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Executive Summary
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The electric transmission system is a key foundation for Alberta’s continued prosperity. With a solid transmission system, power generation, distribution, imports and exports can occur in a manner that enables the provision of safe, reliable and economic electricity. The Alberta Electric System Operator (the AESO) is responsible for planning the transmission system so facilities are in place in a timely manner. This ensures electricity consumers and suppliers have a robust, reliable and efficient system on which they can confidently plan and make investments.

In its Long-term Transmission System Plan (the Plan), the AESO projects the future electrical needs of the province, considers relevant trends and factors and plans the transmission system to meet the requirements of legislation, regulations and industrywide standards.

The 2007 load forecast was a major input into the Long-term Transmission Plan. The AESO recognizes that many factors affect load growth, and that actual load in the future could be higher or lower than forecast.

The nature of transmission is that it is built in large increments and has a long service life (30 to 40 years). The prudent and preferred approach is to add transmission capacity that accommodates long-term growth and minimizes land-use impacts. Stakeholder feedback received through the AESO’s consultation processes supports this approach, as does the Provincial Energy Strategy and the Transmission Regulation.

This long-term approach addresses the risk associated with building low capacity transmission lines to meet a load forecast that, in hindsight, is lower than the actual load growth experienced during the time period. If this were to occur, additional transmission reinforcement would be needed to accommodate the higher load growth. Building more low capacity transmission lines would result in additional land impacts that could have been avoided by installing larger capacity facilities in the first instance, which reduces overall land use and meets long-term growth.
Key factors influencing the Plan are:

- Increasing forecast load growth averaging three per cent annually over the long term.
- The large generation build (11,500 megawatts (MW)) needed over the next 20 years to keep up with load growth and replace retiring generation units.
- The need to plan and build transmission in advance of generation and intertie developments.
- Increasing demand to integrate renewable and low-emission sources of electricity such as wind, hydro, biomass and gasification.
- Increasing the efficiency with which electricity is transmitted and consumed.
- Enabling a robust, competitive market for electricity.
- Minimizing land-use impacts of transmission.
- Enabling economic development.
- Near-term opportunities for lower costs of materials and increased labour availability.

These factors recognize the value of implementing high capacity transmission lines to minimize long-term land-use impacts. The Alberta government’s Provincial Energy Strategy, which was released in December 2008, emphasized renewable energy, low-emission energy and cleaner electricity production from fossil fuels. Increasing the amount of generation from renewable resources increases the need for transmission.

Renewable generation occurs when and where nature provides it, which is often a significant distance from load centres. A strong transmission network is needed to transport electricity when and where the wind is blowing at wind generation sites or when high river flows occur at hydro plants. Conversely, transmission is key to maintaining reliability when renewable generation is at a low output level (as happens when there is no wind or during dry hydro conditions) since energy from other generation sources is needed to deliver to load centres.

The AESO’s Plan presents an integrated, comprehensive and strategic upgrade of the transmission system that: meets statutory requirements, aligns with government policy/strategy respecting electricity, meets load growth, and facilitates resource development. Figure 1 shows the critical transmission system developments expected over the next 10 years.
Figure 1: Long-term critical transmission system development

Transmission Development Projects

- 1. Edmonton-Calgary
- 2. Heartland
- 3. Wabamun Lake-Edmonton-Fort McMurray
- 4. Southern Alberta (wind)
- 5. South Calgary
- 6. Wabamun Lake-Northwestern Alberta
- 7. Fort McMurray-Slave River Hydro
- 8. Interties

Note: For illustrative purposes only; does not depict actual line routes or substation locations.
A central feature of the Plan is two high capacity, high efficiency lines between the Edmonton and Calgary areas. These lines will connect four important electrical zones or hubs:

- **The Southern hub.** This hub is central to substantial renewable generation development potential in southeastern Alberta and is also likely to be central to new interties with provinces to the east and the U.S. to the south.

- **The Calgary area hub.** This hub serves the major load centre of the City of Calgary and will also receive wind energy from the south and southwestern parts of the province. This hub is already connected to B.C. and further interties to B.C. or the U.S. are possible.

- **The Heartland hub northeast of Edmonton.** This hub is a growing industrial area with substantial projected load growth and the potential for development of low-emission generation. The Heartland hub is a gateway to load growth and hydro and other generation development in northeastern Alberta, and a possible connection to interties to the east and north.

- **The Wabamun Lake/Edmonton hub.** This hub is central to a large portion of Alberta’s existing generation and a gateway to generation and interties in the northwest.

*Photo courtesy of TransCanada Corporation.*

A transmission tower at TransCanada’s Redwater Cogeneration Plant.
The following major projects complement the two high capacity, high efficiency lines between Edmonton and Calgary as previously discussed.

- In the Edmonton region, additional transmission is needed to serve load demands in the Heartland area and to connect the existing system to the Heartland hub.

- In the northeast, two 500 kilovolt (kV) alternating current (AC) lines are planned to connect the Wabamun Lake/Edmonton and Heartland hubs to the Fort McMurray hub. Substantial load growth in the northeast is expected as well as renewable and other generation developments and possibly interties.

- In the northwest, additional AC transmission, likely at 500 kV, will connect to the Wabamun Lake/Edmonton hub to address load growth in the northwest, provide access for renewable generation in the northwest and serve a potential additional northern intertie with B.C.

- In the south, a loop of transmission lines will connect wind and other generation and load to the Southern and Calgary hubs.

- In the Calgary region, additional transmission development is needed to serve the main load centre.

The Plan also includes reinforcements to serve regional loads and generation development as discussed in Appendix K, as well as interties with neighbouring systems.

A summary of the costs and schedule for the above projects is presented in Table 1.

### Table 1: Major transmission reinforcements cost and schedule

<table>
<thead>
<tr>
<th>Project</th>
<th>2008 $ millions</th>
<th>Construction schedule</th>
</tr>
</thead>
<tbody>
<tr>
<td>Edmonton to Calgary reinforcements</td>
<td>3,135</td>
<td>2010 to 2013</td>
</tr>
<tr>
<td>Heartland transmission system...</td>
<td>387</td>
<td>2010 to 2015</td>
</tr>
<tr>
<td>Fort McMurray transmission system...</td>
<td>2,045</td>
<td>2010 to 2016</td>
</tr>
<tr>
<td>Southern Alberta (wind)...</td>
<td>2,454</td>
<td>2010 to 2017</td>
</tr>
<tr>
<td>South Calgary transmission...</td>
<td>100</td>
<td>2011 to 2012</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>8,121</strong></td>
<td></td>
</tr>
</tbody>
</table>

These cost estimates will be refined as the developments proceed and additional in-depth analysis, consultation and detailed information about the proposed facilities becomes available.

This total investment will translate to an increase of about $8 per month on the transmission-related portion of a typical residential consumer’s electricity bill by 2017. Given that any increase will not occur until the specific facilities have been built and placed in service, starting in 2012, the magnitude of the impact included on the bill will vary over time.
The Plan is flexible and will be updated as required. It is based on information available today regarding assumptions of future conditions and circumstances. The AESO reviews the Plan annually to determine if circumstances warrant a significant change and it is updated accordingly should new information become available.

The Plan includes projects that will strengthen the main electricity grid (or backbone), address regional needs, restore capacity of existing interties with other jurisdictions and establish new interties.

The critical transmission developments are briefly described on the following pages.

Edmonton to Calgary transmission reinforcements

The transmission system between Edmonton and Calgary has not been upgraded in over 20 years. Reliability concerns occurring as early as 2009 were identified in the original 2004 Needs Identification Document (NID). Since then, a combination of system improvements and a lower rate of load growth has delayed reliability concerns until 2014. However, a strong and rapid improvement in economic conditions in Alberta could result in system reliability concerns occurring before 2014.

The reinforcement of the transmission system between the Edmonton and Calgary areas is needed to avoid reliability issues for consumers in south and central Alberta, improve the efficiency of the transmission system, restore the capacity of existing interties, and avoid congestion, which limits access to the market by competitive supplies. Limited access prevents the market from achieving a fully competitive outcome. Transmission constraints and congestion also slow the development of new competitive generation in the Edmonton area and further north.

Two high capacity lines are planned to be implemented as soon as possible given the key factors previously listed. 500 kV high voltage direct current (HVDC) technology is currently being recommended for this project due to its higher right-of-way efficiency and low land-use impacts.

Analysis indicates the preferred orientation of these lines is for one line on the west/centre portion of the province, connecting the existing Wabamun Lake/Edmonton hub to the Calgary area hub. The preferred orientation of the second line is on the eastern side of the province, connecting the Heartland hub northeast of Edmonton to the Southern hub.

Construction of both lines substantially increases the usable capacity of the first line. The first line alone cannot be fully utilized without the second line being in service, since the loss of the first line would create too large of a contingency on the system.

The total estimated capital cost of the project is $3,135 million (in 2008 dollars). Construction is planned to begin in 2010 with both lines in service by 2013.
Heartland transmission system reinforcements

The Heartland hub is a growing industrial area where development of highly efficient and low-emission generation sources is expected to occur. The demand for power at Heartland is associated with upgrading bitumen into synthetic crude oil in refinery-type facilities. This location is also a gateway to northeastern Alberta, where load growth is occurring and further generation development, including hydro, is expected. Interries to the east and north could also be served from the Heartland hub.

The AESO is continuing to evaluate the following options for reinforcing the system in this area:

- A new 500 kV double circuit line from an existing substation in south Edmonton (Ellerslie) to a new substation in the Industrial Heartland area.
- A new 500 kV double circuit line connecting into an existing line on the west side of Edmonton to a new substation in the Industrial Heartland area.

Further analysis will be performed to determine which option will be recommended for implementation.

The total estimated capital cost of the project is $387 million (in 2008 dollars). The estimate could change based on the option selected. Construction is planned to begin in 2010 with all facilities in service by 2015.
**Fort McMurray transmission system reinforcements**

The oilsands industry is expected to continue its growth and is the primary driver of the need for new electricity infrastructure development in the northeastern part of Alberta. Electrical demand is driven by facilities associated with the extraction, upgrading and refining of bitumen from the oilsands into synthetic crude.

The specific facilities being recommended for this reinforcement are a 500 kV AC line from the Genesee generating station to a new 500 kV substation in the Fort McMurray area, and a 500 kV AC line from the new Heartland substation to the new Fort McMurray 500 kV substation.

The total estimated capital cost of the project is $2,045 million (in 2008 dollars). Construction is planned to begin in 2010 with all facilities in service by 2016.

**Southern Alberta (wind) transmission system reinforcements**

The South region is currently Alberta's primary wind power generation area, with over 7,500 MW of applications for new wind generation received by the AESO.

The recommended option for south system reinforcement is a combination of new 240 kV transmission lines and a new 500 kV substation connecting to the 240 kV network. The new 240 kV lines would create a loop between Pincher Creek into the existing 240 kV substations at Lethbridge, West Brooks, Janet and Peigan. The looped system would provide a high level of reliability.

The AESO filed a proposed transmission plan with the Alberta Utilities Commission (AUC) at the end of 2008. This plan is flexible enough to accommodate various amounts of future wind power through staged development triggered by specific criteria related to the progression of wind projects.

The total estimated capital cost of all potential stages is $2,454 million (in 2008 dollars). Construction is planned to begin in 2010 with all facilities in service by 2017.

**South Calgary transmission system reinforcements**

The AESO is examining options to reinforce the transmission system in southern Calgary to provide additional support that will reduce exposure to outages. Further analysis and stakeholder consultation is planned. These reinforcements may include an additional substation and/or new 138 kV lines.

One option would be a new 240/138 kV substation near the intersection of Macleod Trail and Highway 22X and associated 240 kV and 138 kV lines to interconnect into the existing system.

The total estimated capital cost of the project is $100 million (in 2008 dollars), depending on which option is selected. Construction is planned to begin in 2011 with all facilities in service by 2012.
Additional critical transmission development

The Plan includes other critical transmission developments that are at a less advanced state of planning as well as upgrades, regional projects and projects currently underway. These developments and their cost estimates are presented in the following tables.

Table 2: Transmission to renewable and low-emission energy zones

<table>
<thead>
<tr>
<th></th>
<th>Cost estimate (2008 $ millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Northwest transmission system reinforcements</td>
<td>500</td>
</tr>
<tr>
<td>Northeast transmission system reinforcements</td>
<td>1,400</td>
</tr>
<tr>
<td><strong>Sub-total</strong></td>
<td><strong>1,900</strong></td>
</tr>
</tbody>
</table>

Table 3: Bulk transmission system projects currently underway

<table>
<thead>
<tr>
<th></th>
<th>Cost estimate (2008 $ millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Various bulk system projects underway</td>
<td>570</td>
</tr>
<tr>
<td><strong>Sub-total</strong></td>
<td><strong>570</strong></td>
</tr>
</tbody>
</table>

Table 4: Long-term regional transmission system plan

<table>
<thead>
<tr>
<th></th>
<th>Cost estimate (2008 $ millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>South region</td>
<td>205</td>
</tr>
<tr>
<td>Calgary region</td>
<td>248</td>
</tr>
<tr>
<td>Central region</td>
<td>964</td>
</tr>
<tr>
<td>Edmonton region</td>
<td>851</td>
</tr>
<tr>
<td>Northeast region</td>
<td>903</td>
</tr>
<tr>
<td>Northwest region</td>
<td>701</td>
</tr>
<tr>
<td><strong>Sub-total</strong></td>
<td><strong>3,872</strong></td>
</tr>
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</table>

The estimated total investment in transmission system reinforcements over the 10-year period is $14,463 million.
Interties

The AESO’s Long-term Plan recognizes that Alberta is part of an electricity grid that spans North America and lays the foundation for the development of additional interties in the future. Alberta is currently interconnected with B.C. and Saskatchewan but for the size of Alberta’s electricity system, it remains one of the least interconnected jurisdictions in Canada.

Interties with neighbouring power systems are an essential part of a reliable electricity system and a competitive market. Interties enable imports of electricity when shortages occur and allow surplus electricity to be exported to other jurisdictions when supply exceeds demand. Interties are essential to comprehensive development of Alberta’s plentiful low-emission resources (e.g., wind and hydro power).

The total cost estimate for the potential intertie projects is $2,125 million (in 2008 dollars). The estimate for future interties is not included in the $14,463 million estimate for transmission reinforcements in Alberta over the next 10 years.

From vision to action

The AESO’s Plan paints a picture of the future role electric transmission infrastructure plays in stimulating Alberta’s economy while integrating much needed system reinforcement.

The AESO has consulted on several of the transmission reinforcements described in this Plan and found that most Albertans:

► recognize the importance of electricity.
► support planning for long-term growth.
► encourage developments that minimize long-term impacts on land and the environment.

The AESO’s Plan takes a comprehensive approach to ensure the electric system is strengthened so that all Albertans can continue to depend on safe and reliable electricity. At the same time, the Plan identifies transmission infrastructure that will provide confidence for investors, including those who want to build more renewable and low-emission power generation for Alberta’s competitive market.

The Plan reflects:

► The AESO’s view of Alberta’s electricity future, which is consistent with existing legislation and the Provincial Energy Strategy’s objective of building transmission infrastructure in advance of investor decisions.
► A plan for how electric transmission will be developed with an emphasis on critical infrastructure planned to be under construction by the end of 2010.
► An approach to transmission development that will enhance opportunities for various forms of electricity generation, including renewable and low-emission sources.
► A connection with electricity consumers who depend on reliable electricity for economic sustainability to run computers, bake bread, heat homes, run farms, operate businesses and energize industry.
► A path forward towards a greener, more prosperous and energy efficient Alberta.
Alberta’s growth during the past several years has been equal to adding two cities the size of Red Deer to the power system every year.
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1.0 Introduction

A key job at the AESO is to build the long-term plan to deliver electricity Albertans can count on to power their everyday lives now and into the future. It is not only mandated in legislation, it is an expression of the AESO’s organizational commitment to Albertans – using expertise to provide the best possible transmission infrastructure to meet the future needs of the province. The AESO takes into account Alberta’s growth potential and the important role the transmission system plays in the investment decisions of business and industry. An overview of Alberta’s electric system is included in Appendix A.

This Long-term Transmission System Plan (the Plan) is a blueprint for Alberta’s critical transmission infrastructure. Over the next 10 years, essential transmission lines will be built to ensure Albertans’ electricity needs are met for decades to come.
The Plan is flexible and will be updated as required. It is based on information available today regarding assumptions of future conditions and circumstances. The AESO reviews the Plan annually to determine if circumstances warrant a significant change and the Plan is updated accordingly should new information become available.

The Long-term Plan takes a comprehensive approach to make sure the backbone of the power grid and the regional system are strengthened so that all Albertans can continue to depend on safe and reliable electricity. At the same time, this approach provides confidence for all power generators, including those who want to build more renewable and low-emission power generating facilities, to compete in Alberta's marketplace. It also provides confidence to investors in industry and business that the reliable electricity they depend on will be available to meet their future plans.

The role of transmission is essential as a public good that must be available in advance of need to be capable of meeting long-term load growth throughout Alberta and to enable business investment and the addition of new generation. The Provincial Energy Strategy sets the framework for the importance of the future role of transmission infrastructure in Alberta's economic development. A copy of the Provincial Energy Strategy is provided as Appendix B.

Electricity plays a critical role in our everyday lives. We flip the switch and the power is there. It gets us out of bed on time, keeps our food cold, cleans our clothes, irrigates our crops and lets us read long after the sun has gone down. Reliable electricity powers our businesses, industry and farms. It underpins Alberta's economic progress, our livelihood and our well-being.
Alberta's future prosperity depends in part on a new vision for building critical transmission infrastructure, so that it leads the development of generation and the business investment decisions that rely upon reliable electricity supply. Needed reinforcements to Alberta's electric transmission system will be in place in a timely manner as a positive signal to investors.

This notion of ‘being ready’ is founded on experience. Economic change happens quickly, whereas electric transmission system development is considered in a long-term context. With investor confidence in the provincial transmission infrastructure, Alberta is poised to be a worldwide leader in renewable and low-emission energy.

Alberta is a leader today in the integration of wind power, and will expand that expertise while enhancing its role in hydroelectricity, clean coal and the use of natural gas. The province has committed to support key, smaller developments such as solar energy, biomass and other distributed generation options. The provincial government is also considering whether nuclear power is an appropriate addition to Alberta's electricity mix.

The long-term approach to transmission system development enables Alberta to use a window of opportunity created by the current economic situation. Materials, labour and equipment to build transmission facilities are more readily available and may be procured at lower cost. This window of opportunity is limited as Alberta will be competing for construction resources that are needed to strengthen electric transmission systems throughout North America and in many parts of the world.
While Alberta's existing transmission system has served us well, no new major transmission facilities have been built in the last two decades. During that time, Alberta has grown significantly. For the past several years, growth has been equal to adding two cities the size of Red Deer to the power system every year. For more information about Alberta’s load growth, refer to the AESO’s *Future Demand and Energy Outlook* in Appendix C.

Growth is straining the system’s capability. The time has come to find ways to facilitate needed transmission development and to facilitate strong investment in the future of Alberta.

The needed transmission lines will be sized to accommodate long-term growth and will use advanced technology where possible to maximize efficiency and minimize environmental impacts. Alberta not only needs critical transmission lines within the province, it also needs stronger connections to regions outside the province. Alberta has one of the least externally interconnected electricity systems in Canada. Interties connect the province to its neighbours and allow Alberta to import and export power while supporting competition, renewable energy development, reliability and supply adequacy. The Long-term Plan lays the foundation to develop this needed additional intertie capacity.

The AESO’s Long-term Plan represents a key step in implementing elements of the Provincial Energy Strategy. With leadership by government in supporting the Plan, new transmission lines needed to connect key regions within the province could begin construction in 2010.

The AESO has applied its expertise to prepare a comprehensive plan to facilitate investment in Alberta, which is consistent with the vision put forward by the government.
2.0

Background
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2.0 Background

2.1 Transmission – Creating a foundation for economic development

Providing electricity reliably and cost-effectively to consumers requires robust infrastructure and an effective market structure. Alberta's electricity infrastructure includes over 12,000 megawatts (MW) of generating resources and 21,000 kilometres (km) of transmission lines continuously and instantly delivering electricity to homes and businesses in every corner of the province. In 2008, the competitive market completed over $8 billion in electricity transactions.

An integral part of the physical electrical infrastructure is the interconnected bulk and regional transmission system that carries electricity from where it is produced to where it is used or distributed. The bulk transmission system includes 240 kilovolt (kV) and 500 kV transmission lines and components associated with the Alberta Interconnected Electric System (AIES). The regional transmission system includes transmission lines and components at voltages of 240 kV or lower that are located in six geographic regions in Alberta.

A strong, efficient and unconstrained “electricity highway” is essential to the delivery of power. It is also necessary to ensure the proper functioning of the market. To enable the efficient operation of the competitive electricity market, transmission must be readily available to all producers and consumers. The system must provide sufficient transmission capacity so electricity can move without constraint from where it is produced to where it is needed to power homes, schools, farms, businesses and industry throughout the province.

The existing transmission system is congested, aging and inefficient. In its current state, it is able to meet today’s needs; however, it will not be able to meet the province’s future needs. Alberta’s economy is expected to continue growing over the next 10 to 20 years and a reliable supply of electricity cannot be sustained without enhancing and expanding the existing transmission system. New infrastructure must be in place before demand arises so investment, market access and economic development are not compromised.
Decisions made by those investing in new sources of generation are based in part on confidence that they can transmit the electricity they generate to consumers. For business or industry, decisions on whether to locate in Alberta and to expand existing operations can only be made when there is reasonable assurance of access to an adequate supply of electricity at reasonably predictable and stable future prices. A robust transmission system provides confidence to investors that they can count on access to the transmission system before making investment decisions. Transmission system planning requires a long-term perspective to ensure that decisions made today will provide a reliable system, maximize future value, reduce land-use impact, and not constrain future choices. Given the long lead time associated with transmission infrastructure projects and 30 to 40 year service lives, these facilities must be developed now to accommodate the needs of Albertans far into the future.

To maintain a continuous supply of electricity, new transmission facilities must be built in anticipation of need. Long lead times associated with permitting and construction of transmission facilities means they may not be built in time to respond to a particular identified need. It can take between 18 months and three years to plan, acquire approvals and build some types of natural gas and wind power generators, while it can take five to eight years to plan, acquire approvals and build new major transmission infrastructure.

Transmission development plans must also recognize that Alberta is part of, and connected to, the North American electricity grid. Transmission interties connecting the grid are an essential part of a reliable electricity system and a competitive market. Interties provide the ability to import power into Alberta when economically attractive and export power when provincial supply exceeds demand. Albertans benefit from these interties since they provide access to potentially lower cost electricity and the revenues received by exporters attract more investment and increase competition.
2.2 Role of the Alberta Electric System Operator

The AESO was created in June 2003. Its focus is to operate and plan the transmission system and operate and facilitate the wholesale electricity market in a reliable and efficient manner for the benefit of all Albertans. The AESO is a not-for-profit organization that acts in the public interest and by legislation cannot own any transmission, distribution, retail or generation assets.

The duties and responsibilities of the AESO are defined in the Province of Alberta Electric Utilities Act (EUA) and the Transmission Regulation. The key duties and responsibilities of the AESO are:

- Ensuring the safe, reliable and economic operation of the AIES.
- Operating the power pool and facilitating markets for electricity in a manner that promotes fair, efficient and open competition.
- Providing transmission system access service via a tariff.
- Managing and recovering the costs associated with line losses and ancillary services.
- Determining the future requirements of the AIES, developing transmission plans over long-term horizons that identify the transmission system enhancements needed to meet those requirements, and making the necessary arrangements to implement those enhancements.

The AESO is mandated to plan the transmission system based on legislation taking into account technical considerations, reliability standards and operating and planning criteria, which ensure reliability and well-functioning markets. In addition, other factors such as government policies, forecast load growth, technological advances and environmental impacts are considered.

The Provincial Energy Strategy sets out the government’s integrated vision for the continuing development of the province’s energy resources. It also identifies the urgent need to strengthen the transmission system to avoid barriers to economic development and enable development of Alberta’s low-emission generation resources. The strategy also calls for a review and streamlining of the regulatory process for siting new transmission, while ensuring that stakeholders continue to have a voice in process. The Provincial Energy Strategy is an important factor that the AESO considers in developing a transmission system that will continue to benefit all Albertans.
2.3 Objectives of the Plan

The Plan, prepared in accordance with Section 10 of the Transmission Regulation, projects the future electrical needs of the province relative to the current capability of the transmission system to determine where and when upgrades and expansions to infrastructure will be needed. It also identifies the technical solutions or options that will best accomplish these expansions in the long term. The Plan presents the AESO’s assessments and identifies projects that are necessary to ensure the transmission system is reinforced in support of Alberta’s economic growth. The Plan evaluates both the bulk and regional transmission systems to develop a comprehensive strategy for enhancing the AIES.

The specific objectives are to:

- Identify cost-effective and technically feasible solutions for bulk and regional transmission system enhancements required to meet anticipated demand and provide the necessary operational flexibility for Alberta’s competitive market.
- Satisfy the planning objectives established by the EUA and Transmission Regulation considering applicable policy and implementing elements of the Provincial Energy Strategy.

While the planning process encompasses a long-term view and assesses the types of projects needed in the future, the Plan is focused on the more immediate term – the next 10 years. These projects are described in Section 4.0.
3.0
AESO’s Planning Process

The cables for a 240 kV transmission line were placed in this conduit and then installed underground in Edmonton. The line is now in service delivering electricity to the city centre.
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3.0 AESO’s Planning Process

The AESO plans Alberta’s transmission system with input from many sources, including stakeholder consultation, government policy, legislation and regulations, the Provincial Energy Strategy and other technical planning considerations. The following sections discuss these sources and the input they provide.

System reliability is defined by compliance with planning and operating criteria for the provincial transmission system that are consistent with North American standards. These standards are based on engineering principles to ensure real-time and long-term system integrity. Additional information on reliability criteria and a copy of the AESO’s transmission planning reliability criteria are available in Appendix D.

As indicated in Appendix C, the AESO’s Future Demand and Energy Outlook indicates Alberta’s growth in demand will average about three per cent annually over the long term.

Detailed information and studies regarding the generation scenarios developed to accommodate load growth are shown in Appendices E, F and G. A major generation build of 11,500 megawatts (MW) is needed in the next 20 years to meet forecast growth in electrical load and replace older generating units that are being retired. The capital cost of new generation could be as much as $35 billion, the risk for which will be borne by investors and not Alberta electricity consumers. Renewable energy development will compound demands on the transmission system because new transmission facilities must be located near the renewable resource, for example, where wind regimes support wind power.

Prudent planning also considers the fact that transmission infrastructure is built in large increments. Sizing transmission capacity to meet needs well into the future mitigates the requirement to repeatedly return to build more transmission lines as Alberta’s economy grows. This long-term planning approach maximizes the use of rights-of-way and minimizes the impacts on land and the environment. Prudent planning also incorporates a degree of flexibility to accommodate changes in the economy and demand for electricity.
The transmission facilities required to meet expected growth in electricity demand and generation developments are discussed more fully in Section 4.0.

Planning and developing a transmission system is a continuous process. Plans must be constantly reviewed and, if needed, revised to reflect material changes in anticipated load and generation development. All the inputs discussed in this Plan, including load forecasts, generation scenarios, reliability criteria and policy objectives, are taken into account in identifying various alternatives for reinforcement of the transmission system.

These alternatives are analyzed individually and in combination through computer simulations of the integrated transmission and generation systems. The simulations allow probing of the operational performance of the system over time spans ranging from a few thousandths of a second to several decades. From these simulation results, the best alternatives are chosen considering a range of factors such as technical feasibility, cost, land-use impact and flexibility to respond to future changes.

This Plan outlines the transmission reinforcements identified by the AESO based on the results of the analysis it has conducted to date. In the months ahead, analysis and consultation will be ongoing and may result in refinements and updates.
3.1 Stakeholder consultation

Stakeholder consultation with the general public, elected officials, special interest groups and others provides the AESO with a broad perspective about the plans it develops. In 2007 and 2008, the AESO carried out extensive public consultation on various proposals to develop or expand the transmission system. This consultation included geographic options, potential technologies, and environmental and social considerations. Consultation took place in many locations throughout Alberta. Stakeholders were engaged through various methods to gather their views on Alberta's critical transmission infrastructure. Their input helped form the transmission system development identified in the Plan.

Over 2,000 stakeholders and members of the general public participated in approximately 300 open houses and group meetings as part of the transmission system development consultation process during 2007 and 2008. Statistics regarding the AESO's consultation activities are presented in Table 3.1-1.

Stakeholders were identified as:
- residents, occupants, landowners and businesses
- elected and administrative government officials at local, municipal and provincial levels
- industry
- First Nations and Métis
- advocacy and environmental groups

Based on the following consultation principles, the AESO used a variety of methods to notify, consult and engage members of these groups including:
- mailings
- newspaper and radio ads
- news releases
- website postings
- meetings and presentations
- correspondence (email and mail)
- telephone
- industry sessions and open houses

Based on feedback received, there is a general recognition that Albertans' growing demand for additional power must be addressed and that transmission reinforcement is necessary.

A common view held by stakeholders was that they prefer reinforcements with higher capacity to accommodate long-term growth that also mitigates the need for repeatedly returning to build more transmission lines in the future. Stakeholders said if they must have towers on their land, they would rather have fewer, larger high capacity towers than many smaller towers with lower capacity.
The AESO’s stakeholder engagement principles

Roles and participation in decision-making

► The AESO makes the decisions on changes and the timing of those changes.

► The AESO uses the experience and expertise of stakeholders to improve the quality and implementation of decisions.

► The AESO determines the level of consultation needed on an issue, based on the perceived significance and impact on stakeholders and the time available.

► All stakeholders have the right to comment on the AESO’s plans, decisions and actions.

The process of making decisions

► All potential changes progress through consistent defined stages from problem identification to implementation and review.

► The AESO’s consultation process and the rationale for the AESO’s decisions are transparent.

Informing stakeholders

► All stakeholders have the right to be informed of the AESO’s direction, plans, status of issues and decisions in a timely manner.

► The AESO communicates a consistent position on potential changes that resolves the perspectives across the AESO’s functions.

Continuous improvement

► The AESO measures the success of its engagement process, and the effectiveness of resulting changes, to improve its future performance.
Table 3.1-1: 2007 to 2009 AESO consultation statistics

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<th>2007</th>
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<td>• Mailed to 550,000 households</td>
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<td>NE Alberta</td>
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<td>chambers of commerce and</td>
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<td>town councils</td>
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<td>2008 Spring edition</td>
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<td>• 1.2 million copies mailed to</td>
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<td>all homes in Alberta</td>
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<td>houses (approx. 2,000 copies)</td>
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<td></td>
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<td>• Over 120 copies distributed to</td>
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<td></td>
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<td>Attended/completed over 36 small group meetings/events throughout the province</td>
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<td>64 presentations</td>
<td>84 presentations</td>
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<td><strong>Letters, open house invitations and project backgronders</strong></td>
<td>2.1 million (October 2007 to January 2009)</td>
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3.2 Legislation and regulation

The *Electric Utilities Act (EUA)* created the AESO and defines the organization’s roles and responsibilities for planning the Alberta Interconnected Electric System (AIES). Appendix H describes the Acts, regulations and policies that provide specific direction for the AESO in various areas of its business, including planning and developing Alberta’s transmission system.

The *Transmission Regulation* provides additional planning and operational direction. It directs the AESO to prepare and maintain a 10-year Transmission System Plan that identifies, among other things, the transmission facilities needed to meet the province’s needs.

The *Transmission Regulation* focuses on transmission system planning and directs the AESO to consider a range of factors when forecasting Alberta’s future requirements and the need for new transmission facilities. These factors include:

- Rates and locations for growth in electricity demand.
- Timing and location of future electricity generation development.
- Providing reliable and efficient access to other jurisdictions.
- Improvements to system reliability that new facilities provide.
- Contributions of new facilities to maintaining a robust competitive market.
- Contributions of new facilities to system operability and efficiency.
- Ability of the system to transmit energy during emergency conditions and to allow for maintenance and construction of new facilities.
- Long-term options for development that new facilities provide.

The *Transmission Regulation* directs the AESO to satisfy reliability standards established by the Western Electricity Coordinating Council (WECC) and North American Electric Reliability Corporation (NERC). Subject to amendments required to ensure Alberta’s circumstances are addressed, the province is in the process of adopting these standards and policies, which ensure consistent planning and operating procedures and processes throughout the interconnected North American grid.
The Transmission Regulation also gives direction regarding transmission congestion and access to other jurisdictions as follows:

- The AESO is to plan for the expansion or enhancement of the transmission system so that under normal operating conditions the system can be operated without constraint and all production from competitive generation sources can be utilized.
- The AESO is to plan for enhancements that will restore existing interties with B.C. and Saskatchewan to their original design capacity.

These requirements accommodate Alberta’s competitive wholesale electricity market. In Alberta, established market policy is such that generation additions are not centrally planned but are built in response to market forces. Generation developers in turn require access to markets through an efficient and effective transmission system. Competitive generation developers decide if and when power plants provide supply into the market, and where and when new power plants will be built. These developers, not electricity customers, carry all the commercial risks resulting from their decisions to build and operate these plants.

Transmission congestion, which occurs when power cannot move freely from one location to another, is an additional factor that influences Alberta’s generation development. Congestion can prevent electricity supply from reaching customers and it can make it difficult to maintain aging infrastructure or integrate much needed new facilities. It can also limit transmission access to other jurisdictions, reducing export opportunities for power that is surplus to the needs of Albertans, and access to the supply of imported power when Albertans need it.

By eliminating congestion and increasing intertie capacity, the reliability of the AIES is enhanced while facilitating a robust competitive electricity market. This gives producers and consumers the confidence to invest in Alberta.

Large industrial consumers and producers of electricity will have the confidence to invest in Alberta as the transmission system is strengthened and the reliability of the AIES enhanced.
3.3 Alberta’s Provincial Energy Strategy

The Provincial Energy Strategy provides for developing Alberta’s energy resources in an environmentally sustainable way for a prosperous economic future for all Albertans.

The Provincial Energy Strategy states that Alberta should strive to be “a global leader, recognized as a responsible world-class energy supplier, an energy technology champion, a sophisticated energy consumer, and a solid global environmental citizen.” To achieve this vision, it focuses on achieving three major outcomes:

- clean energy production
- wise energy use
- sustained economic prosperity

Electricity, as a facilitator of economic development in Alberta, plays a major role in achieving these outcomes.

The Provincial Energy Strategy states that Alberta will take the following steps to strengthen the transmission system:

- Lead the development of a plan for a comprehensive upgrade to the transmission system in Alberta. The plan will identify the requirements, technical solutions and schedules for improving the transmission system in Alberta. Improvements will be sized to accommodate long-term growth and will use, where possible, technology such as high voltage direct current (HVDC) to maximize efficiency of rights-of-way and minimize impacts.
- Adopt and implement a policy to build transmission, as part of the AIES, to zones of renewable or low-emission electricity.
- Adopt and implement a policy to build interties to other markets to ensure an adequate supply of electricity to Alberta as well as to facilitate development of additional wind generation.
The Provincial Energy Strategy includes other complementary objectives including:

- Review and streamline the regulatory process for transmission siting ensuring all issues raised by impacted landowners are heard, impacts are mitigated to the extent possible, and that landowners receive fair compensation.
- Assemble multi-use corridors for the siting of future energy and transportation infrastructure.
- Undertake an extensive education and awareness program to inform Albertans of the need for and benefits of a robust, reliable and efficient transmission system.
- Implement policy and provide financial support for the development and deployment of smart grid technology.

The Provincial Energy Strategy reinforces and augments the direction provided by the EUA and the Transmission Regulation to plan transmission system enhancements that eliminate congestion, facilitate a competitive market, enhance reliability and efficiency, and enable long-term options for future development. It further establishes that advancing the construction of new transmission infrastructure provides value for Albertans by:

- ensuring reliable service
- providing confidence to generation and resource developers
- enabling the development of clean energy
- increasing access to other markets

The Plan implements elements of the Provincial Energy Strategy by setting an Alberta-wide vision of the transmission system that will endure for the next 30 to 40 years.
3.4 Additional planning considerations

The AESO monitors trends and emerging developments over the long term that could affect the need and timing for new transmission facilities. The AESO’s planning process considers how:

- Consumer preferences and changes in energy consumer behaviour may result in changes to the way in which new facilities are planned.
- Technological changes may affect transmission designs and options.
- Increased environmental sustainability may affect sources and locations for load customers and new generators.

An important part of the planning process is keeping pace with new developments that have the potential to change the way electricity is produced, delivered and used in the province.

The AESO’s plans consider these factors and are developed with flexibility so transmission infrastructure choices made today do not constrain options available in the future. The following sections describe some of these long-term considerations.

3.4.1 Conservation

Across North America, the public, governments and industry are increasingly emphasizing the wise use of energy through conservation and energy use management. As part of the Provincial Energy Strategy, the Alberta government plans to support a variety of conservation efforts across all sectors of the provincial economy. In addition, other jurisdictions within Canada and the U.S. are setting conservation targets to reduce environmental impacts and the need for new generation facilities.

This increased focus on using energy wisely may result in changes to the volume, pattern and locations of energy usage in the future. The AESO monitors conservation program developments and trends to ensure future transmission plans consider not only changes in demand, but also how transmission systems can increasingly deliver electricity in more efficient ways.
3.4.2 Technological change

Electric system technology changes will have a major affect on future transmission system development. For example, changes in metering and control technology will allow consumers to make more informed and timely choices about how they use electricity.

New time-of-use patterns and increased conservation can be monitored through smart grid and advanced metering infrastructure (AMI) technology. AMI is technology that gathers, processes and uses customer consumption data in a more detailed way than conventional metering. There are many possible applications for this technology. One option is real-time monitoring that allows customers to optimize electricity consumption.

Smart grid technology is used to improve efficiency and allows more control of the electric system. Smart grid technology can be integrated with AMI. For example, a distribution company may get a customer's permission to remotely turn off their air conditioner when system demand is high.

AMI and smart grid technology have the potential to affect the way consumers use electricity by shifting demand from higher cost, peak times to periods when demand is reduced and electricity prices are potentially lower. In the long term, consumption patterns may change and could increase the efficiency of electricity production and transmission in the province.

Increased use of new technologies like plug-in hybrid electric vehicles (PHEVs) also has the potential to change the way electricity is used. If PHEVs are widely adopted in the future, this technology could result in more off-peak electricity demand. Developments in electric vehicles, energy storage and demand-side management may provide additional resources, which will help accommodate high levels of variable renewable sources of generation such as solar and wind power. This could significantly affect overall consumer demand on the electric system in the long term. While these technologies are in the early stages of development, the AESO is monitoring the potential impacts on future demand volumes and patterns.

Given these developments, the AESO sees an ongoing need for a robust transmission system in Alberta. The AESO will continue to monitor technological trends to ensure its planning process remains flexible and well informed. The AESO’s Plan ensures that the power system is flexible and adaptable and leverages new technologies to enhance system reliability, customer choice and overall efficiency.
3.4.3 Environmental trends

Through the Provincial Energy Strategy, the Alberta government supports renewable energy and has introduced policy direction aimed at strengthening transmission system development in areas with renewable and low-emission generation potential. This is in addition to supporting wind generation through increased intertie capability.

The Provincial Energy Strategy also supports clean coal development, carbon capture and storage technologies and other forms of clean electricity production. Information about the federal and provincial greenhouse gas frameworks is in Appendix H. All these factors have the potential to affect the choices, locations, sizes and characteristics of future generation developments.
4.0

Long-term Transmission System Plan
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4.1 Overview

The value and benefits all Albertans receive from the reliable and efficient delivery of electricity is a major factor in the ongoing economic prosperity of the province and the livelihood and well-being of all Albertans. The transmission system is an important foundation for that continued prosperity.

The AESO ensures that the transmission system is reinforced ahead of the planning cycle for new investment, which creates the growing demand for reliable electricity. This is accomplished by strengthening the system where required and building new facilities in anticipation of increased demands for electricity and new generation capacity.

The critical enhancements to Alberta’s existing electrical infrastructure described in this section will provide far-reaching sustainable benefits, sending positive investment signals for industry to choose Alberta for their business expansion plans or new facilities, and facilitating development of generation that could include supply from renewable and low-emission electricity sources.

The 2007 load forecast presented in Appendix C was a major input for developing the long-term transmission plan presented in this document. The AESO recognizes that many factors affect load growth, and that actual load in the future could be higher or lower than forecast.

The nature of transmission is that it is built in large increments. The prudent and preferred approach is to add transmission capacity that accommodates long-term growth and minimizes land-use impact. Stakeholder feedback received through the AESO’s consultation processes, as well as Alberta’s Energy Strategy and Transmission Regulation, support this approach.

This long-term approach addresses the risk associated with building low capacity transmission lines to meet a load forecast that, in hindsight, is lower than the actual load growth experienced during the time period. If this were to occur, additional transmission reinforcement would be needed to accommodate the higher load growth. Building more low capacity transmission lines would result in additional land impacts that could have been avoided by installing larger capacity facilities in the first instance, which reduces overall land use and meets long-term growth.

The Plan is based on information regarding assumptions of future conditions and circumstances. It is reviewed annually to determine if circumstances warrant a significant change and new versions of the Plan are issued as needed.
4.2 Plan deliverables

The AESO’s technical analysis has examined the many factors and conditions that influence transmission planning and the requirements of the transmission system. This includes legislative and regulatory requirements and reliability criteria.

The transmission requirements and conditions are summarized as follows:

- Increasing forecast load growth averaging three per cent annually over the long term.
- Recognize the potential for increased use of electricity due to its efficiency and low environmental impact at point of use.
- Maintain system reliability.
- Lead the large generation build (11,500 megawatts (MW)) needed in the next 20 years and provide certainty to generation investors.
- Provide access to renewable energy zones in various parts of the province.
- Be responsive to the large interest in renewable generation (current wind power queue exceeds 11,500 MW).
- Provide access to low-emission sources including gasification and the use of waste fuels.
- Increase efficiency, reducing costly and wasteful transmission system losses.
- Restore and expand the province’s transmission intertie capacity for imports and exports of electricity.
- Facilitate the fair, efficient and openly competitive wholesale electricity market through a robust and unconstrained transmission system.
- System reinforcements will be sized to accommodate long-term growth and where possible will use technology such as high voltage direct current (HVDC) to maximize efficiencies of rights-of-way and minimize impacts.
- Minimize land-use impacts by reducing the number and size of rights-of-way used for transmission lines.
- Leverage near-term opportunities of potentially lower commodity prices for steel, aluminum and copper used in electrical equipment.
- Recognize North American demand for the resources required to build transmission is increasing.

A number of the factors are related to a worldwide concern for greenhouse gas emissions, multiple green energy agendas, and/or rapid advancements of renewable technologies. Increasing renewable generation increases the need for transmission. Renewable generation occurs when and where nature provides it. A strong transmission network is needed to transport electricity when the wind is blowing or when high river flows occur at hydro plants. Conversely, transmission is also a key requirement when renewable generation is at a low output level (as happens when there is no wind or during dry hydro conditions) as energy from other sources is needed to be delivered to load centres.
4.2.1 Overview of the Long-term Transmission System Plan

The AESO’s Plan presents an integrated, comprehensive and strategic upgrade of the transmission system that: meets statutory requirements, aligns with government policy/strategy respecting electricity, meets load growth, and facilitates resource development.

Figure 4.2.1-1 shows the critical transmission system developments expected over the next 10 years.

A central feature of the Plan is two high capacity and high efficiency lines between the Edmonton and Calgary areas. These lines represent a major upgrade of Alberta’s transmission backbone and will connect four important electrical hubs:

- **The Southern hub** is central to substantial renewable generation development potential in southeastern Alberta. Interest in wind generation development is at high levels such that the area will grow into a very large renewable energy zone. The Southern hub is also likely to be central to future interties with provinces to the east and the U.S. to the south.

- **The Calgary area hub** serves the major load centre of Calgary and will also receive wind energy from the south and southwestern parts of the province. This hub is already connected to B.C. and further interties to B.C. or the U.S. are possible.

- **The Heartland hub** northeast of Edmonton is a growing industrial area with substantial potential for load growth, as well as development of highly efficient and low-emission energy cogeneration sources associated with industry. This location is also a gateway to northeastern Alberta, where load growth is occurring and further generation development, including hydro, is expected. Potential future interties to the east and north would also be served from the Heartland hub.

- **The Wabamun Lake/Edmonton area hub** is central to a large portion of Alberta’s existing generation and is a gateway to generation and interties in the northwest.

The remaining components of the Plan complement these upgrades to the transmission system backbone as follows:

- In the Edmonton region, additional transmission is needed to serve load demands in the Heartland area and to connect the existing system to the Heartland hub.

- In the northeast, two 500 kV alternating current (AC) lines are planned to connect the Wabamun Lake/Edmonton and Heartland hubs to the Fort McMurray hub. Substantial load growth in the northeast is expected, as well as renewable and other generation developments and potentially interties.

- In the northwest, additional AC transmission, likely at 500 kilovolt (kV), will connect the Northwestern hub to the Wabamun Lake/Edmonton hub to address load growth in the northwest, provide access for renewable generation in the northwest and serve a potential additional northern intertie with B.C.

- In the south, a loop of new transmission lines will connect wind and other generation and load to the Southern and Calgary hubs.

- In the Calgary region, additional transmission development is needed to serve the main load centre.
Figure 4.2.1-1: Long-term critical transmission system development

Transmission Development Projects
1. Edmonton-Calgary
2. Heartland
3. Wabamun Lake-Edmonton-Fort McMurray
4. Southern Alberta (wind)
5. Fort McMurray-Slave River Hydro
6. Wabamun Lake-Northwestern Alberta
7. Fort McMurray-Slave River Hydro
8. Interties

Note: For illustrative purposes only; does not depict actual line routes or substation locations.

HVDC: high voltage direct current
kV: kilovolt
AC: alternating current
The Plan also includes reinforcements to serve regional loads and potential generation developments as well as interties with neighbouring systems.

Taken together, the elements of the Plan will provide the province with a transmission grid on which Albertans can rely for years to come.

The Plan permits integration of resources from all parts of the province to meet Alberta’s demand as well as import and export over multiple interties when shortages or surpluses occur.

4.2.2 Summary of critical transmission development

Figure 4.2.1-1 illustrates the following specific projects that are required:

- Two 500 kV HVDC high capacity lines from the Edmonton area to the Calgary, and South regions.
- One 500 kV double circuit AC line from the Edmonton area into the Industrial Heartland area (parts of Sturgeon, Strathcona and Lamont Counties).
- Two 500 kV AC lines from the Wabamun Lake/Edmonton and Heartland areas to the Fort McMurray area.
- Two double circuit 240 kV lines and a new 500 kV substation connecting to the 240 kV network in the South region to interconnect a significant renewable generation source (wind power).
- A 240 kV substation in the south Calgary area.

Each of these developments is described separately in the sections that follow. It is noted that these developments utilize both AC and direct current (DC) technologies. Alberta currently uses 240 kV and 500 kV AC technology for its bulk transmission system. It is anticipated that facilities at these voltage levels will continue to provide the appropriate balance between capacity and cost in the Alberta context.

However, HVDC technology provides the required power transfer capacity with a lower overall land-use impact. In addition to the right-of-way required for the transmission line, HVDC facilities require land for converter stations, which are needed to interface with the existing AC system. HVDC has the ability to directly control both power flow quantity and direction. For these reasons, HVDC is the preferred technology choice for those situations where these attributes are seen as significant advantages for the long-term development of Alberta’s transmission system. This approach is also supported by the government’s Provincial Energy Strategy. Continued detailed analysis, including technical, transmission loss and operational cost studies, will be undertaken to confirm the HVDC option.

Now is the time to begin building these critical transmission facilities given the requirements described in Section 4.2. In addition, current economic conditions warrant a proactive strategy of advancing major transmission facilities to benefit from the current availability of resources (e.g., equipment and labour).
4.2.3 Cost summary of critical transmission development
The current estimate for the required critical components in the previous summary amounts to approximately $8 billion in 2008 dollars. This translates to an increase of about $8 per month on the transmission component of a typical residential customer’s bill by 2017. Given that any increase will not occur until the specific facilities have been built and placed in service, beginning in 2012, the magnitude of the impact on the bill will vary over time. These cost estimates will be refined as developments proceed and additional in-depth analysis, consultation and detailed information about the facilities becomes available.

4.2.4 Additional critical transmission development
In addition to the projects described previously, Figure 4.2.1-1 illustrates the following critical transmission development that needs to be completed over the 10-year period:

- Two 500 kV AC lines from the Wabamun Lake/Edmonton area to the Northwest region to accommodate large-scale biomass or low-emission generation.
- An HVDC line or equivalent to a potential major hydroelectric generation facility in the Northeast region.
- Options for new interties to neighbouring jurisdictions are currently being assessed:
  - southern Alberta to the U.S. Pacific Northwest
  - southern Alberta to Saskatchewan and Manitoba
  - between northern Alberta and northern B.C.
  - between northern Alberta and northern Saskatchewan

Photo courtesy of TransCanada Corporation.

TransCanada’s Cancarb waste heat recovery power plant provides 26 MW of net power to the City of Medicine Hat.
4.3 Edmonton to Calgary transmission system reinforcements

4.3.1 Overview
The existing transmission system to deliver power from the Edmonton to Calgary areas relies on six 240 kV transmission lines in the Edmonton to Red Deer area and seven 240 kV lines between Red Deer and Calgary. Lower voltage lines (138 kV and 69 kV) also contribute to the aggregate capacity, but the majority of the capacity is provided by 240 kV lines. The Edmonton to Calgary system has not been upgraded in over 20 years. Load growth in southern and central Alberta is stressing the existing system such that capacity will fall short of reliability requirements by 2014.

Reinforcement of the transmission system between the Edmonton and Calgary regions is needed to:

► avoid reliability issues for consumers in south and central Alberta.
► improve the efficiency of the transmission system.
► restore the capacity of existing interties.
► avoid congestion, which prevents the market from achieving a fully competitive outcome.

Transmission constraints and congestion also slow development of new competitive generation in the Edmonton area and further north.

Meeting the long-term capacity requirement for the Edmonton to Calgary component of the bulk system using high capacity HVDC transmission lines makes most efficient use of rights-of-way and minimizes land-use impacts.

While a number of factors and conditions are considered in making this technology choice, including consultation, economics and efficiency, a priority is given to minimizing land-use impacts in support of government policy as presented in the Provincial Energy Strategy.

Given all of the conditions noted in Section 4.2, two HVDC high capacity lines are planned as soon as possible. Analysis indicates the preferred orientation of these lines is for one line on the west/central portion of the province connecting the existing Wabamun Lake/Edmonton hub to the Calgary area hub. The preferred orientation of the second line is on the eastern side of the province, connecting the Heartland hub northeast of Edmonton to a Southern hub.

Construction of both lines substantially increases the usable capacity of the first line. The first line alone cannot be fully utilized without the second line being in service as the loss of the first line would create too large of a contingency on the system. Construction of these lines sends a positive and concrete signal to consumers and generation developers that transmission capacity will be in place to deliver future generation to market and reliably meet the electricity needs of consumers in central and southern Alberta.
4.3.2 Technology alternatives considered and preferred option

The AESO reviewed a number of technology options for the required transmission development between Edmonton and Calgary. Overhead options included high capacity HVDC, as well as single and double circuit AC options at 240 kV and 500 kV levels. Additional discussion about HVDC and other transmission technology is contained in Appendix I.

Underground technology options were also examined. Conventional high voltage underground AC and DC transmission technologies are typically five to 10 times the cost of overhead transmission technologies. A new DC underground technology was also examined but it is not commercially proven for a 300 to 500 kilometre (km) line with a capacity of 1,000 MW or higher. In addition, cost estimates indicate new DC underground lines would be at least twice as expensive as a high capacity overhead line.

Each HVDC transmission line would have a capacity of 2,000 MW. The estimated cost of each of the HVDC lines considered in this Plan, including converter stations, is approximately 50 to 90 per cent ($550 to $700 million) higher than a double circuit 500 kV AC line.

4.3.3 Alignment with planning objectives

As load continues to grow in south and central Alberta, the capacity of the existing north to south system of six 240 kV AC lines (from the Wabamun Lake/Edmonton area to Calgary) is expected to fall below the level required for compliance with reliability criteria by 2014.

Also, the capacity of the existing system of six 240 kV AC lines is currently insufficient to permit operation of the B.C. intertie at full design capacity. This expansion of the backbone of the system will meet the Transmission Regulation requirement to restore the B.C. intertie to its full design capability.

The two new HVDC lines would strengthen the transmission system between Edmonton and Calgary such that it will be sufficient to meet the needs of this corridor for at least 20 years. The right-of-way requirements for the two lines are substantially less than all other alternatives. More gradual addition of single circuit lines would result in four or more additions to achieve the same capacity with more than double the right-of-way requirement of the HVDC lines.

The two high capacity lines remove uncertainty for generation and intertie developers. Alberta’s transmission network will be capable of providing efficient and unrestricted access for many years, thereby facilitating investment by others such that in aggregate, electricity can be generated and delivered to Albertans. The lines facilitate access between renewable generation zones and the market to transport large quantities of electricity when the wind is blowing or when high river flows occur at hydro plants.
Implementation of both lines at this time takes advantage of current market conditions for procuring materials and synergies can be achieved in engineering, procurement and construction.

Implementing high capacity alternatives exposes the system to situations where a large loss of capacity can occur; however, adding both circuits at the same time permits each to back up the other and minimizes the exposure to service interruptions.

Adding a higher capacity transmission line reduces how often the system must operate near its limit and thereby reducing line losses. Improving system efficiency saves money and is environmentally beneficial as it reduces greenhouse gases and other emissions created during the production of wasted energy.

Currently, interim technical measures have been required to allow interconnection of new generation. These measures are used as a last resort until the transmission system can be reinforced. All forms of generation in the north will be constrained to some degree until the needed transmission facilities are in place. Transmission reinforcement takes longer to implement than generation projects, and must be developed well in advance of specific generation projects.

### 4.3.4 High-level cost estimate and timeline

The high-level cost estimate and timeline for the two Edmonton to Calgary transmission reinforcements are listed in the Table 4.3.4-1. Construction of both lines could begin in 2010.

<table>
<thead>
<tr>
<th>Year in service</th>
<th>Project Description</th>
<th>Cost estimate (2008 $ millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2013</td>
<td>Edmonton to Calgary Transmission Reinforcement</td>
<td>1,485</td>
</tr>
<tr>
<td>2013</td>
<td>A new high capacity HVDC line between the Edmonton and Calgary areas with converter stations in the Wabamun Lake area and near Langdon.</td>
<td>1,485</td>
</tr>
<tr>
<td>2013</td>
<td>Edmonton to Calgary Transmission Reinforcement</td>
<td>1,650</td>
</tr>
<tr>
<td>2013</td>
<td>A new high capacity HVDC line between the Edmonton and southern Alberta areas with converter stations at the new Heartland substation and in the Brooks area or possibly further south.</td>
<td>1,650</td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td>3,135</td>
</tr>
</tbody>
</table>
4.4 Heartland transmission system reinforcements

4.4.1 Overview

The oilsands industry is expected to continue its growth and is the primary driver of the need for new electricity infrastructure development in the northeastern part of Alberta. There are two main components of load associated with extracting and processing bitumen. The first component includes facilities associated with extracting bitumen from the oilsands. This can be in the form of a mining-type operation that extracts the oilsands from its original location and moves it to a processing facility where bitumen is separated from sand. It can also be in the form of in situ recovery of bitumen directly out of the oilsands formation. In Alberta, most of this activity is located in the Fort McMurray, Cold Lake and Peace River areas (i.e., where the oilsands formations exist).

The second component of oilsands load is the demand for power associated with upgrading bitumen into synthetic crude oil in a refinery-type facility. These facilities can either be located close to bitumen extraction sites (e.g., Fort McMurray area) or in another area with bitumen piped to the facility (e.g., Fort Saskatchewan/Heartland area).

Over the last five years the annual rate of oilsands investment has steadily risen, exceeding $18.1 billion in 2007. Although oil prices have decreased from their record levels in 2008, world oil supplies continue to diminish and investment in the oilsands industry is expected to be strong over the long term. The December 2008 Canadian Association of Petroleum Producers (CAPP)\(^1\) oil production forecast\(^2\), predicts continued increases in average production with the moderate forecast predicting bitumen production levels of 3.3 million barrels per day (b/d) by 2020.

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\(^1\) The Canadian Association of Petroleum Producers (CAPP) represents 130 member companies who explore for, develop and produce more than 95 per cent of Canada's natural gas, crude oil, oilsands and elemental sulphur.

4.4.2 Technology alternatives considered and preferred option

The AESO conducted extensive analysis of various alternatives for providing the transmission reinforcement needed into the northeastern area of Alberta. This included examining considerations such as transfer capability, operational reliability, flexibility, land-use impact and cost. As a result of this analysis, the following two alternatives were identified as having superior advantages with respect to these considerations.

- A new 500 kV double circuit line from an existing substation in south Edmonton (Ellerslie) to a new substation in the Industrial Heartland area.

- A new 500 kV double circuit line connecting into an existing line on the west side of Edmonton to a new substation in the Industrial Heartland area.

At the conclusion of the detailed siting analysis and consultation currently being conducted by the transmission facility owners (TFO), the AESO will select one of these alternatives as its recommended option.

In addition to these options, the AESO evaluated a number of different alternatives and staged approaches to meeting the region’s current and potential future needs. These are summarized below:

- A 240 kV loop option initially involving a new double circuit line from Ellerslie to Heartland and then an additional new double circuit 240 kV line from Keephills to Heartland to supply continued load growth. Alternative routing options were looked at on both the west and east sides of Edmonton. This option was rejected due to its higher cost and greater land-use impact because of the number of lines required in the long term.

- Underground HVDC was also considered. This option would require three separate underground lines to achieve the capacity required. This option was rejected due to a number of technical limitations and its significantly higher cost compared to the AC options.
4.4.3 Alignment with planning objectives

The AESO developed three future scenarios to assess needs and perform long-term planning of the transmission system supplying electricity to the Northeast region of Alberta. These three scenarios are referred to as ‘all projects’, ‘base case’ and ‘high cogeneration’.

The all projects scenario includes all publicly disclosed oilsands projects and the on-site generation proposed for each project, and assumes all projects will be completed on the schedules announced by the proponents. Those projects for which the proponent has indicated that the project is either on hold, or the in-service date has moved beyond 2018, have been excluded from the forecast. This has significantly reduced the amount of upgrading included in the forecast. Using this approach, total upgrading capacity is forecast to fall to less than 50 per cent of bitumen production capacity. This assumes that 40 per cent of the bitumen produced will be upgraded outside of Alberta.

The base case scenario uses a moderate growth forecast of oilsands development consistent with the CAPP moderate growth forecast and the on-site generation proposed for each project.

The final scenario, high cogeneration, uses the moderate growth forecast but assumes both an additional 500 MW of cogeneration will be built, as well as an increase of 10 per cent in the average output from all existing on-site generation in the region.

The forecast transmission requirement for the Northeast region for each of the three scenarios is presented in Figure 4.4.3-1. The updated forecast in Figure 4.4.3-1 shows some changes compared to the forecast presented in the AESO’s summary report titled Alberta’s Industrial Heartland, Bulk Transmission Development dated May 30, 2008. This report is available on the AESO’s website at www.aeso.ca. The most significant changes from the previous forecast are due to announced delays or cancellations of oilsands projects and upgraders to be built in Alberta.

The amount of new upgrading expected to be in operation under the base case scenario by 2015 has fallen from 1.2 million b/d in the previous forecast to 0.5 million b/d in the updated forecast. To date there has not been a significant reduction in the forecast increase in bitumen production. But even with reductions in the amount of upgrading capacity to be added in the short term, analysis indicates that the Heartland transmission project must be completed as soon as possible to meet the needs of even the lowest growth scenario.
4.4.4 High-level cost estimate and timeline

The high-level cost estimate and timeline for the Heartland transmission reinforcements are indicated in Table 4.4.4-1. To provide a strong termination point for one of the Edmonton to Calgary HVDC transmission lines, construction could begin in 2010.

Table 4.4.4-1: Heartland transmission system reinforcements

<table>
<thead>
<tr>
<th>Year in service</th>
<th>Project</th>
<th>Description</th>
<th>Cost estimate (2008 $ millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2013</td>
<td>Heartland Transmission Development</td>
<td>A new double circuit 500 kV line from Ellerslie to a new 500 kV substation in the Industrial Heartland area. or A new double circuit 500 kV AC line tapping an existing line to a new 500 kV substation in the Industrial Heartland area.</td>
<td>260 or 360</td>
</tr>
<tr>
<td>2013</td>
<td>Heartland Transmission Development</td>
<td>Rebuild older 240 kV lines in the north Edmonton area.</td>
<td>23</td>
</tr>
<tr>
<td>2015</td>
<td>Heartland Transmission Development</td>
<td>Upgrade conductor on an 18 km section of the existing double circuit 240 kV line in the north Edmonton area.</td>
<td>4</td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td></td>
<td>287 or 387</td>
</tr>
</tbody>
</table>
4.5 Fort McMurray transmission system reinforcements

4.5.1 Overview
As with the transmission reinforcements required into the Heartland area, transmission reinforcement required into the Fort McMurray area is driven by development of the oilsands resource described in Section 4.4.1.

4.5.2 Technology alternatives considered and preferred option
Four options for the bulk system plans into the Fort McMurray area were developed:

- 500 kV AC transmission: Overlay the existing 240 kV system with a 500 kV loop through the region.
- 240 kV AC transmission: Continue to build 240 kV (staged construction of multiple lines) as the load grows.
- Hybrid HVDC and 500 kV AC transmission: A new HVDC bi-pole line from Heartland to Fort McMurray would be built supported by a 500 kV AC line from the Wabamun Lake area to Fort McMurray.
- Hybrid multi-terminal HVDC and 500 kV AC transmission: Same as the previous option except the terminal at Heartland would be shared with the Edmonton to Calgary project by constructing a three terminal HVDC line with terminal stations in the Fort McMurray, Heartland and southern Alberta areas.

The HVDC alternatives are not recommended for technical reasons, including limitations associated with using HVDC to supply a remote load centre with a high concentration of electrical motors, and the need for intermediate substations as oilsands activities develop further south and west of Fort McMurray.

The specific facilities recommended for this reinforcement are a 500 kV AC line from the Genesee generating station to a new 500 kV substation in the Fort McMurray area and a 500 kV AC line from the new Heartland substation to the new Fort McMurray 500 kV substation.

4.5.3 Alignment with planning objectives
The forecast transmission requirement for the Fort McMurray area for each of the three scenarios (previously described in Section 4.4.3) is presented in Figure 4.5.3-1. The updated forecast for the Fort McMurray area as noted in Figure 4.5.3-1 shows some changes compared to the previous forecast; however, growth still indicates that the first stage of the Fort McMurray transmission development must be completed as soon as possible.
4.5.4 High-level cost estimate and timeline

The high-level cost estimate and timeline for transmission reinforcements into the Fort McMurray area are indicated in Table 4.5.4-1.

Table 4.5.4-1: Fort McMurray transmission system reinforcements

<table>
<thead>
<tr>
<th>Year in service</th>
<th>Project</th>
<th>Description</th>
<th>Cost estimate (2008 $ millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2014</td>
<td>Fort McMurray Transmission Development</td>
<td>A new 500 kV line from Genesee (Wabamun Lake area) to a new 500 kV substation in the Fort McMurray area.</td>
<td>1,225</td>
</tr>
<tr>
<td>2016</td>
<td>Fort McMurray Transmission Development</td>
<td>A new 500 kV line from the new Heartland substation (Edmonton area) to the new 500 kV substation in the Fort McMurray area.</td>
<td>820</td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td></td>
<td>2,045</td>
</tr>
</tbody>
</table>
4.6 Southern Alberta (wind) transmission system reinforcements

4.6.1 Overview

The South region is currently Alberta’s primary wind power generation area. More than 11,500 MW of applications for new wind generation have been received by the AESO, of which over 7,500 MW is located in the South region. It is expected that not all wind generation that has requested connection to the system will be constructed, and there is uncertainty about where the projects will ultimately be located.

Regardless of the location of future wind turbines, there is insufficient capability in the South region transmission system to meet the needs of this new generation. Given the significant system constraints, the South region transmission system will require substantial improvements, including multiple new 240 kV and/or 500 kV transmission system loops and substations and upgrading of existing facilities to accommodate the generation interconnections.

The AESO filed a proposed transmission plan with the Alberta Utilities Commission (AUC) at the end of 2008. This plan is flexible enough to accommodate various amounts of future wind development.

4.6.2 Technology alternatives considered and preferred option

Provincewide at least 4,000 MW of new wind generation could be developed in the next 10 years. At least 2,700 MW of this would be located in southern Alberta.

Extensive analysis was completed on a number of transmission system expansion options to integrate wind generation into the south system. The selected option includes building new 240 kV transmission lines and a new 500 kV substation connecting to the 240 kV network.

The new 240 kV lines would create a loop between Pincher Creek into the existing 240 kV substations at Lethbridge, West Brooks, Janet and Peigan. The looped system would provide a high level of reliability. The new 240 kV lines in southern Alberta would be used primarily for transferring wind energy onto the bulk 240 kV system, where it can be delivered to major load centres such as the Calgary region.

Other options studied include a 240 kV radial system, a 500 kV loop and an HVDC line between the South region and Calgary.

The 240 kV looped system was preferred as it would provide higher capability to deliver the wind generation in southern Alberta than a radial system and would be more flexible for staging than the 500 kV or HVDC option.

The 500 kV and HVDC options would also have limited flexibility because direct interconnection of wind generators is not practical and there would still need to be a significant number of new 240 kV transmission lines to interconnect and gather wind energy.
4.6.3 Alignment with planning objectives
The AESO’s preferred alternative reflects considerable analysis, assessment and evaluation of various options for system reinforcements in the way of transmission technologies, planning alternatives, power flows, reactive power, transient stability, land impacts and economics, including various sensitivity analyses.

The AESO tested the existing southern Alberta transmission system to determine its current and future adequacy by applying its transmission reliability criteria and using reasonable load forecasts and generation assumptions. The AESO’s preferred alternative for the southern Alberta transmission system reinforcement considered various factors as required by the Transmission Regulation.

Although the three-stage expansion plan for the South region meets the projected needs of wind generation development at this time, the 240 kV looped system could potentially be connected to the second Edmonton to Calgary 500 kV HVDC line near Brooks as a way to deliver wind energy to other markets. In light of the Provincial Energy Strategy, the following two aspects of this development will be re-examined through the first half of 2009:

► The potential to advance components of the three-stage plan, in particular to support the southern termination of one of the Edmonton to Calgary HVDC transmission lines.

► The potential to pre-build certain sections of the 240 kV transmission loop to 500 kV standards for future use. Most of the planned 240 kV transmission loop is required for local connection of a large number of wind power generators so future conversion to 500 kV may not be appropriate.

4.6.4 High-level cost estimate and timeline
The high-level cost estimate and timeline for the transmission reinforcements in southern Alberta are indicated in Table 4.6.4-1.

<table>
<thead>
<tr>
<th>Year in service</th>
<th>Project</th>
<th>Description</th>
<th>Cost estimate (2008 $ millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2011–2014</td>
<td>South System Reinforcement for Wind Integration</td>
<td>A new 240 kV looped system to integrate wind generation projects in southern Alberta.</td>
<td>900</td>
</tr>
<tr>
<td>2012</td>
<td>High River Area Upgrades</td>
<td>A new 240/138 kV substation in the High River area and related 138 kV and 240 kV transmission upgrades necessary to integrate the southern Alberta reinforcements into the existing system.</td>
<td>550</td>
</tr>
<tr>
<td>2012</td>
<td>South Transmission Development</td>
<td>A new 240 kV double circuit line replacing the existing 240 kV line from the Peigan system substation to the Janet substation. This new line will deliver wind generation to the Calgary area.</td>
<td>371</td>
</tr>
<tr>
<td>2012</td>
<td>South Transmission Development</td>
<td>A new Milo switching station.</td>
<td>25</td>
</tr>
<tr>
<td>2015</td>
<td>South Transmission Development</td>
<td>A new 500/240 kV substation in the Pincher Creek area and a new double circuit 240 kV transmission line from this substation to the existing Goose Lake substation.</td>
<td>218</td>
</tr>
<tr>
<td>2017</td>
<td>South Transmission Development</td>
<td>A new double circuit 240 kV line from Ware Junction to the Calgary area to provide the transmission required to transfer wind power generation to the Calgary area.</td>
<td>390</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td></td>
<td></td>
<td><strong>2,454</strong></td>
</tr>
</tbody>
</table>
4.7 South Calgary transmission system reinforcements

4.7.1 Overview

The Calgary area peak load is expected to reach approximately 2,000 MW by 2017. Based on information from the City of Calgary’s land-use planning department, the south part of the City of Calgary in particular is expected to continue to grow. The construction of a new South Health Campus in the southeast sector indicates an increasing population in the south area generally. In addition, the South Health Campus requires a geographically separate redundant electric supply.

The transmission system into the south part of the City of Calgary requires reinforcement. Currently, there are three 138 kV circuits supplying south Calgary and if one of these circuits is out of service for maintenance, a subsequent outage would result in the requirement for planned outages to keep the remaining 138 kV circuit from overloading.

A recent example of problems that can result from inadequate transmission occurred in February 2008, when most of the southern part of Calgary experienced an outage as a result of a number of coincident system circumstances. This did not result from any maintenance activity that was occurring at the time. The severity of the outage would have been lessened and likely eliminated if a south 240/138 kV substation had been in place to provide support from the south at the 240 kV system level.

Consequently, the AESO is examining options to reinforce the transmission system in southern Calgary and will be conducting further analysis and stakeholder consultation. These reinforcements may include an additional substation and/or new 138 kV lines.

One option would be a new 240/138 kV substation near the intersection of Macleod Trail and Highway 22X and associated 138 kV and 240 kV lines to interconnect into the existing system. This option has an estimated capital cost of $100 million (in 2008 dollars). The anticipated in-service date for this development is 2012.
4.8 Transmission to renewable and low-emission energy zones

4.8.1 Northwest region transmission system reinforcements

The Northwest region is currently a load area (i.e., load exceeds generation produced in the region). The 240 kV reinforcement currently being developed in northwestern Alberta is sufficient to accommodate 500 to 1,000 MW of new generation from biomass, wind or other sources. Additional generation beyond that level or an intertie to B.C. would be enabled through development of additional transmission, likely at 500 kV. There is about 1,500 MW of wind interest in the Northwest region. The need for transmission reinforcements will be monitored as intertie policy is created and generation development proceeds.

The cost estimate for the potential additional transmission reinforcements required to support this development is indicated in Table 4.8.1-1.

<table>
<thead>
<tr>
<th>Year in service</th>
<th>Project</th>
<th>Description</th>
<th>Cost estimate (2008 $ millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2015</td>
<td>Northwest Transmission Development</td>
<td>Two new 500 kV AC lines from the Wabamun Lake area to the Northwest region.</td>
<td>500</td>
</tr>
<tr>
<td></td>
<td><strong>Total</strong></td>
<td></td>
<td><strong>500</strong></td>
</tr>
</tbody>
</table>

4.8.2 Northeast region transmission system reinforcements

There is potential for significant hydro resources to be developed on the Slave River site north of Fort McMurray near the border with the Northwest Territories (N.W.T.). The transmission reinforcement required to interconnect this project may be an HVDC line from the Fort McMurray area to the hydro plant site.

The cost estimate for the potential additional transmission reinforcement that would be required to support this development is in Table 4.8.2-1.

It is possible that additional hydro generation resources could be developed in the N.W.T. and this development to Slave River could form part of the transmission system needed to deliver energy to markets further south.

<table>
<thead>
<tr>
<th>Year in service</th>
<th>Project</th>
<th>Description</th>
<th>Cost estimate (2008 $ millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2017</td>
<td>Slave River Hydro Transmission Development</td>
<td>A new HVDC line or equivalent from the Fort McMurray area to the Slave River hydro plant site.</td>
<td>1,400</td>
</tr>
<tr>
<td></td>
<td><strong>Total</strong></td>
<td></td>
<td><strong>1,400</strong></td>
</tr>
</tbody>
</table>
4.9 New transmission interties

4.9.1 Overview
There are several benefits of additional intertie capacity including:

- Encourage fair and efficient market development in Alberta.
- Enable further renewable generation (e.g., wind or hydro) development.
- Facilitate further large-scale baseload generation (e.g., nuclear, coal) development.
- Provide access to other markets for increased reliability of supply.

The steps needed to immediately restore the capacity of existing interties and develop new intertie capacity are discussed in this section. Given the benefits of accessing other markets and the controllability of HVDC technology (especially in helping manage variability of large amounts of new wind generation), developing new capacity will initially concentrate on HVDC interties into the U.S. Pacific Northwest and eastern Canada. Appendix H contains additional information about Alberta’s interties.

4.9.2 Restoring existing intertie capability
Alberta currently has two interties to neighbouring jurisdictions – one to Saskatchewan and another to B.C.

The flow of electricity between Alberta and Saskatchewan on the existing intertie is generally bi-directional with nighttime exports from Alberta if the Alberta market price is low, and daytime imports from Saskatchewan when prices in Alberta are high. This is primarily due to the large concentration of baseload generation in Alberta and some surplus peaking capacity of hydro plants in Saskatchewan.

The AESO’s plan to bring the Alberta-Saskatchewan intertie up to its full design rating was included as part of the AESO’s Southeast Alberta Transmission Development, which was applied for in November 2007 and approved in July 2008. The reinforcements are planned to be in service by 2011.

On the B.C. intertie, the normal flow between Alberta and B.C. is bi-directional with nighttime exports from Alberta when the Alberta market price is low and daytime imports from B.C. when prices in Alberta are high. This situation is primarily due to the large concentration of baseload generation in Alberta and the peaking capacity of hydro plants in B.C. The B.C. intertie is currently operating below its design capability for exports. The export capacity of the B.C. intertie cannot be restored significantly until the Edmonton to Calgary transmission system is reinforced.

The AESO’s plan to bring the Alberta-B.C. intertie up to its full design rating is included as part of the required reinforcement of the Edmonton to Calgary transmission system previously described in Section 4.3. The expected in-service date for these reinforcements is 2013.
4.9.3 Developing new intertie capability

There are several options available for the development of new intertie capability. For example, new intertie capability might be created through the addition of regulated rate-based interties similar to the treatment of existing interties. Alternatively, new capability might be added through development of ‘merchant’ interties (i.e., intertie facilities whose cost and associated risk is borne by a non-regulated company). Parties wishing to use the intertie would pay a user fee to the owner of the merchant transmission line. As the AESO continues its planning regarding the provision of new intertie capability, it will take into account the status of any merchant intertie proposals to ensure that the appropriate amount of intertie capability is developed.

Current merchant intertie initiatives

Following is a brief summary of merchant intertie projects the AESO is aware of that are currently being considered. The AESO continues to work with merchant line proponents to ensure these projects are integrated into the AES in an appropriate manner.

THE MONTANA-ALBERTA INTERTIE

Montana Alberta Tie Ltd. (MATL) is proposing to construct an intertie between Lethbridge, Alberta and Great Falls, Montana. The intertie would be at 230 kV and would transfer up to 300 MW in each direction. The project proponents currently have a permit from the National Energy Board and approval from the AUC. Approvals from the necessary agencies in the U.S. are in hand.

NORTHERNLIGHTS TRANSMISSION PROJECT

The NorthernLights bi-directional merchant transmission project being developed by TransCanada Corporation is a ±500 kV, 3,000 MW HVDC transmission line from the Industrial Heartland (Fort Saskatchewan) area to the Pacific Northwest where energy can reach the Pacific Northwest and California markets. The transmission line would be 1,550 km long and has a tentative in-service date of 2015.

Potential new interties

New interties from Alberta could potentially connect to three jurisdictions: B.C., Saskatchewan/Manitoba or the Pacific Northwest. It will be necessary for the AESO to conduct discussions with parties in these adjoining jurisdictions to ensure the benefits of additional intertie capacity are well founded and to facilitate effective coordination of inter-regional planning. A discussion about how future interties could be achieved is presented in the following sections.
Future interties to Saskatchewan and Manitoba

The concept of an intertie between Alberta, Saskatchewan and Manitoba was previously studied by the three provinces in the late 1970s and did not proceed. Since then, electricity demand, climate change policy developments, aging transmission infrastructure, large-scale generation development requiring multiple markets and technological advances in generation and transmission systems justify resumption of studies. An intertie between the three provinces, as shown in Figure 4.9.3-1, has the potential to help meet provincial and federal climate change targets, provide competitively clean energy and increase the security and reliability of supply. Discussions among representatives of the Alberta, Saskatchewan and Manitoba governments are underway regarding an HVDC intertie connecting the three provinces.

The possibility of building significant low-emission (i.e., nuclear) resources in northern Saskatchewan also presents an opportunity to consider an intertie between the Fort McMurray area in northern Alberta and northern Saskatchewan. This intertie would likely be AC. The potential intertie is shown in Figure 4.9.3-1.

Figure 4.9.3-1: Alberta – Saskatchewan/Manitoba intertie options
Future intertie to the Pacific Northwest

It is possible to increase Alberta’s intertie capacity by building an intertie directly to the Pacific Northwest area of the U.S. as shown in Figure 4.9.3-2. Given the distance involved, the most cost-effective connection would likely be an HVDC line.

Figure 4.9.3-2: Alberta – Pacific Northwest intertie option
Future intertie to B.C.

Building a new 500 kV AC intertie between northern Alberta and northern B.C. would significantly increase the supply capacity to northern Alberta and the Fort McMurray area. It would also provide a future means of strengthening supply into northwestern Alberta for either large generation development or large load development (e.g., new technologies are under development to inject electricity into formations to allow for the extraction of bitumen). A northern intertie could avoid populated areas as well as agricultural lands and would improve reliability of the system by providing a high capacity alternative supply with a large geographic separation from the existing intertie. The intertie is shown in Figure 4.9.3-3.

**Figure 4.9.3-3: Alberta – B.C. intertie option**
4.9.4 High-level cost estimate
The high-level cost estimate for these potential transmission interties is indicated in Table 4.9.4-1. These estimates are for the facilities located in Alberta only.

Table 4.9.4-1: Potential transmission interties

<table>
<thead>
<tr>
<th>Project</th>
<th>Description</th>
<th>Cost estimate (2008 $ millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Alberta/Saskatchewan/Manitoba Intertie</td>
<td>A new HVDC line from southern Alberta to Saskatchewan/Manitoba.</td>
<td>760</td>
</tr>
<tr>
<td>Saskatchewan Intertie</td>
<td>A new 500 kV AC line from the Fort McMurray area to Saskatchewan.</td>
<td>350</td>
</tr>
<tr>
<td>U.S. Pacific Northwest Intertie</td>
<td>A new HVDC line from southern Alberta to the Pacific Northwest.</td>
<td>815</td>
</tr>
<tr>
<td>B.C. Intertie</td>
<td>A new 500 kV AC line from the Northwest region of Alberta to B.C.</td>
<td>200</td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td>2,125</td>
</tr>
</tbody>
</table>

4.10 Long-term Transmission Plan capital cost summary
In addition to the critical infrastructure developments identified in the previous sections, the AESO has completed comprehensive technical analysis of regional transmission system requirements, which are discussed in more detail in Appendix K.

The cost estimate for the complete Long-term Transmission System Plan is summarized in Table 4.10-1.
Table 4.10-1: Long-term Transmission System Plan capital cost summary

<table>
<thead>
<tr>
<th>Critical transmission developments</th>
<th>Cost estimate (2008 $ millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Edmonton to Calgary reinforcements</td>
<td>3,135</td>
</tr>
<tr>
<td>Heartland transmission system reinforcements</td>
<td>287 or 387</td>
</tr>
<tr>
<td>Fort McMurray transmission system reinforcements</td>
<td>2,045</td>
</tr>
<tr>
<td>Southern Alberta (wind) transmission system reinforcements</td>
<td>2,454</td>
</tr>
<tr>
<td>South Calgary transmission system reinforcements</td>
<td>100</td>
</tr>
<tr>
<td>Sub-total</td>
<td>8,121</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Transmission to renewable and low-emission energy zones</th>
<th>Cost estimate (2008 $ millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Northwest transmission system reinforcements</td>
<td>500</td>
</tr>
<tr>
<td>Northeast transmission system reinforcements</td>
<td>1,400</td>
</tr>
<tr>
<td>Sub-total</td>
<td>1,900</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Bulk transmission projects currently underway</th>
<th>Cost estimate (2008 $ millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Various bulk system projects underway; see Appendix J for additional information.</td>
<td>570</td>
</tr>
<tr>
<td>Sub-total</td>
<td>570</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Long-term regional transmission plan</th>
<th>Cost estimate (2008 $ millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>South region</td>
<td>205</td>
</tr>
<tr>
<td>Calgary region</td>
<td>248</td>
</tr>
<tr>
<td>Central region</td>
<td>964</td>
</tr>
<tr>
<td>Edmonton region</td>
<td>851</td>
</tr>
<tr>
<td>Northeast region</td>
<td>903</td>
</tr>
<tr>
<td>Northwest region</td>
<td>701</td>
</tr>
<tr>
<td>Sub-total</td>
<td>3,872</td>
</tr>
<tr>
<td>Total</td>
<td>14,463</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Potential transmission interties</th>
<th>Cost estimate (2008 $ millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Various projects; see Table 4.9.4-1 for details.</td>
<td>2,125</td>
</tr>
</tbody>
</table>
5.0 Conclusion

Photo courtesy of AltaLink.

A-frame structures at the Langdon substation east of Calgary.
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5.0 Conclusion

From vision to action

As with any process that transforms vision into action, issues and opportunities can be expected. This Long-term Transmission Plan not only outlines work that is already underway, it can also be used as an instrument for discussion. The Plan can be used to aid in the development of enabling policy and provide a common way forward for all levels of government. During consultation initiatives, the AESO heard from over 2,000 Albertans from landowners to industry players. The Plan can also serve as a point of focus to proactively address issues and opportunities that stakeholders might have.

The Plan paints a picture of a new and exciting future for the role electric transmission plays in stimulating Alberta’s economy while integrating much needed transmission reinforcement. It is a picture with foresight and intention.

The AESO’s Plan takes a comprehensive approach to ensure the electric system is strengthened so all Albertans can continue to depend on safe and reliable electricity. At the same time, the Plan identifies transmission infrastructure that will provide confidence for all investors, including those who want to build more renewable and low-emission power generation for Alberta’s competitive market.

The Plan, which is consistent with the Provincial Energy Strategy, sets a foundation for action so Alberta can continue to benefit from a strengthened and effective transmission system.

Work has already begun on some of the critical projects outlined in the Plan. In some cases, extensive planning, technical work and stakeholder consultation has taken place. The Plan continues that work in a new and forward-looking context.
The Plan reflects:

- The AESO’s view of Alberta’s electricity future, which is consistent with existing legislation and aligns with the Provincial Energy Strategy’s objective of building transmission infrastructure in advance of investor decisions.
- The AESO’s vision of how Alberta’s electric transmission system will be developed with an emphasis on critical infrastructure planned to be under construction by the end of 2010.
- An approach to transmission development that will enhance opportunities for various forms of electricity generation, including renewable and low-emission sources.
- A connection with electricity consumers who depend on reliable electricity for economic sustainability to run computers, bake bread, heat homes, run farms, operate businesses and energize industry.
- A path forward towards a greener, more prosperous and energy efficient Alberta.
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AECO-C: Alberta's natural gas hub. A hub serves as a physical point of exchange and as a market in which buyers and sellers can meet either physically or via paper or electronic mechanisms.

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

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

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

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

Available transfer capability (ATC): The amount of electricity that can flow on interties. This capability is an hourly value that fluctuates with system conditions.

Baseload capacity/generation: The generating equipment normally operated to serve loads on an around-the-clock basis.

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

Biomass fuel: A specific type of biomass used to produce synthetic fuels or that can be burned in its natural state to produce energy. Biomass fuels include wood waste, peat, manure, grain by-products 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 centers. 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.

**Capacitance:** The property of a system of conductors and dielectrics that permits the storage of electrically separated charges when potential differences exist between the conductors. A measure of the amount of electric charge stored (or separated) for a given electric potential.

**Capacitor/capacitor bank:** A static device (sometimes referred to as static capacitors) that introduces capacitive reactance into the power system. Capacitors are used to control voltages by eliminating the voltage drop in the system caused by inductive reactive loads. If connected between conductors or between conductors and ground, they are sometimes described as shunt capacitors. If connected in series with a transmission line, they are described as series capacitors.

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

**Capacity factor:** The ratio of energy actually produced by a generator compared to the energy that could have been produced if the unit were operated at its rated output continuously.

**Carbon capture ready:** The infrastructure required to enable the capture of carbon dioxide and compress it to the pressure required for transporting to a storage location.

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

**Circuit:** A conductor or a system of conductors through which electric current flows.

**Cleaner fuel standard:** The emission intensity requirements defined by Environment Canada for new facilities in the Regulatory Framework for Air Emissions (2008).

**Cogeneration:** The simultaneous production of electricity and another form of useful thermal energy used for industrial, commercial, heating or cooling purposes.

**Coincident demand:** Any demand that occurs simultaneously with any other demand (e.g., regional or peak demand).

**Combined cycle generation:** A system in which a gas turbine generates electricity and the waste heat is used to create steam to generate additional electricity using a steam turbine.

**Commercial operation:** Control of the loading of a generator is turned over to a system dispatcher.

**Commissioning:** The process by which a facility is tested and ultimately accepted for commercial operation.

**Compressed air energy storage (CAES):** A mechanical energy storage system involving the compression of air to be used later as an energy source.

**Conductor:** A metallic wire or combination of wires through which electric current is intended to flow.

**Congestion:** The condition under which transactions that market participants wish to undertake are constrained by conditions on the transmission grid.

**Constraint:** A restriction on a transmission system or segment of a transmission system that may limit the ability to transmit power between various locations.

**Control area:** A defined region of the electricity grid for which supply and demand are kept in balance by the control area's system operator.

**Converter station:** A location where electric energy is converted to direct current (DC) from AC or vice versa.
**Customer sectors:** Types of electric load classified according to type of use. Four sectors commonly used are residential, commercial, farm and industrial.

**Cutplanes:** An imaginary line that cuts across the transmission lines that connect two or more areas. The loading on these lines is summed together to measure the power flow across the cutplane.

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

**Demand opportunity service (DOS):** An opportunity transmission service with regulated rates for each level of interruption (seven minutes and one hour). Load customers pay the distribution transmission service (DTS) rate in accordance with the AESO's tariff.

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

**Demand transmission service (DTS):** The service provided to loads for interconnection access to the Alberta transmission system.

**Derate:** A reduction in a generating unit's or other piece of electric equipment's net capacity.

**Direct current (DC):** Current that flows continuously in the same direction (as opposed to AC). The current supplied from a battery is direct current.

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

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

**Distribution system:** The portion of an electric system that is dedicated to delivering electric energy from the transmission system to an end-use customer.

**Distribution utility:** A regulated electric utility entity that constructs and maintains the distribution wires connecting the transmission grid to an end-use customer.

**Double circuit:** A line of supporting structures that carries two power circuits.

**Effective capacity:** The capacity of a generator that is available to serve peak load.

**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.

**End user:** A residential, farm, commercial or industrial customer in the electricity marketplace who buys electric power for their own consumption and not for resale.

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

**Generating facility:** A facility housing one or more generating units.

**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.

**Generation reserve margin:** See reserve margin.

**Geothermal plant:** A plant in which the prime mover is a turbine driven either by steam produced from hot water or by natural steam that derives its energy from heat found in rocks or fluids at various depths beneath the surface of the Earth.
Gigawatt (GW): One billion watts.

Gigawatt hour (GWh): One billion watt hours.

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

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

Greenhouse gas offset: See carbon offset.

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.

Grid emission intensity factor: A measure of the overall electricity system’s emission intensity.

Gross domestic product (GDP): One of the measures of national income and output for a given country’s economy. GDP is defined as the total market value of all final goods and services produced within the country in a given period of time (usually a calendar year). It is also considered as the sum of the value added at every stage of production (the intermediate stages) of all final goods and services produced within a country in a given period of time and is given a monetary value.

Heat rate: A measure of generating plant thermal efficiency generally expressed as units of energy input per unit of energy output.

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

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

Integrated gasification combined cycle (IGCC): A technology that turns coal into synthesis gas (syngas). Impurities are removed from the synthesis gas before it is combusted in a combined cycle generator.

Interconnection or transmission interconnection: An arrangement of electrical lines and/or transformers that provides an interconnection to the transmission system for a generator or large commercial or industrial customer.

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

Kilovolt-ampere (kVA): A common unit of apparent power, which is 1,000 volt-amperes. The volt-amperes carried or used by an electrical device are the mathematical products of the volts and amperes of the device.

Kilowatt (kW): One thousand watts; a measure of electric demand.

Kilowatt hour (kWh): One thousand watt hours; a measure of electric energy.

Levelized unit electricity cost (LUEC): The constant price required to cover all expenses incurred over the lifetime of a generating unit.

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

Load factor: The ratio of average power demand (load) over a stipulated period of time to the peak or maximum for that same time interval; sometimes expressed as a per cent.

Looped system: A system of power lines in which circuits are contiguously connected between substations and then back to the same substation.
Maximum continuous rating (MCR): The maximum amount of electricity a generating unit can produce on a continuous basis.

Megawatt (MW): One million watts.

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

Merchant transmission line: A transmission line constructed by proponents that are not regulated utilities for the purpose of selling transmission capacity to third parties, usually generators or load customers who wish to make transactions over the merchant transmission line.

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

Meters or metering: Equipment that measures and registers the amount and direction of electrical quantities.

Micro-generation: In Alberta, micro-generation is defined as being from 150 kW to one MW of exclusively renewable or alternative energy that is intended to meet all or a portion of the customer’s electricity needs.

Needs Identification Document (NID): A document filed by the AESO with the Alberta Utilities Commission (AUC) to define the need to reinforce the transmission system to meet load growth and/or provide non-discriminatory access to interconnect new loads and generators to the system.

Net capability: The maximum load-carrying ability of a generator, exclusive of station use, under specified conditions for a given time interval, independent of the characteristics of the load. Capability is determined by design characteristics, physical conditions, adequacy of prime mover, energy supply, and operating limitations such as cooling and circulating water supply and temperature, headwater and tailwater elevations and electrical use.

Non-coincident peak load: The sum of two or more peak loads on individual systems, or a portion of a system, that do not occur in the same time interval.

Non-simultaneous transmission capability: A measure of transmission capability from multiple areas. Non-simultaneous means the maximum transfer capability from each area is considered one at a time and independent from each other.

North American Electric Reliability Corporation (NERC): NERC is an international independent, self-regulatory, not-for-profit organization whose mission is to ensure the reliability of the bulk power system in North America. NERC is subject to oversight by the Federal Energy Regulatory Commission (FERC) and Canadian governmental authorities and was certified by FERC as the electric reliability organization for the U.S. on July 20, 2006.

Nuclear power plant: A facility in which heat produced in a reactor by the fissioning of nuclear fuel is used to create steam in a boiler. This steam is then used to drive a turbine, which in turn drives the electric generator.

Off-peak: Periods of the day, season, year or other defined timeframe when loads are less than the maximum for the timeframe specified.

Offset: See carbon offset.

Oilsands upgrading by-product: High-carbon, low-energy fuel produced through the oilsands upgrading processes.
**On-peak:** Periods of the day, season, year or other defined timeframe when loads are at a maximum level for the timeframe specified.

**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.

**Oxy-firing:** The process of combusting coal in a mixture of oxygen and re-circulated exhaust gas.

**Parallel path flow:** 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:** Generation capacity that is normally used to produce electricity during peak-load hours.

**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.

**Polygeneration:** An industrial system that delivers more than two products to the final user. For example, electricity, hydrogen and heating can be delivered from one polygeneration plant.

**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.

**Pumped-storage hydroelectric plant:** A plant that usually generates electric energy during peak-load periods by using water previously pumped into an elevated storage reservoir during off-peak periods when excess generating capacity is available.

**Reactive compensation:** The ability of electrical equipment to provide reactive power.

**Reactive power:** The component of electric power that does not provide real work but is required to provide voltage.

**Reactive support:** Reactive power provided by certain types of electrical equipment, either capacitors or reactors.

**Reliability:** Electric system reliability has two components: adequacy and security. Adequacy is the ability of the electric system to supply the aggregate electrical demand and energy requirements of customers at all times, taking into account scheduled and unscheduled outages of system facilities. Security is the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system facilities.

**Reliability criteria:** A set of tests against which the operation of a power system is measured to ensure acceptable performance. The AESO's reliability criteria are central to assessing the adequacy of the current and future Alberta transmission system.

**Reserve margin:** The percentage of installed capacity exceeding the expected peak demand during a specified period.
Seasonal coincident peak: A coincident peak measured within a specific period of time defined as a season. Typically summer and winter are used but fall and spring can be included as well.

Series compensation: A technology that is primarily used to reduce transfer reactance, most notably in bulk transmission lines. The result is a significant increase in the transmission lines’ transfer capability and system voltage stability.

Simple cycle gas turbine: A plant in which the prime mover is a gas turbine. A gas turbine consists typically of an axial-flow air compressor, one or more combustion chambers where liquid or gaseous fuel is burned. The hot gases are passed to the turbine where they expand, driving the turbine that in turn drives the generator.

Single circuit: A transmission line where one circuit is carried on a set of structures (poles or lattice towers).

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

Static var compensator (SVC): An electrical device for providing fast-acting reactive power compensation on electricity networks.

Substation/switching station: A facility where equipment is used to tie together two or more electric circuits through switches (circuit breakers). The switches are selectively arranged to permit a circuit to be disconnected or to change the electric connection between the circuits.

Supply transmission service (STS): The service provided to generators for interconnection access to the Alberta transmission system.

Synthesis gas (syngas): A gas mixture that contains varying amounts of carbon monoxide, hydrogen, carbon dioxide and other compounds. Examples of production methods include steam reforming of natural gas or liquid hydrocarbons to produce hydrogen, the gasification of coal and some types of waste-to-energy gasification facilities.

Tap: A point of connection along a transmission line between substations.

Terminal equipment: Equipment needed to terminate a line at a substation or switching station, usually consisting of disconnect switches and breakers and voltage and current transformers used for protection and metering purposes.

Thermal limitations: The temperature limit of a piece of equipment or an electrical line. Electrical lines, both distribution and transmission, are typically limited by clearances to ground, buildings or other fixtures. When current flows through a wire, the wire heats up causing it to sag. The limit of clearance and the structure design determine the amount of sag allowed.

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.

Transient stability: A measure of the performance of the system in the short period, usually one to five seconds, following the application of a fault on the system.

Transient swings: The voltage and power oscillations that occur on a power system during the one to five second period following the application of a fault on the system.
Transmission: The movement or transfer of electric energy over an interconnected group of lines and associated equipment between points of supply and points at which it is transformed for delivery to consumers or is delivered to other electric systems. Transmission is considered to end when the energy is transformed for distribution to the consumer.

Transmission facility owner (TFO): The owner of the system of high voltage power lines and equipment that links generating units to large customer loads and to distribution systems.

Transmission losses: Energy that is lost through the process of transmitting electrical energy.

Transmission must-run (TMR): A generator required to operate at a minimum specified output level to maintain system reliability in the event of an outage to certain transmission system elements.

Transmission path: One or more transmission lines that form the transmission connection between two points on the system.

Transmission path rating: See transfer capability.

Transmission system (electric): An interconnected group of electric transmission lines and associated equipment for moving or transferring electric energy in bulk between points of supply and points at which it is transformed for delivery over the distribution system lines to consumers or is delivered to other electric systems.

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

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 reduction: Any intentional reduction of system voltage by three per cent or greater for reasons of maintaining the continuity of service of the bulk electric power supply system.

Voltage stability limits: Limits established to ensure the system is operated within acceptable voltage ranges. Normal voltage limits are defined as the operating voltage range on the interconnected system that is acceptable on a sustained basis. Emergency voltage limits are defined as the operating voltage range on the interconnected system that is acceptable for the time sufficient for system adjustments to be made following a facility outage or system disturbance.

Voltage violation: A measured or calculated condition where the voltage at a point on the transmission system is outside the acceptable limits as described in the criteria.

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

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

Weighted average cost of capital (WACC): A calculation of a company's cost of capital in which the cost of each category of capital is proportionally weighted.

Western Electricity Coordinating Council (WECC): An organization formed to coordinate and promote electric system reliability for the system that interconnects Alberta, B.C., 14 western U.S. states and part of one Mexican state.
Appendices
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Appendix A
All Albertans depend on reliable electricity for services that are essential to their jobs, lifestyles and well-being. The AESO has a major responsibility to make sure the system for delivering power can meet these electricity needs today and in the future.

Electricity system basics
The AESO develops long-term transmission plans to ensure that Alberta has an adequate transmission system to meet future requirements.

There are three basic components of any electric system: generation, transmission and distribution. A description of each of the components and the role each plays in an electric system is summarized below.

Generation
Generation is how electric power is created. Power can be produced using many different types of energy sources. Some of the more common energy sources include coal, natural gas, wind, nuclear, solar and water. Each type of energy source has advantages and disadvantages and some work better for certain applications. Most power systems use a mix of several different energy sources.

Transmission
In many jurisdictions, electrical systems have developed with large volumes of electricity being generated by large plants that were built a distance away from major population centres. As a result, it is necessary to move the power in bulk from the place where it is generated to the homes, farms and businesses that use it. This is done through a transmission system.

Transmission systems are composed of high voltage power lines, ranging from 240 kilovolts (kV) to 345 kV, 500 kV and 765 kV. These voltage levels far exceed the standard 120 volt outlets in most homes. High voltage power lines provide the most efficient way to move large amounts of power over long distances with fewer line losses.
Transmission is an efficient way to move power

Some heat is always created when electrical current travels through a power line. This is called transmission line losses. The term “losses” describes this electricity because it is used up in the transportation of electricity and does not make it all the way to the customer.

Transmission lines are designed to carry a specific amount of electricity. When a line is consistently operated close to its capacity, more heat is produced and a significant amount of transmission line loss occurs. This is inefficient because all the electricity that enters the line at the power plant is not delivered to the customer. There is a cost to transmission line losses, and all power customers share in this cost. In 2007, the cost of line losses for the system was $183.8 million. Improving system efficiency not only saves money, it is good for the environment as it reduces wasted energy.

How transmission works

To move electricity on a transmission system, it is necessary to boost the voltage of electricity generated at power plants, generally in the range of 10 to 25 kV, to a higher voltage for transmission. The voltage of electricity is increased at transformer stations as it leaves a power generating plant so it can travel long distances on high voltage transmission power lines to the places where it will be used.

When a transmission line reaches a town or city, the voltage of electricity is reduced to the range of 69/72 kV to 138/144 kV. Power lines in the area transmit the electricity to transformer stations located near customers.

Transmission is the backbone of a system

Alberta has about 21,000 kilometres of transmission lines that operate much like a system of highways. There are major routes that connect large centres and handle a high volume of traffic and smaller, secondary routes that branch into every community in Alberta. The power system must be managed every second. This is done by the AESO’s system controllers, who have sophisticated technology at their fingertips to constantly monitor the movement of power from generators through the transmission network and across the province. Their job is to make sure that when a light switch is turned on, the power is there.
Transmission needs to be reliable
It is important that the capacity of the transmission system is in place in advance of the need for additional electricity to help maintain reliable power supply to customers. For example, if one transmission line is automatically taken off line due to equipment malfunction or a bad storm, other lines must be available to carry the load so there is no power outage to customers.

Transmission is essential to a competitive power market
Alberta’s Interconnected Electric System (AIES) is a vital component of the power industry and provides the platform for a competitive wholesale electricity market. To enable competition, all generators must have access (through transmission lines) to provide supply to meet demand for electricity in all areas of the province. Economic and reliable transmission infrastructure encourages investment in new supply, while limited access to the market reduces competition.

The AIES connects generators to customers over a large geographic area, with the objective of delivering electric energy to Alberta customers reliably and efficiently under a wide range of system operating conditions and changing customer demand levels.

Through transmission lines that provide interties with neighbouring jurisdictions, the AIES also facilitates access to the entire North American electric grid. In addition to providing mutual assistance during emergencies, transmission interties are an essential part of a competitive market and provide Alberta with a way to import energy when needed and export energy surplus to the province’s needs.

Distribution systems deliver power to customers
Distribution power lines transmit power in smaller quantities to large customers and distribution system substations in or near population centres at voltages in the range of 13.8 to 25 kV. The final stage is the distribution of power to groups of customers and to individual customers at 600 to 4,160 volts for light industries and 120/240 volts for small commercial and residential customers.

In Alberta, electricity is distributed by a distribution utility or rural electrification association. A distribution utility is also called a wires company, and it may or may not be an affiliate of the same company that supplies power to a consumer. The smaller power poles and wires, common along city streets and rural roadways, are part of the distribution system.
MOVING PARTS

Electricity at work

A Generating plants
Power is generated using a fuel source to create a rotating motion that is then turned into electricity.

B Transmission substation
A set of large transformers increases the voltage of power coming from a generating plant for its long journey through the transmission grid to customers. Voltage can be compared to water pressure in a hose.

Alberta’s power sources
- Coal: 5,893 megawatts
- Gas: 4,669 megawatts
- Hydro: 869 megawatts
- Wind: 497 megawatts
- Other renewables: 214 megawatts (e.g., biomass, solar, run-of-river hydro (March 2008))

How electricity is generated

- Natural gas-fired generation: A gas turbine is like a jet engine. Air is brought in and compressed, then heated by burning natural gas. The high-speed rush of this hot air spins the turbine causing a generator to turn and creating an electrical current. In some plants exhaust from the gas turbine is run through equipment that extracts the heat, which can then be used for another purpose. In a cogeneration power plant, extracted heat is used to produce steam that can be used in an industrial process in an adjacent facility, or it can be used to generate additional electricity in a steam turbine. This is an efficient use of the natural gas.

- Coal-fired generation: Coal is burned in furnaces to heat water. Boiling water creates steam that travels through pipes into a turbine. The turbine spins the generator and creates an electrical current.

- Wind power: A turbine is placed on top of a high tower. When the wind blows, the turbine blades turn, which turns a shaft attached to the blades. As the shaft turns, it spins the generator creating electricity.

- Hydroelectric power: The force of falling water created by dams pushes against turbine blades causing the turbine to spin. This spins the generator and produces electricity. Hydroelectric power is also generated in run-of-river plants that use rushing river water to turn turbines that generate electricity. Some of these plants are integrated into irrigation watering systems.

- Solar power: When sunlight hits solar cells, or photovoltaic cells (thin metallic plates), electrical currents are created that produce electricity. Solar panels can be installed on roofs of houses, office towers, barns and other buildings to supply electricity.

- Biomass power: Examples of biomass are trees, grasses, plants, crops, animal manure and even garbage and landfill fumes. A biomass power plant can use these fuels in a furnace to boil water that creates steam. The pressure of the steam spins a turbine attached to the generator, which creates electricity.

- Nuclear power: A nuclear reactor produces heat by splitting uranium atoms through a process called fission, which creates a lot of heat. This heat boils water in the reactor to create steam. The steam spins large turbines that drive the generators to produce electricity.
Industry uses about 60 per cent of Alberta’s total electricity supply; some companies build their own power sources to support industrial operations such as steel mills, forestry and petrochemical processing plants. When Alberta needs more power, some industrial customers can send their extra energy onto the power system.

Connections with neighbouring electric systems act like a valve that can be opened and closed, allowing power to move in or out of the province.

Solar panels can be installed on roofs of office towers and other buildings to capture the sun’s energy.

Industry uses about 60 per cent of Alberta’s total electricity supply; some companies build their own power sources to support industrial operations such as steel mills, forestry and petrochemical processing plants. When Alberta needs more power, some industrial customers can send their extra energy onto the power system.

These hydroelectric plants use the natural flow of river water to turn turbines and generate electricity.

The amount of electricity delivered to a home, farm or business is measured using a meter.

Low voltage power lines are best suited for transporting electricity over short distances. These power lines carry electricity from a substation to homes, farms and businesses.
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Appendix B
Alberta’s Provincial Energy Strategy
Acknowledgments

The Government of Alberta would like to thank the members of the Provincial Energy Strategy Advisory Committee. The input and expertise of the committee members was invaluable in the development of this document.

- Dr. Michael Percy, University of Alberta (Chair)
- Brenda Bell, formerly Minister of Energy and the Environment of the Northwest Territories
- William Gunter, formerly with the Alberta Research Council
- Robert Mansell, University of Calgary
- Clive Mather, Iugen Corporation
- Michael Raymond, LACC Group
- Lorne Taylor, formerly Environment Minister of Alberta
- Linda Van Gastel, Alberta Science and Research Authority
- Peter Watson, Deputy Minister of Energy (Ex Officio)
Message from the Minister of Energy

The Provincial Energy Strategy is a comprehensive plan for Alberta's energy future and it supports our government's priority of ensuring that our energy resources are developed in an environmentally sustainable way.

In our vision for our energy future, Alberta will remain a global leader, recognized as a responsible world-class energy supplier, an energy technology champion, a sophisticated energy consumer, and a solid global environmental citizen. To realize this vision we must act now to achieve the strategic outcomes outlined in this strategy of clean energy production, wise energy use, and sustained economic prosperity.

Clean energy production will be achieved through the application of energy technology leadership such as our government's investment in development and implementation of gasification technology and carbon capture and storage. In a world counting on energy from all sources, Alberta's advantage lies in being able to produce and consume fossil fuels in a far cleaner way, but our commitment extends to the increasing role of alternative and renewable energy.

Wise energy use will mean Albertans will not only be the champions of energy production, but also set the standard in its consumption. To achieve this we must integrate the “demand side” in our thinking, which is why we are taking energy conservation and energy efficiency measures.

Sustained economic prosperity will be built on optimizing recovery of our resources, broadening energy markets, developing and exporting our energy “know-how,” and going farther along the “value-added” chain with our energy commodities. Actions we have taken to meet this objective include seeking the development of a world-class hydrocarbon processing cluster in Alberta and accepting the royalty share of bitumen production in kind in lieu of cash.

Alberta is blessed with abundant energy resources that play an essential role in the living standards and prosperity of Albertans. We must build on our success with the continued development of our energy resources in ways that are integrated and environmentally sound.

The Provincial Energy Strategy builds on our province's strengths, addresses the challenges we face, and charts a strategic path forward to a bright energy future for Alberta.

Sincerely,

Original signed by

Honourable Mel Knight
Minister of Energy
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1. Introduction and Context

1.1 Energy: Our Platform

Energy has underwritten the story of our province. Today in Alberta, the energy sector directly and indirectly is the single largest contributor to provincial Gross Domestic Product, income, employment and government revenues. It comprises more than two-thirds of our exports. Our strength in energy has helped us cultivate a strong and vibrant economy, a skilled and productive workforce, the lowest overall tax burden of any province in Canada, leadership in innovation and knowledge-based progress, an entrepreneurial and competitive business community, and a modern and efficient infrastructure. Energy has given us a lot to be proud of.

Alberta produces about five trillion cubic feet (tcf) of natural gas, 250 million barrels of conventional oil, 500 million barrels of bitumen (a semi-solid form of crude oil) and, from 11 different mines, more than 30 million tonnes of coal each year.

Keep in mind that innovative Albertans have in the last two decades managed to extend established reserves of oil and gas approximately in tandem with production. In other words, there may still be dozens of years more of oil and gas to drill. We have an extensive pipeline infrastructure and a thriving petrochemicals sector. We have shown leadership in renewable energy development, including hydro, wind and biomass. Our electrical generation capacity is more than 12,000 megawatts, with demand growing at twice the rate of the rest of Canada.

Albertans have controlled the bulk of their energy resources since 1930. Many Albertans are employed directly in the energy industry. Others are not, but they still owe their livelihood to the sector. Alberta’s Aboriginal and Metis communities have a special role in the energy picture. All of us are energy consumers. Energy development has enjoyed a close connection with Alberta communities. What we see today, all around us, is a platform for our energy future.

How we will define that future is the question we must now answer.

International Merchandise Exports from Alberta, 1998 to 2007 ($ billions)

Ownership of minerals in Alberta

<table>
<thead>
<tr>
<th>BYR</th>
<th>2,784,760 ha</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mines, not owned by the Crown</td>
<td></td>
</tr>
</tbody>
</table>

Source: Industry Canada, Trade Data Online

1 GDP is a key measurement of economic activity and defined as the total value of goods and services produced.
1.2 The Basin

Our energy story starts with the formation of the Western Canada Sedimentary Basin (WCSB), a massive wedge of rock underlying northeastern B.C., western North West Territories, most of Alberta, southern Saskatchewan and southwestern Manitoba. Created over hundreds of millions of years, the basin rock is about six kilometres thick at its western extent, thinning gradually to the east.

We call it “sedimentary” because it is old sea bottom; it accumulated through the settling of water-borne sediments. Its layers gradually hardened with the pressure of overlying rock, trapping decayed organic materials that eventually became “fossil fuels,” coal, oil, bitumen and gas. The deepest layers of the basin are more than 500 million years old. The fossil fuels we consume today are essentially storage vessels for solar energy; they started out as plant and animal matter whose life cycles were nourished by the sun’s light and warmth over millennia.

Energy also makes a substantial contribution to the economies of neighbouring B.C. and Saskatchewan, but of the jurisdictions that sit over top of the WCSB today, Alberta is uniquely blessed. We preside over most of the basin’s oil and gas and coal reserves and almost all of its bitumen. Alberta’s first peoples knew well of the outcrops of black rock, of groundwater that lit on fire, and of oily seepages that occasionally surfaced on the landscape. The Cree and Dene used bitumen to waterproof their canoes. Early-arriving Europeans, including fur trader Alexander MacKenzie, mapmaker David Thompson, and geologist Dr. George Dawson, took note.

A natural gas find was recorded near Medicine Hat along the Canadian Pacific Railway line in 1883, when a well meant for water produced gas instead; the escaping gas ignited, destroying the drilling rig. In what is now Waterton Lakes National Park, a successful oil well was drilled in 1902. The prolific “Old Glory” discovery gas well was drilled in 1909 at Bow Island, and the industry took on feverish dimensions when wet gas and oil were discovered at Turner Valley in 1914. A blow-out that burned for three straight weeks in 1924 confirmed the area as an oil producing centre. After mineral resource ownership was transferred from Ottawa in 1930, Alberta took leadership in matters of resource conservation that in the decades following set the standard for jurisdictions worldwide.

Imperial Oil’s oil strike near Leduc in 1947 helped people begin to realize the global scale of our resource. A massive blow-out on Leduc #3 commanded world media attention for six months in 1948, permanently connecting the words “oil” and “Alberta.” In 1958 another substantial milestone was reached when piped western Canadian gas arrived in Toronto: the Trans-Canada pipeline was the longest pipeline in the world until the 1980s.

Conventional oil production peaked in Alberta in the 1970s and conventional gas production has now also peaked. But the resources of the WCSB have impressive diversity. Technology, commodity prices and escalating global demand are combining to extend our relationship with fossil fuels by allowing us to tap “unconventional” resources. Building on pioneering work in the 1920s by Dr. Karl Clark at the Alberta Research Council, the Alberta Oil Sands Technology
and Research Authority (AOSTRA) was created in 1974 to promote the development and use of new technology for oil sands and heavy oil production. For a multi-year expenditure that came in under $1 billion in total, we learned how to economically extract bitumen from our mammoth deposits. Many hundreds of billions of dollars of private investment have followed. More recently, we have made striking advancements making it economic to extract “unconventional gas” – such as natural gas from coal, natural gas from shale layers and natural gas from tight (and previously uneconomic) pockets in the ground. Unconventional gas may be recoverable in quantities that are a multiple of our original conventional gas reserves.

The progress we have experienced has not been continuous. Alberta has surmounted many, many obstacles over the years, including regulatory and ownership hurdles, protectionist sentiment, nationalization, economic recessions, wars, environmental threats, cyclical price downturns, skill and labour shortages, exploration disappointments, and the trials and tribulations of research.

As we look to the future, Alberta must continue to be nimble—responding to challenges, and taking the long-term approach to capitalize on opportunities. Success as we taste it in Alberta today is sweet, but it has been hard-earned. Tomorrow’s challenges will be no different.

Imperial Oil’s oil strike near Leduc in 1947 helped people begin to realize the global scale of our resource.
1.3 Fossil Fuels

The basin's resource diversity has afforded the opportunity to sustain wealth generation for a century now. How are these assets holding up?

Natural Gas

Alberta is today the world's second largest exporter of natural gas and its fourth largest producer. We supply the United States with more than half of its gas imports. Natural gas is also the main contributor of provincial energy royalties. Conventional production peaked in 2001, but some of the decline has been offset by recovery of "unconventional gas," mainly natural gas from coal (known as coalbed methane) thus far. Unconventional gas offers us the potential to extend production of this valuable resource, the cleanest burning of the fossil fuels, well into the future. There is huge potential for tight and shale gas in Alberta, as well as natural gas from coal. New technology will be required to make the most of it.

Conventional Oil

Alberta still leads the country in conventional oil reserves, with 39% of the Canadian total. To continue the production of conventional light oil, industry is searching for remaining undiscovered pools, drilling infill oil wells, and redeveloping existing pools using enhanced oil recovery (EOR) techniques such as waterfloods and carbon dioxide injection, which increase reservoir pressure permitting greater extraction. Currently, only about 27% of light oil is recovered in Alberta, suggesting there is still plenty in the ground awaiting improved

Reserves and Production Summary, 2007

The following table summarizes Alberta's energy reserves at the end of 2007.

<table>
<thead>
<tr>
<th></th>
<th>Crude Bitumen</th>
<th>Crude Oil</th>
<th>Natural Gas</th>
<th>Royl Royl</th>
</tr>
</thead>
<tbody>
<tr>
<td>Measured in</td>
<td>million cubic meters</td>
<td>million cubic meters</td>
<td>million cubic feet</td>
<td>million cubic feet</td>
</tr>
<tr>
<td>Initial Place</td>
<td>271,991</td>
<td>1,712</td>
<td>10,312</td>
<td>68.3</td>
</tr>
<tr>
<td>Initial Established</td>
<td>38,900</td>
<td>179</td>
<td>2,771</td>
<td>17.3</td>
</tr>
<tr>
<td>Cumulative Production</td>
<td>944</td>
<td>5.9</td>
<td>2,511</td>
<td>15.8</td>
</tr>
<tr>
<td>Remaining Established</td>
<td>37,400</td>
<td>175</td>
<td>2,641</td>
<td>17.4</td>
</tr>
<tr>
<td>Annual Production</td>
<td>76.0</td>
<td>6.0</td>
<td>214</td>
<td>13.2</td>
</tr>
<tr>
<td>Ultimate Potential (responsible)</td>
<td>50,000</td>
<td>415</td>
<td>5,130</td>
<td>18.7</td>
</tr>
</tbody>
</table>

- Includes coalbed methane (CBM). Expressed as "mcm" gas.
- Measured in billion cubic feet (of gas available to deliver to market).
- Includes non-CBM.

8. ALBERTA'S PROVINCIAL ENERGY STRATEGY 2008
technology or improved prices. To produce more conventional heavy oil, industry is exploiting new zones in undrilled portions of the basin, or applying EOR schemes such as waterfloods, thermal projects, and miscible floods. Only 15% of heavy oil is currently being recovered. With massive quantities of light and heavy oil still available to be tapped, one could say there is truly another Alberta lying beneath our feet.

**Bitumen**

The reserves of our three major oil sands areas – Athabasca, Cold Lake and Peace River – dwarf those of the conventional oil fields. The oil sands contain 173 billion barrels of economically recoverable crude bitumen (approximately 10% of the mineral deposit), a volume that, when confirmed in 2006, vaulted Canada into second place behind Saudi Arabia in global proven reserves. If we add our bitumen reserves to our reserves of conventional crude, Alberta’s borders contain more than 98% of total Canadian oil reserves – about 13% of global proved reserves.

Oil sands are a mixture of sand, clay, water and bitumen. Sitting beneath 141,000 square kilometres of northern Alberta, they are much less expensive to locate than conventional oil, but they are costlier to produce. We began commercial production by surface-mining these deposits and we are now recovering deeper bitumen by heating the oil sands and drawing bitumen up wells to the surface – a process called “thermal in-situ recovery.” Ultimately, 80% of the bitumen will be developed via the in-situ process which has a significantly smaller footprint on the landscape than strip mining.

With the dramatic rise in oil prices in recent years, oil sands activity has grown quickly. Materials and labour have emerged as significant limiting factors to the pace of growth. With that growth in activity has come an increased environmental focus. Much of that has focused on the significant amounts of water and energy — with its resultant emissions — used to recover and process bitumen. Strip mining and tailing ponds create environmental pressures for the landscape and watershed. These remain critical issues that must be addressed in the years to come by industry, government and the research and technology sector.

**Coal**

The WCSB contains about 90% of Canada’s usable coal resources. Alberta sits on about 70% of Canadian reserves, much of it low in sulphur. Make no mistake; the oil sands are big, but Alberta’s coal reserves contain more than twice the energy of all the province’s other non-renewable energy resources.
Coal in Alberta is generally low in sulphur and therefore burns cleaner than coal found elsewhere around the world. This lower sulphur coal is consumed here at home for electricity generation, where coal is the main fuel for our power grid. About a third of Alberta’s usable coal is “bituminous,” attractive as coking feedstock and thus shipped to areas of concentrated heavy industries in Asia and elsewhere. At current production levels, our reserves will last for hundreds of years.

Despite its abundance, coal is not without its challenges to be addressed. The phrase “clean coal” is heard a lot these days, and even while boasting some of the most technologically advanced coal-fired electricity plants in Canada, there remain significant opportunities for Alberta to lead growth in advancing this technology.

Carbon dioxide (CO₂) emissions are a central issue of coal-fired generation, but there are other emissions that can affect Alberta’s air quality—despite the fact that Alberta is a leader in managing air emissions from coal-fired generation. The electricity we consume in our homes and workplaces is a big part of the standard of living we enjoy, but when it comes to coal, there are huge opportunities for Alberta to pursue cleaner methods to generate that power.

1.4 Beyond Fossil Fuels

Gas, oil, bitumen and coal owe their energy content to the sun—a pretty old energy source. They exist on earth in finite quantities, thus earning the designation “non-renewable.” Once they are used up, they are gone.

Nuclear energy, dependent on mined uranium, is one alternative to fossil fuels. Uranium is still plentiful globally, however issues include waste management and environmental, health, safety, and social concerns. Nuclear has experienced resurgence as the world attempts to reduce its CO₂ emissions. Some synergistic applications involving bitumen processing may be available. Alberta is currently examining the merits and challenges of nuclear power.

Then there are “renewables.” Alberta has a wealth of renewable biomass feedstock in the forestry and agriculture sector that will drive considerable production of low-carbon transportation fuels and power generation. We have long benefited from power generated by hydroelectric dams. Wind, wave, tidal, solar, geothermal, biomass, biogas and run-of-river hydo have increased their presence on the global scene. These are seen to be cleaner, more sustainable sources of energy—although not entirely without environmental impact.

Until recently they were also more expensive, but the rising prices of fossil fuels have leveled the playing field considerably. Renewables are growing off a very small base, but their viability is improving and innovation is percolating. As such, they have the potential to become a significant part of the global energy mix this century, but based on demand here in Alberta and globally, they cannot entirely replace fossil fuels any time soon. Alberta’s development and use of renewables will help in reducing greenhouse gas emissions, enhance Alberta’s diversity of energy supply, stimulate regional activity, and fortify collaboration across industry sectors.

3 Bituminous coal has a high carbon content and can be processed (coked) by a process plant to meet requirements for applications such as the manufacturing of steel.
An additional—and very real—category of energy that must be mentioned is saved energy. Energy not consumed is energy that can be used productively elsewhere. Energy savings contribute to ensuring adequate and efficient supply for all Albertans, while at the same time, reducing incremental emissions. Legislation is being prepared in Alberta to advance energy efficiency and conservation and to help educate Albertans on the benefits of both.

Each source of energy brings challenges with it. The consensus seems to be that in the future the world will need to maximize the provision of energy from all sources—fossil fuels and the rest—in order to satisfy our growing needs. Alberta will have a role to play in helping to keep global energy markets in balance.

1.5 Electricity: Facilitator of Prosperity

Electricity is not pumped out of the ground, hence the tag “secondary” energy source. But it plays an essential role in the living standards and prosperity of Albertans. Simply put, when they flick the switch, Albertans expect the lights to come on.

About 21,000 kilometres of transmission lines cross the province, delivering electricity generated from coal, gas, hydro, wind and other renewables to homes, offices, plants and other facilities. Power in Alberta is supplied under a different market system than in other provinces in that the generation and retail sale of electricity are open to competition. Wholesale power is an $8-billion market in Alberta.

Power consumption has been growing at an annual pace exceeding 3%, a function of population growth as well as today’s more power-intensive lifestyles. But it has been more than 20 years since the backbone of the Alberta transmission system between Edmonton and Calgary was reinforced. By 2027, we will need twice the power we currently consume.

Generation sources are becoming more diverse as renewable energy grows, testing the grid in new ways and creating pressures not experienced before. Our system also remains one of the least “interconnected” in the country with limited capacity to either import or export electricity when necessary to maintain the integrity of the grid. This creates challenges for safety, reliability and affordability. Our electricity system will play a large role in delivering more and cleaner energy to Albertans in years to come.

1.6 The Canadian Energy Picture

According to 2005 figures, Canada is among the top five energy-producing nations in the world, thanks in large part to Alberta’s petroleum industry. Canada produces a lot more energy than the nation consumes, and the resulting exports drive much of our country’s economic wealth.

In 2007, Canada’s energy industry accounted for 5.6% of national GDP and directly employed 372,200 people (2.2% of the Canadian labour force). Energy export revenue totaled $90 billion, which accounted for about 20% of the value of
all exports. This proportion has held steady for the last three years, with energy playing twice the role in Canada’s exports that it did in the 1990s.

As one of the most important sources for U.S. energy imports, Canada is well positioned to play an increasing role in America’s goal to gain independence from overseas oil imports. This is key as neither Alberta nor Canada can operate as an island in North America’s integrated energy market.

As this strategy clearly outlines, Alberta fits prominently into Canada’s energy picture. The development of Alberta’s energy resources—and the demand for those energy resources—provides enormous economic advantages that reach well beyond the province’s borders.

Growth in Alberta’s energy sector has significantly increased the demand for goods and services from other provinces creating jobs throughout the country and significant tax revenues for the federal and provincial governments. In addition, Alberta’s resources provide Canada with energy security and the potential to be energy self-sufficient.

While Canadian law is very clear that the province has jurisdiction over the development of its natural resources, the province has a responsibility to work with the federal government to ensure that any national legislation or policy does not negatively impede Alberta’s responsible development of energy. This includes seeking alignment between provincial and federal policies, such as those on climate change.

Alberta must ensure that national policies take into account our unique position as an energy providing jurisdiction and a key driver of the nation’s economy.


![Net Energy Export Revenues Chart](chart.png)

Source: Stats Canada, NRB

12. ALBERTA’S PROVINCIAL ENERGY STRATEGY 2008
1.7 The World Energy Picture

The price of a litre of gasoline or a kilowatt-hour of electricity is derived primarily by the supply-demand balance of the underlying commodity. World energy demand has grown at a steady pace in the last three decades and that growth is now accelerating as consumption rises in populous developing nations including China and India. At the same time, global energy supply has become more problematic. Issues of technology, geology, politics, access and environment stand in the way of an assured, continuing flow of energy from traditional sources.

We see the effects of these supply-demand imbalances in rising prices. Over the last decade, the price of natural gas has experienced a structural upwards shift. Oil, which was about US $15 at the turn of the millennium, went over US $100/barrel earlier this year and kept climbing before its recent pullback. Even the price of coal, one of the world’s readiest energy sources, has more than tripled as manufacturing industries in previously rural economies have taken off.

We should not forget the potential of energy to address disease, poverty, illiteracy and, ironically, the environment. There is a positive correlation between energy use and human development. Provision of pumped well water, natural gas for cooking, or power for lighting can spur fundamental shifts toward the more equitable, more compassionate world in which most of us want to live. Greater energy production capacity will be required to sustain the improvement occurring in living standards in developing nations, as well as to enable technologies directed at environmental protection.

![Human development and energy graph](source: Physic's Today: The Energy Challenge (ITSE))
Global Oil Production

Russia 2.96
Saudi Arabia 1.50
USA 0.99
Iraq 0.87
Mexico 0.79
China 0.68
Canada 0.18
Norway 0.15
UAE 0.12
Venezuela 0.14

At home in Alberta, energy also supports community development and prosperity. Many Albertans and Alberta communities owe their livelihood and economic success, either directly or indirectly, to oil and gas development.

Alberta’s main global impact is on the supply side. We preside over immense energy resources, we are located adjacent to the U.S.—the world’s largest consumer of energy—and we offer a level of stability and security that is rare given the all-too-exciting geopolitical conditions worldwide. We have earned a place of respectability—and responsibility—on the global energy scene.

Top 10 Countries Providing U.S. Imports of Crude Oil and Petroleum Products

1.8 Bringing It Home

Our energy sector continues to deliver wealth. Alberta has been, on a per capita basis, by far the largest net federal fiscal contributor since 1962, to the benefit of the other regions of Canada. Our GDP product on a per-person basis is the highest among provinces and fully 70% higher than the average for the rest of Canada. A study undertaken at the University of Calgary (see figure below) suggests that our economy without the impact of oil and gas would be barely recognizable—less than half its current size. Energy has allowed Alberta to become a substantial and growing engine, propelling the national economy.

While all fossil fuel development has contributed to Alberta’s current position of strength, investment in Alberta’s conventional oil and gas industry still dominates total Canadian oil and gas investment. But it is the oil sands that are beginning to have what can be described as a transformative impact on our economy. Construction activities in the oil sands have triggered an unprecedented investment boom. Representing the majority of major Alberta project investment, these are long-term, multi-billion dollar projects—many of which are already well into planning or even construction.

In a few years' time, when the majority of the oil sands plants move into operation, an enormous continuing demand for goods and services will be spawned. The
oil sands plants will require more labour on a more sustained basis than the conventional oil and gas sector. Their impact on employment, demand for goods and services, provincial tax and royalty revenues will be substantial. Of note, according to a Canadian Energy Research Institute report, more revenues from oil sands operations will be received by the Canadian federal government than the Government of Alberta over a 20-year period.\(^3\)

### Impact of oil and gas on Alberta GDP

<table>
<thead>
<tr>
<th>Year</th>
<th>Actual</th>
<th>Without Oil Sands</th>
<th>Without Commercial</th>
<th>Without Oil and Gas Sands</th>
</tr>
</thead>
<tbody>
<tr>
<td>2010</td>
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<td></td>
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<tr>
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<tr>
<td>2025</td>
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</tbody>
</table>

Source: University of Calgary

Energy prices historically have tended to be volatile and cyclical, driven by forces outside the control of Albertans. While we cannot neutralize the periodic booms and busts that characterize this sector, there are some things we can do, secure in the knowledge of the attractive long-term prospects of the industry. Government policy must be driven by this long-term focus. As the industry confronts issues related to climate change, skill shortages and infrastructure, a sustained vision by government becomes all the more important, if not critical.

For Alberta in the coming 30 years, no other activities will have the scale or impact of energy development. Agriculture and other sectors are important to Alberta and diversification is good for us, but energy’s impact is pervasive. It is, and will be, our province’s dominant economic engine. Now is the time for Alberta to be proactive on pursuing innovative energy development and environmental protection to help ensure the long-term economic prosperity of the province.

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\(^{3}\) Canadian Energy Research Institute, Economic Impacts of Alberta’s Oil Sands, October 2005

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1.9 Challenges Ahead of Us

Traditionally, the energy challenges Alberta has faced have included ensuring we have a secure supply for ourselves, offering competitive exports for our economic benefit, and taking care of our environment. Relative to comparable jurisdictions, we have excelled in these areas. In the future, our challenges will still boil down to these fundamental three. But the dimensions of the challenges will take on greater complexity. Here are a few of the dimensions we will need to pay particular attention to:

Climate change. We are entering a future where emissions of carbon into the atmosphere will be constrained. Although we have made some progress in lowering the “carbon intensity” of energy production, carbon emissions are still more or less attached at the hip to fossil fuels. Because the world will continue to need fossil fuels, we will need to find cleaner ways to produce and consume fossil fuels. Alberta’s oil sands for example, while they account for just four per cent of Canada’s greenhouse gas emissions and less than one tenth of one per cent of all global greenhouse gases, are a large fossil fuel resource and therefore provide a tremendous responsibility and opportunity for Alberta to lead.

Global markets. The United States has long been our central destination for energy exports. Americans are excellent customers. But the U.S. no longer enjoys uncontested dominance in the world’s economy. China and India want our energy supplies, too. Alberta has opportunities to reduce our singular dependence on the U.S. market – and improve our bargaining power – by cultivating additional markets.

Technology. Innovation in the energy sector is most apparent when near-term benefits can be achieved through incremental change. The timeframe demanded for payback is not consistent with some of the high risk, long-term innovations we must develop to solve our energy challenges. We must move the results of our research through technology development and commercialization to full-scale commercial deployment in order to see our energy research investments pay economic and social dividends. Specifically, that will involve pursuing applied research that will enable us to solve the challenge and the practical issues our province is facing now. There is, consequently, a new and needed role for government in the “innovation supply chain.” We need technology more than ever today to keep our energy industry competitive and sustainable. With all the challenges now lining up for technology solutions, a concerted effort by industry and government is required.

Adding value. Oil and gas has spawned some diversification in Alberta, including development of our financial and telecommunications sectors. Alberta has grown a petrochemical sector, and while it is the largest in Canada, it cannot yet be described as world leading. How can we add more economic value? Carefully planned upgrading and refining capacity provides options for realistically adding value to fossil fuels while contributing to cleaner energy. This provides even greater reason to encourage additional investments that will see more of Alberta’s products advance up the energy value chain.
Labour: The energy sector has endured periods where it was not among students’ top choices when it came to choosing careers. This is unfortunate and must be addressed given that Alberta’s future will be shaped around energy. We need to bring more people into the industry at all levels in order to fully tap the opportunities in years to come.

Energy use. As a resource-rich province we have often considered development before energy efficiency or conservation. But times are changing. More than two-thirds of the energy from a lump of coal is consumed or wasted before the resulting electricity actually enters our households. The efficiency we experience by burning a litre of gasoline in our cars or lawnmowers—following the chain of processing it undergoes from crude oil—is even worse. The way we use energy leaves a lot to be desired: we drive long distances on congested roadways to work; we leave lights on or fail to stem the quiet energy consumption of electrical devices such as phones, televisions and computers; we inadequately insulate our homes.

The majority of global emissions result from the consumption, rather than the development, of energy. The U.S., for example, is not among the top energy producers globally; nevertheless it leads all nations in emissions. Managing the demand side of energy use may cut consumption by as much as one-third. The importance of stemming emissions is bringing our energy consumption patterns squarely into the spotlight.

Awareness and understanding. A better informed debate on our energy sector—both outside and within our boundaries—stands to benefit Alberta. Misunderstandings risk actions with potential to harm our province’s economic advantage and dramatically impact the quality of life Albertans have come to expect. We need to connect fully with our customers on steps we are taking to “produce energy better.” Now is the time to move past the platitudes towards a fully informed debate.
2. Alberta’s Energy Vision

2.1 Sustainable Prosperity

Alberta can take the initiative to lead toward a better, brighter future. This is the path that allows Alberta to not only respond to “issues” but take full advantage of the opportunities. We have taken this path in the past when it has been needed. We believe that it is needed again. Around the world, economies are either proactively managing the new realities, or being managed by them. Alberta has the wherewithal to leverage its current position and prepare for what is coming. This is the path of enlightened self-interest. Notwithstanding the diversity of views on climate change and its causes, it is clearly in Alberta’s and Canada’s economic interest to manage its energy future and carbon better. We can build on our strengths, address our challenges and pursue a strategic approach.

In the end, this path will allow us to move beyond viewing the challenges as the costs of continuing our growth. It will pave the way to sustained wealth creation, while safeguarding our environment and our social advantages for future generations of Albertans. Ultimately, the market will still decide. But the “Sustainable Prosperity” path will allow us to play a significant proactive role in our own future – and to demonstrate leadership and exert our fullest influence on the world stage.

The price, of course, is courage.
2.2 Our Energy Vision

Courage starts with vision. Everything about our past and present, and everything we know about the future, points out that Alberta should aspire to be:

A global energy leader, recognized as a responsible world-class energy supplier, an energy technology champion, a sophisticated energy consumer, and a solid global environmental citizen.

2.3 Critical Assertions

This energy strategy reflects the resourceful and responsible approach Alberta will take toward the long-term development of energy in our province. The following assertions represent fundamental guideposts of that direction:

1. The development of clean hydrocarbons is essential to Alberta’s energy future.

The world’s fossil fuel supply remains plentiful, but in a carbon-constrained world we must find methods to develop and consume fossil fuels in an environmentally responsible way, and this must be Alberta’s responsibility and focus. Alternative and renewable energy sources will play a growing role in Alberta energy’s future, but they cannot match the importance to Alberta of “clean” fossil fuels.

2. Ongoing development of Alberta’s energy resources will be a platform for continued economic growth and success.

Alberta’s energy future is also about revenues, value-added activity and sustainable jobs for Albertans and Canadians. An important benefit of the energy strategy is that it will lead to a future of long-term prosperity, continuing to drive job and wealth creation across Canada and providing value to Albertans as resource owners.

3. Alberta’s energy future will properly account for cumulative effects to the environment and greenhouse gas emissions.

This strategy recognizes that developing Alberta’s energy resources involves more than the need for specialized equipment and skilled labour — that the impacts of development are often more than simply dollars and cents. Decisions associated with energy production and consumption must ultimately take into account cumulative environmental impacts, including greenhouse gas emissions, and impacts to land, air and water.

4. Alberta will invest in energy infrastructure, including policy development and energy research.

Investment in infrastructure is integral to Alberta’s energy future. Investment means funding for tangible infrastructure and it also refers to investing time and effort on policies, regulations and institutional capacity that promote and ensure the development and deployment of new technologies that increase efficiency and reduce environmental impact.
5. Government will encourage energy efficiency and conservation at all levels. From individuals to industry, all Albertans must play a role in using and consuming energy in a responsible manner. Energy resources should be consumed with an emphasis on efficiency, conservation and wise use. We all have a role to play, and the impact that individuals make through personal choices should never be underestimated – be it green buildings, cleaner transportation, efficient appliances, heating and lighting or outright conservation.

6. Alberta will build on success. Alberta’s energy future depends on the continued development of our energy resources in ways that are integrated and environmentally sound. Future development will provide Albertans with tangible benefits and will recognize the responsibilities we shoulder as Canadians and global citizens. Alberta’s energy future will respect the need for meaningful engagement of all Albertans, including Aboriginal Albertans. All development will expand and increase our strengths and competitiveness within integrated North American and global markets.

2.4 Desired Outcomes

Exercising resourcefulness and responsibility, we believe that we will be able to achieve the following explicit outcomes:

- Clean energy production.
- Wise energy use.
- Sustained economic prosperity.

Realizing these three central outcomes will put us well within reach of our energy vision. The burning question, of course, is: How will we do it? There is more than one answer:

1. We will address the environmental footprint of energy.
2. We will investigate and exploit the ways in which we can add value to Alberta’s energy industry.
3. We will seek to change energy consumption behaviour.
4. We will improve our innovation including energy technology leadership and development of people.
5. We will enhance the capability of our electricity system.
6. We will work to bolster knowledge and awareness of and appropriate education on energy issues.
7. We will work to ensure alignment of other initiatives, programs, policies, and regulations with this strategy.

Section 3 expands on the three central outcomes. Section 4 builds on these seven explicit levers. Bold government action today will enable Alberta to write a self-determined future that will reap immediate and far-reaching benefits, while dramatically improving global goodwill. Albertans will lead, rather than be led.

ALBERTA'S PROVINCIAL ENERGY STRATEGY 2008
3. Outcomes

3.1 Clean Energy Production

Overview

How will we improve energy production practices in Alberta so varied sources can continue to grow and deliver benefits to Albertans?

Perhaps the option talked about most often is the development of more renewable energy—wind, solar, biomass, geothermal and hydro. Alberta has a rich endowment of renewable energy resources that will play an increasingly important role in our energy future. Already Alberta has almost three times the national average of electricity generation capacity from wind power. Biofuels can be produced from agricultural products such as grains and canola and cellulose from plant fibre and switch grass, and forestry waste products such as wood chips and wood waste. While the growth of renewables will be constrained by many factors, including manufacturing capacity and expertise, these energy sources are undeniably cleaner sources of energy than fossil fuels.

Along with growing demands for electricity and to support efforts to reduce greenhouse gas emissions, there has been a renewed interest in nuclear energy in many jurisdictions around the world. While CO₂ is not produced in the consumption of uranium, nuclear-generated energy does carry other issues, including concerns around safety, health and the environment. It is because nuclear offers both potential challenges and opportunities that the Alberta government is currently reviewing this issue to determine whether it is an appropriate fit for our province. While the province currently does not have a position on this topic, it has committed to develop one through a process that will involve engagement with the public.

In terms of greening the overall energy supply, neither nuclear nor renewables offer complete answers.

It is true that air, land and water are all affected in the development of fossil fuels. CO₂ and other gases are emitted in their recovery and processing. But fossil fuels do remain plentiful globally and their infrastructure is up and running. By 2030, the world is expected to be consuming more than 50% more energy than it consumes today. Most sources estimate that oil, gas and coal will still constitute the vast bulk of global energy supply by mid-century.

Should Alberta be looking at alternative energy sources? Yes. Should we promote renewables? Again, yes. But the key question for Alberta, in a world that is going to be counting on energy from all sources, is how we can begin to produce and consume fossil fuels in a cleaner way.

Means already exist to tap the energy within fossil fuels with reduced impact on the environment. They include gasification processes, which reduce the carbon impact of fossil fuels prior to combustion, combined with carbon capture and storage (CCS) to gather CO₂ and sequester it safely. These approaches, however, are expensive and yet to be fully validated. Alberta must apply its innovative talents to advancing and employing these means.
Approach

We will tackle the challenge of cleaning Alberta's energy production in the following ways:

- Invest in development and implementation of gasification technology as well as carbon capture and storage to reduce CO₂ emissions.
- Apply energy and environmental technology leadership to the other environmental issues confronting fossil fuel development, such as water consumption and tailings pond management.
- Incent cleaner industry behaviour by maintaining the Specified Gas Emitters Regulation (which puts in place a price on carbon for large emitters), or a version of it, and increasing this price over time.
- Not only support renewable energy development, but promote a market for its consumption.
- Give close consideration to the prospect of nuclear power and engage Albertans in a discussion of its potential for Alberta.
- Explore and capitalize on synergies available through innovative integration of energy sources, e.g., geothermal or hydropower in the oil sands.
- Continue to carefully manage our environmental footprint by respecting limits determined by a cumulative effects approach.
- Ensure monitoring, aligned regulations and enforcement aimed at achieving sustained cleaner energy production.

Clean energy production is not going to happen overnight. Some of the proposed approaches are long-term. But we recognize the urgency to act soon. We intend to take deliberate steps toward achieving this outcome.
3.2 Wise Energy Use

Overview

While much of Alberta's energy policy has focused on supply, increasingly we need to integrate the "demand side" in our thinking. The demand side spans a complex range from the choice of energy sources to extract bitumen to household and transportation energy conservation measures. Albertans, as mentioned, are among the highest per-capita energy consumers on the globe. We'd like to set a more appropriate example. Energy resources may need to be conserved, but they should be conserved with emphasis on efficiency, conservation and overall wise use. It is possible for Albertans not only to set the standard in development of its energy sources, but in their consumption.

There are several pragmatic reasons for adopting a strategic approach to the consumption of energy:

- Energy that companies and individuals do not consume is energy that can be upgraded or sold to further benefit Alberta. So "saving" energy not only reduces heating or lighting costs, but offers the potential to create more wealth for Albertans.

- The reality is that most CO₂ emissions are created in the consumption, not the development, of energy. Reducing per-capita consumption offers real possibilities to help meet emissions targets, even in Alberta where energy development dominates.

- There is real hope that a combination of wise energy use and appropriate technology development can begin to decouple emissions from energy consumption. In other words, we can begin to create a world where the carbon associated with our living patterns is captured and sequestered, or not even produced in the first place.

- We acknowledge that the energy we use in developing our resources is under increasing international scrutiny and has the potential to impact our provincial ability to market our products to other jurisdictions.

It is possible for Albertans not only to set the standard in development of its energy sources, but in their consumption.
Approach

We will accomplish wiser energy use in this province in the following ways:

- Work to convey knowledge and awareness—including the costs and benefits—of energy consumption and emissions.
- Actively support the replacement of natural gas as an oil sands input fuel with a variety of potential substitutes including synthetic gas from the bitumen barrel.
- Support adoption of energy conservation measures in buildings and an energy-conscious approach to urban planning.
- Work with Canada to establish vehicle emission/efficiency guidelines.
- Invest in projects that provide cleaner options to consumers, including mass transit.
- Work to ensure vulnerable Albertans and sectors can cope with high energy costs in the future, while not confusing market signals for conservation.
- Support upgrades to the electricity system that will increase its capacity, make it more robust and enable Albertans to make better use of it.
- Support through planning, technology and education the realization of greater efficiency in the production, conversion and consumption of energy.

Wise energy use is within our reach. It is the right thing to do, and the world is watching Alberta. Champions of energy production, Albertans can also set the standard in its consumption.
3.3 Sustained Economic Prosperity

Overview

Tackling the environmental and other challenges facing energy is seen by some as a "price we have to pay" to continue to grow. We accept the concept of cost. Introducing cleaner ways to produce energy will require strategic investment, some of which has already begun. However, this is not all about emptying our pocket books. The future also represents a significant economic proposition to Alberta. There will be plenty of opportunities for revenue generation and, more broadly, sustained wealth creation for Albertans. We believe the extra opportunities will more than offset the investments that will be required.

Alberta can take a number of steps to derive greater wealth over the longer term and in a more sustainable way through its energy industry. They includes optimizing the recovery of our energy resources—tapping more of what we are currently leaving in the ground, developing our substantial unconventional gas (coalbed methane, shale gas, tight sands) and reaching our oil sands resource potential. They include broadening the markets for our energy resources. They include the development and effective export of energy “know-how”—profitably sharing our solutions with the rest of the world. They also encompass the concept of "value-added"—taking our commodities further along the value chain than we currently do.

The Province of Alberta and its oil, gas and petrochemicals industries have excelled in value-added development of Alberta’s energy resources, particularly conventional oil and gas. Alberta has a major refining industry along “refinery row,” the world’s largest ethane-based petrochemical facility at Joffre, and other major petrochemical facilities in the Fort Saskatchewan region.

Most of the bitumen produced in Alberta is upgraded here, and some of that is further refined into higher-value products in our province. However, as the production of bitumen from the oil sands increases, there is further potential for value-added development in Alberta.

Value-added involves producing higher-value products from raw resources, rather than selling it at the first marketable point. This kind of development provides numerous benefits for the province—for example, new upgraders and refineries mean new, long-term jobs and tax revenues on top of the royalties the province already receives for the resources.
Getting the most value from Alberta resources requires striking a balance. Alberta does not have the capacity or the markets to turn all of its bitumen into diesel fuel or plastics. The province always has, and will continue, to try and obtain the best overall value for Albertans through the sale of a combination of products—everything from diluted bitumen to synthetic crude oil, to refined products and petrochemicals.

A strategy to maximize the value of Alberta’s resources will include a portfolio of sales that get the best from all markets including bitumen markets, synthetic oil markets and petroleum product markets. To some extent, it is the same strategy individuals use in developing their own personal investment portfolios. Variety can create and maintain opportunities for higher returns, while helping to decrease risk.

In addition, when other markets make plans and investments to receive heavier oil as part of their long-term supply, the demand for Alberta’s bitumen will grow, and so too will prices. Meeting that demand can, in turn, increase the royalty value the province receives from bitumen.

Alberta can add economic value through resource upgrading, reprocessing, manufacturing and adding knowledge to increase the value of products leaving Alberta. The need to curb emissions in the energy value chain is also a potential impetus to value-adding activity: if we can strategically plan and integrate the processing, upgrading and refining of our energy feedstocks, we will be able to more economically capture and store CO₂ than similar developments located in other jurisdictions. This provides a comparative advantage to Alberta.

The bottom line is that Albertans can ultimately realize a much greater and sustained value from their resources. Strategic steps beginning now will ensure that the “net present value” of our energy resources is maximized over the long term.

Hydrocarbon value chain

![Diagram of hydrocarbon value chain](image)
Approach

We will address the challenge of sustaining Alberta's economic prosperity in the following ways:

- Seek development of a world-class hydrocarbon processing cluster in Alberta in order to capitalize on advantages offered through feedstocks, footprint, synergies, transportation, logistics and market access.
- Invest in energy technology that will facilitate integrated approaches, value-added solutions to our challenges, including gasification and carbon capture and storage.
- Aggressively seek optimization of our current resource base including investments to improve basin productivity and the development of unconventional gas resources.
- Seek innovative application of energy production from sources other than fossil fuels in order to complement and enhance the goal of clean fossil fuel development.
- Develop a higher capacity and more robust electricity system for the province that enables us to take better advantage of opportunities technology presents us.
- Strive to broaden our energy industry's global customer base and balance its overall markets to ensure best value for our products and services.
- Create policy that provides the long-term certainty required to attract sustained private investment and highly qualified people.
- Promote the export of our energy and environmental technology know-how.
- Create a better understanding among stakeholders, including energy customers within and beyond our boundaries, of our efforts to manage the environmental footprint of energy development.
4. Levers

Levers are the tools we will employ to enable the achievement of our three central outcomes and, therefore, the overall energy vision of Alberta. There are many actions to take, but these are the main ones. They include:

- **Address Environmental Footprint.**
  - Cautious management of our environmental footprint: land, water and air.
  - Ensure an integrated approach to development of energy resources.

- **Add Value**
  - Support for the development of a world-class hydrocarbon processing cluster integrated with oil sands production, energy consumption and carbon capture.
  - Cultivation of markets, of industry participants and of highly qualified people.
  - Support for the optimization of basin resources.
  - Support for alternative and renewable energy development.

- **Change Energy Consumption Behaviour**
  - Development and implementation of energy conservation measures.

- **Innovate**
  - Energy technology leadership including gasification and carbon capture and storage.
  - Investment in the development of Alberta’s next generation of energy professionals.

- **Enhance Electricity**
  - Electricity system capability.

- **Bolster Knowledge and Awareness**
  - Knowledge and awareness of energy issues for Albertans.
  - Understanding by others of the approaches we are taking toward clean, green energy.
  - Input of energy information to the education system.

- **Ensure Alignment**
  - Alignment with related provincial and federal initiatives.
  - Changes to ensure policy, regulatory, and institutional alignment with the energy strategy.
4.1 Address Environmental Footprint

Manage Land, Air and Water

Alberta is resolved to manage the cumulative environmental effects of development. In this respect, the government will:

- Utilize regional plans developed under the Land Use Framework to assess the cumulative effects of development on the environment and to set the limits or thresholds that will guide development decisions. The balance between development and environmental protection—the limits or thresholds at a regional scale—will be set by Government.
- Ensure that regulatory agencies and decision-makers respect Government-approved limits or thresholds when making individual project decisions.
- Update and adapt regional plans as the needs of the province change.

The Land Use Framework will be critical to the achievement of Alberta’s cumulative effects approach. Monitoring and managing cumulative effects is a mammoth undertaking, but it will be enabled by integrated and comprehensive information on resource management. Alberta already has a solid position in geomatics—thanks largely to its connection to oil and gas—and we have policy supportive of sustainable development.

Alberta aspires to be a world leader in providing integrated resource management solutions that contribute value-add to energy, forestry, agriculture, environment and land management and development. Energy has already benefited hugely from data collection in the subsurface (seismic), surface data collection (e.g. geographic information systems incorporating land surveying data) and atmospheric data (e.g. the Clean Air Strategic Alliance’s work in reducing flare gas). Over the period spanned by this energy strategy, geomatics advancements will enable us to collect, organize and understand unimagined amounts of data—advancing cumulative effects assessment.

The Capital Region—encompassing the Industrial Heartland area—is the first Alberta region in which the cumulative effects management approach will be modeled. A series of comprehensive targets, outcomes and actions have been set for the region to protect the air, land and water. These targets and outcomes are specifically designed to address environmental and growth pressures from the pace of development in the region and would provide a greater level of certainty for future developers to plan their investments.

The following section deals with the development and deployment of technologies aimed at minimizing the environmental footprint of energy. We should not limit our efforts to new technologies and major new capital projects, of course. There is considerable headway to be made in deploying current technologies such as amine scrubbing\(^4\) to reduce emissions from existing facilities such as power plants and oil refineries.

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\(^4\) Geomatics is the gathering of information related to the earth’s surface and the mapping, analysis, and interpretation of that data.

\(^5\) Amine scrubbing is a post-combustion process that uses a solvent to capture emissions from fossil fuels.
Integrated and Long-Term Energy Development

Gasification and carbon capture and storage (CCS) are key technology components to realizing the commercial viability of clean fossil fuels. Alberta has much to gain from aggressively pursuing the clean gasification of feed stocks such as asphaltenes (bitumen bottoms), petroleum coke, biomass, waste and coal. Our coal reserves are abundant, while bitumen bottoms and petroleum coke are major, low-value byproducts of oil sands production. If we can employ technology to transform these feed stocks to synthesis gas (syngas) and other valuable products (heat, electricity and petrochemical feedstocks), while sequestering the resulting carbon, we will address a number of challenges:

- We will burn the syngas to create clean electricity.
- We will constructively and responsibly use what will be huge and growing stockpiles of bitumen bottoms and petroleum coke.
- We will divert valuable and exportable natural gas from the in-situ bitumen extraction and upgrading process.
- We will promote and encourage sustainable and highly economic upgrading and refining industries.
- We will add value easily to high-carbon, low-value materials through syngas to derive a wide variety of useful and valuable petrochemicals – launching a new era of clean, economic petrochemical production.
- We will create economic means to control and capture CO₂ emissions for subsequent sequestration.

CO₂ Geological Sequestration

Source: Alberta Geological Survey

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Representations to government from industry experts suggest that Alberta has a unique opportunity to develop a leading petrochemical cluster based on bitumen products and byproducts including gasification of feedstock extracted from bitumen during upgrading and refining. Bitumen piped from northeast Alberta could be processed in a concentrated industrial complex (such as the Industrial Heartland), and diluent could be piped back to the oil sands to complete a closed loop. Captured CO$_2$ could be sequestered. Excess energy could be placed on the grid. An integrated system such as this is more efficient and self-contained—it not only reduces the environmental footprint of its operations, but rewards Albertans with the benefits of value-added activities.

Efforts toward technically and commercially feasible gasification processes are underway through many organizations including the Alberta Energy Research Institute (AERI). We need to complement these efforts with policy that progressively reduces the use of natural gas in the oil sands, and with the launch of an ongoing research initiative that targets gasification with CCS, emphasizing their demonstration and deployment.

Alberta has made a move into CCS with our announcement of public support for a projected three to five projects expected to store about five million tonnes of CO$_2$ a year by 2015. CCS employed in enhanced oil recovery (EOR) and possibly enhanced gas recovery (EGR) promises an early and not insubstantial economic win. For example, research shows that between 500 million and two billion barrels of conventional oil may be recoverable using EOR in Alberta. Industry is already actively pursuing this course of action.

To make CCS work for Alberta, there is a need for a clarity-creating CCS “rulebook” addressing long-term liability (for the risk of escape of CO$_2$), ownership of geological reservoir pore space (including the rights to displace water from the pore space), and project approval (i.e. how to obtain the right to inject and store CO$_2$). It is the government’s intention to address questions including project life requirements, post-closure requirements, development of a monitoring, measurement and verification program, and a longer term management framework. The CCS Development Council is currently developing a blueprint of the most expedient approaches to making the broad-based application of CCS a reality in both the short and long term.

Ultimately, if mastery of the gasification-with-CCS cycle can put our abundant feed stocks into the clean energy category, it will be a boon to this province and to the rest of the world. Alberta’s success with this technology platform will ultimately be a valued and exportable resource unto itself.

**Encourage Complementary Energy Sources**

It is in Alberta’s interests to be an aggressive early adopter of renewable energy, for the following reasons:

- The synergistic relationship of renewables with fossil fuel development may facilitate cleaner production of Alberta’s significant hydrocarbon deposits (e.g. hydroelectric power contributing to bitumen extraction).
We already have a solid position as a host for wind energy, biofuels and hydroelectric production, and we may be able to leverage comparative natural advantages in solar, geothermal energy and biomass.

Renewables can play a role in improving the redundancy, reliability and security of our overall energy supply.

Opportunities in renewables such as micro-generation pique Albertans’ entrepreneurial talents.

Expanding the development of bioenergy will diversify the energy basket with clean alternatives. Bioenergy clusters that facilitate waste to energy conversion will provide significant carbon reduction, a positive energy balance, community development and environmental sustainability. Several development opportunities have been proposed throughout the province to leverage municipal, farm and forestry infrastructure with emerging bioenergy technologies. Going forward Alberta will introduce a renewable fuels standard, consistent with those adopted by Canada and other provinces, to begin the “greening” of transportation fuels.

Electricity generation from renewable resources will be supported by investments in our electrical infrastructure, conservation initiatives, and the new Micro-Generation Policy that will allow Albertans to generate their own environmentally friendly electricity and receive credit for any power they don’t use and send into the electricity grid.

What will create truly ideal conditions for renewable energy will be the rising price of fossil fuels over the long-term and increasing carbon charges in a carbon constrained world.

4.2 Add Value

Optimize Basin Productivity

Natural gas and conventional oil production in Alberta will deliver continuing and expanding benefits in the future if we invest in these activities appropriately today. Ramping Up Recovery, a 2006 investigation into the recoverability of oil and gas in the basin, suggested that in Alberta an incremental 3.6 billion barrels of conventional oil and 18 trillion cubic feet (Tcf) of conventional gas are recoverable simply through more advanced and thorough application of existing technologies. These are mere drops in the bucket compared to the recovery of the mammoth oil sands, but they utilize existing infrastructure and they more broadly benefit communities throughout the province, which are important considerations for sustainability.

Ramping Up Recovery did not focus on unconventional gas, which is probably the principal remaining resource in the basin with massive amounts potentially recoverable. Production of one type of unconventional gas—natural gas from coal (coal-bed methane)—took off three years ago. Advancements in completion technologies in the last 24 months have transformed the economics of the development of another unconventional variety: shale gas. Overall, production of unconventional gas in Canada is still in its early stages, but we are following a path
well paved by the U.S. in this respect. It is anticipated that by 2025, unconventional gas will account for about 80% of new Canadian drilling and 50% of total Canadian gas production. Early signals of this trend include decisions by key Canadian producers to place their corporate focus on the development of unconventional gas.

Continued gas production will supply our petrochemical industry with natural gas liquids that are critical to its existence. Continued conventional oil production generates the pentanes and condensate that serve as diluent to facilitate bitumen’s flow through pipelines. In turn, the CO₂ being captured through bitumen upgrading and refining can be piped to where it is needed and injected to enhance oil and gas recovery. Natural gas, being not only the cleanest fossil fuel, but increasingly recoverable through technology advancements, is assured of playing a substantial role in tomorrow’s energy mix. Sustained activity across the basin—not just in the oil sands areas—will guarantee jobs and deliver a continued boost to rural areas. We have extremely useful assets already in place: capital, skills and facilities including one of the most extensive networks of pipelines in the world—the Alberta Hub. Continuing to tap these resources will not entail any significant expansion in the environmental footprint.

The question for Alberta is how to create the conditions to motivate sustained activity in the basin. The 2006 study advocated the creation of a “public super database” featuring tighter integration of data types. It also suggested that infrastructure such as a CO₂ backbone be put into place and that reservoir characterization be carried out much more aggressively. We support the conclusions of Ramping Up Recovery. Alberta will:

- Invest in improving its integrated data and knowledge base—a “public super database”—and use this to inform not only petroleum recovery, but to inject fact-based arguments into debates over land and water use.
- Partner with industry to support innovation in the province’s already well-advanced geomatics clusters.
- Identify key players with application for CO₂ floods (e.g., Pembina, Redwater and others) and mandate unitization to facilitate CO₂-based enhanced recovery regimes.
- Ensure continued resource access in the face of increasing population density, to facilitate commingling and more concentrated well spacing where appropriate, to address shallow rights reversion, and to adopt further measures to creatively encourage and/or require greater recovery within economically reasonable bounds.
- Consider royalty structures to allow the development of marginal resources and promote best use of current and new technologies.
- Increase enforcement as a means of: protecting the environment and the industry; leveling the playing field for those who adhere to the rules; and sending a signal that we are acting in the public best interest.
Extend Our Role Along the Value Chain

Alberta needs to add value to its products and exports and expand its economy by encouraging the further processing of bitumen, oil, natural gas, and coal in Alberta to increase jobs, diversify the economy and raise tax revenues for Albertans. Value-added activity in the energy industry could occur across Alberta or adjacent jurisdictions. It would include activities such as the Joffre petrochemical complex, the Lloydminster heavy oil upgrader, upgrading and some levels of refining in Fort McMurray, and further development in industrial complexes northeast of Edmonton, the Capital Region including the Industrial Heartland.

Alberta has some prime opportunities to encourage the further development of world-class integrated clusters that could include upgraders, refineries and associated petrochemical and chemical industries (eco-industrial complexes). An integrated cluster of processing facilities also supports the overall goal of clean energy development (see discussion of gasification and CCS, Section 4.1). Development of an integrated cluster can also reduce the overall environmental impact through reduced footprint, less waste produced, lower total impact on air quality (fuel efficiencies), more effective placement of emergency services and infrastructure, reduced or shared water use, and more effective waste water management.

Work done by the Hydrocarbon Upgrading Task Force identified significant realistic value opportunities in upgrading and refining bitumen to transportation fuels and other products, and providing petrochemical feed stock. The Task Force identified, as an “aspirational goal,” an ultimate portfolio mix of one-third bitumen sales, one-third synthetic crude oil sales, and one-third the sales of finished products and petrochemicals. Further work needs to be done to determine the optimum mix as future markets develop.

Steps Alberta will take include:

- Creation of a government-led organization dedicated to planning for and developing policy analysis and options for upgrading/refining/chemical clusters in Alberta.
- Identification of, and shared investment in the development of major corridors for future pipelines, road, electrical transmission and other requirements for such a cluster.
- Assessment of optimum targets for bitumen allocation (direct export/upgrading and refining/petrochemical feedstock).

Alberta has some prime opportunities to encourage the further development of world-class integrated clusters.
Diversify Our Markets

The fundamentals of industry structure tell us that it is wiser to cultivate a stable of customers than remain reliant on a singular customer. Energy demand in the U.S. has grown dramatically, but the development of supplementary markets accessible via tidewater would allow us to better manage risk as well as command greater bargaining power, thus increasing the likelihood we will be paid full value for our exports over the long haul.

Government prefers to collaborate with industry to develop a comprehensive strategy for more aggressive global marketing of Alberta’s energy to achieve a more diverse and resilient customer base.

Sell More Than Products

Many parts of the world are encountering challenges similar to Alberta’s as they confront the imperative to clean up fossil fuel development. Alberta can achieve greater leverage on our investment dollar by sharing the solutions we develop here. Alberta will lend greater strategic assistance to achieving the development of markets for its energy-environment solutions, including technologies, processes and services.

4.3 Change Energy Consumption Behaviour

Encourage Energy Efficiency and Conservation

Energy efficiency and conservation will play a significant role in the future competitiveness of industry and attractiveness of the economic and social climate in Alberta. While such measures have met with mixed success in other jurisdictions, their potential remains substantial. Strategic support for increased efficiency and conservation paired with carbon charges (see next section) will be one of Alberta’s most critical levers in meeting the challenges that the future will pose.

Alberta will develop an overarching policy framework to increase energy efficiency and conservation in all sectors within Alberta. The framework will include, among other things, government action in the following areas:

- Improve measurement. We will promote smart metering, smart grids and better consumption measurement in order to help Albertans better understand their consumption patterns and incentivize greener responses. We will direct the migration of electrical meters to Advanced Metering Infrastructure.

- Green up transportation. The province recently announced a $2-billion program for green transit. Government will also examine the goals for energy efficiency of the government vehicle fleet and work with Canada to assess vehicle emission standards in the province.

- Improve building design. We will strengthen building codes to produce a smaller environmental footprint and complement increased robustness of the grid. We will also support selected retrofit/renovation programs for existing buildings. We will set an example by requiring all new government-funded
buildings to be silver or gold Leadership in Energy and Environmental Design (LEED) standard.

- **Promote wise urban planning.** It is a necessity to rethink urban planning, especially in the context of urban sprawl and the need to increase density if we are to effectively and sustainably reduce energy consumption. Alberta will work with municipal governments to encourage this.

### Carbon Charges

A primary impediment to addressing greenhouse gas emissions is the reality that individuals and companies are not faced with the true costs of their actions related to these emissions. Some jurisdictions, including Alberta, have begun to convey carbon price signals to facilitate wiser use of energy and minimize impacts to the environment. Alberta’s mechanism targets its largest industrial emitters of greenhouse gases, whereby those failing to meet emissions intensity reduction targets have options including paying $15 per tonne of CO₂ into a fund dedicated to technology development and deployment. This is the right approach because it fills a dual role of raising funds that the province can direct to strategic energy technology solutions, while conveying signals to use energy more wisely.

Alberta is wary of the “cap and trade” mechanisms being advocated by others. Their requirements would be onerous and targeted disproportionately at energy producing jurisdictions. Their contribution to physical reduction of greenhouse gases has been questioned and they pose a risk of wealth transfer, trapping us into sending our monies elsewhere, rather than investing them into solving our emissions problems at home.

Any mechanism going forward to price carbon for industrial emissions must be market-based; it must not redistribute wealth from Alberta; it must not impede our competitiveness (issues of reciprocity, for example, will have to be addressed for exporters); and, funds collected must be directed back into solving our unique energy-environment challenges. Alberta’s mechanism should be designed so that it can evolve as needs evolve, and it should be time-limited, with its purpose and impact periodically reviewed.

The reality of CO₂ emissions is that most emissions are generated in the consumption, rather than production, of energy. We burn fuel in our vehicles; we burn fuel to heat and light our homes and buildings. The issue of carbon emissions thus affects all consumers of energy—all Albertans, not just Alberta’s industrial emitters. While Alberta is vigorously pursuing solutions to reduce our industrial emissions, such as Carbon Capture and Storage, we must not be lulled into thinking this is just an energy production problem.

Alberta will not introduce a carbon tax on consumers of energy. These taxes have questionable results on reducing actual emissions. We do support increasing energy conservation standards and ensuring in future that our vehicles are more efficient, and our homes, buildings and communities use less energy. This may cost us more in the short term, but we’ll also be assured that our energy efficiency will increase, improving our ability to cope with higher energy prices in future.

**Alberta’s Provincial Energy Strategy 2008**  39
Similar to our approach to industrial emissions, our costs will be targeted at real solutions that position us for the future, rather than redistributing wealth.

Going forward, Alberta will:

- Review its emissions targets and carbon charges for large industrial facilities, and ensure that appropriate increases are made to both, while being mindful of our competitiveness.
- Work with Canada to ensure a clear compliance path for large industrial facilities with the regulatory frameworks in place and proposed.
- Work with Canada to ensure that approaches to transportation fuels account for the full life-cycle emissions from production site to the tailpipe, and that vehicle emission standards are improved.
- Strengthen building codes to ensure new housing and building stock being put in place for the future is as efficient as possible.
- Work to ensure that the most vulnerable Albertans and sectors are able to afford the cost of energy now and in the future. At the same time, ensuring that market price signals that can help promote consumer choices to conserve energy are not distorted by programs such as the Natural Gas Rebate Program.

Alberta’s energy future relies heavily on technology.
4.4 Innovate

Develop and Deploy Technology

Clearly, the path to optimizing Alberta’s energy future relies heavily on technology. Many of the technologies that will enable our energy future are already proven and simply require more deliberate deployment. Some of the technologies remain to be proven, while others have yet to be imagined. Technology commercialization is not a straightforward business here or elsewhere. As such, realizing our energy vision will depend on our concerted efforts to address the full curve of technology development, from conception to commercial deployment.

We have referred to an AOSTRA-scale effort in order to support the proposed gasification-CCS platform. AOSTRA helped Alberta unlock the potential of the oil sands in the first place. Now, we need a clean solution for energy production. Alberta will increase investment in research, development, demonstration and deployment in sustainable energy technology. The funds will not be proportionately distributed to existing granting agencies. The bulk will be dedicated to a focused, consolidated, coordinated initiative—a one-window approach with publicly established goals inviting industry capital and guidance.

This effort, perhaps organized as a centre supporting clean energy production, will employ best practices in governance and incorporate rigorous, arm’s-length evaluation of outcomes. It will not try to be all things to all people, keeping a tight focus on gasification-CCS and directly related questions (including regulatory, engineering and business applications supporting clean energy).

The centre will coordinate activities along that curve, but it would allocate resources to different parties depending on their distinct competencies (i.e., universities for fundamental research; applied research facilities for early scale-up work). Its particular direct involvement will be in pilot plants, demonstration projects, which offer potential to advance new generation technology and ideas. Both industry and government recognize the value of launching small, but commercial-scale, pilots to prove out the more massive investments that may follow.

In this way, Alberta can expect progress not only on the gasification-CCS file that will drive the clean energy centre, but in a host of other important areas, including:

- Unconventional gas development.
- Water use efficiency, groundwater protection and beneficial re-use, water storage, tailing pond management/use.

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We need a clean solution for energy production.

ALBERTA'S PROVINCIAL ENERGY STRATEGY 2008
• Integrated resource management.
• Reservoir characterization facilitating enhanced oil and gas recovery.
• Hydrogen.
• Petrochemicals.
• Renewables including geothermal and biomass waste that, in an integrated setting, may enhance clean fossil fuel production.

It is fruitless to attempt global leadership in all facets of energy research. Technologies will emerge from other parts of the globe with direct applicability to the challenges facing Alberta. Areas in which we may fill a role as early adopters include electrical storage, wind generation, geothermal, small-scale nuclear and biofuel production.

New ideas for old technologies could involve exploring something as innovative as developing strategic reserves of critical resources and products within Alberta. Alberta has a significant natural strategic reserve of the raw resources right now, but an assessment of strategic quantities of intermediate and final products, such as transportation fuels, could also be considered to help avoid the occasional physical and market fluctuations in supply caused by unexpected shutdowns of refineries or other operational issues.

Nurture an Innovation Culture

The feature that will sustain our innovation efforts is an “innovation culture.” Alberta has shown determination to develop a high-tech business environment through its recent announcement of an action plan called Bringing Technology to Market. It is critical to nurture an integrated innovation supply chain, or the economic benefits promised by research and development investments will continue to languish.

Develop the People Resource

Perhaps the key ingredient to innovation is people: as an emerging global energy hub, the only resources we are actually short on are human resources. Adam Smith’s three “components parts of price” were land, labour and capital stock—capital and land tend not to be in short supply here in Alberta. The energy industry has suffered in the last 20 years because youth, buying into the perception of oil and gas as a sunset industry, chose other paths. Now we are facing a daunting “crew change” as baby boomers leave the work force. Alberta needs to scale up its strategies so that we can attract not only our most promising youth, but the best expertise available globally. In a world of highly uncertain future energy and environment challenges, one of the best investments lies in developing the people with the capability of meeting those challenges (and seizing the opportunities associated with them).
4.5 Enhance Electricity

Strengthen Transmission

Electricity is a facilitator of economic development in Alberta. To this end a robust, reliable and efficient electricity transmission system is required. Transmission infrastructure is a public good that must be available in advance of need, enable addition of new generation and be capable of meeting long-term load growth throughout the province.

Growing our transmission system is urgent. No significant new upgrades to the transmission system have been built in more than 20 years in Alberta. The current transmission system has not kept pace with Alberta’s growing economy. The existing system is congested, ageing, and results in significant wasted electricity as a result of large system losses.

An uncongested transmission system with sufficient intertie capacity to other jurisdictions is required to encourage the development of new electricity generation. By ensuring development of a robust transmission system, generation developers will know that they will be able to efficiently move their product to market. In turn, they will have confidence to develop new generation ensuring an adequate, reliable supply of electricity for Albertans.

Alberta’s electricity prices are based on the principles of supply and demand in a market context. Vibrant markets depend on the ability of many suppliers to reach many buyers. Thus, a robust transmission system is essential to ensure an adequate supply of competitively priced electricity for Albertans.

Until transmission is improved, potential renewable or low emission electricity generation in Alberta will remain location-constrained. There are hydroelectric resources in the northern area of the province, wind and solar in the south, and biomass in the northwest. Optimal use of power from these sources depends on our ability to bring it to where it is needed.

There are additional arguments for the improvement of our electricity system:

- If we can use gasification-with-CCS to burn bitumen bottoms, coke, biomass, waste and coal cleanly, electricity will become a province-wide medium for clean energy, applicable not only to lighting and appliances, but home heating and recharging (should plug-in electric cars rise to prominence). This has the potential to dramatically reduce end-user emissions.
- Lower-cost electricity using these carbon-rich fuels will help make bitumen recovery more economical and reduce dependence on valuable natural gas.
- Robust transmission will support new electric power generation that will underpin future economic growth and support new consumer products such as plug-in electric cars that are fuel-efficient and help reduce end-user emissions.
Advancing new transmission investment will ensure reliable service for Albertans, help drive our clean energy agenda by growing new renewable energy potential, and enhance our ability to serve electricity export markets.

At its point of use, electricity is one of the most efficient and cleanest forms of energy.

Since electricity is most commonly generated at large single-point sources, the environmental impacts of its generation are easier to address.

Alberta will take the following steps to strengthen the provincial transmission system:

- Lead the development of a plan for a comprehensive upgrade to the transmission system in Alberta. The plan will identify the requirements, the technical solutions, and the schedules for improving the transmission system in Alberta. Improvements will be sized to accommodate long-term growth and will use, where possible, technology such as high-voltage direct current to maximize efficiency of rights of way and minimize impacts.

- Adopt and implement a policy to build transmission, as part of the Alberta interconnected electricity system, to zones of renewable or low-emission electricity.

- Adopt and implement a policy to build interties to other markets to ensure an adequate supply of electricity to Alberta as well as to facilitate development of additional wind generation.

- Review and streamline the regulatory process for transmission siting. We will ensure that all impacted landowner issues are heard, impacts are mitigated to the extent possible, and that landowners receive fair compensation.

- Assemble multi-use corridors for the siting of future energy and transportation infrastructure.

- Undertake an extensive education and awareness program to inform Albertans of the need and the benefits of a robust, reliable, and efficient transmission system.

- Implement policy and provide financial support for the development and deployment of “smart grid” technology.
Address Distribution Level Challenges

There are opportunities for increased efficiency at the distribution level—where electricity is delivered to the customer. Improvements Alberta will advocate include:

- Enabling online measurement of electricity consumption by all consumers. This will include integration of energy and carbon measurement systems at industrial, commercial and residential levels. Facilitating measurement will empower millions of small decisions to manage the consumption footprint. This will be a substantial contributor in helping Alberta meet its emission reduction targets.
- Reducing regulatory bottlenecks associated with approvals, streamlining permitting for small-scale generation, and ensuring that regulations facilitate less traditional activities such as distributed generation and demand management.
- Periodically reviewing the Micro-Generation Policy to identify enhancements that may more appropriately facilitate small-scale generation as well as efficiency and conservation.

We defer to the market to determine what mix and proportion of energy sources Alberta will ultimately use for electricity, and to what extent electricity will be profitably exported. Assuming that carbon costs continue to rise, and assuming that coal will require gasification-with-CCS, we project that generation sources such as wind, run-of-river hydro, geothermal and biomass will become more competitive, and that renewables' proportion of Alberta's generation will therefore increase. Alberta a hub for clean fossil fuels, Alberta will still set a table that will allow renewable and alternative energy to flourish.

4.6 Bolster Knowledge & Awareness

The energy-environment question has fueled a very public and widespread debate. There is plenty of solid information out there, but lots of misinformation too, and it is getting harder to discern the experts. This debate will not die down in the foreseeable future. Alberta will take part.

Promoting understanding, awareness and education of Alberta's energy issues has numerous benefits, including:

- Providing Albertans of all ages with information about how the province develops and uses energy, our environmental challenges ahead of us and the environmental protection measures that are already in place.

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• Promoting a greater understanding of how Alberta’s energy sector provides economic stability and benefits to the province.

• Increasing knowledge of how personal accountability, through conservation and efficiency, are essential in promoting the responsible use of energy and addressing global challenges like climate change.

• Providing Albertans with a better basis on which to become involved in discussions around energy development (e.g. transmission siting).

• Developing skilled and trained professionals, who may seek careers in the energy sector.

Here are some of the steps that the province will take:

• We will audit the effectiveness of current communications and public reporting efforts and develop a more comprehensive understanding of Albertans’ knowledge of and views on energy-environment issues.

• We will supplement our actions with words: speak out directly to explain our vision and our actions, and to defend them as required. Audiences will include Albertans as well as stakeholders and influential individuals in Canada, U.S. and Europe.

• Alberta will carefully reconcile sources of divergent views. It is clear that a strategy that supports clean fossil fuels will not win all non-government organizations over, but we stand to benefit by productively engaging them.

• We will work within Alberta’s education system to facilitate a flow of age-appropriate information about the energy industry, its importance and its future.

This document supports significant investment opportunities by government and industry. This investment represents the crossroads of where energy development meets environmental protection to provide long-term economic prosperity for our province. Investing just a little more to deliver Alberta’s story on our own terms through well-structured knowledge and awareness efforts will help us secure our prosperous and sustainable energy future.

4.7 Ensure Alignment

Albertans are the main players in their energy future. We are, after all, the principal owners of the resource. We live, however, in an increasingly interconnected world. Energy is pervasive, and its impacts are inseparable from many other activities underway within—and beyond—our boundaries. No longer will it optimally serve Albertans to address energy strictly from a narrow point of view. Alberta’s energy strategy must encompass a broader vision and transcend the traditional silos if we are to realize intended outcomes.

This strategy introduces a vision, desired outcomes, and the series of levers available to Alberta to make progress toward its energy future. These levers will be exceptionally effective in that they will “pull in the same direction” toward the desired outcomes and vision. In the same vein, we will work to ensure maximum alignment with other Government of Alberta policies influencing energy outcomes.
much as the Land-use Framework, Water for Life and Alberta’s Aboriginal Policy Framework, among others.

Led by the Department of Energy, many government departments will be directly involved in executing this strategy. It will also encompass the activities of a number of energy agencies, including the Alberta Utilities Commission (AUC), Alberta Energy Research Institute (AERI), the Energy Resources Conservation Board (ERCB), and the Alberta Electric System Operator (AESO).

The aboriginal peoples of Alberta have an historic connection to Alberta’s land and environment. Alberta recognizes that those First Nations and Métis communities that hold constitutionally protected rights are uniquely positioned to inform land-use planning. The Government of Alberta has the constitutional mandate to manage lands in the province for the benefit of all Albertans. However, the Government of Alberta will continue to meet Alberta’s legal duty to consult aboriginal communities whose constitutionally protected rights under section 35 of the Constitution Act,1982 (Canada) are potentially adversely impacted by development.

The private sector will play a critical role in implementing this strategy. The private sector raises and directs capital to various aspects of the energy value chain: exploration, production, upgrading, transport, consumption and so on. The market is fluid and free to operate as it sees fit, within the boundaries Albertans establish.

Further, the strategy will influence, and be influenced by, factors beyond our boundaries. Global financial markets have a large bearing on the ability of our companies to raise capital. Many of our energy customers are outside Alberta and a few are outside of North America. Some of the companies that operate within Alberta are headquartered elsewhere. The federal government plays a hand, largely through the National Energy Board, an independent federal agency that “promotes safety and security, environmental protection and efficient energy infrastructure and markets in the Canadian public interest,” and also through its initiatives to address climate change. In turn, through income taxes, equalization payments and other means, we are substantial contributors to the national well-being. Dynamics in neighbouring provinces impact us. Human capital migrates readily. Building greater capacity and support across all stakeholders is vital to any strategy.

As Albertans, we are not in control of everything that goes on here, but we do have an important say. We are the principal owner of the resource. We have the levers of this strategy at our disposal. And we will exercise our obligation to influence other factors, both inside and outside Alberta, to ensure to the extent possible that that alignment exists with our path forward. You can expect to see deliberate steps taken in order to achieve productive alignment in policy, regulation, programs and initiatives.
5. Implementation

This strategy sets future policy direction for clean energy production, wise energy use and sustained economic prosperity related to energy. The strategy contains policies and recommendations that will be implemented by the Department of Energy and other departments.

The Government will develop an implementation plan that will include a monitoring process to facilitate the assessment of our progress towards meeting the policy objectives of the strategy and allow us to reassess our objectives and strategies on an ongoing basis as conditions evolve. Taking into account the need for departments to prepare, plan and execute their respective policy recommendations, the implementation plan will incorporate three horizons: short-term, medium-term and long-term. Benchmarks and outcomes will be identified over each horizon.

The Government will prepare an annual report card to communicate progress to Albertans. The report card will also showcase collaboration across government on energy-related matters and it will be incorporated into annual business plan reporting.
6. It is Time

Energy and global financial markets move up and down. We are used to a lot of flux. Economic growth is not a measured climb, but rather a series of ultimately ascending zigs and zags. Over short and medium term horizons, this volatility can tempt course changes.

The ultimate horizon commanded by this strategy is long-term. Global demand for energy is expected to rise over this period, while the world experiences an increasingly constrained supply. Finally, the imperative to have clean energy will continue to climb. Looking beyond today’s market lather, we must exert courage to plot the steadfast course that will ultimately serve Albertans best.

Alberta is resourceful. Albertans are responsible. This strategy delineates a trajectory that will best reward us. It defines our energy future and puts Albertans back in the driver’s seat.

Alberta is resourceful.
Albertans are responsible.
Appendix C
Appendix C
Overview of the AESO’s Future Demand and Energy Outlook

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1.0 Introduction

The AESO’s long-term load forecast is a study of past energy use patterns and future economic indicators, that are, in simple terms, combined to produce a future energy forecast. The AESO annually updates its forecast with a 20-year outlook of Alberta’s electric energy consumption and peak load demand. The estimates of future electricity market needs are one of the drivers the AESO uses in analyzing and planning the timely development of the transmission system.

Since 2002, Alberta Internal Load (AIL)\(^1\) has increased from 59,437 gigawatt hours (GWh) to 69,947 GWh in 2008 (an increase of 2.8 per cent per annum). During this same period, peak demand has risen from 8,570 megawatts (MW) to 9,806 MW, an increase of 2.3 per cent per annum. In 2008, the average hourly load in Alberta was approximately 8,000 MW, which results in a load factor of approximately 81 per cent.

Alberta Interconnected Electric System (AIES)\(^2\) consumption grew by an annual average of 1.3 per cent from 53,673 GWh in 2002 to 57,934 GWh in 2008. Peak demand grew by 1.5 per cent in the same period from 7,552 MW to 8,237 MW. The average annual growth rates for the six-year historical period from 2002 to 2008 are lower for the AIES than the AIL because behind-the-fence (BTF) load has grown faster than consumption in the retail sectors (e.g., residential, farm, commercial and industrial).

In 2008, total electricity consumption showed little growth over 2007. The three main contributors to this outcome were 1) global economy and its effects on Alberta sectors such as forestry, energy and chemicals, 2) slowing local economy, and 3) system loss reductions resulting from transmission system additions.

Figure 1.0-1: AIL energy and demand

![Figure 1.0-1: AIL energy and demand](image)

Source: AESO

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\(^1\) AIL is the total electricity consumption including BTF and losses (transmission and distribution). In 2002, AIL was redefined to include approximately 400 MW of BTF load. BTF is industrial load that is characterized by being served in whole, or in part, by on-site generation. The AESO’s forecast is for gross demand and energy. AIL includes the City of Medicine Hat.

\(^2\) AIES load is the power flowing through the transmission system excluding BTF and the City of Medicine Hat’s load served by its own generation. AIES is the sum of all electricity sales (residential, commercial, industrial and farm) and losses (both transmission and distribution).
In assessing Alberta’s load, the AESO also examines electricity consumption by sector. In 2007, the electricity consumption results by customer segment are shown in Figure 1.0-3 (note that at time of printing, 2008 data was not yet available).

Details of forecasts completed in 2007 (Future Demand and Energy Outlook 2007-2027) or FC2007 and 2008 (Future Demand and Energy Outlook 2008-2028) or FC2008 are discussed further in this document. Copies are included and available on the AESO’s website www.aeso.ca Together with the AESO’s generation scenarios, these long-term load forecasts serve as an input to aid in transmission planning.

Events in late 2008 had a major impact on the global economy and are not reflected in either the AESO’s 2007 or 2008 forecasts. In the fall of 2008, The Conference Board of Canada released indicators that point to a slowing of Alberta’s growth in the short term (2008 and 2009). By 2010, the Conference Board expects Alberta to once again show strong economic growth, with real gross domestic product (GDP) growth forecast at 3.8 per cent.

Preliminary estimates show that the slowdown in the economy will have the effect of shifting growth later in the 10-year horizon as compared to the AESO’s long-term load forecast. More details in regards to this economic impact can be found in the FC2008. The AESO will continue to monitor the situation as it unfolds.
To study bulk electric flows, the AESO’s planners examine region peaks at the time when the provincial peak is occurring (e.g., a provincewide coincident peak). The bulk-regional peak values differ from those incorporated into regional planning studies. Regional studies examine demand at the time of region peak (a coincident peak among all areas that falls in the region under review).

1.1 Comparison of FC2007 and FC2008

In the short term the FC2008 shows a slight drop in growth rates compared to the FC2007. However, in the 10- to 20-year horizon the two forecasts converge with similar demand levels. The recent fall economic update indicates, in the very near term, growth may be slower than that forecast in the FC2008. Details of the possible impact of the latest economic turmoil can be found in the FC2008 report.

Figure 1.1-1: FC2007 vs FC2008 AIL demand comparison

1.2 Alberta’s GDP growth

GDP is a function of consumer spending, private and public investment, exports and imports. The following is a comparison of the FC2007 and FC2008. Over the last two decades, Alberta had the highest rate of GDP growth in Canada, averaging 3.8 per cent per year.

Table 1.2-1: GDP forecast comparison

<table>
<thead>
<tr>
<th>Year</th>
<th>The Conference Board of Canada Provincial Outlook 2007 Released: March 2007 (%)</th>
<th>The Conference Board of Canada Provincial Outlook 2008 Released: March 2008 (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2006</td>
<td>7.0 (not final)</td>
<td>6.7</td>
</tr>
<tr>
<td>2007</td>
<td>5.0</td>
<td>3.4 (not final)</td>
</tr>
<tr>
<td>2008</td>
<td>4.2</td>
<td>3.4</td>
</tr>
<tr>
<td>2009</td>
<td>3.7</td>
<td>3.6</td>
</tr>
<tr>
<td>2010</td>
<td>3.9</td>
<td>3.7</td>
</tr>
<tr>
<td>2018</td>
<td>2.6</td>
<td>2.8</td>
</tr>
<tr>
<td>2028</td>
<td>2.6</td>
<td>2.6</td>
</tr>
</tbody>
</table>

Actuals in bold
In 2008, The Conference Board of Canada adjusted its short-term GDP growth to reflect a more conservative outlook due to unsustainable growth in many sectors of the Alberta economy.

1.3 Alberta’s population growth

In 2007, Alberta’s population grew by approximately 100,000 people (three per cent) to 3.47 million. As depicted in Figure 1.3-1, the forecast for population growth is expected to remain steady and there is very little difference between the two forecasts. This is largely due to the steady demand for skilled labour.

1.4 Oilsands production growth

The FC2007 and FC2008 recognize Alberta’s unique resource composition and profile. For example, future large oilsands and upgrader projects provide a challenge in regards to timing, size and number of facilities. This difficulty is highlighted by the large number of project delays and cancellations announced since late 2008. As well, the use of unproven or new technologies used in these projects can lead to unanticipated start-up challenges.
FC2007 REGIONAL RESULTS ADDENDUM

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2.0 Introduction

To perform regional planning studies, the demand at time of region peak is required (a coincident peak among all areas that falls in the region under review). This section presents the regional breakout for FC2007.

2.1 FC2007 – Forecast results for regional planning purposes

The Province of Alberta covers over 661,100 square kilometres (km²). This represents approximately seven per cent of Canada's total land mass. Given the considerable size of the province, it is reasonable to expect that the geography, local economies and climate will vary from one region to another. This geographical diversity is apparent in the AESO's load forecast as seen in the tables on the following pages. Figure 2.1-1 shows the province divided into areas. These areas can be added together to explore the electric power needs unique to that particular region.

For regional planning purposes, the areas have been grouped to represent six regions: South, Calgary, Central, Edmonton, Northeast and Northwest.

The following tables show regional peak coincident for both the summer and winter seasons. FC2007 results are compared to the forecast numbers for 2007, 2012, 2017 and 2027.
Figure 2.1-1: Grouping of areas for regional planning purposes

Note:
Names and number references on the map are used for internal regional planning purposes.
2.2 South region
The South region includes the Medicine Hat, Sheerness, Brooks, Empress, Stavely, Vauxhall, Fort Macleod, Lethbridge and Glenwood planning areas.

Table 2.2-1: Coincident peak (MW) for South region

<table>
<thead>
<tr>
<th></th>
<th>FC2007 2007</th>
<th>FC2007 2012</th>
<th>Average annual growth (%)</th>
<th>FC2007 2017</th>
<th>Average annual growth (%)</th>
<th>FC2007 2027</th>
<th>Average annual growth (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Winter</td>
<td>941</td>
<td>1,035</td>
<td>1.9</td>
<td>1,130</td>
<td>1.9</td>
<td>1,541</td>
<td>2.5</td>
</tr>
<tr>
<td>Summer</td>
<td>994</td>
<td>1,083</td>
<td>1.7</td>
<td>1,177</td>
<td>1.7</td>
<td>1,567</td>
<td>2.3</td>
</tr>
</tbody>
</table>

2.3 Calgary region
Included in this region are the Calgary, Strathmore/Blackie, Seebe, High River and Airdrie planning areas as well as a City of Calgary breakout.

Table 2.3-1: Coincident peak (MW) for Calgary region

<table>
<thead>
<tr>
<th></th>
<th>FC2007 2007</th>
<th>FC2007 2012</th>
<th>Average annual growth (%)</th>
<th>FC2007 2017</th>
<th>Average annual growth (%)</th>
<th>FC2007 2027</th>
<th>Average annual growth (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Winter</td>
<td>2,105</td>
<td>2,512</td>
<td>3.6</td>
<td>2,818</td>
<td>3.0</td>
<td>3,614</td>
<td>2.7</td>
</tr>
<tr>
<td></td>
<td>1,598</td>
<td>1,943</td>
<td>4.0</td>
<td>2,172</td>
<td>3.1</td>
<td>2,643</td>
<td>2.5</td>
</tr>
<tr>
<td>Summer</td>
<td>1,948</td>
<td>2,314</td>
<td>3.5</td>
<td>2,574</td>
<td>2.8</td>
<td>3,275</td>
<td>2.6</td>
</tr>
<tr>
<td></td>
<td>1,510</td>
<td>1,824</td>
<td>3.8</td>
<td>2,014</td>
<td>2.9</td>
<td>2,424</td>
<td>2.4</td>
</tr>
</tbody>
</table>

2.4 Central region
The Central region is considered to be between Edmonton and Calgary. Included are the Lloydminster, Hinton/Edson, Drayton Valley, Wainwright, Abraham Lake, Red Deer, Alliance/Battle River, Provost, Caroline, Didsbury, Hanna and Vegreville planning areas.

Table 2.4-1: Coincident peak (MW) for Central region

<table>
<thead>
<tr>
<th></th>
<th>FC2007 2007</th>
<th>FC2007 2012</th>
<th>Average annual growth (%)</th>
<th>FC2007 2017</th>
<th>Average annual growth (%)</th>
<th>FC2007 2027</th>
<th>Average annual growth (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Winter</td>
<td>1,616</td>
<td>1,817</td>
<td>2.4</td>
<td>1,982</td>
<td>2.1</td>
<td>2,698</td>
<td>2.6</td>
</tr>
<tr>
<td>Summer</td>
<td>1,455</td>
<td>1,653</td>
<td>2.6</td>
<td>1,799</td>
<td>2.1</td>
<td>2,290</td>
<td>2.3</td>
</tr>
</tbody>
</table>
As the Central region is large, it has been broken down into smaller sub-regions. These are listed below.

### 2.5 Central West
This sub-region is composed of the Hinton/Edson, Drayton Valley, Abraham Lake and Caroline planning areas.

**Table 2.5-1: Central West – Coincident peak (MW) for Central region**

<table>
<thead>
<tr>
<th></th>
<th>FC2007 2007</th>
<th>FC2007 2012</th>
<th>Average annual growth (%)</th>
<th>FC2007 2017</th>
<th>Average annual growth (%)</th>
<th>FC2007 2027</th>
<th>Average annual growth (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Winter</td>
<td>397</td>
<td>441</td>
<td>2.1</td>
<td>483</td>
<td>2.0</td>
<td>676</td>
<td>2.7</td>
</tr>
<tr>
<td>Summer</td>
<td>371</td>
<td>413</td>
<td>2.2</td>
<td>455</td>
<td>2.1</td>
<td>556</td>
<td>2.0</td>
</tr>
</tbody>
</table>

### 2.6 Central East
This sub-region is composed of the Lloydminster, Provost, Vegreville, Battle River and Wainwright planning areas.

**Table 2.6-1: Central East – Coincident peak (MW) for Central region**

<table>
<thead>
<tr>
<th></th>
<th>FC2007 2007</th>
<th>FC2007 2012</th>
<th>Average annual growth (%)</th>
<th>FC2007 2017</th>
<th>Average annual growth (%)</th>
<th>FC2007 2027</th>
<th>Average annual growth (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Winter</td>
<td>430</td>
<td>473</td>
<td>1.9</td>
<td>504</td>
<td>1.6</td>
<td>639</td>
<td>2.0</td>
</tr>
<tr>
<td>Summer</td>
<td>396</td>
<td>432</td>
<td>1.7</td>
<td>459</td>
<td>1.5</td>
<td>553</td>
<td>1.7</td>
</tr>
</tbody>
</table>

### 2.7 Hanna

**Table 2.7-1: Hanna – Coincident peak (MW) for Central region**

<table>
<thead>
<tr>
<th></th>
<th>FC2007 2007</th>
<th>FC2007 2012</th>
<th>Average annual growth (%)</th>
<th>FC2007 2017</th>
<th>Average annual growth (%)</th>
<th>FC2007 2027</th>
<th>Average annual growth (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Winter</td>
<td>163</td>
<td>199</td>
<td>4.0</td>
<td>213</td>
<td>2.7</td>
<td>276</td>
<td>2.7</td>
</tr>
<tr>
<td>Summer</td>
<td>141</td>
<td>195</td>
<td>6.7</td>
<td>207</td>
<td>3.9</td>
<td>251</td>
<td>2.9</td>
</tr>
</tbody>
</table>

### 2.8 Red Deer and Didsbury

**Table 2.8-1: Red Deer and Didsbury – Coincident peak (MW) for Central region**

<table>
<thead>
<tr>
<th></th>
<th>FC2007 2007</th>
<th>FC2007 2012</th>
<th>Average annual growth (%)</th>
<th>FC2007 2017</th>
<th>Average annual growth (%)</th>
<th>FC2007 2027</th>
<th>Average annual growth (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Winter</td>
<td>626</td>
<td>705</td>
<td>2.4</td>
<td>782</td>
<td>2.2</td>
<td>1,107</td>
<td>2.9</td>
</tr>
<tr>
<td>Summer</td>
<td>547</td>
<td>613</td>
<td>2.3</td>
<td>6778</td>
<td>2.2</td>
<td>930</td>
<td>2.7</td>
</tr>
</tbody>
</table>
2.9 Edmonton region
Acting as a transmission hub, the Edmonton region includes the Wetaskiwin, Fort Saskatchewan, Wabamun and Edmonton planning areas as well as a City of Edmonton breakout.

Table 2.9-1: Coincident peak (MW) for Edmonton region

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Winter</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Edmonton Area</td>
<td>2,547</td>
<td>3,013</td>
<td>3.4</td>
<td>3,648</td>
<td>4,512</td>
<td>2.9</td>
</tr>
<tr>
<td>City of Edmonton (EPCOR)</td>
<td>1,200</td>
<td>1,338</td>
<td>2.2</td>
<td>1,451</td>
<td>1,933</td>
<td>2.4</td>
</tr>
<tr>
<td>Summer</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Edmonton Area</td>
<td>2,368</td>
<td>2,826</td>
<td>3.6</td>
<td>3,480</td>
<td>4,298</td>
<td>3.0</td>
</tr>
<tr>
<td>City of Edmonton (EPCOR)</td>
<td>1,194</td>
<td>1,332</td>
<td>2.2</td>
<td>1,445</td>
<td>1,899</td>
<td>2.4</td>
</tr>
</tbody>
</table>

2.10 Northeast region
The Northeast region is forecast to experience the greatest load growth over the next 10 years. This is due in large part to the oilsands, forestry industries and related secondary service industries in the municipalities. The Northeast region includes the Fort McMurray, Athabasca/Lac La Biche and Cold Lake planning areas.

Table 2.10-1: Coincident peak (MW) for Northeast region

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Winter</td>
<td>1,590</td>
<td>2,383</td>
<td>8.4</td>
<td>3,268</td>
<td>4,687</td>
<td>5.6</td>
</tr>
<tr>
<td>Summer</td>
<td>1,411</td>
<td>2,239</td>
<td>9.7</td>
<td>3,031</td>
<td>4,420</td>
<td>5.9</td>
</tr>
</tbody>
</table>

2.11 Northwest region
The Northwest region includes the Rainbow Lake, High Level, Peace River, Grande Prairie, High Prairie, Grand Cache, Valleyview, Fox Creek and Swan Hills planning areas.

Table 2.11-1: Coincident peak (MW) for Northwest region

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Winter</td>
<td>1,160</td>
<td>1,238</td>
<td>1.3</td>
<td>1,303</td>
<td>1,588</td>
<td>1.6</td>
</tr>
<tr>
<td>Summer</td>
<td>1,095</td>
<td>1,169</td>
<td>1.3</td>
<td>1,229</td>
<td>1,475</td>
<td>1.5</td>
</tr>
</tbody>
</table>
FUTURE DEMAND AND ENERGY OUTLOOK 2007-2027 (FC2007)

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Executive summary

The Future Demand and Energy Outlook, 2007-2027 (FC2007) is the Alberta Electric System Operator’s (AESO) long-term load forecast. FC2007 describes the assumptions, methodology and processes that the AESO uses to assess Alberta’s future demand and energy requirements.

This report is prepared annually in accordance with the duties of the AESO as outlined in Alberta’s Electric Utilities Act (EUA) and the Transmission Regulation (AR 86/2007) and will be used in filings with the Alberta Energy and Utilities Board (EUB), now the Alberta Utilities Commission (AUC).

FC2007 includes a 20-year peak load and electricity consumption forecast for Alberta. The load forecast is generated from economic growth, gross domestic product (GDP) and population projections, with regional adjustments based on historical results and customer-driven growth expectations.

In the past five years, Alberta’s Internal Load (AIL) peak demand has grown by an average of 375 megawatts (MW) (four per cent) per year from 7,785 MW to 9,661 MW (an overall increase of 24 per cent). Electricity consumption has grown by an average of five per cent per year from 54,054 gigawatt hours (GWh) to 69,370 GWh.

The AESO forecasts the peak AIL demand to grow by an average 3.1 per cent per year for the next 20 years. Electricity consumption is expected to grow by 3.3 per cent per year.

In addition to reporting the detailed forecast results, this report includes a review of the AESO’s load forecasting methodology. The energy and demand forecast is prepared based on an examination of three sectors: industrial and commercial, residential and farm. The results are organized by the AESO’s five bulk transmission planning regions and six regional planning regions.

FC2007 concludes with a brief discussion of the challenges faced in preparing a load forecast for Alberta. The foremost of these challenges is the rapid development of the oilsands in the province’s northeast. Although the AESO does not forecast oil production, the energy forecast for the northeast accommodates oil production forecasts from the Canadian Association of Petroleum Producers (CAPP) and the National Energy Board (NEB).

1.0 Introduction

The Future Demand and Energy Outlook, 2007-2027 (FC2007) describes the assumptions, methodology, and processes that the AESO employs to assess Alberta’s future demand and energy requirements.

This report is prepared annually in accordance with the duties of the AESO as outlined in Alberta’s Electric Utilities Act (EUA). With respect to load forecasting, the EUA states that the AESO is to “…collect, store and disseminate information relating to the current and future electricity needs of Alberta and the capacity of the interconnected electric system to meet those needs….”

This duty is further defined in the Transmission Regulation (AR 86/2007) where the AESO is mandated to “…anticipate future demand for electricity….” and “…make assumptions about future load growth….” The Transmission Regulation also indicates that a load forecast must be included as part of the AESO’s 10-year Transmission System Plan, the 20-year Transmission System Outlook and all Needs Identification Documents (NID). Therefore FC2007 is to be used in filings with the AUC.
The remainder of FC2007 comprises five main sections:

- Section 2.0: Alberta’s economic outlook
- Section 3.0: Detailed results
- Section 4.0: Methodology
- Section 5.0: Historical forecast results
- Section 6.0: Challenges

In addition to being prepared as an input into the transmission planning process, FC2007 is also used by the AESO for generation adequacy assessments, revenue projections, losses calculations, and transmission tariff development. In keeping with the direction of the EUA and the Transmission Regulation, this report is made available to all stakeholders.

2.0 Alberta’s economic outlook

The backdrop for the AESO’s electricity demand and energy forecast is Alberta’s economic outlook, which continues to remain strong. In 2006, Alberta experienced a 6.8 per cent increase in real GDP. According to The Conference Board of Canada, economic growth will be more moderate in the coming decade, ranging from 2.6 to 4.6 per cent.

The key factor driving the economy is strong oil prices that result in continued investment in the oilsands. This investment creates jobs that ensure a continuation of large annual increases in retail sales. Economic growth is tempered by the cost of living and basic infrastructure, which has caused a slowdown of net migration and immigration.

For the purpose of forecasting electricity load, two aspects of the provincial economy are examined in detail: economic growth as measured by GDP and population growth.

2.1 Alberta’s GDP growth

GDP is a function of consumer spending, private and public investment and exports and imports. In Alberta, these fundamental economic characteristics continue to be strong:

- **Consumer spending:** From 2004 to 2006, retail sales grew by more than 10 per cent per year. The forecast for 2007 is 8.5 per cent, but during the first half of 2007 retail sales have grown 11 per cent.

- **Investment:** Capital investment in 2006 was $75 billion. This is expected to grow by five per cent in 2007. Since 2000, investment in the oilsands has been over $30 billion and proposed projects total more than $70 billion. At $22,296 in 2006, Alberta has the highest investment per capita in Canada. In 2007, the Alberta government announced a three-year, $18.2 billion infrastructure development program.

- **Exports and imports:** Exports continue to increase, with energy leading the way, followed by industrial goods and agricultural products. These are up nine per cent in 2007 thanks to high oil prices, large natural gas volumes, and manufactured goods.
As shown in Figure 2.1-1, the real economic growth (per cent change in real GDP) in 2006 was 6.8 per cent.

**Figure 2.1-1: Change in Alberta’s GDP**

![Graph showing change in Alberta’s GDP](image-url)

Source: The Conference Board of Canada

According to The Conference Board of Canada, Alberta’s real GDP will grow by 3.4 per cent compound annually forecast to 2020. Over the last two decades, Alberta had the highest rate of GDP growth in Canada at 3.8 per cent per year.

The main factors influencing The Conference Board of Canada’s GDP forecast are:

- sustained high oil prices
- immense non-conventional oil reserves
- declining natural gas production
- fluctuating productivity as the aging workforce is revitalized with migration and immigration and the province continues to attract business and job seekers

Potential economic complications include:

- labour shortages
- low natural gas prices
- the rising Canadian dollar
- increasing interest rates
- escalating construction and housing costs
### 2.2 Alberta’s population growth

In 2006, Alberta’s population grew by over 100,000 people (3.2 per cent). As depicted in Figure 2.2-1, the forecast for population growth is expected to remain steady. This is largely due to the steady demand for skilled labour.

#### Figure 2.2-1: Population growth in Alberta

![Population growth in Alberta chart](chart.png)

The prospect of employment will continue to attract workers from across Canada and around the world. Since 2004, the unemployment rate has steadily fallen from 4.6 to 3.3 per cent.

### 3.0 Detailed results

This section provides detailed forecast results for the period from 2007 to 2027 for both the Alberta Interconnected Electric System (AIES) and the Alberta Internal Load (AIL).

#### 3.1 AIES and AIL forecasts

The AIES is the sum of all electricity sales (residential, commercial, industrial and farm) and losses (both transmission and distribution).

AIL includes AIES plus behind-the-fence load (BTF). BTF is an industrial load that is characterized by being served in whole or in part by on-site generation. However, the forecast is for gross demand and energy.

Table 3.1-1 on the following page shows the growth in AIES demand and electricity consumption comparing FC2007 with FC2006. Since 2001, average annual demand growth has been 1.7 per cent and energy has grown 1.8 per cent. FC2007 shows an average growth rate of 3.1 per cent for AIES load and a growth rate for energy of three per cent for the period 2007 to 2027.
### Table 3.1-1: Alberta Interconnected Electric System (AIES)

<table>
<thead>
<tr>
<th>Year</th>
<th>FC2006 (MW)</th>
<th>FC2007 (MW)</th>
<th>Growth (%)</th>
<th>Forecast difference</th>
</tr>
</thead>
<tbody>
<tr>
<td>2000/01</td>
<td>–</td>
<td>7,666**</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td>2001/02</td>
<td>–</td>
<td>7,527</td>
<td>1.8</td>
<td>–</td>
</tr>
<tr>
<td>2002/03</td>
<td>–</td>
<td>7,552</td>
<td>0.3</td>
<td>–</td>
</tr>
<tr>
<td>2003/04</td>
<td>–</td>
<td>7,650</td>
<td>1.3</td>
<td>–</td>
</tr>
<tr>
<td>2004/05</td>
<td>–</td>
<td>7,910</td>
<td>3.4</td>
<td>–</td>
</tr>
<tr>
<td>2005/06</td>
<td>–</td>
<td>8,066</td>
<td>2.0</td>
<td>–</td>
</tr>
<tr>
<td>2006/07</td>
<td>8,286*</td>
<td>8,177</td>
<td>1.4</td>
<td>-108.6</td>
</tr>
<tr>
<td>2007/08</td>
<td>8,369</td>
<td>8,625</td>
<td>3.5</td>
<td>256.2</td>
</tr>
<tr>
<td>2008/09</td>
<td>8,620</td>
<td>8,983</td>
<td>4.3</td>
<td>363.3</td>
</tr>
<tr>
<td>2009/10</td>
<td>8,725</td>
<td>9,148</td>
<td>4.5</td>
<td>423.4</td>
</tr>
<tr>
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<tr>
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<td>9,750</td>
<td>9.1</td>
<td>840.1</td>
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<tr>
<td>2012/13</td>
<td>8,951</td>
<td>10,064</td>
<td>3.4</td>
<td>1,112.9</td>
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<tr>
<td>2013/14</td>
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<td>10,425</td>
<td>3.0</td>
<td>1,268.2</td>
</tr>
<tr>
<td>2014/15</td>
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<td>10,719</td>
<td>3.0</td>
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</tr>
<tr>
<td>2015/16</td>
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<td>11,005</td>
<td>2.7</td>
<td>1,444.5</td>
</tr>
<tr>
<td>2016/17</td>
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<td>11,328</td>
<td>2.8</td>
<td>1,484.9</td>
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<tr>
<td>2017/18</td>
<td>10,075</td>
<td>11,647</td>
<td>3.1</td>
<td>1,572.0</td>
</tr>
<tr>
<td>2018/19</td>
<td>10,300</td>
<td>11,909</td>
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<td>2019/20</td>
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<td>2020/21</td>
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<td>12,560</td>
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<td>1,728.9</td>
</tr>
<tr>
<td>2021/22</td>
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<td>13,000</td>
<td>3.4</td>
<td>2,001.5</td>
</tr>
<tr>
<td>2022/23</td>
<td>11,379</td>
<td>13,422</td>
<td>3.2</td>
<td>2,042.6</td>
</tr>
<tr>
<td>2023/24</td>
<td>11,681</td>
<td>13,856</td>
<td>3.2</td>
<td>2,175.9</td>
</tr>
<tr>
<td>2024/25</td>
<td>11,808</td>
<td>14,250</td>
<td>3.3</td>
<td>2,442.3</td>
</tr>
<tr>
<td>2025/26</td>
<td>12,110</td>
<td>14,758</td>
<td>3.2</td>
<td>2,648.3</td>
</tr>
<tr>
<td>2026/27</td>
<td>12,377</td>
<td>15,223</td>
<td>3.2</td>
<td>2,846.5</td>
</tr>
<tr>
<td>2027/28</td>
<td>12,664</td>
<td>15,703</td>
<td>3.2</td>
<td>3,039.0</td>
</tr>
</tbody>
</table>

* denotes forecast
** denotes actuals

Table 3.1-2 on the following page shows the growth in AIL demand and electricity consumption comparing FC2007 with FC2006.

In the last five years, AIL demand has grown by four per cent per year and AIL energy has grown by five per cent per year. For the next five years average annual demand is forecast to grow by 3.2 per cent and energy is expected to grow by 3.7 per cent. FC2007 shows an annual average growth rate of 3.1 per cent for AIL load and a growth rate for energy of 3.3 per cent for the period 2007 to 2027.
Table 3.1-2: Alberta Internal Load (AIL)

<table>
<thead>
<tr>
<th>Year</th>
<th>FC2006 (MW)</th>
<th>FC2007 (MW)</th>
<th>Growth (%)</th>
<th>Forecast difference</th>
</tr>
</thead>
<tbody>
<tr>
<td>2000/01</td>
<td>–</td>
<td>7,785**</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td>2001/02</td>
<td>–</td>
<td>7,934</td>
<td>1.9</td>
<td>–</td>
</tr>
<tr>
<td>2002/03</td>
<td>–</td>
<td>8,570</td>
<td>8.0</td>
<td>–</td>
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<tr>
<td>2003/04</td>
<td>–</td>
<td>8,967</td>
<td>4.6</td>
<td>–</td>
</tr>
<tr>
<td>2004/05</td>
<td>–</td>
<td>9,236</td>
<td>3.0</td>
<td>–</td>
</tr>
<tr>
<td>2005/06</td>
<td>–</td>
<td>9,580</td>
<td>3.7</td>
<td>–</td>
</tr>
<tr>
<td>2006/07</td>
<td>10,045*</td>
<td>9,661</td>
<td>0.8</td>
<td>-384.1</td>
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<td>2007/08</td>
<td>10,262</td>
<td>10,028</td>
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<td>-234.2</td>
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<tr>
<td>2008/09</td>
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<td>10,467</td>
<td>3.9</td>
<td>-183.4</td>
</tr>
<tr>
<td>2009/10</td>
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<td>10,793</td>
<td>3.1</td>
<td>-118.4</td>
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<td>2010/11</td>
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<td>11,121</td>
<td>3.9</td>
<td>-71.3</td>
</tr>
<tr>
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<td>11,662</td>
<td>4.0</td>
<td>195.3</td>
</tr>
<tr>
<td>2012/13</td>
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<td>12,062</td>
<td>3.4</td>
<td>378.2</td>
</tr>
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<td>2013/14</td>
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<td>12,519</td>
<td>3.8</td>
<td>532.7</td>
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<td>2014/15</td>
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<td>12,929</td>
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</tr>
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<td>13,312</td>
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<td>752.1</td>
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<td>2016/17</td>
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<td>13,711</td>
<td>3.0</td>
<td>852.7</td>
</tr>
<tr>
<td>2017/18</td>
<td>13,148</td>
<td>14,155</td>
<td>3.2</td>
<td>1,006.7</td>
</tr>
<tr>
<td>2018/19</td>
<td>13,431</td>
<td>14,566</td>
<td>2.9</td>
<td>1,135.3</td>
</tr>
<tr>
<td>2019/20</td>
<td>13,667</td>
<td>14,971</td>
<td>2.8</td>
<td>1,303.4</td>
</tr>
<tr>
<td>2020/21</td>
<td>14,071</td>
<td>15,355</td>
<td>2.6</td>
<td>1,283.8</td>
</tr>
<tr>
<td>2021/22</td>
<td>14,316</td>
<td>15,852</td>
<td>3.2</td>
<td>1,536.4</td>
</tr>
<tr>
<td>2022/23</td>
<td>14,705</td>
<td>16,323</td>
<td>3.0</td>
<td>1,618.8</td>
</tr>
<tr>
<td>2023/24</td>
<td>15,087</td>
<td>16,808</td>
<td>3.0</td>
<td>1,720.7</td>
</tr>
<tr>
<td>2024/25</td>
<td>15,226</td>
<td>17,241</td>
<td>2.6</td>
<td>2,014.7</td>
</tr>
<tr>
<td>2025/26</td>
<td>15,548</td>
<td>17,796</td>
<td>3.2</td>
<td>2,248.0</td>
</tr>
<tr>
<td>2026/27</td>
<td>15,878</td>
<td>18,304</td>
<td>2.9</td>
<td>2,426.1</td>
</tr>
<tr>
<td>2027/28</td>
<td>16,237</td>
<td>18,824</td>
<td>2.8</td>
<td>2,587.6</td>
</tr>
</tbody>
</table>

* denotes forecast
** denotes actuals

3.2 Selected regional results

From a transmission planning perspective there are five primary regions in Alberta. There are also two large urban centres: Calgary and Edmonton.

Figure 3.2-1 on the following page shows the regional winter peaks for 2006 and 2020 and Figure 3.2-2 shows the regional summer peaks for the same periods.

Both figures provide an indication of the associated seasonal load factors. In this case, the winter season is the period from November 1 to April 30 and the summer season is from May 1 to October 31.
Figure 3.2-1: Winter region peaks

**Northwest**
- Load factor
  - 2006: 1,134 MW (90.9%)
  - 2020: 1,343 MW (90.5%)
  - +209

**Northeast**
- Load factor
  - 2006: 2,040 MW (87.9%)
  - 2020: 5,107 MW (92.1%)
  - +3,067

**Edmonton and North Central**
- Load factor
  - 2006: 2,155 MW (74.2%)
  - 2020: 2,867 MW (72.9%)
  - +712

**Edmonton only**
- Load factor
  - 2006: 1,140 MW (72.3%)
  - 2020: 1,401 MW (71.3%)
  - +261

**Calgary and South Central**
- Load factor
  - 2006: 3,444 MW (77.2%)
  - 2020: 4,865 MW (75.0%)
  - +1,421

**Calgary only**
- Load factor
  - 2006: 1,515 MW (68.3%)
  - 2020: 2,129 MW (67.9%)
  - +614

**South**
- Load factor
  - 2006: 909 MW (83.6%)
  - 2020: 1,186 MW (82.4%)
  - +277
### Figure 3.2-2: Summer region peaks

<table>
<thead>
<tr>
<th>Region</th>
<th>2006 Load</th>
<th>2020 Load</th>
<th>Increase</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Northwest</strong></td>
<td>1,094 MW</td>
<td>1,257 MW</td>
<td>+163 MW</td>
</tr>
<tr>
<td><strong>Northeast</strong></td>
<td>2,061 MW</td>
<td>4,888 MW</td>
<td>+2,827 MW</td>
</tr>
<tr>
<td><strong>Edmonton and North Central</strong></td>
<td>1,983 MW</td>
<td>2,603 MW</td>
<td>+620 MW</td>
</tr>
<tr>
<td><strong>Calgary and South Central</strong></td>
<td>3,109 MW</td>
<td>4,296 MW</td>
<td>+1,187 MW</td>
</tr>
<tr>
<td><strong>Calgary only</strong></td>
<td>1,449 MW</td>
<td>2,018 MW</td>
<td>+569 MW</td>
</tr>
<tr>
<td><strong>South</strong></td>
<td>972 MW</td>
<td>1,199 MW</td>
<td>+227 MW</td>
</tr>
<tr>
<td><strong>Edmonton only</strong></td>
<td>1,155 MW</td>
<td>1,379 MW</td>
<td>+224 MW</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Region</th>
<th>2006 Load</th>
<th>2020 Load</th>
<th>Increase</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Northwest</strong></td>
<td>1,094 MW</td>
<td>1,257 MW</td>
<td>+163 MW</td>
</tr>
<tr>
<td><strong>Northeast</strong></td>
<td>2,061 MW</td>
<td>4,888 MW</td>
<td>+2,827 MW</td>
</tr>
<tr>
<td><strong>Edmonton and North Central</strong></td>
<td>1,983 MW</td>
<td>2,603 MW</td>
<td>+620 MW</td>
</tr>
<tr>
<td><strong>Calgary and South Central</strong></td>
<td>3,109 MW</td>
<td>4,296 MW</td>
<td>+1,187 MW</td>
</tr>
<tr>
<td><strong>Calgary only</strong></td>
<td>1,449 MW</td>
<td>2,018 MW</td>
<td>+569 MW</td>
</tr>
<tr>
<td><strong>South</strong></td>
<td>972 MW</td>
<td>1,199 MW</td>
<td>+227 MW</td>
</tr>
<tr>
<td><strong>Edmonton only</strong></td>
<td>1,155 MW</td>
<td>1,379 MW</td>
<td>+224 MW</td>
</tr>
</tbody>
</table>
4.0 Forecast methodology

The AESO continues to take a standard econometric approach to estimating future demand and electricity usage. This methodology provides a consistent approach to load forecasting through the use of a combination of fitted statistical models, historical data, third-party economic forecasts and customer-specific information.

The long-term load forecast is developed in three broad categories:

- industrial and commercial
- residential
- farm

A high-level overview of the AESO's load forecasting methodology is found in Figure 4.0-1 and the details for each sector are discussed in the following three sections. In this section the figures cover the period to 2020.

Figure 4.0-1: AESO load forecast methodology flow diagram

Note: MP_ID refers to metering points.
4.1 Industrial and commercial sector

The industrial and commercial sector is the largest in terms of load and energy consumption. The forecast for this sector is a function of real economic growth and historical usage.

The AESO’s industrial and commercial energy forecast relies on the historical relationship between Alberta’s economic growth and electricity energy growth. This relationship (in Figure 4.1-1) is analyzed and, along with a forecast of Alberta’s future economic growth, is used to determine future electricity energy growth.

Figure 4.1-1: Industrial and commercial energy growth and Alberta GDP growth

Regression analysis is used to determine the relationship of Alberta GDP to industrial and commercial energy. The relationship between megawatt hour (MWh) and real GDP growth ($ million) is plotted in Figure 4.1-2.

Figure 4.1-2: Industrial and commercial energy intensity

Since 1992 this relationship has ranged between a high of 390 MWh/$ million GDP and a low of 350 MWh/$ million. The energy forecast maintains the 390 MWh limit for the forecast period.
4.2 Residential electricity

Future energy requirements for the residential sector are calculated by multiplying the forecast number of customers in the province by the historical 10-year average use by customer (approximately 6,900 kilowatt hour (kWh) per customer).

In general, residential electricity consumption (kWh per customer) has declined for the past decade (Figure 4.2-1).

**Figure 4.2-1: Average residential use**

![Average Residential Use Graph](image)

Although Figure 4.2-1 suggests there might be a relationship between residential use and heating degree days, there is no statistically significant support. The most likely reason for this is the limited penetration of electric space heating in the residential sector.

The AESO's residential customer forecast (Figure 4.2-2) is driven by The Conference Board of Canada's population forecast.

**Figure 4.2-2: Annual change in the number of residential customers**

![Annual Change in Residential Customers Graph](image)
4.3 Farm electricity

The relationship between energy and the agriculture portion of Alberta GDP is analyzed through regression analysis to predict the farm energy component. This relationship is found in Figure 4.3-1.

Since 1992, electricity usage as a function of agricultural GDP has been declining. The notable exception was in 2002. At that time, agricultural GDP dropped sharply due to export restrictions and soft commodity prices. This resulted in a large increase in the relationship with energy since the amount of electricity consumed on farms did not change significantly.

In 2006, agricultural GDP grew sharply by almost 16 per cent. For the period from 2007 to 2020, the average increase is expected to be two per cent. Although the cultivated land area in Alberta is not increasing, more land is irrigated each year. This results in higher crop yields per acre.

5.0 Historical forecast results

In the process of preparing the long-term load forecast, the AESO assesses past forecasts and Alberta’s actual demand and electricity usage to verify methodology and identify variances that could impact the current forecast.

The past three long-term load forecasts compare favourably to Alberta’s actual demand and electricity usage experience. As represented in Table 5.0-1, all three electricity forecasts have been between -1.6 per cent and +1.4 per cent for the years 2005 and 2006. On a year-to-date (YTD) basis, all forecasts for 2007 are greater than the electricity consumed.

Table 5.0-1: Energy forecast variance history

<table>
<thead>
<tr>
<th>Year of actuals</th>
<th>Actuals (GWh)</th>
<th>Year-over-year</th>
<th>FC2004 (%)</th>
<th>FC2005 (%)</th>
<th>FC2006 (%)</th>
<th>FC2007 (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2005</td>
<td>66,266.5</td>
<td>–</td>
<td>+1.4</td>
<td>+1.0</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td>2006</td>
<td>69,369.6</td>
<td>+3,103.1</td>
<td>-0.1</td>
<td>-1.6</td>
<td>+1.2</td>
<td>–</td>
</tr>
<tr>
<td>2007 YTD</td>
<td>46,125.1</td>
<td>–</td>
<td>-2.5</td>
<td>-2.7</td>
<td>-1.7</td>
<td>-0.5</td>
</tr>
</tbody>
</table>
Table 5.0-2 examines the variance between actual peak load and forecast peak load. The table also highlights the convergence of summer and winter peaks since 2004. The winter peak in 2004/05 was higher than forecast, while the winter peak for both 2005/06 and 2006/07 was lower than forecast.

<table>
<thead>
<tr>
<th>Year of actuals</th>
<th>Actuals (MW)</th>
<th>Year-over-year</th>
<th>Season-over-season</th>
<th>FC2004 (%)</th>
<th>FC2005 (%)</th>
<th>FC2006 (%)</th>
<th>FC2007 (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2004/05 winter</td>
<td>9,236</td>
<td></td>
<td></td>
<td>-0.8</td>
<td>-</td>
<td>-</td>
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<td>2005 summer</td>
<td>8,566</td>
<td></td>
<td></td>
<td>-670</td>
<td>-3.1</td>
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<tr>
<td>2005/06 winter</td>
<td>9,580</td>
<td>+344</td>
<td>+1,014</td>
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<td>+0.5</td>
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<td>-</td>
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<td>2006 summer</td>
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<td>-2.4</td>
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<td>2006/07 winter</td>
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<td>+81</td>
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<td>-1.3</td>
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<td>-</td>
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<td>2007 summer</td>
<td>9,321</td>
<td>+271</td>
<td>-340</td>
<td>-2.6</td>
<td>+2.4</td>
<td>+1.0</td>
<td>-</td>
</tr>
</tbody>
</table>

In 2006/07 the winter peak occurred in November. Although the weather was cold, the peak did not coincide with the sustained cold and festive lights of a typical December winter peak. Furthermore, the peak was impacted by the phasing out of some industrial loads and the inability of several projects to meet their originally scheduled in-service dates.

Summer peaks are getting higher in Alberta. To a large extent this is being driven by the population growth in southern Alberta and Calgary in particular. As the population grows, there are more users and, frequently, more users who are using more electricity. In a general sense, the increase in summer peaks is referred to as increased air-conditioning load.

The FC2006 forecast for the summer of 2007 was lower than the actual peak by 2.4 per cent. This volume, approximately 225 MW, coincides with the amount of price-responsive load on the Alberta system. This summer, at the time of peak, there were no forced outages and the price of electricity remained stable at $55/MWh.

### 6.0 Challenges

Each year the Future Demand and Energy Outlook explores a select number of economic challenges that might impact load growth in Alberta. This year three such challenges are examined:

- the large number of oilsands and upgrader projects proposed by customers
- optimistic growth outside of the northeast
- weather as a factor in load growth assumptions

In addition, the AESO recognizes there are other challenges on the horizon including demand-side management and greenhouse gas (GHG) emission costs. These are discussed in Section 6.4.
6.1 Challenge – large number of oilsands and upgrader projects

According to information gathered on oilsands and upgrader projects (size, timing, phasing) provided by customers, the total growth in energy and demand exceeds the forecast for the industrial sector. Careful analysis and judgment is required to place customer proposed projects in the context of the most likely forecast. To respect the forecast energy growth limits, the following criteria were established:

- An initial customer project list was generated from customer surveys, interconnection applications and customer meetings.
- All projects not yet under construction are delayed by one year or more to start on January first of the next plus one year.
- All projects not yet under construction were ramped up at slower rates than proposed. Ramp rates were used to reduce load rather than identifying and reducing the one (or more) projects that might face cancellation or delay.
- Lower than proposed ramp rates were also used for projects that are currently under construction.
- Existing and operating projects’ future growth plans were adjusted last, and only if necessary.

The justification for applying the one- to two-year delay and the slower ramp-up to future projects lies in identifying and understanding the significant challenges facing oilsands developers. These include but are not limited to: labour costs, water availability, pipeline capacity, regulatory approval and stakeholder concerns.

Although the AESO does not forecast oil production, it is possible to convert the energy forecast to a range of production numbers. Figure 6.1-1 shows this range in the context of several publicly available forecasts: CAPP, EUB and NEB.

The AESO’s estimated range for non-upgraded bitumen (NUB) and synthetic crude oil (SCO) is derived by converting the energy forecast in the northeast to barrel per day (bpd) of NUB and SCO using 19 kWh/barrel and 25 kWh/barrel.

Figure 6.1-1: Oilsands production (NUB + SCO)
The year-over-year production additions (Figure 6.1-2) were also analyzed to test for reasonable additions. The past four-year average has been +95,000 bpd. The AESO’s forecast calls for an average of +200,000 bpd for the next 10 years. CAPP 2007 calls for an average of +250,000 bpd for the next 10 years with +400,000 occurring in 2013.

Figure 6.1-2: Oilsands production (year-over-year) (NUB + SCO)

Some oilsands developers are reviewing new technologies such as gasification of syngas to reduce their natural gas consumption. This will increase their demand for electricity for each barrel of oil. This potential increase in electricity intensity may be countered as the percentage share of steam-assisted gravity drainage (SAGD) production increases. SAGD requires less electricity per barrel than mining does.
6.2 Challenge – areas outside of the northeast have optimistic growth future

A second challenge faced in the development of FC2007 was to ensure the energy forecast for regions outside the oilsands production and upgrading region reflects the optimistic economic outlook throughout the province.

Figure 6.2-1 shows the annual industrial energy growth outside of the northeast. This has been incorporated into FC2007. Non-project growth was arrived at by using the past five-year performance for each planning region as a guide.

Figure 6.2-1: Non-oilsands energy growth (year-over-year)

6.3 Challenge – weather as a factor in future load assumptions

Since the primary determining factors for electricity demand are Alberta’s real GDP and population growth, the AESO does not employ a weather normalization scheme within the load forecasting process.

As noted in Section 4.2, there is no statistical support for applying weather normalization to the Alberta load forecast. The AESO does, however, examine this relationship on an annual basis.

The AESO captures weather variations implicitly through conversion of the annual energy forecast into an hourly forecast by using the two previous years’ load shapes and averaging the values. This allows approximately 17,520 (8,760 hours x two years) different weather conditions to be incorporated into the hourly load forecast. In this way, a suitable range of weather conditions is captured in FC2007.
6.4 Challenges on the horizon

Each year in the process of developing the load forecast, there are internal discussions about changes on the Alberta horizon that may have a material impact on future load and energy requirements.

This year four future challenges have been identified:

- new demand-side management initiatives, including demand response programs
- new technology with different electricity intensities
- new environmental regulations around GHG
- new exploration, particularly coal bed methane extraction

Each of these challenges will be explored in the coming year to determine their significance with respect to the fundamental relationships that form the basis of the AESO’s Future Demand and Energy Outlook.

List of reference documents


Canadian Association of Petroleum Producers (June 2007) Crude Oil Forecast, Markets and Pipeline Expansions.


# FUTURE DEMAND AND ENERGY OUTLOOK 2008-2028 (FC2008)

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Executive summary

The Future Demand and Energy Outlook, 2008-2028 (FC2008) is the Alberta Electric System Operator’s (AESO) long-term load forecast. FC2008 describes the assumptions, methodology, and processes that the AESO uses to assess Alberta’s future demand and energy requirements.

This report is prepared annually in accordance with the duties of the AESO as outlined in Alberta’s Electric Utilities Act (EUA) and the Transmission Regulation (AR 86/2007) and will be used to support filings that may be submitted to the Alberta Utilities Commission (AUC).

FC2008 includes a 20-year peak load and electricity consumption forecast for Alberta. The load forecast is generated from economic growth (GDP), oilsands production forecast, population projections and by select customer sectors, with regional adjustments based on historical results and customer-driven growth expectations.

In the past five years (2003-2007) Alberta’s Internal Load (AIL) peak demand has grown by an average of 228 megawatts (MW) (2.5 per cent) per year from 8,570 MW to 9,710 MW (an overall increase of 13.3 per cent). Electricity consumption has grown by an average of 3.2 per cent per year from 59,437 gigawatt hours (GWh) to 69,660 GWh.

The AESO forecasts the peak AIL demand to grow by an average 3.4 per cent per year for the next 20 years. Electricity consumption is expected to grow by 3.5 per cent per year.

In addition to reporting the detailed forecast results, this report includes a review of the AESO’s load forecasting methodology and a brief statement on the potential impact of this past fall’s economic turmoil. The energy and demand forecast is prepared based on an examination of five sectors: industrial without oilsands, oilsands, commercial, residential and farm. The results are organized by the AESO’s five bulk transmission planning regions and six regional planning regions.

The FC2008 concludes with a brief discussion of the challenges faced in preparing a load forecast for Alberta.

1.0 Introduction

The AESO’s long-term load forecast is a study of past energy use patterns and future economic indicators, that are, in simple terms, combined to produce a future energy forecast. The AESO annually updates this energy forecast with a 20-year outlook of Alberta’s electric energy consumption and peak load demand. The estimates of future electricity market needs are one of the drivers the AESO uses in analyzing and planning the timely development of the transmission system. The annual forecast is based on economic, demographic and customer information collected from January through June of 2008.

Completed in the third quarter of 2008, the AESO’s Future Demand and Energy Outlook, (2008-2028) or FC2008, describes the assumptions, methodology and processes that the AESO employs to assess Alberta’s future demand and energy requirements.

The FC2008 recognized some future project uncertainty in regards to timing, size and number of large oilsands extraction facilities and upgraders in the northeast of the province. This uncertainty is reflected in the FC2008 demand and shows a drop in demand from the FC2007 in the first 10-year period.
1.1 Economic update November 2008

The AESO has performed a preliminary assessment to measure the impact of recent global economic events on the future demand for electricity in Alberta. Preliminary estimates show a short-term slowdown in economic growth could result in a reduction in peak demand of about 200 to 400 MW in the 10-year horizon and 500 to 600 MW in the 20-year horizon in relation to the forecast contained in this report. This assessment further indicates that the recent global economic turmoil should not affect electricity growth in the province to a large degree in the long term.

Table 1.1-1: Alberta GDP growth comparison

<table>
<thead>
<tr>
<th>Year</th>
<th>The Conference Board of Canada Provincial Outlook 2008 Released: March 2008 (%)</th>
<th>The Conference Board of Canada Provincial Outlook Autumn 2008 Released: November 2008 (%)</th>
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<td>3.6</td>
<td>1.2</td>
</tr>
<tr>
<td>2009</td>
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<td>2.6</td>
</tr>
<tr>
<td>2010</td>
<td>3.7</td>
<td>3.8</td>
</tr>
</tbody>
</table>

2.0 Economic outlook

The foundation for the AESO's electricity demand and energy forecast is Alberta's economic outlook, which continues to be strong according to The Conference Board of Canada's long-term economic forecast (Provincial Outlook Long-term Forecast 2008, published in March 28, 2008).

Economic growth, as measured by the provincial gross domestic product (GDP), is expected to be strong in the coming decade, ranging from 2.6 per cent to 3.7 per cent. According to The Conference Board of Canada, GDP is forecast to be 3.6 per cent in 2008 and 3.6 per cent in 2009. Over the last two decades, Alberta had the highest rate of GDP growth in Canada, averaging 3.8 per cent per year.

The AESO's economic outlook is developed using information and analysis from The Conference Board of Canada, Statistics Canada, and other independent subject-matter experts.

The key factor driving the Alberta economy continues to be investment in the development of oilsands, which is largely driven by oil demand and oil prices on the world market. This investment – direct, indirect and tertiary – creates jobs that ensure a continuation of large annual increases in retail sales. Economic growth in Alberta will be somewhat tempered by an increasing cost of living and under-developed infrastructure, which has caused a slowdown of net migration and immigration.

2.1 Alberta’s GDP growth

GDP is a function of consumer spending, private and public investment, exports and imports. In Alberta, these fundamental economic characteristics continue to be strong:

- **Consumer spending:** From 2004 to 2007, retail sales grew over 10 per cent per year. The forecast growth for 2008 is 7.5 per cent, but more recent figures in October 2008 indicate retail sales growth will drop to approximately 4.1 per cent.

- **Investment:** Capital investment in 2006 was $75 billion. This grew by five per cent to $80 billion in 2007. Recent indicators suggest capital investment will reach $83 billion in 2008. Between 2006 and 2011, over $50 billion is expected to be invested in the oilsands. At $23,230 in 2007, Alberta had the highest investment per capita in Canada. Also in 2007, the Alberta government announced a three-year, $18.2 billion infrastructure development program.

- **Exports and imports:** Net exports continue to increase, with natural gas and crude oil production leading the way followed by industrial goods and agricultural products.
As shown in Figure 2.1-1 the real economic growth (per cent change in real GDP) in 2007 was 3.1 per cent.

**Figure 2.1-1: Changes in GDP**

![Figure 2.1-1: Changes in GDP](image)

Alberta’s GDP is influenced by:

- energy prices
- immense non-conventional oil reserves (oilsands)
- declining natural gas production
- fluctuating productivity as the aging workforce is revitalized with migration and immigration and the province continues to attract businesses and job seekers

The overarching strength of the Alberta economy does not preclude the existence of economic difficulties in some sectors. In 2007, the most noticeable of these was the chemical sector. In 2008, the indicators suggest that the forestry sector will be adversely affected by the virtual disappearance of the U.S. housing construction market. By the end of the first quarter, two mills had closed indefinitely. With respect to electricity demand, this is the loss of approximately 15 MW. Reduced wood product sales, with the possibility of further mill closures, are expected to affect the industry for the next 12 to 24 months.

The electricity energy growth forecast is based in part on a GDP forecast, which has since been impacted by the following:

- labour shortages
- low natural gas prices
- volatile oil prices
- strength of the Canadian dollar
- health of the U.S. economy
- escalating construction and housing costs

In summary, in the short- to medium-term, the energy sector will continue to be Alberta’s primary economic driver contributing to the continued growth in electricity consumption. This is based on energy prices, a very significant non-conventional oil supply and extraction technology improvements. Over the 20-year forecast horizon, Alberta’s economy is expected to exhibit solid GDP growth, expanding at an average annual rate of three per cent.
2.2 Alberta’s population growth

In 2007, Alberta’s population grew by approximately 100,000 people (three per cent) to 3.47 million. As depicted in Figure 2.2-1, the forecast for population growth is expected to remain steady. This is largely due to the steady demand for skilled labour.

Figure 2.2-1: Population growth in Alberta

![Population growth in Alberta](image)

Source: The Conference Board of Canada

The prospect of employment will continue to attract workers from across Canada and around the world. Since 2004, the unemployment rate has steadily fallen from 4.6 per cent to 3.5 per cent.

2.3 Oilsands production growth

Due to the strong dependency of the Alberta economy on oilsands activity, the AESO has added a separate customer sector for the energy consumed by oilsands sites in the 2008 methodology. The oilsands sector is located in the Cold Lake, Athabasca/Lac La Biche and Fort McMurray transmission planning areas. The energy consumption to produce a barrel of synthetic crude oil from bitumen can be measured fairly easily; therefore, energy consumption by this sector can be forecast with assumptions of kWh/barrel multiplied by an oilsands production forecast.

For the FC2008, the AESO used Canadian Association of Petroleum Producers (CAPP) Crude Oil Forecast, Markets & Pipeline Expansions – June 2008 production forecast of oil sands mining and in situ moderate growth as a starting point. After evaluating past CAPP forecasts to actual production figures, the AESO added an adjustment factor to CAPP’s 2008 forecast. The mining production forecast was adjusted by nine per cent and in situ was adjusted by three per cent each from 2008 until 2020. Years 2021 through to 2028 were extrapolated using the CAPP’s 2015-2020 growth rate (3.3 per cent). In the short term, this forecast will be impacted by project deferrals but in the long term is still appropriate as an indicator into the future energy and demand outlook for Alberta.
Figure 2.3-1: Oilsands production forecast

Source: CAPP – Crude Oil Forecast, Market & Pipeline Expansions – June 2008 – Moderate Growth

Figure 2.3-2: AESO adjusted oilsands production forecast

Source: AESO adjusted CAPP
3.0 Methodology

The AESO uses a standard econometric approach to estimating future demand and electricity usage. This methodology provides a consistent approach to load forecasting through the use of a combination of fitted statistical models, historical data, third-party economic forecasts and customer-specific information.

The long-term load forecast is developed in five categories:

- industrial without oilsands
- oilsands
- commercial
- residential
- farm

Figure 3.0-1: Customer sector as a percentage of total energy (2007)

A high-level overview of the AESO’s long-term load forecasting methodology is found in Figure 3.1-1 and the details for each sector are discussed in the following sections.
3.1 AESO methodology diagram

Figure 3.1-1: AESO load forecast methodology flow diagram

* Note: MP_ID refers to metering points.

DFO: distribution facility owner
### 3.2 Industrial (without oilsands) customer sector

The industrial sector is the largest in terms of load and energy consumption, comprising roughly 49 per cent of total AIL energy use. The forecast for this sector is a function of real economic growth and historical usage.

The AESO's industrial energy forecast relies on the historical relationship between Alberta's economic growth and electricity energy growth. This relationship (in Figure 3.2-1) is analyzed and, along with a forecast of Alberta's future economic growth, is used to determine future electricity energy growth.

In designing the economic models for the 2008 to 2028 forecast, the AESO looked at various economic indicators that should be used to best predict the future demand of this sector. In the AESO's studies, the best fit was found between Alberta mining GDP and this sector. The Alberta mining category used by Statistics Canada measures the value of output of all industries engaged in extracting naturally occurring minerals. The term *mining* is used in the broad sense to include quarrying, well operations, milling and other preparation customarily done at site. This includes oil and gas exploration and development. With the dependency of Alberta's economy on the energy sector, it is intuitive that the industrial sector is highly dependent on the health of energy exploration and development.

**Figure 3.2-1: Industrial (without oilsands) energy growth & Alberta mining GDP growth**

![Graph showing industrial (without oilsands) energy growth & Alberta mining GDP growth](image)

Source: AESO, ERCB and Statistics Canada
Regression analysis is used to determine the relationship of Alberta mining GDP to industrial without oilsands energy. The relationship between megawatt hours (MWh) and real GDP growth ($ million) is plotted in Figure 3.2-2.

**Figure 3.2-2: Industrial (without oilsands) energy intensity**

Since 2002, the average kWh/barrel required for in situ production has been 9.8 kWh. With the possibility of higher electric intensity processes being considered by some sites, such as gasifying upgrading by-products, the AESO included an increasing mix of higher intensity sites. The AESO’s forecast includes an increasing electric intensity by the in situ operators to 15.2 kWh/barrel by 2020.

The kWh/barrel for mining operations has steadily increased since 2002 from 18.1 kWh to 24.8 kWh in 2006, dropping slightly in 2007 to 23.7 kWh. The AESO used a value of 25.2 kWh in the FC2008 to estimate for the electric intensity by mining operators for the period 2008 to 2028.
Figure 3.3-1: Oilsands energy intensity

Source: AESO, ERCB and Statistics Canada

Figure 3.3-2: Oilsands energy

Source: AESO
### 3.4 Commercial customer sector

The commercial sector is the second largest in terms of energy consumption, accounting for roughly 19 per cent of total AIL energy use. The forecast for this sector is a function of real economic growth and historical usage.

The AESO’s commercial energy forecast relies on the historical relationship between Alberta’s economic growth and electricity energy growth. This relationship (in Figure 3.4-1) is analyzed and, along with a forecast of Alberta’s future economic growth, is used to determine the future electricity energy growth.

**Figure 3.4-1: Commercial energy growth and Alberta GDP growth**

![Commercial energy growth and Alberta GDP growth](source: AESO, ERCB and Statistics Canada)

**Figure 3.4-2: Commercial energy intensity**

![Commercial energy intensity](source: AESO, ERCB and Statistics Canada)
3.5 Residential customer sector

Future energy requirements for the residential sector are calculated by multiplying the forecast number of customers in the province by the historical 10-year average use by customer (approximately 6,941 kWh per customer). The residential sector is roughly 12 per cent of total AIL consumption.

In general, residential electricity consumption (kWh per customer) has seen little change over the past decade (Figure 3.5-1).

Figure 3.5-1: Average residential use

![Graph showing average residential use from 1998 to 2028.](image)

Source: AESO and ERCB

The AESO’s residential customer forecast (Figure 3.5-2) is driven by The Conference Board of Canada’s population forecast.

Figure 3.5-2: Annual change in the number of residential customers

![Graph showing annual change in the number of residential customers from 1998 to 2028.](image)

Source: AESO and ERCB
3.6 Farm customer sector

The farm sector is the smallest of all the sectors to be analyzed by the AESO and is roughly three per cent of total AIL energy consumption. The relationship between energy and the agriculture portion of the Alberta GDP is studied through the use of regression analysis to predict the farm energy component. This relationship is found in Figure 3.6-1.

Since 1992, electricity usage as a function of agricultural GDP has been declining. The notable exception was in 2002. At that time, agricultural GDP dropped sharply due to export restrictions and soft commodity prices. This resulted in a large increase in the relationship with energy since the amount of electricity consumed on farms did not change significantly.

In 2006, agricultural GDP grew sharply by almost 16 per cent. For the period from 2008 to 2028, the average increase is expected to be two per cent.
4.0 Forecast results

This section provides detailed forecast results for the period from 2008 to 2028 for the AIL and Alberta Interconnected Electric System (AIES).

4.1 Provincial results – AIL forecast

AIL is the sum of all electricity sales (residential, commercial, industrial and farm), losses (both transmission and distribution) and behind-the-fence load (BTF). BTF is any industrial load that is characterized by being served in whole, or in part, by on-site generation.

Tables 4.1-1 through 4.1-3 compare the growth in AIL demand and energy from the FC2008 with last year’s forecast, the FC2007. In the last five years, AIL demand has grown by 2.5 per cent per year and AIL energy has grown by 3.2 per cent per year. For the next five years, average annual demand is forecast to grow by 4.2 per cent and energy is expected to grow by 4.5 per cent. FC2008 shows an annual average growth rate of 3.4 per cent for AIL load and a growth rate for energy of 3.5 per cent for the period 2008 to 2028.

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* denotes forecast
** denotes actuals

Table 4.1-2: Alberta Internal Load (AIL) – Summer peak demand

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<th>FC2007 (MW)</th>
<th>FC2008 (MW)</th>
<th>FC2008 growth (%)</th>
<th>Forecasts diff. (MW)</th>
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Table 4.1-3: Alberta Internal Load (AIL) – Annual energy

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<th>Load Factor (%)</th>
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* denotes forecast
** denotes actuals

Note: 2002 includes a redefinition of BTF load of approximately 400 MW.
4.2 Provincial results – AIES forecast with behind-the-fence (BTF) load estimation

The AESO forecasts the changes in the amount of on-site generation. In order to calculate the AIES demand and energy, the AESO forecasts the amount of AIL served based on historical on-site generation or any subsequent changes. The results from this work are presented in the following three tables.

### Table 4.2-1: Alberta Interconnected Electric System (AIES) – Winter peak demand

<table>
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<th>FC2007 (MW)</th>
<th>FC2008 (MW)</th>
<th>FC2008 growth (%)</th>
<th>Forecasts diff. (MW)</th>
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</tr>
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* denotes forecast
** denotes actuals

### Table 4.2-2: Alberta Interconnected Electric System (AIES) – Summer peak demand

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<th>FC2008 (MW)</th>
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<td>2025</td>
<td>13,330</td>
<td>3.2</td>
<td>+1,176</td>
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<tr>
<td>2026</td>
<td>13,724</td>
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<td>+1,246</td>
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<tr>
<td>2027</td>
<td>14,130</td>
<td>3.0</td>
<td>+1,285</td>
</tr>
<tr>
<td>2028</td>
<td>14,827</td>
<td>2.9</td>
<td>+1,039</td>
</tr>
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</table>
Table 4.2-3: Alberta Interconnected Electric System (AIES)

<table>
<thead>
<tr>
<th>Year</th>
<th>FC2007 (GWh)</th>
<th>FC2008 (GWh)</th>
<th>FC2008 growth (%)</th>
<th>Forecasts diff. (GWh)</th>
<th>Load Factor (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2000</td>
<td>52,914**</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>78.6</td>
</tr>
<tr>
<td>2001</td>
<td>52,480</td>
<td>2.3</td>
<td>-</td>
<td>-</td>
<td>81.1</td>
</tr>
<tr>
<td>2002</td>
<td>53,169</td>
<td>-0.9</td>
<td>-</td>
<td>-</td>
<td>79.3</td>
</tr>
<tr>
<td>2003</td>
<td>54,669</td>
<td>1.9</td>
<td>-</td>
<td>-</td>
<td>78.7</td>
</tr>
<tr>
<td>2004</td>
<td>55,697</td>
<td>4.8</td>
<td>-</td>
<td>-</td>
<td>78.8</td>
</tr>
<tr>
<td>2005</td>
<td>57,433</td>
<td>3.1</td>
<td>-</td>
<td>-</td>
<td>80.2</td>
</tr>
<tr>
<td>2006</td>
<td>58,615*</td>
<td>57,701</td>
<td>0.5</td>
<td>-914</td>
<td>80.1</td>
</tr>
<tr>
<td>2007</td>
<td>63,054</td>
<td>61,461</td>
<td>1.1</td>
<td>-3,133</td>
<td>79.4</td>
</tr>
<tr>
<td>2008</td>
<td>64,766</td>
<td>63,169</td>
<td>3.0</td>
<td>-2,949</td>
<td>79.3</td>
</tr>
<tr>
<td>2009</td>
<td>66,337</td>
<td>66,731</td>
<td>3.8</td>
<td>-4,396</td>
<td>78.6</td>
</tr>
<tr>
<td>2010</td>
<td>69,271</td>
<td>69,687</td>
<td>5.8</td>
<td>-4,116</td>
<td>79.2</td>
</tr>
<tr>
<td>2011</td>
<td>71,787</td>
<td>72,648</td>
<td>5.1</td>
<td>+861</td>
<td>79.5</td>
</tr>
<tr>
<td>2012</td>
<td>73,940</td>
<td>76,020</td>
<td>4.6</td>
<td>+2,079</td>
<td>79.9</td>
</tr>
<tr>
<td>2013</td>
<td>76,278</td>
<td>78,333</td>
<td>5.0</td>
<td>+3,055</td>
<td>80.4</td>
</tr>
<tr>
<td>2014</td>
<td>78,841</td>
<td>83,521</td>
<td>4.6</td>
<td>+4,680</td>
<td>80.7</td>
</tr>
<tr>
<td>2015</td>
<td>80,962</td>
<td>86,293</td>
<td>5.0</td>
<td>+5,331</td>
<td>81.1</td>
</tr>
<tr>
<td>2016</td>
<td>82,784</td>
<td>88,531</td>
<td>5.8</td>
<td>+5,747</td>
<td>80.9</td>
</tr>
<tr>
<td>2017</td>
<td>84,737</td>
<td>90,809</td>
<td>6.9</td>
<td>+6,072</td>
<td>80.8</td>
</tr>
<tr>
<td>2018</td>
<td>87,614</td>
<td>93,794</td>
<td>6.8</td>
<td>+6,181</td>
<td>80.8</td>
</tr>
<tr>
<td>2019</td>
<td>90,264</td>
<td>96,722</td>
<td>6.8</td>
<td>+6,458</td>
<td>81.0</td>
</tr>
<tr>
<td>2020</td>
<td>92,948</td>
<td>99,830</td>
<td>6.8</td>
<td>+6,882</td>
<td>80.9</td>
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<tr>
<td>2021</td>
<td>95,695</td>
<td>103,009</td>
<td>5.3</td>
<td>+7,315</td>
<td>80.9</td>
</tr>
<tr>
<td>2022</td>
<td>98,517</td>
<td>106,226</td>
<td>3.1</td>
<td>+7,709</td>
<td>80.7</td>
</tr>
<tr>
<td>2023</td>
<td>101,461</td>
<td>109,462</td>
<td>3.5</td>
<td>+8,001</td>
<td>80.7</td>
</tr>
<tr>
<td>2024</td>
<td>104,424</td>
<td>112,916</td>
<td>3.2</td>
<td>+8,492</td>
<td>80.7</td>
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<td>116,447</td>
<td>3.1</td>
<td>+8,945</td>
<td>80.8</td>
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<tr>
<td>2026</td>
<td>110,624</td>
<td>120,051</td>
<td>3.1</td>
<td>+9,427</td>
<td>80.6</td>
</tr>
</tbody>
</table>

* denotes forecast
** denotes actuals
4.3 Forecast results for bulk planning purposes

Together with the AESO’s generation scenarios, the long-term load forecast serves as a tool to aid in transmission planning. Bulk transmission planners (i.e., the planning on the 240 kV and 500 kV system) will use the forecast to determine where future load growth and demand is expected. They can also use the forecast to study the flow of electric power up to 20 years in the future from region to region. It is for this purpose the provincial forecast, including demand peaks, is produced. The 20-year forecast also provides a transparent input to the AESO’s plans for the industry.

To study the bulk electric flows, bulk transmission system planners examine the region peaks at the time when the provincial peak is occurring (i.e., a provincewide coincident peak). FC2008 results are presented in a format that is applicable for bulk planning purposes. It should be noted that the bulk regional peak numbers will differ from the peak numbers studied by the regional transmission planners (i.e., planning performed within specific regions) as the regional planners are interested in demand at the time of region peak (a coincident peak among all the areas that fall under the region they are studying). The regional coincident peak forecasts are examined further in Section 4.4.

From a bulk transmission planning perspective, the AESO has defined five primary regions in Alberta. There are also two large urban centres: Calgary and Edmonton.

Figure 4.3-1 shows the forecast regional winter peaks for 2008, 2018 and 2028 and Figure 4.3-2 shows the regional summer peaks for the same periods. In this case, the winter season is the period from November 1 to April 30 and the summer season is from May 1 to October 31.
Figure 4.3-1: Region demand at time of winter AIL peak

2008 winter peak is not final at date of publication; therefore, forecast winter demands are shown in this figure.
Figure 4.3-2: Region demand at time of summer AIL peak

<table>
<thead>
<tr>
<th>Region</th>
<th>2008</th>
<th>2018</th>
<th>2028</th>
</tr>
</thead>
<tbody>
<tr>
<td>Northwest</td>
<td>1,007 MW</td>
<td>1,250 MW</td>
<td>1,490 MW</td>
</tr>
<tr>
<td>2008</td>
<td>1,007 MW</td>
<td>1,250 MW</td>
<td>1,490 MW</td>
</tr>
<tr>
<td>2018</td>
<td>1,225 MW</td>
<td>1,461 MW</td>
<td>1,930 MW</td>
</tr>
<tr>
<td>2028</td>
<td>2,110 MW</td>
<td>2,632 MW</td>
<td>3,416 MW</td>
</tr>
<tr>
<td>Edmonton only</td>
<td>1,225 MW</td>
<td>1,461 MW</td>
<td>1,930 MW</td>
</tr>
<tr>
<td>2008</td>
<td>2,110 MW</td>
<td>2,632 MW</td>
<td>3,416 MW</td>
</tr>
<tr>
<td>2018</td>
<td>3,211 MW</td>
<td>4,222 MW</td>
<td>5,513 MW</td>
</tr>
<tr>
<td>2028</td>
<td>4,150 MW</td>
<td>5,760 MW</td>
<td>7,050 MW</td>
</tr>
<tr>
<td>Northeast</td>
<td>1,861 MW</td>
<td>4,150 MW</td>
<td>5,760 MW</td>
</tr>
<tr>
<td>2008</td>
<td>1,861 MW</td>
<td>4,150 MW</td>
<td>5,760 MW</td>
</tr>
<tr>
<td>2018</td>
<td>3,211 MW</td>
<td>4,222 MW</td>
<td>5,513 MW</td>
</tr>
<tr>
<td>2028</td>
<td>5,513 MW</td>
<td>7,050 MW</td>
<td>9,400 MW</td>
</tr>
<tr>
<td>Calgary and South Central</td>
<td>3,211 MW</td>
<td>4,222 MW</td>
<td>5,513 MW</td>
</tr>
<tr>
<td>2008</td>
<td>3,211 MW</td>
<td>4,222 MW</td>
<td>5,513 MW</td>
</tr>
<tr>
<td>2018</td>
<td>4,222 MW</td>
<td>5,513 MW</td>
<td>7,050 MW</td>
</tr>
<tr>
<td>2028</td>
<td>5,513 MW</td>
<td>7,050 MW</td>
<td>9,400 MW</td>
</tr>
<tr>
<td>Calgary only</td>
<td>1,508 MW</td>
<td>1,853 MW</td>
<td>2,272 MW</td>
</tr>
<tr>
<td>2008</td>
<td>1,508 MW</td>
<td>1,853 MW</td>
<td>2,272 MW</td>
</tr>
<tr>
<td>2018</td>
<td>1,508 MW</td>
<td>1,853 MW</td>
<td>2,272 MW</td>
</tr>
<tr>
<td>2028</td>
<td>1,508 MW</td>
<td>1,853 MW</td>
<td>2,272 MW</td>
</tr>
<tr>
<td>South (w/o Stavely)</td>
<td>958 MW</td>
<td>1,260 MW</td>
<td>1,559 MW</td>
</tr>
<tr>
<td>2008</td>
<td>958 MW</td>
<td>1,260 MW</td>
<td>1,559 MW</td>
</tr>
<tr>
<td>2018</td>
<td>958 MW</td>
<td>1,260 MW</td>
<td>1,559 MW</td>
</tr>
<tr>
<td>2028</td>
<td>958 MW</td>
<td>1,260 MW</td>
<td>1,559 MW</td>
</tr>
</tbody>
</table>

* denotes actuals
4.4 Forecast results for regional planning purposes

The Province of Alberta covers over 661,100 square kilometres (km²). This represents approximately seven per cent of Canada's total land mass. Given the considerable size of the province, it is reasonable to expect that the geography, economics and climate will vary from one region to another. This geographical diversity is apparent in the AESO's load forecast as seen in the tables on the following pages. Figure 4.4-1 shows the province divided into areas. These areas can be added together to explore the electric power needs unique to that particular region.

For regional planning purposes, the areas have been grouped together to represent six regions: South, Calgary, Central, Edmonton, Northeast and Northwest regions.

The following tables show regional peak coincident for both the summer and winter seasons. FC2008 results are compared to the forecast numbers for 2013, 2018 and 2028.
Figure 4.4-1: Grouping of areas for regional planning purposes

Planning Regions
- Orange: Calgary
- Yellow: Central
- Green: Northwest
- Purple: Edmonton
- Brown: South

Note:
Names and number references on the map are used for internal regional planning purposes.
4.5 South region

The South region includes the Medicine Hat, Sheerness, Brooks, Empress, Stavely, Vauxhall, Fort Macleod, Lethbridge and Glenwood planning areas.

Table 4.5-1: Coincident peak (MW) for South region

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Winter</td>
<td>954</td>
<td>1,039</td>
<td>1.7</td>
<td>1,136</td>
<td>1.8</td>
<td>1,399</td>
<td>1.9</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Summer</td>
<td>1,084</td>
<td>1,174</td>
<td>1.6</td>
<td>1,292</td>
<td>1.8</td>
<td>1,601</td>
<td>2.7</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

4.6 Calgary region

Included in this region are the Calgary, Strathmore/Blackie, Seebe, High River and Airdrie planning areas as well as a City of Calgary breakout.

Table 4.6-1: Coincident peak (MW) for Calgary region

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Winter</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Calgary Area</td>
<td>2,034</td>
<td>2,480</td>
<td>4.0</td>
<td>2,818</td>
<td>3.3</td>
<td>3,653</td>
<td>3.0</td>
<td></td>
<td></td>
</tr>
<tr>
<td>City of Calgary (ENMAX)</td>
<td>1,527</td>
<td>1,881</td>
<td>4.3</td>
<td>2,149</td>
<td>3.5</td>
<td>2,783</td>
<td>3.0</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Summer</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Calgary Area</td>
<td>1,900</td>
<td>2,334</td>
<td>4.2</td>
<td>2,663</td>
<td>3.4</td>
<td>3,405</td>
<td>3.0</td>
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<td></td>
</tr>
<tr>
<td>City of Calgary (ENMAX)</td>
<td>1,472</td>
<td>1,844</td>
<td>4.6</td>
<td>2,116</td>
<td>3.7</td>
<td>2,696</td>
<td>2.7</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

4.7 Central region

The Central region is considered to be between Edmonton and Calgary. Included are the Lloydminster, Hinton/Edson, Drayton Valley, Wainwright, Abraham Lake, Red Deer, Alliance/Battle River, Provost, Caroline, Didsbury, Hanna and Vegreville planning areas.

Table 4.7-1: Coincident peak (MW) for Central region

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Winter</td>
<td>1,561</td>
<td>1,742</td>
<td>2.2</td>
<td>1,975</td>
<td>2.4</td>
<td>2,604</td>
<td>2.6</td>
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<tr>
<td>Summer</td>
<td>1,387</td>
<td>1,570</td>
<td>2.5</td>
<td>1,810</td>
<td>2.7</td>
<td>2,356</td>
<td>2.7</td>
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</tr>
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</table>
4.8 Edmonton region
Acting as a transmission hub, the Edmonton region includes the Wetaskiwin, Fort Saskatchewan, Wabamun and Edmonton planning areas as well as a City of Edmonton breakout.

Table 4.8-1: Coincident peak (MW) for Edmonton region

<table>
<thead>
<tr>
<th></th>
<th>FC2008</th>
<th>FC2008</th>
<th>Average</th>
<th>FC2008</th>
<th>FC2008</th>
<th>Average</th>
<th>FC2008</th>
<th>FC2008</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2008</td>
<td>2013</td>
<td>growth</td>
<td>2018</td>
<td>2018</td>
<td>growth</td>
<td>2028</td>
<td>2028</td>
</tr>
<tr>
<td>Winter</td>
<td></td>
<td></td>
<td>(%)</td>
<td></td>
<td></td>
<td>(%)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Edmonton Area</td>
<td>2,517</td>
<td>3,027</td>
<td>3.8</td>
<td>3,654</td>
<td>3.8</td>
<td>4,792</td>
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<td>1,127</td>
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<td>1,461</td>
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<td>1,929</td>
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<tr>
<td>Summer</td>
<td></td>
<td></td>
<td>(%)</td>
<td></td>
<td></td>
<td>(%)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Edmonton Area</td>
<td>2,450</td>
<td>2,938</td>
<td>3.7</td>
<td>3,553</td>
<td>3.8</td>
<td>4,647</td>
<td>3.3</td>
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<tr>
<td>City of Edmonton (EPCOR)</td>
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<td>1,481</td>
<td>2.7</td>
<td>1,955</td>
<td>2.7</td>
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</tbody>
</table>

4.9 Northeast region
The Northeast region is forecast to experience the greatest load growth over the next 10 years. This is due in large part to the oilsands, forestry industries and related secondary service industries in the municipalities. The Northeast region includes the Fort McMurray, Athabasca/Lac La Biche and Cold Lake planning areas.

Table 4.9-1: Coincident peak (MW) for Northeast region

<table>
<thead>
<tr>
<th></th>
<th>FC2008</th>
<th>FC2008</th>
<th>Average</th>
<th>FC2008</th>
<th>FC2008</th>
<th>Average</th>
<th>FC2008</th>
<th>FC2008</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2008</td>
<td>2013</td>
<td>growth</td>
<td>2018</td>
<td>2018</td>
<td>growth</td>
<td>2028</td>
<td>2028</td>
</tr>
<tr>
<td>Winter</td>
<td></td>
<td></td>
<td>(%)</td>
<td></td>
<td></td>
<td>(%)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Northeast</td>
<td>1,567</td>
<td>2,666</td>
<td>11.2</td>
<td>3,550</td>
<td>8.5</td>
<td>5,052</td>
<td>6.0</td>
<td></td>
</tr>
<tr>
<td>Summer</td>
<td>1,468</td>
<td>2,351</td>
<td>9.9</td>
<td>3,338</td>
<td>8.6</td>
<td>4,712</td>
<td>6.0</td>
<td></td>
</tr>
</tbody>
</table>

4.10 Northwest region
The Northwest region includes the Rainbow Lake, High Level, Peace River, Grande Prairie, High Prairie, Grand Cache, Valleyview, Fox Creek and Swan Hills planning areas.

Table 4.10-1: Coincident peak (MW) for Northwest region

<table>
<thead>
<tr>
<th></th>
<th>FC2008</th>
<th>FC2008</th>
<th>Average</th>
<th>FC2008</th>
<th>FC2008</th>
<th>Average</th>
<th>FC2008</th>
<th>FC2008</th>
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<tbody>
<tr>
<td></td>
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<td>2013</td>
<td>growth</td>
<td>2018</td>
<td>2018</td>
<td>growth</td>
<td>2028</td>
<td>2028</td>
</tr>
<tr>
<td>Winter</td>
<td></td>
<td></td>
<td>(%)</td>
<td></td>
<td></td>
<td>(%)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Northwest</td>
<td>1,109</td>
<td>1,258</td>
<td>2.6</td>
<td>1,391</td>
<td>2.3</td>
<td>1,687</td>
<td>2.1</td>
<td></td>
</tr>
<tr>
<td>Summer</td>
<td>1,078</td>
<td>1,220</td>
<td>2.5</td>
<td>1,341</td>
<td>2.2</td>
<td>1,594</td>
<td>2.0</td>
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</tr>
</tbody>
</table>
5.0 Other load forecasting considerations

In addition to the uncertainty associated with the economic and demographic variables, there are other significant challenges in developing a long-term load forecast for Alberta. Many of these are addressed implicitly by the AESO’s load forecasting models. Although the factors discussed below are not explicitly included in the load forecasting models, they are examined by the AESO on a regular basis to inform the load forecasting process.

5.1 Demand responsive load and conservation

The potential impact of conservation and efficiency (which will drive the advancement of new technologies), and demand responsive load programs represents an additional source of uncertainty and challenge for the AESO’s load forecast. In general, these can be programs that encourage conservation and efficiency, or programs that allow consumers to respond to market signals and voluntarily reduce consumption based on market prices. Another change affecting the forecast relates to the system controller and the direction to facility owners during supply shortfall in the form of Operational Policies and Procedures. With such programs there is the potential to reduce or shift the timing of the Alberta system peaks and energy requirements.

The current Alberta market design relies primarily on price signals to provide consumer incentives for economically efficient energy consumption and production decisions. Price responsive load has been seen primarily from industrial customers that have flexible production such that they can turn down operations and respond to high market prices. Depending on the market price, the amount of price responsive load has ranged from 175 MW to 300 MW.

The AESO has implemented a combination of demand response programs to assist in managing or preventing emergency system operating conditions. These include:

- Voluntary load curtailment protocol (VLCP) – a demand response program based on a pre-arranged contract.
- Demand opportunity service (DOS) – an opportunity transmission service with regulated rates for each level of interruption (seven minute and one hour).
- Frequency load shed service (FLSS) – load shed instantaneously during system events.
- Supplemental operating reserves (SUP) – Ancillary service available to arrest frequency decline but not required to respond directly to frequency deviations. This can be a load or generator service.

The net impact of these programs is captured in the AESO’s long-term load forecast modelling processes.

There is a major emphasis on energy efficiency and conservation programs in various North American jurisdictions, which are encompassed by the term demand-side management (DSM). DSM generally refers to activities that occur on the demand side of the meter, and are implemented by the customer directly or by load serving entities. DSM initiatives are aimed at achieving energy savings as a result of conservation, energy efficiency and load displacement programs. A substantial portion of these energy savings has resulted from appliance and building standards. Another major portion of savings has been the utility programs mandated by governments and regulators, including efficiency services in the form of energy audits, financial incentive, load-shifting activities and rate design.
Several jurisdictions are implementing very aggressive DSM programs including California, the U.S. Pacific Northwest and B.C. For example, BC Hydro is required to acquire 50 per cent of its incremental resource needs through conservation (DSM) by 2020. The approach adopted to load forecasting in these jurisdictions typically involves a detailed assessment of the impact of DSM programs and price effects on electricity demand. These analytical requirements characteristically necessitate an extremely detailed end-use approach to demand forecasting. To date, load-serving entities or retailers in Alberta have not developed price responsive, efficiency or conservation programs in the same way as other jurisdictions, especially those that rely on the traditional integrated utility model. Consequently, opportunities from this sector to date have been negligible. The potential impacts of demand response and DSM type programs are not explicitly included in the AESO’s load forecasting models, given that such programs are not widespread and that any future programs are unknown at this time. The AESO will continue to evaluate appropriate programs related to DSM.

### 5.2 Alberta market structure

The unique structure of the Alberta market contributes to the uncertainty associated with the load forecast. The competitive Alberta generation market and the power pool based pricing structure involve greater load forecast uncertainty than is associated with more traditional regulated markets. In part, this is because of the expectation of greater volatility in wholesale power prices in Alberta, which in turn can be expected to have an impact on the demand (i.e., cause a price response) for electricity, on a short-term and longer-term basis. Therefore, similar and related to the impact of DSM, the potential impact of the future level and volatility of prices is not specifically modelled, but it is captured in the long-term load forecast through the econometric modelling of electricity consumption by sector.

### 5.3 Composition of load

Industrial load represents a very high percentage of the total load in Alberta, and this can be expected to contribute to greater uncertainty in the load forecast.

Unlike the residential and commercial sectors, where the uses of electricity are relatively similar in different houses or buildings, the industrial uses of electricity are diverse. It is difficult to generalize about the uses of electricity in a typical industrial plant. Electricity consumption is typically greater in this sector than other sectors. Alberta’s industrial electricity consumption is tied closely to the level of economic activity, and to world oil and gas market conditions. Beyond the general risk of higher or lower than expected economic growth materializing, a significant risk to the industrial load forecast pertains to discrete one-time, unforeseen changes in load that are the result of corporate decisions that impact the opening, timing, restarting or closing of major facilities.

The oilsands industry in particular, which is driving the BTF load in Alberta, is very dynamic. These projects have unique attributes in terms of the size, cost, location, labour, and electricity requirements. Since oilsands producers are expected to behave differently from the rest of the industrial sector, they are a potential source of significant uncertainty in the long-term load forecast. This includes the development of specific major oilsands projects, which have announced on-site generation, and projects that are likely to do so. Given the many options available to developers, the volatility of oil prices, and the shortage of labour and material for constructing new projects, the load growth in the oilsands industry is not expected to occur in a smooth, easily foreseeable or predictable manner.
5.4 Distributed generation
Distributed generation involves the installation of small-scale power sources (typically in the range of three kilowatts (kW) to 10 MW) at or near a customer’s site, to provide an alternative to or an enhancement of the traditional electric power system.

For generation smaller than 150 kW, modelling and forecasting of this generation and the load that it offsets is not specifically tracked. Advanced metering infrastructure (AMI) and smart grid could facilitate specific tracking of micro- and other generation. It is assumed that the impact of any potential drop in load caused by distributed generation will be captured through trends seen in the econometric modelling of energy consumption by sector. Major shifts can be addressed as they are identified.

5.5 Environmental costs
The costs of meeting environmental requirements are expected to rise across North America, particularly for large greenhouse gas (GHG) emitters. While this may have an impact on the in-service dates for some oilsands and upgrader projects, at this time there is no basis for assuming that these costs will significantly slow expansion in Alberta’s energy producing sectors. Because it is unlikely that reduction in GHG emissions will occur without cost, future climate control policy is a risk of uncertain magnitude and timing to the load forecast. Load forecasting models used in other jurisdictions generally tend to use a fuel carbon content tax as a proxy for the cost of mandated GHG reductions, whatever the means of implementation.

It can be expected that any costs associated with meeting environmental requirements for electricity generation facilities in the future will ultimately be reflected in electricity prices. As previously discussed, the AESO's load forecasting models do not explicitly include the influence of electricity prices on electricity demand. However, any changes in demand patterns are captured through the modelling process that accounts for historic trends that capture various econometric drivers.

5.6 Challenges on the horizon
Each year in the process of developing the load forecast, there are internal discussions about changes on Alberta’s horizon that may have a material impact on the future load and energy requirements.

This year a number of future challenges have been identified:
- new demand-side management initiatives, including demand response programs
- new technology with different electricity intensities
- new environmental regulations around GHG
- new vehicle technology, including plug-in electric cars
- global economic turmoil

Each of these challenges will be explored in the coming year to determine their significance to the fundamental relationships that form the basis of the AESO’s Future Demand and Energy Outlook (2008–2028).
6.0 Historical and past forecast results

In the process of preparing the long-term load forecast, the AESO assesses past forecasts, along with Alberta's actual demand and electricity usage, to verify the methodology and identify variances that could impact the current forecast.

6.1 Past forecast variances

Table 6.1-1: Energy forecast variance history

<table>
<thead>
<tr>
<th>Year</th>
<th>Actuals (GWh)</th>
<th>Year-over-year change</th>
<th>FC2005 (%)</th>
<th>FC2006 (%)</th>
<th>FC2007 (%)</th>
<th>FC2008 (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2006</td>
<td>69,370</td>
<td>-</td>
<td>-1.6</td>
<td>+1.2</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>2007</td>
<td>69,660</td>
<td>290</td>
<td>-3.4</td>
<td>-1.5</td>
<td>-1.2</td>
<td>-</td>
</tr>
<tr>
<td>2008</td>
<td>69,946</td>
<td>286</td>
<td>-7.7</td>
<td>-4.9</td>
<td>-4.8</td>
<td>-1.3</td>
</tr>
</tbody>
</table>

Table 6.1-2 examines the variance between the actual peak load and the forecast peak load. This table also highlights the convergence of summer and winter peaks since 2005. The winter peak in 2005/06 was higher than forecast, while the winter peak for both 2006/07 and 2007/08 were lower than forecast.

Table 6.1-2: Peak forecast variance history

<table>
<thead>
<tr>
<th>Year of actuals</th>
<th>Actuals (MW)</th>
<th>Year-over-year change</th>
<th>Season-over-season</th>
<th>FC2005 (%)</th>
<th>FC2006 (%)</th>
<th>FC2007 (%)</th>
<th>FC2008 (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2005/06 Winter</td>
<td>9,580</td>
<td>-</td>
<td>-</td>
<td>+0.5</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>2006 Summer</td>
<td>9,050</td>
<td>-</td>
<td>-530</td>
<td>-2.4</td>
<td>+2.3</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>2006/07 Winter</td>
<td>9,661</td>
<td>81</td>
<td>611</td>
<td>-4.0</td>
<td>-3.8</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>2007 Summer</td>
<td>9,321</td>
<td>271</td>
<td>-340</td>
<td>-2.6</td>
<td>+2.4</td>
<td>+1.0</td>
<td>-</td>
</tr>
<tr>
<td>2007/08 Winter</td>
<td>9,710</td>
<td>49</td>
<td>389</td>
<td>-5.6</td>
<td>-5.4</td>
<td>-3.2</td>
<td>-</td>
</tr>
<tr>
<td>2008 Summer</td>
<td>9,541</td>
<td>220</td>
<td>-169</td>
<td>-4.0</td>
<td>+1.2</td>
<td>+0.3</td>
<td>+1.0</td>
</tr>
</tbody>
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List of reference documents


Energy Resources and Conservation Board Table 11: Electric Energy Distribution Sales and Number of Customers.

Canadian Association of Petroleum Producers (June, 2008) Crude Oil Forecast, Markets and Pipeline Expansions.


National Energy Board (June 2006) Canada’s Oil Sands – Opportunities and Challenges to 2015: An Update. (Review only)

Statistics Canada (December 2008) Retail Sales by Industry (monthly).


Appendix D
Appendix D
Reliability Criteria and Mandatory Reliability Standards

Reliability criteria are designed to ensure there are adequate transmission resources available to reliably connect generation and load at all times, taking into account variations in load levels, generation dispatch, transaction levels and scheduled and reasonably expected unscheduled outages of generation and transmission system elements.

These criteria provide a set of important tests for planning future developments or operating the Alberta Interconnected Electric System (AIES), and represent a minimum standard to which the AIES is planned and operated. There are a variety of other considerations that must also be taken into account. Planning and operating decisions must be made with due regard for costs to meet the criteria, impact on stakeholders and risks associated with not meeting the criteria.

The AESO is a member of the Western Electricity Coordinating Council (WECC) and a signatory to its Reliability Management System Agreement. As such the AESO has agreed to follow the North American Electric Reliability Corporation (NERC) and WECC Reliability Criteria and Standards for planning and operating the Alberta system and its interties.

Adherence to these NERC and WECC reliability criteria and standards is more fully described in the AESO Transmission Reliability Criteria included in this Appendix. To ensure the adequacy and reliability of the AIES, technical studies are carried out to measure system performance against these criteria.
**Mandatory reliability standards project in Alberta**

Currently within the U.S. NERC, under the jurisdiction of the Federal Energy Regulatory Commission, administers development of and compliance with a set of Mandatory Reliability Standards by the applicable U.S.-based entities. It is intended that these Mandatory Reliability Standards will result in a consistent set of reliability standards across North America.

The AESO is committed to supporting this effort while maintaining jurisdictional authority for the province.

The AESO’s Mandatory Reliability Standards project delivers a comprehensive Alberta program for the development, review, approval and implementation of reliability standards, as well as the efficient monitoring of compliance to reinforce adherence to standards.

The adoption of Alberta reliability standards requires stakeholder consultation, carried out via the AESO Reliability Committee, and recommendation by the AESO for approval by the Alberta Utilities Commission (AUC).

The AESO is working with stakeholders to establish a compliance monitoring program. The compliance enforcement authority in Alberta is the Market Surveillance Administrator. As the regulator, the AUC sets penalties for non-compliance.

The AESO is implementing an operating agreement with the WECC to ensure streamlined processes for ongoing interface and cooperation that align with the AESO’s participation as a member of the WECC.

At such time as a complete set of Mandatory Reliability Standards have been adopted for use in Alberta, the AESO Transmission Reliability Criteria as described in this Appendix will be amended accordingly.
Appendix D: AESO Transmission Reliability Criteria

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Preface

The transmission system connects generators to loads over a large and diverse geographic area and delivers electric energy to Alberta customers reliably and efficiently under a wide variety of system operating conditions and continuously changing customer demands. Transmission is a vital component of the electric industry providing a platform for a competitive wholesale electricity market.

Through transmission lines that provide interconnection with neighbouring jurisdictions (called interties1), the Alberta Transmission System (ATS) also provides access to the entire North American electric grid. In addition to providing mutual assistance during emergencies, interties are an essential part of a competitive market providing Alberta the ability to import energy when needed, and to export energy when it is surplus to Alberta’s needs.

The AESO Reliability Criteria (Reliability Criteria) is central to assessing the adequacy of the current and future ATS. The Reliability Criteria applies equally to regulated, non-regulated and merchant facilities interconnected with the ATS. With an adequate system and prudent operating criteria, the AESO is able to operate the ATS securely and at the same time facilitate an open and competitive electricity market.

Alberta has chosen to adopt both the North American Electric Reliability Council (NERC) and Western Electricity Coordinating Council (WECC) reliability criteria for application in Alberta as well as for its interconnections. The Reliability Criteria summarizes important elements of the NERC and WECC reliability criteria and identifies applicable performance standards and interpretations used in planning and operating the ATS.

The Reliability Criteria is intended to document the complete set of transmission reliability criteria used to plan and operate the ATS.

Reliability criteria provide one very important input to planning future developments or operating the ATS. The Reliability Criteria generally are a minimum standard to which the ATS should be planned and operated. However there are a wide variety of other considerations that must be weighed in the process of planning and operating the ATS. There are often a variety of solutions that may be considered to meet both the planning and operating criteria. Both planning and operating decisions must be made with due regard for the costs to meet the Reliability Criteria, impact on stakeholders, land use impacts and the risks associated with not meeting the Reliability Criteria. Development of the AIES, both the transmission and distribution systems, must be done in an economic, orderly and efficient manner. The AIES needs to be planned with an appropriate mix of transmission and distribution facilities to achieve this standard.

The AESO’s transmission planning, design and interconnection standards or guides are or will be included in separate documents. The assumptions associated with particular studies or regulatory applications are stated therein.

The intent of this document is to create clarity around the Reliability Criteria that apply to Alberta and interpretations particular to Alberta.

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1 The first use of a defined term is in bold type.
1.0 Introduction

The WECC is the largest of ten regional reliability councils that make up NERC. The WECC was established in 1967 in part, to promote electric system reliability throughout the 14 USA western states, British Columbia, Alberta and the northern portion of Baja California, Mexico.

Alberta has chosen to follow both the NERC and WECC reliability criteria for planning and operating the ATS and its interconnections. NERC requires that each regional reliability council conform with the NERC Reliability Standards. WECC has responded to this requirement and has, for example, included the NERC Reliability Standards as the foundation for the NERC/WECC Planning Standards.

The WECC Reliability Criteria can be found at www.wecc.biz In addition to the WECC planning standards, there are standards that are established specifically for the ATS.

The WECC Reliability Criteria contain both planning and operating criteria. The planning criteria are designed to ensure that there are adequate transmission resources available to the system operators so they are able to maintain system reliability through a wide variety of load levels, generation dispatches, interchange levels, adverse weather conditions and system outages. The AESO intends to apply both the planning and operating elements of the WECC Reliability Criteria to the ATS and its interconnections. The AESO recognizes there may be specific situations where meeting the NERC, WECC or Reliability Criteria does not meet a reasonable cost versus risk test. On the other hand, there may be circumstances where the AESO or a customer determines that facilities beyond those required to meet the Reliability Criteria are desirable. In either case, good engineering and business judgement will be applied.

The NERC and WECC reliability criteria apply to the Bulk Electric System which is defined as:

“The bulk electric system is a term commonly applied to that portion of an electric utility system, which encompasses the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher.”

The Reliability Criteria will apply to the bulk electric system as defined by NERC and WECC as well as the 69 and 72 kV systems. This definition encompasses the entire ATS as defined by the EU Act.

Planners use the Reliability Criteria to ensure the system can withstand Category B and C events under a specific adverse generation scenario and peak loading conditions. Although this event may not occur over the heaviest load hour the system may experience more extreme events over hours with less load but with less favourable generation dispatch. The planner’s role is to provide adequate transmission resources so the operator will be able to operate the system reliably in real time. The Reliability Criteria also serve as a foundation for needs documents, functional specifications and operating policies and procedures.
The AESO is also a signatory to the WECC’s Reliability Management System (RMS) Agreement. The RMS is more specific in defining the requirements for meeting defined standards of reliability, the measures, how to report compliance and sanctions for non-compliance. The RMS can be found on the AESO website at www.aeso.ca.

Operators know what the prevailing system conditions are at the moment but are unaware of what events may transpire in the future. They establish operating procedures to ensure that the system can withstand the next contingency events, in accordance with the WECC Minimum Operating Reliability Criteria (MORC). Operating Policies and Procedures based on the operating criteria can be found in the ISO Rules on the AESO web page.

The WECC Reliability Criteria include a standard titled “Power Supply Assessment Policy” that addresses the requirement for the regions to assess and report on the adequacy of power supply in the future. With deregulation, Alberta depends on market forces to ensure the adequacy of supply and therefore there is no generation adequacy standard applied in Alberta.

Methods or guides adopted for use in Alberta are identified in the appropriate criteria.

2.0 Definitions

The definitions in the WECC Reliability Criteria are the basis for the terms used in this document unless otherwise defined herein. Appendix A contains definitions and acronyms specific to Alberta as well as selected important definitions from the WECC and NERC for the convenience of the reader.

The application of these definitions is intended solely for the purpose of the Reliability Criteria document and is not necessarily intended to represent the definitions used by the AESO in other documents.

In each Part the first use of a defined term is in bold type.

3.0 AESO powers to change rules

NERC and WECC will make changes to their reliability criteria from time to time. The AESO will participate in the process of changing these criteria and will incorporate changes to the Reliability Criteria as required.

The AESO may exercise its powers under the Act to change the Reliability Criteria from time to time, as it considers desirable and appropriate. Any changes are subject to review by and directives from the Alberta Energy and Utilities Board (EUB).

The AESO will plan and operate according to this Reliability Criteria to the extent possible and reasonable. The AESO reserves the right to fall short of or exceed the Reliability Criteria when warranted and will disclose such exceptions to stakeholders and the EUB through information submissions or regulatory applications on a case by case basis.
Appendix A – Definitions and acronyms

“abnormal operating conditions” means conditions where transmission facilities are out of service, emergency conditions exist, construction or commissioning of transmission facilities occur or situations when transmission facility maintenance cannot be coordinated with generation outages. (EU Act Transmission Regulation)

“Act” means the Electric Utilities Act (Alberta), as amended from time to time. (AESO Rules)

“adequacy” means the ability of the electric system to supply the aggregate electrical demand and energy requirements of the system access customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements. (AESO Rules)

“ADOE” means the Alberta Department of Energy.

“AIES” means Alberta’s “Interconnected Electric System” as that term is defined in the Act. (AESO Rules)

“ATS” means Alberta Transmission System, the transmission component of the AIES as defined in the Act.

“bi-pole” means a DC power system which has both a positive and negative conductor.

“bulk electric system” means “that portion of an electric utility system, which encompasses the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher.” This is the NERC and WECC definition and applies to the ATS as defined by the EU Act including 69 kV and 72 kV elements of the ATS.

“bus” means a group of conductors that serve as a common connection for two or more system elements.

“capacity” means the rated continuous load-carrying ability, expressed in megawatts (MW) or megavolt-amperes (MVA) of generation, transmission, or other electrical equipment. Used interchangeably with capability.

“capacitor bank” means a set of electrical devices used to maintain or increase transmission voltage by providing reactive power.

“cascading” means the uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread service interruption which cannot be restrained from sequentially spreading beyond an area predetermined by appropriate studies. (NERC/WECC Planning Standards Table 4.1-1)

“circuit” means a conductor or a system of conductors through which electric current flows and can be automatically segregated by circuit breakers or fuses.

“circuit breaker” means a protective switch which automatically interrupts the flow of an electric current in case of an overload, electrical fault, or short circuit.

“cogeneration” means a generating facility that produces electricity and another form of useful thermal energy (such as heat or steam), used for industrial, commercial, heating, or cooling purposes.
"combined cycle" means an electric generating technology in which electricity and process steam is produced from otherwise lost waste heat exiting from one or more combustion turbines. The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for use by a steam turbine in the production of electricity. This process increases the efficiency of the electric generating unit.

"congestion" means the condition under which the transactions that market participants wish to implement exceed the constraints on a transmission path. Congestion usually requires the system operator to adjust the output of generators, decreasing it in one area to relieve the constraint and increasing it in another to continue to meet customer demand.

"constraint" means a restriction on a transmission system or segment of a transmission system that may limit the ability to transmit power between various locations. A path rating establishes the limits of power flow across defined paths. The path rating is established taking into account physical limitations, such as the thermal limits of a transmission elements; local voltage and stability restrictions, or contingency limits that are established to assure secure operations in the event of an unexpected failure of a transmission elements or a generation facility.

"contingency" means an event occurring on the ATS resulting in the loss of a system element.

"largest single generation contingency" – means the loss of an ATS or customer element that would result in the largest loss of generation measured in MW. This contingency includes more then one generator if a single elements outage could result in a prolonged outage of associated generators i.e., a combined cycle turbine outage may result in the outage of an associated steam generator or a interconnection transformer may result in the outage of more then one generator.

"single contingency" – The loss of a single system element under any operating condition or anticipated mode of operation. Single contingency events are Category B events and include the outage of a generator, single transmission circuit or a transformer. For the purpose of the Reliability Criteria a double or multiple circuit outage is not considered a single contingency.

"multiple contingency" – The loss of two or more system elements caused by unrelated events or by a single low probability event occurring within a time interval too short (less than ten minutes) to permit system adjustment in response to any of the losses.

"criteria" means standards on which a judgment or decision may be based. (Merriam-Webster Dictionary)

"cycle" means the single complete series of changes in voltage and current direction of an alternating electric current. The standard used in North America is 60 cycles per second. One cycle is equal to 1/60th of a second or 17 milliseconds.

"DC" (direct current) means current that flows continuously in the same direction (as opposed to alternating current). The current supplied from a battery is direct current.

"dynamic VAR control devices" means a device that can rapidly vary its VAR output in response to control signals that are more than simply on off.

"dispatch" has the same meaning as that provided in the Act, which means a direction from the ISO to a pool participant to cause, permit or alter the exchange of electric energy or ancillary services. (AESO Rules)
"distributor" means a party providing "distribution access service" as defined in the Act.
(AESO Rules)

"double circuit" means a transmission line having two separate circuits on a single structure. In
an AC system each circuit carries three-phase power, requiring three conductors or conductor
bundles per circuit.

"economic dispatch" means a method of managing the operation of generation and transmission facilities to produce the most cost-effective result. Economic dispatch most commonly involves the selection of the lowest-cost available generating units.

"element" means any electric device with terminals that may be connected to other electric devices, such as a generator, transformer, circuit breaker, bus section or transmission line. An element may be comprised of one or more components. A fault on an element usually results in the clearing of one protective zone by circuit breakers.

"EUB" means the Alberta Energy and Utilities Board established under the Alberta Energy and Utilities Board Act (Alberta). (AESO Rules)

"fault" means an event occurring on an electric system where abnormally high current flow resulting in the operation of a protection device or such as a short circuit, or a total interruption of an electrical circuit.

"firm load" means the load that the ISO and system members will use reasonable best efforts to supply without interruption. (AESO Rules)

"frequency" means the number of cycles through which an alternating current passes in a second. The North American standard is 60 cycles per second, known as 60 hertz.

"general distribution POD" means a point of delivery to a distributor where the energy is delivered to many end use customers, typically less than 90% of the load is to one industrial customer.

"HEE Act" means the Hydro and Electric Energy Act of Alberta.

"in merit" means a designation applied to an asset dispatched by the system controller that qualifies the asset as eligible to set pool price. (AESO Rules)

"interchange" means electric power or energy that flows between Alberta and other jurisdictions such as British Columbia and Saskatchewan.

"interconnected system" means a system consisting of two or more individual electric systems that normally operate in synchronism and have connecting tie lines.

"intertie" means a transmission line that interconnects the ATS with jurisdictions outside of Alberta. Used interchangeably with tie line.

"load" means a customer or process that takes energy from the AIES.

"local network" is "a non-radial portion of a system and has been planned such that a disturbance may result in loss of all load and generation in the LN.

1. The LN is not a control area.

2. The loss of the LN should not cause a Reliability Criteria violation external to the LN."

(WECC Reliability Criteria, Part IV page 5)
“losses” means the energy that is lost through the process of transmitting electric energy. (AESO Rules)

“Mega Var” or “MVAr” means 1 million VARs or 1000 kiloVARs of reactive power. (AESO Rules)

“merit order” means the list of all valid offers and bids for a settlement interval sorted in order of offer and bid price blocks.

“MORC” means WECC’s Minimum Operating Reliability Criteria.

“most critical generator” means the generator outage that results in the worst system performance during subsequent outages and includes additional generators if a single element outage could result in a prolonged outage of associated generators i.e., a combined cycle turbine outage may result in the outage of an associated steam generator or an interconnection transformer may result in the outage of more than one generator.

“MVA” means Mega Volt Amperes.

“MW” means megawatt(s) or means 1 million watts or 1000 kilowatts of real electrical power. (AESO Rules)

“MWh” means megawatt hour(s). A unit of energy. (AESO Rules)

“MCR” (Maximum Continuous Rating) is the maximum output a plant can sustain on a continuous basis and prescribed conditions.

“NERC” means the North American Electric Reliability Council.

“normal operating conditions” means conditions where all transmission facilities are available for service including generators.

“operating reserves” means the capability above system demand required to provide for regulation, load forecasting errors, equipment forced and scheduled outages and local area protection. It consists of spinning reserve and non-spinning reserve. (AESO Rules)

“opportunity service” means “system access service offered to any system access customer who can establish to the ISO’s satisfaction that it would not take system access service pursuant to rate schedule DTS and with respect to which, therefore, the service requirement presents the opportunity for incremental revenue with which the ISO can offset transmission costs, subject to the availability of transmission capacity.” (AESO Rules) Opportunity service is often used interchangeably with non-firm or interruptible service.

“out-of-merit” means a designation applied to a block dispatched by the system controller that disqualifies the block from being eligible to set pool price. (AESO Rules)

“over frequency” means the abnormal operating state or system condition that results in a system frequency above the normal 60 hertz. (AESO Rules)

“path” means a transmission line or set of lines that carry energy from one region to another.

“path rating” means “the rating assigned to the transmission facility when it was placed in service and rated in accordance with reliability standards.” (EU Act Transmission Regulation s1(1), (d)). The term can also be used to reflect the current rating of a path.

“p.u.” means per unit.
“PCR” (peak continuous rating) means the maximum rating a generator can produce for a prescribed period of time and conditions.

“peak demand” means the maximum power demand registered by a customer or a group of customers or a system in a stated period of time such as a month or a year. 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” means plants that run when the pool price is high. Typically capacity factors are below 50% and the cost of fuel is relatively high.

“RMS” means the WECC’s Reliability Management System agreement with participating WECC members.

“POD” (point of delivery) means a conceptual point of delivery from the transmission system. A POD is the point at which energy is deemed to be delivered from the transmission system to the distribution system. (AESO Rules)

“post transient” means the state of equilibrium of a power system after a transient event.

“power factor” means the ratio of real power to apparent power. (AESO Rules)

“radial customer” means a customer served from an electric system in which the electrical service is through a single transmission element. (NERC)

“reactive power” means the portion of electricity that establishes and sustains the electric and magnetic fields of alternating current equipment, usually expressed in kiloVArS (“kVAr”) or megaVArS (“MVAr”). (AESO Rules)

“reliability” means the degree of performance of the elements of the bulk electric system that results in electricity being delivered to customers within accepted standards and in the amount desired. Reliability may be measured by the frequency, duration, and magnitude of adverse effects on the electric supply. Electric system reliability can be addressed by considering two basic and functional aspects of the electric system adequacy and security.

“adequacy” means the ability of the electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.

“security” means the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements.

“reliability criteria” means a set of standards and principles used to design, plan, operate, and assess the adequacy of an electric system.

“Reliability Criteria” means the AESO’s Reliability Criteria except where otherwise noted.

“remedial action scheme (RAS)” means protection schemes designed to perform pre-planned corrective measures following a disturbance to provide for acceptable AIES performance or equipment protection. (AESO Rules) Used interchangeably with special protection system (SPS). Typical automatic remedial actions include generator tripping or equivalent reduction of energy input to the system, controlled tripping of interruptible load, DC line ramping, insertion of braking resistors, insertion of series capacitors and controlled opening of interconnections and/or other lines including system islanding. Typical manual remedial actions include manual tripping of load, tripping of generation, etc.
“safety net system” means a control system that protects the system from widespread cascading outages and loss of load. Systems include under frequency load shedding, and under voltage load shedding.

“single pole trip and reclose (SPT&R)” means a transmission circuit protection system which is capable of opening only the faulted phase of a circuit for single phase faults and successfully reclosing after the fault has been cleared.

“special protection scheme” means the same as RAS.

“stability” means the ability of an electric system to maintain a state of equilibrium and synchronism between its parts during normal and abnormal system conditions or disturbances.

“stability limit” means the maximum power flow possible through some particular point in the system while maintaining stability, during both normal and defined contingencies, in the entire system or the part of the system to which the stability limit refers.

“steady state” means the operation of a power system with no disturbances or after regaining equilibrium after a disturbance.

“stacking order” means the order in which plants are assumed to dispatch in the merit order.

“standard” means something established by authority, custom, or general consent as a model or example. (Merriam-Webster Dictionary)

“substation” means a facility for switching electrical elements, transforming voltage, regulating power, or metering.

“summer rating” means the rating a piece of equipment is given when summer ambient weather conditions prevail.

“switching station” means a facility for switching electrical elements.

“synchronism” means the timing of alternating current generators so that their voltage waves go through their maximum and minimum values at exactly the same rate.

“system” means integrated electrical facilities which may include generation, transmission, distribution, protection, control and communications facilities.

“thermal rating” means the maximum amount of electrical current that a transmission line or electrical facility can conduct over a specified time period before it sustains permanent damage by overheating or before it violates public safety requirements.

“tie line” means a circuit connecting two or more systems and used interchangeably with intertie.

“transfer capability” means 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 are in terms of electric power, generally expressed in megawatts (MW).

“transformer” means an electrical device for changing the voltage of alternating current.

“transient” means the period when a power system is moving from one state of equilibrium to another (post transient) state.
“transmission circuit” means a set of wires energized at transmission voltages extending beyond a substation which has its own protection zone and set of breakers for isolation.

“transmission facility owner (TFO)” has the same meaning as that provided for “owner” and “transmission facility” in the Act. (AESO Rules)

“transmission line” means a set of structures, wires and insulators that together make up one or more transmission circuits.

“transmission must-run (TMR)” means a generator is constrained on to operate at a minimum specified MW output level in order to maintain system security. (AESO Rules)

“transmission reliability margin (TRM)” means that amount of transmission transfer capability necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions. (AESO Rules)

“trip” means the disconnection or breaking of a circuit, usually in context of an automatic interruption of the circuit such as the opening of a circuit breaker.

“underfrequency” means the abnormal operating state or system condition that results in a system frequency below the normal system operating frequency of 60 hertz. (AESO Rules)

“VARs” means volt-amp reactive, a measure of reactive power. (AESO Rules)

“voltage collapse” means an event that occurs when an electric system does not have adequate reactive support to maintain voltage stability. Voltage collapse may result in outage of system elements and may include interruption in service to customers.

“voltage instability” means a system state in which an increase in load, disturbance, or system change causes voltage to decay quickly or drift downward, and automatic and manual system controls are unable to halt the decay. Voltage decay may take anywhere from a few seconds to tens of minutes. Unabated voltage decay can result in angular instability or voltage collapse.

“voltage limits”

Normal Voltage Limits
The operating voltage range on the interconnected systems that is acceptable on a sustained basis.

Emergency Voltage Limits
The operating voltage range on the interconnected systems that is acceptable for the time sufficient for system adjustments to be made following a facility outage or system disturbance.

“voltage recovery” means the nature of voltage returning to an equilibrium state after a transient event.

“voltage stability” means the condition of an electric system in which the sustained voltage level is controllable and within predetermined acceptable limits.

“WECC” means the Western Electricity Coordinating Council.

“winter rating” means the rating a piece of equipment is given when winter ambient weather conditions prevail.
Appendix D: AESO Transmission Reliability Criteria
Part II System Planning

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1.0 Introduction

This document presents the reliability criteria, which will be used as the basis for planning the Alberta Transmission System (ATS).

As Part 2 of the AESO Reliability Criteria (Reliability Criteria), this document must be read in the context of the whole. The definitions in the WECC Reliability Criteria are the basis for the terms used in this document unless otherwise defined. Definitions of terms and acronyms can be found in the appendices of Part I.

2.0 General approach

The ATS is comprised of transmission facilities with several owners, including regulated and non-regulated transmission facility owners (TFOs). As well, there are many loads and generators directly connected to the ATS. Market participants, end use customers, landowners, the general public and other stakeholders all have an interest in the reliability and development requirements of the ATS.

The AESO’s role is to ensure that there are adequate transmission facilities available so that the ATS can operate in a safe, reliable and efficient manner and to promote a fair, efficient and openly competitive market for electricity taking into account the interest of all stakeholders.

The objective of the Reliability Criteria is to provide a basis for planning a reliable transmission system taking into account the need for continuity of service, operating costs, capital investments and the need to facilitate the electric market in Alberta. Although not considered in the Reliability Criteria, other impacts such as social, land use and environmental must also be considered when establishing a system development plan. The system will normally be designed to meet or exceed the Reliability Criteria under credible worst-case loading and generation conditions unless stated otherwise. However, if extraordinary expenditures are required or a proposed plan does not meet the Reliability Criteria, the reasons, related costs, and risks involved must be evaluated on an individual basis. Conversely, if studies show that certain very unlikely contingencies will result in extraordinary consequences; projects may be initiated to mitigate such consequences. Each decision must stand the test of good engineering and business judgment.

3.0 Transmission’s role and adequacy

Given the role and importance of the transmission system, the Government of Alberta, through the Electric Utilities Act (EU Act) and the associated Transmission Regulation (Transmission Regulation) has identified several requirements related to system reliability and adequacy. The Regulation requires the AESO to forecast future needs of market participants and create 10 and 20 year long term plans to fulfil these needs. Further, the AESO must plan the ATS to meet NERC and WECC reliability standards and provide adequate transmission capability under normal and abnormal conditions. The AESO must also report to the Alberta Energy and Utilities Board (EUB) regarding development plans and compliance with reliability standards periodically.

The following standards are important aspects central to planning adequate resources for the ATS.
3.1 Market facilitation

The market facilitation standards for the AIES are established in the EU Act Transmission Regulation. The following paragraphs are a summary of the market facilitation requirements, for the complete context and text refer to the Regulation.

The ATS shall be planned sufficiently robust to allow for transmission of 100% of anticipated in-merit electric energy referred to in section 17(c) of the EU Act when all transmission facilities are in service\(^1\). That is, all anticipated in-merit generation must be able to deliver energy to the Alberta market recognizing the ATS must be operated in a manner that anticipates single contingency events as defined by the AESO’s Transmission Operating Criteria, the AESO’s operating procedures and WECC’s MORC (Minimum Operating Reliability Criteria).

The ATS shall be planned so that on an annual basis, at least 95% of all anticipated in-merit electric energy referred to in section 17(c) of the EU Act can be traded when operating under abnormal operating conditions\(^2\). Abnormal operating conditions include conditions where transmission facilities are out of service, emergency conditions exist, construction or commissioning of transmission facilities occur or situations when transmission facility maintenance cannot be coordinated with generation outages\(^3\).

3.2 Generation dispatch

For the purpose of determining ATS adequacy, generation will be dispatched according to the forecast merit order for the period of study. Non-dispatchable generation such as wind or run of river hydro will be assumed at its minimum or maximum seasonal output whichever is more onerous.

The transmission supply to each predominantly load area will be planned so that a Category B event will result in acceptable performance with the most critical generator out of service, for commercial or maintenance reasons, and with the system readjusted after re-dispatching the remaining generation according to the forecast merit order. The most critical generator out of service is the generation dispatch approach utilized in Alberta to assess the most onerous loading into any particular load area in an open market. This is often referred to as the N-G-1 criteria, where the system is normal, the most critical generator is out of service, the system is adjusted and a WECC defined Category B event occurs.

The most critical generator is the unit that will cause the greatest stress on the component of the ATS being studied. The most critical generator could include more than one generator if a second generator is dependent on the first to operate or if one system element (including a generator component) could result in more than one generator being unable to operate. The critical generating unit may be different under different study conditions and for different study areas. Category C and D events will be assessed with all generation available and dispatched according to the forecast merit order.

The transmission capability out of predominately generation surplus areas will be planned so that a Category B or C event will result in acceptable performance with maximum reasonable generation dispatch and with coincident minimum local load. Assessing the maximum reasonable generation dispatch shall take into account the maximum forecast coincident combination of maximum continuous rating (MCR), peak continuous rating (PCR) and contract levels.

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\(^1\) Electric Utilities Act, Transmission Regulation, s8(1), (e), (i).

\(^2\) Ibid., s8(1), (e), (ii).

\(^3\) Ibid., s1(1), (a).
3.3 Transmission must-run (TMR)

The AESO will consider specific and limited application of non-wires solutions to provide transmission capacity where:

a) in areas where there is limited potential for growth of load, and the cost of the non-wires solution is materially less than the life-cycle cost of the transmission wires solution, compared over an equivalent study period, or

b) on a temporary basis, if the non-wires solution is required to ensure reliable service due to the shorter lead time of the non-wires solution.

3.4 Interconnection with other jurisdictions

The ATS will be planned so that, under normal operating conditions, the transmission system interconnections with jurisdictions outside Alberta can import and export electricity on a continuous basis, at or near the transmission facility’s path rating.

The ATS will be planned so that imports over interconnections are not required in order to meet performance standards. See NERC/WECC Planning Standards Table 1 presented in Figure 4.1-1.

For assessing firm transmission capacity ratings, non-dispatchable generation such as wind or run of river hydro will be assumed at its most adverse seasonal output.

3.5 Opportunity service

The ATS will not be planned to provide for opportunity service.

The capability to enter into opportunity energy transactions will be measured with all generation available and dispatched in merit. Non-dispatchable generation such as wind or run of river hydro will be assumed at their most advantageous seasonal output. The system shall be capable of withstanding a Category B or C event with opportunity load shedding allowed.

It is recognized that opportunity service capability may be increased as a result of restoring transfer capability of the interties to their path ratings as described in Section 3.4.

4.0 Transmission planning reliability criteria

The ATS will be planned to meet the WECC Reliability Criteria and more specifically the NERC/WECC Planning Standards contained therein. Specific WECC guides and AESO standards also apply to planning the ATS. A summary of applicable documents can be found in Appendix A.

The WECC’s planning reliability criteria is titled the NERC/WECC Planning Standards as they are the NERC Planning Standards with additional requirements specific to the WECC. Many of the additional requirements result from the long distances between generation and load centers in the WECC as compared with other NERC regions.

The NERC Planning Standards apply to internal systems, while the WECC extensions to the NERC Planning Standards are only applied to external systems by the WECC unless otherwise stated either in the NERC/WECC Reliability Standards or herein.

The goal of the NERC/WECC Planning Standards is to ensure that there is an adequate transmission system where adequate is defined as “The ability of the electric systems to supply the aggregate electrical demand and energy requirements of their customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.”

For convenience, key aspects of the NERC/WECC Planning Standards are summarized in this document. For a full presentation of these criteria, refer to the full WECC Reliability Criteria.

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4 EU Act Transmission Regulation, s8(4).
5 Ibid., s8(1), (fg).
6 WECC NERC/WECC Planning Standards and Minimum Operating Reliability Criteria Definitions.
4.1 Normal and contingency conditions

Transmission systems are subject to a wide variety of conditions and events. Load, generation and interchanges are constantly changing in response to customer needs and the need for load and generation to balance instantaneously. The ATS extends over a wide geographic area and must operate though a wide variety of market, weather, maintenance and equipment outage conditions.

The NERC/WECC's Reliability Standards Table 4.1-1 on the following page titled “Transmission System Standards – Normal and Contingency Conditions” provides a definition of the categories of system events and acceptable response to these events. For convenience a summary of the four categories of events follows. For full details see Table 4.1-1.

Category A represents a normal system with no contingencies and all facilities in service. This is often referred to as the N-0 condition. The system must be able to supply all firm load and firm transfers to other areas. All equipment must operate within its applicable rating, voltages must be within their applicable ratings and the system must be stable with no cascading outages.

Category B events result in the loss of any single specified system element under specified fault conditions and normal clearing. The specified elements are a generator, a transmission circuit, a transformer or a single pole of a DC transmission line. This is often referred to as an N-1 event or with the most critical generator out of service, an N-G-1 event. The acceptable impact on the system is the same as Category A. Radial customers, including loads or generators, are allowed to disconnect from the system. The loss of opportunity load or opportunity interchanges is allowed.

Category C events result in the loss of one or more specified system elements under specified fault conditions and include both normal and delayed fault clearing events. When any two specified system elements are lost simultaneously, this is referred to as an N-2 event. All of the system limits for Category A and B events apply with the exception that planned, controlled loss of either firm load, firm transfers and/or certain generation is acceptable provided there is no cascading.

Category D represents a wide variety of extreme, rare and unpredictable events, which may result in the loss of customer demand (firm load) and generation in widespread areas. The system may not be able to reach a new stable state. These events need to be evaluated for risk and consequences. The WECC is currently drafting the “Extreme Contingency Guide” to provide additional guidance around this class of event.

This criteria applies to the system or path at its maximum load or loading condition based on the average MW flow over the highest load or path loading hour. Planned or controlled interruption of electric supply to radial customers or some local network customers, connected to or supplied by the faulted element or by the affected area, may occur in certain areas without impacting the overall security or the interconnected transmission system.\footnote{\textit{NERC/WECC: Planning Standards Table 1 page 25, footnote b).}}
### Figure 4.1-1 NERC/WECC planning standards

#### I. System adequacy and security

#### A. Transmission systems

#### Table I. Transmission systems standards – Normal and contingency conditions

<table>
<thead>
<tr>
<th>Category</th>
<th>Contingencies</th>
<th>Elements out of service</th>
<th>Thermal limits</th>
<th>Voltage limits</th>
<th>System stable</th>
<th>Loss of demand or curtailed firm transfers</th>
<th>Cascading outages (^a)</th>
</tr>
</thead>
<tbody>
<tr>
<td>A – No contingencies</td>
<td>All facilities in service</td>
<td>None</td>
<td>Applicable rating (^a) (A/R)</td>
<td>Applicable rating (^d) (A/R)</td>
<td>Yes</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>B – Event resulting in the loss of a single element</td>
<td>Single Line Ground (SLG) or 3-phase (3Ø) fault, with normal clearing: 1. Generator 2. Transmission circuit 3. Transformer 4. Loss of an element without a fault</td>
<td>Single</td>
<td>A/R</td>
<td>A/R</td>
<td>Yes</td>
<td>No (^b)</td>
<td>No</td>
</tr>
<tr>
<td>C – Event(s) resulting in the loss of two or more (multiple) elements</td>
<td>SLG Fault, with normal clearing(^c): 1. Bus section 2. Breaker (failure or internal fault) 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency 4. Bipolar block, with normal clearing(^c): 5. Any two circuits of a multiple circuit towerline(^d) 6. SLG fault, with delayed clearing(^c) (stuck breaker or protection system failure):</td>
<td>Multiple</td>
<td>A/R</td>
<td>A/R</td>
<td>Yes</td>
<td>Planned/controlled (^d)</td>
<td>No</td>
</tr>
</tbody>
</table>

\(^a\) Applicable ratings apply to A/R systems only.

\(^b\) Loss of demand or curtailed firm transfers may occur if system stability cannot be maintained.

\(^c\) Faults cleared by manual system adjustments followed by another fault.

\(^d\) Planned/controlled outages refer to the need for pre-notification and coordination for outages.

\(^e\) Thermal limits apply to A/R systems only.

\(^f\) Voltage limits apply to A/R systems only.

\(^g\) System stability is maintained.

\(^h\) Loss of demand or curtailed firm transfers may not occur if system stability can be maintained.

\(^i\) Manual system adjustments followed by another fault.

\(^j\) Bipolar block, with normal clearing.

\(^k\) Fault (non 3Ø) with normal clearing.

\(^l\) Manual system adjustments, followed by another fault.

\(^m\) Bipolar block, with normal clearing.

\(^n\) Fault (non 3Ø) with normal clearing.

\(^o\) Manual system adjustments, followed by another fault.

\(^p\) Bipolar block, with normal clearing.

\(^q\) Fault (non 3Ø) with normal clearing.

\(^r\) Manual system adjustments, followed by another fault.

\(^s\) Bipolar block, with normal clearing.

\(^t\) Fault (non 3Ø) with normal clearing.

\(^u\) Manual system adjustments, followed by another fault.

\(^v\) Bipolar block, with normal clearing.

\(^w\) Fault (non 3Ø) with normal clearing.

\(^x\) Manual system adjustments, followed by another fault.

\(^y\) Bipolar block, with normal clearing.

\(^z\) Fault (non 3Ø) with normal clearing.

\(^{**}\) Manual system adjustments, followed by another fault.
## Figure 4.1-1 NERC/WECC planning standards (continued)

### I. System adequacy and security

#### A. Transmission systems

#### Table I. Transmission systems standards – Normal and contingency conditions

<table>
<thead>
<tr>
<th>Category</th>
<th>Contingencies</th>
<th>System limits or impacts</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>D</strong> – Extreme event resulting in two or more (multiple) elements removed or cascading out of service</td>
<td>3Ø fault, with delayed clearing(^f) (stuck breaker or protection system failure): 1. Generator 2. Transmission circuit 3. Transformer 4. Bus section</td>
<td>Evaluate for risks and consequences.</td>
</tr>
<tr>
<td>D – Extreme event resulting in two or more (multiple) elements removed or cascading out of service</td>
<td>3Ø fault, with normal clearing(^g): 5. Breaker (failure or internal fault)</td>
<td>- May involve substantial loss of customer demand and generation in a widespread area or areas. - Portions of all of the interconnected systems may or may not achieve a new, stable operating point. - Evaluation of these events may require joint studies with neighboring systems.</td>
</tr>
<tr>
<td>Other:</td>
<td>6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of-way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large load or major load centre 12. Failure of a fully redundant special protection system (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant special protection system (or remedial action scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from disturbances in another Regional Council</td>
<td></td>
</tr>
</tbody>
</table>

Table footnotes:

\(a\) Applicable rating (A/R) refers to the applicable normal and emergency facility thermal rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable ratings may include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All ratings must be established consistent with applicable NERC Planning Standards addressing facility ratings.

\(b\) Planned or controlled interruption of electric supply to radial customers or some local network customers, connected to or supplied by the faulted element or by the affected area, may occur in certain areas without impacting the overall security of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted firm (non-recallable reserved) electric power transfers.

\(c\) Cascading is the uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread service interruption which cannot be restrained from sequentially spreading beyond an area pre-determined by appropriate studies.

\(d\) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment or contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission system.

\(e\) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

\(f\) Normal clearing is when the protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer (CT), and not because of an intentional design delay.

\(g\) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.
4.2 Maintenance standard for planning the ATS

The NERC/WECC Planning Standard requires that “… systems must be capable of meeting Category B requirements while accommodating the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.” The AESO intends to meet the above standard with the exception of Local Networks. Due regard will be given to the ability to reduce the area load by running generation out of merit or moving distribution connected load to adjacent supply sources. The bulk electric equipment considered is limited to transmission circuits, transformers and protection systems.

4.3 Facility design and interconnection

The AESO has established and posted standards for the interconnection of load and generation facilities. With time the range of facility design and other technical standards will increase and evolve. Appendix A summarizes the current standards and will be updated as new standards emerge.

4.4 System protection and controls

Remedial Action Schemes (RAS) or Special Protection Schemes (SPS) are designed for specific foreseen events and shed load or generation to preserve system integrity. They may be used when the cost of additional facilities are not warranted on a cost versus benefit evaluation, when facilities cannot be built in time, to shed opportunity loads or transactions, to increase operating limits beyond planning limits of system capacity, or when the frequency of the RAS triggering event is very low. The consequence of RAS failure must also be considered.

A RAS may be acceptable for an interim period to allow for generation or load interconnection pending completion of required transmission developments. Alternately, system conditions may be in transition whereby a transmission development may not be required in the longer term. The required system performance could be provided through the application of a RAS. Interim period, in this context, could be as long as it takes to complete the proposed transmission development. Good engineering and business judgment must be used when considering the benefits and risks of a RAS.

Safety net systems should be used to protect the system from events are more critical than Category B. They have a characteristic of protecting the system from many different events by sacrificing some firm load to protect the system from uncontrolled outages over wider areas and promote faster restoration of the system. It is recognized that safety nets will not effectively protect the ATS from all Category D events. Safety net systems may well protect the system in the event of a Category B or greater event under abnormal or emergency conditions. Underfrequency and undervoltage load shedding schemes are examples of safety nets.

Automatic reclosing systems can have a positive impact on system reliability and are widely applied. System studies must pay due regard for existing or proposed reclosing systems.

Single Pole Trip and Reclose (SPT&R) is used within Alberta and on the B.C. intertie to enhance availability of transmission circuits. Application of SPT&R may be used to enhance reliability but does not increase system capabilities to withstand Category B events as these events include three phase faults.

240 and 500 kV protection systems, in Alberta, are designed to higher standards with the view to increasing the speed of fault clearing, reducing protection failures and preserving security of the ATS and its interties.
4.5 Point of delivery (POD) criteria
The WECC Reliability Criteria accepts that individual PODs may be supplied via a single radial transmission circuit and single transformers. Outages of radial elements will result in the loss of firm and/or opportunity load.

The customer may make arrangements with the AESO for additional supply facilities, such as second transformers, additional supply transmission lines or additional distribution supply circuit breakers as desired by the customer for reliability, financial or other reasons. Commercial arrangements for these additions will be those that apply from time to time.

The parts of the system upstream from the dedicated supply facilities will be designed to meet the Reliability Criteria.

Refer to the AESO’s load interconnection standard for related design standards at www.aeso.ca

4.6 Point of supply (POS) and generation surplus area criteria
NERC and the WECC do not have a standard regarding the loss of generation other than the impacts they would have on the remainder of the system such as overloads, voltage stability and loss of firm load including non-recallable transfers.

Loss of generation is acceptable for outages to the radial elements of the ATS interconnecting the generator. New radial generator interconnections that will exceed the MW equivalent of the existing or planned largest single generation contingency shall be evaluated for impact on the ATS. Consideration shall be given to, but not be limited to, impact on interchange capacities, generation reserve requirements and system dynamic response.

In generation rich areas, RASs designed to achieve full generation output are not acceptable in the long term for Category B events. Due consideration shall be given to light load conditions.

Refer to the AESO’s generator interconnection standard for related design standards at www.aeso.ca

5.0 Performance standards
Performance standards relate to how the system responds to normal or contingency events and are measured in voltage or voltage change, thermal loading, stability or off frequency voltage limits.

5.1 Voltage standards
The ATS must be capable of steady state operation within acceptable voltage ranges during normal and abnormal conditions. In areas where there are concerns such as voltage stability or over voltages, more restrictive voltage ranges may apply. Table 5.1-1 on the following page summarizes the acceptable ranges of steady state voltage for each nominal voltage class. These classes are established to ensure that equipment in each nominal voltage range is specified according to a standard that allows for equipment standardization and interchangeability.
Table 5.1-1 Acceptable range of steady state voltage (kV)

<table>
<thead>
<tr>
<th>Nominal</th>
<th>Extreme minimum</th>
<th>Normal minimum</th>
<th>Normal maximum</th>
<th>Extreme maximum</th>
</tr>
</thead>
<tbody>
<tr>
<td>500</td>
<td>500</td>
<td>510</td>
<td>540</td>
<td>550</td>
</tr>
<tr>
<td>240</td>
<td>220</td>
<td>240</td>
<td>264</td>
<td>264</td>
</tr>
<tr>
<td>240</td>
<td>220</td>
<td>250</td>
<td>269</td>
<td>275</td>
</tr>
<tr>
<td>Ft. McMurray, Northwest</td>
<td>144</td>
<td>130</td>
<td>137</td>
<td>151</td>
</tr>
<tr>
<td></td>
<td>138</td>
<td>124</td>
<td>135</td>
<td>145</td>
</tr>
<tr>
<td>72</td>
<td>65</td>
<td>71</td>
<td>75</td>
<td>78</td>
</tr>
<tr>
<td>69</td>
<td>62</td>
<td>65</td>
<td>72</td>
<td>74</td>
</tr>
</tbody>
</table>

Extreme maximum voltages are voltages above which TFOs become concerned with exceeding maximum equipment ratings and high supply voltages to end use customers. The ATS must be capable of operating below the extreme maximum voltage following a Category B event on a reasonably expected system precondition.

Extreme minimum voltages are voltages below which TFOs may not be able to supply adequate voltages to end use customers. The ATS must be capable of operating above the extreme minimum voltage following a Category B event on a reasonably expected system precondition.

The ATS must be capable of operating within the extreme maximum and extreme minimum voltages as described above after adjustments have been made to generators, on load tap changer transformers and reactive compensation devices.

The normal maximum to minimum voltage range represent desired or typical operating voltages taking into account over and under voltage conditions at remote busses under normal and post contingency conditions.

The Fort McMurray and Northwest areas of the ATS were interconnected via long, lightly loaded 240 kV lines. The areas operated at higher voltages than the remainder of the 240 kV system and equipment was installed with higher voltage capability. These areas will continue to operate at higher level into the foreseeable future.

The standard summarized in Table 5.1-1 will not be applied retroactively. Equipment ratings must be respected by planning and operating the system to avoid overstressing legacy equipment. Legacy equipment may limit the ability to plan or operate the ATS to the extreme voltage limits.

While Table 5.1-1 presents acceptable steady state voltages after automatic and manual adjustments, Table 5.1-2 on the following page presents the acceptable post contingency voltage change limits for three defined post event time frames. This standard is used in conjunction with the “NERC/WECC Planning Standards Table 4.1-1.”

The “Low Voltage Bus” in Table 5.1-2 refers to the interface point between the ATS and load customers including distribution system supply points which are generally 25 kV or less. The voltage drop standards apply to Category B events while the voltage rise standards apply to events such as switching single system elements or Category B events.
Table 5.1-2 Acceptable post contingency voltages

<table>
<thead>
<tr>
<th>Parameter and reference point</th>
<th>Time period</th>
</tr>
</thead>
<tbody>
<tr>
<td>Voltage Deviation from Steady State at POD Low Voltage Bus</td>
<td>Post transient (up to 30s)</td>
</tr>
<tr>
<td></td>
<td>± 10%</td>
</tr>
</tbody>
</table>

For the purpose of this standard, the post transient period is the time up to 30 seconds after an event and generally prior to the automatic tap changing or switching operations. The post automatic control period is the time after the post transient period and before manual control and adjustments to the system are made. Post manual control is the period of time after system operators have been able to make manual adjustments to the system.

Following a Category B or C event, and after manual control adjustments, the ATS must be able to operate within the voltages defined in Table 5.1-2. In some cases variations from Table 5.1-2 are allowed and defined in AESO operating procedures or system design specifications.

5.2 Voltage stability criteria

Figure 5.2-1 below shows the power voltage curves for pre and post-contingency system conditions. This figure can be used as a guide to understanding and measuring the WECC voltage stability criteria.

The WECC voltage stability criteria states, “for load areas, post-transient voltage stability is required for the area modelled at a minimum of 105% of the reference load level for system normal conditions (Category A) and for single contingencies (Category B). For multiple contingencies (Category C), post-transient voltage stability is required with the area modelled at a minimum of 102.5% of the reference load level. For this standard, the reference load level is the maximum established planned load. Table 5.2-1 on the following page is taken from the WECC Voltage Stability Criteria, Undervoltage Load Shedding Strategy, and Reactive Power Reserve Monitoring Methodology dated May 1998 and summarizes the Power Voltage (P-V) and Reactive Power (V-Q) margin requirements.
### Table 5.2-1 Voltage stability criteria

#### WSCC voltage stability criteria

<table>
<thead>
<tr>
<th>Performance level</th>
<th>Disturbance</th>
<th>MW margin (P-V method)</th>
<th>MVAR margin (V-Q method)</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>Any element such as: One generator One circuit One transformer One reactive power source One DC monopole</td>
<td>≥ 5%</td>
<td>Worst case scenario (8)</td>
</tr>
<tr>
<td>B</td>
<td>Bus section</td>
<td>≥ 2.5%</td>
<td>50% of margin requirement in Level A</td>
</tr>
<tr>
<td>C</td>
<td>Any combination of two elements such as: A line and a generator A line and a reactive power source Two generators Two circuits Two transformers Two reactive power sources DC bipole</td>
<td>≥ 2.5%</td>
<td>50% of margin requirement in Level A</td>
</tr>
<tr>
<td>D</td>
<td>Any combination of three or more elements such as: Three or more circuits on ROW Entire substation Entire plant including switchyard</td>
<td>&gt; 0</td>
<td>&gt; 0</td>
</tr>
</tbody>
</table>

1. This table applies equally to the system with all elements in service and the system with one element removed and the system readjusted (see Section 2.2).
2. For application of this criteria within a member system, controlled load shedding is allowed to meet Performance Level A (see Section 2.2 for a description of provisions for application of this criteria within a member system).
3. The list of element outages in each Performance Level is not intended to be different than the Disturbance Performance Table in the WECC reliability Criteria. Additional element outages have been added to this table to show more examples of contingencies. Determination of credibility for contingencies for each Performance Level is based on the definitions used in the existing WECC base Reliability Criteria.
4. Margin for N-0 (base case) conditions must be greater than the margin for Performance Level A.
5. Maximum operating point on the P axis must have a MW margin equal to or greater than the values in this table as measured from the nose point of the P-V curve for each Performance Level.
6. Post-transient analysis techniques shall be utilized in applying the criteria.
7. Each member system should consider, as appropriate, the uncertainties in Section 2.3 to determine the required margin for its system.
8. The most reactive deficient bus must have adequate reactive power margin for the worst single contingency to satisfy either of the following conditions, whichever is worse: (i) a 5% increase beyond maximum forecast loads or (ii) a 5% increase beyond maximum allowable interface flows. The worst single contingency is the one that causes the largest decrease in the reactive power margin.

(*) Table 1 is an excerpt from the WSCC Reliability Criteria for Transmission System Planning in effect at the time of this document’s approval. The most current version of the Council's Table of Allowable Effects on Other Systems should be referred to when conducting studies.
5.3 Voltage swing criteria

The Voltage Swing Criteria as presented in the NERC/WECC Reliability Standard9, shall apply at both ends of the interconnections between the WECC and Alberta for Category B events. This criteria does not apply to other parts of the ATS.

The WECC voltage dip criteria require that “a single element outage in one system shall not cause a transient voltage dip in another system that is greater than 20% for more than 20 cycles at load buses, or exceed 25% at load buses or 30% at non-load buses at any time other than during the fault.” Figure 5.3-1 shows the typical voltage performance that manifests on interconnections between major systems such as the B.C. Tie. This figure provides guidance around interpreting the magnitude and duration of voltage swings in comparison to the criteria.

For faults on either system there is a voltage drop during the fault followed by a power and voltage swing on the path after the fault is cleared. In the extreme the swing will grow and the two systems will go out of synchronism. The protective relaying will monitor the condition and take the intertie out of service to prevent equipment damage or cascading outages of other system elements. This phenomenon, if not controlled, can lead to widespread system failures.

Table W-1 titled WECC Disturbance-Performance Table of Allowable Effects on Other Systems is included on the following page in Table 5.3-2. It summarizes the voltage swing effects that a system may have on another system for single contingency events.

Figure 5.3-1: Voltage performance parameters

---

9 Table W-1, WECC Disturbance-Performance Table of Allowable Effects on Other Systems.
Table 5.3-2 WECC Disturbance-Performance standard

I. System adequacy and security

<table>
<thead>
<tr>
<th>WECC Disturbance-Performance Table of allowable effects on other systems</th>
</tr>
</thead>
<tbody>
<tr>
<td>NERC and WECC categories</td>
</tr>
<tr>
<td>--------------------------</td>
</tr>
<tr>
<td>A</td>
</tr>
<tr>
<td>B</td>
</tr>
<tr>
<td>C</td>
</tr>
<tr>
<td>D</td>
</tr>
</tbody>
</table>

Notes:

1. The WECC Disturbance-Performance Table applies equally to either a system with all elements in service, or a system with one element removed and the system adjusted.

2. As an example in applying the WECC Disturbance-Performance Table, a Category B disturbance in one system shall not cause a transient voltage dip in another system that is greater than 20% for more than 20 cycles at load buses, or exceed 25% at load buses or 30% at non-load buses at any time other than during the fault.

3. Additional voltage requirements associated with voltage stability are specified in Standard I-D. If it can be demonstrated that post transient voltage deviations that are less than the values in the table will result in voltage instability, the system in which the disturbance originated and the affected system(s) should cooperate in mutually resolving the problem.
5.4 Thermal loading
The continuous thermal rating of any transmission element shall not be exceeded under normal operating conditions.

The emergency overload rating of any transmission element shall not be exceeded for a loss of one transmission element. The system shall be capable of returning to normal equipment load levels without the loss of load.

TFOs have the accountability for identifying the maximum loading that their equipment can safely withstand for various conditions.

5.5 Off-nominal frequency
Alberta complies with the WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Plan.

The WECC plan may be supplemented with additional load subject to underfrequency tripping to achieve specific performance goals.

Category B and C events or the loss of the B.C. Tie shall not result in a system frequency over 61.0 Hz. The overfrequency must settle to less than 60.3 Hz quickly enough to avoid uncoordinated generator tripping in Alberta.

5.6 Short circuit levels and circuit breaker capacities
Circuit breakers shall be capable of interrupting 100% of maximum short circuit duty that a circuit breaker could experience with all generation on and all system available.
6.0 Power system modelling

The AESO sponsors the Alberta Transmission Data Committee (TDC) whose role is to continuously improve the AIES model and validate the models against system performance. The TDC document titled “Transmission Modelling Data Requirements” is posted at www.aeso.ca.

6.1 System model

The ATS shall be modelled with as much accuracy as necessary to ensure that the response of the ATS to disturbances can be accurately determined and current and future short circuit levels can be assessed. The model shall include, but not be limited to, representations of generators, transmission lines, transformers, capacitors, reactors, power control equipment, control systems, loads and interconnections.

6.2 System load

The ATS will be designed to supply forecast peak load and peak flows based on a forecast of MWh/hour in a normal weather year.

There are elements or paths of the system that may need to be designed to accommodate peak loads that are substantially higher when measured over shorter durations.

The loads to be used for specific geographic areas are the expected forecast coincident peak loads for load areas.

The loads to be used for generation surplus areas may be the light or peak loads. The system shall be planned for the most onerous reasonable load and generation conditions.

The system will be planned to accommodate long-term firm contracts for interchanges to other jurisdictions.

Operational loads will be based on one-minute values unless otherwise stated.

6.3 Load model

Individual motors over 10 MW are modelled. Where an aggregate of motor loads is deemed to affect system performance the aggregated motors are modelled.

For dynamic studies, the remainder of the load is modelled using the WECC default model of 20% induction motor load with the remaining load of 100% constant current and 100% constant impedance for real and reactive components of AB load respectively. When a more accurate model is developed and correlated with system experience, the new model may be used for either the ATS or parts of the ATS.

For load flow studies a constant MVA model shall be used.
6.4 Clearing times

Studies shall be done with the actual or specified clearing times of existing systems whichever is slower. No intentional safety margins or time delays will be added. Table 6.4-1 presents a set of maximum clearing times for each voltage level. Systems where clearing times are slower than this standard shall be examined to ensure system security is not compromised.

Faster clearing times can be employed provided they are achievable and verified.

Table 6.4-1 Standard new system clearing times

<table>
<thead>
<tr>
<th>Nominal kV</th>
<th>Fast end cycles</th>
<th>Slow end cycles</th>
</tr>
</thead>
<tbody>
<tr>
<td>500</td>
<td>4</td>
<td>5 to 6</td>
</tr>
<tr>
<td>240</td>
<td>5</td>
<td>6 to 7</td>
</tr>
<tr>
<td>144</td>
<td>6</td>
<td>7 to 8</td>
</tr>
<tr>
<td>138</td>
<td>6</td>
<td>7 to 8</td>
</tr>
<tr>
<td>72 &amp; 69</td>
<td>No established standard</td>
<td></td>
</tr>
</tbody>
</table>

The intent of Table 6.4-1 is to indicate the maximum clearing times to be employed on additions to the system. Actual equipment ratings are used in system studies unless experience indicates otherwise.

These clearing times are intended to represent periods when short circuit levels are high due to generation dispatch patterns along with near to station bolted three phase or single phase faults.
Appendix A – Applicable criteria and guides

The following is a list of documents the AESO complies with or is guided by when planning developments to the ATS.

**AESO complies with:**

- EU Act and Transmission Regulation (The Government of Alberta, Queen’s Printer at www.qp.gov.ab.ca)
- HEE Act and regulations (The Government of Alberta, Queen’s Printer at www.qp.gov.ab.ca)
- WECC Reliability Criteria, including the NERC/WECC Planning Standard (The WECC at www.wecc.biz)
- WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Plan (Contact the WECC or AESO)
- ISO Rules and Operating Policies (The AESO at www.aeso.ca)
- Reliability Management System Agreement with the WECC (The AESO at www.aeso.ca)

**AESO uses the following guides:**

- Undervoltage Load Shedding Guide (The WECC at www.wecc.biz)
- Voltage Stability Criteria, Undervoltage Load Shedding and Reactive Reserve Monitoring Methodology (The WECC at www.wecc.biz)
- WECC Policy Regarding Extreme Contingencies and Unplanned Events (The WECC at www.wecc.biz)
- Transmission Data Committee – Transmission Modeling Data Requirements

**AESO applicable standards:**

- Alberta Interconnected Electric System Protection Standard (at www.aeso.ca)
Appendix D: AESO Transmission Reliability Criteria

Part III Operating Criteria

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1.0 Introduction

One of the responsibilities of the Alberta Electric System Operator (AESO) is the reliable operation of the transmission system. The AESO must direct the operation of the transmission system within defined capabilities and limits to achieve the desired level of reliability. A well-defined transmission operating criteria is required to guide the studies used to determine system limits as well as for the procedures to be used for day-to-day operation of the transmission system. The purpose of this document is to define the AESO transmission operating criteria.

The AESO transmission operating criteria must recognize not only the operating reliability needs within Alberta, but also the obligations that arise from being connected to other electric systems in North America. The criteria must also be compatible with the capabilities of the Alberta system and with the criteria used to plan the system (described in Part II).

This document begins with a review of pertinent reliability requirements for the operation of the interconnected system. The AESO transmission operating criteria is then described.

2.0 Background

The North American Electric Reliability Council’s (NERC) mission is to ensure that the bulk electric system in North America is reliable, adequate and secure. NERC has established operating policies and planning standards to ensure that the electric system operates reliably. NERC’s operating policies are based on the concept that “all control areas share the benefits of interconnected systems operation and, by their participation in NERC, they recognize the need to operate in a manner that will promote reliability in interconnected operation and not burden other interconnected Control Areas.” The operating policies place the responsibility for operating reliably primarily on the Control Areas that operate within the interconnected system. As operator of the Alberta Control Area, the AESO has the obligation to meet this responsibility for reliable operation.

NERC achieves its mission through its 10 regional councils. The Western Electricity Coordinating Council (WECC) is the Regional Council that coordinates and promotes reliable operation in the Western Interconnection. The Alberta system is part of the Western Interconnection. The WECC sets the reliability requirements for all entities that operate within the Western Interconnection. These requirements must meet the standards and requirements specified by NERC. The WECC requirements also include additional requirements specific to the Region and provide specific measures that meet NERC requirements. As a member of the WECC, the AESO chooses to meet the reliability requirements set by the WECC.

---

1 NERC Operating Manual, Preamble to Operating Policies.
2 In this document, capitalized terms are used to indicate terms defined by either NERC or WECC.
3.0 Overview of NERC operating policies

The NERC operating policies are described in the NERC Operating Manual\(^3\). The NERC Operating Manual consists of a number of policies that define operating Standards, Requirements, and Guides. All control areas are expected to adhere to the operating Requirements and Standards. The operating Guides are suggested operating practices that control areas may wish to consider, but they are not mandatory.

The NERC Operating Manual defines the following basic requirement for its operating standards and requirements:

“All Control Areas shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency.”\(^4\)

This is supplemented by the following requirement:

“Following a contingency or other event that results in an operating security limit violation, the control area shall return its transmission system to within operating security limits as soon as possible, but no longer than 30 minutes.”

The overall emphasis is that each Control Area is expected to take actions necessary so that problems within its system will not cause problems for neighbouring systems. Each Control Area may operate to single contingency criteria but, following a contingency, must take action so that it can sustain a subsequent contingency. NERC provides that radial and local networks allow loss of firm load for single contingencies provided that problems in those areas will not affect the overall security of the interconnected system.

The operating Standards and Requirements most relevant to the Alberta transmission operating criteria are described in the Operating Manual in the following sections\(^5\):

- Policy 2 – Transmission
- Policy 6 – Operations Planning

The operating Standards and Requirements generally describe the level of transmission system reliability performance expected from the Control Areas. However, they do not identify specific criteria to be used to meet those expectations. This provides each Region with the flexibility to develop requirements specific to their areas. For Alberta, the regional requirements are defined by WECC Standards and Requirements.

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\(^3\) The NERC Operating manual is available at [http://www.nerc.com/standards/](http://www.nerc.com/standards/)

\(^4\) NERC Operating Manual, Preamble, page I-1.

4.0 Overview of WECC operating policies

The WECC requirements for reliable operation are identified in a number of policy and procedure documents. The overall philosophy of the WECC requirements is very similar to the NERC operating requirements. It could be summarized as:

- A member system must be able to sustain a specified single contingency without loss of firm load.
- A system must also be able to sustain a specified multiple contingency (or another contingency after system adjustment following the first specified single contingency) without causing cascading outages on the interconnected system. Planned or controlled curtailment of load and/or generation can be used to achieve this requirement.
- Following any contingency, adjustments to the system must be made so that the system could sustain another specified single contingency. These adjustments could include curtailment of load and/or generation.
- The contingency response requirements are not required for radial customers or Local Networks, providing that there is no impact to the reliability of the Interconnection.

Since Alberta is part of the Western Interconnection and has chosen to comply with NERC and WECC Reliability Criteria, the WECC operating requirements are a major influence on the AESO transmission operating criteria. The following discussion is intended to highlight portions of the WECC operating requirements that should be carefully considered when defining the AESO operating criteria.

The primary reference for the reliability requirements for the operation of the Alberta system is the WECC Reliability Criteria. The Reliability Criteria identifies Standards, Measures and Guides to be used to achieve reliable operation on the interconnected system. The Standards and Measures are mandatory for all Control Area operators. They provide specific indication of the operating criteria to be applied. Guides provide further suggestions on appropriate practices, but they are not mandatory.

The Reliability Criteria consists of five parts. The parts most relevant (in order of priority) to the AESO transmission operating criteria are:

- Part III – Minimum Operating Reliability Criteria (referred to as MORC) and
- Part I – NERC/WECC Planning Standards
- Part IV – Definitions

These parts are discussed below. References to other pertinent policies and procedures are included in this discussion.

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6 The WECC Policies and Procedures can be accessed at [http://www.wecc.biz/docs_pubs.html](http://www.wecc.biz/docs_pubs.html) Many of the Policies are also included in the OC Handbook which is listed under Publications.
4.1 Part III – Minimum Operating Reliability Criteria

The MORC outlines the overall Requirements for reliable operation of the system. Section 2 – Transmission states the Basic Criteria for reliable operation. These basic criteria are similar to the NERC basic requirements. Extracts of the MORC basic criteria that are most pertinent to the AESO operating criteria are:

“Continuity of service to load is the primary objective of the Minimum Operating Reliability Criteria”,

“The interconnected power system shall be operated at all times so that general system instability, uncontrolled separation, cascading outages, or voltage collapse will not occur as a result of any single contingency or multiple contingencies of sufficiently high likelihood.”

and

“The necessary operating procedures, equipment, and remedial action schemes shall be in place to prevent unplanned or uncontrolled loss of load or total system shutdown.”

Section 2 – Transmission also indicates the requirements for voltage control on the interconnected system. It includes the concept of under voltage load shedding to avoid cascading. The requirements include:

“Operating entities shall assess the need for and install undervoltage load shedding as required to augment other reactive reserves to protect against voltage collapse and ensure system reliability performance criteria as specified in the WECC Disturbance-Performance Table of Allowable Effect on Other Systems7 are met during all internal and external outage conditions.”

Overall system stability requirements are defined in MORC Section 3 – Interchange, which indicate:

“The interconnected power system shall remain stable upon loss of any one single element without system cascading that could result in the successive loss of additional elements. The system voltages shall be within acceptable limits defined in the NERC/WECC Planning Standards. … loss of either single or multiple elements should not cause uncontrolled, widespread collapse of the interconnected power system.”

The MORC provides some specific directions for operations planning studies in Section 6 – Operations Planning. The criteria for studies are not stated in this section. Instead, the MORC refers to the criteria in the NERC/WECC Planning Standards. Section 6 states: “To be considered acceptable, operating study results must be in compliance with the WECC Disturbance-Performance Table8 within the NERC/WECC Planning Standards.” Section 6 also provides direction on the use of automatic load shedding and system sectionalizing as a method to avoid system collapse.

---

7 Table W-1 of the NERC/WECC Planning Standards, page 13.
8 See Part II Section 5.3.
4.2 Part I – NERC/WECC Planning Standards

This section is intended to illustrate the linkage between NERC/WECC Planning Standards and MORC.

Most of the NERC and WECC planning criteria applicable to operating purposes are indicated in Part I – NERC/WECC Planning Standards. In this document, WECC has merged its planning standards into the NERC Planning Standards. This conveniently places the NERC and WECC planning requirements into a single document. Section I of the Planning Standards deals with System Adequacy and Security. Two of the subsections – A. Transmission Systems, and D. Voltage Support and Reactive Power – are most relevant to the AESO transmission operating criteria.

The Standards and Measures in section I.A. Transmission define the criteria for operating studies. These criteria are conveniently summarized in Table I. Transmission System Standards – Normal and Contingency Conditions. This table summarizes operating conditions that must be met under four categories of operating situations:

- A – No contingencies (System Normal)
- B – Events resulting in the loss of any single specified element
- C – Events resulting in the loss of two or more (multiple) specified elements
- D – Extreme event resulting in two or more (multiple) elements removed or cascading out of service

The standards require all systems to be able to meet firm load and firm transfers following a single contingency event (Category B). It should be noted that this standard is not expected of radial customers and customers on a Local Network, provided that there is no impact to security of the interconnected system. Planned or controlled loss of firm load is permitted for the multiple contingency events (Categories C and D). Cascading outages (uncontrolled successive loss of system elements) that would affect the interconnected system are not permitted for Category B and C events.

In section I.A. Transmission, the WECC has added the requirements illustrated in Table W-1 WECC Disturbance-Performance Table of Allowable Effects on Other Systems. This table provides voltage and frequency deviation criteria for the various categories mentioned above. It is emphasized that these performance standards are not required internal to a member system.

The Standards required to avoid voltage instability and widespread system collapse are indicated in section I.D. Voltage Support and Reactive Power. The standards set requirements for all contingency levels described in Table I. This section promotes the use of P-V and V-Q analysis to ensure that appropriate reserves are available to maintain voltage stability. It suggests that undervoltage load shedding may be helpful in avoiding voltage collapse under Category C & D contingencies. The WECC provides two additional references to the support these standards. The Undervoltage Load Shedding Guidelines illustrate the need for automatic undervoltage load shedding to avoid cascading outages. The Voltage Stability Criteria, Undervoltage Load Shedding Strategy, and Reactive Power Reserve Monitoring Methodology provides detailed instructions on how to perform P-V and V-Q analysis to establish voltage reserve margins.

These policies illustrate the concept of a single contingency operating criteria supplemented with a backstop or Safety Net that enables the system to withstand more severe events. The WECC Policy Regarding Extreme Events and Unplanned Events reinforces this approach. It provides further information on Safety Nets and encourages the use of Safety Nets to reduce the severity of low probability and unforeseen events.

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9 Table I of the NERC/WECC Planning Standards, page 25, See Part II Section 4.1 for copies.
10 Local Network is defined in Reliable Criteria, Part IV Definitions.
11 See Part II Section 5.3.
5.0 AESO Transmission Operating Criteria

5.1 Overall philosophy of the AESO Transmission Operating Criteria

The AESO Transmission Operating Criteria is based on the WECC Reliability Criteria. In general, it adopts the requirements and standards identified by the WECC, and supplements them with requirements that recognize special situations on the Alberta system. Significant features of the AESO operating criteria include:

- The Alberta transmission system must be able to sustain any specified single contingency without loss of firm load with the exception of local networks and radial connected load.
- The Alberta transmission system must also be able to sustain a specified multiple contingency, or a subsequent contingency to the first contingency, without causing cascading outages on the interconnected system. Planned or controlled loss of load and/or generation may be used to achieve this requirement.
- Following any contingency, adjustments to the system must be made so that the system could sustain another contingency. These adjustments may include curtailment of load and/or generation.

5.2 Contingency criteria

The system response requirements to contingency conditions are defined by the WECC Reliability Criteria with most requirements appearing in Part I – NERC/WECC Planning Standards. These requirements are summarized in Table I. Transmission Standards – Normal and Contingency Conditions. This table illustrates the expected responses of the system to four categories of contingencies. These categories, which will be used in discussions in other sections, are:

- Category A – No contingencies (System Normal)
- Category B – Specified events resulting in the loss of a single element
- Category C – Specified events resulting in the loss of two or more (multiple) elements.
- Category D – Extreme event resulting in two or more (multiple) elements removed or cascading out of service

The NERC/WECC Planning Standards require that the transmission system must be able to sustain category B events without loss of firm or non-radial load and remain with the applicable ratings, prior to any operator adjustment. For application in Alberta, the applicable ratings immediately following a contingency are the emergency ratings. Operator actions are one of the options that may be required to bring the system within normal ratings. The required responses listed in Table I recognize that planned or controlled interruption of supply to radial customers or Local Network customers may occur in all contingency categories. This will apply to many situations in Alberta, and will be further discussed below.

The system response to Category C events must meet the same limits as required by Category B, except that planned or controlled loss of load and/or generation is permitted.

A fundamental operating requirement is that the system must be able to sustain any B or C contingency while avoiding cascading outages. Following any contingency, adjustments must be made to the system so that the next Category B contingency will not cause cascading. The use of the Safety Net concept is an important part of preventing cascading on the Alberta system.

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12 Table I is reproduced in Figure 4.1-1 (Part II Section 4.2).
13 Level D requires an evaluation of the risks and consequences. A party may choose to accept the consequences.
5.3 Application of the AESO Transmission Operating Criteria

The application of the contingency requirements to the Alberta transmission system is illustrated in Figure 5.3-1. Response to Contingencies. This diagram illustrates the desired response to WECC contingency categories under various operating conditions. The diagram also emphasizes the activities required to prepare for the next contingency.

As illustrated in Figure 5.3-1, the Alberta transmission system operating in the Normal state (all equipment in service) must be able to withstand a single contingency (Category B event) without cascading and without load curtailments. The system must continue to operate within all equipment limits. Operation of automatic Remedial Action schemes (RAS) may occur if part of the designed response. Following the contingency, action must be taken so that the system can sustain the next contingency and meet the response requirements shown for that contingency. A key requirement of this preparation is to ensure that another contingency would not cause cascading.

The required single contingency (Category B event) response when the transmission system is operating with one element out of service is also shown in Figure 5.3-1. This case is similar to the required contingency response for the Normal state in that the contingency must not cause cascading. However, it differs from the Normal state response in that some loss of load may occur. Operation of Safety Net devices such as undervoltage load shedding (UVLS) may also occur. Additional detail provided in Section 5.7.

The required contingency responses to Category C and D events are also shown in Figure 5.3-1. The diagram illustrates that either event could result in loss of load, generation, and/or interchange and that operation of Safety Net devices may occur. A Category C event must not cause cascading. Following either event, actions must be taken to prepare for a subsequent contingency.
Figure 5.3-1: Response to contingencies

Operating state

<table>
<thead>
<tr>
<th>Normal</th>
<th>One element out of service</th>
<th>Two or more elements out of service</th>
<th>Extreme events (two or more elements out of service)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Prepare for contingency</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Implement limits</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Single contingency (forced or maintenance) – Category B event</strong></td>
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<td></td>
<td></td>
</tr>
<tr>
<td><strong>Results in:</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>• No cascading</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>• No load loss</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>• No overload</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>• No voltage limit violation</td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>• Possible RAS operation</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Prepare for next contingency</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Limit import/export</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Curtail generation</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Dispatch TMR</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Shed load</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Single contingency – Category B event</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>• No cascading</td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>May result in:</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Generation curtailment</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Load shedding</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Import/export reductions</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Safety net operation</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Prepare for next contingency:</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Limit import/export</td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>• Curtail generation</td>
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<td></td>
<td></td>
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<tr>
<td>• Dispatch TMR</td>
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<td></td>
<td></td>
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<tr>
<td>• Shed load</td>
<td></td>
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<td></td>
</tr>
</tbody>
</table>
Figure 5.3-1: Response to contingencies (continued)

<table>
<thead>
<tr>
<th>Operating state</th>
<th>Normal</th>
<th>One element out of service</th>
<th>Two or more elements out of service</th>
<th>Extreme events (two or more elements out of service)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Multiple contingencies – Category C event</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>• No cascading</td>
<td></td>
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<tr>
<td>May result in:</td>
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<td></td>
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<tr>
<td>• Generation curtailment</td>
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<tr>
<td>• Load shedding</td>
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<tr>
<td>• Import/export reductions</td>
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<tr>
<td>• Safety net operation</td>
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<td></td>
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<tr>
<td>Prepare for next contingency:</td>
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<td></td>
<td></td>
<td></td>
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<tr>
<td>• Limit import/export</td>
<td></td>
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<tr>
<td>• Curtail generation</td>
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<tr>
<td>• Dispatch TMR</td>
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<tr>
<td>• Shed load</td>
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<td></td>
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<tr>
<td>Extreme – Category D event – May originate from any operating state</td>
<td></td>
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<td></td>
<td></td>
</tr>
<tr>
<td>May result in:</td>
<td></td>
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<td></td>
<td></td>
</tr>
<tr>
<td>• Generation curtailment</td>
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<tr>
<td>• Load shedding</td>
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<tr>
<td>• Import/export reductions</td>
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<td>• Safety net operation</td>
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<tr>
<td>Prepare for next contingency:</td>
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<tr>
<td>• Limit import/export</td>
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<tr>
<td>• Curtail generation</td>
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<tr>
<td>• Dispatch TMR</td>
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<tr>
<td>• Shed load</td>
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</tbody>
</table>
5.4 Local networks and radial supply

The AESO Reliability Criteria provides, as does WECC Criteria, for Local Networks. (Part II Section 4.1) The AESO will designate Local Networks, from time to time, as necessary. The following discussion provides some clarification on how the Radial Systems and Local Networks will be identified for application of the AESO Transmission Operating Criteria.

The determination of the Alberta transmission facilities that would be considered a Radial System is a straightforward application of the WECC definition. However, some clarification on how to designate Local Networks would be helpful. The WECC provides the following definition of Local Network:

“A Local Network (LN) is a non-radial portion of a system and has been planned such that a disturbance may result in loss of all load and generation in the LN.

1) The LN is not a control area.

2) The loss of the LN should not cause a Reliability Criteria violation external to the LN.”

This definition does not place any limit on the size or voltage level of the facilities that could be considered a Local Network except that the whole Alberta system (a control area) could not be considered as a Local Network. A key requirement of facilities designated as a Local Network is that outages within the Local Network must be contained within that network.

The AESO Transmission Operating Criteria uses the WECC definition for a Local Network. The primary consideration in designating a Local Network is that there must be the capability to contain any disturbance within that Local Network. This requirement may be achieved through the normal response of the network (depends on configuration) or special protection may be required. Consequently, the boundaries of a Local Network may change as the system is developed.
5.5 Safety nets

A fundamental aspect of the WECC Reliability Criteria (and the AESO Transmission Operating Criteria) is that all contingencies (except for Category D), or series of contingencies, must be controlled to prevent cascading of outages on the interconnected system. The WECC Policy Regarding Extreme Contingencies and Unplanned Events recognizes that "it is not feasible or even possible to predict or prevent all multiple contingency events. Therefore, Safety Nets are needed to minimize and reduce the severity of these low probability and unforeseen events to prevent cascading." Examples of Safety Net schemes include direct load tripping schemes, undervoltage load shedding schemes, and controlled islanding schemes. Although Safety Nets are intended to operate for extreme disturbances, portions of these Safety Nets may be used to prevent more likely disturbances from escalating into a more severe disturbance.

For many parts of the Alberta transmission system, the Safety Net concept is an important factor in providing capability to avoid cascading following multiple contingency events (as well as single contingency events for some Local Networks). Undervoltage load shedding can be a particularly helpful form of Safety Net for the Alberta transmission system.

The application of undervoltage load shedding to the Alberta system must be carefully designed. Alberta has a high proportion of industrial load that is sensitive to low voltage. Some of this load is protected with customer-owned devices that are set to meet customer needs. These low voltage protection settings may not be compatible with transmission undervoltage load shedding requirements. In order to prevent an excessive amount of load shedding, the transmission undervoltage scheme must recognize that some customer load may trip before the transmission scheme operates.

5.6 Limits

Table I. Transmission Standards – Normal and Contingency Conditions includes columns showing the various limits that should be applied for the various operating situations. These appear as "Applicable Rating" in the table. The following sections indicate the "Applicable Ratings" that will be applied by the AESO Transmission Operating criteria.

5.6.1 Thermal limits

The steady state thermal ratings, specified by the Transmission Facility Owners, (TFO) will be the Applicable Ratings during Category A conditions. Following a contingency (Categories B, C and D), the Applicable Ratings will be the Emergency Limits specified by the TFOs.

5.6.2 Voltage limits

The equipment voltage limits, for steady state and post-contingency situations will be provided by the TFOs.
5.6.3 Stability limits

Several types of limits will be recognized in this category:

- The limits defined by the NERC/WECC Planning Standards in Table W-1 WECC Disturbance-Performance Table of Allowable Effects on Other Systems\(^\text{16}\) will not apply to the ATS with the exception that it will apply to the BC 500 kV Tie.

- The limits will also recognize voltage stability limits as defined by the WECC report Voltage Stability Criteria, Undervoltage Load Shedding Strategy, and Reactive Power Reserve Monitoring Methodology. The limits indicated in Table 1 WECC Voltage Stability Criteria\(^\text{17}\) will generally apply to the Alberta system. Note that, as indicated by the table, controlled load shedding may occur within the Alberta system in order to meet these requirements. The AESO may identify Local Networks or Radial Systems where the voltage stability limits would not apply.

5.6.4 Point of delivery limits

In addition to the voltage limits described above, consideration must also be given to the impacts of contingencies and routine switching of transmission elements on the voltages at the transmission delivery points. The following table illustrates the limits on the voltage variations.

Table 5.6.4-1:

<table>
<thead>
<tr>
<th>Acceptable post contingency voltage deviation at low voltage bus</th>
<th>Time period</th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Voltage deviation from steady state at low voltage bus</td>
<td>Post transient (up to 30s)</td>
<td>Post auto control (30 sec to 5 min)</td>
<td>Post manual control (steady state)</td>
</tr>
<tr>
<td>± 10%</td>
<td>± 7%</td>
<td>± 5%</td>
<td></td>
</tr>
</tbody>
</table>

5.6.5 Frequency limits

Alberta complies with the WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Plan.

The WECC Plan is supplemented with additional underfrequency load shed to cover the loss of tie line at maximum import and loss of 2 large generating units at the same time.

Category B and C events or the loss of the BC Tie shall not result in a system frequency over 61.0 Hz. The overfrequency must settle to less than 60.3 Hz quickly enough to avoid uncoordinated generator tripping in Alberta.

\(^{16}\) Table W-1 is reproduced Part II Section 5.3 Figure 5.3-2.

\(^{17}\) This table is reproduced in Part II Section 5.2.
5.7 Operating criteria for maintenance conditions

The ATS will be planned to meet Category B performance standards during a planned maintenance outage of a single element, see Part II Section 4.2. This standard does not apply to Local Networks, areas of the system where meeting this standard is not deemed to be economic or prudent or areas where development does not yet meet the criteria.

All elements of the ATS must be maintained. To mitigate risks during maintenance the AESO has established a maintenance scheduling risk assessment process\(^{18}\) which includes the following:

- Choosing a time when loads are lower.
- Choosing a season when the impact of load loss is lower.
- Choosing a season (or day) when the contingency risks are lower.
- Coordinating with load or generation turnarounds.
- Consider live line maintenance techniques.
- Use of probabilistic analysis to evaluate various strategies that could be employed to reduce the contingency consequences.
- Coordination with other maintenance activities.

5.8 Revisions to the Transmission Operating Criteria

The AESO is responsible for revisions to the Operating Criteria. These revisions may occur, from time to time, in response to changing industry needs (particularly WECC and NERC), as well as to respond to changing conditions on the Alberta transmission system. As a minimum, the AESO Transmission Operating Criteria will be reviewed every five years.

\(^{18}\) The maintenance scheduling process is described in AESO Operating Policy and Procedure OPP 602.
Appendix E
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Appendix E
Generation Scenarios

This section presents the generation scenarios that are used in the development of the long-term transmission system plans. It is recognized that generation development in Alberta is a non-regulated, competitive business and it is not possible to definitively describe the timing and location of generation facilities 20 years into the future. As such, the AESO creates a range of generation scenarios against which the transmission system can be tested to identify where future reinforcements are required.

The generation scenarios are based on the transmission policy and market structure currently in place and the assumption that transmission is not a constraint in locating new generation. The generation scenarios do, however, anticipate future changes in the market related to environmental standards, technology development, increasing fuel costs and changing capital and operating costs.

Section 1.0 Key drivers: describes a number of key drivers that have an impact on the development of generation.

Section 2.0 Generation technology options: details the generation resources available for development in Alberta.

Section 3.0 Comparative costs of generation technology options.

Section 4.0 Generation scenarios: describes the generation scenarios to meet future capacity requirements.
1.0 **Key drivers**

There are many factors that affect generation developers' decisions regarding when and where new power plants are built in Alberta. These include: resource availability, the state of technology development, relative generation costs, environmental constraints, market structure, intertie capacity and the ability to finance projects in a competitive marketplace.

In Alberta, generation developers have diverse resources available for power projects including: coal, natural gas, hydro, wind, biomass and oilsands by-products. The availability and relative costs of the different resources and technologies are a key factor in generation development. These factors are investigated in more detail throughout Sections 3.0 and 4.0.

The future costs of greenhouse gas (GHG) emissions have an impact on the relative costs of generation. The impacts are disproportional, increasing the costs for fossil-fuel fired generation most heavily. GHG legislation and estimated costs to meet emission standards are incorporated into the relative costs calculated in Section 4.0.

While Alberta's energy-only market structure presents challenges for financing power generation projects that are high capacity and high capital cost types of investments, large projects remain viable options in the province.

The capability of interties with other jurisdictions is another important consideration for power generation developers. The Alberta Interconnected Electric System (AIES) is one of the least interconnected jurisdictions in Canada. Additional interties increase the ability for Alberta generators to sell surplus energy during off-peak periods. New interties also provide access to more sources of supply during on-peak periods. These benefits can promote generation investment in Alberta and reduce price volatility in the market.

Technology options, relative costs of generation and environmental factors are discussed in the following sections and considered in the development of the generation scenarios.
2.0 Generation technology options

Alberta has a variety of resources that provide generation development opportunities. This section describes these resources, focusing on the applicable generation technologies, the potential for development and location within the province. This information is one of the major inputs used in the development of the generation scenarios.

Hydroelectric power

Alberta has a total installed capacity of 869 megawatts (MW) of hydroelectric generation that represents seven per cent of the total installed capacity in the province.

Of this total, 789 MW was developed by Calgary Power (now TransAlta Corporation) at 13 different plants that were brought online between 1911 and 1972. The Bow River Hydro System comprises 11 individual plants on the Bow River and several of its tributaries located between Banff and Calgary. The Brazeau hydro plant is situated on the Brazeau River, southwest of Drayton Valley and the Bighorn hydro plant is located on the main stem of the North Saskatchewan River upstream of Nordegg. These plants operate largely in a peaking/reserve role on the system.

The remaining hydro capacity totals 80 MW, and is located at five separate plants ranging in size from the 7.2 MW Irricana project to the 32 MW Oldman River project. These relatively small hydro projects either do not have significant storage, or use the storage they do have primarily for irrigation during the summer months. All these plants operate at low capacity factors.

Whereas the existing hydro plants are on the North and South Saskatchewan and Bow River systems, which flow east and drain into Lake Winnipeg and then Hudson Bay, the potential for future hydro development is largely on the Athabasca, Peace and Slave Rivers, which flow north into the Mackenzie River and drain into the Arctic Ocean.

Two large hydro projects on the Peace/Slave system have been studied by project proponents in the past. The first is the Dunvegan project on the Peace River near its confluence with Hines Creek between Grande Prairie and Fairview. The site of the second project is on the Slave River near the boundary between Alberta and the Northwest Territories (N.W.T.).

A 900 MW hydroelectric project at the Dunvegan site on the Peace River was studied in the mid-1970s. However no further action was taken at that time. In 2000, Glacier Power applied for regulatory approval to develop a much smaller run-of-river project at the same site. The application was initially rejected but Glacier Power has received regulatory approval and continues to work towards implementing the project. The project would have an installed capacity of 100 MW and an average output of about 50 MW. Similar projects could potentially be built upstream of the site to the B.C. border.

A feasibility study of the Slave River Hydro Project sponsored by the Alberta government was completed in 1982. The study investigated alternative sites for development on the river between Fitzgerald, Alberta and Fort Smith, which is located immediately north of the Alberta/N.W.T. border.
The preferred alternative identified in the feasibility study included a dam located about a kilometre south of the Alberta/N.W.T. border. The installed capacity of this Slave River project proposal would be just over 1,800 MW at an estimated capacity factor of 56 per cent.

The authors of the feasibility study concluded that the Slave River project “…could provide an economically attractive source of power for Alberta”. However, shortly after the study was completed, economic and electric load growth slowed substantially and the project was not pursued. Project proponents in the private sector have initiated studies for a major hydroelectric project on the Slave River. Because of this potential for hydroelectric power development, northeastern Alberta is considered to be a renewable energy zone that would warrant future transmission to facilitate development of this valuable resource.

**Coal-fired generation**

Alberta has seven coal-fired power generation plants with a total installed capacity of 5,893 MW.

With the exception of the 143 MW H.R. Milner plant at Grande Cache, these power plants are located adjacent to open-pit surface mines that have been developed specifically to serve the power plants. The coal used typically has a heating value of 16 to 20 gigajoules (GJ)/tonne, and is low in sulphur, a significant amount having less than 0.3 per cent sulphur. The better reserves cost about $1/GJ to mine. The coal’s relatively low heating value has made it uneconomic to transport any distance with mine mouth power generation being its only significant use to date.

Alberta’s remaining coal reserves are estimated to be 34 billion tonnes, equivalent to 1,000 years of supply at Alberta’s current production rate of just over 30 million tonnes per year. A significant portion of the 34 billion tonnes of reserves can be mined using open-pit methods.

The coal-fired Keephills power plant is 70 km west of Edmonton.
These reserves form a large arc from northwest of Edmonton to southeast of Calgary, with coal quality declining from northwest to southeast. The best coal, and the greatest concentration of mine mouth power plants, are west of Edmonton where the Wabamun, Sundance, Keephills and Genesee power plants have a total installed capacity of 4,330 MW. The 664 MW Battle River and 756 MW Sheerness plants are to the southeast of Red Deer. These are all pulverized coal-fired plants.

The most recently completed coal-fired unit is Genesee 3, commissioned in March 2005, which includes a supercritical pressure steam cycle and clean air technologies to enhance operational and environmental performance. Keephills Unit 3, which is a similar design, is under construction with commissioning projected to be in 2011.

The higher efficiencies of these supercritical units reduce their coal consumption and carbon dioxide (CO\textsubscript{2}) emissions per megawatt hour (MWh) produced. Whereas subcritical units, such as units 1 and 2 at Keephills and Genesee, have CO\textsubscript{2} emissions of about one tonne/megawatt hour (MWh), the supercritical units are about 10 per cent lower at 0.9 tonnes/MWh. Ultra supercritical units, which achieve higher efficiencies and are starting to be built in parts of the world, further reduce CO\textsubscript{2} emissions to about 0.75 tonne/MWh.

Proposed federal environmental standards for coal-fired plants, as described in Appendix H, will require plants completed after 2012 to reduce CO\textsubscript{2} emissions by 2018 to those of an ‘integrated gasification and combined cycle (IGCC) plant with carbon capture’. This is equivalent to approximately 0.1 to 0.2 tonne/MWh and is far below emission levels that can be achieved with efficiency improvements alone.

Techniques for capturing CO\textsubscript{2} from large commercial coal-fired power plants are under development. The three principal techniques are:

- Pre-combustion carbon capture, which can be applied to an IGCC plant, is the basis of the proposed 2018 standard. The coal is gasified to produce a syngas comprising mainly of carbon monoxide (CO) and hydrogen. In a situation without capture, the syngas fuels the combined cycle plant. Carbon capture is achieved by using shift convertors to react the CO fraction of the syngas with water to produce hydrogen and CO\textsubscript{2}, which can be captured. The hydrogen is used to fuel the power plant and when burned produces water vapour.

- Post-combustion carbon capture, which can be applied to the pulverized coal-fired steam plants discussed above, involves removing the dilute CO\textsubscript{2} from the flue gases after combustion. The flue gas is passed through a solvent such as amines or chilled ammonia that absorbs the CO\textsubscript{2}. The CO\textsubscript{2}-rich solution is then submitted to a temperature and/or pressure change that releases the CO\textsubscript{2}, which in turn can be captured.

- Oxy-firing, which can also be applied to pulverized coal-fired steam plants, involves the combustion of coal in a mixture of oxygen and recirculated exhaust gas. This process results in an exhaust stream that has highly concentrated CO\textsubscript{2} that can be readily captured.
Once captured and compressed, the CO₂ can be utilized to enhance oil recovery by injection into a reservoir or enhance gas production by injection into coal seams. It can also be stored in geological formations such as depleted oil or gas reservoirs, deep coal formations that cannot be mined and deep saline aquifers.

Work on clean coal and carbon capture and storage (CCS) is ongoing worldwide with Alberta playing an active role.

- In September 2006, Alberta Energy Research Institute, Canadian Clean Power Coalition and EPCOR Utilities Inc. announced a $33-million, front-end engineering design (FEED) study research project to find the cleanest ways to generate power from coal including the removal of CO₂.
- In April 2008, Alstom International and TransAlta Corporation announced an agreement to work together to develop a large-scale CCS facility. The project will pilot Alstom’s proprietary chilled ammonia process at one of TransAlta’s coal-fired generating plants west of Edmonton and is expected to reduce current CO₂ emissions by one million tonnes per year.
- In July 2008, the Alberta government announced the creation of a $2-billion fund to advance CCS projects. Funds will be allocated to encourage construction of large-scale CCS projects that can be built quickly and will provide the best opportunities to significantly reduce GHG emissions.

The initiatives by the power companies combined with the offer of government funding for CCS make the continued installation of coal-fired generation in Alberta highly probable. The most likely locations for the new coal units are the existing sites capable of sustaining additional power plants, which include Keephills, Genesee, H.R. Milner, Sheerness and Battle River. It has been assumed that the Sundance power plant would continue to operate until 2027 either through life extension of existing units or replacement with equivalent capacity at the site. The most advanced greenfield coal-fired power plant is the proposed 1,000 MW Bow City project near Brooks.

The lead times of these plants will depend on progress in development of the CCS technologies, the success of the proponents in obtaining funding to install carbon capture in new plants and whether proponents install carbon capture at the outset or proceed with a carbon capture ready plant so that carbon capture can be added at a later date. The carbon capture ready approach would accommodate installing capture facilities when technologies are more mature, when regulations regarding GHG emissions are in place and would keep open the option of buying offsets rather than capturing CO₂.

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1 The additional unit at Battle River would be developed after the Battle River 3 and 4 units are retired; water requirements limit the ability to develop a new unit while the existing units are still operating.
**Natural gas**
Most of the 4,669 MW of gas-fired generation on the Alberta system has been added over the past 10 years. These gas-fired generation additions have been either simple cycle gas turbines, combined cycle plants or cogeneration plants.

**Simple cycle gas turbines**
Simple cycle gas turbines' short start-up time and ability to ramp up and down rapidly make them well suited for providing peaking capacity and operating reserves for the system. Historically, much of the peaking capacity and reserve on the Alberta system was provided by the hydro plants. With no major hydro additions since 1972, the retirement of the 628 MW Clover Bar plant in 2005 and removal of the 209 MW Rossdale plant from the energy market, the proportion of peaking capacity on the system has declined.

Close to 300 MW of simple cycle gas turbine capacity were expected to be added in 2008 with EPCOR Utilities Inc. installing 144 MW at its Clover Bar site in Edmonton. In northwestern Alberta, ATCO Power was adding 47 MW and Grande Prairie Generation Inc. was adding 99 MW. ENMAX Corporation was proceeding with a 120 MW simple cycle gas turbine at Crossfield just north of Calgary to be commissioned in 2009, and EPCOR Utilities Inc. was adding another 100 MW unit at the Clover Bar site by 2010. Other proponents also announced intentions to build simple cycle gas turbine plants at various locations in the province over the next few years.

**Combined cycle plants**
By utilizing the gas turbine's waste heat to generate electricity in a heat recovery steam generator, combined cycle plants can achieve efficiencies of greater than 50 per cent, which compares to 35 to 40 per cent for pulverized coal-fired plants and about 40 per cent for simple cycle gas turbines. This level of efficiency makes combined cycle plants competitive in mid-range, and in some instances, baseload operation. The higher efficiency, together with the higher proportion of hydrogen in natural gas compared to coal, results in CO₂ emissions of 0.4 tonne/MWh, which is substantially below coal plant emissions of 0.9 tonne/MWh.

In a constrained GHG environment, a combined cycle plant's relatively low CO₂ emissions could be addressed by buying offsets rather than installing carbon capture equipment. This lower environmental impact, together with a lower initial investment per kilowatt (kW) than coal and a greater choice of locations to site plants, makes combined cycle plants a viable source of generation at a time when future environmental regulations are still being developed. Offsetting these advantages is the uncertainty surrounding future natural gas prices.

TransCanada Corporation has proposed building a 350 MW combined cycle plant south of Calgary between Okotoks and High River with commissioning in 2011, and ENMAX Corporation has announced its intention to build an 800 MW combined cycle plant in southeast Calgary with commissioning in 2012.
Cogeneration

Cogeneration is defined as the simultaneous generation of electric power and thermal energy. Various configurations of power generation and heat production are possible, but the most common in Alberta is the combination of a gas turbine generating power with the waste heat used to produce steam or hot water for use in an industrial process. The use of the gas turbine’s waste heat in this manner leads to a very high operating efficiency for a cogeneration facility.

Oilsands extraction operations have substantial heat requirements and provide the opportunity to install cogeneration facilities with power output that exceeds the needs of the extraction and associated upgrading facilities. Some of the existing oilsands developments generate more power than their own needs, selling the surplus to the grid. However, recently developers have been focusing on the production of oil and generally sizing power facilities to meet only their own needs.

This practice is expected to continue in the short term but in the longer term it will be influenced by the high efficiency and low CO₂ emissions of cogeneration. In a GHG-constrained environment, possibly combined with less severe construction bottlenecks in Fort McMurray and Fort Saskatchewan and unconstrained transmission capability, increased cogeneration could become an additional source of power.

Modest growth in sales of gas-fired cogeneration to the grid is expected. Essentially, all these sales are anticipated to originate from the Fort McMurray and Fort Saskatchewan areas where industrial growth is expected to occur.

Oilsands by-products

OPTI Canada Inc. and Nexen Inc. are joint venture partners in the Long Lake Project, which is the first in Alberta to use an oilsands by-product to generate power both to meet its own needs and to sell to the grid. The project’s asphaltene gasification unit provides hydrogen to the hydrocracker and syngas, which is largely CO₂ for power and steam generation. Power generation will be sufficient for facility use with up to about 60 MW available for sale to the grid. The term polygeneration has been coined to describe plants such as Long Lake, which generate three or more products such as electricity, steam and hydrogen.

The likelihood of more projects similar to OPTI/Nexen’s will, like future gas-fired cogeneration sales to the grid, be influenced by oilsands developers’ priorities for natural gas use and power generation relative to oilsands extraction and upgrading.
Factors favouring this type of project include use of asphaltene or coke to displace natural gas and the opportunity to reduce CO₂ emissions at a relatively low cost. The CO₂ emissions from a gasification plant without capture are about 0.8 tonne/MWh, slightly below those of a pulverized coal plant. However, the incremental facilities required to convert the CO in the syngas to CO₂ (to be captured), and hydrogen (for firing the gas turbines) are less extensive and less costly than the facilities required to capture CO₂ from a pulverized coal plant.

Gasifiers are currently being planned as part of oilsands developments but the intent, for the most part, is to use the syngas and hydrogen produced in upgrading and refining processes rather than power generation. This practice reflects the current situation that hydrogen can add more value in the production of transportation fuels and petrochemicals than in the generation of power.

The use of oilsands by-products to generate power, as depicted in Figure 2.0-1, is expected to start during the 2008 to 2017 timeframe as gasification technologies mature and GHG emissions are more constrained. Sales to the grid would be from the Fort McMurray area, where there are significant stockpiles and ongoing production of coke, and from the Fort Saskatchewan area using by-products from the planned upgraders.

**Figure 2.0-1: Oilsands project with gasification**

Bitumen is extracted through mining or in situ methods. The bitumen is put through a series of processes that turn it into synthetic crude oil and syngas. The synthetic crude oil is then ready to be sold to the market. The syngas is used within the operation in the upgrading process to create steam and power or for other uses.
Wind power

Wind power in Alberta has seen substantial growth in the last few years. As of March 2008, Alberta had 497 MW of transmission-connected wind power from 10 wind farms. Wind power facilities provided approximately two per cent of the total energy consumed in Alberta in 2007. Wind power is an intermittent source of energy, but Alberta wind facilities have relatively high capacity factors, some reaching as high as 35 per cent.

Alberta was the first jurisdiction in Canada to develop wind interconnection standards and to conduct detailed studies on forecasting wind patterns.

The AESO's Market and Operational Framework for Wind Integration (MOF) forms the foundation for initiatives required to further refine and define rules, tools, and the Operating Policies and Procedures (OPPs) needed to integrate as much wind power into the Alberta system as is feasible without compromising system reliability or the fair, efficient and openly competitive operation of the market.

Alberta provides an attractive regime for future development of wind resources because of the market structure, significant wind resources and the AESO's forward-looking actions developed in consultation with wind industry stakeholders.
The Canadian government is providing financial incentives for power produced from renewable fuel sources, including wind power. The federal ecoENERGY for Renewable Power Program provides an incentive of one cent per kilowatt hour (kWh) for up to 10 years for renewable projects built between April 1, 2007 and March 31, 2011.

There is significant interest in the development of wind power projects in Alberta witnessed by the fact that as of August 2008 there was 11,500 MW of wind projects in the AESO’s interconnection queue. The AESO’s MOF allows market forces to determine the pace of wind interconnection assuming no transmission constraints exist. Section 4.6 in the transmission plan describes the AESO’s current and future transmission reinforcement initiatives to integrate wind in the South region of the province.

**Nuclear**

With 440 nuclear units currently in operation around the world, nuclear generation is positioned to address increased pressure to reduce GHG emissions.

The next generation of nuclear reactors is now being developed on many fronts. Atomic Energy of Canada Ltd. (AECL), AREVA SA, Westinghouse Electric Company and GE are all actively involved. Whereas the plants now in operation are in the 600 to 1,100 MW range, the new units will be larger.

In Alberta, Energy Alberta Corporation entered into an exclusivity agreement with AECL to market, own and operate CANDU units in Alberta, and in May 2007 announced it was proceeding with twin ACR 1000s in the Peace River area.

In March 2008, Bruce Power Alberta purchased the assets of Energy Alberta Corporation relating to nuclear power plant development and filed an application with the Canadian Nuclear Safety Commission to prepare a site in the Peace River area near Lac Cardinal for potential construction of western Canada’s first nuclear power plant of up to four reactors that could produce approximately 4,000 MW. Bruce Power Alberta subsequently withdrew its application due to the proximity to the Grimshaw Gravels Aquifer and is considering reapplying in 2009 for a site nearby.

In addition, small nuclear reactors could produce steam and electricity for oilsands projects. Generally, these small reactors are at an early stage of investigation and, if built, are likely to be sized for the primary purpose of meeting steam and electricity requirements rather than having significant power sales to the grid. The Government of Alberta has appointed a nuclear power expert panel which has provided a report on nuclear energy.
Other generation options

There are a number of other technologies that will likely be developed in Alberta over the next 20 years. These include other renewable technologies, micro-generators and waste heat generators. Energy storage capability may also be developed in the province.

Biomass power generation

Alberta currently has five biomass power facilities with a total capacity of 178 MW. Wood waste from pulp and saw mills is the primary fuel for biomass generation plants in Alberta, while a small amount of agriculture waste is also used for fuel. Wood fuel and other biomass resources are available in Alberta from the forestry industry (industrial and commercial wood residues) and the agricultural sector (crop and livestock waste). Generation from biomass is generally restricted to locations at the source of the fuel due to transportation costs.

Currently, there has been almost 200 MW of biomass projects announced to be in service by 2011. A large portion of the new biomass capacity will come from a plant to be constructed by Weyerhaeuser in the Grande Prairie area, while the remainder will be fuelled by the forestry industry, livestock operations and the agricultural-related food industry.

Both the provincial and federal governments are providing incentives to biomass-fired generation projects as renewable energy. The Alberta government is allocating funding to bioenergy projects through the Bio-refine Commercialization and Market Development Program and the Bioenergy Infrastructure Development Program. Both grant programs are part of the Alberta government’s $239-million Nine-Point Bioenergy Plan designed to encourage the growth of a clean, renewable fuel industry in Alberta. The federal government is providing financial incentives for power produced from renewable fuels sources, including biomass, through the ecoEnergy for Renewable Power Program.
**Storage capabilities**

Energy storage may play a role in managing fluctuations in power demand and supply in the future, particularly from variable energy supply sources such as wind. Large energy storage systems, such as pumped hydro and compressed air energy storage, can provide significant amounts of daily changes in supply and demand. During times when there is surplus, energy can be stored via these methods and released during times of high demand. Smaller energy storage systems, such as batteries and flywheels, may be able to provide voltage support or operating reserves.

Compressed air energy storage, as shown in Figure 2.0-2, could be used in Alberta given the extensive underground reservoirs and aquifers in the province. This method uses energy to pressurize and store air in reservoirs such as large salt caverns or depleted oil and gas wells.

**Figure 2.0-2: Compressed air energy storage in salt caverns**

A compressor uses energy during times of surplus supply to compress air and store it underground. When power is needed, the compressed air is preheated and mixed with fuel. This mixture is used by a turbine to create electricity. By using compressed air, the turbines operate more efficiently and require less fuel per MW of output.
Other renewable generation technologies

Generating electricity from renewable resources is becoming increasingly common as efforts to improve environmental performance continue to grow. Technologies such as solar generation, geothermal generation, generation from waste heat and micro-generation are all sources of electricity that could contribute to Alberta’s generation mix. Most of the technologies, with the exception of large biomass, wind and geothermal, are connected to the distribution system and would not directly have an impact on transmission system plans. To the extent that these technologies offset consumption, the effect will show as reduced load. Government policies at both the federal and provincial levels have provided incentives for producing energy from renewable sources.

Solar power

Alberta boasts 1,900 hours of sunshine in the northern half of the province, and 2,300 in the south, making it Canada’s sunniest province. There are a number of provincial initiatives underway to promote the development of solar power. Twenty municipalities are participating in the Alberta Solar Showcase, which demonstrates solar projects on highly-visible public buildings. ENMAX Energy Corporation has a Solar Demonstration Centre on the roof of its Calgary office building to test solar photovoltaic and solar thermal technologies for heating or domestic hot water. It is expected that the use of small-scale photovoltaic generation will increase in the 20-year timeframe.

EPCOR’s 4.8 MW Clover Bar Landfill Gas Facility in Edmonton is the first of its kind in Alberta to both recover methane and use it to generate electricity.
**Geothermal generation**

Geothermal power generation extracts steam and heat from the Earth's crust to power a steam turbine. This type of generation typically provides small quantities of reliable baseload power (up to 50 MW). Studies are underway to assess the potential for geothermal energy in Alberta. Based on preliminary research undertaken by the Institute for Sustainable Energy, Environment and Economy, Alberta has abundant geothermal resources, which could be developed once the technology is commercially available. The Canadian Geothermal Energy Association has estimated that Alberta and the N.W.T. have the combined potential of 500 MW to 1,000 MW of geothermal energy. The AESO will continue to monitor developments in this area.

**Figure 2.0-3: Geothermal power generation**

In geothermal power generation, natural steam from the production wells powers the generator. The steam is condensed in cooling towers and pumped down an injection well to sustain production.
**Waste heat**

Waste heat can be captured from industrial processes to create steam to power a turbine. Given Alberta’s industrial economy, small installations of this type of power generation may arise as overall energy efficiency becomes increasingly important. An example of this type of plant is the Cancarb Waste Heat Recovery Power Plant in the City of Medicine Hat. This plant is owned and operated by TransCanada Corporation and is able to produce 26 MW from the waste heat from the Cancarb carbon black facility.

**Micro-generation**

In Alberta, micro-generation is defined as being one MW or less that is connected to the distribution system and used to meet all or a portion of the customer's electricity needs.

Current technologies include photovoltaic, small-scale hydroelectric, wind power, biomass, micro-cogeneration and fuel cells. On February 1, 2008 the Alberta government enacted a regulation allowing Albertans to generate electricity through micro-generators and receive credit for any power sent to the grid. Interconnection standards and processes are being developed by distribution companies to simplify approvals and generation interconnection arrangements. Micro-generation will affect load and is not explicitly shown as a generation resource.

TransCanada’s Redwater Cogeneration Plant is a behind-the-fence generator providing electricity and thermal energy to an on-site industrial customer.
3.0 Comparative costs of generation technology options

The previous sections focus on the factors affecting developers' decisions to build new generating plants and the technology options available. To develop generation scenarios for use by the AESO's transmission planners, the relative cost of the different technologies is considered. This exercise is used to determine which technologies might be developed and is not a reflection of the overall merits of any specific generation project. Recognizing there is a great deal of uncertainty associated with some of the inputs, the relative costs are examined under various cases where there is a particular sensitivity to factors such as fuel cost and the cost of GHG offsets. Sensitivity calculations are aimed at confirming that the technologies selected in the various scenarios are reasonable.

Methodology

Each of the generation technologies discussed in the previous section has unique financial and technical characteristics. One method to incorporate the various characteristics and assess the relative economic merits of different generation technologies is to calculate the levelized unit electricity cost (LUEC).

The comparative cost represented by the LUEC is the constant electricity price required to cover all costs, including a specified rate of return, over the entire life of the project. Specifically, the LUEC is derived by using a discounted cash flow approach, which sets the present worth of revenue equal to the present worth of expenses, determining the constant price required to cover all expenses. The costs included in the calculation are capital, financing, operating and maintenance (O&M), fuel, emission, and taxes, giving a busbar cost that excludes transmission-related charges.

The assumptions used in the calculation of the LUEC are Alberta-specific based on public information adjusted through consultation with generation developers as well as industry stakeholders. A first draft of these estimates was prepared in November 2007 when the AESO's long-term planning process began. As additional information became available, the LUECs have been updated.
Selection of technologies
The LUEC calculation is undertaken for typical generation technologies that are likely to be developed in Alberta in the next 10 years. The six technologies examined in the LUEC analysis include:

- Simple cycle gas-fired turbine with a net capacity of 90 MW and a capacity factor of 10 per cent.
- Combined cycle gas-fired plant with a net capacity of 500 MW and a capacity factor of 60 per cent.
- High efficiency cogeneration plant with a net capacity of 85 MW and a capacity factor of 90 per cent.
- Supercritical pulverized coal (SCPC) plant without carbon capture at a brownfield site. It is assumed to be similar to the Genesee Unit 3, which has a net capacity of 450 MW. Its capacity factor is assumed to be 92 per cent.
- Coal-fired integrated gasification combined cycle (IGCC) plant without carbon capture at a greenfield site. It has a net capacity of 550 MW and a capacity factor of 80 per cent.
- Wind power generation with a net capacity of 100 MW and a capacity factor of 35 per cent.

The characteristics of the technologies assessed are listed in Table 3.0-1.

Table 3.0-1: Generation technology characteristics

<table>
<thead>
<tr>
<th></th>
<th>Simple cycle</th>
<th>Combined cycle</th>
<th>Cogeneration</th>
<th>Brownfield</th>
<th>SCPC</th>
<th>IGCC without capture</th>
<th>Wind</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capacity (net MW)</td>
<td>90</td>
<td>500</td>
<td>85</td>
<td>450</td>
<td>550</td>
<td>100</td>
<td></td>
</tr>
<tr>
<td>Heat rate (GJ/MWh)</td>
<td>9.8</td>
<td>7.1</td>
<td>10*</td>
<td>9.4</td>
<td>8.7</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Average capacity factor (%)</td>
<td>10</td>
<td>60</td>
<td>90</td>
<td>92</td>
<td>80</td>
<td>35</td>
<td></td>
</tr>
<tr>
<td>Emission intensity factor (t/MWh)</td>
<td>0.50</td>
<td>0.37</td>
<td>0.31</td>
<td>0.90</td>
<td>0.80</td>
<td>0</td>
<td></td>
</tr>
<tr>
<td>Project life (years)</td>
<td>25</td>
<td>30</td>
<td>30</td>
<td>35</td>
<td>35</td>
<td>30</td>
<td></td>
</tr>
</tbody>
</table>

* Includes energy used to create electricity and steam.
Cost components
The following section delineates the cost components of the levelized cost and summarizes the inputs and assumptions used. All costs are expressed in 2008 Canadian dollars and assume a 2008 construction start date for all technologies.

Capital cost and financing costs
The capital cost is the initial investment necessary to plan, permit, construct and start up a plant. These costs have risen dramatically in Alberta due to high commodity prices for energy, steel and other input materials, as well as the tight labour market. Since the publication of the last 10-year Transmission Plan in February 2007, brownfield SCPC capital costs have increased by 50 per cent, while IGCC and combined cycle capital costs have increased by over 60 per cent. Given the infancy of IGCC and other clean coal technologies, there is a high degree of uncertainty around their capital costs. Worldwide economic conditions in early 2009 have reduced the cost of labour and materials, but have made financing projects more difficult. Given the uncertainty, the comparative generation costs developed in 2008 are expected to yield reasonable scenarios.

Table 3.0-2 lists the 2008 overnight capital cost and construction time for the technologies. Overnight capital cost does not include the financing cost incurred during construction; rather, it is the cost of a construction project if no interest was incurred during construction, as if the project was completed overnight. The interest charges accumulated during construction are accounted for separately within the LUEC calculation.

Table 3.0-2: Generation technology overnight capital costs and construction time

<table>
<thead>
<tr>
<th>Technology</th>
<th>Simple cycle</th>
<th>Combined cycle</th>
<th>Co-generation</th>
<th>Brownfield SCPC</th>
<th>IGCC without capture</th>
<th>Wind</th>
</tr>
</thead>
<tbody>
<tr>
<td>Overnight capital cost (2008$/kW)</td>
<td>870</td>
<td>1,365</td>
<td>1,450</td>
<td>3,045</td>
<td>4,000</td>
<td>2,200</td>
</tr>
<tr>
<td>Construction time (years)</td>
<td>3</td>
<td>3</td>
<td>3</td>
<td>4</td>
<td>5</td>
<td>2</td>
</tr>
</tbody>
</table>

For the purposes of cost comparison, common assumptions are used for financing costs, recognizing that each project will have unique ownership structures and financial circumstances. It is assumed that all plants are financed 60 per cent by debt and 40 per cent by equity. The debt ratio is held constant during the construction year(s). It is assumed that the projects require a seven per cent rate of return on debt and a 15 per cent rate of return on equity. With a tax rate of 29.5 per cent, this implies a weighted average cost of capital (WACC) of nine per cent. The inflation rate used is two per cent over the lifetime of the project. For the first five years (2008 to 2013), the capital cost escalates at five per cent and then at two per cent thereafter.
Operation and maintenance costs

O&M costs for each of the technologies are shown in Table 3.0-3. Fixed O&M costs are reported in 2008 dollars per net kW of capacity per year. Variable O&M costs are reported in 2008 dollars per MWh. The operating capital required for technologies periodically throughout their lifetime is included in the fixed O&M costs. For all technologies, O&M costs are projected to remain constant, in constant dollars, during the entire economic lifetime of the plant.

Table 3.0-3: Generation technology operation and maintenance costs

<table>
<thead>
<tr>
<th>Technology</th>
<th>Simple cycle</th>
<th>Combined cycle</th>
<th>Co-generation</th>
<th>Brownfield SCPC</th>
<th>IGCC without capture</th>
<th>Wind</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fixed O&amp;M (2008 $/kW-yr)</td>
<td>12</td>
<td>13</td>
<td>13</td>
<td>31</td>
<td>41</td>
<td>56</td>
</tr>
<tr>
<td>Variable O&amp;M (2008 $/MWh)</td>
<td>4</td>
<td>4</td>
<td>4</td>
<td>6</td>
<td>7</td>
<td>–</td>
</tr>
</tbody>
</table>

Fuel costs

Fuel costs include all fuel supply costs at the power plant. Natural gas and coal are the only purchased fuels considered in the technologies investigated in this section.

The AECO-C gas forecast (see Figure 3.0-1) for the period 2008 to 2018 prepared in May 2008 by Sproule Associates Limited is used to calculate the cost of natural gas for the combined cycle, cogeneration and simple cycle gas turbine plants. After 2018, a constant escalation factor of two per cent per year is used. The LUEC for natural gas-fired power plants is sensitive to fluctuating natural gas prices. A sensitivity analysis related to the price of natural gas is presented at the end of this section.

Figure 3.0-1: Alberta AECO-C natural gas price forecast

The price for coal in Alberta for power generation is generally stipulated under long-term, cost-of-service arrangements and is relatively stable. Based on the available public information and discussions with generation developers, the coal prices at brownfield sites and greenfield sites are assumed to remain constant in real terms at an estimated $1/GJ and $1.7/GJ respectively.

As of May 31, 2008 forecast; http://www.sproule.com/prices/gas_escalated.htm
Greenhouse gas offset costs/credits

The environmental costs and credits related to GHG emission constraints will affect the costs of different generation technologies in different ways. Non-fossil fuel power plants could gain an economic advantage over fossil fuel power plants depending on the level of the constraints. Required emission intensity targets have evolved since the analysis for this Long-Term Plan began. The federal government first released its Federal Air Emission Framework in 2007. This initial framework was supplemented with additional information in March 2008. The additional information translated into stricter emission intensity requirements for coal-fired generation built after 2012. The original cost analysis was re-evaluated to incorporate this new GHG intensity information. This meant modifying the intensity targets for coal-fired plants starting in 2012 or later and increasing the offset price forecast used in the calculation to appropriately account for the higher demand. At the time of writing this report, no firm commitment had been made by the Government of Canada on how GHG emissions will be regulated.

All new facilities that come on stream before 2012 will need to meet what the federal government refers to as the tougher emission intensity standard. Generation plant owners have four options to meet emission intensity levels: actual emission reductions; purchasing offsets; for a limited time purchasing technology fund credits; and, purchasing limited quantities of Kyoto Protocol Clean Development Mechanisms. These projects must meet a cleaner fuel standard equivalent to the CO₂ emission intensity of supercritical technology for coal-fired generation, which is assumed to be 0.9 t/MWh, and combined cycle technology for natural gas-fired generation or 0.418 t/MWh as stated by Environment Canada. The projects will have a three-year grace period after commissioning, after which they will be required to meet the cleaner fuel standard with an additional two per cent continuous improvement to the emission intensity each year. Cogeneration facilities are exempt from the continuous improvement requirement.

New coal-fired generation commencing operation in 2012 or later will be required to meet an even lower CO₂ emission intensity standard. All plants will need to meet the standard of 0.9 t/MWh until 2018, after which the standard shifts to IGCC with CCS. Based on Environment Canada preliminary estimates, approximately 75 per cent of GHG emissions of coal-fired plants would need to be captured. This makes the emission intensity of IGCC with CCS approximately 0.2 t/MWh.

In all cases the AESO has assumed that generators purchase technology fund credits and GHG offsets to reach their required emission intensity. The cost of technology fund credits is defined by the federal government at $15/tonne until 2013, after which the price increases to $20/tonne, increasing at the rate of gross domestic product (GDP) each year thereafter. The cost of future offsets is uncertain; this uncertainty will remain as the policies and legislation on GHG emissions continue to develop. As a starting point, the offset price forecast from Environment Canada, as presented in Figure 3.0-2, is used³. Environment Canada estimates the cost per tonne of GHG will increase from $25 in 2010 to $65 in 2018. After 2020, prices are assumed to grow at the rate of GDP or 2.4 per cent per annum. The sensitivity of coal-fired generation costs to GHG costs is investigated with alternative GHG offset price forecasts at the end of this section.

The GHG credits for renewable power in Alberta are uncertain at this time and assumed to be the emission intensity rate of combined cycle natural gas turbine technology or 0.418 t/MWh. These credits are assumed to continue over the operating life of the facility.

Figure 3.0-2: GHG offset price forecast

Source: Environment Canada

Genesee Unit 3 features the first-time use of supercritical combustion in Canada. Genesee 3 is co-owned by EPCOR and TransAlta Corporation.
Summary of levelized unit electricity costs

The LUECs are presented in Figure 3.0-3 by cost components: capital cost, O&M cost, fuel cost, GHG offset cost and taxes. The LUECs for the existing commercial technologies (cogeneration, SCPC, wind, combined cycle) are within a $24/MWh range of each other, implying that the continued development of all of these technologies is a reasonable conclusion to use in developing generation scenarios.

Cogeneration, SCPC built prior to 2012, and wind generators are all competitive generation options with a LUEC of about $70/MWh. However, the ranking of SCPC changes for projects built after 2012 due to additional emission requirements.

Cogeneration units are estimated to have the lowest LUEC at $68/MWh. This is due to their high efficiency, emission credits and steam revenue. In the case of cogeneration, both steam and electricity costs are included in the LUEC calculation. The steam is considered to be sold as a source of revenue and is deducted from the fuel cost. The price of steam is estimated to be 60 per cent of the cost of producing steam from a natural gas-fired once through steam generator, averaging $7/GJ. The actual cost of steam from specific cogeneration units is determined through contractual agreements, and has an impact on the cost of electricity from the cogeneration plant. The decision to develop cogeneration within an industrial process is also dependent on factors other than cost. These include operational complexity, increased capital costs, natural gas consumption and contractual agreements.

The LUEC of SCPC at greenfield sites is generally 20 per cent higher than at brownfield sites due to a higher capital cost and the higher fuel cost associated with a new mine and other infrastructure.

The additional emission intensity reduction requirements for coal-fired plants built after 2012 increase the SCPC LUEC to $92/MWh, a 31 per cent increase. In this calculation it is assumed that a developer is able to purchase offsets to achieve 0.2 t/MWh (the IGCC with CCS emission intensity level), increasing the total GHG offset cost from $8/MWh to $29/MWh.

Figure 3.0-3: Comparative levelized generation costs

<table>
<thead>
<tr>
<th></th>
<th>LUEC (2008$/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Capital costs</td>
</tr>
<tr>
<td>Cogeneration</td>
<td>$68</td>
</tr>
<tr>
<td>SCPC*</td>
<td>$70</td>
</tr>
<tr>
<td>Wind</td>
<td>$71</td>
</tr>
<tr>
<td>Combined cycle</td>
<td>$89</td>
</tr>
<tr>
<td>SCPC**</td>
<td>$92</td>
</tr>
<tr>
<td>IGCC w/o capture</td>
<td>$112</td>
</tr>
<tr>
<td>Simple cycle</td>
<td>$216</td>
</tr>
</tbody>
</table>

* In service prior to 2012
** In service after 2012

Numbers may not add due to rounding.
Wind power facilities have relatively high capital costs, no fuel costs and are expected to receive GHG offset credits. The LUEC of $71/MWh includes the application of emission credits. If wind power projects receive an ecoENERGY\textsuperscript{4} grant, this further reduces the LUEC to $66/MWh.

The LUEC for combined cycle generation is $89/MWh. A high portion of the overall cost is due to the cost of fuel.

IGCC power plants built after 2012 without carbon capture have a LUEC of $112/MWh. The high capital costs of this technology contribute to the higher LUEC. IGCC has a slightly lower emission intensity than SCPC and thus a lower GHG offset obligation ($24/MWh versus $29/MWh).

For simple cycle gas turbines, the LUEC is higher than other generation options because of the assumed capacity factor of 10 per cent. Even with a high LUEC, peaking units are still expected to be built to capture scarcity pricing and provide ancillary services.

**Sensitivity analysis**

Sensitivity calculations are used to determine the impact of changes to the assumptions used to calculate the LUEC of different generation technologies. The goal is to confirm that their inclusion in the generation scenarios is reasonable.

For coal-fired generators such as SCPC and IGCC in service after 2012, sensitivity to GHG emission costs is considered. The costs of CCS technologies are also included. For combined cycle gas-fired generators, the impacts of changes to capacity factors and natural gas prices are examined.

**Coal-fired generator emission cost sensitivity**

Coal-fired generation is most affected by GHG emission cost assumptions because of the relatively high CO\textsubscript{2} emission levels per MWh.

Future GHG offset prices are uncertain. The sensitivity of coal-fired generation costs to a high and a low case for GHG offset costs was investigated. A 30 per cent decrease in the GHG offset price shown in Figure 3.0-2 drops the LUEC of SCPC generation from $92/MWh to $84/MWh and the LUEC of IGCC from $112/MWh to $105/MWh. A 50 per cent increase in GHG offset price increases the SCPC LUEC to $109/MWh, while the IGCC LUEC increases to $125/MWh. These results are shown in Figure 3.0-4.

This analysis assumes that developers of coal-fired plants built after 2012 will be able to purchase offsets to meet the required emission intensity. If this is not the case, new coal-fired plants built after 2012 will need to incorporate CCS into their projects.

Adding carbon capture to an SCPC plant eliminates the GHG offset costs and could increase the LUEC to $105/MWh, a 65 per cent increase to the costs (excluding GHG offsets) shown in Figure 3.0-3. Similarly, adding carbon capture to an IGCC plant would increase the LUEC by about 33 per cent to $116/MWh. These values are plotted in Figure 3.0-4 beside the LUEC range for variations in GHG offset prices. The results indicate that, even with the uncertainty of the key cost components, it is reasonable to continue to include coal-fired generation in the scenarios.

\textsuperscript{4} ecoENERGY credit is available for wind farms commissioned between April 1, 2006 and March 31, 2011. The program provides an incentive of one cent per kwH for up to 10 years. The maximum contribution payable per project is $80 million.
Combined cycle generator capacity factor and fuel cost sensitivity

The LUEC for combined cycle units is most sensitive to changes in two parameters: capacity factor and fuel cost. As the capacity factor (CF) of a combined cycle unit increases to a baseload level, the LUEC decreases, reaching $82/MWh at an 80 per cent capacity factor. In addition, for each of the capacity factors, a range of natural gas prices is analyzed. The results are presented in Figure 3.0-5. The LUEC is calculated for a natural gas price forecast 50 per cent higher and 30 per cent lower than the base forecast presented in Figure 3.0-1. Overall, the LUECs for these sensitivities range from $65/MWh to $116/MWh. While the relative ranking for combined cycle generation might change, the analysis confirms that the technology is a reasonable option for the generation scenarios.

Figure 3.0-4: Sensitivity of LUEC of coal-fired generation to GHG offset price and carbon capture and storage costs

Figure 3.0-5: Sensitivity of natural gas combined cycle LUEC to capacity factor and natural gas price
4.0 Generation scenarios

To provide an outlook of the future transmission system required in Alberta, information about the size, location and type of future generation that may develop in the province is required. Generation development is a competitive business, which makes forecasting the timing and location of new generation challenging. In recognition of this challenge, the AESO creates a range of generation scenarios against which the transmission system is tested to identify where system reinforcement could be required to meet future need.

The generation scenarios are used as input to the Long-term Transmission System Plan and to ensure the transmission system is adequately planned to provide reliable power to Albertans and to facilitate the competitive electricity market.

The following section discusses the generation scenarios as well as the methodology and rationale used in their development.

Generation reserve margin

Since generation of electricity is a competitive business in Alberta, the amount of generation developed in the province is determined by market participants based on market signals. There is no adequacy reserve margin requirement defined by an authoritative body in Alberta.

The AESO expects that the market will continue to send the appropriate signals to generation developers, motivating them to develop additional supply in the province as it is required.

The AESO uses a reserve margin as a proxy for the amount of generation added to the system due to market signals. Based on the information presented in Appendix F, an effective reserve margin of 10 per cent is considered appropriate for the purposes of estimating the generation capacity that will be installed to meet total Alberta peak load.

The term effective generation capacity is used to denote the capacity available to serve peak load. It is determined by taking the maximum continuous rating (MCR) of the existing generation and derating wind and hydro capacity. The derates applied to wind and hydro capacity to calculate the reserve margin remain unchanged from those used in the AESO’s 2007 to 2016 10-year Transmission System Plan issued in February 2007. Wind and irrigation hydro are derated to 20 per cent of total capacity, legacy hydro is derated to 67 per cent of total capacity and new hydro is derated to 50 per cent of capacity. Wind is derated to a level that approximates the capacity of other generating technologies that will not be installed in the competitive market due to the addition of the wind generation. As an example, if 100 MW of wind capacity is added to the system it is assumed that 20 MW of other generation will not be built.

The effective reserve margin of 10 per cent is approximately equivalent to a 20 per cent installed reserve if generation is not derated, and a 30 per cent reserve if interties (950 MW) are included. Based on this effective reserve margin and forecast load, effective generation capacity in Alberta will increase from 11,500 MW today to 15,500 MW by 2017 and 20,700 MW by 2027, as shown in Figure 4.0-1.
Table 4.0-1: Alberta system forecast effective generation capacity

<table>
<thead>
<tr>
<th></th>
<th>Effective generation capacity (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2007</td>
</tr>
<tr>
<td>Alberta Internal Load peak demand</td>
<td>9,710</td>
</tr>
<tr>
<td>10% reserve</td>
<td>971</td>
</tr>
<tr>
<td><strong>Expected effective generation capacity</strong></td>
<td><strong>10,681</strong></td>
</tr>
<tr>
<td>Total existing effective generating capacity</td>
<td>11,435</td>
</tr>
<tr>
<td>Retirements</td>
<td>0</td>
</tr>
<tr>
<td><strong>Net effective generating capacity after retirements</strong></td>
<td><strong>11,435</strong></td>
</tr>
<tr>
<td>Total effective generating capacity over/under expected amount</td>
<td>754</td>
</tr>
</tbody>
</table>

**Required generation additions**

The load forecast with the 10 per cent effective reserve margin, as presented in Figure 4.0-1, provides an estimate of the total effective generation capacity that will be installed over the next 20 years. This forecast is compared to existing effective generation capacity to determine the amount of generation additions expected for Alberta. The existing effective generation capacity excludes intertie capacity and incorporates future retirements and derates to intermittent generation. Retirements of the following units are included in determining the effective generation capacity in future years:

- Units retired by 2017:
  - Rossdale 8, 9, 10 (209 MW)
  - Wabamun 4 (279 MW)
  - Rainbow 1, 2, 3 (87 MW)
  - Sturgeon 1, 2 (18 MW)

- Units retired by 2027:
  - Battle River 3, 4, 5 (664 MW)
  - Sheerness 1, 2 (756 MW)
  - H.R. Milner (143 MW)

**Figure 4.0-1: Expected effective generation capacity**

![Expected effective generation capacity graph](image)
The difference between the expected effective generation capacity and the existing effective generation capacity equals the amount of generation that will be added to the market. Based on the calculation shown in Table 4.0-1, Figure 4.0-2 shows the existing effective generation capacity and the expected effective generation capacity that will be installed on Alberta’s system. By 2017 the amount of effective generation additions required is expected to be 5,000 MW and by 2027 it is expected to be 11,500 MW. Over the next 20 years the generation capacity is expected to almost double from what it was in 2008.

Figure 4.0-2: Contribution of installed capacity to expected effective generation capacity

*Existing effective irrigation hydro is below 10 megawatts in all years.
**Generation scenarios**

Given the amount of generation that is required to be added to the system over the next 20 years, the AESO created a number of reasonable generation scenarios against which the transmission system can be tested to identify where reinforcement is required. The AESO expects that existing generation technologies will continue to be developed in the near term. Technology advancement will provide additional generation options later in the 20-year planning horizon. Figure 4.0-3 shows the general location and type of generation potential in Alberta. The relative costs of a number of these technologies are estimated in Section 3.0.

Given the assessment of coal resources in Alberta as outlined in Section 2.0 and, in particular, the significant coal resources located in the Wabamun Lake area near Edmonton, there continues to be a significant potential for coal generation development in that part of the province. There are adequate coal resources to support further developments at other brownfield coal sites, specifically Battle River and H.R. Milner. The two greenfield coal sites that have been investigated in depth are Bow City north of Brooks and Dodds-Roundhill east of Camrose. The Dodds-Roundhill site is shown as combined cycle in Figure 4.0-3. Cogeneration, combined cycle and simple cycle gas turbines all remain as possibilities for new generation. Cogeneration capacity will likely continue to increase in the oilsands industry. The flexibility of combined cycle and simple cycle gas turbine generation provides opportunities in both the energy and ancillary services markets and presents options for the market to address the variability of increasing wind capacity in Alberta.
Figure 4.0-3: Potential location and type of future generation resources

- Coal
- Hydro
- Wind
- Nuclear
- Cogeneration (gas and oilsands by-products)
- Combined cycle and simple cycle gas turbine
- Biomass

Locations:
- Fort McMurray
- Grande Prairie
- Calgary
- Red Deer
- Medicine Hat
- Lethbridge
- Edmonton
- Buthanion
- Grande Prairie
The upgrading segment of the oilsands industry is currently producing low value by-products that can be used for power generation. The cogeneration and polygeneration options would be project-specific and optimally configured on a site-by-site basis depending on the value of the various products. These oilsands by-products are not expected to be shipped a substantial distance, and as such, generation development would likely be close to upgraders.

The combination of Alberta's competitive electricity market, a potential GHG offset market and wind resources triggers significant interest in wind power development in Alberta. The existing wind generation is located in the southern part of the province. It is expected that wind developers will continue to expand capacity in southern Alberta; however, additional wind resources are also being investigated by developers in other areas of the province as indicated in Figure 4.0-3.

In the longer term, 10 years and beyond, there is potential for the development of nuclear power in Alberta as well as large-scale hydro development. Public consultation, environmental approval and construction time put these options past 2017. Potential hydroelectric locations are discussed in Section 2.0.
Given the information on potential generation resources and the relative costs of generation, five generation scenarios were created. These scenarios represent a reasonable range of future developments to comprehensively test the transmission system for planning purposes. The AESO expects an additional 5,000 MW of effective generation capacity by 2017 and 11,500 MW by 2027. This defines the magnitude of the generation scenarios.

As a basis for developing the scenarios, it is assumed that within the next 10 years, significant generation additions are expected to be composed of SCPC, combined cycle gas units, simple cycle gas turbine units, cogeneration units and wind power. This assumption stems from the commercial availability of the technologies and the long lead time for other existing technologies such as nuclear and large hydro. Over time, clean coal technologies will develop and allow for ongoing development of available coal resources. From 2018 to 2027, technology improvements and the value of GHG emissions will drive generation development to large hydro, nuclear, coal-fired plants with pre- and post-combustion removal of CO₂, wind, combined cycle and cogeneration.

Two different views of the future were considered in the creation of the generation scenarios, a business-as-usual (BAU) case (scenarios A1 and A2) and an environmentally-driven case (scenarios B4 and B5). Each case has characteristics that increase the likelihood of a particular generation scenario developing in Alberta. These characteristics include GHG emission constraints, technology development, future natural gas prices, oilsands development and other environmental constraints. As shown in the comparative cost analysis, the factors that have the greatest impact on relative generation costs are GHG costs and natural gas prices.

In the BAU case, generation development over the next 10 years continues in a manner similar to what has occurred in the past. Large coal plants are added to the system with gas-fired, wind and other generation added as required to fill the supply gaps between the large additions. This case could occur under three possibilities: 1) GHG costs remain relatively low, 2) natural gas costs are high enough to offset the GHG costs for coal, or 3) clean coal technologies make significant advancements. These possibilities all allow for continued development of Alberta’s coal resource for power generation. Scenarios A1 and A2 could both be developed in this type of situation. In the first 10 years, scenarios A1 and A2 both include the addition of three large coal plants, cogeneration, simple cycle gas turbines and wind generation. They differ in that scenario A1 includes the addition of a fourth large coal unit, whereas scenario A2 includes the development of a petroleum coke gasification cogeneration plant in the Fort Saskatchewan area.

From 2018 to 2027, under the BAU case, it is assumed that environmental concerns surrounding GHG emissions will warrant the development of longer lead time low emission hydro and nuclear projects. There will also be the continued development of coal, combined cycle, simple cycle gas turbines, wind and cogeneration.
In the environmentally-driven case, GHG costs are high enough that minimal new coal-fired generation is added in the first 10 years. Instead, gas-fired combined cycle and more wind generation are developed. After 2017, clean coal technologies are considered viable, as are nuclear and large hydro projects. Either scenario B4 or B5 would be developed in this case. They both include additional combined cycle and wind in place of the coal plants included in scenarios A1 and A2. Prior to 2018, scenario B4 includes the addition of 1,230 MW of combined cycle generation. Scenario B5 includes the addition of 1,230 MW of combined cycle generation and an additional 1,800 MW of wind capacity. From 2018 to 2027, generation additions in the environmentally-driven case come from numerous low emission sources such as nuclear, hydro, clean coal, cogeneration, combined cycle and wind.

There is one additional scenario – B3, which represents a blend of the two electricity futures, falling between the BAU and environmentally-driven cases. Generation additions in the first 10 years are made up of a mix of coal, combined cycle, simple cycle gas turbine, cogeneration and wind.

The cases discussed above result in five scenarios. The five scenarios are discussed in separate 10-year intervals focusing on 2008 to 2017 and the second section on 2018 to 2027.
2008 to 2017 generation scenarios

Based on the forecast load, existing generation and expected retirements, 5,000 MW of new generation facilities are expected to be added to the system by 2017. The scenarios created to meet this amount of required generation are presented in Table 4.0-2.

Table 4.0-2: 10-year generation scenarios: 2008-2017 (MW)

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Significant northern generation development</th>
<th>Significant southern generation development</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>A1</td>
<td>A2</td>
</tr>
<tr>
<td>Coal</td>
<td>1,950</td>
<td>1,500</td>
</tr>
<tr>
<td>Cogeneration</td>
<td>1,760</td>
<td>2,260</td>
</tr>
<tr>
<td>Combined cycle</td>
<td>90</td>
<td>90</td>
</tr>
<tr>
<td>Hydro installed</td>
<td>100</td>
<td>100</td>
</tr>
<tr>
<td>effective</td>
<td>50</td>
<td>50</td>
</tr>
<tr>
<td>Other small additions</td>
<td>100</td>
<td>100</td>
</tr>
<tr>
<td>Simple cycle</td>
<td>800</td>
<td>800</td>
</tr>
<tr>
<td>Wind installed</td>
<td>1,600</td>
<td>1,600</td>
</tr>
<tr>
<td>effective</td>
<td>320</td>
<td>320</td>
</tr>
<tr>
<td>2008-2017 effective additions</td>
<td>5,070</td>
<td>5,120</td>
</tr>
</tbody>
</table>

Coal additions in the scenarios include Keephills 3 and a number of unit upgrades, accounting for 600 MW of new coal capacity in all of the scenarios. The remaining coal additions are as follows:

- A1 includes three additional 450 MW units in the northern part of the province.
- A2 and B3 include two additional 450 MW units in the northern part of the province.
- B4 and B5 include the addition of one 450 MW unit in the northern part of the province.

In all scenarios the majority of the cogeneration capacity additions support behind-the-fence (BTF) load, with the bulk occurring within the oilsands industry in the northeast area of the province. The 1,760 MW of cogeneration capacity added in scenarios A1, B3, B4 and B5 exceed growth in BTF load by 500 MW. Scenario A2 includes the addition of another 500 MW of cogeneration, which may be fuelled by oilsands by-products and would be located in the Fort Saskatchewan area.

Scenario B3 assumes 720 MW of combined cycle generation is developed. Scenarios B4 and B5 assume the development of 1,230 MW. All combined cycle generation additions are assumed to be located in southern Alberta and in the Calgary area.

The 100 MW Dunvegan hydro project is included in all the scenarios. The hydro project contributes 50 MW of effective capacity, reflecting the potential for restricted operation (e.g., icing, reduced flow rates, etc.) at peak-load periods. The 100 MW of other small additions are included to capture the future development of biomass generation and other small projects.
Each scenario includes at least 430 MW of additional simple cycle gas turbine generation to be added by 2017. The characteristics of simple cycle gas turbine generation allow it to provide peaking capability in Alberta's baseload heavy generation mix to manage load and supply fluctuations.

Large amounts of wind generation are planned for the province. All scenarios include the addition of at least 1,600 MW of wind generation by 2017. Scenario B5 includes the addition of more wind capacity, with a total of 3,400 MW being added to the system by 2017. Including the existing capacity of 497 MW, this will amount to 3,900 MW of wind generation in Alberta by 2017. As explained in more detail in Appendices F and G, the addition of wind generation is assumed to be limited by the inability to construct wind farms at the rate desired and the economic viability of the projects as the amount of wind on the system increases and not by transmission constraints. New wind generation projects are split proportionally throughout the province based on wind applications in the AESO’s interconnection queue as of February 2008, with 80 per cent being developed in southern Alberta and the remaining 20 per cent developing in central Alberta. In each scenario, 20 per cent of the wind capacity is included as effective capacity. This approximates the amount of other capacity that will not be installed in Alberta’s competitive market due to the addition of wind generation.

2018 to 2027 generation scenarios

During the 2018 to 2027 period, 6,500 MW of effective capacity is expected to be added to the system, bringing the total additions over the next 20 years to 11,500 MW. The 2018 to 2027 generation scenarios are presented in Table 4.0-3.

Table 4.0-3: 20-year generation scenarios: 2018-2027 (MW)

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Significant northern generation development</th>
<th>Significant southern generation development</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>A1</td>
<td>A2</td>
</tr>
<tr>
<td>Coal</td>
<td>1,050</td>
<td>1,050</td>
</tr>
<tr>
<td>Cogeneration</td>
<td>1,400</td>
<td>1,400</td>
</tr>
<tr>
<td>Combined cycle</td>
<td>500</td>
<td>500</td>
</tr>
<tr>
<td>Hydro installed</td>
<td>1,400</td>
<td>1,400</td>
</tr>
<tr>
<td>Hydro effective</td>
<td>700</td>
<td>700</td>
</tr>
<tr>
<td>Nuclear</td>
<td>2,200</td>
<td>2,200</td>
</tr>
<tr>
<td>Other small additions</td>
<td>100</td>
<td>100</td>
</tr>
<tr>
<td>Simple cycle</td>
<td>300</td>
<td>300</td>
</tr>
<tr>
<td>Wind installed</td>
<td>2,000</td>
<td>2,000</td>
</tr>
<tr>
<td>Wind effective</td>
<td>400</td>
<td>400</td>
</tr>
<tr>
<td>2018-2027 effective additions</td>
<td>6,650</td>
<td>6,650</td>
</tr>
<tr>
<td>2008-2017 effective additions</td>
<td>5,070</td>
<td>5,120</td>
</tr>
<tr>
<td>Total 20-year effective additions</td>
<td>11,720</td>
<td>11,770</td>
</tr>
</tbody>
</table>
Coal additions included in these scenarios are made up of three different plants: Bow City (two 500 MW units), a replacement unit at Battle River (450 MW) and a generic 600 MW unit. Scenarios A1 and A2 include Battle River and the generic unit, with the generic unit being located in the south in scenario A1 and in the Wabamun area in scenario A2. Scenarios B3, B4 and B5 include the Bow City and Battle River units.

Peaking capacity comes from the addition of 500 MW of combined cycle and 300 MW of simple cycle gas turbine generation. The units are located throughout the central and southern parts of the province in all scenarios. Scenario B5 includes 300 MW of additional combined cycle capacity in southern Alberta.

In scenarios A1 and B5, a nuclear plant addition is located in the Edmonton region (as defined by the bulk system). In scenarios A2, B3 and B4, the nuclear plant is located in the northwest part of the province. All scenarios include two 1,100 MW nuclear units.

All scenarios include the development of a number of small hydro generators totalling 400 MW. An additional 1,000 MW of capacity comes from a development on the Slave River in northeastern Alberta. This project is included in all scenarios except B5. The effective capacity from hydro additions is assumed to be 50 per cent of installed capacity.

The continued development of wind generation is expected in the 2018 to 2027 time period. Scenarios A1 and A2 include an additional 2,000 MW of wind power and scenarios B3, B4 and B5 include an additional 4,000 MW of wind generation. When paired with the wind generation additions in the 2008 to 2017 generation scenarios, scenario B5 has a total installed wind capacity of nearly 8,000 MW by 2027, with an effective capacity of 1,600 MW. The 2018 to 2027 wind additions are dispersed throughout the south, central and northwest parts of the province.

Cogeneration additions of at least 600 MW are included in all scenarios, matching growth in BTF load. Scenarios A1 and A2 assume an additional 800 MW of cogeneration will be installed in excess of BTF load.
Appendix F
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Appendix F
Evaluation of Generation Development Scenarios
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EDC Evaluation of Generation Scenarios
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EDC Evaluation of Generation Scenarios
Introduction

The key purpose of this report is to evaluate 5 generation scenarios provided by the AESO in terms of the price outcomes that result from the mix of supply and demand in each scenario.

Scope of Work

EDC was engaged by the AESO to determine the following quantitative results from the forecast generation and demand scenarios developed by the AESO.

- Are the forecast spot market prices that result from the demand forecast combined with the assumed generation development reasonable?
- If the scenarios are not economically viable, alter the generation sequence in order to produce price outcomes that support the generation.
- Determine the average price received for wind production facilities in all forecast years.
- Estimate the average number of hours the system would be operating under emergency conditions (all generation dispatched) as well as the number of MWh of load that would potentially be unserved due to a shortfall.

EDC Evaluation of Generation Scenarios
Methodology

EDC Price Forecast Model

EDC produced the results highlighted in this report via its proprietary HELP price forecast model. An iterative methodology was used wherein the supply assumptions were altered until price outcomes were consistent with the assumptions about the long-run cost of new generation. Outside of the supply assumptions, all conditions were held constant across scenarios. The key assumptions common to all the scenarios include:

- Hourly demand – supplied by the AESO. Note that the model uses domestic AIES demand rather than AIL demand.
- Current supply assumptions for existing units supplied by EDC. Market behavioral assumptions for all units supplied by EDC. This includes offer strategies (50MW, marginal cost based, shadow pricing, scarcity pricing, etc.) as the key element. Scheduled and forced outages are supplied by EDC. Each of the large existing units has a unique scheduled maintenance profile, and all units have forced outage rates consistent with their vintage and technology type.
- Import and export behaviour – supplied by EDC. Flows over the intertia are largely based on arbitrage opportunities with Mid C, but there is an element of strategic behaviour that takes advantage of BC’s storage capacity as well. Note that imports and exports are not constant across scenarios, but the assumptions that drive the flows are constant.
- Wind power profile – supplied by EDC. Wind production is modeled hourly based on historical production patterns from existing facilities. All future wind energy is expected to be strongly correlated with existing units.

Iterative Approach

In order to develop a generation sequence that produced economically viable price results, the original AESO supply forecast along with demand forecast were input into the pricing model. The model simulated market prices for 2008 through 2017 under the initial assumptions.

In the event that prices for a given year or period were significantly above the expected long-run cost of new generation, generation was added to the scenario or projects already in the generation forecast were advanced. When prices for a given year or period were significantly below the expected long-run cost of new generation, generation was removed from the scenario or delayed if already in the generation forecast. For the period between 2008 and 2010, generation was left largely as prescribed to reflect the reality that in the near-term, generation development is more fixed than it is in the long term.

In all of the scenarios, the average forecasted unserved load is within typical industry-acceptable levels of adequacy. For Scenario 5, the very high wind scenario, early years fully comply. The last two years fully comply in 7 of 10 cases with only three random outliers. Also, in that case, EDC assumed that all wind would be very highly correlated. In all likelihood, with such a high wind penetration, progressively more wind would locate at uncorrelated sites, reducing unserved energy at the end of the study period. Similarly, only the last year in Scenario 3 is slightly high, caused by one large outlier. These may not be statistically significant departures from an adequate reliability target, given the high variability of the metric.

Long Run Cost of New Generation

The long-run cost of new coal generation is assumed to set the approximate average cost of new generation in Alberta, although with the assumed GHG policy, coal has a very similar cost structure to combined cycle generation. The levelized cost of new baseload generation in the model is assumed to be between $75/MWh and $80/MWh in 2007 dollars, which includes GHG compliance costs. The GHG policy is assumed to follow the April 2007 federal and provincial policies. The policies are assumed to be complimentary, i.e. no double counting. GHG offsets are assumed to cost $15/tonne initially, and rise to $36.12/tonne (2007 dollars) by 2017.
Results

Results are presented for each of the five identified scenarios. Price forecast results along with the final forecast generation development sequence are presented. With respect to the Reserve Margin calculation presented in the tables, note that the results are calculated based on AIES net to grid supply as compared to AIES load. An alternative presentation of total supply versus AIL load would yield different results for the same generation assumptions.

Each scenario also presents three supply adequacy metrics, MWh of unserved energy, number of hours in which there was any short fall (small or large) and the MW outage from the worst single event. Each metric is the numeric average of all of the iterations or seeds of a Monte Carlo analysis for that ear and scenario. Because of this averaging, it is possible to have the unlikely result of a positive value for the average worst hour (i.e. extra capacity even in the tightest hour) and still have some small expected hours with unserved MWh.

Scenario 1 Results

Scenario 1 has the following generation additions:

Table 1 - Scenario 1 Generation Additions

<table>
<thead>
<tr>
<th>Generation Additions</th>
<th>Base MWh</th>
<th>AIL MWh</th>
<th>Total MWh</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas</td>
<td>10</td>
<td>12</td>
<td>22</td>
</tr>
<tr>
<td>Coal</td>
<td>5</td>
<td>6</td>
<td>11</td>
</tr>
<tr>
<td>Nuclear</td>
<td>2</td>
<td>3</td>
<td>5</td>
</tr>
<tr>
<td>Wind</td>
<td>4</td>
<td>5</td>
<td>9</td>
</tr>
<tr>
<td>Total</td>
<td>12</td>
<td>14</td>
<td>26</td>
</tr>
</tbody>
</table>

Total Installed Generation

<table>
<thead>
<tr>
<th>Total Installed Generation</th>
<th>2009</th>
<th>2010</th>
<th>2011</th>
<th>2012</th>
<th>2013</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total</td>
<td>11,361</td>
<td>11,590</td>
<td>12,086</td>
<td>12,566</td>
<td>12,947</td>
</tr>
<tr>
<td>Gas</td>
<td>10</td>
<td>12</td>
<td>22</td>
<td>22</td>
<td>22</td>
</tr>
<tr>
<td>Coal</td>
<td>5</td>
<td>6</td>
<td>11</td>
<td>11</td>
<td>11</td>
</tr>
<tr>
<td>Nuclear</td>
<td>2</td>
<td>3</td>
<td>5</td>
<td>5</td>
<td>5</td>
</tr>
<tr>
<td>Wind</td>
<td>4</td>
<td>5</td>
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<td>Total</td>
<td>12</td>
<td>14</td>
<td>26</td>
<td>26</td>
<td>26</td>
</tr>
</tbody>
</table>

Dispersed Total/Per AIESO Formula

<table>
<thead>
<tr>
<th>Dispersed Total/Per AIESO Formula</th>
<th>2009</th>
<th>2010</th>
<th>2011</th>
<th>2012</th>
<th>2013</th>
</tr>
</thead>
<tbody>
<tr>
<td>Peak Demand</td>
<td>10,000</td>
<td>10,000</td>
<td>10,000</td>
<td>10,000</td>
<td>10,000</td>
</tr>
<tr>
<td>Reserve Margin</td>
<td>10%</td>
<td>10%</td>
<td>10%</td>
<td>10%</td>
<td>10%</td>
</tr>
</tbody>
</table>

Scenario 1 is characterized by 4 major coal plant additions, beginning in 2011 with Keephills 3. Gas units are added to the market in the short term, with about 1,170 MW added between 2008 and 2011. 1,590 MW of wind power is added in Scenario 1, with 590 MW coming before 2012 and 1,000 MW after 2012.

The reserve margin, calculated as per the AESO formula, ranges from a high level of 11% in 2007 to a low level of 5% in several years. This value averages 8% over the 10 years from 2008 through 2017. In terms of the gross capacity margin, Scenario 1 averages 31%, with a low of 24% in 2008 and a high of 34% in 2017.

In addition to the generation additions highlighted in Table 1, the analysis calculated price outcomes in the simulated market, as well as summary revenues for wind capacity. It was assumed that future wind capacity was strongly correlated with existing wind capacity in the simulation, based on an absence of observable data to the contrary. However, as wind becomes more geographically dispersed over time, the correlation of production between farms could decrease, which would likely improve the revenue for all wind farms as well as improve the system reliability metrics presented in Table 3, for a given level of wind generation.

EDC Evaluation of Generation Scenarios
Table 2 - Summary of Price Simulation and Wind Capacity Revenues

<table>
<thead>
<tr>
<th>Average Spot Price (M$M/Wh)</th>
<th>Average Pool Price (M$M/Wh)</th>
<th>Average Real Price (M$M/Wh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>$100.00</td>
<td>$90.00</td>
<td>$80.00</td>
</tr>
<tr>
<td>$90.00</td>
<td>$80.00</td>
<td>$70.00</td>
</tr>
<tr>
<td>$80.00</td>
<td>$70.00</td>
<td>$60.00</td>
</tr>
</tbody>
</table>

The price results show prices are forecast to average $89/MWh between 2008 and 2017. Forecast prices are above the $75/MWh real price line for all but one year of the forecast, though not dramatically so. This suggests the resource additions are supportable by market prices, and the scenario maintains an incentive for new generation across the entire forecast range. Wind units receive about $75/MWh on average across the forecast, which represents a discount of $8/MWh to $22/MWh relative to the average spot market price. This discount occurs partially due to the assumption that wind production is strongly correlated across facilities — if the correlation falls over time, the discount to average price would be expected to fall, especially for those units that are correlated the most weakly to the average wind unit.

Table 3 – Supply Adequacy Metrics

<table>
<thead>
<tr>
<th>Scenario 2 Results</th>
</tr>
</thead>
<tbody>
<tr>
<td>Scenario 2 has the following generation additions:</td>
</tr>
</tbody>
</table>

Table 4 – Scenario 2 Generation Additions

| Scenario 2 is characterized by 3 major coal plant additions, beginning in 2011 with Keeplills 3. Gas units are added to the market in the short term, with about 1,170 MW added between 2008 and 2011, and, the key difference from Scenario 1, an additional 500 MW net to grid of cogeneration capacity in 2015. 1,590 MW of wind power is added in Scenario 2, with 590 MW coming before 2012 and 1,000 MW after 2012. |

EDC Evaluation of Generation Scenarios
The reserve margin, calculated as per the AESO formula, ranges from a high level of 11% in 2007 to a low level of 5% in 2006. On average, this value is 9% over the 10 years from 2008 through 2017. In terms of the gross capacity margin, Scenario 1 averages 31% with a transient low of 24% in 2008 and a high of 35% in 2015.

Once again, in addition to the generation additions highlighted in Table 4, the analysis calculated price outcomes in the simulated market, as well as summary revenues for wind capacity. All wind assumptions are identical to those in Scenario 1.

Table 5 - Summary of Price Simulation and Wind Capacity Revenues

The price results show prices are forecast to average $48/MWh between 2008 and 2017. Forecast prices oscillate around the $75/MWh real price line for the entire forecast, and generally the same as in Scenario 1. Wind units receive about $74/MWh on average across the forecast, which represents a discount of $10/MWh to $20/MWh relative to the average spot market price, which is again very similar to Scenario 1.

Table 6 - Supply Adequacy Metrics

The reliability metrics for Scenario 2 are presented in Table 6. These results are the average reliability across 10 seeds of the simulation. Generally, the results show that reliability is somewhat improved relative to Scenario 1, but the improvement is not statistically significant.

Scenario 3 Results

Scenario 3 has the following generation additions:

Table 7 – Scenario 3 Generation Additions

Scenario 3 is characterized by 3 major coal plant additions, beginning in 2011 with Keeplills 3. Gas units are added to the market in the short term, with about 1500 MW between 2008 and 2011, 330 MW more than Scenarios 1 and 2, all combined cycle. 1,590 MW of wind power is added in Scenario 3, with 900 MW coming before 2012 and 1,000 MW after 2012. The key feature in Scenario 3 is that significant southern combined cycle plants are substituted for the last coal unit in Scenario 1, for a total of 633 MW of combined cycle capacity.

EDC Evaluation of Generation Scenarios
The reserve margin, calculated as per the AESO formula, ranges from a high level of 12% in 2011 to a low level of 5% in 2008. During 2009-2010, this is lower than Scenario 1 or 2 because the simple cycle capacity scheduled for the early years is reduced by 200 MW. On average, this value is 9% over the 10 years from 2008 through 2017. In terms of the gross capacity margin, Scenario 1 averages 32% with a low of 24% in 2008 and a high of 35% in 2012.

Once again, in addition to the generation additions highlighted in Table 7, the analysis calculated price outcomes in the simulated market, as well as summary revenues for wind capacity. All wind assumptions are identical to those in Scenario 1.

Table 8 - Summary of Price Simulation and Wind Capacity Revenues

<table>
<thead>
<tr>
<th></th>
<th></th>
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<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Average Fee Income (MWh)</td>
<td>1,450</td>
<td>1,470</td>
<td>1,490</td>
<td>1,510</td>
<td>1,530</td>
<td>1,550</td>
<td>1,570</td>
<td>1,590</td>
<td>1,610</td>
<td>1,630</td>
<td>1,580</td>
<td>1,600</td>
</tr>
<tr>
<td>Average Wind Production (MWh)</td>
<td>1,000</td>
<td>1,020</td>
<td>1,040</td>
<td>1,060</td>
<td>1,080</td>
<td>1,100</td>
<td>1,120</td>
<td>1,140</td>
<td>1,160</td>
<td>1,180</td>
<td>1,120</td>
<td>1,140</td>
</tr>
<tr>
<td>Average Wind Revenue (MWh)</td>
<td>750</td>
<td>770</td>
<td>790</td>
<td>810</td>
<td>830</td>
<td>850</td>
<td>870</td>
<td>890</td>
<td>910</td>
<td>930</td>
<td>870</td>
<td>890</td>
</tr>
<tr>
<td>Average Revenue for Wind (MWh)</td>
<td>750</td>
<td>770</td>
<td>790</td>
<td>810</td>
<td>830</td>
<td>850</td>
<td>870</td>
<td>890</td>
<td>910</td>
<td>930</td>
<td>870</td>
<td>890</td>
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<tr>
<td>Standard Deviation</td>
<td>100</td>
<td>120</td>
<td>140</td>
<td>160</td>
<td>180</td>
<td>200</td>
<td>220</td>
<td>240</td>
<td>260</td>
<td>280</td>
<td>150</td>
<td>170</td>
</tr>
</tbody>
</table>

The price results show prices are forecast to average $85/MWh between 2008 and 2017. Forecast prices are marginally below the expected cost of new generation from 2012 through 2017 due to the addition of both a new coal plant and a large combined cycle plant in 2011. However, on average, the market still returns prices that sustain generation investment. Wind units receive about $74/MWh on average across the forecast, which represents a discount of $9/MWh to $17/MWh relative to the average spot market price, which is just slightly below Scenario 1 and 2.

Table 9 – Supply Adequacy Metrics

<table>
<thead>
<tr>
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<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Whs of Imbalance Energy</td>
<td>1,230</td>
<td>1,250</td>
<td>1,270</td>
<td>1,290</td>
<td>1,310</td>
<td>1,330</td>
<td>1,350</td>
<td>1,370</td>
<td>1,390</td>
<td>1,410</td>
<td>1,340</td>
<td>1,360</td>
</tr>
<tr>
<td>Total AES Energy (MWh)</td>
<td>1,230</td>
<td>1,250</td>
<td>1,270</td>
<td>1,290</td>
<td>1,310</td>
<td>1,330</td>
<td>1,350</td>
<td>1,370</td>
<td>1,390</td>
<td>1,410</td>
<td>1,340</td>
<td>1,360</td>
</tr>
<tr>
<td>Energy (Total Energy)</td>
<td>1,230</td>
<td>1,250</td>
<td>1,270</td>
<td>1,290</td>
<td>1,310</td>
<td>1,330</td>
<td>1,350</td>
<td>1,370</td>
<td>1,390</td>
<td>1,410</td>
<td>1,340</td>
<td>1,360</td>
</tr>
<tr>
<td>,’s with Imbalance Energy (MWh)</td>
<td>1,230</td>
<td>1,250</td>
<td>1,270</td>
<td>1,290</td>
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<td>1,330</td>
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<td>1,370</td>
<td>1,390</td>
<td>1,410</td>
<td>1,340</td>
<td>1,360</td>
</tr>
<tr>
<td>Resource (MWh)</td>
<td>1,230</td>
<td>1,250</td>
<td>1,270</td>
<td>1,290</td>
<td>1,310</td>
<td>1,330</td>
<td>1,350</td>
<td>1,370</td>
<td>1,390</td>
<td>1,410</td>
<td>1,340</td>
<td>1,360</td>
</tr>
</tbody>
</table>

The reliability metrics for Scenario 3 are presented in Table 9. These results are the average reliability across 10 seeds of the simulation. Generally, reliability is once again very similar to the previous forecasts and the previously identified relationships between prices, reserve margin and reliability also hold true.

Scenario 4 Results

Scenario 4 has the following generation additions:

Table 10 – Scenario 4 Generation Additions

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Installed Generation</td>
<td>220</td>
<td>240</td>
<td>260</td>
<td>280</td>
<td>300</td>
<td>320</td>
<td>340</td>
<td>360</td>
<td>380</td>
<td>400</td>
<td>320</td>
<td>340</td>
</tr>
<tr>
<td>Total Installed Generation</td>
<td>220</td>
<td>240</td>
<td>260</td>
<td>280</td>
<td>300</td>
<td>320</td>
<td>340</td>
<td>360</td>
<td>380</td>
<td>400</td>
<td>320</td>
<td>340</td>
</tr>
<tr>
<td>Coal</td>
<td>100</td>
<td>120</td>
<td>140</td>
<td>160</td>
<td>180</td>
<td>200</td>
<td>220</td>
<td>240</td>
<td>260</td>
<td>280</td>
<td>200</td>
<td>220</td>
</tr>
<tr>
<td>Natural Gas</td>
<td>100</td>
<td>120</td>
<td>140</td>
<td>160</td>
<td>180</td>
<td>200</td>
<td>220</td>
<td>240</td>
<td>260</td>
<td>280</td>
<td>200</td>
<td>220</td>
</tr>
<tr>
<td>Wind</td>
<td>100</td>
<td>120</td>
<td>140</td>
<td>160</td>
<td>180</td>
<td>200</td>
<td>220</td>
<td>240</td>
<td>260</td>
<td>280</td>
<td>200</td>
<td>220</td>
</tr>
<tr>
<td>Nuclear</td>
<td>100</td>
<td>120</td>
<td>140</td>
<td>160</td>
<td>180</td>
<td>200</td>
<td>220</td>
<td>240</td>
<td>260</td>
<td>280</td>
<td>200</td>
<td>220</td>
</tr>
<tr>
<td>Hydro</td>
<td>100</td>
<td>120</td>
<td>140</td>
<td>160</td>
<td>180</td>
<td>200</td>
<td>220</td>
<td>240</td>
<td>260</td>
<td>280</td>
<td>200</td>
<td>220</td>
</tr>
<tr>
<td>Total</td>
<td>500</td>
<td>600</td>
<td>700</td>
<td>800</td>
<td>900</td>
<td>1,000</td>
<td>1,100</td>
<td>1,200</td>
<td>1,300</td>
<td>1,400</td>
<td>1,000</td>
<td>1,100</td>
</tr>
<tr>
<td>Total Installed Generation</td>
<td>500</td>
<td>600</td>
<td>700</td>
<td>800</td>
<td>900</td>
<td>1,000</td>
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<td>1,100</td>
</tr>
<tr>
<td>Coal</td>
<td>100</td>
<td>120</td>
<td>140</td>
<td>160</td>
<td>180</td>
<td>200</td>
<td>220</td>
<td>240</td>
<td>260</td>
<td>280</td>
<td>200</td>
<td>220</td>
</tr>
<tr>
<td>Natural Gas</td>
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<td>120</td>
<td>140</td>
<td>160</td>
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<td>200</td>
<td>220</td>
<td>240</td>
<td>260</td>
<td>280</td>
<td>200</td>
<td>220</td>
</tr>
<tr>
<td>Wind</td>
<td>100</td>
<td>120</td>
<td>140</td>
<td>160</td>
<td>180</td>
<td>200</td>
<td>220</td>
<td>240</td>
<td>260</td>
<td>280</td>
<td>200</td>
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<tr>
<td>Hydro</td>
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<td>220</td>
<td>240</td>
<td>260</td>
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<td>200</td>
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<td>Total</td>
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<td>1,000</td>
<td>1,100</td>
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<tr>
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<td>700</td>
<td>800</td>
<td>900</td>
<td>1,000</td>
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<td>1,300</td>
<td>1,400</td>
<td>1,000</td>
<td>1,100</td>
</tr>
<tr>
<td>Peak Demand</td>
<td>500</td>
<td>600</td>
<td>700</td>
<td>800</td>
<td>900</td>
<td>1,000</td>
<td>1,100</td>
<td>1,200</td>
<td>1,300</td>
<td>1,400</td>
<td>1,000</td>
<td>1,100</td>
</tr>
<tr>
<td>Reserve Margin</td>
<td>500</td>
<td>600</td>
<td>700</td>
<td>800</td>
<td>900</td>
<td>1,000</td>
<td>1,100</td>
<td>1,200</td>
<td>1,300</td>
<td>1,400</td>
<td>1,000</td>
<td>1,100</td>
</tr>
<tr>
<td>Source:MW Reserve Margin</td>
<td>500</td>
<td>600</td>
<td>700</td>
<td>800</td>
<td>900</td>
<td>1,000</td>
<td>1,100</td>
<td>1,200</td>
<td>1,300</td>
<td>1,400</td>
<td>1,000</td>
<td>1,100</td>
</tr>
</tbody>
</table>

EDC Evaluation of Generation Scenarios

9
Scenario 4 is characterized by 2 major coal plant additions, beginning in 2011 with Keephills 3. Gas units are added to the market in the short term, with 1,084 MW between 2008 and 2011, which is 420 MW less than Scenario 3 but 85 MW more than Scenarios 1 and 2. 1,590 MW of wind power is added in Scenario 4, with 590 MW coming before 2012 and 1,000 MW after 2012. The key feature in Scenario 4 is that significant southern combined cycle units are added to the simulation, beginning in 2012 and completed in 2015.

The reserve margin, calculated as per the AESO formula, ranges from a high level of 13% in 2012 to a low level of 5% in 2008. On average, this value is 9.8% over the 10 years from 2008 through 2017. In terms of the gross capacity margin, Scenario 4 averages 32% with a low of 24% in 2008 and a high of 38% in 2015.

Once again, in addition to the generation additions highlighted in Table 11, the analysis calculated price outcomes in the simulated market, as well as summary revenues for wind capacity. All wind assumptions are identical to those outlined in Scenario 1.

### Table 11 - Summary of Price Simulation and Wind Capacity Revenues

<table>
<thead>
<tr>
<th>Year</th>
<th>Average Spot Price (C/kWh)</th>
<th>Average Annual Power Production (GW)</th>
<th>Average Wind Revenue (C/kWh)</th>
<th>Average Wind Revenue (GW)</th>
<th>Average Ann. Wind Revenue</th>
<th>Average Annual Wind Revenue (GW)</th>
<th>Average Annual Wind Revenue (C/kWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2008</td>
<td>76.00</td>
<td>2,488,320</td>
<td>0.01</td>
<td>248.832</td>
<td>76.00</td>
<td>1,988,696</td>
<td>76.00</td>
</tr>
<tr>
<td>2009</td>
<td>76.00</td>
<td>2,488,320</td>
<td>0.01</td>
<td>248.832</td>
<td>76.00</td>
<td>1,988,696</td>
<td>76.00</td>
</tr>
<tr>
<td>2010</td>
<td>76.00</td>
<td>2,488,320</td>
<td>0.01</td>
<td>248.832</td>
<td>76.00</td>
<td>1,988,696</td>
<td>76.00</td>
</tr>
<tr>
<td>2011</td>
<td>76.00</td>
<td>2,488,320</td>
<td>0.01</td>
<td>248.832</td>
<td>76.00</td>
<td>1,988,696</td>
<td>76.00</td>
</tr>
<tr>
<td>2012</td>
<td>76.00</td>
<td>2,488,320</td>
<td>0.01</td>
<td>248.832</td>
<td>76.00</td>
<td>1,988,696</td>
<td>76.00</td>
</tr>
<tr>
<td>2013</td>
<td>76.00</td>
<td>2,488,320</td>
<td>0.01</td>
<td>248.832</td>
<td>76.00</td>
<td>1,988,696</td>
<td>76.00</td>
</tr>
<tr>
<td>2014</td>
<td>76.00</td>
<td>2,488,320</td>
<td>0.01</td>
<td>248.832</td>
<td>76.00</td>
<td>1,988,696</td>
<td>76.00</td>
</tr>
<tr>
<td>2015</td>
<td>76.00</td>
<td>2,488,320</td>
<td>0.01</td>
<td>248.832</td>
<td>76.00</td>
<td>1,988,696</td>
<td>76.00</td>
</tr>
</tbody>
</table>

The price results show prices are forecast to average $85/MWh between 2008 and 2017. Forecast prices are generally above the expected long run cost of new generation in this scenario. The average price in the market simulation still returns prices that sustain generation investment. Wind units receive about $74/MWh on average across the forecast, which represents a discount of $8/MWh to $13/MWh relative to the average spot market price. The discount to pool price is slightly less than previous scenarios, which is likely a function of the increased amount of combined cycle generation relative to coal. With less coal (or cogeneration), periods with high wind are less likely to push the spot price for power down to the marginal cost of coal in the merit order.

### Table 12 - Supply Adequacy Metrics

<table>
<thead>
<tr>
<th>Year</th>
<th>Summary of Supply Adequacy Metrics</th>
</tr>
</thead>
<tbody>
<tr>
<td>2008</td>
<td></td>
</tr>
<tr>
<td>2009</td>
<td></td>
</tr>
<tr>
<td>2010</td>
<td></td>
</tr>
<tr>
<td>2011</td>
<td></td>
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<tr>
<td>2012</td>
<td></td>
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<tr>
<td>2013</td>
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<tr>
<td>2014</td>
<td></td>
</tr>
<tr>
<td>2015</td>
<td></td>
</tr>
</tbody>
</table>

The reliability metrics for Scenario 4 are presented in Table 12. These results are the average reliability across 10 seeds of the simulation. This scenario has the best reliability by a marginal amount, but the results are not statistically different from those in the previous scenarios.

### Scenario 5 Results

Scenario 5 is characterized by approximately twice as much total wind capacity as all previous scenarios. 3,395 MW of wind capacity is added to the supply stack by 2017, with 2,500 MW of this total added in 2013 or later. Gas Units add 1,012 MW to the market in the short term, with total additions of 2,301 MW in this scenario. Significant southern combined cycle units are added to the supply mix by 2014, but only two coal plants are built in this scenario.

The reserve margin, calculated as per the AESO formula, ranges from a high level of 13% in 2014 to a low level of 5% in 2008. On average, this value is 10% over the 10 years from 2008 through 2017. In terms of the gross capacity margin, Scenario 5 averages 36% with a low of 24% in 2008 and a high of 49% in 2017. The impact of discounting wind capacity is very apparent in this scenario, as the difference between the gross capacity margin and the AESO definition of capacity margin is much larger.
Scenario 5 has the following generation additions:

Table 13 – Scenario 5 Generation Additions

<table>
<thead>
<tr>
<th></th>
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<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal</td>
<td>100</td>
<td>90</td>
<td>80</td>
<td>70</td>
<td>60</td>
<td>50</td>
<td>40</td>
</tr>
<tr>
<td>Natural Gas</td>
<td>50</td>
<td>30</td>
<td>20</td>
<td>10</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Wind</td>
<td>10</td>
<td>20</td>
<td>30</td>
<td>40</td>
<td>50</td>
<td>60</td>
<td>70</td>
</tr>
<tr>
<td>Total</td>
<td>150</td>
<td>130</td>
<td>130</td>
<td>120</td>
<td>120</td>
<td>120</td>
<td>120</td>
</tr>
</tbody>
</table>

Once again, in addition to the generation additions highlighted in Table 14, the analysis calculated price outcomes in the simulated market, as well as summary revenues for wind capacity. All wind assumptions, outside of the total amount of capacity in this scenario, are identical to those outlined in Scenario 1.

Table 14 - Summary of Price Simulation and Wind Capacity Revenues

The price results show prices are forecast to average $86/MWh between 2008 and 2017. Forecast prices are generally above the expected long run cost of new generation in this scenario, although 2014 through 2018 are below the long run cost line. However, on average, the market simulation still returns prices that sustain generation investment. Wind units receive about $70/MWh on average across the forecast, which represents a discount of $8/MWh to $24/MWh relative to the average spot market price. The discount to pool price is dramatically higher than the previous scenarios, especially in the final years of the forecast when the wind capacity grows over 3,000 MW in total. Given the assumption that all future wind capacity is correlated with existing capacity, the simulation reveals that when it is windy, spot market prices will tend to be quite low relative to days when the wind does not blow.

Table 15 - Supply Adequacy Metrics

The reliability metrics for Scenario 5 are presented in Table 15. These results are the average reliability across 10 seeds of the simulation. This scenario has the second worst average reliability of all scenarios, and in the last three years the difference appears to be significant. The decline in reliability again appears most notably in the final years of the forecast when the total amount of wind capacity rises from 2,500 to 3,000 MW.
Appendix G
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Appendix G

Alberta Wind Scenarios to 2027 for AESO Resource Adequacy

Baden Energy Consulting
Background, purpose, objectives

- The AESO has asked BECL and Associates Ltd. (BECL) to develop a number of wind power scenarios for their transmission planning purposes.
- The scenarios describe the phasing and magnitude of wind power development in Alberta under several sets of assumptions.

How will this information be used?

- The AESO has specifically requested
  - the magnitude of wind generation capacity
  - the rate of addition of wind generating capacity
- This information will be used in the AESO's Long-term Transmission System Plan to determine the provincial transmission requirements for wind.

Key assumptions about project readiness

<table>
<thead>
<tr>
<th>Group</th>
<th>MW</th>
<th>Project start date</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>600</td>
<td>2009</td>
<td>Ready to go now</td>
</tr>
<tr>
<td>B</td>
<td>1,600</td>
<td>2010</td>
<td>Transmission ready; waiting for turbines and environmental work</td>
</tr>
<tr>
<td>C</td>
<td>&gt;9,000</td>
<td>2011</td>
<td>Waiting for transmission</td>
</tr>
<tr>
<td>Total</td>
<td>11,200</td>
<td></td>
<td>Matches current interconnection queue</td>
</tr>
</tbody>
</table>

- It was assumed that an additional 500 megawatts (MW) would be added to the queue each year.
- Scenarios assume transmission will be built and in service coincident with a project's start date (i.e., no congestion or constraints).

Key assumptions about wind capacity

- The net capacity factor (CF) distribution shown to the right was used in the scenarios.
- It was assumed that projects in each of groups A, B and C had the same distribution of net capacity factors.
  - 10 per cent of projects were given 37.5 per cent CF
  - 40 per cent of projects were given 34 per cent CF
  - 40 per cent of projects were given 31 per cent CF
  - 10 per cent of projects were given 27.5 per cent CF
- For consistency all wind power projects were assumed to use a GE 1.5 sle turbine with an 80 metre hub height.
Key economic parameters

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Low</th>
<th>Mid</th>
<th>High</th>
</tr>
</thead>
<tbody>
<tr>
<td>Power values per megawatt hour (MWh)</td>
<td>$80</td>
<td>$95</td>
<td>$110</td>
</tr>
<tr>
<td>Capital costs (CC)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Low</td>
<td>$2,100/kW</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Mid</td>
<td>$2,250/kW</td>
<td></td>
<td></td>
</tr>
<tr>
<td>High</td>
<td>$2,400/kW</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Average project size</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>100 MW</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Carbon pricing</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Low</td>
<td>$5/tonne</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Mid</td>
<td>$15/tonne</td>
<td></td>
<td></td>
</tr>
<tr>
<td>High</td>
<td>$25/tonne</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Grid intensity factor (GIF)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Low</td>
<td>0.50</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Mid</td>
<td>0.66</td>
<td></td>
<td></td>
</tr>
<tr>
<td>High</td>
<td>0.90</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Limits to wind capacity installation

- Recognizing the current economic environment in Alberta and worldwide expansion in the wind industry, an annual maximum capacity addition was applied to the installation of economic wind projects based on the following:
  - 109 MW of wind generation capacity was installed in 2006 and 139 MW was installed in 2007.
  - It was assumed that installed capacity could continue to grow at 30 MW a year until the installation rate was equal to twice the 2007 rate or 280 MW each year. The rate of capacity additions was then capped at 280 MW for the following years.
  - As a sensitivity, installations were allowed to grow to a maximum of three times the 2007 level or 420 MW/year and subsequently capped at this annual rate.

Methodology

- To simplify the number of scenarios, revenue was evaluated on a combined power plus carbon dioxide (CO₂) offset basis.
  - For example: $80 power, $25 carbon and GIF = 0.9 results in revenue of $103/MWh.
  - Equivalently, $95 power, $15 carbon and GIF = 0.5 also results in revenue of $103/MWh.
  - Three revenue scenarios were evaluated at $85, $105 and $125/MWh.
- Nine revenue/capital cost combinations were run to determine the economic projects.
- The scenarios were built by identifying the economic projects each year and removing them from the pool for subsequent years.
- If more than the annual maximum capacity addition was identified as economic, the built projects were prorated across capacity factors.
Equivalent revenues

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
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<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>$ -</td>
<td>$ 80</td>
<td>$ 95</td>
<td>$110</td>
<td></td>
</tr>
<tr>
<td>0.5</td>
<td>$ 5</td>
<td>$ 83</td>
<td>$ 98</td>
<td>$113</td>
<td></td>
</tr>
<tr>
<td>0.66</td>
<td>$ 5</td>
<td>$ 83</td>
<td>$ 98</td>
<td>$113</td>
<td></td>
</tr>
<tr>
<td>0.9</td>
<td>$ 5</td>
<td>$ 85</td>
<td>$100</td>
<td>$115</td>
<td></td>
</tr>
<tr>
<td>0.5</td>
<td>$15</td>
<td>$ 88</td>
<td>$103</td>
<td>$118</td>
<td></td>
</tr>
<tr>
<td>0.66</td>
<td>$15</td>
<td>$ 90</td>
<td>$105</td>
<td>$120</td>
<td></td>
</tr>
<tr>
<td>0.9</td>
<td>$15</td>
<td>$ 94</td>
<td>$109</td>
<td>$124</td>
<td></td>
</tr>
<tr>
<td>0.5</td>
<td>$25</td>
<td>$ 93</td>
<td>$108</td>
<td>$123</td>
<td></td>
</tr>
<tr>
<td>0.66</td>
<td>$25</td>
<td>$ 97</td>
<td>$112</td>
<td>$127</td>
<td></td>
</tr>
<tr>
<td>0.9</td>
<td>$25</td>
<td>$103</td>
<td>$118</td>
<td>$133</td>
<td></td>
</tr>
</tbody>
</table>

GIF: grid intensity factor: tonnes CO₂ equivalent/MWh.

- Closest to $85/MWh scenarios
- Closest to $105/MWh scenarios
- Closest to $125/MWh scenarios

Potential for storage facilities

- It was assumed that an economic energy storage technology would be available to projects built in 2018 and after.

- A power price uplift from storage was calculated from historical data to be 40 per cent of total revenue.
  - Storage facility has 60 per cent efficiency and deliverability at one-third of installed capacity.
  - Decision rule to inject at prices 20 per cent below 30-day trailing average and withdraw at prices 20 per cent above 30-day trailing average.

- Capital cost was assumed to be $900/kilowatt hour (kWh) ($2008) with deliverability at one-third of wind facility capacity.
Results

Low revenue scenario: $85/MWh

- Revenue at $85/MWh provides incremental 800 to 1,500 MW in the first 10 years.
- Storage technology provides sufficient uplift for further development.
- Incremental wind between 4,000 and 4,500 MW by 2027.

Mid-revenue scenario: $105/MWh

- At $105/MWh, significantly more projects are economic leading to a build of 2,500 MW in the first 10 years and a total of over 5,500 MW installed by 2027.
- At this revenue level, installation of wind projects is limited by assumed resource constraints.
Price increase to $125/MWh results in no additional installation as the limits on materials, equipment and labour have been reached.

**Sensitivity: higher annual build limit**

Raising the maximum annual build limit to 420 MW per year results in a maximum installation of 3,500 MW by 2018 and almost 7,500 MW by 2027.
**Determine likely capital scenario**

- Assume an even distribution of capital projects
  - 33 per cent – $2,100/kilowatt (kW)
  - 33 per cent – $2,250/kW
  - 33 per cent – $2,400/kW

- Assume an even distribution on combined revenue
  - 33 per cent – $85/MWh
  - 33 per cent – $105/MWh
  - 33 per cent – $125/MWh

- Assume an even distribution on the annual build limit
  - 50 per cent – 280 MW/year
  - 50 per cent – 420 MW/year

- Even distributions are assumed because we have no information that one scenario is more likely than any other.

**Probable Alberta wind MW**

- The possible range of wind is between 4,000 and 7,300 MW.
- The expected case is 6,000 MW.
Model limitations

- Capacity factor distribution.
  - Poor resolution of capacity factor distribution.
  - Large influence from sole factor.
    - Recommended follow up:
      - Run a finer resolution model.
      - Confirm capacity factor assumptions.
- Assumes a standard acceptable return rate.
  - Entrants into the market may have lower cost of debt or access to a higher proportion of debt.
- Relative costs and benefits of storage technology are highly subject to assumptions.
  - Introduction of storage may change power price dynamics.
  - Analysis without storage indicates 5,200 MW of expected wind capacity in 2028. The table below shows high and low scenarios plus the expected case with the assumption of no storage technology.

Alberta wind MW without storage

Without storage, the possible range of wind is between 1,500 and 7,300 MW.
Without storage, the expected case is 5,000 MW.

Additional assumptions used in calculation

- ecoEnergy Renewable Portfolio Incentive.
  - None.
- After-tax weighted average cost of capital = 9.5 per cent; 11.5 per cent after 2018.
  - Maximum debt on merchant market is about 30 per cent.
  - Cost of debt assumed is approximately five per cent.
  - Cost of equity is approximately 10 to 12 per cent.
  - 30 per cent effective tax rate.
- Variable costs: $15 to 35/MWh.
- Inflation of five per cent for five years; two per cent thereafter.
Appendix H
Appendix H

Key Legislation, Policy and Statistical Information

1.0 Electricity policy

In fulfilling its mandate, the AESO is guided by legislation, regulations and policies set by the Government of Alberta. The Electric Utilities Act (EUA) created the AESO and defines the organization's roles and accountabilities. There are other policies and regulations that provide specific direction for the AESO in various areas of its business, including planning and developing Alberta's interconnected transmission system. The evolution of these policies and regulations is depicted in Figure 1.0-1.

In March 2008, Premier Ed Stelmach issued a letter to Minister of Energy Mel Knight outlining the government's priorities and commitments. The letter made the following statement about electricity:

"Develop and implement policy to ensure sufficient and reliable electric transmission facilities are available in a timely manner to support continued economic growth in the province."

The Transmission Regulation directs the AESO to develop long-term transmission plans to assess the needs of Alberta and to plan and arrange for necessary enhancements and upgrades to the transmission system. These system plans and reinforcements must maintain system reliability and support a robust and efficient wholesale market in Alberta.

In addition to specific direction on development of the transmission system in Alberta, the Transmission Regulation also recognizes the importance of transmission interties to a fully functioning competitive wholesale electricity marketplace. Interties are transmission lines and associated facilities connecting the electric systems of Alberta and its neighbours.
Transmission Regulation direction on long-term planning

The Transmission Regulation provides direction regarding forecasting the needs of Alberta as it relates to long-term planning of the provincial transmission system.

In forecasting the needs of Alberta under section 33 of the Act, the Independent System Operator (ISO) [all ISO references in the Regulation refer to the AESO]:

- 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 and other related assumptions to support transmission system planning.
- Must make an assessment of the transmission facilities required to provide for the efficient and reliable access to jurisdictions outside Alberta.
- May, if the ISO considers it necessary to do so, make an assessment of the contribution of a proposed transmission facility to any of the following:
  - Improving transmission system reliability.
  - A robust competitive market.
  - Improving transmission system efficiency.
  - Improving operational flexibility.
  - Maintaining options for long-term development of the transmission system.

Figure 1.0-1: Alberta electricity industry: evolution of policy and regulation

<table>
<thead>
<tr>
<th></th>
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<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Electric Utilities Act (EUA) passed</td>
<td>Power Pool of Alberta Council (PPC) formed</td>
<td>EUA takes effect; Power Pool begins operation; Grid Company of Alberta Ltd. formed</td>
<td>Independent Transmission Administrator appointed</td>
<td>Government auctions rights to market generator output under Power Purchase Arrangements (PPA)</td>
<td>Balancing Pool Phase I PPA auction</td>
<td>Retail competition begins</td>
<td></td>
</tr>
</tbody>
</table>
With respect to long-term transmission system planning for Alberta, the Transmission Regulation goes on to describe the AESO's responsibilities as they pertain to the 20-year Transmission System Outlook in Part 2, Section 9 below:

**As part of its duties under section 17 of the Act, the ISO must:**

9 (a) prepare and maintain a long term transmission system outlook document that projects, for at least the next 20 years,

- (i) the forecast load on the interconnected electric system, including exports of electricity,
- (ii) the anticipated generation capacity, including appropriate reserves and imports of electricity required to meet the forecast load,
- (iii) the timing and location of future generation additions,
- (iv) the transmission facilities required to meet the forecast load, imports and exports of electricity and anticipated generation capacity, including appropriate reserves, in a timely and efficient way,
- (v) the transmission facilities required to provide for the efficient and reliable access to jurisdictions outside Alberta, and
- (vi) other matters related to the items described in subclauses (i) to (v) that the ISO considers appropriate,

(b) update the long-term transmission system outlook document periodically as required, but at least every 4 years, and

(c) make the long-term transmission system outlook document, and the updates made to it, available to the public, and file copies of them with the Commission for information.
The Transmission Regulation also outlines the AESO’s responsibilities as they pertain to the 10-year Transmission System Plan in Part 2, Section 10.

**10(1) As part of its duties under section 17 of the Act, the ISO must:**

(a) prepare and maintain a transmission system plan in greater detail than the long term transmission system outlook document, that projects, for at least the next 10 years,

(i) the forecast load on the interconnected electric system, including exports of electricity,

(ii) the anticipated generation capacity, including appropriate reserves and imports of electricity required to meet the forecast load,

(iii) the timing and location of future generation additions,

(iv) the transmission facilities required to meet the forecast load, imports and exports of electricity and anticipated generation capacity, including appropriate reserves, in a timely and efficient way,

(v) the transmission facilities required to provide for the efficient and reliable access to jurisdictions outside Alberta, and

(vi) other matters related to the items described in subclauses (i) to (v) that the ISO considers appropriate,

(b) update the transmission system plan periodically as required, but at least every 2 years, including updating the plan to restore the interties referred to in section 16, and

(c) make the transmission system plan, including the assumptions and supporting data on which the plan is based, and the updates made to the plan, available to the public, and file copies of them with the Commission for information.

(2) The transmission system plan must:

(a) identify the transmission facility projects the ISO proposes to initiate by a needs identification document within 5 years of the date of the plan and within 5 years of each update of the plan, and

(b) provide an anticipated implementation schedule for each transmission facility project identified.

**15(1) In making rules under section 20 of the Act, and in exercising its duties under section 17 of the Act, the ISO must:**

(a) plan a transmission system that satisfies reliability standards,

(b) ensure that transmission facilities adhere to reliability standards,

(c) monitor and ensure overall reliability of the interconnected electric system,

(d) comply with directives of the Commission,

(e) taking into consideration the characteristics and expected availability of generating units, plan a transmission system that

(i) is sufficiently robust so that 100% of the time, transmission of all anticipated in merit electric energy referred to in section 17(c) of the Act can occur when all transmission facilities are in service, and

(ii) is adequate so that, on an annual basis, and at least 95% of the time, transmission of all anticipated in merit electric energy referred to in section 17(c) of the Act can occur when operating under abnormal operating conditions,
(f) make arrangements for the expansion or enhancement of the transmission system so that, under normal operating conditions, all anticipated in merit electricity referred to in clause (e)(i) and (ii) can be dispatched without constraint, and

(g) make rules respecting the preparation of needs identification documents for, and the planning and processing of, enhancements or upgrades to transmission facilities that existed on August 12, 2004 for the purpose of providing transmission capacity to import or export electricity to or from Alberta in excess of the path ratings that existed on August 12, 2004 for those transmission facilities.

 Requirement for siting transmission lines

15.1(1) In preparing plans and making arrangements for new transmission facilities or for enhancements or upgrades to existing transmission facilities, the ISO must take into consideration geographic separation for the purposes of ensuring reliability of the transmission system.

(2) When considering the location of new transmission facilities or of enhancements or upgrades to existing transmission facilities, the ISO must consider:

(a) wires solutions that reduce or mitigate the right of way, corridor or other route required, and

(b) maximizing the efficient use of rights of way, corridors or other routes that already contain or provide for utility or energy infrastructure.

(3) The ISO must consider the measures described in subsections (1) and (2) notwithstanding that those measures may result in additional costs.

(4) In subsection (2)(a), “wires solutions” includes, without limitation,

(a) providing new, higher capacity transmission facilities in combination with the salvage of lower capacity transmission facilities, or

(b) providing staged transmission capacity increases that reduce the need to access rights of way for subsequent capacity increases.

Restoring interties existing on August 12, 2004 to their path rating

16(1) In making rules under section 20 of the Act, and in exercising its duties under section 17 of the Act, the ISO must prepare a plan and make arrangements to restore each intertie that existed on August 12, 2004 to, or near to, its path rating.

(2) The plan to restore interties to their path ratings must specify how the ISO intends to restore and maintain each intertie to, or near to, its path rating without the mandatory operation of generating units.

(3) The plan to restore and maintain interties must be incorporated into and form part of the transmission system plan as soon as practicable.
2.0  Greenhouse gas framework

In early 2008, both the federal and Alberta governments released additional details for their respective frameworks regarding greenhouse gas (GHG) emission reductions. The details of these plans, including associated legislation, are in development. This section provides a high-level discussion of both plans. As specific initiatives and targets outlined in the policy frameworks are implemented and accompanying regulations developed, there is the potential they will affect load growth and generation investment decisions in Alberta. A significant change in generation development patterns and load growth could have an impact on long-term transmission system plans.

Alberta’s 2008 climate change strategy

In January 2008, the Alberta government released its climate change strategy to accompany the Specified Gas Emitters Regulation. In its announcement, the government said the strategy would establish achievable goals for real reductions in GHG emissions that would ensure Alberta’s economy can continue to take advantage of its energy production opportunities. The strategy confirmed that the government will continue its emission intensity target approach. Currently, Alberta accounts for about one-third of Canada’s total GHG emissions and Canada contributes about two per cent of global emissions.

The government’s plan identifies a long-term commitment to reduce emissions below the business-as-usual (BAU) case. The goal, as shown in Figure 2.0-1, is to stabilize GHG emissions in 2020, with a 50 megatonne (Mt) reduction from the BAU case, and a 200 Mt reduction from the BAU case by 2050. The 2050 emissions target in the strategy is 14 per cent (28.7 Mt) below 2005 emission levels.

The government expects these reductions to be achieved in the following three areas: 1) conserving and using energy efficiently, 2) greening energy production, and 3) carbon capture and storage (CCS).

The government’s strategy aims to engage all Albertans and all sectors of society and the economy in conserving and reducing energy use. The strategy suggests actions that will increase conservation and energy efficiency, reducing emissions by 24 Mt by 2050. A number of these actions will have an impact on either electricity consumption or generation. The suggested actions are:

- Develop an Energy Efficiency Act.
- Establish an incentive program to promote the use of energy efficient appliances and home improvements.
- Implement energy efficiency standards in building codes for homes and commercial buildings.
- Provide capacity building support to municipalities and other climate change partners to identify emission reduction strategies, including land-use planning and sustainable development initiatives, for inclusion in appropriate municipal plans and bylaws.
- Develop protocols for all facilities that emit over 50,000 tonnes of GHG (typically gas plants, smaller power plants and pulp and paper/wood products facilities) to report emissions.
- Provide government leadership in introducing energy efficiency standards for government buildings, purchasing more energy efficient vehicles and buying more environmentally-friendly products.
The second element of the government’s strategy aims to transform the way Alberta produces energy and expand the use of alternative energy sources and sustainable approaches to energy production. The strategy lists the following actions related to power generation that are expected to reduce 2050 BAU case emissions by 37 Mt:

- Further removing barriers and considering incentives for expanding the use of renewable and alternative energy sources.
- Streamlining transmission system access for small power producers.
- Developing and introducing new bioenergy products.
- Increasing investment in the demonstration and deployment of clean energy technologies and value-added energy technologies.

The strategy also notes that the majority of reductions from BAU (139 Mt) are expected to be achieved through CCS, which strives to take advantage of Alberta’s unique opportunity to store large quantities of carbon dioxide (CO₂) in the province’s geological formations instead of releasing it into the atmosphere. A number of suggested actions that would promote the use of the technology are related to power generation. This includes ensuring new large power generators are designed and built to enable the capture of CO₂ and ensuring existing large industrial facilities have plans in place to implement CO₂ capture.
In July 2008, the Alberta government announced a $2-billion fund to advance CCS projects to reduce GHG emissions. Funds will be allocated to encourage construction of Alberta’s first large-scale CCS projects. The province issued a request for expressions of interest to begin identifying CCS proposals with the greatest potential of being built quickly and those that provide the best opportunities to significantly reduce GHG emissions. Twenty projects have been selected to move from the expression of interest stage to the provision of full project proposals by March 31, 2009. The province is expected to announce funding decisions by the end of June 2009. With the potential to reduce emissions at facilities such as coal-fired electricity plants and oilsands extraction sites and upgraders, the $2-billion fund will support CCS projects that are expected to reduce emissions by up to five million tonnes annually. That is the equivalent of taking a million vehicles off the road or one-third of all vehicles registered in Alberta.

The Alberta government has legislation in place to move forward on attaining its climate change strategy. On July 1, 2007, the province established intensity reduction targets for the large emitters in Alberta through the Specified Gas Emitters Regulation. Any industrial facility emitting more than 100,000 tonnes of GHG annually is required to reduce its emission level 12 per cent below its baseline emission intensity. The reduced emission level can be attained by reducing emissions at the facility, purchasing emission offsets that were generated in Alberta, or purchasing $15 per tonne credits from the government’s Climate Change and Emission Management Fund. Ultimately the fund, which will invest in technology to reduce GHG emissions in the province, caps the price of emissions in Alberta at $15 per tonne until reductions beyond those specified by the Alberta government are required by facilities. Additional reductions could potentially come from the federal government’s emission reduction framework as it has more stringent targets.

**Federal government’s regulatory framework for air emissions**

On March 10, 2008, the federal government released additional details on its Regulatory Framework for Air Emissions initially published in April 2007. The framework is intended to meet the government’s commitment to achieve a 330 Mt reduction from projected levels by 2020, which is 20 per cent below 2006 levels. The government’s framework sets GHG reduction targets for existing and new facilities and final compliance mechanisms including a technology fund, offset system and credit for early action.

The federal government has stated its regulatory system will apply to all industries and become more stringent over time. For existing facilities in all industrial sectors, mandatory reductions will start in 2010 and increase each year. For new plants in key sectors coming on stream in 2004 and later, higher emission reduction targets are set to drive the adoption of cleaner fuels and technologies. The most stringent regulations are for oilsands facilities and coal-fired power plants coming on stream in 2012 and later.

The following outlines the program’s impacts on new generation projects.
Greenhouse gas reduction targets
Existing facilities: 18 per cent reduction from 2006 emission intensity levels in 2010; two per cent annual improvement thereafter.

- Target application: corporate-specific for the electricity sector. Each company will receive a target of an 18 per cent reduction from the average 2006 emission intensity of its entire fleet of facilities. With this approach, electricity companies can reduce their emission intensity through the addition of non- or lower-emitting facilities (e.g., wind, hydro and other renewables, and nuclear).

- New facilities: include greenfield facilities, major expansions and major transformations that came into operation in 2004 and beyond. There is a three-year grace period until these facilities must meet a fuel-specific cleaner fuel standard and reduce emissions by two per cent per year thereafter. New coal-fired generation commencing operation in 2012 or later will need to meet the supercritical pulverized coal technology cleaner fuel standard until 2018, after which the cleaner fuel standard shifts to integrated gasification combined cycle with CCS.

- Clean electricity: the federal government will establish a clean electricity task force to work with the provinces and industry to meet an additional 25 Mt reduction goal from the electricity sector by 2020.

Timeline for regulations
At the time of writing this report, the federal government had set the following schedule for regulations to implement this framework.

- Draft regulations are yet to be published.
- Final regulations are expected to be approved and published in the fall of 2009.
- GHG provisions of the regulations are to come into force on January 1, 2010.

In summary
Both the Alberta provincial strategy and the federal framework will affect the economy, the electricity market, generation developments, electricity demand and transmission development. There are numerous uncertainties at this time, making the costs associated with emissions and the programs to promote clean coal and renewable energy development unresolved. Initial analysis has been undertaken to assess the impacts of the programs on the relative economics of generation technologies and the timing of project developments. The range of generation scenarios developed in this document are sufficiently broad to consider the consequences of current GHG policy and legislation. When further details become available or additional regulations are finalized, the AESO will be better able to provide a more comprehensive analysis of the impacts on Alberta’s electricity industry.
3.0 Current generation situation

Alberta’s diverse mix of power generation supply has developed over the 98 years since the province’s first large-scale hydroelectric power plant was built in 1911. The breakdown of the total generating capacity by fuel type is representative of Alberta’s natural resources and the development of the electricity industry in the province.

As of March 2008, the total installed generating capacity in Alberta was 12,142 megawatts (MW) as shown in Figure 3.0-1. Table 3.0-1 lists all the installed generators in Alberta.

Figure 3.0-1: Existing generation capacity by fuel type (March 2008)

- 49% 5,893 MW (Coal)
- 38% 4,669 MW (Gas)
- 7% 869 MW (Hydro)
- 4% 497 MW (Wind)
- 2% 214 MW (Biomass and other)

Total capacity: 12,142 MW

Coal-fired generation is the largest proportion of electricity generation in the province, representing 49 per cent of the total capacity. Alberta has more than 34 billion tonnes of remaining established coal reserves. In 2007, 26 million tonnes of sub-bituminous coal were produced in Alberta. The majority of this coal was used for the generation of electricity. The type of coal found in Alberta is generally low in sulphur and burns relatively clean when compared to other coal sources around the world. Coal-fired generators are baseload generators, providing power to Albertans 24 hours a day, seven days a week.

Gas-fired generation is the second largest proportion of power generation in the province, making up 38 per cent of the total capacity. Gas-fired generators can be separated into three categories: simple cycle gas turbine plants, combined cycle plants and cogeneration plants. Gas-fired generators that are able to power up quickly and provide energy during times of high demand (peak) are called peaking plants. These units play an important role in Alberta’s wholesale electricity market because they can provide power when demand exceeds baseload supply.
Combined cycle plants are more efficient than simple cycle gas turbine generators and can be more competitive at lower market prices compared to simple cycle peaking generators. This makes combined cycle plants well suited for an intermediate role between baseload and peaking generation.

Cogeneration facilities are used to provide both steam and electricity for industrial processes. When these plants are built on the industrial host’s site they are called behind-the-fence (BTF) generators. When these plants have excess power available, it can be sold into the competitive wholesale marketplace. Alberta also has abundant wind resources. Since 2000, the total transmission connected capacity for wind in Alberta has grown from about 20 MW to 497 MW.

There is currently 869 MW of hydroelectric generation in the province. This accounts for approximately seven per cent of the total Alberta capacity. Hydroelectric generation in Alberta has limited storage and is used primarily to provide a combination of baseload (run-of-river) and peaking supply. Hydroelectric power plants can manage small changes on the system and provide back up if a baseload or other generator unexpectedly trips off line.

Other power generation in the province is primarily made up of biomass-fired generation from the forestry, pulp and paper and agricultural industries.

Figure 3.0-2 identifies energy generated by fuel type in 2007.

**Figure 3.0-2: Total energy production for 2007 by fuel type**

- **64%** 44,244 GWh (Coal)
- **29%** 20,384 GWh (Gas)
- **3%** 2,013 GWh (Hydro)
- **2%** 1,433 GWh (Wind)
- **2%** 1,138 GWh (Other)

Total production: 69,213 GWh

* GWh: gigawatt hours

Note: numbers may not add due to rounding.
## Table 3.0-1: Existing generation (March 2008)

<table>
<thead>
<tr>
<th>Coal-fired generation</th>
<th>Gas-fired generation</th>
<th>Hydroelectric power</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Generation unit name</strong></td>
<td><strong>Location</strong></td>
<td><strong>MCR</strong></td>
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<tr>
<td>Battle River #3</td>
<td>Central</td>
<td>148</td>
</tr>
<tr>
<td>Battle River #4</td>
<td>Central</td>
<td>148</td>
</tr>
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<td>Battle River #5</td>
<td>Central</td>
<td>368</td>
</tr>
<tr>
<td>Genesee #1</td>
<td>Edmonton</td>
<td>384</td>
</tr>
<tr>
<td>Genesee #2</td>
<td>Edmonton</td>
<td>384</td>
</tr>
<tr>
<td>Genesee #3</td>
<td>Edmonton</td>
<td>450</td>
</tr>
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<td>H.R. Milner</td>
<td>Northwest</td>
<td>143</td>
</tr>
<tr>
<td>Keephills #1</td>
<td>Edmonton</td>
<td>381</td>
</tr>
<tr>
<td>Keephills #2</td>
<td>Edmonton</td>
<td>381</td>
</tr>
<tr>
<td>Sheerness #1</td>
<td>South</td>
<td>378</td>
</tr>
<tr>
<td>Sheerness #2</td>
<td>South</td>
<td>378</td>
</tr>
<tr>
<td>Sundance #1</td>
<td>Edmonton</td>
<td>280</td>
</tr>
<tr>
<td>Sundance #2</td>
<td>Edmonton</td>
<td>280</td>
</tr>
<tr>
<td>Sundance #3</td>
<td>Edmonton</td>
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</tr>
<tr>
<td>Sundance #4</td>
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<td>406</td>
</tr>
<tr>
<td>Sundance #5</td>
<td>Edmonton</td>
<td>353</td>
</tr>
<tr>
<td>Sundance #6</td>
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<tr>
<td>Maxim #2</td>
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</tr>
<tr>
<td>Maxim #3</td>
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<td>7</td>
</tr>
<tr>
<td>Maxim #4</td>
<td>South</td>
<td>6</td>
</tr>
<tr>
<td>Medicine Hat #1</td>
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<td>Musker River</td>
<td>Northeast</td>
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<tr>
<td>Nexen Inc. #1</td>
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<td>Nexen Inc. #2</td>
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<tr>
<td>Poplar Hill #1</td>
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<td>Primrose #1</td>
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<tr>
<td>Rainbow #1</td>
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<td>26</td>
</tr>
<tr>
<td>Rainbow #2</td>
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<td>40</td>
</tr>
<tr>
<td>Rainbow #3</td>
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<td>Rainbow #5</td>
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<td>47</td>
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<td>Rainbow Lake #1</td>
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<td>Redwater Cogen</td>
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<tr>
<td>Rossdale #8</td>
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<td>Rossdale #9</td>
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<td>71</td>
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<tr>
<td>SAIT</td>
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<td>6</td>
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<tr>
<td>Shell Caroline</td>
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</tr>
<tr>
<td>Sturgeon #1</td>
<td>Northwest</td>
<td>10</td>
</tr>
<tr>
<td>Sturgeon #2</td>
<td>Northwest</td>
<td>8</td>
</tr>
<tr>
<td>Suncor #1</td>
<td>Northeast</td>
<td>525</td>
</tr>
<tr>
<td>Syn crude #1</td>
<td>Northeast</td>
<td>510</td>
</tr>
<tr>
<td>Talisman Edson</td>
<td>Edmonton</td>
<td>11</td>
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<tr>
<td>University of Alberta</td>
<td>Edmonton</td>
<td>39</td>
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<tr>
<td>Valleyview</td>
<td>Northwest</td>
<td>45</td>
</tr>
<tr>
<td>Weldwood</td>
<td>Edmonton</td>
<td>50</td>
</tr>
</tbody>
</table>

1 Location matches the bulk system categorization defined in Appendix J.
2 Maximum continuous rating (MCR) is the maximum volume of electricity a generating unit can produce on a continuous basis.
4.0 Current transmission system

Alberta’s bulk transmission system

The bulk transmission system is the integrated system of 500 kilovolt (kV) and 240 kV transmission lines and substations that delivers electric power from major generating facilities to load centres. It connects the major load and generation centres of Fort McMurray, Edmonton and Calgary, as well as interconnecting all the regions of Alberta. The bulk system also includes the interties with B.C. and Saskatchewan. The bulk transmission system substations and transmission lines are shown in Figure 4.0-1.

The bulk system is considered a single system that integrates the load and generation of the regions into the Alberta grid which is, in turn, connected with the rest of the North American system. See Figure 1 in Appendix I for an illustration of the regions of the North American power system.

Alberta’s regional transmission system

The regional system is studied using several transmission regions. These regions are defined by load and generation attributes specific to each area. There are six regions illustrated in Figure 2.0-1 in Appendix K, and defined below.

1. South region – consists of the area generally south of an east-west line through the City of Calgary. The area is primarily rural with two larger urban centres, the City of Lethbridge and the City of Medicine Hat. Generation in Medicine Hat is fired by natural gas, while generation in the remainder of the region is primarily wind and small hydro.

2. Calgary region – consists of the area that includes the City of Calgary and surrounding communities, as well as the area between Calgary and the Alberta-B.C. border. The City of Calgary and suburban areas dominate the electrical load in the area. Generation is primarily natural gas combined cycle and peaking facilities.

3. Central region – consists of the area between the cities of Calgary and Edmonton from the Saskatchewan border to the B.C. border. This area has a mix of loads including rural, urban (City of Red Deer) and industrial. The industrial load is primarily pipelines that run from Edmonton down the east side of the province. Generation is a mix of hydro in the west, simple cycle gas turbines in the central area and coal-fired thermal plants in the east.

4. Edmonton region – consists of the City of Edmonton and surrounding communities and extends west to the Wabamun Lake area. The load is dominated by the City of Edmonton and the refinery facilities on the east side of Edmonton. Generation is dominated by the larger coal-fired generating plants in the Wabamun Lake area. Other generation includes simple cycle gas turbine generators near the City of Edmonton.

5. Northeast region – consists of the northeast quadrant of the province, east of the Fifth Meridian and north of the City of Edmonton. Loads in this area are dominated by oilsands extraction and upgrading. This area is unique in that many of the load facilities also have on-site generation in the form of gas-fired cogeneration.

6. Northwest region – consists of the northwest quadrant of the province, west of the Fifth Meridian and north of Edmonton. The area loads are a mix of industrial, primarily gas and oil, rural and urban. Generation in the area is primarily simple cycle gas turbine generators.
Figure 4.0-1: Existing bulk transmission system
5.0 Current imports and exports

Interties are transmission system connections between neighbouring electric systems. They consist of high voltage transmission lines and other transmission system equipment. Interties are beneficial to Albertans, offering electricity supplies from out of province, opportunities to sell surplus energy and power system support in emergencies.

Alberta currently has two interties – one with B.C. and another with Saskatchewan. The intertie with B.C. was designed to import up to 1,200 MW and export up to 1,000 MW. The intertie with Saskatchewan was designed to import and export up to 150 MW. Both interties are currently operating below these levels due to existing transmission constraints within Alberta. In 2007, the intertie with B.C. had a maximum import and export capability of 675 MW and 735 MW respectively. In 2007, the Saskatchewan intertie had a maximum import and export capability of 153 MW and 60 MW respectively.

The intertie between Alberta and B.C. allows both provinces to benefit from resource synergy. Most of B.C.’s generation is provided by hydroelectric power, while most of Alberta’s power generation is fossil-fuel based. This diversity allows Alberta generators to export surplus energy at night when provincial demand is less and provides an opportunity for B.C. to sell surplus hydroelectric power into Alberta at times of increased demand.

Alberta is one of the least interconnected jurisdictions in Canada with only two transmission interties providing limited export and import capacity. Additional interties increase the ability for Alberta generators to sell surplus energy during off-peak periods. New interties also provide access to more sources of supply during on-peak periods. These benefits can promote generation investment in Alberta and reduce price volatility in the market.

The AESO is working with the British Columbia Transmission Corporation (BCTC) to explore the benefits and costs of additional intertie capacity between Alberta and B.C.

**Intertie statistics 2000 to 2007**

As shown in the data in Table 5.0-1, since 2002, Alberta has been a net importer of electric energy. In 2007, Alberta had net imports of about 494,000 megawatt hours (MWh). Export volumes increased in 2007 compared to 2006 levels. This increase can be attributed in part to higher transfer capability on the interties.

<table>
<thead>
<tr>
<th>Intertie statistics (MWh)</th>
<th>2000</th>
<th>2001</th>
<th>2002</th>
<th>2003</th>
<th>2004</th>
<th>2005</th>
<th>2006</th>
<th>2007</th>
</tr>
</thead>
<tbody>
<tr>
<td>Imports on B.C. intertie</td>
<td>564,238</td>
<td>232,052</td>
<td>895,753</td>
<td>898,717</td>
<td>1,073,471</td>
<td>1,070,848</td>
<td>1,101,207</td>
<td>927,108</td>
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<tr>
<td>Imports on Sask. intertie</td>
<td>742,704</td>
<td>676,130</td>
<td>239,406</td>
<td>428,949</td>
<td>418,267</td>
<td>463,726</td>
<td>415,828</td>
<td>540,113</td>
</tr>
<tr>
<td><strong>Total imports</strong></td>
<td><strong>1,306,942</strong></td>
<td><strong>908,182</strong></td>
<td><strong>1,135,159</strong></td>
<td><strong>1,327,666</strong></td>
<td><strong>1,534,574</strong></td>
<td><strong>1,517,035</strong></td>
<td><strong>1,467,221</strong></td>
<td></td>
</tr>
<tr>
<td>Year-over-year growth (%)</td>
<td></td>
<td>-30.51</td>
<td>24.99</td>
<td>16.96</td>
<td>12.36</td>
<td>2.87</td>
<td>-1.14</td>
<td>-3.28</td>
</tr>
<tr>
<td>Exports on B.C. intertie</td>
<td>797,092</td>
<td>1,974,107</td>
<td>465,939</td>
<td>1,194,264</td>
<td>968,434</td>
<td>987,581</td>
<td>460,050</td>
<td>885,551</td>
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<tr>
<td>Exports on Sask. intertie</td>
<td>27,166</td>
<td>63,388</td>
<td>105,337</td>
<td>32,903</td>
<td>929,403</td>
<td>50,493</td>
<td>29,415</td>
<td>87,666</td>
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<tr>
<td><strong>Total exports</strong></td>
<td><strong>824,258</strong></td>
<td><strong>2,037,495</strong></td>
<td><strong>571,276</strong></td>
<td><strong>1,227,167</strong></td>
<td><strong>1,061,374</strong></td>
<td><strong>1,038,074</strong></td>
<td><strong>489,465</strong></td>
<td><strong>973,217</strong></td>
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<tr>
<td>Year-over-year growth (%)</td>
<td></td>
<td>147.19</td>
<td>-71.96</td>
<td>114.81</td>
<td>-13.51</td>
<td>-2.20</td>
<td>-52.85</td>
<td>98.83</td>
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<tr>
<td><strong>Net yearly import (export)</strong></td>
<td><strong>482,684</strong></td>
<td><strong>(1,129,313)</strong></td>
<td><strong>563,883</strong></td>
<td><strong>100,499</strong></td>
<td><strong>430,364</strong></td>
<td><strong>496,500</strong></td>
<td><strong>1,027,570</strong></td>
<td><strong>494,004</strong></td>
</tr>
</tbody>
</table>
**Intertie utilization on the rise in 2007**

The available transfer capability (ATC) is the amount of electricity that can flow on the interties. This capability is an hourly value that fluctuates with system conditions. Figure 5.0-1 shows a historic analysis of the number of hours when the interties were at least 80 per cent utilized (i.e., recorded power flow on the interties was at 80 per cent or higher of the ATC for that hour). Utilization is both the amount of hourly scheduled flows and the amount of reserves provided by the interties divided by the hourly ATC. In 2007, the frequency of highly-utilized hours on both interties, for imports and exports, was higher than the previous year.

**Figure 5.0-1: Number of hours the interties are highly used**
(Highly used = 80% or greater utilization of the intertie ATC)
Appendix I
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This appendix is a general discussion of some of the technologies that are advancing the transmission of electricity.

**High voltage direct current (HVDC)**

The Alberta Interconnected Electric System (AIES) operates using three-phase alternating current (AC) transmission. This means that transmission circuits in Alberta consist of three sets of conductors, one set per phase, to carry energy and may include additional conductors installed higher on the structure that act as overhead shield wire(s) to shield the current-carrying lines beneath from lightning strikes. In both AC and direct current (DC) systems, high voltage is advantageous when transmitting energy as it minimizes losses in the transmission process.

When integrating a DC transmission facility with an AC system, conversion terminals are required at either end of a DC transmission line and are an integral part of the HVDC system. The terminal that converts AC to DC is called a rectifier terminal and the terminal that converts from DC back to AC is called an inverter terminal. Instead of the set of three current-carrying conductors used in an AC system, a DC system requires two sets of current-carrying conductors. This type of DC system is described as bipolar. In some cases a third set of conductors is required to provide a metallic ground current path. The reduction in conductor sets leads to smaller towers and reduced right-of-way requirements compared to AC.
DC is mainly used for long distance transmission. Where appropriate, HVDC offers high capacity and efficiency with a lower right-of-way requirement than AC alternatives. HVDC lines have lower transmission losses over long distances than AC lines. Cable and tower costs are typically lower for DC transmission. However, the lower line costs of DC systems are offset when the costs of the inverter and rectifier terminals required at either end are included. There are numerous variables involved; however, DC for overhead lines is generally more economic than AC when the transmission distance is greater than 700 kilometres (km).

HVDC projects have achieved power ratings of up to 3,000 megawatts (MW) at ±500 kilovolts (kV). The need to move large amounts of power over longer distances is pushing HVDC into the next frontier (voltage levels above ±600 kV) of ultra high voltage direct current (UHVDC). UHVDC projects are being planned that will provide power ratings in excess of 4,000 MW at ±600 kV.

According to the corporate technical journal of the ABB Group, HVDC systems can carry 2-5 times the capacity of an AC transmission line of similar voltage.

One characteristic of DC transmission is that it does not allow the flexibility of interconnection along the transmission route that AC transmission does. This is because an inverter station is required at every interconnection point to convert from DC back to AC to be able to make use of the energy. In AC transmission, interconnections can be made almost anywhere and transformers can be used to increase or decrease the voltage. Typical HVDC systems have a converter station at each of the sending and receiving ends with an HVDC line connecting the two, thereby creating a two-terminal HVDC line. When more than one two-terminal HVDC line is being considered, it is possible to reduce the overall cost of the development by designing a multi-terminal HVDC system that essentially combines the converter stations at the common point into one facility.

There is a technical limit as to the number of converter stations that can be simultaneously operated on a DC transmission line. Currently the maximum number of terminals in operation on a multi-terminal HVDC line in the world is three.

Some examples of HVDC currently in use in Canada include HVDC transmission lines in Manitoba and Quebec. There are also HVDC lines operating within the Pacific Northwest and the California-Nevada areas of the U.S.

The Alberta and Saskatchewan electric systems are interconnected through a back-to-back HVDC converter station that is owned and operated by ATCO Electric. The back-to-back aspect of the intertie refers to the fact that there is no transmission line involved. The AC of the AIES is converted to DC and then immediately from DC back to AC to connect to Saskatchewan’s transmission grid (and vice versa). Whereas AC in North America operates at a frequency of 60 Hertz (Hz), DC has a frequency of zero. As a result, a back-to-back HVDC converter configuration such as the intertie connecting the Alberta and Saskatchewan electric systems prevents problems affecting frequency on the Western Interconnection (see NERC Interconnections Figure 1), to which the AIES belongs, from impacting the Eastern interconnection, to which Saskatchewan’s transmission grid belongs.
North America, including Canada and Mexico, is divided into three separate transmission interconnections: the Eastern Interconnection, the Western Interconnection and the Texas Interconnection. WECC is the Western Electricity Coordinating Council.

Flexible AC transmission systems (FACTS) devices

Traditionally, strengthening power grids has involved construction of new transmission lines. However, as these have become more difficult and more expensive to site, industry has responded by developing new technologies. FACTS devices are a family of controllers integrated into a transmission system to allow improved power flow management and control. It is estimated that FACTS devices can boost the transmission capacity of lines now limited by voltage or stability considerations by as much as 20 to 40 per cent.

FACTS devices tend to be highly technical. An overview of the major FACTS devices is provided in Figure 2. The left column identifies conventional devices that use fixed or mechanically switchable components that alter the physical electric system characteristics of resistance (R), inductance (L) and capacitance (C). FACTS devices contain these components as well, but came about as a result of the increased rating and improved performance of power electronics. Power electronic valves and converters allow faster switching in smaller steps. This combination allows FACTS devices to better control elements of the power system such as voltage, reactive power and impedance resulting in such benefits as the ability to dampen power system oscillations and actively filter out unwanted harmonics and phase unbalance. FACTS devices are also considered static; however, since unlike the mechanical switching required in conventional devices, they have no moving parts.

Figure 2: Overview of major FACTS devices

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Resistance (R), inductance (L) and capacitance (C) are basic components of the transmission system. The resistance, measured in ohms (Ω), of transmission line conductors, is the most significant cause of power loss in a transmission line. In the very simplest of terms:

\[
\text{Resistance} = \frac{\text{power loss in a conductor}}{(\text{current in a conductor}) \times (\text{current in a conductor})}
\]

The inductance (L), measured in henrys (H), is the property of the transmission line that relates the voltage induced by changing flux to the rate of change of the current. The capacitance (C), measured in farads per metre (F/m), is the charge on the conductors per unit of potential difference between them.

“Technology development has opened new ways of managing grids. Progress in static reactive power compensation and power storage technologies enables new sources of electrical energy to be connected to existing grids. Power electronics have made it possible to control grids and new FACTS (flexible AC transmission systems) devices are improving controllability.”

Overview of major FACTS devices
Some of the devices now included under the FACTS umbrella pre-date the introduction of the FACTS concept. The AIES installed a static voltage-ampere reactive compensator (SVC) near Langdon in 1986. SVCs are the simplest of the FACTS devices and are used for reactive power control. Table 1 shows the estimated number of worldwide installed FACTS devices and their estimated total installed power.

Table 1: Estimated number of worldwide installed FACTS devices and their estimated total installed power

<table>
<thead>
<tr>
<th>Type</th>
<th>Number</th>
<th>Total installed power (MVA)*</th>
</tr>
</thead>
<tbody>
<tr>
<td>SVC</td>
<td>600</td>
<td>90,000</td>
</tr>
<tr>
<td>STATCOM</td>
<td>15</td>
<td>1,200</td>
</tr>
<tr>
<td>Series compensation</td>
<td>700</td>
<td>350,000</td>
</tr>
<tr>
<td>TCSC</td>
<td>10</td>
<td>2,000</td>
</tr>
<tr>
<td>HVDC B2B</td>
<td>41</td>
<td>14,000</td>
</tr>
<tr>
<td>HVDC VSC B2B</td>
<td>1 + (7 with cable)</td>
<td>900</td>
</tr>
<tr>
<td>UPFC</td>
<td>2 – 3</td>
<td>250</td>
</tr>
</tbody>
</table>

*MVA: megavolt-ampere

In Kayenta, Arizona, Siemens built the world’s first continuously controlled three-phase series compensator. The system has been in operation since 1993.

HVDC VSC

HVDC voltage source converter (VSC) technology takes advantage of the complementary nature of HVDC and FACTS technologies. These systems incorporate HVDC lines with the VSC technology of FACTS devices allowing very rapid voltage, power and stability control. There are at least two commercial versions of such systems: HVDC Light® by ABB Ltd. (Figure 3) and HVDC PLUS (Power Link Universal System) by Siemens (Figure 4). Currently there are nine installations utilizing ABB’s HVDC Light®, eight of which are underground or sub-marine installations, and three more projects identified to be in service by 2010. The first Siemens HVDC Plus installation is scheduled to be in service by 2010 on the Trans Bay project in California.

Figure 3: Shoreham HVDC Light converter station ⁵

HVDC Light® was designed by ABB in 1997 to transmit power underground, under water and over long distances.

Figure 4: HVDC PLUS ⁶

The Siemens high voltage direct current transmission system HVDC Plus is based on a new generation of power converters using VSC technology.

“Transmission and distribution of electrical energy is not possible without losses in the lines, but high voltage DC and FACTS (Flexible AC Transmission Systems) offer excellent ways to reduce these losses.” ⁷

⁷ From ABB Review 2/2007, p. 3.
Wide-range monitoring systems

There is also a group of technologies whose goal is to provide detailed and timely information on grid status as a means of improving grid management. These systems measure and monitor system operating parameters over a large portion of the system and rely on high-speed communications to be effective. An example of this technology is referred to as wide area measurement systems (WAMS); however, the terms wide area monitoring systems and wide area control systems also refer to technology of this type. One of the first monitoring concepts relying on new measurement technologies was ABB's voltage instability predictor (VIP). The VIP provides a transmission system operator with a local measure of the power margin before voltage collapse at a particular substation occurs.

Another example of the types of components that provide information into these innovative wide-range monitoring systems is the phasor measurement unit (PMU). These units provide time-synchronized values of the local magnitudes and angles of sinusoidal signals with high resolution in the time domain. PMUs are a common component of the AIES, but they are not currently used for real-time operations. PMUs are used for disturbance monitoring, performance monitoring and validation. The AESO is an active member of WECC's Disturbance Monitoring Work Group and participates with a number of other organizations in WECC on a WAMS initiative that utilizes PMUs. A real-time dynamic monitoring system workstation for offline analysis by the California Independent System Operator (CAISO) is a product of the initiative. One example of a direct benefit of the initiative is Southern California Edison's (SCE) power systems outlook software, which has been used by SCE for post-disturbance analysis and is currently demonstrating its real-time capabilities in their grid control centre. The AESO is working towards incorporating PMUs into its real-time operations.

High temperature superconductors

Research into superconductivity, a laboratory phenomenon of zero electrical resistance occurring in certain materials at extremely low temperatures, has provided the electric utility industry with the more practical high-temperature superconducting (HTS) technology. HTS cables have some resistance, but can improve line losses from the five to eight per cent experienced with traditional power cables to approximately 0.5 per cent. The refrigeration required to super cool the HTS cables is generally supplied by liquid nitrogen. HTS cables are said to be able to carry approximately five times as much power as traditional copper wires with the same dimensions. The benefits of HTS also apply to power system components such as transformers. Due to refrigeration costs, superconductors are more expensive than traditional conductors and are suitable for only select projects.

HTS cable is currently being tested in Albany, New York by the U.S. Department of Energy and is being installed in Lower Manhattan, New York by the U.S. Department of Homeland Security working with Consolidated Edison. The Albany project is a 350 metre length of conductor that will be installed between two substations.

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Underground transmission lines

Underground installation of transmission lines is an important area of development. HTS cables, for example, require underground installation. The non-superconducting conductor that is being increasingly used for burial of transmission lines is XLPE cable, which is insulated by a solid material (polyethylene). Although first introduced commercially in the 1960s, XLPE use at 230 kV or above was rare until recently. XLPE cable, often referred to as extruded cable because of the method used to apply the insulation, is now being used for voltages up to 500 kV.

According to a 2006 Report of the Joint Legislative Audit and Review Commission to the Governor and The General Assembly of Virginia, underground lines are typically four to 10 times more expensive than overhead lines.

HVDC VSC cables have been developed specifically for underground burial. Currently there are eight underground or sub-marine installations utilizing HVDC VSC technology. These installations have been for moderate capacity and relatively short distances. The longest installation to date is the Murraylink project in Australia. The route traverses over 180 km through national parks and significant Aboriginal heritage sites transmitting 220 MW.

Due to its high cost, underground installation of transmission lines is typically limited to environmentally sensitive or extremely congested areas. The latter reason (lack of available aerial transmission corridors and the difficulties involved in obtaining suitable rights-of-way) contributed to the decision to install 9.4 km of 240 kV XLPE underground cable in the downtown Edmonton area.
Composite conductors

Another advancement in transmission line technology is the composite conductor. Aluminum conductor steel-reinforced (ACSR) refers to a commonly used type of overhead conductor composed of a central steel core for physical strength surrounded by stranded aluminum conductors that conduct electricity. New cores developed from composite materials reduce the sagging ACSR conductors experience at high temperatures. Reduced sagging eliminates the need to derate lines operating at higher temperatures.

Figure 5: Designed to increase clearance – less sag at high temperature
(Allows simple replacement on existing structures)

Existing line steel ACSR
1,200 amps

3M ACCR conductor
2,400 amps
+100%

Design sag (80°C)

High temp sag (240°C)

NESC* clearance

230 kV thermal upgrade
(+500 MVA increase)

Aluminum conductor composite reinforced (ACCR)

* NESC: National Electrical Safety Code

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The smart grid/intelligent grid/super grid

Moving to a more wholistic view of the transmission system, new concepts are emerging under the umbrella names Smart Grid, intelligent grid or IntelliGrid™ and super grid. Research Reports International describes the Smart Grid as “the next phase in the evolution of electrical power generation, transmission and distribution” and as a “fully automated power delivery network that monitors and controls every customer and node, ensuring a two-way flow of electricity and information between the power plant and the appliance, and all points in between.”

A broad range of products is being implemented in support of this new type of grid. A few examples are:

- In Dallas, Texas, the CURRENT Smart Grid™ system links the utility’s control centre to devices in a consumer’s home, such as programmable communicating thermostats and load control switches, using a high-speed broadband over the power line network. This link allows consumers to participate in programs designed to reduce electricity demand and the utility to verify, in real-time, that a reduction in load has occurred.

- Remotely readable transformer monitors provide adjustable sampling rates as frequently as once every seven minutes for critical fault gases, an important indicator of a transformer’s overall condition. AltaLink Management Ltd. (AltaLink), which uses online transformer monitors, believes that by monitoring these critical assets it is able to lower its maintenance costs and extend the lives of transformers while deferring capital expenditures. In the past AltaLink relied on two age-sensitive triggers to maintain all components of its transmission system: time and number of operations. Because factors other than age and number of operations, including temperature, load, fault currents and constantly changing operating conditions can affect the useful life of a transformer, it is important to have other measures of transformer performance. Intrusive maintenance performed to determine a transformer’s condition is no longer cost effective or necessary with the introduction of monitoring devices and computerized analytical diagnostic tools.

- As a pilot project for the AESO, AltaLink installed dynamic thermal line rating units on a transmission line in southern Alberta between Pincher Creek and the Peigan substation. Line ratings represent the maximum allowable power flow through a transmission line and are based on line ampacity (the physical capability of a line to carry current), ambient temperature, conductor temperature and wind speed. In the past, winter and summer line ratings have been established based on assumptions about these factors (and considering a safety factor), and the line has been operated only up to these seasonal ratings. This pilot project will provide system operators with real-time information about the line, which allows them to increase the amount of power flowing on the line under certain conditions. This operating flexibility helps increase system reliability and creates the opportunity to reduce congestion.
Another wholistic approach to improving the movement of electricity is the concept of a continental super grid. According to Thomas J. Overbye, a professor in electrical and computer engineering at the University of Illinois at Urbana-Champaign, “In short, the super grid concept envisions the use of underground, superconducting direct current cables for long distance power transmission at levels of perhaps five to 10 gigawatts.”

Other efforts are underway to develop the IntelliGrid – a nimbler, more flexible network that marries electric power with cutting-edge communication and computing capabilities. This initiative intends to move the grid from a patchwork of proprietary information systems to a system with standardized interfaces so new applications can be easily commissioned. The international consortium pursuing this goal consists of the Electric Power Research Institute, electric utilities, public agencies and leading equipment manufacturers.

**Nanotechnology**

Nanotechnology is a popular current research area that has the potential to significantly change the electric utility industry. Carbon nanotubes, which are about the size of a human hair, are long, thin cylinders of carbon that can be single- or multi-walled (cylinders inside the other cylinders). Carbon nanotubes have a broad range of electronic, thermal, and structural properties that change depending on the different kinds of nanotube (defined by its diameter, length and spiral quality). Carbon-nanotube wire product (also called armchair quantum wire for the type of nanotube best suited for the process) has been estimated to have the potential to increase grid capacity by perhaps a million times. There are some serious obstacles to moving this technology from theory to production. These include consistent production of nanotubes with controlled and desirable conduction properties and improved understanding of transport across tube junctions.

**Alberta industry collaboration**

The AESO continuously monitors advancements in transmission technology to facilitate its application to the AIES. It also participates in efforts such as the Alberta Power Industry Consortium with the objective of promoting opportunities in power careers at the University of Alberta to enhance the longer-term supply of engineers in the electric utility profession. In addition to the AESO, the consortium also includes AltaLink Management Ltd., ATCO Electric Ltd., EPCOR and FortisAlberta Inc.

An example of the consortium’s work is its support of the Natural Sciences and Engineering Research Council of Canada/Informatics Circle of Research Excellence – Alberta Power Companies Industrial Research Chair in Power Quality at the University of Alberta. Dr. Wilson Xu was appointed to this Chair in early 2008. Dr. Xu is leading a team of researchers in using modern information and communication technologies to enhance performance of the AIES.

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10 From Building Tomorrow’s Super Grid EnergyBiz Magazine, September/October 2006.
Appendix J
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1.0 Introduction

The AESO plans the Alberta transmission system by evaluating requirements within various geographic regions in the province and the bulk system that interconnects these regions.

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

The bulk transmission system is critical to overall system reliability, for delivering bulk power to load centres, for connecting new generation and enabling import and export transactions with neighbouring jurisdictions.

The AESO’s technical analysis examines and identifies the required reinforcements of the bulk transmission system, aligning which facilities are required in a specific timeframe to meet forecast generation, and load requirements and planning scenarios and to facilitate the Provincial Energy Strategy.

The bulk system is studied by defining several transmission cutplanes. These cutplanes combine the loading on groups of transmission lines that connect two areas within the bulk system. Four major cutplanes are used to study the bulk transmission system in Alberta as follows:

1. **Edmonton to northeast transmission path (NE cutplane)** – There are currently two 240 kV lines between Edmonton and the northeast area. These two lines, plus a number of 138 kV lines, interconnect the Edmonton area with the northeast area and are referred to as the NE cutplane.

2. **Edmonton to northwest transmission path (NW cutplane)** – There are currently three 240 kV lines between the Wabamun area and the northwest area. These three lines, plus a number of 138 kV lines, interconnect the Wabamun area with the northwest area and are referred to as the NW cutplane.

3. **Edmonton to Calgary transmission path (SOK cutplane)** – There are currently six 240 kV transmission lines between Edmonton and the Red Deer area. These six lines, plus a number of 138 kV lines, carry all the power from northern Alberta, south from the generating plants in the Wabamun Lake area (Keephills, Genesee, Sundance and Wabamun) to central and southern Alberta and are referred to collectively as the SOK cutplane.

4. **South to Calgary and central transmission path (South cutplane)** – There are currently four 240 kV lines between the south area and the Calgary and central areas. Three of these lines, plus a number of 138 kV lines, interconnect the south area with the Calgary and central areas and are referred to as the South cutplane.
Figure 1.0-1: Existing bulk transmission system and cutplanes

- **BULK SYSTEM SUBSTATIONS**
- Existing transmission lines
- Voltage
  - 240 kV
  - 500 kV
  - Planning cutplanes
Besides the four cutplanes internal to Alberta, there are two interties to other jurisdictions that are considered as part of the bulk system. They are:

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

- **Alberta to Saskatchewan transmission path** – Synchronous operation with Saskatchewan is not possible as it is part of the Eastern Interconnection of North America and Alberta is part of the Western Interconnection. These two large interconnected systems are joined together via high voltage direct current (HVDC) back-to-back (i.e., asynchronous) links at various points in Canada and the U.S. (Refer to Figure 1 in Appendix I for a map showing the Eastern and Western Interconnections.) The Alberta-Saskatchewan intertie comprises such a link, known as the McNeill converter station, which is located near Empress, Alberta. The converter station is connected via a 138 kV transmission line to the Alberta system and a 230 kV line to Swift Current, Saskatchewan. The converter station itself is operated at 42.2 kV. This intertie provides Alberta access to the electricity markets in the Eastern Interconnection through Saskatchewan and Manitoba and the U.S. Midwest and similarly provides entities in these jurisdictions with access to the Alberta market.

The main facilities of the existing bulk transmission system and the associated cutplanes are shown in Figure 1.0-1. As the figure shows, the bulk system connects the major load/generation centres of Fort McMurray, Edmonton and Calgary, as well as interconnecting all the regions of Alberta. The bulk system also includes the interties to B.C. and Saskatchewan.

### 2.0 Transmission technology alternatives

There are a number of possible technological choices that could be considered to meet the long-term system development requirements for Alberta's transmission system. The system can be reinforced using transmission lines designed for alternating current (AC) operation with voltages ranging from 240 to 765 kV. A HVDC option with transmission lines designed for operation at voltages ranging from ±250 kV to ±500 kV is also possible.

Alberta currently uses 240 kV and 500 kV AC for its bulk transmission system and it is anticipated that facilities at these voltage levels will continue to provide the appropriate balance between capacity and cost in the Alberta context. A significant portion of the bulk transmission systems in the western half of North America uses the same voltage levels and for these reasons, these voltage levels are considered appropriate for future transmission development in Alberta. However, as discussed in Section 4.0 of the Long-term Transmission Plan, HVDC transmission is recognized as providing the required power transfer capacity at a lower overall land-use impact as well providing the ability to directly control both power flow quantity and direction. For these reasons, HVDC has been selected as the preferred technology choice for those situations where these attributes are seen as significant advantages for the long-term development of the bulk transmission system in Alberta.
3.0 **Bulk system projects currently underway**

There are a number of projects for which Needs Identification Documents (NID) have been filed with the Alberta Utilities Commission (AUC) and the projects are at various stages of completion. These projects are listed in Table 3.0-1 along with a brief description and the estimated cost. The transmission capability increases provided by these developments are assumed to have been achieved when assessing the future needs on the bulk transmission system.

**Table 3.0-1: Bulk transmission system projects currently underway**

<table>
<thead>
<tr>
<th>Year in service</th>
<th>Project</th>
<th>Description</th>
<th>Bulk region</th>
<th>Cost estimate (2008 $ millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2010</td>
<td>Southwest Alberta Transmission Development</td>
<td>New Goose Lake 240/138 kV 400 MVA* substation adjacent to Pincher Creek; a new double circuit 240 kV line from Goose Lake to Peigan to North Lethbridge and various 138 kV system reinforcements to accommodate wind generation development.</td>
<td>South</td>
<td>154</td>
</tr>
<tr>
<td>2010</td>
<td>Northwest Alberta Transmission Development</td>
<td>A single 240 kV line between Brintnell and Wesley Creek to meet the load growth in the northwest area and maintain reliability of supply.</td>
<td>Northwest</td>
<td>208</td>
</tr>
<tr>
<td>2010</td>
<td>Transmission Conversion of 1202L between Keephills 320P and Edmonton Areas</td>
<td>Conversion of 1202L between Keephills 320P and Ellerslie to its design voltage of 500 kV; installation of a 240 kV 600 MVA phase-shifting transformer at Keephills 320P and a minor alteration to the existing 240 kV 902L or 909L line to reinforce the transmission system between the Wabamun Lake and Edmonton areas and facilitate connection of Keephills 3 to the grid.</td>
<td>Edmonton</td>
<td>67</td>
</tr>
<tr>
<td>2010</td>
<td>Transmission Separation of 946/947L into two 240 kV lines, one from Ellerslie to East Edmonton and the other from Ellerslie to Clover Bar, to increase the transfer capability from Edmonton into the northeast area.</td>
<td>Separation of 946/947L into two 240 kV lines, one from Ellerslie to East Edmonton and the other from Ellerslie to Clover Bar, to increase the transfer capability from Edmonton into the northeast area.</td>
<td>Edmonton</td>
<td>19</td>
</tr>
<tr>
<td>2010-2011</td>
<td>Edmonton Region 240 kV Line Upgrades</td>
<td>Debottlenecking/upgrading/reconfiguring the existing 240 kV lines (902L, 904L, 908L and 909L) and installing a new 240 kV 600 MVA phase-shifting transformer in 9L57 line to address overloads in the Edmonton area and increase transfer capability on the northeast transmission path out of the area.</td>
<td>Edmonton</td>
<td>122</td>
</tr>
</tbody>
</table>

Total 570

* MVA: megavolt-ampere.
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Appendix K

Long-term Regional Transmission System Plan

1.0 Introduction

The Long-term Regional Transmission System Plan provides a detailed view of transmission requirements of the regional transmission system for the upcoming 10-year period. The results for each region are presented in the following sections. Each of these sections includes a brief description of the region’s boundaries, the existing facilities and conditions, expected future growth in load and generation, transmission projects underway or at different stages in the regulatory process, region challenges by 2017 and conceptual plans to address these challenges. Specific transmission projects are presented as recommended options for development. In addition to meeting forecast load and generation, these plans also consider the need to facilitate the Provincial Energy Strategy.

The new transmission facilities as depicted in the system diagrams provided in this Appendix are not intended to convey specific routes or locations. Detailed analysis and stakeholder consultation will be conducted during the planning process, and in some cases such activity is currently underway. This document does not pre-empt any results of that effort.
2.0 Regional transmission system plan background

The next six sections discuss the regional transmission system needs. Generally, the regional transmission system collects power from the bulk transmission system and delivers it to local area loads. The regional system includes lines and substations operating at 240 kilovolts (kV), 144/138 kV and 72/69 kV.

The AESO’s load forecast used for regional planning purposes is presented in Appendix C and provides a forecast of demand megawatts (MW) at the time of region peak. The regions discussed in this section are all experiencing varying degrees of load growth. This regional growth is then applied to specific load supply substations in the planning model for the region under review. This identifies the potential impacts to the local system should the projected load growth occur.

The generation scenarios presented in Appendix E were selected for study purposes based on the impact that the resulting flows would have on a particular region. Dispatch of generation in the north or south will provide different flow patterns, which may have a greater impact on one region over another. The regional planning process included an assessment of the generation scenario that was most onerous on the transmission system within a region. The generation dispatch in the selected scenario was then adjusted, if necessary, to determine if the re-dispatch of local generation increased impacts on the region.

The conceptual plans presented for each region indicate the approximate facilities that may be required by 2017. The specific solutions recommended for implementation will be identified in future Needs Identification Documents (NIDs). While engineering judgment was used in determining these conceptual plans, they should not be interpreted as eliminating any other options or alternatives.

For planning purposes, the province is divided into six regions as shown in Figure 2.0-1.
Figure 2.0-1: Alberta regional transmission system planning map
3.0 South region

The South region of Alberta has its south boundary at the Canada-U.S. border. The region is bordered on the north by Seebe, Calgary, Hanna and Sheerness. The region is also bordered by B.C. and Saskatchewan on the west and east respectively. The major transmission facilities of the South region are shown in Figure 3.0-1.

South region current conditions

The region has historically been a net importer of power from the rest of the Alberta Interconnected Electric System (AIES) even though the non-coincident peak load in the region is less than its generating capacity. Imports are dependent upon the output of wind generation in the region, which is intermittent. The region has typically imported about five per cent of its annual energy supply, which indicates that the region has almost enough generation to supply the load within the region.

The portion of the generation produced by wind generating facilities located in the South region is expected to increase substantially over the next five years. Energy production from these facilities will vary based upon the available wind to drive the turbines. During certain wind conditions, the South region will have a surplus of power to deliver to the rest of Alberta, and export to B.C. and Saskatchewan through transmission interties.

The South region has transmission connections to both the Calgary and Central regions. In addition, the region interconnects with B.C. and Saskatchewan. These South region connections include:

- **Central region**
  - a 240 kV circuit from Anderson to Cordel
  - a 138 kV circuit from Empress to the Hanna area

- **Calgary region**
  - two 240 kV circuits from West Brooks and North Lethbridge through the use of three terminal lines to Langdon
  - a 240 kV circuit from Peigan to Janet
  - a 138 kV circuit from Vulcan to Blackie
  - a 138 kV circuit from West Brooks to Queenstown

- **Saskatchewan intertie**
  - a back-to-back direct current (DC) converter station located at McNeill interconnecting to the Saskatchewan transmission system

- **B.C. intertie (portion)**
  - a 138 kV circuit from Coleman to Natal, B.C.
Figure 3.0-1: Existing South region transmission system
South region expected growth

The forecast 2007, 2012 and 2017 seasonal coincident peaks for the South region are shown in Appendix C.

Within the South region, the AESO has received system access applications for a significant number of generation projects as well as the Montana Alberta Tie Line merchant intertie project that will connect the Lethbridge area with Montana.

There is 497 MW of wind generation connected to the transmission system in the South region. In September 2007, the AESO removed a restriction that limited the number of wind generation connections to the AIES to 900 MW. More than 11,500 MW of wind generation system access applications have been submitted to the AESO, with more than 7,500 MW located in the South region.

South region current transmission projects

The South region current transmission projects are listed in Table 3.0-1. The list includes projects that have a NID submitted to the Alberta Utilities Commission (AUC) for approval or have been approved but are not yet constructed.

<table>
<thead>
<tr>
<th>Year in service</th>
<th>Project</th>
<th>Description</th>
<th>Cost estimate (2008 $ millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2008-2011</td>
<td>Lethbridge Area</td>
<td>Partial rebuild of 734L/813L North Lethbridge to MacDonald to double circuit and upgrade terminal equipment.</td>
<td>7</td>
</tr>
<tr>
<td></td>
<td></td>
<td>North Lethbridge 370S 200 MVA* 240/138 kV transformer addition.</td>
<td>8</td>
</tr>
<tr>
<td>Brooks Area</td>
<td>Replace two 240/138 kV transformers at West Brooks with two 400 MVA units.</td>
<td>12</td>
<td></td>
</tr>
<tr>
<td></td>
<td>West Brooks to Brooks 138 kV line addition and 100L reconfiguration.</td>
<td>9</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Add 27 MVAr** capacitor bank addition at Tilley.</td>
<td>2</td>
<td></td>
</tr>
<tr>
<td>Empress Area</td>
<td>New 240 kV substation with two 200 MVA units.</td>
<td>25</td>
<td></td>
</tr>
<tr>
<td></td>
<td>951L termination at Jenner.</td>
<td>6</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Add two 27 MVAr capacitor banks at McNeill.</td>
<td>4</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Existing line rating upgrade requiring terminal equipment modification.</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td></td>
<td>74</td>
</tr>
</tbody>
</table>

* MVA: megavolt-ampere.
** MVAr: megavolt-ampere reactive.
South region challenges to 2017

Special considerations
The largest challenge for the South region is the amount of wind generation that has requested to be connected to the AIES. This issue has been addressed with the Southern Alberta (wind) Development discussed in Section 4.6 of the Long-term Transmission System Plan.

Issues identified
In addition to the wind integration thermal and voltage violations on the transmission system, load-related thermal overloads and voltage violations were identified in the Glenwood area. The issues identified are shown in Figure 3.0-2. The map shows overloads due to wind integration as well as the Glenwood area issues. The Glenwood area is the southern most part of the system from Waterton to Stirling.

The conceptual plans that address the South region’s issues due to load growth are included in Table 3.0-2. The AESO is at various stages of planning within this region and the conceptual plans will be updated as the process proceeds. The conceptual developments identified are representative of the alternatives that will be assessed.

Table 3.0-2: Conceptual South region transmission plans to 2017

<table>
<thead>
<tr>
<th>Year in service</th>
<th>Project</th>
<th>Description</th>
<th>Cost estimate (2008 $ millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2012-2016</td>
<td>Glenwood Area 69 kV Conversion to 138 kV</td>
<td>New 138 kV single circuit; Pincher Creek, Waterton, Drywood, Glenwood, Spring Coulee, Magrath, Stirling, Raymond tap and Raymond Reservoir.</td>
<td>119</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Convert substations to 138 kV; Waterton, Glenwood, Spring Coulee and Raymond Chute.</td>
<td>12</td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td></td>
<td>131</td>
</tr>
</tbody>
</table>
Figure 3.0-2: South region transmission issues identified to 2017
4.0 Calgary region

The Calgary region is the geographic area surrounding and including the City of Calgary. In the north, the region is bordered by Abraham Lake, Caroline, Didsbury and Hanna. In the south and east, the region is bordered by Sheerness, Brooks, Vauxhall and Stavely. The region is also bordered by B.C. on the west. The major transmission facilities of the Calgary region are shown in Figure 4.0-1.

**Calgary region current conditions**

The Calgary region is a major load centre for the province with close to 25 per cent of Alberta’s total load. The region imports power from the rest of the AIES because the non-coincident peak load is greater than the region’s generating capacity. On an annual basis, the region imports about 80 per cent of energy demand. The region depends on its six northern 240 kV interconnections to supply its load. In addition, some of the energy produced by local generation is currently operated out of economic merit to meet local reliability needs. This is transmission must-run (TMR) generation. The need to operate TMR generation indicates that the transmission system is not adequate to serve the current load. TMR payments are additional costs to consumers that an investment in transmission would avoid.

The Calgary region is connected to both the Central and South regions. In addition, an intertie with B.C. is within the Calgary region. The region’s connections include:

- **Central region**
  - two 240 kV circuits from Sarcee to Benalto
  - a 240 kV circuit from Beddington to Benalto
  - three 240 kV circuits from Janet to the Red Deer area
  - a 138 kV circuit from Ghost to the Didsbury area

- **South region**
  - a double circuit 240 kV (three terminal lines) from Langdon to West Brooks and North Lethbridge through Milo Junction
  - a 240 kV circuit from Janet to Peigan
  - a 138 kV circuit from Blackie to the Stavely area
  - a 138 kV circuit from Queenstown to the Brooks area

- **B.C. intertie (portion)**
  - a 500 kV circuit from Langdon to Cranbrook, B.C.
  - a 138 kV circuit from Pocaterra to Britt Creek

---

1 Transmission OPP 510 – Calgary Area Operations – available on the AESO’s website at [www.aeso.ca](http://www.aeso.ca)
Figure 4.0-1: Existing Calgary region transmission system

- EXISTING SUBSTATIONS
- Existing transmission lines
  - Voltage
- 69 kV/72 kV
- 138 kV/144 kV
- 240 kV
- 500 kV
**Calgary region expected growth**

The forecast 2007, 2012 and 2017 seasonal coincident peaks for the Calgary region are included in Appendix C. Construction of new distribution substations continues to accommodate the increase in demand. Along with additional distribution growth, the bulk 240 kV network that supplies power to the points of delivery (POD) will also require development to keep pace with the strong and steady growth.

**Calgary region current transmission projects**

The Calgary region current projects are listed in Table 4.0-1. The list includes those projects that have a NID submitted to the AUC for approval or have been approved but are not yet constructed.

<table>
<thead>
<tr>
<th>Year in service</th>
<th>Project</th>
<th>Description</th>
<th>Cost estimate (2008 $ millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2009</td>
<td>Balzac</td>
<td>Transformer addition (25 MVA).</td>
<td>5</td>
</tr>
<tr>
<td>ENMAX</td>
<td>New Substation</td>
<td>Addition of 138/25 kV capacity in northwest Calgary based on forecast 47S load in the area.</td>
<td>13</td>
</tr>
<tr>
<td>ENMAX</td>
<td>New Substation</td>
<td>Addition of 138/25 kV capacity in southwest Calgary based on forecast 6S load in the area.</td>
<td>6</td>
</tr>
<tr>
<td>ENMAX</td>
<td>Capacity Upgrade 26S</td>
<td>Addition of transformer capacity (30 MVA) in southeast Calgary based on forecast load in the area.</td>
<td>8</td>
</tr>
<tr>
<td>ENMAX</td>
<td>Capacity Upgrade 9S</td>
<td>Transformer addition.</td>
<td>5</td>
</tr>
<tr>
<td>ENMAX</td>
<td>Capacity Upgrade 7S</td>
<td>Transformer addition.</td>
<td>5</td>
</tr>
<tr>
<td>2010</td>
<td>ENMAX</td>
<td>Transformer addition.</td>
<td>6</td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td></td>
<td>48</td>
</tr>
</tbody>
</table>
**Calgary region challenges to 2017**

**Special considerations**

In the City of Calgary, there is an issue related to the capability to conduct maintenance on the existing transmission equipment. When specific transmission equipment is removed from service for maintenance, there are single contingencies that could result in the loss of load in the area. This condition occurs in the south area of the Calgary system and the city centre.

ENMAX Power, the transmission facility owner (TFO) within the City of Calgary, has indicated that the age of its facilities will require either maintenance or replacement within the 10-year horizon. In particular, this involves the existing 69 kV system in the south and north areas of the city, as well as the city centre 138 kV underground cables between ENMAX 1S, ENMAX 5S and ENMAX 8S. The city centre cables are approaching the end of operating life and have been derated due to high levels of dissolved gas in the oil insulator, which is a precursor to equipment failure. ENMAX is currently monitoring the cables and is keeping them in service by flushing out the gases. As the lines continue to age and the loading increases, the rate of gassing will increase.

The development of a transportation/utility corridor (TUC) around Calgary will be critical to allow the transmission system to develop and keep ahead of increasing demand. In addition, the establishment of new TUCs connecting to existing infrastructure would provide an opportunity for the orderly development of additional transmission infrastructure. The ring road development may provide opportunities to expand the existing TUC by completing the southwest portion of the transmission loop around Calgary. As the system continues to grow, it may be beneficial to investigate a larger TUC loop around Calgary to facilitate growth and minimize landowner impact.

There has also been increased interest in development of generation in the Calgary region. To date, the AESO has received over 1,800 MW of applications for new generation. In addition to these applications, wind generation from southern Alberta flows into the Calgary area and will potentially provide a large generation injection into the region in the longer term.

**Issues identified**

With the current projects in place, analysis was conducted using generation scenarios A1, B3 and B5 to outline system impacts in the 2017 timeframe (see Table 4.0-2 in Appendix E). Thermal overloads were identified in most of the region from Airdrie through the City of Calgary and south to High River, as well as east to Strathmore and west to Cochrane. Voltage violations were identified around Airdrie, in the City of Calgary and in the High River and Black Diamond areas. In addition to thermal overloads and voltage issues identified in scenario B5, additional support may be required to maintain the normal operating range of the Langdon static var compensator (SVC). The issues identified are shown in Figure 4.0-2.
Figure 4.0-2: Calgary region transmission issues identified to 2017

EXISTING SUBSTATIONS

Existing transmission lines
Voltage

- 69 kV/72 kV
- 138 kV/144 kV
- 240 kV
- 500 kV

Thermal overloads
Voltage violations
Conceptual Calgary region plans

The conceptual plans that address the Calgary region’s system performance issues are shown in Table 4.0-2. The AESO is at various stages of planning within this region and the conceptual plans will be updated as the planning process proceeds. The AESO has completed sufficient technical analysis on some of these plans to be able to make a recommendation. Other conceptual developments identified are representative of the alternatives that will be considered.

The AESO expects that further development will be required around north Calgary and Airdrie, as well as around Sarcee and the city centre, mostly related to the 138 kV system. Increased transformer capacity is also being considered at Balzac. The Airdrie area is seeing high load growth and as a result, additional 138 kV and possibly 240 kV enhancements will be required in that area. Studies have been initiated and a recommendation is expected in mid-2009.

To accommodate the load increase and resolve voltage issues in the High River area, a new 138 kV line between the proposed High River area 240 kV substation and the Black Diamond 138 kV substation is being considered. In addition, several capacitors may be required at the Black Diamond and High River substations to support voltages in the area under system contingency conditions. To resolve line overloads in the Strathmore area, a new 138 kV line is proposed from Blackie to Queenstown to off load the Janet to Strathmore line.

Table 4.0-2: Conceptual Calgary region transmission plans to 2017

<table>
<thead>
<tr>
<th>Year in service</th>
<th>Project Description</th>
<th>Cost estimate (2008 $ millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2009-2013</td>
<td>Increase the capacity at four substations.</td>
<td>31</td>
</tr>
<tr>
<td>2010</td>
<td>Increase the capacity at the Balzac and Dry Creek substations and add capacitor banks.</td>
<td>14</td>
</tr>
<tr>
<td>2011-2017</td>
<td>Three new 138/25 kV substations to the southeast, northwest and northeast of Calgary.</td>
<td>45</td>
</tr>
<tr>
<td>2012</td>
<td>New 138 kV single circuit from new High River area 240/138 kV substation to Black Diamond.</td>
<td>25</td>
</tr>
<tr>
<td>Upgrade Black Diamond High River 138 kV System</td>
<td>New 138 kV single circuit from Black Diamond to High River.</td>
<td>24</td>
</tr>
<tr>
<td>Upgrade Black Diamond High River 138 kV System</td>
<td>One 15 MVAr 138 kV capacitor bank at each of the High River and Black Diamond substations.</td>
<td>2</td>
</tr>
<tr>
<td>2014</td>
<td>New 138 kV single circuit from Blackie to Queenstown.</td>
<td>17</td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td>158</td>
</tr>
</tbody>
</table>
Recommended Calgary region projects

The AESO has completed comprehensive technical analysis and recommends the transmission reinforcements included in Table 4.0-3.

The underground cables that connect the downtown Calgary substations are near the end of their operating life and need to be replaced as failure of one of the cables would result in load loss in the Calgary city centre.

The 69 kV system in south Calgary is near the end of its operating life and is no longer adequate to carry loads in that part of the city. Hence, the AESO is recommending enhancements to replace the 69 kV system with a 138 kV system. These 138 kV improvements will tie in with the existing 138 kV lines in south Calgary and enhance overall reliability in south Calgary.

Table 4.0-3: Recommended Calgary region transmission projects to 2017

<table>
<thead>
<tr>
<th>Year in service</th>
<th>Project</th>
<th>Description</th>
<th>Cost estimate (2008 $ millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2011</td>
<td>Calgary Area Upgrades</td>
<td>Upgrade and replace the existing 138 kV underground cables in Calgary city centre between 1S, 6S and 8S.</td>
<td>20</td>
</tr>
<tr>
<td>2012</td>
<td>South Calgary Area 69 kV Conversion</td>
<td>Conversion of the 69 kV system in south Calgary to 138 kV; reconfiguration of south Calgary 138 kV transmission system.</td>
<td>22</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td></td>
<td></td>
<td><strong>42</strong></td>
</tr>
</tbody>
</table>
5.0 Central region

The Central region spans the province east to west between Edmonton and Calgary. The Central region is bordered on the north by the Edmonton, Grande Cache, Fox Creek, Wabamun, Wetaskiwin, Fort Saskatchewan and Cold Lake areas. The region is bordered on the south by the Calgary, Seebe, Airdrie, Strathmore, Sheerness and Empress areas. The region is also bordered by B.C. and Saskatchewan on the west and east respectively. The major transmission facilities of the Central region are shown in Figure 5.0-1.

Central region current conditions

The Central region imports power from the rest of the AIES even though non-coincident peak load in the region is less than the generating capacity. The region imports about 30 per cent of its annual energy supply. This means that the region is dependent on transmission lines to other areas to supply its load.

With its location in the middle of Alberta, there is also a significant transfer of energy through this region on the north-to-south path between Edmonton and Calgary on the existing 240 kV system. The Central region has connections to all of the other regions within Alberta: Northwest, Northeast, Edmonton, Calgary and South. These include:

- **Northwest region**
  - a 138 kV circuit from Marlboro to the Fox Creek area

- **Northeast region**
  - a 144 kV circuit from Whitby Lake to the Athabasca area
  - a 144 kV circuit from Whitby Lake to the Cold Lake area
  - a 144 kV circuit from Vermilion to the Cold Lake area

- **Edmonton region**
  - two 240 kV circuits from Benalto to Sundance
  - two 240 kV circuits from Benalto to Keephills
  - a 240 kV circuit from Red Deer to the Edmonton area
  - a 240 kV circuit from Red Deer to the Wetaskiwin area
  - a 138 kV circuit from North Holden to the Wetaskiwin area
  - a 138 kV circuit from West Lacombe to the Wetaskiwin area
  - a 138 kV circuit from Keystone to the Wabamun area
  - a 69 kV circuit from Moon Lake to the Wabamun area

- **Calgary region**
  - three 240 kV circuits from Benalto to the Calgary area
  - three 240 kV circuits from Red Deer to the Calgary area
  - a 138 kV circuit from Didsbury to Wabamun

- **South region**
  - a 240 kV circuit from Cordel to the Sheerness area
  - a 144 kV circuit from Michichi Creek to the Sheerness area
  - a 144 kV circuit from Oyen to the Empress area
Figure 5.0-1: Existing Central region transmission system
Central region expected growth
The forecast 2007, 2012 and 2017 seasonal coincident peaks for the Central region are provided in Appendix C.

Central region current transmission projects
The Central region current projects are listed in Table 5.0-1. The list includes those projects that have a NID submitted to the AUC for approval or have been approved but are not yet constructed.

Table 5.0-1: Central region current transmission projects

<table>
<thead>
<tr>
<th>Year in service</th>
<th>Project Description</th>
<th>Cost estimate (2008 $ millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2008-2009</td>
<td>Interconnection of four Keystone Pumpstation Loads</td>
<td>New 144 kV line from Ribstone Creek substation to Keystone 144/4.16 kV Lakesend substation.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>New 144 kV line from Monitor substation to 144/4.16 kV Keystone Monitor substation.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>New 144 kV line tapping off 7L98 to 144/4.16 kV Keystone Oyen substation.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Build 144 kV line tapping off 7L760 to 144/4.16 kV Keystone Bindloss substation.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Addition of 27 MVAr mobile capacitor bank at Monitor substation.</td>
</tr>
<tr>
<td></td>
<td>Interconnection of Hardisty Pipeline Loads</td>
<td>New 138 kV line tapping off the 704L line with an in-and-out to the new Tucuman substation.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Addition of 27 MVAr mobile capacitor bank at Hill and Tucuman substations.</td>
</tr>
<tr>
<td></td>
<td>Buffalo Creek Substation Upgrade</td>
<td>Convert Buffalo Creek to an in-and-out scheme and add one 144/25 kV 15/20/25 MVA transformer.</td>
</tr>
<tr>
<td></td>
<td>Upgrade Edgerton Substation</td>
<td>Replace existing 138/25 kV 10 MVA transformer with 138/25 kV 15/20/25 MVA transformer.</td>
</tr>
<tr>
<td></td>
<td>Upgrade Wainwright Substation or Addition of Second Transformer</td>
<td>New 144/25/4.16 kV substation and a 144 kV line tapping off 7L86.</td>
</tr>
<tr>
<td></td>
<td>Blackfalds Upgrades</td>
<td>Addition of one 138/25 kV 15/20/25 MVA transformer and two 25 kV feeder breakers.</td>
</tr>
<tr>
<td></td>
<td>Sylvan Lake Substation</td>
<td>New Sylvan Lake substation with in-and-out scheme consisting of two 138/25 kV 15/20/25 MVA transformers.</td>
</tr>
<tr>
<td></td>
<td>Transformer Addition at Rosyth Substation</td>
<td>Add a fourth 15/20/25 MVA 138/4.16 kV transformer at Rosyth.</td>
</tr>
</tbody>
</table>

Total 121
Central region challenges to 2017

Special considerations

HANNA AND WAINWRIGHT AREAS

One of the key drivers for load growth in the Wainwright and Hanna areas is the projected building of a number of new pipelines for carrying bitumen and oil products from oilsands projects to markets in the U.S. and other destinations. Bitumen output from oilsands projects is expected to double by 2016. Due to the potential doubling of bitumen output, and the resultant impact on pipeline capacity, a sensitivity analysis was initiated for this region. The results of this study indicated that additional pipeline capacity load, over and above the load indicated in Appendix C, may be required. Therefore, an additional pumping load increase of 375 MW was added to test the sensitivity of the plans.

In addition to the pipeline loads, there has been activity in the drilling of coal bed methane (CBM) wells. The majority of CBM operations currently employ gas drives in the process; however, there is potential to use electric drives in these applications. Therefore, an additional 50 MW of potential load associated with CBM was added to the base forecast to test the plan for a potential higher adoption rate of electric drives.

The AESO has also received system access service applications for the interconnection of about 1,500 MW of wind generation projects in the Hanna area.

RED DEER AND DIDSBURY AREAS

The Red Deer and Didsbury areas have operational constraints associated with the Joffre generation that relate to the limited capacity of the 138 kV transmission system. This constraint is managed via an AESO Operating Policy and Procedure (OPP), which states that the inflows into the Joffre area will be limited to a maximum of 170 MW and 140 MW in summer and winter respectively under certain contingencies when all three units at Joffre are out of service. These are voltage stability limits. Under normal conditions, outflow from the Joffre plant onto the system will be limited to 280 MW in summer and 300 MW in winter when the plant is in service under certain load levels. These are thermal limits. The proposed transmission plan addresses the above issue. In addition, the AESO has received applications for connecting about 420 MW of wind projects to the grid in the Red Deer area.

Issues identified

Most of the analysis for the Central region was based on generation scenario B3 (a blend of north and south generation); however, scenario B5 (high south generation) was used as the primary generation scenario for the Hanna area. Several other north and south generation and load scenarios were tested for their impact on the Central region. Most of the identified transmission issues existed in all scenarios. These issues are highlighted in Figure 5.0-2. The 10-year generation scenarios are described in Table 4.0-2 in Appendix E.
Figure 5.0-2: Central region transmission issues identified to 2017
Conceptual Central region plans

The conceptual plans that address the Central region's transmission issues are shown in Table 5.0-2. The AESO is at various stages of planning within this region and the conceptual plans will be updated as the planning process proceeds. The conceptual developments identified provide a representation of alternatives that will be assessed. They are grouped into four areas within the region.

Central East area

The improvements in this area are required, in part, to supply possible pipeline loads and general area load increases. In addition, some improvements are required to replace aging facilities.

Central West area

Upgrades to the 138 kV system in the Central West area are required to meet load increases.

Table 5.0-2: Conceptual Central region transmission plans to 2017

<table>
<thead>
<tr>
<th>Year in service</th>
<th>Project</th>
<th>Description</th>
<th>Cost estimate (2008 $ millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2012-2013</td>
<td>St. Paul Area</td>
<td>New double circuit 144 kV line from 7L70 to the St. Paul substation and convert the substation to 144 kV.</td>
<td>28</td>
</tr>
<tr>
<td></td>
<td>Uplgades</td>
<td>Salvage existing 72/25 kV transformers at Bonnyville and install a 144/72 kV 25/33/42 MVA transformer.</td>
<td>4</td>
</tr>
<tr>
<td></td>
<td>Central West Area</td>
<td>New 138 kV line from Edson to Bickerdike.</td>
<td>8</td>
</tr>
<tr>
<td></td>
<td>Uplgades</td>
<td>Upgrade 138 kV 745L Cold Creek to Edson or a new line from Coldspur to Cold Creek.</td>
<td>30</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Install capacitor banks at Cold Creek and Pinedale.</td>
<td>8</td>
</tr>
<tr>
<td>2013</td>
<td>Hardisty Area</td>
<td>New double circuit 240 kV line by tapping 9L953 midway between Cordel and Hansman Lake; upgrade the 138 kV substation to 240 kV with a new 240/138 kV transformer.</td>
<td>47</td>
</tr>
<tr>
<td>2013-2017</td>
<td>Wainwright Area</td>
<td>New 138 kV single circuit line from Wainwright to Edgerton plus breakers and protection upgrades at Jarrow, Tucuman and Wainwright.</td>
<td>32</td>
</tr>
<tr>
<td></td>
<td>Uplgades</td>
<td>New 138 kV single circuit line from Hayter to Provost.</td>
<td>33</td>
</tr>
<tr>
<td></td>
<td></td>
<td>New 138 kV single circuit line from Killarney Lake to Killarney Lake tap.</td>
<td>19</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Upgrade or rebuild existing 138 kV line from Battle River to Vermilion.</td>
<td>90</td>
</tr>
<tr>
<td></td>
<td></td>
<td>New 144 kV line from Heislter to 7L701 tap point; convert the existing 72 kV substation to 144 kV substation.</td>
<td>6</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Install a 15 MVAR capacitor bank and associated equipment at Irish Creek.</td>
<td>2</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td></td>
<td></td>
<td><strong>307</strong></td>
</tr>
</tbody>
</table>
Recommended Central region projects

The AESO has completed comprehensive technical analysis and recommends the transmission reinforcements shown in Table 5.0-3.

Red Deer area

Transmission development is required in the Red Deer area to meet projected load growth. These enhancements include another 240/138 kV substation in the area, as well as several substation and 138 kV transmission line upgrades.

Hanna area

The plan for the Hanna area was developed to meet the possibility of additional pipeline loads and wind generation. To accommodate these loads, the plan is to construct a 240 kV loop from Anderson to Metiskow with two new 240/144 kV substations between Oyen and Metiskow. This requires 138 kV line and substation upgrades, as well as the addition of capacitor banks and static var compensators (SVC) for voltage support. Wind integration will require a new 240 kV double circuit line and a substation west of Anderson.

Table 5.0-3: Recommended Central region transmission projects to 2017

<table>
<thead>
<tr>
<th>Year in service</th>
<th>Project</th>
<th>Description</th>
<th>Cost estimate (2008 $ millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2009</td>
<td>Red Deer/Didsbury Area Upgrades</td>
<td>Terminal switching upgrades to 138 kV circuits at Gaetz and at north Red Deer.</td>
<td>7</td>
</tr>
<tr>
<td></td>
<td></td>
<td>New 240/138 kV substation near Didsbury.</td>
<td>20</td>
</tr>
<tr>
<td></td>
<td></td>
<td>New 138 kV line from northeast Lacombe to Ellis.</td>
<td>11</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Add a second transformer at Benalto substation.</td>
<td>9</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Provide VAR* support by adding capacitor banks at Joffre, Gaetz, Prentiss, Ellis and Blackfords.</td>
<td>25</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Upgrade 80L 138 kV line from south Red Deer to north Red Deer.</td>
<td>3</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Upgrade 155L 138 kV from Red Deer to Piper Creek.</td>
<td>7</td>
</tr>
<tr>
<td>2012-2017</td>
<td>Hanna Area Upgrades</td>
<td>New 240 kV double circuit line from Anderson to Oyen.</td>
<td>137</td>
</tr>
<tr>
<td></td>
<td></td>
<td>New 240 kV line from Monitor to Metiskow; add a 240/144 kV substation near Monitor.</td>
<td>79</td>
</tr>
<tr>
<td></td>
<td></td>
<td>New 240 kV line from Oyen to Monitor; add a 240/144 kV substation near Oyen.</td>
<td>97</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Add one 144/72 kV 75 MVA transformer at Battle River.</td>
<td>4</td>
</tr>
<tr>
<td></td>
<td></td>
<td>New 240 kV double circuit line from Anderson to new wind collector substation to the west.</td>
<td>31</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Increase capacity of Hansman Lake and Metiskow substations.</td>
<td>15</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Add one 100 MVar SVC and two 240 kV 36 MVar capacitor banks at Hansman Lake.</td>
<td>42</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Add one 50 MVar SVC at Three Hills.</td>
<td>20</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Add one 20 MVar SVC at Rowley.</td>
<td>14</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Add capacitor banks at various substations.</td>
<td>15</td>
</tr>
<tr>
<td></td>
<td>Total</td>
<td></td>
<td>536</td>
</tr>
</tbody>
</table>

* VAR: volt-ampere reactive.
6.0 Edmonton region

The Edmonton region, which is located approximately in the centre of the AIES, includes the City of Edmonton and the Wabamun, Wetaskiwin and Fort Saskatchewan areas. The region is bordered on the south by the Central region and on the north by the Northeast and Northwest regions. The Edmonton region is not only a major load and generation centre in the province, but is also the key connection centre for the transmission network connecting the northwest, northeast and south areas of the AIES bulk transmission systems together through 240 kV lines. The Edmonton region is a central hub for the major transmission paths in the system.

The current Edmonton region system is comprised of transmission lines and substations that operate at 500 kV, 240 kV, 138 kV and 69 kV. Figure 6.0-1 shows the existing transmission system in this region.

Edmonton region current conditions

The main source of electrical generation for the entire province is situated near Wabamun Lake in the Edmonton region. There is more than 4,000 MW of baseload generation connected to the AIES near Wabamun Lake to support various load centres, including central and south Alberta loads, Northwest region loads, Edmonton area loads and major industrial loads located in the Fort Saskatchewan area. Because the Edmonton region has more generation than load, it delivers energy to other regions of Alberta.

The major transmission paths to other regions include:

- **Northwest region**
  - two 240 kV circuits from Sundance to Sagitawah
  - two 240 kV circuits from Sundance to Bickerdike
  - a 240 kV circuit from Sundance to the High Prairie area

- **Northeast region**
  - two 240 kV circuits from Lamoureux to the Cold Lake area

- **South region**
  - two 240 kV circuits from Sundance to Benalto
  - two 240 kV circuits from Keephills to Benalto
  - two 240 kV circuits from Ellerslie to the Red Deer area
Figure 6.0-1: Existing Edmonton region transmission system
Edmonton region expected growth
The forecast 2007, 2012 and 2027 seasonal peaks for the Edmonton region are included in Appendix C.

New substations have been proposed by distribution facility owners to serve demand in this region. Some of the large future requirements of transmission services are attributed to the siting of bitumen upgraders and generation facilities in the Fort Saskatchewan area.

Edmonton region current transmission projects
The current projects in the Edmonton region are listed in Table 6.0-1. The list includes those projects that have a NID submitted to the AUC for approval or have been approved but are not yet constructed.

Table 6.0-1: Edmonton region current transmission projects

<table>
<thead>
<tr>
<th>Year in service</th>
<th>Project Description</th>
<th>Project</th>
<th>Year in service</th>
<th>Description</th>
<th>Cost estimate (2008 $ millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2008 Gainford 165S 138 kV Conversion</td>
<td>Convert Gainford substation to 138 kV operation by tapping 156L; salvage 124L (69 kV) between Entwistle and Wabamun.</td>
<td>2008</td>
<td>3</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2009 New EPCOR Clover Bar Substation</td>
<td>New 240/25 kV substation at the Clover Bar substation to supply growing load.</td>
<td>2009</td>
<td>8</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2009 138 kV Line Upgrades</td>
<td>Transmission capacity upgrades to 807L and 708L.</td>
<td>2009</td>
<td>2</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2010 New EPCOR Summerside Substation</td>
<td>New 240/25 kV substation next to Ellerslie.</td>
<td>2010</td>
<td>21</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2010 Leduc 138/25 kV Substation</td>
<td>New 138/25 kV substation near Leduc.</td>
<td>2010</td>
<td>21</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td></td>
<td></td>
<td>66</td>
<td></td>
</tr>
</tbody>
</table>
Edmonton region challenges to 2017

Special considerations
The Edmonton region is a major corridor for electricity flows between the Northeast, Central and South regions. The power requirements of the major oil production facilities in the Northeast region can have a significant impact on transmission infrastructure in the Edmonton region.

Around the City of Edmonton, the Government of Alberta has designated lands for a TUC. Development of the TUC was seen as an effective means for future major infrastructure development to serve the steadily expanding urban area. Based on the conceptual plans listed in Table 6.0-2, there is potential to use the existing TUC.

Issues identified
While most of the analysis was based on generation scenario A1 (high northern generation), several other north and south generation scenarios were tested for their impact on the Edmonton area transmission system. The worst-case scenario for the Edmonton region system is high Wabamun area generation, including Keephills 3 and 4 and Genesee 4 with a high power transfer into the Fort McMurray region. The 10-year generation scenarios are described in Table 4.0-2 in Appendix E.

There are major thermal overloads of transmission facilities throughout the Edmonton region under all generation scenarios. The 138 kV transmission paths from Wabamun to North Calder, East Edmonton to Nisku and from East Edmonton to the Fort Saskatchewan area are weak sections during peak load condition. As well, most of the voltage violations exist in those two areas due to weak system support. Within the City of Edmonton there are some thermal overload issues in the 72 kV system.
Figure 6.0-2: Edmonton region transmission issues identified to 2017
Conceptual Edmonton region plans

The discussion of improvements is grouped into four areas within the region. Table 6.0-2 shows the conceptual plans that address the issues by groups for the Edmonton region.

Wabamun

The Wabamun 19S substation is still required after the retirement of Wabamun Unit 4 generation, which is scheduled for 2010. This substation will need to be rebuilt with an increase of transformation capacity. In addition, relocating the 904L termination from Wabamun to Keephills removes area 240 kV overloads. The line will also be rebuilt to a higher capacity that will maintain a strong 240 kV supply into west Edmonton (reconfiguration of the 240 kV system forms part of the Keephills Unit 3 interconnection project).

Developing a new 240/138 kV substation (tapping 908L or 909L) will reinforce the Wabamun and Wetaskiwin areas’ 138 kV supply by interconnecting to 739L between Acheson and Devon. Salvaging the Wabamun area 69 kV system or converting it to 138 kV supply improves reliability, removes the aging infrastructure and eliminates low voltage issues.

Wetaskiwin area

Capacitor bank additions in this area will improve system voltages in the event of the loss of a single transmission element. As well, opening 80L between Ponoka and West Lacombe removes parallel flows between the 240 kV and 138 kV systems during high north-to-south transfer situations. Installing a new 240/138 kV substation northeast of Leduc (tapping 910L) will reinforce the Wetaskiwin area 138 kV supply by interconnecting into Blackmud. Splitting 803L/804L into two separate circuits between Bigstone and Wetaskiwin will improve reliability to the Wetaskiwin area.

Fort Saskatchewan area

Several heavy oil upgrader projects are being proposed in the Fort Saskatchewan area. A 240 kV transmission system will be developed to deliver power to these loads. Also, associated load growth is anticipated for the 138 kV systems in support of the upgrader projects. These expansions are forecast to need two new substations and related new 138 kV lines.

Edmonton

Opening 700L, 726L and 783L in northeast Edmonton removes parallel flows on the 240 kV and 138 kV systems between Edmonton and Fort Saskatchewan. The 138 kV systems will be reconfigured to create a loop that will supply four substations from the East Edmonton station and the 726L/783L line between East Edmonton and North Calder.

A new 138 kV line between Viscount and St. Albert will be required. The existing line between Viscount and North Calder needs to be upgraded to a higher capacity. A second 240/138 kV transformer is needed at North Calder to address supply issues.

About five additional substations will be needed to supply new load in the Edmonton area.
### Table 6.0-2: Conceptual Edmonton region transmission plans to 2017

<table>
<thead>
<tr>
<th>Year in service</th>
<th>Project</th>
<th>Description</th>
<th>Cost estimate (2008 $ millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2010-2015</td>
<td>Wabamun Area Upgrades</td>
<td>New 240/138 kV substation tapping 908L or 909L and 739L.</td>
<td>50</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Rebuild 129L between Entwistle/Drayton Valley/Violet Grove to 138 kV.</td>
<td>20</td>
</tr>
<tr>
<td>2010-2017</td>
<td>Fort Saskatchewan Area Upgrades</td>
<td>Develop a 240 kV system to connect large load and generation projects.</td>
<td>300</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Expand 138 kV system to connect new distribution load and generation projects.</td>
<td>150</td>
</tr>
<tr>
<td>2012-2015</td>
<td>Wetaskiwin Area Upgrades</td>
<td>Add capacitor banks at Acheson, Devon, Pigeon Lake and Bardo.</td>
<td>12</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Terminate 803L at Bigstone and Wetaskiwin.</td>
<td>8</td>
</tr>
<tr>
<td></td>
<td></td>
<td>New 240/138 kV substation tapping 910L with 138 kV line development to Blackmud.</td>
<td>40</td>
</tr>
<tr>
<td>2012-2017</td>
<td>Edmonton Area Upgrades</td>
<td>Open 700L, 726L, and 783L northeast of Edmonton; connect 726L and 783L to create an East Edmonton line to North Calder; a new 138 kV switching station at the junction of 746L/746L and a new line to connect 783L.</td>
<td>30</td>
</tr>
<tr>
<td></td>
<td></td>
<td>New 138 kV line between Viscount and St. Albert; upgrade capacity on the existing Viscount to North Calder line; install second 240/138 kV transformer at North Calder.</td>
<td>25</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Add approximately five new 240/25 kV or 138/25 kV substations and associated transmission lines.</td>
<td>150</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td></td>
<td></td>
<td><strong>785</strong></td>
</tr>
</tbody>
</table>
7.0 Northeast region

The Northeast region of Alberta is bordered on the north by the Northwest Territories (N.W.T.),
on the east by the Saskatchewan border, on the west by the Fifth Meridian and on the south
by Township 60. This region includes Fort McMurray, Athabasca/Lac La Biche and Cold Lake.
The landscape is heavily forested and covered with vast bogs and muskeg. Bitumen extraction,
heavy oil processing, pipelines and forestry are the dominant industries in this area. The major
transmission facilities of the Northeast region are shown in Figure 7.0-1.

The majority of the electrical load and generation in the region is currently located on oilsands
leases north of the City of Fort McMurray and in Cold Lake. This region is unique as it has
significant behind-the-fence (BTF) load and generation connected to the grid as industrial
systems. The coincident load values will increase over time as bitumen extraction facilities and
pipeline loads exceed generator additions.

Northeast region current conditions

The Northeast region normally exports power to the rest of the AESO since non-coincident peak
load plus BTF load are usually less than BTF generating capacity. However, it has been observed
that for some hours of the year, this area is seen as a net load.

The Northeast area has connections to both the Edmonton and Northwest regions. These
include:

- **Northwest region**
  - a 240 kV circuit from the Fort McMurray area (Dover to Mitsue)

- **Edmonton region**
  - two 240 kV circuits from the Fort McMurray area (Dover and Ruth Lake) to Lamoureux

The 240 kV system is operating at capacity due to the growth of oilsands development in the
Fort McMurray area.

The Fort McMurray 144 kV supply has improved with the construction of the third 240 kV line
in 2004 and the addition of the McMillan 240/144 kV substation at the south end of the
144 kV system. The 144 kV north supply at the Ruth Lake substation is provided via a complex
240/72 kV step-down and 72/144 kV step-up transformation arrangement. The 144 kV system
is operating at its design capacity.
Figure 7.0-1: Existing Northeast region transmission system

- **EXISTING SUBSTATIONS**
- Existing transmission lines
- Voltage
  - 69 kV/72 kV
  - 240 kV
  - 138 kV/144 kV
The Cold Lake 144 kV system is connected to the AIES via the Marguerite Lake 240/144 kV substation to the west and two 144 kV lines to the south towards the Vegreville and Lloydminster areas. The 144 kV transmission system that serves the bitumen extraction facilities is operating at capacity due to exports from cogeneration facilities.

The Athabasca/Lac La Biche 138 kV system was reinforced with the addition of the Heart Lake 240/138 kV substation in 2004 to the north and is connected to the south through the Vegreville and Wabamun/Edmonton regions. The area load is expected to increase due to pipeline pumping load additions. The transmission system is operating near its capacity.

The only 72 kV transmission facilities in the area are located near Fort McMurray. These facilities were originally constructed to supply the early mining and processing loads for the oilsands that were sourced from the Ruth Lake substation. The 72 kV connections are being replaced with 240 kV systems that are constructed within the Syncrude Canada Ltd. and Suncor Energy industrial site designation (ISD) complexes and remain connected to the AIES at Ruth Lake. Parts of the 72 kV system are still in use today as plant distribution lines within the ISDs. No other loads are supplied off the 72 kV transmission lines in this region.

**Northeast region expected growth**

The forecast 2007, 2012 and 2017 seasonal peaks for the Northeast region are included in Appendix C.

**Northeast region current transmission projects**

Projects that are underway or expected in the Northeast region are listed in Table 7.0-1. The list includes those projects that have a NID submitted to the AUC for approval or have been approved but are not yet constructed.

<table>
<thead>
<tr>
<th>Year in service</th>
<th>Project</th>
<th>Description</th>
<th>Cost estimate (2008 $ millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2009</td>
<td>Athabasca Area Upgrade</td>
<td>Relocate the Lac La Biche capacitor bank to Waupisoo.</td>
<td>1</td>
</tr>
<tr>
<td>2009</td>
<td>Cold Lake Area Upgrades</td>
<td>New 144 kV lines and substations to connect customer loads.</td>
<td>34</td>
</tr>
<tr>
<td>2011</td>
<td>Fort McMurray Area Upgrades</td>
<td>New Cache Creek 240/144 kV substation tapping 9L990.</td>
<td>25</td>
</tr>
<tr>
<td></td>
<td></td>
<td>New Cache Creek to Hangingstone 144 kV line.</td>
<td>5</td>
</tr>
<tr>
<td></td>
<td></td>
<td>New Livock 240/144 kV substation tapping 9L57.</td>
<td>20</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td></td>
<td></td>
<td><strong>85</strong></td>
</tr>
</tbody>
</table>
**Northeast region challenges to 2017**

**Special considerations**

The Fort McMurray area is unique from a planning perspective as it has a significant number of large industrial customers. These customers will be contracting both demand transmission service (DTS) and supply transmission service (STS) with varying degrees of usage to supply process requirements and for electric supply reliability. Their services can be divided into high load factor and low load factor categories. High load factor DTS and STS represents the normal load and generation conditions that will be present most of the time. Low load factor DTS represents load that could appear as a result of the loss of one or more generators due to maintenance or forced outages. Similarly, low load factor STS represents excess generation output that could be present due to a change to, or loss of, processing load.

Planning for a transmission system that is capable of handling the full range of all contracted DTS and STS, irrespective of load factor, will result in large capital investments. On the other hand, planning for only the high load factor DTS and STS contracts can result in congestion and possible violation of the AESO’s reliability criteria. The solution is to find the most likely maximum load and supply scenarios that the Fort McMurray region will experience during the next 10 years. The 10-year generation scenarios are shown in Table 4.0-2 in Appendix E.

**Issues identified**

The existing transmission facilities in the northeast were near or at capacity in 2008. The three planning areas that comprise the Northeast region are unique and are weakly interconnected such that each area can be reviewed independently.

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

**Cold Lake area** – The 144 kV transmission system in this area is near its capacity due to high generation exports. In addition, new generation is expected to be connected in the northern part of the Cold Lake transmission system. Over the next 10 years, new oilsands extraction facilities and upgrader loads should absorb some of this generation and unload the transmission system. Even so, new transmission facilities will be required to ensure supply can reach the new loads.

**Fort McMurray area** – The majority of Northeast region growth is expected to occur in this area. The load and generation developments are expected to generally balance each other. There is, however, potential for the situation to rapidly swing from being balanced to turning into a load centre or supply area. Not only are transmission thermal overloads and voltage fluctuations a concern, but transient swings and increased inertia of the larger Fort McMurray electrical system may also impact the stability of the transmission system.

These issues are also highlighted in Figure 7.0-2.
Figure 7.0-2: Northeast region transmission issues identified to 2017

EXISTING SUBSTATIONS
Existing transmission lines
Voltage
- 69 kV/72 kV
- 138 kV/144 kV
- 240 kV
- Thermal overloads
- Voltage violations

Athabasca
Firebag
Christina Lake
Fort McMurray
Bonnyville
Westlock
Elk Point
Legal
CROW
BOYLE
DOVER
ALGAR
DO5
MARIANA
WABASCA
BRINTNELL
MCMILLAN
CROW
LEISMER
WINEFRED
Christina Lake
HEART LAKE
FLAT LAKE
Lac La Biche
FLATBUSH
COLINTON
WHITEFISH LAKE
LEISMER
WINEFRED
Marguerite Lake
Lac La Biche
Colinton
Whitefish Lake
Leismer
Winefred
Mariana
Crowsnest
Brintnell
Mcmillan
Wabasca
Athabasca
Conceptual Northeast region plans

Conceptual plans have been developed for the three planning areas that comprise the Northeast region as described below.

Athabasca/Lac La Biche area — The area 138 kV transmission system will be strengthened by the addition of reactive compensation to provide voltage support. Within 10 years, this system will need to be reinforced by constructing a new 138 kV circuit from Heart Lake 898S to Waupisoo 405S.

Cold Lake area — New 144 kV transmission facilities are required to mitigate overloads in the area as well as to accommodate the expected addition of new generation facilities and the associated loads.

Fort McMurray area — The greatest amount of oilsands activity is located north of the City of Fort McMurray. These bitumen extraction facilities will be interconnected to the grid via a 240 kV network. The area south and west of the City of Fort McMurray is developing into a significant load centre, thereby requiring the addition of two or three 240/144 kV substations and 144 kV transmission lines connecting to new load.

Table 7.0-2: Conceptual Northeast region transmission plans to 2017

<table>
<thead>
<tr>
<th>Year in service</th>
<th>Project</th>
<th>Description</th>
<th>Cost estimate (2008 $ millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2012-2013</td>
<td>Cold Lake Area</td>
<td>New switching station at Primrose tap.</td>
<td>16</td>
</tr>
<tr>
<td></td>
<td>Upgrades</td>
<td>New 144 kV line from Marguerite Lake to new Primrose substation.</td>
<td>14</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Rebuild 7L74 line from Wolf Lake to Primrose tap.</td>
<td>3</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Upgrade capacity of Marguerite Lake to Wolf Lake 144 kV line.</td>
<td>2</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Salvage portion of 7L91L line from Marguerite Lake to Leming Lake; extend line to Bonnyville to form a new line between Bonnyville and Leming Lake.</td>
<td>25</td>
</tr>
<tr>
<td></td>
<td></td>
<td>New 144 kV line from Leming Lake to new Primrose substation.</td>
<td>17</td>
</tr>
<tr>
<td></td>
<td></td>
<td>New 144 kV line from Mahinikan to Grand Centre; transfer La Corey tap from 7L89 to 7L.</td>
<td>28</td>
</tr>
<tr>
<td>2012-2017</td>
<td>Fort McMurray</td>
<td>Customer-related transmission connection of oilsands extraction facilities to the system.</td>
<td>450</td>
</tr>
<tr>
<td></td>
<td>Area Upgrades</td>
<td>New Cache Creek to Black Fly 240 kV line.</td>
<td>90</td>
</tr>
<tr>
<td></td>
<td></td>
<td>New Livock to Joslyn Creek 240 kV line to connect developing oilsands facilities west of Fort McMurray.</td>
<td>140</td>
</tr>
<tr>
<td>2014</td>
<td>Athabasca Area</td>
<td>Install second capacitor bank at Waupisoo.</td>
<td>3</td>
</tr>
<tr>
<td></td>
<td>Upgrades</td>
<td>New Heart Lake to Waupisoo 138 kV line to reinforce the Athabasca area system and system upgrades to 223L and 728L.</td>
<td>30</td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td></td>
<td>818</td>
</tr>
</tbody>
</table>
8.0 Northwest region

The Northwest region of Alberta is a large geographic area northwest of the Edmonton region. It is bordered by Fort McMurray and Athabasca to the east, Hinton and Wabamun to the south, B.C. to the west and the N.W.T. to the north. While the Northwest region represents approximately one-third of the area of the province, it represents about one-tenth of the total load. The major transmission facilities of the Northwest region are shown in Figure 8.0-1.

Northwest region current conditions

The Northwest region imports power from the rest of the AIS because peak load in the region is greater than generating capacity. The region imports about 55 to 60 per cent of its annual energy supply. This means the region is dependent on its interconnections to supply its load.

The transmission system in the region is relatively weak and relies on generation units located in the region to provide voltage support and reliability, particularly in the far northwest corner of the area. The need to operate this generation indicates that the transmission system is not adequate to reliably serve the current load.

The Northwest region has connections to both the Northeast and Edmonton regions. These include:

- **Northeast region**
  - a 240 kV circuit from Mitsue to the Fort McMurray area

- **Edmonton region**
  - a 240 kV circuit from Mitsue to Wabamun
  - two 240 kV circuits from Sagitawah to Sundance
  - a 144 kV circuit from Benbow to Bickerdike
  - a 144 kV circuit from Sagitawah to Wabamun
  - a 144 kV circuit from Sarah Lake to Wabamun
Figure 8.0-1: Existing Northwest region transmission system

- **EXISTING SUBSTATIONS**
- Existing transmission lines
- Voltage:
  - 69 kV/72 kV
  - 240 kV
  - 138 kV/144 kV
Northwest region expected growth
The forecast 2007, 2012 and 2017 coincident peaks for the Northwest region are included in Appendix C.

Northwest region current transmission projects
The Northwest Alberta Transmission NID identified transmission issues in three areas of the Northwest region:

- The area from Hotchkiss north currently has insufficient transmission capability to meet the existing load without using TMR generation.
- The area from south of Hotchkiss to Little Smoky and Mitsue is at risk for customer outages due to voltage stability issues during winter peak load conditions.
- The area south of Little Smoky and Mitsue will be at risk for customer outages due to voltage stability issues by the 2011/12 winter peak.

In addition, there are thermal overloads, low voltages and the risk of voltage collapse during facility maintenance conditions on the 72 kV and 144 kV systems.

In March 2007, the AESO applied for approval to build the facilities identified in the Northwest Alberta Transmission NID. In August 2007, the AESO received regulatory approval for the projects included in the NID.

The first phase of the transmission development includes adding new 240/144 kV transformers, capacitor banks and reactive support devices and the addition of four new transmission lines. The current projects for the Northwest region are listed in Table 8.0-1. The list includes those projects that have a NID submitted to the AUC for approval or have been approved but are not yet constructed.

Table 8.0-1: Northwest region current transmission projects

<table>
<thead>
<tr>
<th>Year in service</th>
<th>Project Description</th>
<th>Cost estimate (2008 $ millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2010-2011</td>
<td>Capacitor banks at Ksituan River (15 MVAr), Friedenstal (15 MVAr), Goodfale (30 MVAr), Little Smoky (90 MVAr), Lubicon (60 MVAr) and Big Mountain (30 MVAr). New 240/144 kV transformer at Louise Creek. New SVC (+30 MVAr) at Cranberry Lake. New double circuit 144 kV line from Wesley Creek to Meikle substation. New SVCs at Little Smoky (+100 MVAr), High Level (+30 MVAr) and Arcenciel (+30 MVAr). Add capacitor banks at Arcenciel (30 MVAr). New Sulphur Point to High Level 144 kV line. New Ring Creek to new Arcenciel substation 144 kV line. Add synchronous condenser at Arcenciel (+50/-30 MVAr). Teleprotection upgrades in Peace River and Rainbow Lake areas.</td>
<td>18 3 12 193 68</td>
</tr>
</tbody>
</table>
Northwest region challenges to 2017

Special considerations
BC Hydro has forecast significant load growth in the Fort Nelson, B.C. region that exceeds the load forecast used in the development of the Northwest Alberta Transmission NID. The Fort Nelson area is connected to the Alberta system via a 144 kV line supplied from the Rainbow Lake substation. Additional TMR services may be required to support this incremental load until new transmission facilities can be constructed. Additional transmission facilities beyond those identified in the NID may be required for the Rainbow Lake area. Possible transmission reinforcements required to serve the additional B.C. loads are not included in this plan.

Issues identified
The 144 kV transmission system in the Grande Prairie area will be at capacity due to load growth and generation additions. TMR services are required to support this region to mitigate voltage violations throughout the local area system.

The 72 kV system connecting the High Prairie, Slave Lake and Swan Hills areas has exceeded its design capability and requires replacement due to its age.

The major issues are highlighted in Figure 8.0-2. The 10-year generation scenarios are shown in Table 4.0-2 in Appendix E.
Figure 8.0-2: Northwest region transmission issues identified to 2017
**Conceptual Northwest region plans**

The conceptual plans presented in Table 8.0-2 indicate the approximate facilities that may be required by 2017. The specific solutions recommended for implementation will be identified in future NIDs. While engineering judgment was used in selecting the conceptual plans, they should not be interpreted as eliminating any other options or alternatives.

The Grande Prairie area 144 kV system requires additions to meet the continued load growth. These additions include a 240 kV line into the area with a new 240/138 kV substation near the City of Grande Prairie.

**Table 8.0-2: Conceptual Northwest region transmission plans to 2017**

<table>
<thead>
<tr>
<th>Year in service</th>
<th>Project</th>
<th>Description</th>
<th>Cost estimate (2008 $ millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2014</td>
<td>Grande Prairie Area Upgrades</td>
<td>New double circuit 240 kV line from Little Smoky to Grande Prairie and a 240/144 kV substation.</td>
<td>155</td>
</tr>
<tr>
<td></td>
<td></td>
<td>New 144 kV line from Poplar Hill substation to a new switching station at the junction of 7L03 and 7L09.</td>
<td>17</td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td></td>
<td>172</td>
</tr>
</tbody>
</table>

**Recommended Northwest region projects**

The AESO has completed comprehensive technical analysis and recommends the transmission reinforcements shown in Table 8.0-3.

Upgrades in the Slave Lake area are required to replace the aging 72 kV system, which can no longer serve the area loads. The system will be upgraded to 138 kV.

**Table 8.0-3: Recommended Northwest region transmission projects to 2017**

<table>
<thead>
<tr>
<th>Year in service</th>
<th>Project</th>
<th>Description</th>
<th>Cost estimate (2008 $ millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2011-2012</td>
<td>Slave Lake Area Upgrades</td>
<td>144 kV and 72kV line reconfigurations and substation improvements at Slave Lake, Otauwau and Mitsue.</td>
<td>8</td>
</tr>
<tr>
<td></td>
<td></td>
<td>New 144 kV line from Sarah Lake to Edith Lake.</td>
<td>12</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Convert High Prairie substation to 144 kV operation and extend 144 kV line.</td>
<td>30</td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td></td>
<td>50</td>
</tr>
</tbody>
</table>
## 9.0 Summary of results

Table 9.0-1 provides a summary of the transmission expenditures required to implement the regional transmission system plans over the next 10 years.

<table>
<thead>
<tr>
<th>Region</th>
<th>Cost estimate (2008 $ millions)</th>
<th>Current transmission projects</th>
<th>Conceptual transmission plans to 2017</th>
<th>Recommended transmission projects to 2017</th>
<th>Sub-total</th>
</tr>
</thead>
<tbody>
<tr>
<td>South region</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>205</td>
</tr>
<tr>
<td>Calgary region</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>248</td>
</tr>
<tr>
<td>Central region</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>964</td>
</tr>
<tr>
<td>Edmonton region</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>851</td>
</tr>
<tr>
<td>Northeast region</td>
<td></td>
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<td></td>
<td>903</td>
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<tr>
<td>Northwest region</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>701</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td><strong>3,872</strong></td>
</tr>
</tbody>
</table>
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