pose lower risk to developers. Conventional oil development is also negatively impacted by lower oil prices, further reducing expectations for economic growth in Alberta.

The reduced oil price outlook and resulting modest pace of anticipated oilsands development impacts the overall Alberta economy, which is not expected to grow as fast as it did before the crude oil price drop in 2014.



## 5.0 Load forecast

### 5.1 LOAD FORECAST METHODOLOGY

The 2017 LTO's load forecast methodology is a blend of top-down economic-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 economic-driven AIL-level forecast.

The top-down approach utilizes a forecast of AIL which is based upon a similar framework to the AESO's mid-term load forecast used in the AESO's [24 Month Supply and Demand Forecast](#). A decision to rely on this forecast model was made following a review of the AESO's 2016 LTO Reference Case load forecast and the near-term load growth of that scenario (See 2016 LTO, Section 4).

This load forecast model was extended out to 2037 for the purposes of the 2017 LTO. The 2017 LTO load forecast model is an hourly AIL load model that accounts for economic variables (Alberta Real Gross Domestic Product (GDP), population, and labour) aligned with the aforementioned economic outlook as well as temperature and calendar variables including time of day, holidays, weekdays, and months. The AIL winter peaks are extracted from this forecast and are adjusted for energy-efficiency assumptions. These efficiency-adjusted winter peaks are used as a target to calibrate the bottom-up POD-by-POD forecast.

To generate POD-level area and regional load forecasts, a bottom-up approach is used. Every POD in the province receives a generic hourly load shape based on historical load values. These shapes are then grown based on economic and regional information, distribution facility owner information at time of forecast development, and historical growth rates. The summation of the hourly load across every POD is then reconciled to the energy efficiency-adjusted AIL winter peak forecast described above. From there, load forecast values across the province are assessed for reasonableness and alignment with recent known information.

This load forecast methodology was used to derive the 2017 LTO. However, the AESO is reviewing its load forecast methodology and tools as part of the capacity market implementation and as part of the AESO's goal of continual process improvement. Through that review, the AESO may adjust its load forecast for the purpose of ongoing NIDs as more information becomes available, and adjust its methodology process for future LTOs.

### 5.2 LOAD FORECASTS

The 2017 LTO contains two load forecast scenarios.

The Reference Case load growth reflects the current economic outlook. The Low Load-growth Scenario tests the impacts of lower load growth corresponding to significantly reduced oilsands and economic growth in Alberta. A high-growth scenario was not explored as prior AESO LTO forecasts have significantly higher load than the 2017 LTO Reference Case and these can be used to understand the impacts of higher load growth.

### 5.2.1 Reference Case load growth

The Reference Case Scenario load growth represents the AESO's current estimate of future load growth. It is aligned with the economic outlook described in Section 4 and leverages the load forecast methodology outlined in Section 5.1. There has historically been a very strong relationship between load growth and economic (GDP) growth.

The impact of reduced long-run oil price expectations affects the AESO's load forecast through two main impacts. The first impact is that large-scale oilsands greenfield investments are generally not expected to be economic with lower oil price expectations. Long-run crude oil price forecasts only support smaller-scale and incremental expansions at existing oilsands sites. This means that there is less forecast electricity required in the oilsands sector compared to prior LTO forecasts. Secondly, lower expected growth in the oilsands reduces long-run anticipated growth of Alberta's economy, causing lower growth across other industry sectors, fewer jobs, and reduced immigration compared to previous forecasts.

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

### 5.2.2 Energy efficiency assumptions

As mentioned, the 2017 LTO load growth is based on an economically-driven AIL forecast which is then adjusted for energy efficiency. The energy efficiency assumptions are based on expectations of policy and non-policy-driven energy efficiency gains within the province. The efficiency improvements are assumed to primarily impact long-run urban (residential and commercial) and oilsands load growth. The overall impact of these energy efficiency improvements results in a drop of AIL peak demand by approximately eight per cent by 2037.

### 5.2.3 Low Load-growth Scenario

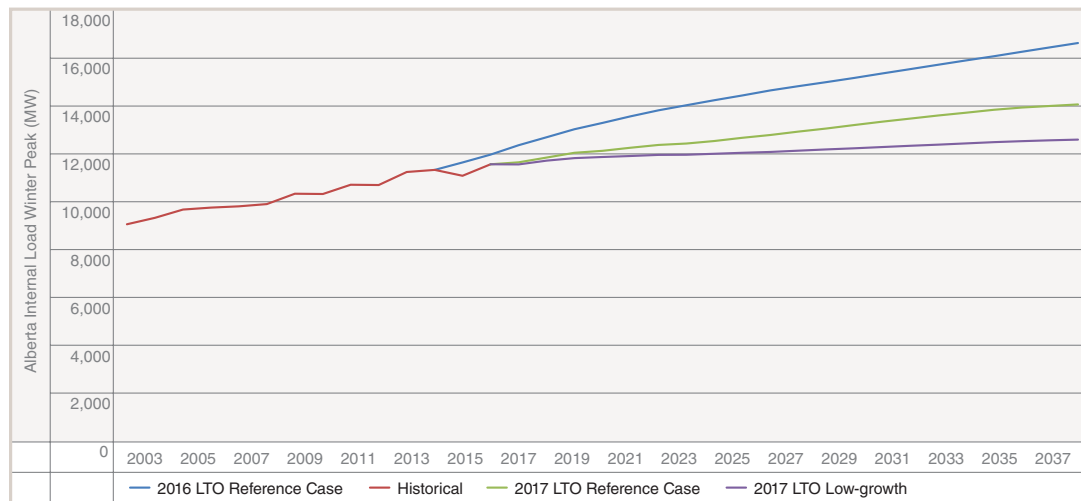
The Low Load-growth Scenario assumes that oil prices stay low such that there is no new development in the oilsands beyond current under-construction projects. Due to the significant reduction of investment in oilsands development and the corresponding economic impacts, load throughout the province grows considerably slower than in the Reference Case.

The methodology to create the Low Load-growth Scenario was similar to that of the Reference Case, as described in Section 2.1. However, the peak AIL targets to which the bottom-up POD-by-POD loads are reconciled were assumed to be considerably lower. As part of that reconciliation, oilsands growth, and therefore Fort McMurray and Cold Lake area growth, was assumed to be more impacted than other regions of the province.

### 5.2.4 Load forecast results

Overall, the 2017 LTO Reference Case load forecast is significantly lower than the 2016 LTO Reference Case. The drop is due to changes in the economic outlook for the province as well as changes to energy efficiency assumptions and adjustments made to the load forecast methodology from the 2016 LTO. The majority of the drop, however, is due to changes in the economic outlook for Alberta. As a result of these changes, long-run load growth in the 2017 LTO is approximately half compared to the 2016 LTO Reference Case (see Figure 2).

**FIGURE 2: 2017 Long-term Load Growth**



# 6.0 Generation scenario forecasts

## 6.1 ASSUMPTIONS AND METHODOLOGY

In addition to the Reference Case, the 2017 LTO contains six other scenarios which are based on known uncertainties currently facing Alberta's electricity market. Each scenario contains an assumption change from the Reference Case while maintaining an underlying set of assumptions.

The generation development in the 2017 LTO scenarios is based on two main factors: ensuring demand is met, and aligning with policy directions including renewables additions and coal-fired retirements. In considering what generation is 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.

A principal assumption is that all forecast load is served. For most of the scenarios, the Reference Case load growth was utilized except for the generation scenario developed for the low-growth load forecast. To ensure that load is served, a target reserve margin is utilized in developing the generation outlook. This is consistent with previous AESO LTO forecasts. For the purposes of the 2017 LTO, a reserve margin target of 15 per cent is assumed. A reserve margin is a comparison of generation supply and demand in Alberta. It is a calculation of the firm generation capacity that is in excess of annual peak AIL demand, expressed as a percentage of the peak demand. Firm generation is defined as installed and future generation capacity, adjusting for seasonal hydro capacity<sup>17</sup> and excludes wind and solar capacity. The 2017 LTO reserve margin assumption is not intended to provide an indication of a target or methodology for the in-development capacity market. It is also assumed that market mechanisms including the capacity market, or support through mechanisms like the REP, will provide the necessary revenue for new generation to be developed.

Intermittent generation sources such as wind and solar do not provide the same level of reliability as non-intermittent sources such as simple-cycle or combined-cycle gas-fired generation. It is often the case that wind and solar resources will be unavailable during Alberta peak loads, and therefore wind and solar additions are not assumed to contribute towards the target reserve margin. This assumption is not intended to provide an indication of the eligibility of these resources for the in-development capacity market.

Another key input to the generation scenarios is that at least 30 per cent of energy produced in Alberta in 2030 will come from renewable sources, in accordance with the *Renewable Electricity Act*. In order to achieve the 30 per cent target by 2030, it is likely that more renewables than the 5,000 MW target for the REP will need to develop in the province. It is expected that a variety of renewable resources will be developed through the REP and other Alberta initiatives, with the relative economics of the resource types, project development timelines, and specific policy objectives and initiatives guiding the resulting mix. However, specific assumptions for the various generation types were required to develop the generation scenarios.

The 2017 LTO assumes that the REP will incent the development of approximately 5,000 MW of renewables and that the 5,000 MW will consist primarily of wind generation. In addition to

<sup>17</sup> Hydro capacity has been included at 67 per cent legacy hydro, 20 per cent irrigation and 50 per cent run-of-river

wind generation development in the generation scenarios, the 2017 LTO scenarios also include solar generation development. In the near term, it is assumed that the Government of Alberta's RFP for solar generation will incent approximately 80–to–100 MW with additional solar support in the 2020s, altogether resulting in 500 MW of utility-scale solar generation by the end of 2030. The 2017 LTO scenarios also assume that 350 MW of hydro development(s) will be completed by the end of 2030. Cogeneration additions are an exogenous input to the scenarios and are based on a historical ratio of cogeneration capacity to oilsands production. Based on this assumption, cogeneration projects currently under construction, plus approximately 400 MW of additional cogeneration, are assumed in the Reference Case and most scenarios over the forecast horizon. However, given the possibility that the attractiveness of cogeneration may change as a result of potential CLP or technology changes, the High-cogeneration Scenario tests this assumption.

Retirements are also a key assumption in the 2017 LTO. Generally, the coal retirements associated with the coal phase-out follow a similar assumption methodology between scenarios; however, the schedule varies within the coal-to-gas scenarios. The AESO assumes that no more than two coal-fired units retire per year, that all units shut down by 2030 if not converted, and that the order of retirement generally follows an order of oldest to newest. The assumed coal retirement schedules for the scenarios are presented in Appendix A. While these dates are assumed in the 2017 LTO scenarios, the actual retirement dates will depend on coal-unit owner decisions.

The Reference Case and other scenarios assume that the forecast generation additions are transmission grid-connected for modelling purposes. However, it is possible that generation additions, especially small-scale solar and smaller natural gas simple-cycle and cogeneration resources may connect at the distribution level. These are often referred to as Distributed Energy Resources (DERs), and include generation and other resources which are connected to the distribution network within the province; they often do not input power onto the transmission system.

With these key assumptions made, a long-term expansion model is used to simulate the wholesale electricity market and calculate market-driven capacity additions. If economical, renewables projects are added by the model. Combined-cycle and simple-cycle units are assumed to be the main sources of firm capacity additions.

## **6.2 GENERATION SCENARIOS**

### **6.2.1 Reference Case Scenario**

The AESO's Reference Case can be characterized as the “base” case. Against this scenario, all other scenarios will be compared to understand impacts of changing specific assumptions within the other scenarios.

The Reference Case incorporates recent information and announcements with respect to generation and supply of electrical energy in Alberta at the time of 2017 LTO development. This encompasses announcements made by the Government of Alberta, the federal government and major stakeholders.

### **6.2.2 Assumptions**

#### ***Coal retirements and conversions to gas***

The Reference Case assumes that approximately 2,400 MW of coal-fired capacity will be converted to natural gas-fired generation between 2021 and 2023. These units are assumed to operate as coal-to-gas (CTG) units for 15 years before retiring. The remaining coal-fired units are assumed to retire between 2019 and 2030 in order of vintage and at a rate of no more than two units per year. A detailed coal retirement schedule for the Reference Case can be found in Appendix A.

### **Generation location assumptions**

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. Technology considerations include utilizing existing infrastructure (such as brownfield sites), fuel resources (such as the location of strong wind and solar resources), future planned transmission enhancements, and developer information. Within these regions, unit-specific locations are assigned to locations on the transmission system such that they utilize the existing transmission capability and minimize the impact to transmission reinforcement requirements, subject to resource availability and generation technology considerations.

Renewable generation additions, primarily wind generation, are split between the AESO's South and Central planning regions, with some resources anticipated to develop in the Northwest Planning Region. The actual location of future wind generation and other renewable projects, including their development timeframe, will ultimately depend upon developer decisions, REP outcomes, availability of integration capability and other factors. The locations of renewable generation stated within the 2017 LTO represent a reasonable assumption, based on where resources are available, to be used as a starting point for transmission planning purposes.

Utility-scale solar generation is assumed to locate in the South and Central planning regions. Solar resources are best in the South Planning Region, with highly suitable resources also located in the Central Planning Region.

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

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

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

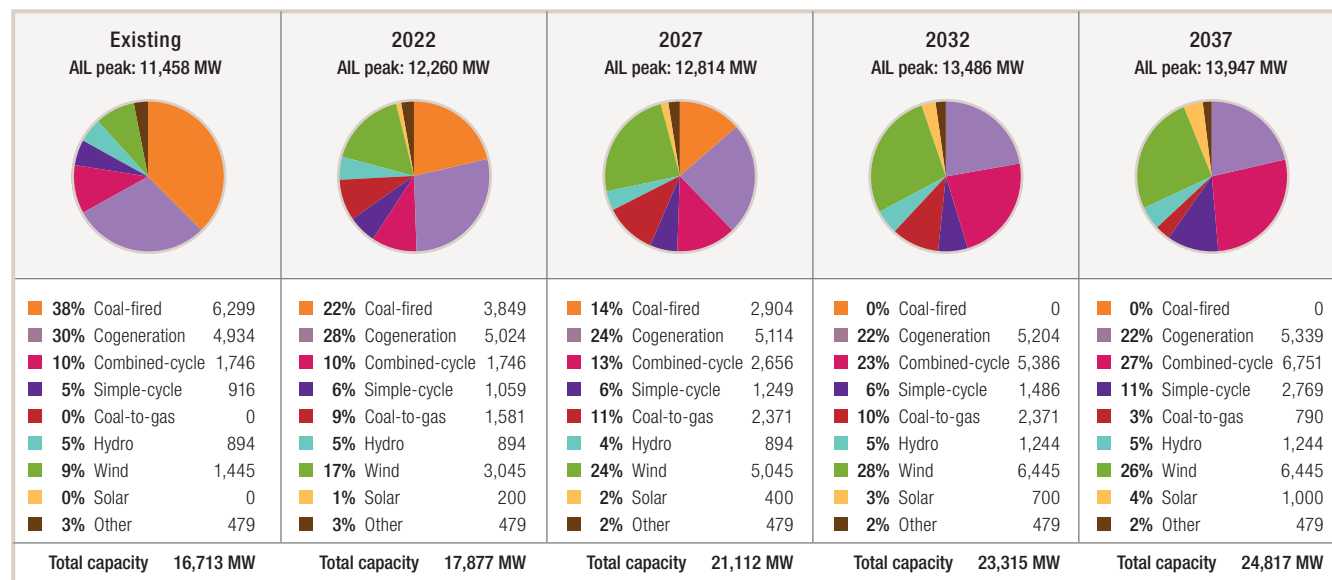
Please see the planning region map in Appendix C.

### **6.2.3 Results**

There are a number of relevant results derived from the aforementioned assumptions in the Reference Case. Coal generation is phased out by the end of 2030, as per provincial policy, and is replaced with firm natural gas capacity including both coal-to-gas converted units as well as combined-cycle and simple-cycle additions.

Renewable energy provides 32 per cent of energy produced in Alberta and represents 36 per cent of total installed generation capacity. By 2037, approximately two-thirds of energy generated in Alberta originates from renewables and cogeneration.

Additional details of the Reference Case generation scenario, including regional data, can be found within the 2017 LTO [data file](#).

**FIGURE 3: Reference Case Scenario capacity\***

\*Future capacity as of the end of year; existing capacity includes under-construction projects.

### 6.3 HIGH COAL-TO-GAS CONVERSION SCENARIO

There is uncertainty around the amount and potential of future coal-to-gas conversion. As mentioned in Section 3.0, the federal government is considering changes to coal emissions regulation, and is developing a gas emission regulation which could either encourage or discourage coal-to-gas conversions. The High Coal-to-gas Conversion (High CTG) Scenario tests whether most coal-fired units will convert to gas. This scenario, in effect, tests an upward boundary of coal-to-gas conversion in Alberta.

#### 6.3.1 Assumptions

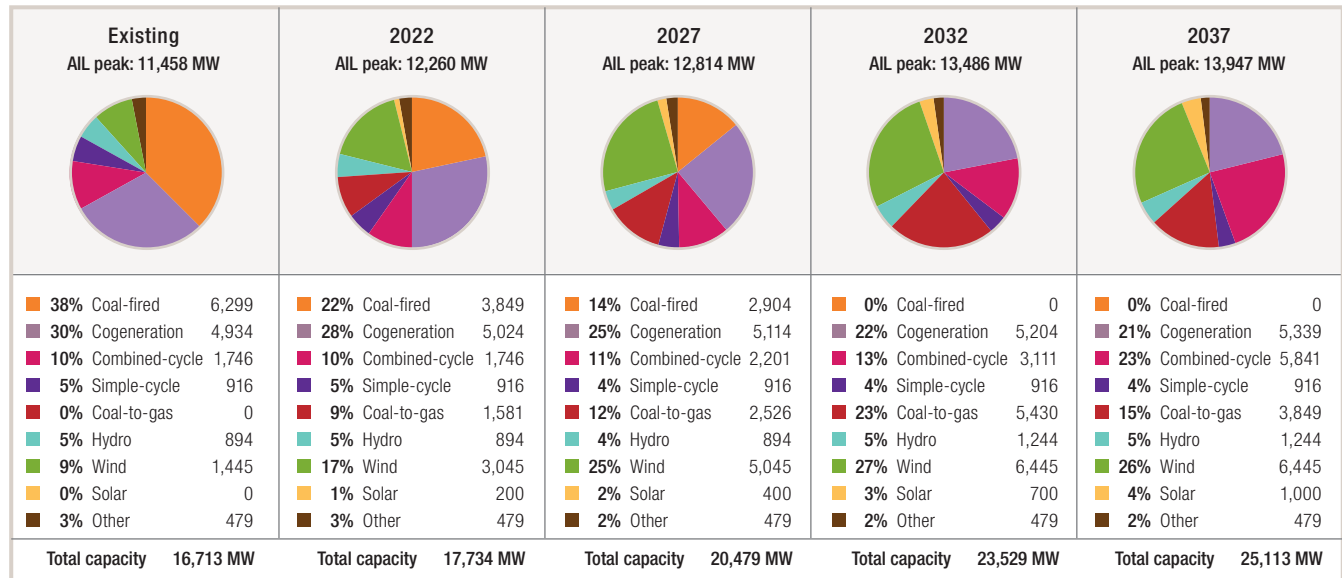
The majority of assumptions in the High CTG Scenario are the same as in the Reference Case. The key difference is that approximately 5,400 MW of coal units are converted to gas-fired units between 2021 and 2030. The remaining amount (approximately 900 MW) of coal capacity is older and is therefore assumed to retire in this scenario. The conversion and retirement schedule for this scenario is identified in Appendix A. All other assumptions in this scenario are the same as in the Reference Case.

#### 6.3.2 Results

The key difference in results between the High CTG Scenario and the Reference Case is that new gas generation development occurs later in the forecast (mid-to-late 2030s). The effect of converting coal units to natural gas means the coal retirement-driven need to build new generation is effectively delayed. The additional CTG conversions occur at existing coal-fired facilities; they primarily offset simple-cycle builds which have considerable flexibility in terms of where they can locate. As a result, the High CTG Scenario has more gas-fired generation located at existing coal-fired generation sites compared to the Reference Case.

Other results are similar to the Reference Case. By 2030, over 30 per cent of energy in Alberta comes from renewable sources and by 2037, renewables and cogeneration make up approximately two-thirds of total energy.

**FIGURE 4: High Coal-to-gas Scenario capacity\***



\*Future capacity as of the end of year: existing capacity includes under-construction projects.

## 6.4 NO COAL-TO-GAS CONVERSION SCENARIO

Due to uncertainty regarding federal coal and gas emission regulations which could impact the incentives for coal-to-gas conversion, the 2017 LTO contains a No Coal-to-gas (No CTG) Scenario where none of the coal-fired units in Alberta convert to natural gas.

### 6.4.1 Assumptions

The assumptions in the No CTG Scenario are nearly the same as the Reference Case except there are no coal-to-gas conversions. Instead, coal-fired units are assumed to retire based on the following criteria: the 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. The coal retirement schedule for the Low CTG Scenario can be found in Appendix A.

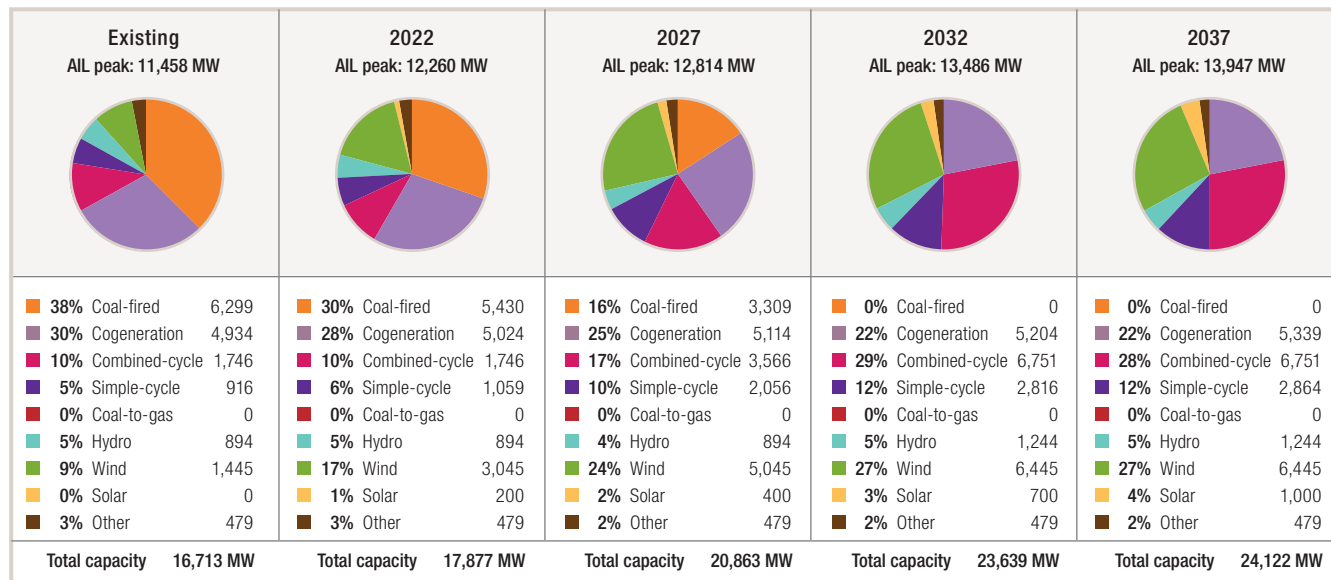
Similar to the Reference Case, the combined-cycle units developed in this scenario are primarily assumed to be built at brownfield coal sites.

### 6.4.2 Results

In the No CTG Scenario, new gas-fired units are required to replace coal-fired units as they retire. Therefore, combined-cycle and simple-cycle units build sooner compared to the Reference Case. However, by the end of the forecast horizon (2037), the total number of combined-cycle and simple-cycle units in the No CTG Scenario is similar to the Reference Case as the CTG units in the Reference Case are assumed to retire by 2038.



**FIGURE 5: No Coal-to-gas Scenario capacity\***



\*Future capacity as of the end of year: existing capacity includes under-construction projects.

## 6.5 NEW LARGE-HYDRO GENERATION SCENARIO

Initiatives such as the RECSI are considering impacts from large-scale infrastructure projects such as large hydroelectric (hydro) generation development in Alberta. The New Large-hydro Generation Scenario (New Large-hydro) considers the construction of a large hydro generation development in Alberta and uprates at existing hydro sites.

### 6.5.1 Assumptions

Alberta has several river systems suitable for relatively large hydro development. Depending on the river and the configuration of the hydro facility, the impacts to the generation forecast can vary. The Peace River has managed water flows from upstream storage dams, thereby changing the flow and energy output profile. The Athabasca and Slave rivers do not have managed water flows, resulting in seasonal variation of flows. Run-of-river facilities normally have seasonal flows and output unless they are managed upstream, or they must be relatively small in order to allow for daily shaping of output. This is in contrast to large storage dams which are capable of managing water flow and storing sufficient water for year-round output.

For the purpose of this scenario, a new 1,000 MW run-of-river hydroelectric generation facility on the Slave River is assumed to come into service 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 uprates at existing North Saskatchewan River hydro facilities of 170 MW in the late 2020s which, in conjunction with the 350 MW already assumed in the Reference Case and other scenarios, means 1,520 MW of new hydro is assumed to develop in this scenario.

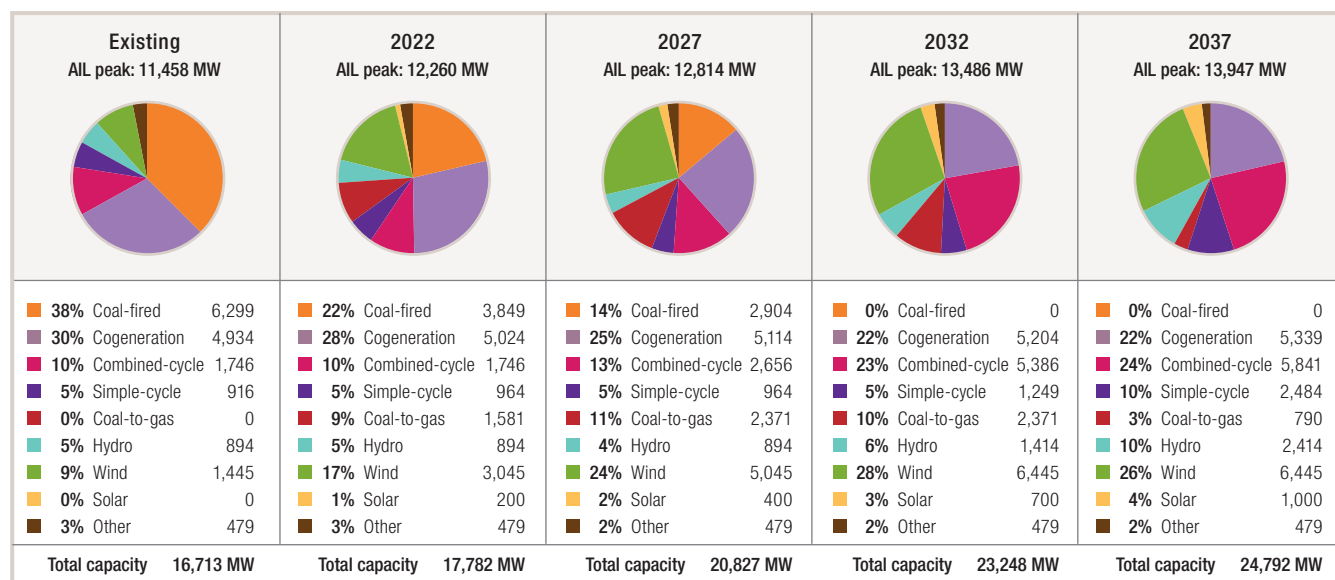
The remaining assumptions in this scenario are the same as the Reference Case.

### 6.5.2 Results

The results of the New Large-hydro Scenario are the same as the Reference Case until the development of the new hydro facilities is complete. The 170 MW of hydro uprates have no impact on overall capacity development and a minimal impact on renewable energy production.

The large hydro development in the 2030s effectively replaces some combined-cycle additions late in the forecast horizon, based on its assumed contribution to the reserve margin. However, there are limitations to the effective capacity of large run-of-river facilities on unmanaged river systems. The seasonal nature of the flows on these rivers means the run-of-river facilities will typically see significant flows and energy output during spring months when demand is relatively light, then significantly lower flows during other times of the year when demand is higher. This can limit the potential of hydro to replace gas facilities unless the facilities have large storage, which would add to the cost, environmental and regulatory requirements.

**FIGURE 6: New Large-hydro Generation Scenario capacity\***



\*Future capacity as of the end of year: existing capacity includes under-construction projects.

## 6.6 WESTERN INTEGRATION SCENARIO

The RECSI project is considering potential new infrastructure projects in western Canada, including a new intertie between B.C. and Alberta. The Western Integration Scenario considers a new large intertie between the two provinces.

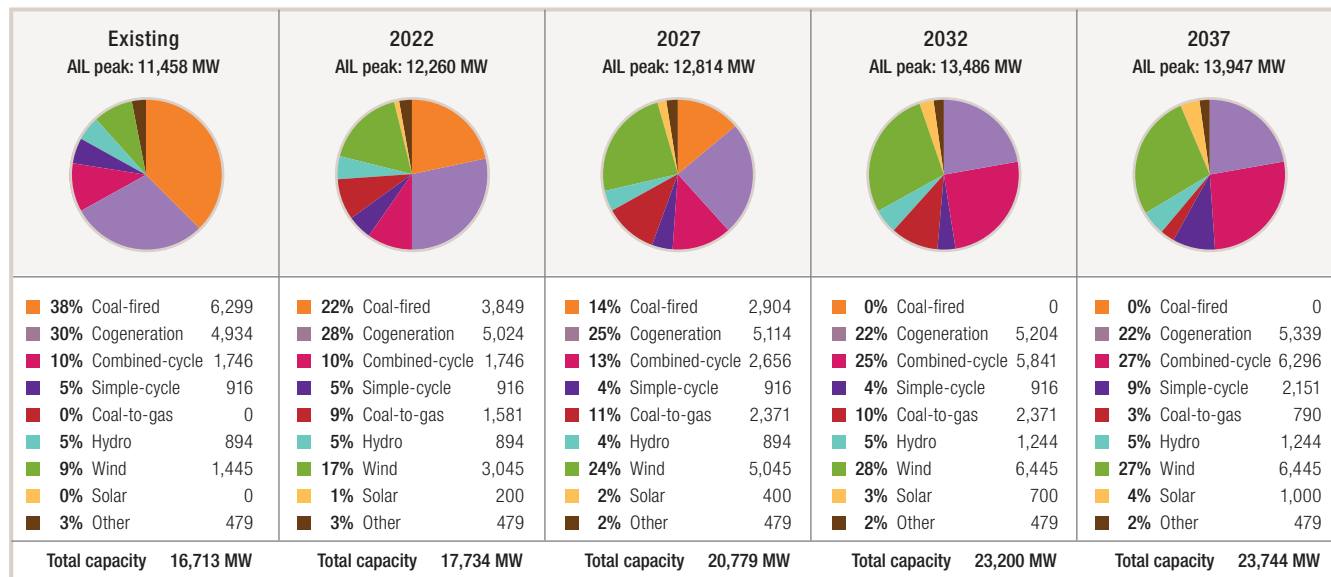
### 6.6.1 Assumptions

The main assumption of the Western Integration Scenario is that a new transmission line with approximately 1,700 MW of nameplate transfer capability between Alberta and B.C. is developed and comes into service by 2027. This intertie is assumed to operate as an opportunity service (as opposed to a firm service), similar to the existing Alberta–B.C. interconnection.

With a second large intertie to B.C., the total effective transfer capability with B.C. could reach 1,700 MW following the restoration of the existing 1201L (Path-1) intertie. The total Alberta transfer-in

capability could reach up to approximately 2,000 MW including the Montana–Alberta tie-line. This simultaneous transfer capability allows the new intertie to fully back the existing intertie, and an outage of the existing or new tie-line will not cause a trip of the other tie-line(s). The remaining assumptions in this scenario are the same as in the Reference Case.

**FIGURE 7: Western Integration Scenario capacity\***



\*Future capacity as of the end of year: existing capacity includes under-construction projects.

**6.6.2 Results**

The overall results in the Western Integration Scenario are not significantly different from the Reference Case. The main difference is that less simple-cycle capacity is required under the Western Integration Scenario because the intertie offers ramping capability, offsetting some simple-cycle requirements. However, since the intertie is assumed to operate as an opportunity service, its capacity is not considered firm and therefore it does not materially displace firm gas generation builds in Alberta. Although the generation capacity in this scenario is not very different from the Reference Case, it is still a useful scenario for the AESO to understand the operational, transmission and market considerations evolving from it.

**6.7 HIGH COGENERATION SCENARIO**

The CLP introduces limits to oilsands emissions<sup>18</sup> with 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. The High Cogeneration Scenario considers a larger amount of cogeneration development compared to the Reference Case.

<sup>18</sup> [www.alberta.ca/climate-oilsands-emissions.aspX](http://www.alberta.ca/climate-oilsands-emissions.aspX)

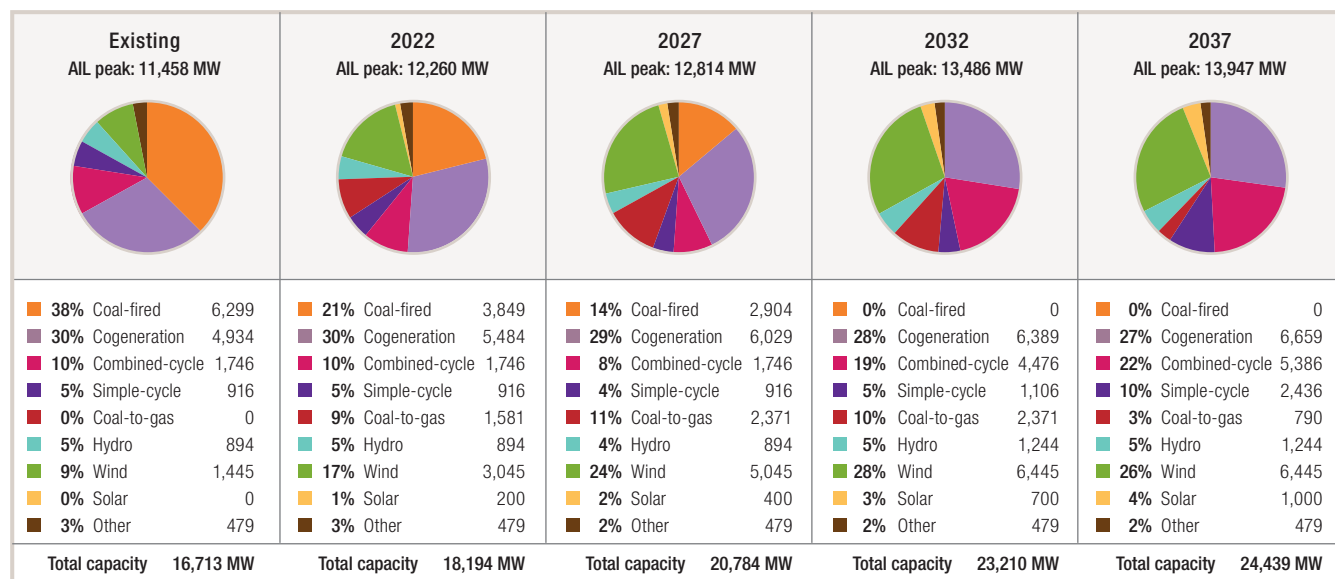
### 6.7.1 Assumptions

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

### 6.7.2 Results

The primary impact of additional cogeneration development is that it displaces combined-cycle and simple-cycle capacity additions assumed in the Reference Case. Due to a large portion of the additional cogeneration coming online in the early 2020s, new combined-cycle and simple-cycle unit builds are deferred when compared with the Reference Case. By 2037 under this scenario, renewables and cogeneration make up approximately three-quarters of total energy.

**FIGURE 8: High Cogeneration Scenario capacity\***



\*Future capacity as of the end of year: existing capacity includes under-construction projects.

## 6.8 LOW LOAD-GROWTH SCENARIO

The Low Load-growth Scenario is based on the low load-growth outlook outlined in Section 5.2.3. To test the impacts of lower load growth in isolation, the majority of assumptions are the same as the Reference Case.

### 6.8.1 Assumptions

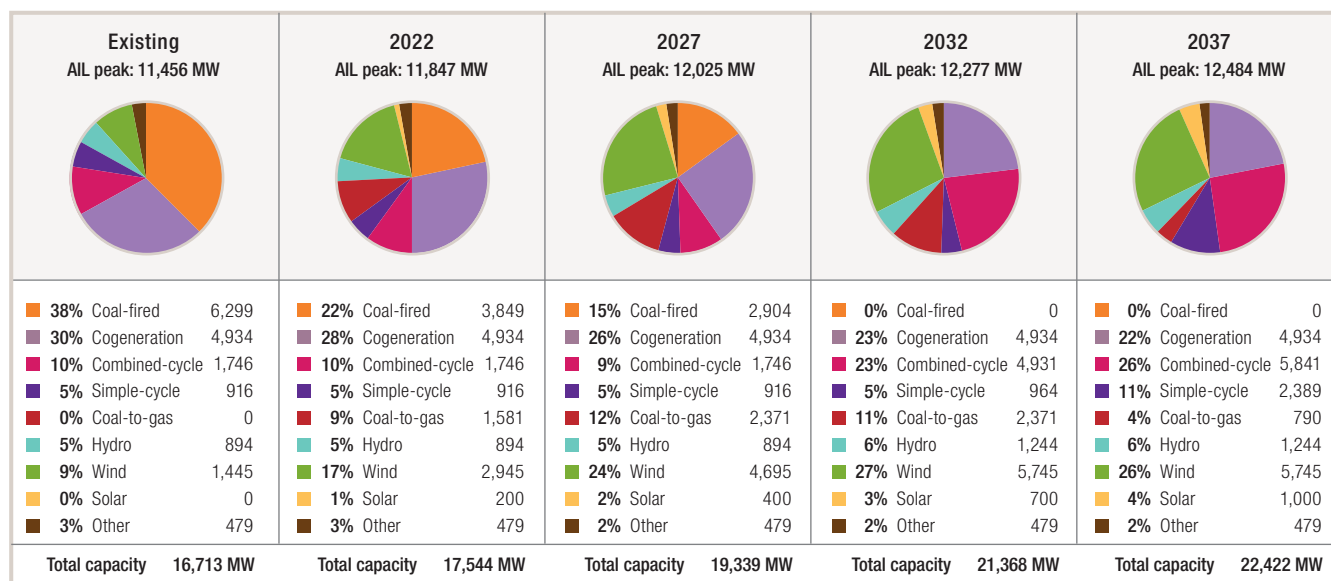
There are two key assumption changes in the Low Load-growth Scenario from the Reference Case. The first is that due to lower oilsands growth in the Low Load-growth Scenario, the amount of assumed cogeneration growth is reduced. Only existing and under-construction cogeneration is included in this scenario.

The second key assumption change is that with lower load growth, less capacity of installed renewables is required in order to achieve 30 per cent of energy produced in Alberta from renewable sources by 2030. The Low Load-growth Scenario has 4,300 MW of wind additions compared to 5,000 MW under the Reference Case.

### 6.8.2 Results

Due to the lower load growth of this scenario compared to the Reference Case, less combined-cycle and simple-cycle generation develops over the forecast horizon. The majority of new firm gas generation is for replacement of coal-fired retirements rather than load growth. The reduction of load growth also means that gas-fired builds are delayed compared to the Reference Case, with new additions required in the late 2020s instead of the early-to-mid 2020s.

FIGURE 9: Low Load-growth Scenario capacity\*



\*Future capacity as of the end of year: existing capacity includes under-construction projects.

# Appendix A

## COAL-FIRED GENERATION RETIREMENT/COAL-TO-GAS CONVERSION SCHEDULE

This appendix contains the assumed retirement dates for the 2017 LTO scenarios. The actual retirement dates will depend on coal-unit owner decisions.

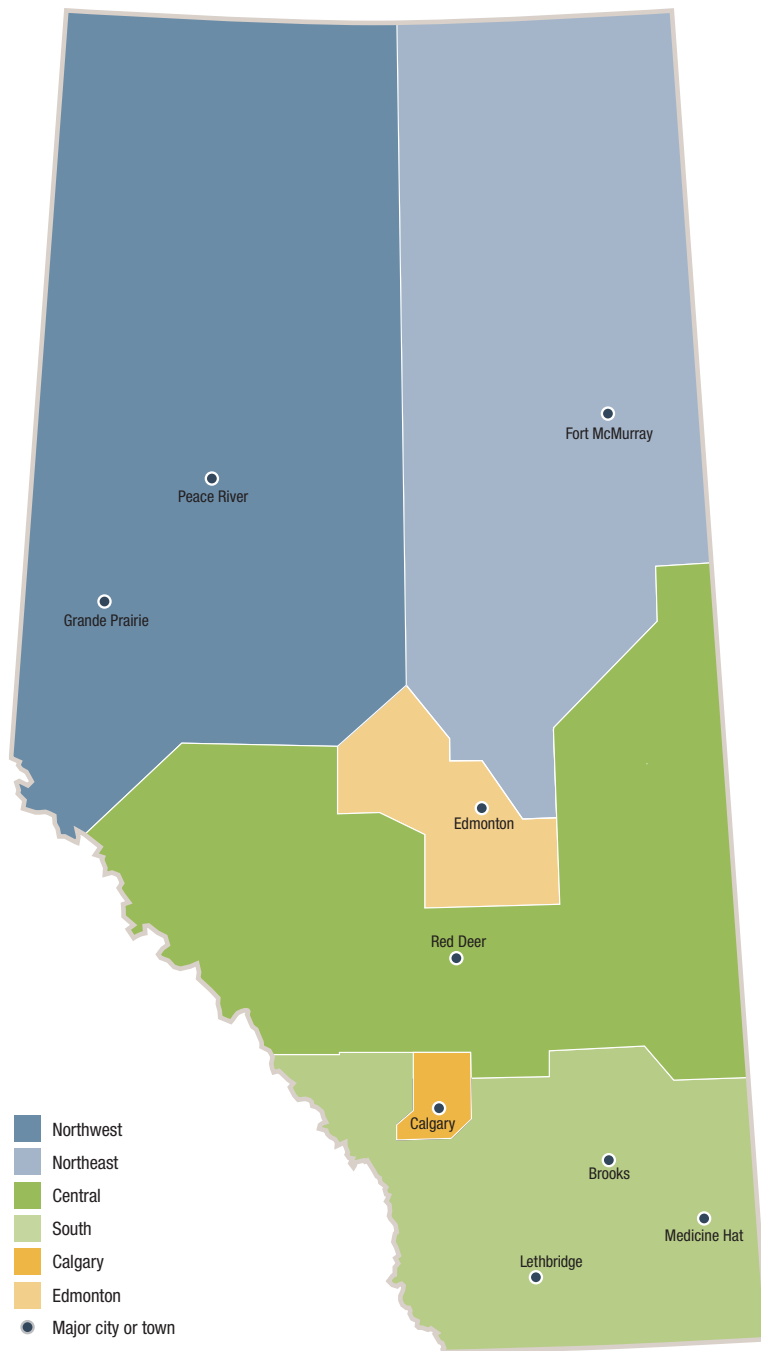
**TABLE 1: Coal retirement date assumptions**

Asset	Year of Commissioning	End of Useful Life Under Current Federal Coal Regulations	Reference Case, High Hydro, Western Integration, High Cogeneration, Low Load-growth	Low Coal-to-gas Conversion	High Coal-to-gas Conversion
Battle River #3 (BR3)	1969	Dec. 31, 2019	Dec. 31, 2019	Dec. 31, 2019	Dec. 31, 2019
Sundance #1 (SD1)	1970	Dec. 31, 2019	Dec. 31, 2019	Dec. 31, 2019	Dec. 31, 2019
H.R. Milner (HRM)	1972	Dec. 31, 2019	Dec. 31, 2019	Dec. 31, 2019	Dec. 31, 2019
Sundance #2 (SD2)	1973	Dec. 31, 2019	Dec. 31, 2019	Dec. 31, 2019	Dec. 31, 2019
Battle River #4 (BR4)	1975	Dec. 31, 2025	Dec. 31, 2025	Dec. 31, 2024	Dec. 31, 2025*
Sundance #3 (SD3)	1976	Dec. 31, 2026	Dec. 31, 2020*	Dec. 31, 2024	Dec. 31, 2020*
Sundance #4 (SD4)	1977	Dec. 31, 2027	Dec. 31, 2020*	Dec. 31, 2025	Dec. 31, 2020*
Sundance #5 (SD5)	1978	Dec. 31, 2028	Dec. 31, 2021*	Dec. 31, 2025	Dec. 31, 2021*
Sundance #6 (SD6)	1980	Dec. 31, 2029	Dec. 31, 2021*	Dec. 31, 2026	Dec. 31, 2021*
Battle River #5 (BR5)	1981	Dec. 31, 2029	Dec. 31, 2027	Dec. 31, 2026	Dec. 31, 2027*
Keephills #1 (KH1)	1983	Dec. 31, 2029	Dec. 31, 2022*	Dec. 31, 2027	Dec. 31, 2022*
Keephills #2 (KH2)	1984	Dec. 31, 2029	Dec. 31, 2022*	Dec. 31, 2027	Dec. 31, 2022*
Sheerness #1 (SH1)	1986	Dec. 31, 2036	Dec. 31, 2028	Dec. 31, 2028	Dec. 31, 2028*
Genesee #2 (GN2)	1989	Dec. 31, 2039	Dec. 31, 2029	Dec. 31, 2029	Dec. 31, 2029*
Sheerness #2 (SH2)	1990	Dec. 31, 2040	Dec. 31, 2028	Dec. 31, 2028	Dec. 31, 2028*
Genesee #1 (GN1)	1994	Dec. 31, 2044	Dec. 31, 2029	Dec. 31, 2029	Dec. 31, 2029*
Genesee #3 (GN3)	2005	Dec. 31, 2055	Dec. 31, 2030	Dec. 31, 2030	Dec. 31, 2030*
Keephills #3 (KH3)	2011	Dec. 31, 2061	Dec. 31, 2030	Dec. 31, 2030	Dec. 31, 2030*

\*Denotes coal-to-gas conversion dates

# Appendix B

## PLANNING REGION MAP



# Appendix C

## ALBERTA RELIABILITY STANDARD REQUIREMENTS

The AESO has undertaken an initiative to adopt the applicable North American Electric Reliability Council (NERC) reliability standards as Alberta Reliability Standards.

In January 2010, four standards were approved relating to modelling, data and analysis (MOD) and load forecasting. The four standards relating to documentation and reporting requirements are listed in Table 2.

More information regarding Alberta Reliability Standards can be found on the [AESO website](#)

Under MOD-016-AB-1.1, the AESO must have documentation identifying the scope and details of the actual and forecast demand data and net energy for load data to be reported for system modelling and reliability analyses. This 2017 LTO publication is that documentation. In accordance with MOD-016-AB-1.1, the 2016 LTO is published and distributed within 30 calendar days of a revision being approved by the AESO.

Under MOD-017-AB-0.1, the AESO is required to report, on an annual basis, to the Western Electricity Coordinating Council (WECC) monthly and annual hourly peak demand and energy for the prior year as well as forecast for the next 10 years. Under MOD-019-AB-0, the AESO must also provide to WECC its forecast of interruptible demand data for the next 10 years for summer and winter peak system conditions. This data is included in the 2017 LTO data file.

Under MOD-018-AB-0, the AESO must indicate whether the demand data of entities not within the Alberta balancing authority area is included. For the purposes of this document, the load of other balancing authorities is not included in any of the values or figures shown. That MOD also requires that the AESO address how it treats uncertainties in the forecast. The AESO uses scenarios to deal with uncertainties.

**TABLE 2: Reliability requirements – documentation and reporting standards**

<b>MOD-016-AB-1.1</b>	Documentation of Data Reporting Requirements for Actual and Forecast Demands, and Net Energy for Load
<b>MOD-017-AB-0.1</b>	Aggregated Actual and Forecast Demands and Net Energy for Load
<b>MOD-018-AB-0</b>	Reports of Actual and Forecast Demand Data
<b>MOD-019-AB-0</b>	Forecast of Interruptible Demands Data

## LOAD FORECAST REPORTING TO WECC

For compliance to the related standards as described above, as well as reporting requirements to WECC, AESO load forecasts are described in the following terms:

- A) Alberta Internal Load (AIL)
- B) Behind-the-Fence (BTF) is classified as Non-reserved Demand
- C) Demand Opportunity Service and Load Shed Service – Imports (LSSI) are classified as Non-firm Demand
- D) Load that is not classified as either non-reserved or non-firm is classified as: Firm Peak Demand such that **A=B+C+D**





# 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).

**Baseload generation:** Generation capacity normally operated to serve load on an around-the-clock basis.

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

**Biomass:** Organic matter that is used to produce synthetic fuels or is burned in its natural state to produce energy. Biomass fuels include wood waste, peat, manure, grain byproducts and food processing wastes.

**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.

**Capability:** The maximum load that a generating unit, generating station or other electrical apparatus can carry under specified conditions for a given time period without exceeding limits of temperature and stress.

**Carbon offset:** A financial instrument representing a reduction in greenhouse gas (GHG) emissions.

**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.

**Demand (electric):** The volume of electric energy delivered to or by a system, part of a system, or piece of equipment at a given instant or averaged over any designated period of time.

**Demand-side management:** Activities that occur on the demand (customer) side of the meter and are implemented by the customer directly or by load-serving entities.

**Dispatch:** The process by which a system operator directs the real-time operation of a supplier or a purchaser to cause a specified amount of electric energy to be provided to, or taken off, the system.

**Distribution-connected generation:** Small-scale power sources typically connected to a distribution system at customer locations.

**Emission intensity:** The ratio of a specific emission (such as carbon dioxide) to a measure of energy output. For the electricity sector, emission intensity is usually expressed as emissions per megawatt hour (MWh) of electricity generated.

**Gas turbine:** See: simple-cycle.

**Generating unit:** Any combination of an electrical generator physically connected to reactor(s), boiler(s), combustion or wind turbine(s) or other prime mover(s) and operated together to produce electric power.

**Geothermal energy:** Where the prime mover is a turbine driven either by steam produced from hot water or by natural steam that derives its energy from heat found in rocks or fluids beneath the surface of the Earth.

**Gigawatt (GW):** One billion watts.

**Gigawatt hour (GWh):** One billion watt hours.

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

**Greenhouse gas (GHG) emissions:** Gases that trap the heat of the sun in the Earth's atmosphere, producing a greenhouse effect.

**Grid:** A system of interconnected power lines and generators that is operated as a unified whole to supply customers at various locations. Also known as a transmission system.

**Independent system operator (ISO):** A system and market operator that is independent of other market interests. In Alberta the entity that fulfils this role is the Alberta Electric System Operator.

**Intertie:** A transmission facility or facilities, usually transmission lines, that interconnect two adjacent control areas.

**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 time period and, through comparison, show what percentage of potential load was actually used.

**Megawatt (MW):** One million watts.

**Megawatt hour (MWh):** One million watt hours.

**Offset:** See: carbon offset.

**Peak load/demand:** The maximum power demand (load) registered by a customer or a group of customers or a system in a stated time period. The value may be the maximum instantaneous load or, more usually, the average load over a designated interval of time such as one hour, and is normally stated in kilowatts or megawatts.

**Point-of-delivery (POD):** Point(s) for interconnection on the transmission facility owner's (TFO) system where capacity and/or energy is made available to the end-use customer.

**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 generation 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.

**Solar (power):** A process that produces electricity by converting solar radiation into electricity or to thermal energy to produce steam to drive a turbine.

**Tariff (Transmission):** The terms and conditions under which transmission services are provided, including the rates or charges that users must pay.

**Tie-line:** See Intertie.

**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 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.

**Watt:** The unit of power equal to one joule of energy per second. It measures a rate of energy conversion. A typical household incandescent light bulb uses electrical energy at a rate of 25-to-100 watts.

**Watt hour (Wh):** An electrical energy unit of measure equal to one watt of power supplied to or taken from an electric circuit steadily for one hour.

This document complements the AESO's existing publications and supports our commitment to sharing information with market participants, other stakeholders and all Albertans in a timely, open and transparent manner. Readers are invited to provide comments or suggestions for future reports. For more information, or to provide feedback, contact [\*\*forecast@aeso.ca\*\*](mailto:forecast@aeso.ca)

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