

20

TRANSMISSION SYSTEM OUTLOOK

year

[2005-2024]

Alberta Electric System Operator

20-YEAR OUTLOOK DOCUMENT (2005-2024)
ALBERTA ELECTRIC SYSTEM OPERATOR

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Executive Summary

The Alberta Electric System Operator (“AESO”) has prepared this 20-Year Outlook Document (2005 – 2024) (“Outlook”) to provide market participants, customers and interested stakeholders with the overall direction regarding Alberta’s transmission system development over the next twenty year period. In the new competitive market structure in Alberta the role of the transmission system has changed in that it must also facilitate generation development in order to ensure long term adequacy of electricity supply while continuing to maintain reliability of supply. The Outlook is intended to create a foundation for future transmission system development for the industry. It will be filed with the Alberta Energy and Utilities Board (“EUB”) for information and use in assessing future transmission project need applications.

The AESO is directed by policy and regulation to take a proactive approach to transmission system development to ensure that generation and loads have access to constraint free transmission capacity in order to facilitate an openly competitive and efficient electricity market while maintaining system reliability.

The Outlook aligns with the principles of the Alberta government’s Transmission Policy (“Policy”) and meets the requirements of the associated Transmission Regulation (“Regulation”). In particular, this Outlook describes the infrastructure developments required to address current and forecasted market participant needs. This provides context and direction for the AESO’s more detailed 10-Year Transmission System Plans and need applications for specific transmission capital additions. The AESO is committed to strengthening the transmission system to meet market participants’ needs. In this regard the objectives of the 20-Year Outlook are to:

- Set the context for more specific 10-year transmission plans and individual transmission project need applications;
- Set the stage for shorter term actions to be taken to facilitate provision of transmission in the longer term, e.g. acquisition of rights-of-way for major transmission developments;
- Facilitate generation development;
- Meet future load growth requirements reliably;
- Identify potential alternative transmission system developments to account for the uncertainty surrounding generation development; and
- Facilitate merchant or independent transmission developments to neighbouring jurisdictions.

Alberta's transmission system has served the province well for many years. Over the 1999 to 2003 time period the Alberta Internal Load ("AIL") has increased on average by 3.9 per cent per year. Based on the economic outlook for the next 20 year period, the AESO forecasts AIL peak demand will increase on average by 2.8 per cent per year. This will result in a total peak demand increase of 6,650 MW from 8,967 MW in 2003 to 15,617 MW in 2024 for the 'Most Likely' load growth scenario.

In this Outlook the AESO has used a scenario analysis approach, identifying a total of six possible scenarios spanning the range of reasonable conditions. The generation scenarios were developed on the basis of defining the requirements for the end year (2024) of the period only; no attempt was made to identify the timing of specific developments within the 20 year period. Scenario planning techniques are well known and commonly used tools when conducting planning analysis. They are not intended to forecast a definitive outcome, but rather are intended to identify combinations of possible future variables that are critical in making near-term decisions. This approach identifies a range of possible future outcomes, allowing the AESO to develop flexible and responsive plans and strategies for transmission system development, thereby reducing the likelihood of over or under-building transmission in an increasingly uncertain future.

The AESO forecasts that between an additional 6,150 and 13,400 MW of new generation will need to be integrated into the Alberta Interconnected Electric System ("AIES") to meet new load growth and replace retired plant capacity over the next twenty year period.

There are a number of possible technological choices that can be considered to meet the need and long-term system development requirements for Alberta's transmission system. The system can be reinforced using transmission lines designed for AC operation with voltages ranging from 240 kV to 765kV. An alternative to the AC option is the High Voltage Direct Current (HVDC) option with transmission lines designed for operation at voltages ranging from 250 kV to 500 kV.

Alberta currently uses 240 kV AC for its transmission system and 500 kV AC is used for the B.C. Tie. The Keeppills to Genesee to Ellerslie transmission lines as well as the approved new 500 kV circuit from Genesee to Langdon will extend the 500 kV system from the Calgary area to the Edmonton area. Most of the bulk transmission systems in the western half of North America are 240 kV and 500 kV. For these reasons, 240 kV and 500 kV are considered to be the appropriate voltage levels for future transmission development in Alberta.

Based on the scenarios developed there are a number of transmission expansion projects that are common to several scenarios, specifically:

- 500 kV reinforcement from the Fort McMurray area, including:
 - a 500 kV line from the Fort McMurray area to Wesley Creek in northwest Alberta;
 - a 500 kV line from the Fort McMurray area to the Edmonton area;
- further reinforcement of the Edmonton-Calgary transmission system, in the form of initially a second 500 kV line from the Edmonton area to the Calgary area; and
- additional 240 kV development in several areas of Alberta including:
 - the Grande Prairie area;
 - the East Edmonton – Fort Saskatchewan area;
 - the Lloydminster area;
 - the Calgary area;
 - the Lethbridge – Medicine Hat – Empress area; and
 - the Pincher Creek area.

The AESO has recognized that obtaining transmission line rights-of-way is becoming increasingly difficult, in urban areas as well as areas where extensive residential and other development is occurring. The AESO will continue to monitor this situation and will file the necessary need applications to secure the transmission line right-of-way in anticipation of the actual transmission line development.

With respect to interconnections to neighbouring jurisdictions the AESO is directed by the Transmission Development Policy and related Transmission Regulation to:

- restore the existing interties to their original design ratings, and
- facilitate the development of merchant intertie projects.

The transmission developments described in the Outlook will achieve the objective of restoring the existing interties to original design ratings. In regard

to the second requirement the AESO has been collaborating with several merchant line developers and transmission service providers in neighbouring jurisdictions including:

- the NorthernLights Transmission Project;
- the Montana – Alberta Tie project; and
- the Northwest Transmission Assessment Committee of the Northwest Power Pool.

The AESO is also directed by government policy to evaluate provision of additional intertie capacity with neighbouring jurisdictions as a means to stimulating generation development in Alberta. In this regard, the AESO will be increasing its focus on examining intertie alternatives as a means to ensure overall reliable supply of service to Albertans. As well, the AESO will continue to collaborate with transmission service providers in these jurisdictions, including merchant or independent transmission proponents, and will participate in regional transmission planning studies to ensure that Alberta's market participants' needs are met in a timely and cost effective manner. In this Outlook, the AESO has considered the overall transmission system reliability benefits of additional interties, as well as considerations of currently-proposed merchant intertie developments. However, additional thought will need to be applied in the future regarding long term supply adequacy implications.

This is the first 20-Year Outlook Document prepared after the adoption of the Policy and enactment of the Regulation. Subsequent further work will be undertaken by the AESO to

- update and issue the next 10-Year Transmission System Plan,
- continue further detailed analysis, including stakeholder consultation, on the projects outlined above with a view to filing need applications with the EUB,
- continue coordination efforts with neighbouring jurisdictions regarding interconnections, and
- initiate further work to implement the recommendations included in the Electricity Policy Framework.

In summary, this initial 20-Year Outlook Document provides a forward look with regard to transmission system development in Alberta with an emphasis on maintaining flexibility for the future. This approach will result in a robust

transmission system that will continue to provide reliable service to Albertans, attract new generation supply, support merchant or independent transmission proponents, encourage investment in Alberta and facilitate a competitive marketplace.

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1.0 Introduction

The Alberta Electric System Operator (“AESO”) is a statutory corporation established by the *Electric Utilities Act* to lead the safe, reliable and economic planning and operation of Alberta’s interconnected power system and facilitates Alberta’s competitive hourly wholesale electricity market. The AESO has prepared this 20-Year Outlook Document (2005 – 2024) to provide market participants, customers and interested stakeholders with an overview of possible developments in Alberta’s transmission system over the next 20 year period. It is intended to create a foundation for transmission system development in Alberta and in this regard is filed with the EUB for information.

Planning and developing a transmission system is a continuous process. Plans must be constantly revised to reflect changes in load and generation developments. This is particularly true in a competitive electricity market where the timing and location of generation additions are not centrally planned, but are determined by market forces. This 20-Year Outlook Document describes how the transmission system may need to develop given a range of different generation development scenarios. It is intended to be a ‘living’ document and will evolve in response to market participants’ needs.

The AESO prepares a 10-Year Transmission System Plan and a 20-Year Outlook Document, as well as Need Applications as necessary on a specific project basis, to ensure the safe, reliable and economic operation of the AIES. The 10-Year Plan and 20-Year Outlook will be updated as needed or at maximum intervals of two and four years respectively. The 20-Year Outlook Document describes the long-term strategic direction and outlook for the internal Alberta transmission system and transmission interconnections to neighbouring jurisdictions. The 10-Year Plan provides greater detail of the projects required to meet the most likely scenario(s) of load and generation forecasts on a regional basis. Need Applications filed with the EUB for each project will contain the greatest level of detail regarding the need for a specific project.

The AESO is committed to strengthening the transmission system to meet market participants’ needs. The objectives of the 20-Year Outlook are to:

- Set the context for more specific 10-year transmission plans and individual facility need applications;
- Set the stage for shorter term actions to be taken to facilitate provision of transmission in the longer term, e.g. provision of rights-of-way for major transmission developments;

- Anticipate future load growth and generation development scenarios;
- Identify potential alternative transmission system developments to accommodate the scenarios identified; and
- of any merchant or independent transmission developments.

This 20-Year Outlook Document consists of five main sections, including this Introduction (Section 1), and a number of appendices.

Section 2 discusses the forecast load growth and generation development scenarios used as a basis for the 20-Year Outlook.

Section 3 describes the system planning methods used and the resulting transmission system developments proposed for six different load growth and generation development scenarios.

Section 4 discusses current proposals for merchant transmission interconnections between Alberta and neighbouring jurisdictions and provides some information regarding future transmission plans in these areas.

Section 5 outlines the conclusions reached in the Outlook.

Section 6 contains a list of the tables and figures included in the document.

Appendix A contains the report describing the creation of the generation scenarios prepared by the independent consultant retained by the AESO.

Appendix B includes the ‘bubble’ diagrams (graphical representations of regional area loads, generation and transmission flow to other regions) used in the high-level analysis of the transmission development scenarios.

Appendix C provides additional context for the Outlook by way of a brief summary of the Transmission Regulation and the AESO’s reliability criteria, similar to that provided in the 10-Year Transmission System Plan 2005 – 2014.

Appendix D provides an overview of the components of the electricity system and how it functions, the role of transmission interconnections and an historical perspective of the generation and bulk transmission system development in Alberta. This information is also similar to that provided in the 10-Year Transmission System Plan 2005 – 2014.

2.0 Input Data and Assumptions

2.1 Context for Planning Alberta's Transmission System

The current context for the AESO's planning of Alberta's transmission system is best described in the following passage from the recently released Electricity Policy Framework paper¹:

"To support the new market structure, transmission must be available to all supply and load customers in a non-discriminatory manner and with sufficient capacity to ensure that neither load nor generation is constrained. Transmission remains the agent of reliability and in Alberta's electric marketplace is also the facilitator of the competitive market.

In 2004 the government articulated a new transmission policy and approved a regulation to implement the policy. This new policy fundamentally and comprehensively changed the way that transmission effectiveness and need are to be measured. The Transmission Regulation provides public policy direction to the ISO and the Alberta Energy and Utilities Board (EUB) regarding transmission development and for future development of Alberta's interconnected transmission system to:

- ensure Albertans continue to receive safe, reliable and economic electric service throughout the province;
- facilitate generation development and support Alberta's competitive electricity markets and
- support the development of Alberta's vast resource base."

In Alberta's market-based model, knowledge of where and when new generation will proceed is an important consideration for transmission development. Another consideration is that generation developers can build new gas-fired or wind projects with as little as two years lead time. The lead time for a major transmission expansion can typically range from five to eight years. The AESO must recognize these differences in lead times and factor them into the transmission planning process to create a forward looking and flexible transmission system development plan.

¹ Alberta's Electricity Policy Framework: Competitive – Reliable – Sustainable, June 6, 2005, Alberta Department of Energy, page 7.

The objectives of a forward looking and flexible transmission system development plan are as follows; identifying a number of options in a timely and prudent manner maximizes the ability to achieve these objectives:

- 1) Meet load supply reliability requirements;
- 2) Incorporate most likely generation developments into the AES;
- 3) Facilitate a competitive wholesale market;
- 4) Restore capacity of existing interconnections;
- 5) Improve efficiency;
- 6) Improve operational flexibility; and
- 7) Facilitate refurbishment/replacement of aging/obsolete equipment.

2.2 20-Year Outlook Development Methodology

An important consideration in the preparation of the 20-Year Outlook Document is how to account for the uncertainties relating to load and generation development when determining transmission system developments. In this Outlook the AESO has used the scenario analysis approach, identifying a total of six possible scenarios spanning the range of reasonable conditions. Scenario planning techniques are well known and commonly used tools when conducting planning analysis. They are not intended to forecast a definitive outcome, but rather are intended to identify combinations of possible future variables that are critical in making near-term decisions. This approach identifies a range of possible future outcomes, allowing the AESO to develop flexible and responsive plans and strategies for transmission system development, thereby reducing the likelihood of over or under-building transmission in an increasingly uncertain future. This Outlook will be used as the foundation to set a framework within which the AESO will develop its more detailed 10-Year Transmission System Plans and to evaluate specific transmission projects. However, approval of individual transmission projects will continue to be the purview of the EUB through the processes established for this purpose.

2.3 Economic Outlook and Load Forecast

The AESO annually updates its forecast for Alberta's electric load demand and energy consumption. These estimates of future market needs are one of the critical drivers the AESO uses in analyzing and planning the transmission system. This following section is an extract from the AESO's 2004 Future Demand and Energy Requirements Forecast [FC-2004-1]. The report is available on the AESO's website at

<http://www.aeso.ca/loadsettlement/7717.html>.

2.3.1 *Economic Outlook*

During the last ten years, Alberta created significant advantages over other provinces with the strongest economy, fastest growing population and the lowest overall taxes creating a strong foundation for the future. To formulate an economic outlook, the AESO uses external sources such as the Conference Board of Canada, Statistics Canada, and other independent subject-matter experts.

In the short to medium term, positive employment outlook and strong immigration should be the foundation for Alberta's economy. The energy sector should remain a primary economic driver with sustained high commodity prices, a very significant non-conventional oil supply and extraction technology improvements. Over the forecast horizon, Alberta's economy should exhibit good GDP growth expanding at an average annual rate of 2.7 per cent.

2.3.2 *Historical Load Growth*

The AESO uses two terms to define electrical load as follows:

AIES: The Alberta Interconnected Electric System ("AIES") load is the power flowing through the Alberta Interconnected Electric System excluding 'behind-the-fence' loads (industrial loads supplied by onsite generation) and the City of Medicine Hat's load served by its own generation.

AIL: Alberta Internal Load ("AIL") is the total domestic consumption including behind-the-fence and City of Medicine Hat load. The redefinition of AIL in 2002 added approximately 400 MW of behind-the-fence load.

Electrical demand has risen with the expansion of Alberta's economy. Over the past five years, AIL peak demand increased at an average annual rate of 3.9 per cent per year while energy consumption increased by 4.3 per cent per year (as shown in Table 2.3.-1). Over the same period, AIES peak demand grew at an average annual rate of 1.4 per cent and energy consumption by 1.2 per cent per year. The average annual growth rates for the five-year historical period 1999-2003 are lower for the AIES than the AIL. This results from a reclassification of grid load to behind-the-fence load through the creation of industrial site designations, rather than a slowing of the AIES growth.

2.3.3 *Forecast Load Growth*

Table 2.3-1 shows the forecast of most likely peak demand and energy consumption, including system losses, until 2024. As shown in the Table, AIL

peak demand is forecast to increase by 2.1 per cent per year over the next twenty years, while energy consumption is expected to increase by 2.2 per cent per year. The AESO forecasts AIES peak demand growth at an annual rate of 2.0 per cent and energy consumption by 2.0 per cent per year. The AIL higher growth rate results from a greater increase in behind-the-fence loads.

As discussed in Section 2.3.4 below after the 2004 Forecast had been completed it was found necessary to make an adjustment to the behind-the-fence component of the forecast.

Table 2.3-1: Alberta Future Market Outlook – Most Likely Forecast

AIES

Year	Peak Demand (MW)*	Year	Energy (GW.h)
1999/00 A	7,202	1999 A	50,174
2000/01 A	7,651	2000 A	52,460
2001/02 A	7,606	2001 A	52,376
2002/03 A	7,558	2002 A	53,628
2003/04 A	7,733	2003 A	53,248
2004/05 F	7,877	2004 F	55,321
2005/06 F	8,113	2005 F	56,636
2006/07 F	8,389	2006 F	58,606
2007/08 F	8,573	2007 F	59,898
2008/09 F	8,794	2008 F	61,686
2009/10 F	8,826	2009 F	61,845
2010/11 F	8,995	2010 F	63,028
2011/12 F	9,176	2011 F	64,264
2012/13 F	9,365	2012 F	65,816
2013/14 F	9,531	2013 F	66,788
2014/15 F	9,757	2014 F	68,008
2015/16 F	9,899	2015 F	69,311
2016/17 F	10,105	2016 F	71,017
2017/18 F	10,303	2017 F	72,211
2018/19 F	10,483	2018 F	73,484
2019/20 F	10,661	2019 F	74,725
2020/21 F	10,851	2020 F	76,305
2021/22 F	11,037	2021 F	77,402
2022/23 F	11,227	2022 F	78,748
2023/24 F	11,420	2023 F	80,113
2024/25 F	11,617	2024 F	81,757

*Note: Demand is winter peak demand (Nov. - Feb.)

Average Annual Growth Rates

99/00-03/04	1.4%	1999-2003	1.2%
04/05-09/10	2.3%	2004-2009	2.3%
04/05-14/15	2.2%	2004-2014	2.1%
04/05-24/25	2.0%	2004-2024	2.0%

AIL

Year	Peak Demand (MW)*	Year	Energy (GW.h)
1999/00 A	7,408	1999 A	50,851
2000/01 A	7,785	2000 A	54,052
2001/02 A	7,934	2001 A	54,464
2002/03 A	8,570	2002 A	59,428
2003/04 A	8,967	2003 A	62,714
2004/05 F	9,321	2004 F	64,756
2005/06 F	9,594	2005 F	67,207
2006/07 F	9,974	2006 F	69,453
2007/08 F	10,315	2007 F	71,486
2008/09 F	10,597	2008 F	74,468
2009/10 F	10,738	2009 F	75,044
2010/11 F	11,002	2010 F	77,136
2011/12 F	11,259	2011 F	79,159
2012/13 F	11,493	2012 F	81,324
2013/14 F	11,694	2013 F	82,574
2014/15 F	11,946	2014 F	84,059
2015/16 F	12,117	2015 F	85,586
2016/17 F	12,355	2016 F	87,594
2017/18 F	12,588	2017 F	88,994
2018/19 F	12,798	2018 F	90,519
2019/20 F	13,005	2019 F	92,004
2020/21 F	13,224	2020 F	93,879
2021/22 F	13,440	2021 F	95,171
2022/23 F	13,663	2022 F	96,762
2023/24 F	13,891	2023 F	98,373
2024/25 F	14,123	2024 F	100,316

*Note: Demand is winter peak demand (Nov. - Feb.)

+ 2002 redefinition added approx. 400 MW of 'behind the fence load'

Average Annual Growth Rates

99/00-03/04	3.9%	1999-2003	4.3%
04/05-09/10	2.9%	2004-2009	3.0%
04/05-14/15	2.5%	2004-2014	2.6%
04/05-24/25	2.1%	2004-2024	2.2%

The load factor in Alberta is approximately 80 per cent. With a slightly higher forecast growth in energy consumption compared to peak demand, the load factor will increase over the planning horizon. This load factor is higher than many other jurisdictions due to the high percentage of industrial load in Alberta's total load composition.

High and Low Probability Ranges

The previous section detailed the most likely future load forecast given a set of baseline assumptions. To assist in planning, particularly long-term analysis, the AESO develops high and low probability bands around the most likely outlook, as shown in Table 2.3-2. These bands form an 80 per cent confidence interval around the most likely forecast.

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Table 2.3-2: Alberta Future Market Outlook

AIES							
Year	Peak Demand (MW)			Year	Energy (GWh)		
	Low	2004 Most Likely	High		Low	2004 Most Likely	High
2003		7,733		2003		53,248	
2004	7,560	7,877	8,194	2004	53,377	55,321	57,264
2005	7,652	8,113	8,574	2005	53,822	56,636	59,450
2006	7,805	8,389	8,973	2006	55,040	58,606	62,172
2007	7,883	8,573	9,262	2007	55,690	59,898	64,107
2008	8,004	8,794	9,585	2008	56,841	61,686	66,532
2009	7,957	8,826	9,696	2009	56,524	61,845	67,167
2010	8,038	8,995	9,952	2010	57,170	63,028	68,886
2011	8,132	9,176	10,219	2011	57,879	64,264	70,649
2012	8,236	9,365	10,495	2012	58,879	65,816	72,752
2013	8,319	9,531	10,743	2013	59,369	66,788	74,208
2014	8,456	9,757	11,058	2014	60,085	68,008	75,932
2015	8,520	9,899	11,278	2015	60,876	69,311	77,745
2016	8,640	10,105	11,570	2016	62,022	71,017	80,012
2017	8,753	10,303	11,853	2017	62,719	72,211	81,702
2018	8,851	10,483	12,116	2018	63,486	73,484	83,482
2019	8,946	10,661	12,375	2019	64,225	74,725	85,226
2020	9,052	10,851	12,650	2020	65,252	76,305	87,357
2021	9,154	11,037	12,920	2021	65,866	77,402	88,938
2022	9,259	11,227	13,195	2022	66,690	78,748	90,806
2023	9,366	11,420	13,474	2023	67,527	80,113	92,699
2024	9,476	11,617	13,757	2024	68,595	81,757	94,918

Average Annual Growth Rates							
2004-2009	1.0%	2.3%	3.4%	2004-2009	1.2%	2.3%	3.2%
2004-2014	1.1%	2.2%	3.0%	2004-2014	1.2%	2.1%	2.9%
2004-2024	1.1%	2.0%	2.6%	2004-2024	1.3%	2.0%	2.6%

AIL							
Year	Peak Demand (MW)			Year	Energy (GWh)		
	Low	2004 Most Likely	High		Low	2004 Most Likely	High
2003		8,967		2003		62,714	
2004	8,946	9,321	9,695	2004	62,481	64,756	67,030
2005	9,049	9,594	10,140	2005	63,868	67,207	70,546
2006	9,279	9,974	10,669	2006	65,227	69,453	73,679
2007	9,485	10,315	11,144	2007	66,463	71,486	76,508
2008	9,644	10,597	11,550	2008	68,618	74,468	80,318
2009	9,680	10,738	11,796	2009	68,587	75,044	81,502
2010	9,831	11,002	12,172	2010	69,967	77,136	84,305
2011	9,978	11,259	12,539	2011	71,294	79,159	87,024
2012	10,107	11,493	12,880	2012	72,753	81,324	89,894
2013	10,207	11,694	13,181	2013	73,401	82,574	91,747
2014	10,353	11,946	13,539	2014	74,265	84,059	93,853
2015	10,429	12,117	13,805	2015	75,171	85,586	96,001
2016	10,564	12,355	14,147	2016	76,499	87,594	98,689
2017	10,694	12,588	14,482	2017	77,296	88,994	100,691
2018	10,805	12,798	14,791	2018	78,203	90,519	102,834
2019	10,913	13,005	15,097	2019	79,076	92,004	104,932
2020	11,032	13,224	15,417	2020	80,281	93,879	107,476
2021	11,147	13,440	15,733	2021	80,987	95,171	109,356
2022	11,268	13,663	16,058	2022	81,945	96,762	111,579
2023	11,393	13,891	16,389	2023	82,918	98,373	113,828
2024	11,520	14,123	16,725	2024	84,167	100,316	116,466

Average Annual Growth Rates							
2004-2009	1.6%	2.9%	4.0%	2004-2009	1.9%	3.0%	4.0%
2004-2014	1.5%	2.5%	3.4%	2004-2014	1.7%	2.6%	3.4%
2004-2024	1.3%	2.1%	2.8%	2004-2024	1.5%	2.2%	2.8%

Note: low / high bands is 80% confidence interval

2.3.4 *Adjustment to Behind-the-fence Load Forecast*

Subsequent to the completion of the AESO's 2004 Forecast (FC-2004-1) discussions held with a number of industrial customers indicated that the forecast of behind-the-fence load additions was somewhat on the low side. This component of the load forecast for the study year 2024 was therefore revised to reflect this more current information. The behind-the-fence load forecast was consequently revised from 2,044 MW to 2,860 for the Low forecast, from 2,506 MW to 4,000 MW for the Most Likely forecast and from 2,968 MW to 5,150 MW for the High Forecast respectively.

2.4 Generation Expansion Forecast

An important objective of the Outlook is to identify generation development scenarios and associated transmission developments required to integrate these generation additions. The AESO recognizes that it is not possible to definitively describe the timing and location of generation development 10 to 20 years into the future. Generation development in Alberta is a competitive business and decisions regarding future generation development are made by independent power producers and are subject to rigorous evaluations that take into account many complex and inter-related social, economic and environmental factors.

Alberta has diverse existing electric generation resources, mainly comprised of hydro, coal, gas and wind. In addition, Alberta also has significant undeveloped coal reserves and cogeneration opportunities. The AESO engaged the services of an independent consultant to assist in identifying generation development opportunities in Alberta and rank, on an outlook basis, the various developments into one of three categories:

1. Generation scenarios to meet the requirements of the Low load forecast during the next 20 years.
2. Generation scenarios that would meet the requirements of the Most Likely load forecast during the next 20 years.
3. Generation scenarios that would meet the requirements of the High load forecast during the next 20 years.

The consultant's report outlining these above noted generation development scenarios is included in Appendix A; a summary of the major findings of the report follows.

The generation development scenarios developed by the consultant were prepared on the basis of defining the generation requirements for the end year (2024) of the period only; no attempt was made to identify the timing of specific developments within the 20-year period.

These scenarios were then used as the basis, along with the load forecast, for preparing the transmission system development scenarios described in Section 3.

A firm generation capacity reserve margin of 10 per cent was selected for the purposes of estimating the firm generation capacity that will be installed to meet the total Alberta peak load demand. In other words, it is expected that new generation would be added in response to price signals such that the margin between the peak load and the firm capacity would not fall below 10 per cent as load growth takes place.

The 10 per cent reserve margin used here is calculated on the basis of a determination of firm generation capacity, and is not directly comparable to reserve margins that are calculated based on total installed capacity such as have been used in Alberta in the past. Since installed capacity is greater than firm capacity, reserve margins based on total installed capacity are higher for a given system. The reserve margin of 10 per cent used here is equivalent to a reserve margin of about 17 per cent if calculated on the basis of the installed, rather than firm, hydro and wind capacity and is equivalent to a reserve margin of about 26 per cent if the full capacity of the B.C. and Saskatchewan inter-ties were also to be included. This reserve margin calculation, on the basis of firm capacity, is considered more meaningful for this purpose than calculations on the basis of installed capacity, and recognizes the contributions of lower output factor generation rather than simply completely removing these types of generation from calculations based on installed capacity.

Although the above definition relative to reserve margin has been taken into consideration, the Electricity Policy Framework requires the AESO to undertake further work to respond to the question of what is the appropriate reserve margin to ensure the long-term supply adequacy to loads².

2.4.1 Existing Generation Capacity and Fuel Type

Table 2.4-1 indicates the amount of generation operating in Alberta by fuel type as of December 31, 2004.

² Alberta's Electricity Policy Framework: Competitive – Reliable – Sustainable, June 6, 2005, Alberta Department of Energy, page 34.

Table 2.4-1: Summary of AIES Generation by Fuel Type

Generation Fuel Type	Installed Capacity (MW)
Hydro	899
Coal	5,617
Gas	5,060
Wind	282
Biomass and Other	148
TOTAL	12,006

As of December 31, 2004 Alberta had approximately 12,000 MW of generation available to the AIES, including a number of smaller generating units connected to distribution (i.e. 25 kV) lines. Some 84 per cent of this generation is located in three zones: Lake Wabamun/Edmonton area (5,900 MW), Fort McMurray (1,100 MW) and southern Alberta (3,000 MW). Approximately 1,500 MW of this is so-called behind-the-fence generation serving on-site industrial needs.

2.4.2 Forecasted Generation Additions

As described in the consultant's report all of the scenarios developed assumed that the behind-the-fence load increases would be served by corresponding increases in behind-the-fence generation leaving a net amount of grid-supplied new load growth needing to be resourced. As well, all of the scenarios assumed that an incremental 2,000 MW of wind generation would be added over the 20-year period. However, in recognition of the variability of the wind output, this amount of generation was "derated" to 300 MW in order to make a determination of how much total additional generation would be required³. Similarly, all of the scenarios assumed some additional small hydro units, suitably derated

³ As indicated in the Alberta's Electricity Policy Framework: Competitive – Reliable – Sustainable paper the AESO will need to determine the appropriate capacity factors for various types of generation resource to be used in the determination of long-term supply adequacy (page 31).

to account for energy availability, as well as unit uprates at Sundance and Keephills and other smaller units with various fuel sources would be developed.

The consultant's report describes in detail how the various generation development scenarios were derived. After determining the net grid-supplied amount of load, allowing for the 10 per cent reserve margin, and making adjustments to account for unit retirements and to reflect the variability of certain types of energy sources, the net amount of required new generation for the Low, Most Likely and High load growth scenarios was determined. Two generation development scenarios achieving the required amount of new generation were prepared for each load growth scenario. Table 2.4-2 below summarizes the new generation additions thus determined.

Table 2.4-2: Net Grid Resource Requirements

	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6
(All Quantities in MW)	Low Load Forecast Coal and Southern Generation	Low Load Forecast Cogen and Northern Generation	Most Likely Load Forecast Coal and Southern Generation	Most Likely Load Forecast Cogen and Northern Generation	High Load Forecast Coal and Southern Generation	High Load Forecast Cogen and Northern Generation
Wind	300 net (2,000 installed)	300 net (2,000 installed)	300 net (2,000 installed)	300 net (2,000 installed)	300 net (2,000 installed)	300 net (2,000 installed)
Small Hydro	100 net (200 installed)	100 net (200 installed)	100 net (200 installed)	100 net (200 installed)	100 net (200 installed)	100 net (200 installed)
Upgrades at Keephills and Sundance	200	200	200	200	200	200
Other Small Units of Various Fuel Type	300	300	500	500	800	800
New Coal Units at Keephills and Genesee	1,000	500	1,500	1,500	1,500	1,500
Coal at Other Sites	0	0	1,000	0	2,500	1,000
Cogeneration at Fort McMurray Surplus to Local Needs	600	1,400	1,100	2,600	1,500	3,800
Peaking Units Near Calgary	300	0	500	0	800	0
TOTAL	4600	4600	7000	7000	9500	9500

All of the above generation scenarios were used in determining the transmission system development alternatives.

2.5 Interties to Other Jurisdictions

The AESO's approach to interties with other jurisdictions in this Outlook reflects several objectives stemming from the Transmission Development Policy and related Transmission Regulation, namely:

- to restore existing interties to original design ratings; and

- to facilitate the development of merchant intertie projects.

These objectives have been incorporated into the scenarios developed with consideration being given to the impacts those developments would have on the Alberta transmission system.

The AESO has also taken into consideration the potential benefits to overall transmission system reliability of additional interties where those interties dovetail into the planning of the transmission system for intra-Alberta needs. As well, the AESO is directed by the recently released Electricity Policy Framework to evaluate provision of additional intertie capacity with neighbouring jurisdictions as a means to stimulating generation development in Alberta that would "...directly enhance system adequacy and reliability."⁴ While this is addressed to some extent in the consideration applied to transmission system reliability, the AESO will be increasing its focus in the future on examining intertie alternatives as a means to ensure overall reliable supply of service to Albertans. Additional thought will also need to be applied in the future regarding long term supply adequacy implications as long term adequacy measures are developed as envisioned in the Electricity Policy Framework.

⁴ Alberta's Electricity Policy Framework: Competitive – Reliable – Sustainable, June 6, 2005, Alberta Department of Energy, page 39.

3.0 Transmission System Development Scenarios

This Outlook focuses primarily on the bulk transmission system in Alberta, which generally consists of the 500 kV and 240 kV transmission lines and substations. A bulk transmission system is typically considered as the integrated system of higher-voltage transmission lines and substations through which electric power is reliably delivered from major generating stations both to and between load centres and also delivered and received reliably to and from neighbouring jurisdictions.

By the end of the 20-year period being considered, some of the existing 240 kV lines will be reaching an advanced age and may require replacement of the conductor and other components. Some of the older 240 kV substation equipment may also need to be replaced. These types of system changes are not specifically addressed in the Outlook as it is considered likely that they will be replaced on a like-for-like basis, much like existing roads are resurfaced. However, as further detailed analysis is conducted on a project-specific basis the issues of aging infrastructure impacted by those projects will be addressed.

This Section will describe possible transmission system developments for each of the scenarios described previously in Section 2. It must be emphasized that these are “possible” developments only. The new transmission lines and facilities as depicted in the system diagrams provided are not intended to convey specific routes or locations. Where ever possible, existing stations have been used to indicate the general location of the terminations for the new transmission lines. The actual terminations may occur at these stations, other stations in the vicinity, or at new stations constructed at some time in the future. Detailed analysis and stakeholder involvement will be conducted on all aspects of the planning process, and in some cases such activity is currently underway. This Outlook does not pre-empt any of that effort.

3.1 Technology Alternatives

There are a number of possible technological choices that can be considered to meet the need and long-term system development requirements for Alberta’s transmission system. The system can be reinforced using transmission lines designed for AC operation with voltages ranging from 240 kV to 765kV. An alternative to the AC option is the High Voltage Direct Current (HVDC) option with transmission lines designed for operation at voltages ranging from 250 kV to 500 kV.

Alberta currently uses 240 kV AC for its transmission system and 500 kV AC is used for the B.C. Tie. The Keephills to Genesee to Elnerslie transmission lines as well as the approved new 500 kV circuit from Genesee to Langdon will extend the 500 kV system from Langdon to the Edmonton area. Most of the bulk transmission systems in the western half of North America are 240 kV and 500 kV. For these reasons, 240 kV and 500 kV are considered to be the appropriate voltage levels for future transmission development in Alberta.

The decision as to whether 240 kV or 500 kV is the most appropriate voltage to use is primarily an economic decision but is also influenced by the increased dynamic and voltage stability provided by the higher voltage. The increased capital cost of 500 kV is offset by the lower MW and MVAR losses and the lower \$/MW capability of the higher voltage lines. As a high level guideline it can be considered that for any path loaded above approximately 1000 MVA it is more economical to construct two 500 kV lines rather than four 240 kV lines. This, along with the significantly higher capacity it provides, drives the use of 500 kV for the major transmission paths in the 20-Year Outlook.

The main alternative to AC transmission is High Voltage Direct Current ("HVDC") transmission. This technology has advanced significantly over the last twenty years and costs are likely to continue to decrease. HVDC is more commonly being used today worldwide for transmission lines greater than 1000 km in length and special applications including asynchronous links such as Alberta's tie with Saskatchewan. One advantage of HVDC is lower cost for the transmission line. A bipolar HVDC line costs about 40% less than two 500 kV AC lines of similar transfer capability. However, an HVDC system requires costly terminal equipment to convert DC currents to/from AC currents. Currently the HVDC option is more costly than the AC option for distances less than 1000 km. The terminal cost is expected to continue to decline, however, given the relatively short point-to-point distances required to interconnect the loads and generation on the Alberta bulk system, HVDC is not considered a likely alternative when considering only intra-Alberta system requirements. The AESO will continue to monitor the development of HVDC technology in order to assess its application for use in Alberta.

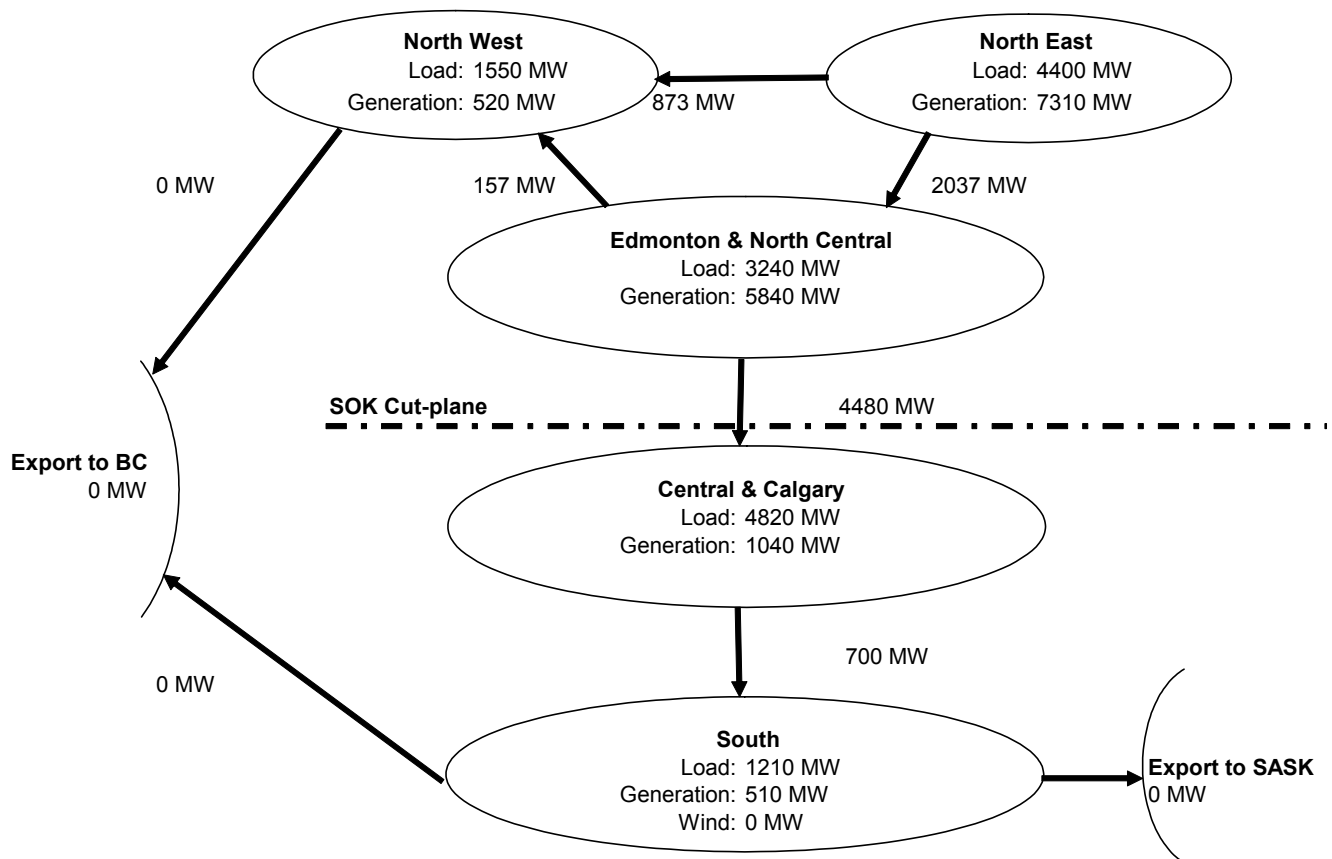
3.2 Methodology for Determining Inter-Regional Transfer Requirements

The bulk transmission system is primarily used to move power from generation surplus regions in Alberta to load regions as well as to and from neighbouring jurisdictions. The time of day and system conditions for which different sections of the bulk system are most stressed do not necessarily coincide with times of peak system load nor does the time of peak loading on different paths necessarily coincide with each other. To assess the existing and required future capability needs of the bulk system major transmission paths between regions are defined by using "cut-planes" which are hypothetical lines "cutting" through all of the transmission circuits at a given location. This permits the system to be evaluated based on the total capability of multiple transmission circuits interconnecting regions of the system and under the loading conditions which most stress these circuits.

'Bubble' diagrams are a common method used in the power industry for depicting in a simplified yet understandable way the power flows between regions for an assumed system loading and generation dispatch condition. In order to assess the transmission requirements contemplated in this 20-Year Outlook Document the transmission grid and associated transmission paths within Alberta are divided into five major regions, each represented by a bubble. Bubble diagrams have been created using the load and generation forecasts for 2024 to predict the future required capability on the main transmission paths. An example of one of the bubble diagrams produced for this Outlook is

shown in Figure 3.2-1. For each region the load and the generation dispatched within the region is shown. The difference between the generation and the load moves into or out of the region on the main transmission paths. For example, Figure 3.2-1 depicts the peak load condition for the winter of 2024/2025 for Scenario 4 which assumes the generation development is cogeneration and northern generation. Given this scenario, the bubble diagram shows generation exported from both the North East and the Edmonton regions, flowing both to the North West and Central and South Alberta regions. The path between Edmonton and Calgary is shown to be heavily loaded at above 4,400 MW. Using this method, future path loadings can be forecast for various system conditions and used to develop the plans for the transmission additions that may be required.

Figure 3.2-1: Bubble Diagram Example - Scenario 4 Winter Peak



This Outlook considers three different system operating conditions to heavily stress the different transmission paths in order to assess the transmission development required for each scenario. These conditions are:

- (a) Winter Peak Load, No Wind, No Import/Export
- (b) Summer Daytime Load, No Wind, Exports
- (c) Spring Load, Maximum Wind, Imports

The winter peak loading condition represents the winter peak hour with no production from the wind generation due to calm wind conditions and no imports into Alberta. A forced outage of a large generator in the south is assumed in order to increase northern dispatched generation and, as a result, further stress the paths flowing from the north to the large loads in the Calgary area.

The summer daytime export condition represents moderate early summer daytime loading in Alberta combined with an export of power out of Alberta. No wind has been assumed and southern base load generation has been reduced for planned maintenance to stress all the paths from the north through to B.C.

To stress the south to north paths, a spring load condition has been used in combination with full wind production, imports from B.C. and all base load plants in the south available.

A complete set of bubble diagrams for each of the three operating conditions described above and studied for the six scenarios is provided in Appendix B.

3.3 **Scenario 1: Low Load Forecast, Coal and Southern Generation**

This scenario assumes very minimal generation additions due to the low load growth forecast. The transmission system development contemplated for this scenario is shown in Figure 3.3-1.

The low amount of load growth will drive only a modest increase in generation exports from the North East and a more significant increase on the loading of the Edmonton to Calgary north – south path. Only modest system reinforcements are required for the North East and North West but the systems from Edmonton and the South East going to Calgary would require significant expansion.

3.3.1 ***Fort McMurray Area***

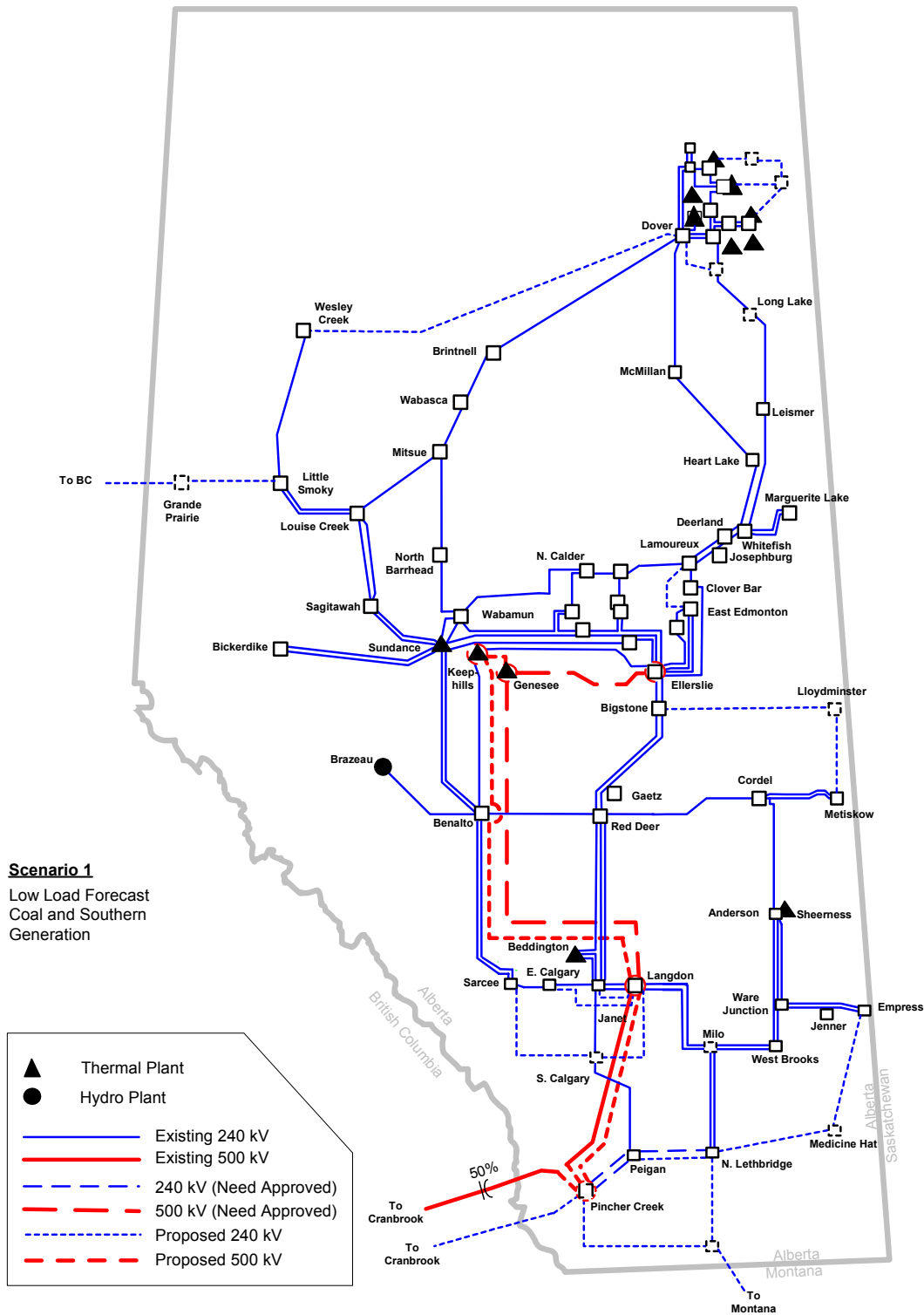
The 240 kV system in the Fort McMurray area is expanded to encompass development of additional oil sands leases and provide both backup and export capacity for oil sands operations with on-site generation. Even with the modest increases in cogeneration at Fort McMurray assumed in Scenario 1, the path loading out of the North East, as shown in Appendix B Figure B.1 - A, exceeds the current system capability during heavy winter loading. The path capacity into the North West is also exceeded during spring loading conditions. Both concerns are addressed through the construction of a line from Dover in the North East to Wesley Creek in the North West as shown in Figure 3.3-1.

This solution provides significant flexibility for directional changes in the development of the system. The Dover – Wesley Creek line could be built in stages as the need manifests itself, starting with either a line from Dover to Brintnell or from Brintnell to Wesley Creek as the initial development. The lines could be designed for 500 kV operation which would permit them to be converted and developed into the higher capacity 500 kV system depicted in Figure 3.4-1 to handle higher export levels from the North East or, if no north generation development occurs, a 500 kV line could be brought up from Keephills to Brintnell and connected to the line to supply both the North East and North West at 500 kV.

3.3.2 ***Grande Prairie Area***

To meet the growing load in the Grande Prairie area, the 240 kV system is extended from Little Smoky into Grande Prairie via a double circuit 240 kV line and a new tie line from Grande Prairie to B.C. The North West tie to B.C. will help to stabilize the Alberta system relative to B.C., improve the reliability of supply for both the B.C. and Alberta local regions and reduce system losses in Alberta when energy is imported from B.C. during the peak hours.

Figure 3.3-1: Scenario 1 - Bulk Transmission System Development



3.3.3 *Edmonton – Calgary Transmission Path*

The Edmonton to Calgary path is the most heavily loaded during the summer daytime export conditions. The level of path loading indicated in Appendix B Figure B.1 - B will require the second north – south 500 kV circuit to be completed from Keephills to Langdon. The NorthernLights +/- 500 kV HVDC transmission line from Fort McMurray to the Pacific Northwest could provide an alternative to the second north - south 500 kV circuit. A HVDC terminal with 1000 MW or more capacity installed near Calgary (interconnected as shown in Figure 3.6-3: Scenario 4C - HVDC Merchant Line from Fort McMurray) in conjunction with a contractual agreement for transmission capacity from the merchant entity would provide the additional capability required on the path. In the event of an outage on the Genesee to Langdon 500 kV line, the HVDC terminal output would be ramped up to 1000 MW or more to move energy from the North East directly to Calgary, thereby offloading the Edmonton to Calgary path to a safe level of operation.

3.3.4 *Lloydminster Area*

To meet the growing load in the Lloydminster and Metiskow area, as well as the loss of supply due to the retirement of the Battle River generation, the 240 kV is extended from Edmonton to Lloydminster and south to Metiskow, creating a supply loop off the Edmonton to Calgary path.

3.3.5 *Calgary Area*

To supply the load growth in the Calgary area an additional supply station, South Calgary, is added as well as additional 240 kV circuits from the 500 kV station at Langdon to the existing load substations at Janet, East Calgary and Sarcee.

3.3.6 *Lethbridge – Medicine Hat – Empress Area*

Transmission reinforcements for load growth are required for the Lethbridge, Medicine Hat and Empress areas. This is addressed with 240 kV circuits from North Lethbridge to Medicine Hat to Empress. Components of this development could be staged with the 240 kV lines initially being energized at 138 kV. A number of the existing 138 kV lines in this area are of an advanced age and may be replaced with 240 kV construction when a complete line rebuild is required. At the Lethbridge end of the loop, capacity to supply the growing loads would be initially supplied out of Lethbridge by a 240 kV circuit energized at 138 kV.

3.3.7 Southern Alberta Area

The supply to southern Alberta is further reinforced with the addition of a 240/500 kV substation at Pincher Creek that serves to both supply the loads and to provide an outlet for the wind generation. As can be seen in Appendix B Figure B.1 - C, south to north transfers exceed 2,800 MW during maximum wind production. The capability of the existing 240 kV system out of southern Alberta requires significant reinforcement to carry this level of loading. The new circuit from Lethbridge to Medicine Hat as well as the new 500 kV station at Pincher Creek provide additional paths for the energy. To provide capacity for this level of path loading, the existing 500 kV circuit to Langdon must be backed up with a second 500 kV circuit from Pincher Creek to Langdon. It will also likely be necessary to develop more extensive 138 and 240 kV lines to integrate the wind farm projects in southern Alberta. Such transmission development will be identified in more detail as the locations and sizes of specific wind farms become known. This transmission development could also potentially be integrated with the proposed merchant tie line to Montana.

To maintain the 1,200 MW of import and 1,000 MW of export capability and prevent separation of Alberta from the rest of the WECC grid, the existing 138 kV line from Pincher Creek to B.C. is upgraded to 240 kV. This, in combination with the proposed Montana – Alberta merchant tie and the North West 240 kV tie to B.C. will stabilize the system and prevent separation of Alberta when the 500 kV tie to B.C. trips. The existing LRAS (direct tripping of load using a remedial action scheme) would still be required. Preventing separation is expected to become critical for system reliability as more wind generation is added to the Alberta system because in an islanded state it may be very difficult to replace the loss of generation caused by a sudden drop off in wind production in a timely manner with internal generation reserves.

3.4 Scenario 2: Low Load Forecast, Cogeneration and Northern Generation

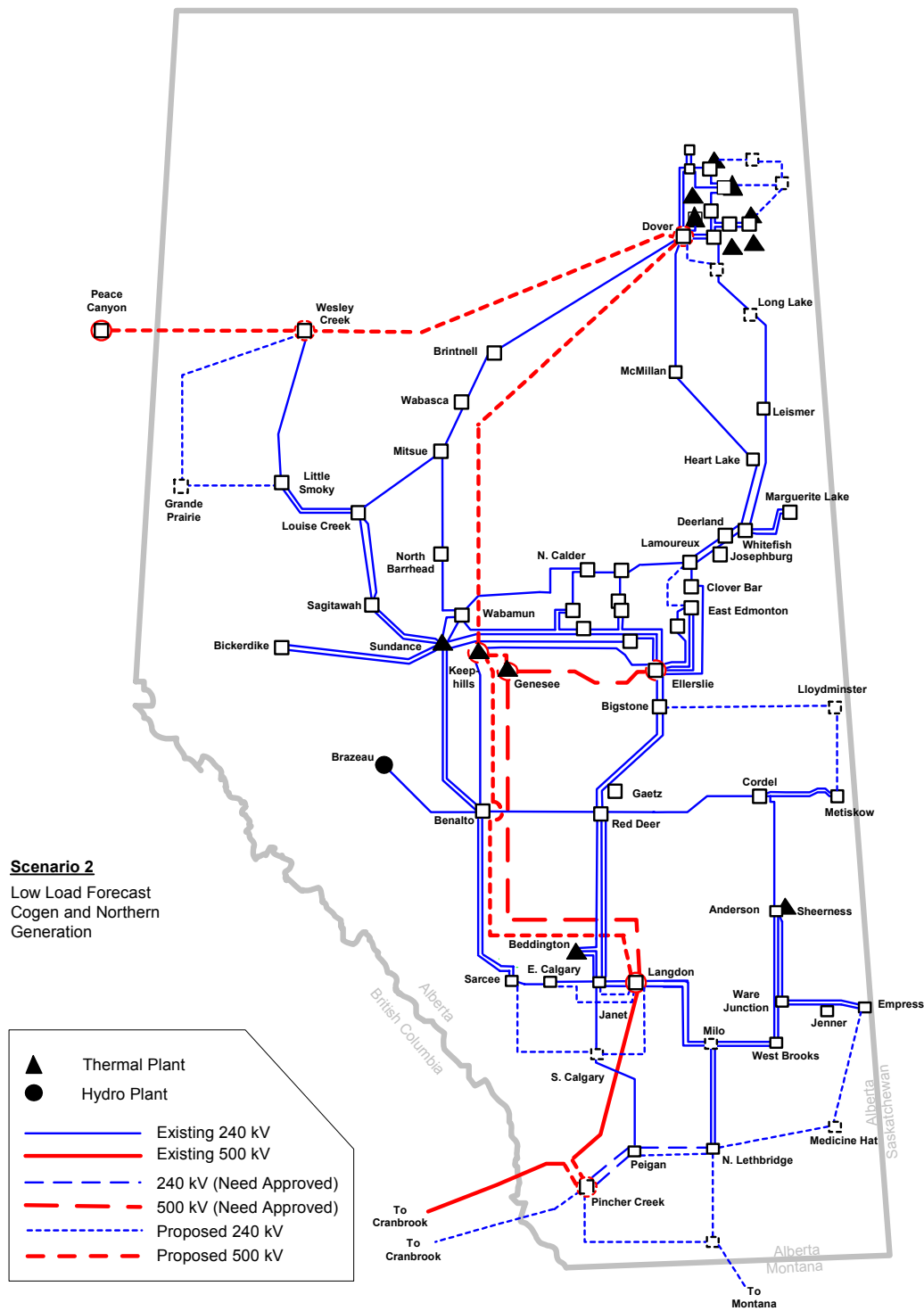
This scenario assumes very minimal generation additions due to the low load forecast but with the majority of the new generation additions in the North East. This will drive significant increases to the loading of both the North East and Edmonton to Calgary paths. System reinforcements are required for all regions. The transmission system development contemplated for this scenario is shown in Figure 3.4-1.

3.4.1 Fort McMurray Area

As in Scenario 1, the 240 kV system in the Fort McMurray area is expanded to encompass additional development of the oil sands leases. This network will provide both backup for oil sands operations as well as transmission capability for surplus electrical energy produced from cogeneration. The increased flows out of the North East under both the winter peak, as shown in Appendix B Figure B.2 - A, and summer export loading conditions, as shown in Appendix B Figure B.2 - B, are carried by a 500 kV line from Dover to Keephills in combination with a 500 kV line from Dover to Wesley Creek as well as a new 500 kV tie line from Wesley Creek to Peace Canyon in B.C.

This solution provides significant flexibility for both staging the additions and responding to changes in the direction the system develops. The lines would be designed for 500 kV operation but initially operated at 240 kV. This would permit them to be converted and developed into the higher capacity 500 kV system depicted in Figure 3.4-1 as load and generation levels increase. The initial stages of development could be a staged development of the northern system as described for Scenario 1. The system could then continue to develop as a 240 kV expansion with the Dover to Keephills line constructed initially only as far as Mitsue. This would provide a total of five circuits energized at 240 kV with an estimated path capability in the order of 1,200 MW available to bring generation out of Fort McMurray. Once this level of path loading is exceeded, the Dover to Keephills line would be completed and the line voltage increased to 500 kV.

Figure 3.4-1: Scenario 2 - Bulk Transmission System Development



The line from Dover to Keephills as shown in Figure 3.4-1 could instead be constructed from Dover to Ellerslie as shown in Figure 3.6-1. The route to Ellerslie has the advantage of making possible the addition of a 500 kV source into the Fort Saskatchewan area. The two routes are virtually the same distance but the Dover to Keephills route provides greater opportunities to stage the construction of the line in smaller segments over time and more of the route can be built with lower cost guyed structures. For the low load growth scenario the capital costs would be spread out over a wide span of years, significantly reducing the overall cost. Under the low growth scenario, the lower cost of the Dover to Keephills route could outweigh the benefits of a new 500 kV source station in the Fort Saskatchewan area that could be developed as part of the Dover to Ellerslie line.

If the amount of north generation development anticipated were to decline, the Dover to Keephills 500 kV line shown in Figure 3.4-1 could alternately be brought up from Keephills and end at Brintnell. A 240/500 kV substation added at Brintnell and connected to the Dover to Wesley Creek line constructed in the initial stages of the plan would supply both the North East and North West at 500 kV. The Wesley Creek to Peace Canyon circuit would serve to complete a 500 kV supply loop through the north.

3.4.2 *Grande Prairie Area*

The increased North West load is addressed in the system plan through the construction of a 500 kV line from Dover in the North East to Wesley Creek in the North West as shown in Figure 3.4-1. To meet the growing load in the Grande Prairie area as well as providing capability for North East generation to move south, the 240 kV system is extended from both Wesley Creek and Little Smoky into Grande Prairie.

3.4.3 *Edmonton – Calgary Transmission Path*

As shown in Appendix B Figure B.2 - B, the northern 500 kV tie to B.C. significantly reduces the loading on the Edmonton to Calgary path during export, but the path loading still exceeds the path capability during the summer daytime export conditions. The level of path loading indicated will require the second north – south 500 kV circuit to be completed from Keephills to Langdon. The NorthernLights +/- 500 kV HVDC transmission line from Fort McMurray to the Pacific Northwest could provide an alternative to the second north - south 500 kV circuit. An HVDC terminal with 500 MW or more capacity installed near Calgary (interconnected as shown in Figure 3.6-3) in conjunction with a contractual agreement for transmission capacity from the merchant entity would provide the additional capability required on the path. In the event of an outage of the Genesee to Langdon 500 kV line, the HVDC terminal output would be ramped up to 500 MW or more to move energy from the North East directly to Calgary, thereby reducing the loading on the Edmonton to Calgary path to a safe level.

3.4.4 *Lloydminster Area*

The transmission development in the Lloydminster area in this scenario would be the same as described in Section 3.3.4.

3.4.5 *Calgary Area*

The transmission development in the Calgary area in this scenario would be the same as described in Section 3.3.5.

3.4.6 *Lethbridge – Medicine Hat – Empress Area*

The transmission development in the Lethbridge – Medicine Hat – Empress area in this scenario would be the same as described in Section 3.3.6.

3.4.7 *Southern Alberta Area*

The transmission development in the southern Alberta area in this scenario would be the same as described in Section 3.3.7 with the exception that the need for a second 500 kV circuit from Pincher Creek to Langdon is avoided because of the northern 500 kV tie to B.C. In the event of a trip of the Langdon to Pincher Creek 500 kV line, the wind generation output can be accommodated by a counterflow from the South East into B.C. and back out into the North West over the Peace Canyon to Wesley Creek 500 kV tie line. This is not anticipated to cause problems in B.C. as the flow is counter to the normal direction of flow on the B.C. grid. However, some reinforcements in B.C. may still be required. As in Scenario 1, it will also likely be necessary to develop more extensive 138 and 240 kV lines to integrate the wind farm projects in southern Alberta and to further integrate the Montana – Alberta intertie.

The northern 500 kV tie to B.C. ensures the 1,200 MW import and 1,000 MW export capabilities can be maintained or increased, stabilizes the system and prevents separation of Alberta and B.C. after a tie line trip. Preventing the separation of Alberta and B.C. is necessary both to increase the inter-regional transfer capabilities and to stop the over frequency events occurring in the province when the south 500 kV tie to B.C. trips. Overfrequency events stress all types of electrical equipment and can reduce the life of the turbine blades in both steam and gas turbines. The existing LRAS (direct tripping of load using a remedial action scheme) would no longer be required following the addition of a second 500 kV tie.

For B.C., the strengthened interconnection with Alberta reduces the risk of Alberta and B.C. separation if the ties between B.C. and the U.S. trip, ensuring that the spinning reserves and inertia of both systems will be shared for this event. This could increase the capability of the existing B.C. to U.S. ties to transfer energy south to north which is limited today by the risk of underfrequency in B.C. after a separation with the U.S.

Using a northern route for a second 500 kV tie to B.C. has a number of significant advantages over a southern route. The amount of line construction required is approximately 800 km less than a series of lines south and west to Selkirk, B.C. The stability of the Peace Canyon generation in B.C. is improved by the connection to Alberta which would permit further generation additions at the site. Another benefit for the B.C. system is that the power flows from the two radial subsystems, namely Peace Canyon and Mica/Revelstoke, would be more balanced reducing the need to achieve the balance through the generation dispatch changes. By connecting the two systems at the northern ends, the two systems provide a backup to each other after a line outage occurs. This benefits both systems by increasing the north to south transfer capability of both systems without adding an additional line. The AESO will be undertaking much more detailed analysis of this proposal with the British Columbia Transmission Corporation ("BCTC") to ensure that the potential benefits of such an interconnection are assessed and realized.

3.5 Scenario 3: Most Likely Load Forecast, Coal and Southern Generation

This scenario assumes generation additions across Alberta will be built in response to the load growth. The generation and load growth will drive significant increases in the loading of both the North East and Edmonton to Calgary paths. System reinforcements are expected to be required for all regions. The transmission system development contemplated for this scenario is shown in Figure 3.5-1.

3.5.1 Fort McMurray Area

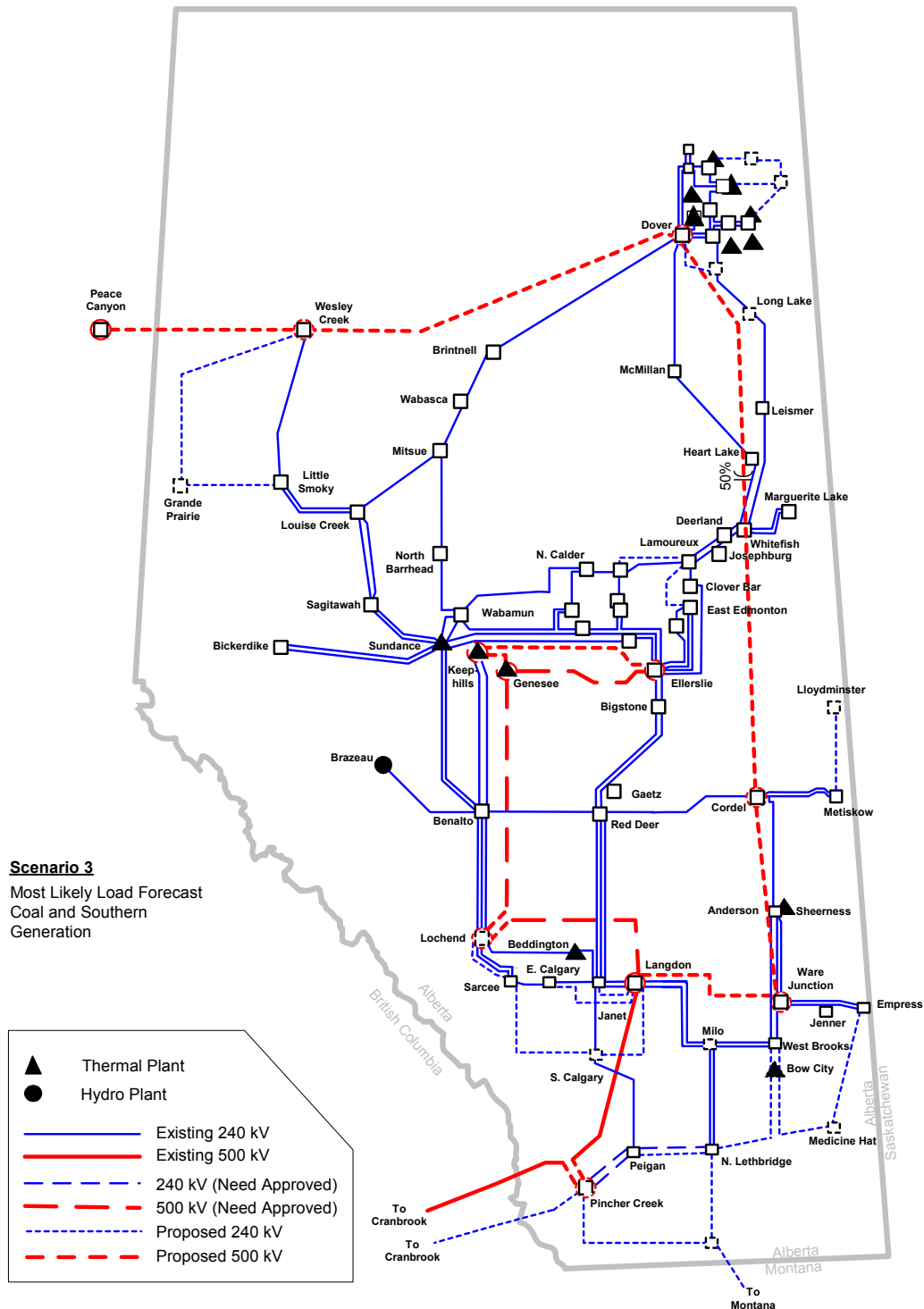
The 240 kV system in the Fort McMurray area is expanded to encompass additional development of oil sands leases. This network provides both backup for oil sands operations as well as transmission capability for surplus electrical energy produced from cogeneration. The heavy flows out of the North East under both the winter peak and summer export loading conditions are carried by a 500 kV line running down the eastern side of the province from Dover to Cordel to Ware Junction to Langdon which, in combination with the Dover to Wesley Creek 500 kV circuit, provides sufficient capability to move the energy to the load centres. These circuits also provide sufficient capability to move energy from the coal plants in the South East to the load centres.

A 500 kV interconnection to B.C. would be extended from Wesley Creek as described in Section 3.4.1.

3.5.2 Grande Prairie Area

The transmission development in the Grande Prairie area in this scenario would be the same as described in Section 3.4.2.

Figure 3.5-1: Scenario 3 - Bulk Transmission System Development



3.5.3 *Edmonton – Calgary Transmission Path*

The Edmonton to Calgary path is the most heavily loaded during the summer daytime export conditions as shown in Appendix B Figure B.3 - B. The level of path loading indicated will not require the second north – south 500 kV circuit to be completed from Keephills to Langdon because the east side 500 kV line from Dover through to Langdon fulfills this need.

The development could be staged and has some flexibility to respond to changes in the direction of system development. The Langdon to Ware Junction circuit and the Cordel to Anderson segment of the north - south circuit shown in Figure 3.5-1, could be initially energized at 240 kV to provide staged additional capability out of the South East if generation develops first in the south. If northern generation development failed to materialize, the direction of the 500 kV development could be shifted by constructing an Ellerslie to Camrose-Ryley circuit instead of the Dover to Cordel circuit to create an Ellerslie to Camrose-Ryley to Ware Junction to Langdon loop the same as that shown for Scenario 5 in Figure 3.7-1.

3.5.4 *Lloydminster Area*

To meet the growing load in the Lloydminster and Metiskow regions, as well as the loss of supply due to the retirement of the Battle River generation, a 240/500 kV station is placed at Cordel. The 240 kV system is then extended to Lloydminster from Metiskow.

3.5.5 *Calgary Area*

To supply the load growth in the Calgary area a 240/500 kV substation is added at Lochend and an additional 240 kV line is extended from Lochend to Sarcee. The other transmission development in the Calgary area in this scenario is the same as described in Section 3.3.5.

3.5.6 *Lethbridge – Medicine Hat – Empress Area*

The transmission development in the Lethbridge – Medicine Hat – Empress area in this scenario is the same as described in Section 3.3.6.

3.5.7 *Southern Alberta Area*

The supply to southern Alberta is further reinforced with the addition of a 240/500 kV station at Pincher Creek which serves to both supply the loads and provide an outlet for the wind and coal generation. During maximum wind production, the capability of the existing 240 kV system out of southern Alberta is exceeded. The new 240 kV circuits from Bow City to Medicine Hat as well as the new 500 kV stations at Pincher Creek and Ware Junction provide additional paths for the energy. A second 500 kV circuit from Pincher Creek to Langdon is avoided because of the additional capability provided by the northern 500 kV tie to B.C. combined with the new 500 kV circuit from Ware Junction to Langdon. In

the event of a trip of the Langdon to Pincher Creek 500 kV line, a small counterflow from the South East into B.C. and back out into the North West over the Peace Canyon to Wesley Creek 500 kV tie line may occur. The majority of the flow will be redirected onto the Ware Junction to Langdon 500 kV circuit.

As in Scenario 1, it will also likely be necessary to develop more extensive 138 and 240 kV lines to integrate the wind farm projects in southern Alberta and to further integrate the Montana – Alberta intertie.

The northern 500 kV tie to B.C. will also ensure the 1,200 MW of import and 1,000 MW of export capability can be maintained, stabilize the system and prevent separation of Alberta when the south 500 kV tie to B.C. trips. The existing LRAS (direct tripping of load using a remedial action scheme) would no longer be required.

The NorthernLights +/- 500 kV HVDC transmission line from Fort McMurray to the Pacific Northwest could provide an alternative to the 500 kV line running down the eastern side of the province from Dover to Cordel to Ware Junction. An HVDC terminal with 1000 MW or more capacity installed near Calgary (shown in Figure 3.6-3) in conjunction with a contractual agreement for transmission capacity from the merchant entity would provide the additional capability required on the paths south from Fort McMurray. In the event of an outage on the Genesee to Langdon or the Dover to Wesley Creek 500 kV lines, the HVDC terminal output would be ramped up to 1000 MW or more to move energy from the North East directly to Calgary, offloading the paths between the North East and Calgary to a safe level of operation.

3.6 Scenario 4: Most Likely Load Forecast, Cogeneration and Northern Generation

This scenario assumes generation additions concentrated in the northern half of Alberta will be built in response to the load growth. The generation and load growth will drive significant increases to the loading of both the North East and Edmonton to Calgary paths. System reinforcements are expected to be required for all regions. The transmission system development alternatives contemplated for this scenario are shown in Figure 3.6-1, Figure 3.6-2, and Figure 3.6-3.

3.6.1 Fort McMurray Area

The 240 kV system in the Fort McMurray area is expanded to encompass development of additional oil sands leases. This network will provide both backup for oil sands operations as well as acting as transmission capability for significant surplus electrical energy produced from cogeneration. The flows out of the North East exceed 2,900 MW during the winter peak as indicated in Appendix B Figure B.4 – A. This heavy path loading requires both a second 500 kV line as well as series compensation of all of the 500 kV circuits coming out of Dover to increase the path capability to the level needed.

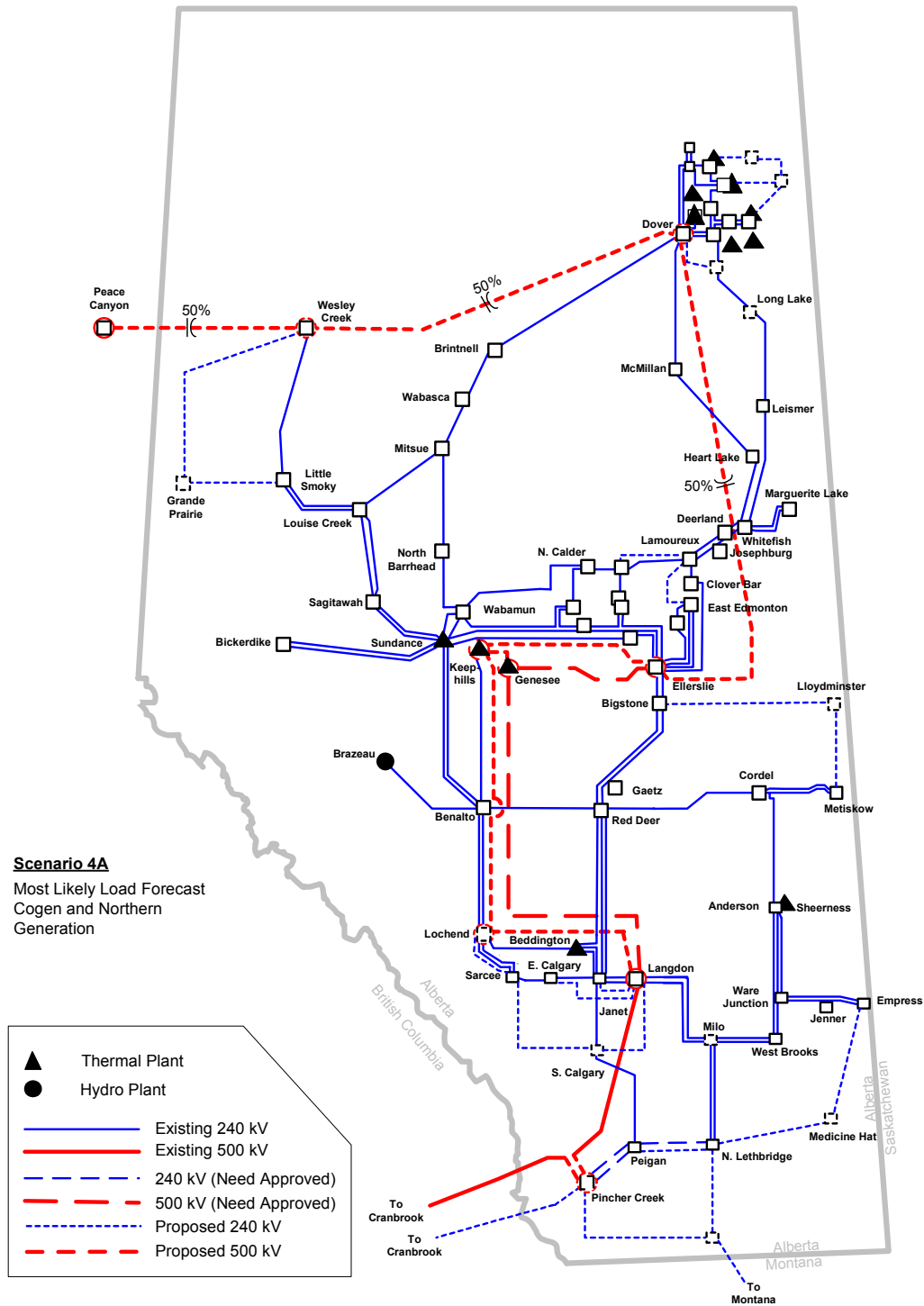
The second circuit could either be a 500 kV line from Dover to Ellerslie as shown in Figure 3.6-1 or to Keephills as shown in Figure 3.6-2. The Dover to Keephills route provides the same staging and flexibility as was previously discussed for Scenario 2. The Dover to Ellerslie route has the flexibility of permitting the construction of a 500 kV circuit energized at 240 kV from Ellerslie to Deerland as a first step. This would provide additional supply to the Fort Saskatchewan area in the near term when load is expected to initially grow more rapidly than generation additions in the North East. The 500 kV system could then either proceed as planned under Scenario 4 or, if generation development did not occur in the north as anticipated, a 500 kV circuit from Deerland to Brintnell could be constructed to complete a northern 500 kV loop through to B.C. in a similar manner as was previously discussed for Scenario 2. It is anticipated that a right-of-way for the Dover to Ellerslie line will be difficult to site in the vicinity of Ellerslie due to residential and other development surrounding the substation.

3.6.2 Grande Prairie Area

During heavy winter loading, both the path loading out of the North East and into the North West exceeds the current system capability. The increased North West load is addressed in the system plan through the construction of a 500 kV line from Dover in the North East to Wesley Creek in the North West as well as a new 500 kV tie line from Wesley Creek to Peace Canyon in B.C. as shown in Figure 3.6-1. This part of the plan could be staged and provides the same flexibility as was previously discussed for Scenario 1.

The other transmission developments in the Grande Prairie area in this scenario are the same as described in Section 3.4.2.

Figure 3.6-1: Scenario 4A - Eastern Route for 500 kV from Dover



3.6.3 *Edmonton – Calgary Transmission Path*

The Edmonton to Calgary path is heavily loaded during both the winter peak and the summer daytime export conditions. The level of path loading indicated in Appendix B Figure B.4 - A will require the second north – south 500 kV circuit to be completed from Keephills to Langdon.

The NorthernLights +/- 500 kV HVDC transmission line from Fort McMurray to the Pacific Northwest could provide an alternative to the second north - south 500 kV circuit. An HVDC terminal with 1000 MW or more capacity installed near Calgary (shown in Figure 3.6-3) in conjunction with a contractual agreement for transmission capacity from the merchant entity would provide the additional capability required on the path. In the event of an outage on the Genesee to Langdon 500 kV, the HVDC terminal output would be ramped up to 1000 MW or more to move energy from the North East directly to Calgary, offloading the Edmonton to Calgary path. The 500 kV circuit from Dover to Edmonton would still be required to provide sufficient capability out of the North East, however the need for series compensation of the 500 kV circuits out of Dover would likely be avoided.

3.6.4 *Lloydminster Area*

The transmission development required in the Lloydminster area in this scenario is the same as described in Section 3.3.4.

3.6.5 *Calgary Area*

The transmission development required in the Calgary area in this scenario is the same as described in Section 3.5.5.

3.6.6 *Lethbridge – Medicine Hat – Empress Area*

The transmission development required in the Lethbridge – Medicine Hat – Empress area in this scenario is the same as described in Section 3.4.6.

3.6.7 *Southern Alberta Area*

The transmission development required in the southern Alberta area in this scenario is the same as described in Section 3.5.7.

Figure 3.6-2: Scenario 4B - Western Route for 500 kV from Dover

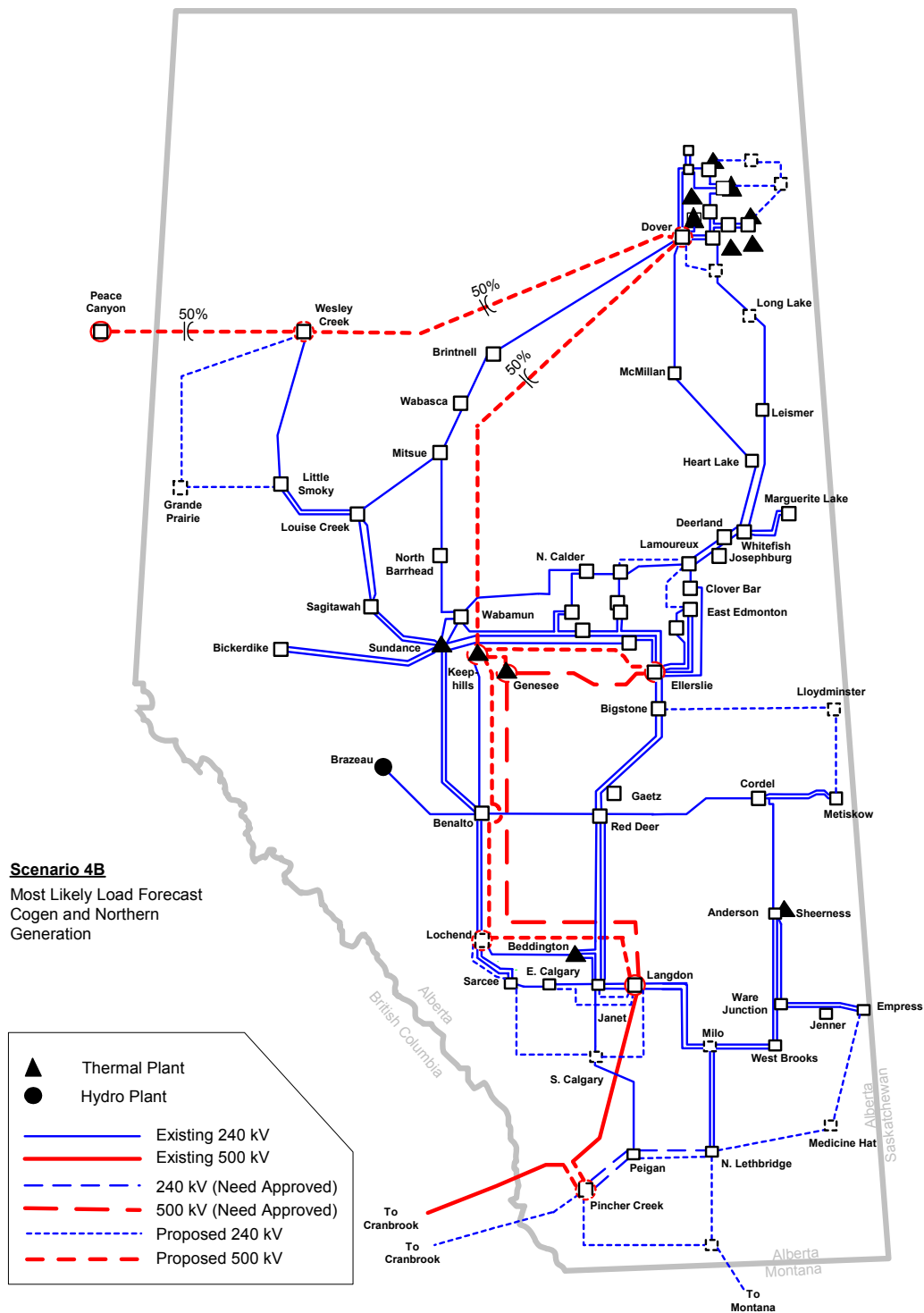
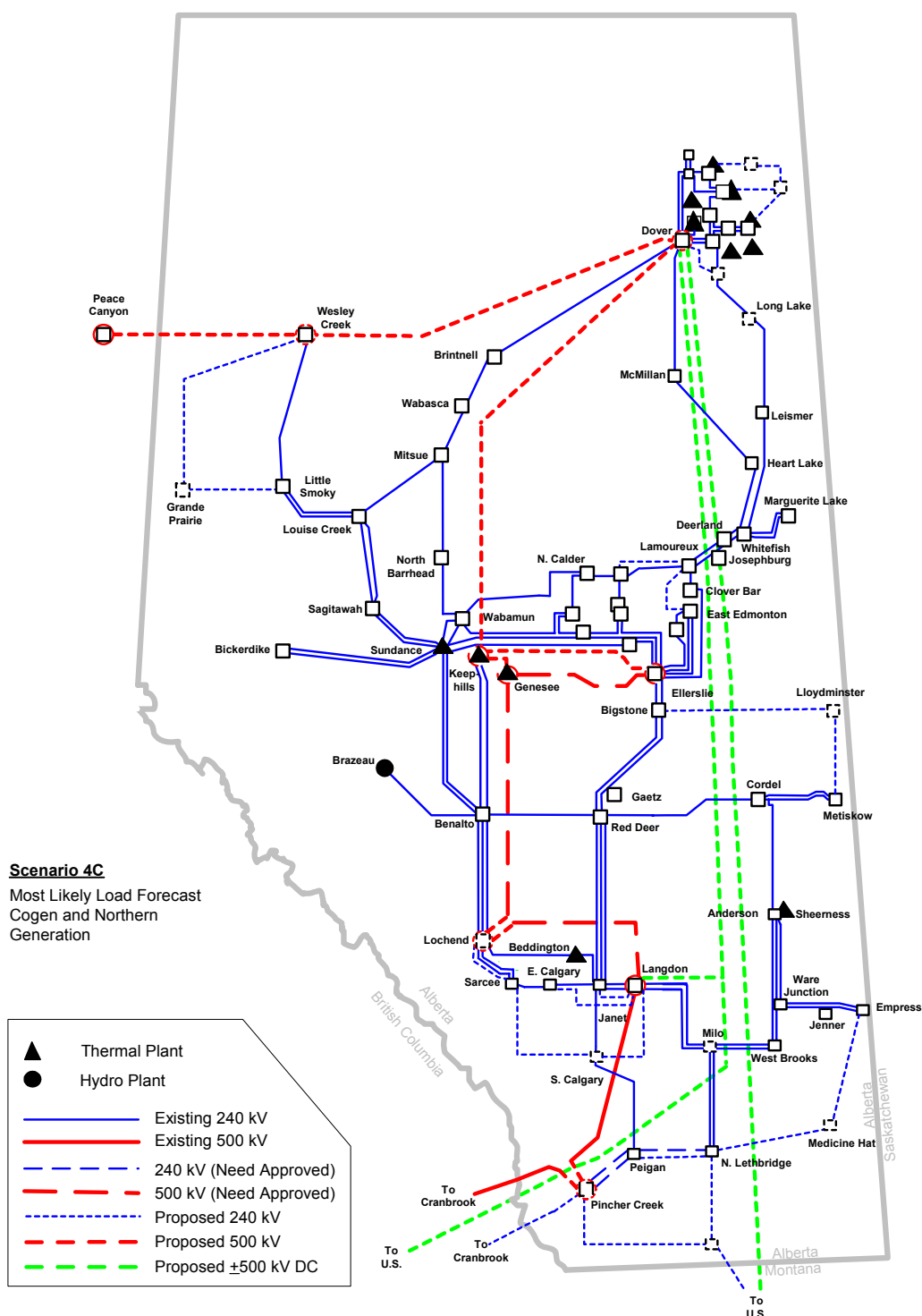


Figure 3.6-3: Scenario 4C - HVDC Merchant Line from Fort McMurray



3.7 Scenario 5: High Load Forecast, Coal and Southern Generation

This scenario assumes generation additions across Alberta will be built in response to the load growth. The generation and load growth will drive significant increases to the loading of both the North East to Edmonton and Edmonton to Calgary paths. System reinforcements are expected to be required for all regions. The transmission system development contemplated for this scenario is shown in Figure 3.7-1.

3.7.1 Fort McMurray Area

The 240 kV system in the Fort McMurray system is expanded to encompass additional development of oil sands leases. This network provides both backup for oil sands operations as well as transmission capability for surplus electrical energy produced from cogeneration. The flows out of the North East exceed 2,200 MW under the summer export condition as indicated in Appendix B Figure B.5 - B. This level of path loading requires two 500 kV lines. The flows out of the North East are carried by a 500 kV line running down the eastern side of the province from Dover to Camrose-Ryley to Ware Junction to Langdon which, in combination with the 500 kV line to Wesley Creek, provides sufficient capability to move the surplus North East energy to the load regions of the North West and Calgary. These circuits also provide sufficient capability to move energy from coal units at Camrose-Ryley and south of Brooks to the load centres. Series compensation of all of the 500 kV circuits coming out of Dover is required to maintain stability of the large amount of total generation forecast to be installed in the North East.

The NorthernLights +/- 500 kV HVDC transmission line from Fort McMurray to the Pacific Northwest could provide an alternative to the Dover to Camrose-Ryley 500 kV circuit as well as the series compensation on the Dover to Wesley Creek to Peace Canyon 500 kV circuits. An HVDC terminal with 1000 MW or more capacity installed near Calgary (interconnected as shown in Figure 3.6-3) in conjunction with a contractual agreement for transmission capacity from the merchant entity would provide the additional capability required on the path. In the event of an outage on the Genesee to Langdon 500 kV, the HVDC terminal output would be ramped up to 1000 MW or more move energy directly from the North East to Calgary, offloading the north - south paths. The 500 kV circuit from Ellerslie to Camrose-Ryley to Ware Junction would still be required to move energy from the coal units at Camrose-Ryley and south of Brooks to the load centres.

3.7.2 Grande Prairie Area

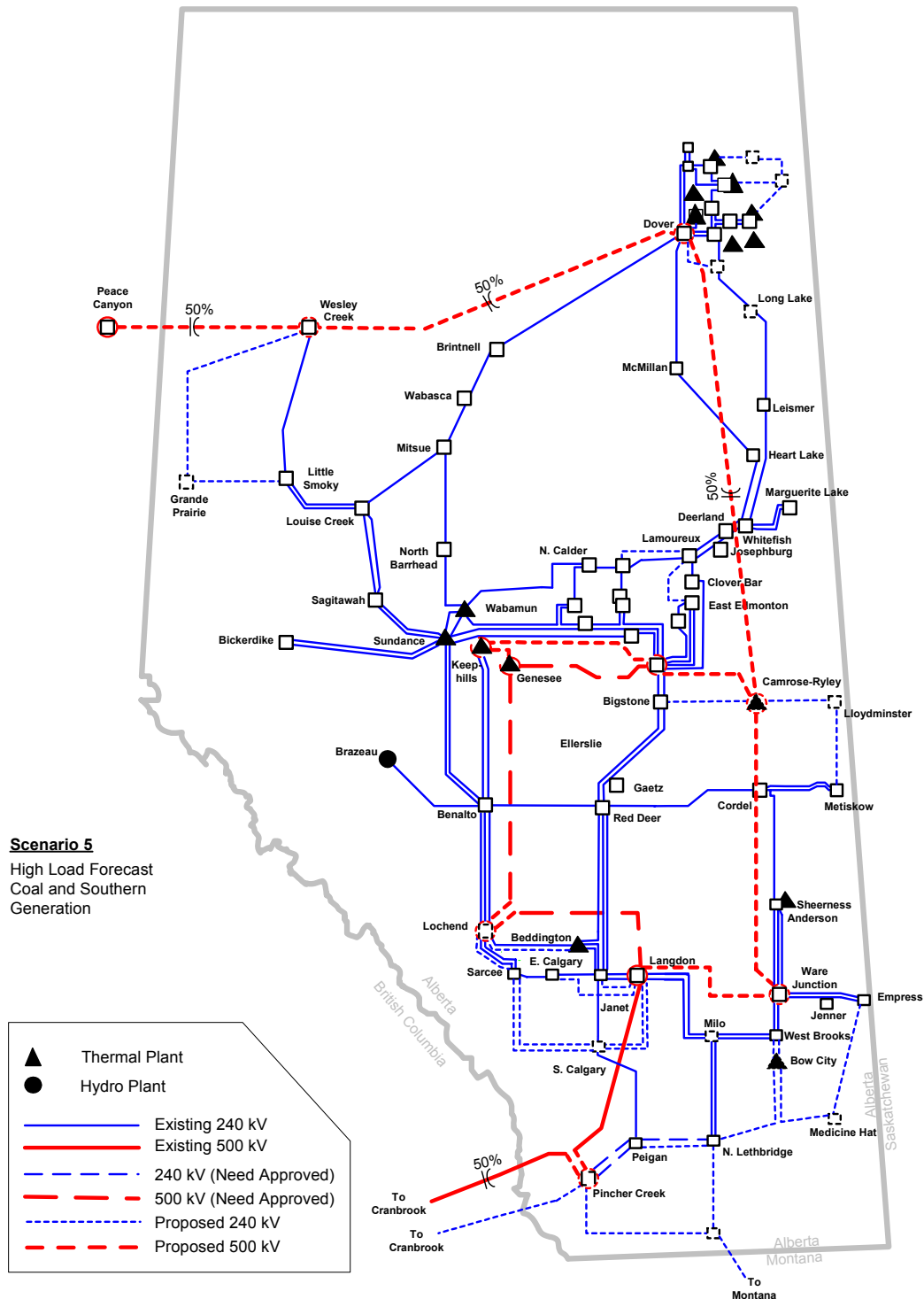
During heavy winter loading, both the path loading out of the North East and into the North West exceeds the current system capability. The increased North West load is addressed through the construction of a 500 kV line from Dover in the North East to Wesley Creek in the North West as well as a new 500 kV tie line from Wesley Creek to Peace Canyon in B.C.

Other transmission developments in the Grande Prairie area in this scenario are the same as described in Section 3.4.2.

3.7.3 *Edmonton – Calgary Transmission Path*

The Edmonton to Calgary path is the most heavily loaded during the summer daytime export conditions as indicated in Appendix B Figure B.5 - B. The level of path loading indicated will not require the second north – south 500 kV circuit to be completed from Keephills to Langdon because the east side 500 kV line from Dover through to Langdon offloads the Genesee to Langdon line. Conversion of the north line of the Keephills-Ellerslie-Genesee system to 500 kV and a 500 kV circuit from Ellerslie to Camrose-Ryley ensures that the Edmonton to Calgary path will remain balanced for outages of either of the 500 kV circuits on the path.

Figure 3.7-1: Scenario 5 - Bulk Transmission System Development



3.7.4 ***Lloydminster Area***

To meet the growing load in the Lloydminster and Metiskow regions, as well as the loss of supply due to the retirement of the Battle River generation, a 240/500 kV substation is placed at Camrose-Ryley. The 240 kV is extended from Camrose-Ryley to Lloydminster and south to Metiskow. The new 240/500 kV station is tied into the Edmonton to Calgary 240 kV at Bigstone which supplies loads south of Edmonton.

3.7.5 ***Calgary Area***

To supply the load growth in the Calgary area an additional 240/500 kV substation is added at Lochend and an additional 240 kV supply station, South Calgary, is added. The supply is further reinforced with 240 kV circuits from the 500 kV substations at Langdon and Lochend to the existing load substations at Janet, East Calgary and Sarcee as shown in Figure 3.7-1.

3.7.6 ***Lethbridge – Medicine Hat – Empress Area***

The transmission development in the Lethbridge – Medicine Hat – Empress area in this scenario is the same as described in Section 3.5.6.

3.7.7 ***Southern Alberta Area***

The transmission development in the southern Alberta area in this scenario is the same as described in Section 3.6.7. In addition, due to the significant increase in the system size for the "High Forecast", series compensation is likely to be necessary for Pincher Creek to Cranbrook 500 kV line to ensure the system remains stable both internally and with the rest of the WECC after a line fault occurs.

3.8 Scenario 6: High Load Forecast, Cogeneration and Northern Generation

This scenario assumes generation additions concentrated in the northern half of Alberta will be built in response to the load growth. The generation and load growth will drive significant increases to the loading of both the North East and Edmonton to Calgary paths. System reinforcements are expected to be required for all regions. The transmission system development contemplated for this scenario is shown in

Figure 3.8-1.

3.8.1 *Fort McMurray Area*

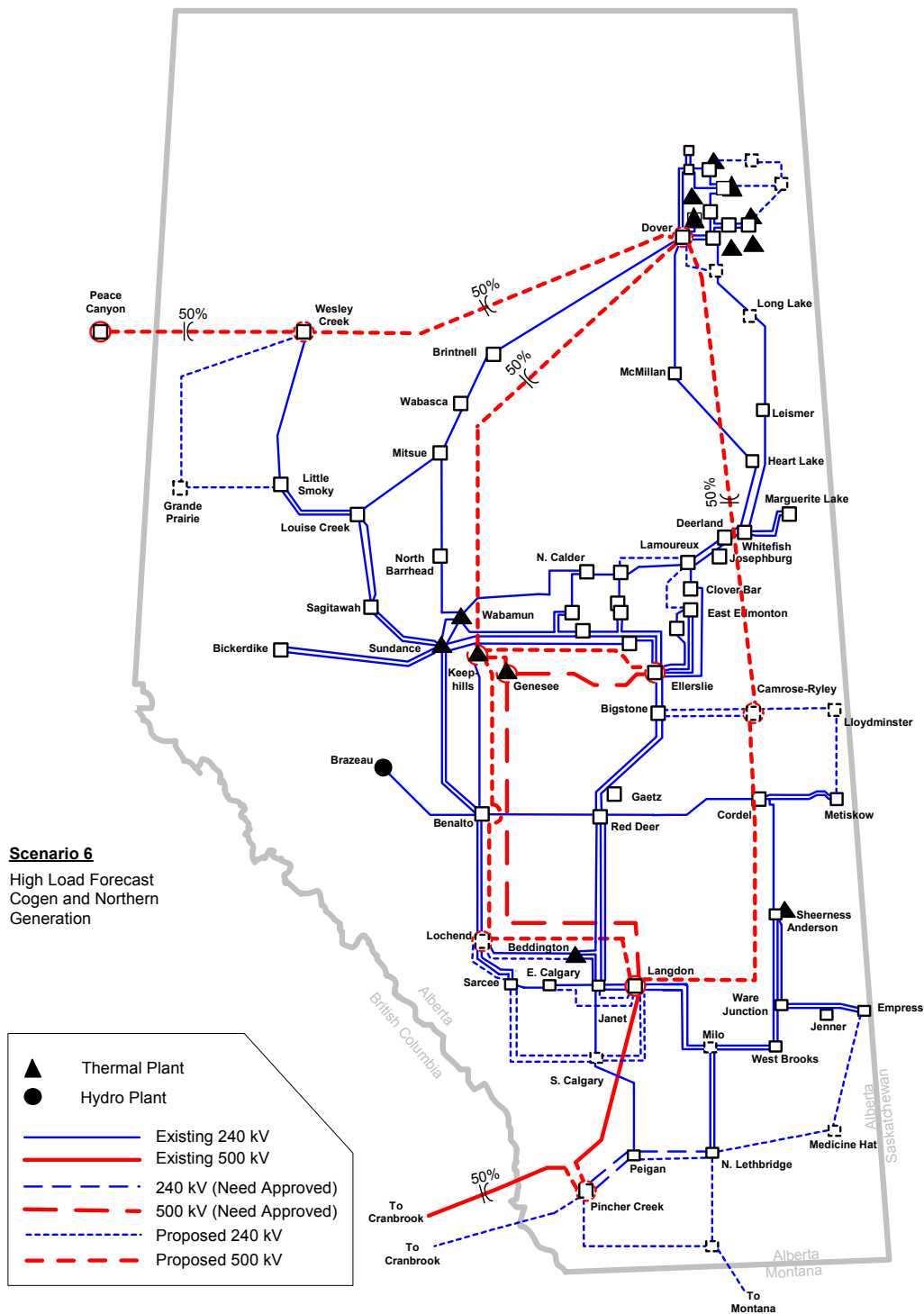
The 240 kV system in the Fort McMurray area is expanded to encompass development of additional oil sands leases. This network provides both backup for oil sands operations as well as acting as transmission capability for surplus electrical energy from cogeneration. The flows out of the North East exceed 4,000 MW during the winter peak as indicated in Appendix B Figure B.6 - A. This level of path loading requires three series compensated 500 kV lines. The first is the Dover to Wesley Creek circuit previously described. The second is from Dover to Keephills which feeds energy into the Keephills-Ellerslie-Genesee loop and onto the two 500 kV Edmonton to Calgary circuits. The third is an eastern circuit from Dover to Camrose-Ryley to Ware Junction to Langdon.

When staging the development, the second circuit could be the Dover to Keephills circuit which provides the same staging and flexibility advantages as was previously discussed for Scenario 2. The eastern route has the flexibility of permitting the construction of short sections of 500 kV line energized at 240 kV to provide smaller incremental increases in both the path south out of the North East as well as the Edmonton to Calgary path. The Deerland to Camrose-Ryley, Camrose-Ryley to Battle River, and Battle River to Langdon segments could each be constructed sequentially to defer capital expenditures while adding increments of capability from the North East through to Calgary. The 500 kV system could either proceed as planned under Scenario 6 or, if less than expected generation development occurred in the North East, a 500 kV circuit from Ellerslie to Camrose-Ryley could be constructed to complete a third Edmonton to Calgary 500 kV line instead of the eastern Dover to Camrose-Ryley to Langdon circuit.

3.8.2 *Grande Prairie Area*

The transmission developments needed in the Grande Prairie area in this scenario are the same as described in Section 3.7.2.

Figure 3.8-1: Scenario 6 - Bulk Transmission System Development



3.8.3 *Edmonton – Calgary Transmission Path*

The Edmonton to Calgary path is the most heavily loaded during the winter peak conditions as indicated in Appendix B Figure B.6 - A. The level of path loading indicated will require the second north – south 500 kV circuit to be completed from Keephills to Langdon in addition to the east side 500 kV line from Dover through to Langdon. Conversion of the north line of the Keephills-Ellerslie-Genesee system to 500 kV and a 500 kV circuit from Ellerslie to Camrose-Ryley ensures that the heavy load area to the east and north of Edmonton will have a reliable supply from both the expanded Lake Wabamun area coal and new generation in the North East.

The NorthernLights +/- 500 kV HVDC transmission line from Fort McMurray to the Pacific Northwest could provide an alternative to the Dover to Camrose-Ryley to Langdon 500 kV circuit. An HVDC terminal with 1000 MW or more capacity installed near Calgary (interconnected as shown in Figure 3.6-3) in conjunction with a contractual agreement for transmission capacity from the merchant entity would provide the additional capability required on the paths from the North East to Calgary. In the event of an outage on any of the 500 kV circuits, the HVDC terminal output would be ramped up to move energy directly from the North East to Calgary, offloading the north - south paths.

3.8.4 *Lloydminster Area*

To meet the growing load in the Lloydminster and Metiskow regions, as well as the loss of supply due to the retirement of the Battle River generation, a 240/500 kV substation is placed at Camrose-Ryley. The 240 kV is extended from Camrose-Ryley to Lloydminster and south to Metiskow. The new 240/500 kV substation is tied into the Edmonton to Calgary 240 kV lines at Bigstone which supplies loads south of Edmonton.

3.8.5 *Calgary Area*

The transmission development required in the Calgary area in this scenario is the same as described in Section 3.7.4.

3.8.6 *Lethbridge – Medicine Hat – Empress Area*

The transmission development required in the Lethbridge – Medicine Hat – Empress area in this scenario is the same as described in Section 3.3.6.

3.8.7 *Southern Alberta Area*

The transmission development required in the southern Alberta area in this scenario is the same as described in Section 3.7.7.

4.0 Interconnections to Neighbouring Jurisdictions

The value and importance of transmission interconnections from Alberta to neighbouring jurisdictions is highlighted by the following excerpt from the Electricity Policy Framework⁵:

“Transmission interconnections with neighbouring jurisdictions are essential to a well-functioning power market as they support reliability, price stability, generation development and continued economic growth in Alberta. Albertans benefit from these interconnections by having the ability to import or export power as needed.”

The AESO will continue to coordinate planning efforts with the transmission service providers in these jurisdictions as well as other jurisdictions in the Pacific Northwest region of the U. S. to ensure that the potential benefits of additional interconnection capacity are identified and considered in its long-term plans.

4.1 Description of Existing Interconnections

Alberta is currently interconnected to both British Columbia and Saskatchewan. These existing interties play an important role in the competitive market in Alberta and allow the exchange of energy with other markets. Additionally, these interties provide reliability benefits to Alberta in the form of post generation contingency support and during supply emergency conditions.

4.1.1 *Alberta - B.C. Interconnection*

The B.C. intertie is a synchronous connection and is comprised of a 500 kV line from Langdon, Alberta, to Cranbrook, B.C., a 138 kV line from Pocaterra, in Alberta, to Natal, in B.C. and a 138 kV line from Coleman, Alberta, to Natal. Through this intertie Alberta is connected to the B.C. system and on through to the transmission systems in the Pacific Northwest and the rest of WECC.

The design capability of the B.C. intertie is about 1,000 MW in an export mode and 1,200 MW in an import mode. However, the actual operating limit is much less than that because of the need to maintain acceptable levels of frequency in Alberta in the event of intertie separation while importing and voltage concerns in the Calgary area in the event of intertie separation while exporting.

⁵ Alberta's Electricity Policy Framework: Competitive – Reliable – Sustainable, June 6, 2005, Alberta Department of Energy, page 32.

4.1.2 *Alberta - Saskatchewan Interconnection*

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 tied together via High Voltage Direct Current (“HVDC”) back-to-back (i.e. asynchronous) links at various points in Canada and the U.S. The Alberta - Saskatchewan intertie is comprised of such a link, known as the McNeill Converter Station and 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. Mid-west.

While the import capability from Saskatchewan to Alberta is at its maximum equipment rating of 150 MW, the Alberta to Saskatchewan export transfer limit is constrained from its full capability by limitations on the local transmission system in southeast Alberta and the Edmonton to Calgary transmission path.

4.2 *New Proposed Merchant Interconnections From/To Alberta*

The scenarios explored in Section 3 included some consideration regarding two proposed merchant interconnections to neighbouring jurisdictions. Following is a brief summary of those merchant projects that are currently being considered. (These do not include the possible intertie developments the AESO considered in Section 3 purely for transmission system reliability – those are discussed on a case-by-case basis within Section 3 and as outlined in Section 2.5.) The AESO has been and will continue to work with the merchant line proponents to ensure that these projects are integrated into the AIES in an appropriate manner.

4.2.1 *NorthernLights Transmission Project*

NorthernLights, a TransCanada initiative, is developing a +/- 500 kV HVDC transmission line from Fort McMurray, Alberta to the Pacific Northwest where energy can reach the Pacific Northwest and/or California markets. The transmission line will be 1,800 km long and has a tentative in-service date of 2011.

A second future +/- 500 kV HVDC project is being considered from Fort McMurray south to the inland U. S. where energy could be supplied to a DC backbone system currently under development by NorthernLights. The backbone DC system would extend from Montana and Idaho through to Las Vegas, Nevada and Los Angeles, California where energy from Montana, Idaho, Wyoming and Nevada could be delivered.

The discussion regarding transmission development alternatives described in Section 3 outlined the potential for utilizing Northern Lights to partially meet the internal needs of the Alberta system.

4.2.2 *The Montana - Alberta Tie*

Montana Alberta Tie Ltd. (“MATL”), a partnership between Rocky Mountain Power Ltd., ELECTRIX Ltd. and Tonbridge Power Corporation, is proposing to construct a synchronous interconnection between Lethbridge, Alberta and Great Falls, Montana. The interconnection would be at 230 kV and will transfer up to 300 MW in each direction. A phase-shifting transformer will be installed to control power flows and schedule transactions on the intertie.

The project proponents conducted a successful open season for line capacity in early 2005 and project development is continuing to the next phase of seeking regulatory approval. Commercial operation is expected in early 2007.

The discussion regarding transmission development alternatives described in Section 3 outlined the potential for utilizing MATL to partially meet the internal needs of the Alberta system.

MATL is presently contemplating plans to build another interconnection with Montana. This interconnection is planned to be a 500 kV transmission line connecting at Langdon in Alberta and the Townsend station in Montana. An in-service date for such a possible development has not been determined.

4.3 Potential Developments with Neighbouring Jurisdictions

The AESO is active in inter-regional planning initiatives in order to ensure that the AESO’s view of possible intertie development and potential benefits and impacts are well founded and to ensure coordination of projects is occurring in an effective manner. Planning initiatives regarding coordination with neighbouring jurisdictions are being conducted in a number of forums, and the risk of overlap and duplication of effort are a constant concern as the electric industry continues to evolve within the U. S. The AESO’s participation varies between the various initiatives from active participation and leadership in the more relevant forums to maintaining an awareness of other activities that could become more relevant in the future.

As described above Alberta is currently interconnected to both British Columbia and Saskatchewan. With regard to increased interconnection capability with Saskatchewan there has been some discussion of an HVDC back-to-back merchant interconnection between the two provinces in the Lloydminster area, however, these discussions are not currently active. The primary focus on increased interconnection capability for Alberta has been with neighbouring jurisdictions in the WECC. The most immediately relevant of those initiatives are described below.

4.3.1 North West Power Pool

As was indicated in the 10-Year Transmission System Plan the AESO is actively participating in system studies that are examining future long term transmission requirements of the Western Interconnection, including interconnections with Alberta. This work is being done through the auspices of the Northwest Transmission Assessment Committee (“NTAC”) of the Northwest Power Pool (“NWPP”). NTAC is an open forum to address forward looking planning and development for a robust and cost effective transmission system in the broader Pacific Northwest region, including Alberta. Further information on this and other NTAC committees can be found at the following web site -

<http://209.221.152.82/ntac/publications.html>

The AESO is actively participating in the "Canada-California Transmission Study Group". The objective of the Canada-NW-California studies is to provide high-level information on the feasibility of potential transmission projects to transfer a variety of new resources out of Canada into the Northwest and California. To date the group has selected a short list of twelve alternatives to be studied and is now in the early stages of developing system models and performing power system analysis in order to refine the facility requirements and access the potential increases in path capabilities for the alternatives.

The intention is that the AESO and BCTC will use the results of this study as a starting point for more detailed joint discussion and analysis. Following the conclusion of that analysis the AESO will incorporate the relevant aspects of the work into subsequent 10-Year Transmission System Plans.

4.3.2 Rocky Mountain Area Transmission Study

The Rock Mountain Area Transmission Study (“RMATS”) originated as a result of some initial study work⁶, done under the auspices of the Western Governors’ Association. The purpose of RMATS is to identify potential generation projects in the Rocky Mountain sub-region (Colorado, Idaho, Montana, Utah and Wyoming) and the electric transmission needed to support these projects. Significant study work was conducted with the result that a number of transmission upgrades were recommended. The shorter-term and longer-term developments recommended are shown in Figures 4.3 – 1 and 4.3 – 2 respectively.⁷

Efforts to develop some of the projects contemplated in RMATS are progressing. The Governors of Wyoming, Utah, Nevada and California recently announced the creation of a partnership through the signing of a Memorandum of Understanding for the development of the ‘Frontier Line’. This major transmission line project will be constructed through

⁶ Conceptual Plans for Electricity Transmission in the West, Western Governors’ Association, 2002.

⁷ Rocky Mountain Area Transmission Study, Montana Transmission Advisory Presentation, September 8, 2004

Wyoming, Utah, Nevada and California and is intended to deliver renewable and conventional energy resources generated by wind and thermal power plants using clean coal technology.

While the AESO has not directly participated in this study it has been monitoring its development through other inter-regional planning coordination forums.

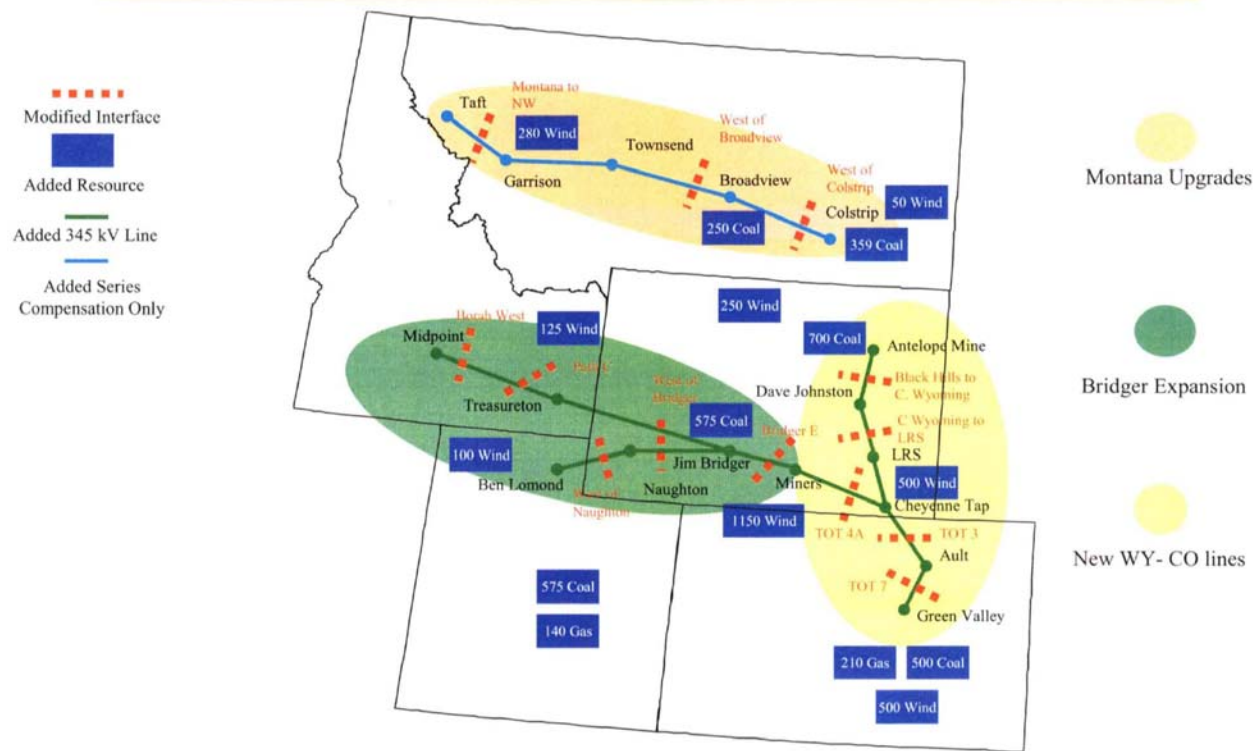
4.3.3 *Bonneville Power Administration Developments*

The Bonneville Power Administration (“BPA”) is a U.S.-federal agency that operates approximately 24,000 km of high-voltage transmission lines in the states of Oregon, Washington, Idaho and Montana. Similar to other jurisdictions its transmission network has become constrained as a result of load growth, interconnection of new generation resources and requests for more inter-regional transfers of power across its system. In response to these pressures BPA initiated a significant program of system upgrades and new line construction a few years ago. Figure 4.3 – 3 provides a high level overview of the major components of the program and the current status of the projects.⁸

As with RMATS the AESO has not directly participated in studies related to these projects and has been monitoring their development through other inter-regional planning coordination forums.

⁸ http://www.transmission.bpa.gov/PlanProj/Transmission_Pprojects/ProjectMapMar2005.pdf

Recommendation 1 Transmission Projects



2

Figure 4.3 - 1: RMATS - Shorter-Term Development

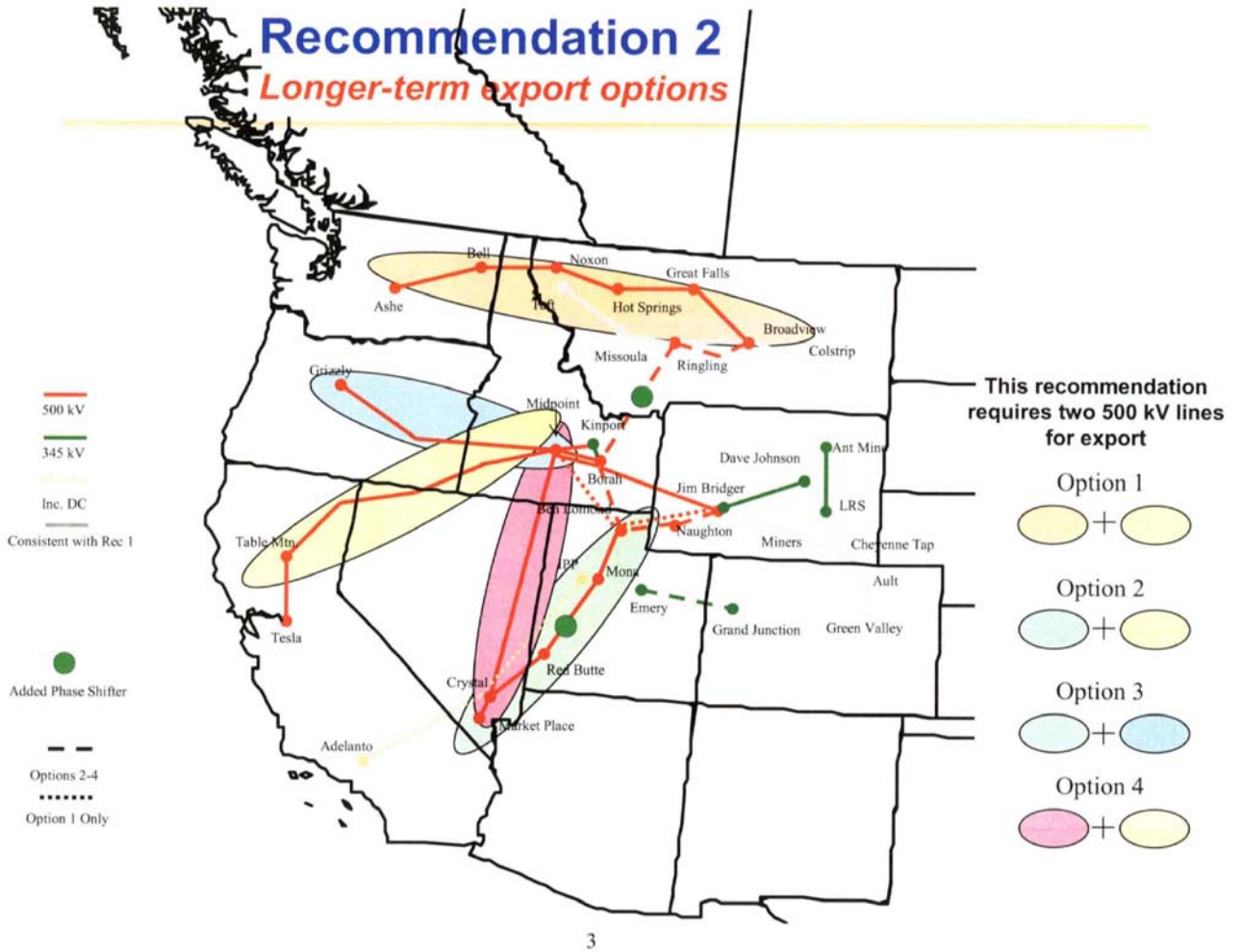


Figure 4.3 - 2: RMATS - Longer-Term Development

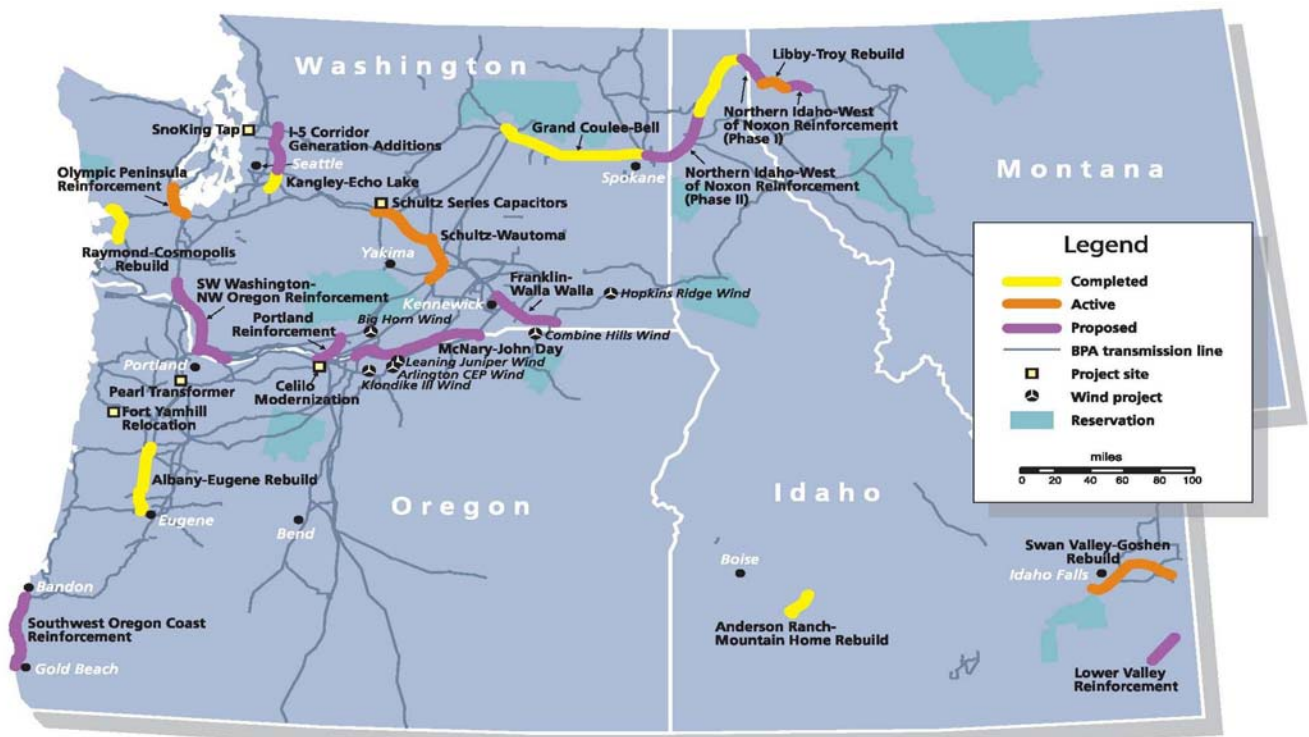


Figure 4.3 - 3: BPA Transmission System Upgrades

5.0 Conclusions

This 20-Year Outlook Document (2005 – 2024) describes six scenarios for future load and generation development in Alberta and the transmission system development needed for each of these scenarios. The developments contemplated in the Outlook will provide market participants unconstrained access to the transmission system and will facilitate an open and efficient electricity market while ensuring overall system reliability.

Based on the scenarios developed in this Outlook the need to reinforce key transmission paths within Alberta has been identified. A number of transmission expansion projects are common to several scenarios, specifically:

- 500 kV reinforcement from the Fort McMurray area, including:
 - a 500 kV line from the Fort McMurray area to Wesley Creek in northwest Alberta;
 - a 500 kV line from the Fort McMurray area to the Edmonton area;
- further reinforcement of the Edmonton-Calgary transmission system, in the form of initially a second 500 kV line from the Edmonton area to the Calgary area; and
- additional 240 kV development in several areas of Alberta including:
 - the Grande Prairie area;
 - the East Edmonton – Fort Saskatchewan area;
 - the Lloydminster area;
 - the Calgary area;
 - the Lethbridge – Medicine Hat – Empress area; and
 - the Pincher Creek area.

Further detailed analysis of these and other projects identified in the Outlook will be required in forthcoming 10-Year Transmission System Plans and project-specific need applications filed with the EUB based on the direction and context provided in this Outlook.

The AESO has recognized that obtaining transmission line rights-of-way is becoming increasingly difficult, in urban areas as well as areas where extensive residential and other development is occurring. The AESO will continue to monitor this situation and will file the necessary need applications to secure the transmission line right-of-way in anticipation of the actual transmission line development. Applications for the actual transmission line facilities will then be filed at an appropriate future date. The requirements for taking this approach will also be identified in forthcoming 10-Year Transmission System Plans.

This 20-Year Outlook Document places emphasis on maintaining flexibility for the future. Flexibility is provided through options to stage the construction of different components of the development alternatives. Flexibility is also provided through options to design and build certain components at one voltage level, e.g. 240 kV, but initially operate them at a lower voltage, e.g. 138 kV, and then upgrade the facilities to operate at the design voltage level at the appropriate time.

Some examples that demonstrate the flexibility in several of the scenarios studied include:

1. The Dover – Wesley Creek line could be built in stages as the need manifests itself, starting with either a line from Dover to Brintnell or from Brintnell to Wesley Creek as the initial development. The lines could be designed for 500 kV operation which would permit them to be converted and developed into the higher capacity 500 kV system to handle higher export levels from the North East or, if no north generation development occurs, a 500 kV line could be brought up from Keepphills to Brintnell and connected to the line to supply both the North East and North West at 500 kV.
2. The Langdon to Ware Junction circuit and the Cordel to Anderson segment of the north - south circuit could be initially energized at 240 kV to provide staged additional capability out of the South East if generation develops first in the south. If northern generation development failed to materialize, the direction of the 500 kV developments could be shifted by constructing an Ellerslie to Camrose-Ryley circuit instead of the Dover to Cordel circuit to create an Ellerslie to Camrose-Ryley to Ware Junction to Langdon loop.

This Outlook has identified some of the obligations required of the AESO contained within the Electricity Policy Framework document, in particular obligations relating to long-term supply adequacy and transmission interconnections to neighbouring jurisdictions. In this regard the AESO will be

undertaking additional work in conjunction with the Alberta Department of Energy and other stakeholders to develop an implementation plan and schedule.

This Outlook describes possible development alternatives that will restore the existing interties to their designed path rating. This Outlook also demonstrates the possibility of integrating proposed merchant transmission projects with transmission upgrades required for intra-Alberta needs. For example, to maintain the 1,200 MW of import and 1,000 MW of export path rating to/from B.C. and prevent separation of the Alberta transmission system from the rest of the WECC, the existing 138 kV line from Pincher Creek to Natal can be upgraded to 240 kV. This, in combination with the proposed Montana merchant tie and the north west tie to B.C. will stabilize the system and prevent separation of Alberta when the existing 500 kV tie to B.C. trips. The Outlook also describes the possibility of using the NorthernLights merchant project to similarly meet some of the internal needs of the Alberta system.

This Outlook describes the AESO's participation in a number of initiatives with transmission service providers in neighbouring jurisdictions to identify and assess the benefits of additional inter-regional transmission developments. The AESO will continue its participation in these efforts in accordance with the mandate provided to it in the Transmission Policy, the Transmission Regulation and, more recently, the Electricity Policy Framework.

In summary, this initial 20-Year Outlook Document (2005 – 2024) provides a forward look with regard to transmission system development in Alberta with an emphasis on maintaining flexibility for the future. This approach will result in a robust transmission system that will continue to provide reliable service to Albertans, attract new generation supply, support merchant or independent transmission proponents, encourage investment in Alberta and facilitate a competitive marketplace.

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Appendix A – AMEC AMERICAS LIMITED Report

ALBERTA GENERATION OUTLOOK

Prepared For

ALBERTA ELECTRIC SYSTEM OPERATOR

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SUMMARY

This document presents an outlook of possible generation addition scenarios to the Alberta system over the next twenty years.

This generation outlook is prepared to facilitate the AESO's obligation to maintain a long term transmission outlook. It is based on the load forecasts prepared by the AESO of which the 'Most Likely' forecasts the peak Alberta load to increase from 9,240 MW in 2004 to 15,620 MW in 2024, an average growth rate of 2.7% per annum. Based on this load growth and the projected retirements of the Clover Bar, Wabamun, HR Milner and Battle River Plants, it is estimated that 9,600 MW of new generation capacity will be installed over the twenty-year period.

As set out in Table 1 the sources of the 9,600 MW of new generation are:

- 2,600 MW of cogeneration serving behind the fence load as estimated by the AESO as part of its load forecast. This cogeneration will be largely in Fort McMurray as part of oil sands development;
- 2,000 MW of wind generation located in the southern part of the province;
- 200 MW of hydro, most of which will probably be on the Peace River. Development of the larger Slave River and Dunvegan hydro projects that have been studied in the past is considered unlikely in the twenty-year time frame;
- 200 MW of upgrades of existing coal-fired units at the Sundance and Keephills plants similar to the recent upgrade of the Sundance Unit 6;
- 500 MW of small additions, using a diverse range of technologies, which are typically less than 50 MW each;
- 1,500 MW of new coal-fired generation at the existing Keephills and Genesee sites which have access to low-cost coal and the advantage of infrastructure in place that result in plant costs that are lower than at green-field sites;
- Up to 1,000 MW of new coal-fired generation at another site(s) which could be the existing Wabamun or Battle River sites, Bow City near Brooks which is actively being pursued or another green-field site;
- 1,100 to 2,600 MW of oil sands cogeneration which is based on the expectation that by-products such as asphaltenes and coke will displace natural gas as the principle source of fuel and, as this change occurs, oil sands cogeneration will become a major source of new generation to the Alberta grid; and
- Up to 500 MW of mid range/peaking generation which is assumed to be located near Calgary.

The range of additions of new coal-fired generation at sites other than Keephills and Genesee, cogeneration, and mid range/peaking generation, as shown in items 7, 8 and 9 below, reflect the uncertainty of the relative economics of coal-fired plants and oil sands cogeneration over the longer term as environmental standards tighten and oil sands by-products become more widely used as fuel sources. If 1,000 MW of new coal at other sites occurs, 500 MW of mid range/peaking is projected to be installed to supplement the largely base-load additions. Alternatively, if the 2,600 MW of cogeneration is installed, it will fill this mid range/peaking role as all new cogeneration is expected to be able to cycle in response to pool prices.

Table 1 Summary of Generation Additions (MW)

1. Cogeneration Seving Behind the Fence Load	2,600
2. Wind	2,000
3. Small Hydro	200
4. Upgrades at Sundance and Keephills	200
5. Other Small Additions	500
6. New Coal Units at Keephills and Genesee	1,500
7. New Coal at Other Site(s)	0 to1,000
8. Oil Sands Cogeneration to the Grid	1,100 to 2,600
9. Mid Range/Peaking near Calgary	0 to 500
10. Total	9,600

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Introduction

The Transmission Regulation (174/2004) under the Electric Utilities Act requires the Alberta Electric System Operator (AESO) to “prepare” and “maintain” a “long term transmission outlook document”. A necessary input to the preparation of this document is determining the timing and location of future generation additions to the Alberta Interconnected Electric System (AIES).

This document has been prepared to meet the AESO’s requirement for a “Macro” long- term conceptual “outlook” for generation development in Alberta. In doing so it is recognized that generation development is a non-regulated competitive business and that it is not possible to definitively describe the timing and location of generation development 10 to 20 years into the future.

The analysis in this report of the likely types and locations of new generation is based on the transmission policy and market structure that is currently in place and on the assumption that transmission is not a constraint in locating new generation. It does however anticipate further tightening of environmental standards, particularly with respect to carbon dioxide emissions.

Section 1 of the report develops an estimate of the amount of new generation that will be installed over the next 20 years based on the AESO’s load forecast and projected retirements; Section 2 presents a review of Alberta’s electric generation resources; Section 3 compares the major generation options and Section 4 develops generation scenarios to meet the expected requirements.

Disclaimer

This report has been prepared for the AESO to meet its obligations under the Act. The discussion and analysis presented herein are to provide the AESO with a range of possibilities of how generation may develop in Alberta. It should not be relied on by third parties and, in the event it is used by third parties in any way, AMEC accepts no liability.

1. NEW GENERATION REQUIREMENTS

1.1 The Existing Alberta System

The Alberta power system as of the first quarter of 2005 is made up of 5,840 MW of coal-fired plant, 4,802 MW of gas-fired plant, 869 MW of hydro and 429 MW of wind and other for a total installed capacity of 11,940 MW.

Up until the 1950s generation in Alberta was primarily from hydroelectric plants on the Bow River and from small gas and coal-fired thermal plants owned by municipalities. With the more rapid load growth after the discovery of oil at Leduc in 1947, larger steam electric plants were added to the system. From the 1960s onward these were predominantly mine mouth coal-fired plants of progressively larger size and higher efficiency. Between 1960 and 1995, 5,600 MW of coal-fired generation were added to the system. With the addition of these thermal plants, which operate as base load, the use of the hydro system changed so that it could take on a greater peaking role.

Most of the 3500 MW of additions to the system since the mid-1990s are gas-fired power plants. Technical improvements in gas turbines, lower load growth which is better met by smaller additions, low gas prices, major heat loads required for oil sands extraction and petrochemicals and the restructuring of the power sector all contributed to this choice of generation. Other recent additions to the system are the 450 MW coal-fired unit at Genesee, 250 MW of wind in the southwest and 80 MW of small hydro.

Alberta has a 500 kV transmission interconnection with British Columbia and a 150 MW DC tie with Saskatchewan. The Alberta system is connected to all the systems in the western United States through the BC tie and to central Canada and the entire eastern portion of the U.S., excluding Texas, through the Saskatchewan tie.

The restructuring of the Alberta power sector in 1996 created a power pool for trading electric energy and provided open access for new generators. Rather than the three incumbent utilities [TransAlta Utilities Corporation, ATCO Power and Edmonton Power (EPCOR)] having to divest their generating assets, the output of their plants was sold in Power Purchase Arrangements (PPAs) with durations of up to 20 years to third parties. Of the total 5840 MW of coal-fired generation in place, 5390 MW is held as PPAs; and of the 869 MW of hydro generation, 789 MW is held as PPAs.

1.2 Load Forecast

The estimates of new generation requirements described in Section 1.3 are based on the load forecast prepared by the AESO in June, 2004 titled "Future Demand and Energy Requirements" 2004 – 2024 and the AESO's subsequent modification to the behind the fence load in that forecast.

Table 1.1 presents the actual 2004/05 and forecast 2024/25 total Alberta peak load (line 1) and grid peak load (line 2) together with the behind the fence load (line 3) which is the difference between the total and grid loads. The total Alberta load is forecast to increase at 2.7% per annum and the grid load is forecast to increase at 2.0% per annum.

Table 1.1 Alberta Peak Load and Installed Capacity (MW)

	2004/05	2024/25
PEAK LOAD		
1. Total Alberta Load	9,240	15,620
2. Grid Load	7,877	11,617
3. Behind Fence Load	1,363	4,003
PEAK LOAD + RESERVE		
4. Total Alberta Load + 10% Reserve	10,164	17,182
GENERATION CAPACITY		
5. Total Firm Capacity in 2004/05	11,036	11,036
6. Retirements	0	1,718
7. Firm Capacity Net of Retirements	11,036	9,318
SURPLUS (SHORTFALL)		
8. Total Surplus (Shortfall)	872	(7,864)

1.3 New Generation Capacity

Given the existing installed capacity of 11,940 MW and the forecast load in 2024/25 of 15,620 MW, the question becomes, how much new generation will be built to serve that load?

Prior to restructuring in Alberta this question would have been addressed using a generation planning model which simulated the operation of the system and provided a basis for determining the amount of new generation capacity that had to be added each year to meet a given loss of load probability (LOLP) criterion. This analysis determined the amount of generation capacity in excess of the peak demand, known as the reserve margin, which was required to reliably meet the load.

Since the Alberta power sector has been restructured the amount of new generation built is no longer determined in a generation planning analysis but rather by many different corporate entities in response to the expected future pool prices. Since pool prices increase as reserve

margins decline, the forecast reserve margin on the system will affect the amount and timing of new generation investment.

The approach in this report is first to define the firm generation capacity that is available to meet the load and then using that definition of firm capacity to select a reserve margin that is expected to occur over the longer term with Alberta's market structure.

1.3.1 Firm Capacity

The firm capacity of hydro generation is based on the capacity that is likely to be available during the winter when the peak load occurs on the Alberta system. Wind on the other hand is examined conceptually in terms of the extent to which additional wind capacity has a downward pressure on pool prices and, in turn, the extent to which the effect on pool prices delays the additions of other generation. The approach used for wind has a fairly minor effect on the estimate of firm capacity in 2004/05, since only about 250 MW of wind are in place but, with large wind additions forecast to be made by 2024, has a significant effect on the analysis described in Section 4 in determining other generation to be added by 2024/25.

The calculation of Total Firm Capacity of 11,036 MW shown in Table 1.1 for the first quarter of 2005 is calculated by (i) starting with Total Installed Capacity on the Alberta system of 11,940 MW from the AESO website, (ii) subtracting the 209 MW capacity of the Rosssdale plant which although included in the 11,940 MW is no longer available for the purposes of merit order dispatch, (iii) de-rating the hydro and (iv) de-rating the wind. This calculation is summarized in Table 1.2 and the approach to hydro and wind is described in the text below the Table.

Table 1.2 Calculation of Firm Capacity (MW)

Installed Capacity 1st Quarter 2005	11,940
Less: Rosssdale Capacity	-209
Small Hydro Derate	-64
Regulated Hydro Derate	-417
Wind Derate	-214
 Total Firm Capacity	 11,036

Hydro

Alberta's hydro plants have little storage and limited output during winter at the time the peak load occurs. To take this into account:

- The 80 MW of small hydro is de-rated by 80 percent, or 64 MW to a net of 16 MW and;
- The 789 MW of the larger previously regulated hydro is de-rated by 417 MW to a total in December of 372 MW as calculated in the hydro PPA.

Wind

Wind does not provide a dependable source of firm capacity from the perspective of daily operations, since the system controller cannot count on it and dispatch it, but over the longer

term the addition of more wind on the Alberta system will delay the installation of other types of generation. Specifically the addition of more wind capacity:

- Will, by offering in at zero, reduce pool prices relative to what they would be in the absence of that wind generation and in so doing will delay the addition of other new generation; and
- Because new and existing plants have to reduce output when the wind generation operates, therefore affecting their ability to recover their capital costs, the addition of wind means that new plants require a higher pool price to be financially viable than they would in the absence of more wind generation, which further delays their installation.

Wind is included as capacity over peak load periods but is substantially de-rated. The existing 252 MW of wind on the system, which has a capacity factor of about 30%, is de-rated by 85 percent, or by 214 MW. Similarly each 100 MW of wind added to the system in the future is assumed to contribute 15 MW of firm capacity, or put differently, to displace 15 MW of other generation that would otherwise be added.

1.3.2 Reserve Margin

A reserve margin of 10% is selected for the purposes of estimating the firm capacity that will be installed to meet the Total Alberta Peak Load in Table 1.1. In other words it is expected that new generation will be added in response to price signals when the margin between the peak load and the firm capacity falls below approximately 10% as a result of load growth.

The 10% reserve margin used here is based on the definition of firm capacity developed above and is not directly comparable to reserve margins that are based on total installed capacity that have been used in the past in Alberta. Since installed capacity is greater than firm capacity, reserve margins based on total installed capacity are higher for a given system. The reserve margin of 10% used here is equivalent to a reserve margin of about 17% if calculated on the basis of the installed, rather than firm, hydro and wind capacity and is equivalent to a reserve margin of about 26% if the full capacity of the BC and Saskatchewan inter-ties are also included.

This reserve margin calculation, which could be characterized as “firm capacity reserve margin”, is considered more meaningful than calculations on the basis of installed capacity since it recognizes the contributions of lower output factor generation rather than simply completely removing some types of generation from calculations based on installed capacity. The tabulation below summarizes how the firm capacity reserve margin compares to the other two definitions.

<u>Definition</u>	<u>Equivalent Margins</u>
1. Firm Capacity Reserve Margin	10%
2. Margin including the installed hydro and wind capacity	17%
3. Margin including the installed hydro and wind capacity and interties	26%

1.3.3 Retirements

The firm capacity net of retirements in 2024/25 is calculated by subtracting the projected retirements from the firm capacity in 2004/05. These retirements up to 2013 are the same as those projected by the AESO in its 10-Year Plan and include Wabamun at its planned retirement date of 2010 and the Clover Bar Plant and Battle River Units 3 and 4 in 2010 and 2013 respectively consistent with the PPAs and HR Milner in 2012. Battle River 5 is projected to retire at the end of its PPA in 2020. There is, of course, no requirement that Clover Bar and the Battle River units be retired in those years but the terms of the PPAs with respect to the liability for decommissioning encourages the owners to retire the units within a year of the end of the PPAs.

Although the Wabamun and Battle River plants are assumed to be retired, these plant sites are considered to be good candidate locations for new generation to meet the shortfall estimated in Table 1.1. The assumptions regarding which coal-fired units are retired, which continue to operate and which sites are candidates for additional generation are discussed further in Section 2.1.

Table 1.3 Retirements (MW)

Wabamun 4 in 2010	279
Clover Bar in 2010	632
Battle River 3&4 in 2013	296
HR Milner in 2012	143
Battle River 5 in 2020	368
Total	1,718

1.3.4 Surplus and Shortfall

The Total Surplus (Shortfall) in Table 1.1 is simply the difference between the Total Firm Capacity and the Total Alberta Load plus the 10% Reserve. As noted the estimated surplus in 2004/05 is 872 MW and, taking into account load growth and retirements, the shortfall in 2024/25 is 7,864 MW.

The balance of this report addresses how this shortfall will likely be met.

2. ALBERTA ELECTRIC GENERATION RESOURCES

Alberta's electric generation resources are discussed in the order that they were developed historically – hydro, coal, gas, wind, followed by other types of resources. A comparison of the costs of the likely candidates for providing major additions to the Alberta system is presented in Section 3.

2.1 Hydro

2.1.1 Existing Hydro

The total installed hydro capacity in Alberta in March 2005, as reported by the AESO, is 869 MW.

PPA Hydro

Of this total, 789 MW was developed by Calgary Power (now TransAlta) at thirteen different plants, and was commissioned between 1911 and 1972. At the time the Alberta electricity supply industry was restructured, the continuing outputs from these plants were covered under Power Purchase Arrangements (PPAs). The following table provides a breakdown of the installed capacities at the PPA hydro plants.

	Installed Capacity (MW)
Bow River Hydro (11 plants)	319
Brazeau Hydro (1 plant)	350
Bighorn Hydro (1 plant)	120
Total PPA Hydro	789

The Bow River Hydro system comprises eleven separate 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, south-west of Drayton Valley and the Bighorn hydro plant is located on the main stem of the North Saskatchewan River upstream of Nordegg.

Small Hydro

The remaining “small” hydro capacity reported by the AESO totals 80 MW, and is located at five separate plants, as follows:

	Installed Capacity (MW)
CUPC Oldman River	32
Chin Chute	11
Irrican Hydro	7
Raymond Reservoir	18
Taylor Hydro	12

Total Small Hydro	80
-------------------	----

The small hydro projects either do not have significant reservoir storage or the storage that does exist is used primarily to augment the supply of water for irrigation during the summer months. These plants operate at a low capacity factor and, as noted in Section 1, the 80 MW has been de-rated by 80% to 16 MW.

The total average annual energy generation from existing PPA and small hydro plants in the province is just over 1,900 GWh.

2.1.2 Provincial Hydro Potential

In May 1981, the ERCB published a report entitled, "Alberta's Hydroelectric Energy Resources". The Board estimated the hydro energy potential in all the river basins draining the province, using different definitions. Among those definitions was, "Ultimate Developable Hydroelectric Energy Potential" (UDHE). The UDHE estimates are the Board's best assessment of hydro potential taking into account foreseeable technology improvements, and physical, economic, social and environmental conditions. The following table summarizes the estimates of UDHE.

River Basin	UDHE (GWh/a)	Capacity (MW) @ Capacity Factor of		
		20%	40%	60%
Athabasca	15,580	8,890	4,450	2,970
North Saskatchewan	9,800	5,590	2,800	1,860
Peace	24,970	14,260	7,120	4,740
Slave	8,570	4,890	2,450	1,630
South Saskatchewan	3,160	1,800	900	590
Total UDHE for Alberta	62,080	35,430	17,720	11,790

The major northern basins (Athabasca, Peace and Slave) contain almost 80% of Alberta's total UDHE, while the remaining 20% is in the North and South Saskatchewan basins in the southern half of the province.

Although Alberta's potential hydro resources appear to be large, there are a number of obstacles to its development. It is revealing that the total existing hydro development in the province (approximately 1,900 GWh/a) makes up only a small portion (3%) of the total potential, and that the hydro resources developed in the past 33 years total less than 300 GWh/a. The apparent reasons for this lack of major hydro development are summarized below.

2.1.3. Major Hydro Projects Studied

In the past 30 years, two potential large hydro projects in the province have been studied in some detail. The first is the Dunvegan project on the Peace River near its confluence with

Hines Creek, which is just upstream of where Highway 2 crosses the Peace, between Grande Prairie and Fairview. The site of the second project is on the Slave River at the boundary between Alberta and the Northwest Territories. Both the Peace and Slave Rivers are part of the Mackenzie River system which drains into the Arctic Ocean.

It is considered that these two projects are the only large hydro resources in Alberta that have any prospect for development in the next 20 years. However, it can be expected that small hydro development in the province will continue but this will not make a major contribution to supplying growth in total electricity demand.

Dunvegan Hydro Project

Flow in the Peace River is regulated by a large storage facility at Williston Lake that was created by the construction in the 1960s of the WAC Bennett Dam, which is located in BC approximately 165 km upstream of the Alberta/BC boundary. The project was developed by BC Hydro and feeds water to the GM Shrum Hydro Plant. Regulated flows from Williston Lake would improve outputs at hydro projects downstream, including Dunvegan.

High Dam Project

A major project at the Dunvegan site on the Peace River was studied by Monenco on behalf of Calgary Power in the mid-1970s. The preferred layout at the time would impound a reservoir with a normal maximum water elevation of 381 m, which would flood water back approximately 130 km to the Alberta/BC boundary. The project would develop 38.8 m of gross head and the installed capacity would be some 900 MW. The estimated period of construction activities is 9.25 years. The average annual energy production would be just over 4,300 GWh.

The study concluded that, under the industry and regulatory structures that existed at the time, the project was both technically and economically feasible. However, the project did not proceed.

Low Dam Run-of-River Project

In 2000, Glacier Power made a joint application to the EUB and the Natural Resources Conservation Board to develop a much smaller alternative run-of-river project at Dunvegan. The application was rejected by the Boards in March 2003, mainly because of concerns over the risk of flooding in the Town of Peace River due to ice build-up below the dam, and over restrictions to the movement of fish in the river. Glacier Power is in the process of addressing these concerns.

The project would develop approximately 6 m of head and the installed capacity would be about 100 MW. Although the estimated energy production from this configuration is not given in the EUB/NRCB Decision, it can be expected to be in the order of 600 to 700 GW.h/a, on average. Construction of the project would take an estimated three years. The latest newsletter from Glacier Power, dated December 2004, shows project completion in early 2009, assuming regulatory approval in early 2006.

Slave River Hydro Project

A feasibility study of the Slave River Hydro Project was sponsored by the Alberta government. The study was completed in 1982. The study investigated alternative sites for development of the river between Fitzgerald, Alberta and Fort Smith, which is immediately north of the Alberta/NWT boundary. The preferred alternative for the project would develop a gross head of approximately 35 m. The project would flood water back to the outlets of the Peace-Athabasca Delta. The installed capacity would be some 2,000 MW and the estimated average energy

production would be just over 9,800 GWh/a. The total period of construction was estimated to be eight years.

The study concluded that the project is technically feasible and that its development would be less costly than alternative means of supplying growth in electricity demand in Alberta.

Environmental concerns over the project centred on the impact on the downstream fishery and on the construction of the transmission line either through Wood Buffalo National Park, across the Peace-Athabasca Delta, or over Lake Athabasca.

2.1.4. Prospects for Major Hydro Development

There appears to be a reasonable possibility that the low dam, run-of-river project at Dunvegan will be approved and constructed. The earliest completion date for this project is 2009. Even if developed, this project would not make a large contribution to meeting growth in provincial electricity demand during the 20-year period.

As noted both the High Dam Project at Dunvegan and the Slave River Project were studied to feasibility level in the late 1970s and early 1980s, and both projects were judged to be technically feasible and economically attractive. However, neither project was developed. Among the principal reasons for this appear to have been the uncertainty surrounding the financial risk associated with their high costs and very long lead times, and concerns over potential environmental impacts.

The restructuring of the electricity supply industry in Alberta that has occurred since the time of the feasibility studies increases the financial risks. Prior to restructuring, utilities had reasonable assurance that their prudent investments in new generating plant would be recovered through regulated electricity tariffs. Since restructuring, there is no assurance of cost recovery.

There has been a growing general awareness of environmental issues of large power projects. The effect of this awareness relative to a project's impact on the immediate environment can be observed in the time that has been spent to date on the evaluation of the low dam, run-of-river alternative at Dunvegan, which has not yet received regulatory approval. Environmental concerns of the potential larger hydro projects at Dunvegan and Slave would almost certainly be significant.

Possibly offsetting the higher financial risks and concerns about local environmental impacts is the fact that hydro power generation does not produce any greenhouse gases.

On balance it is considered unlikely that either the Dunvegan high dam alternative or the Slave River project will be developed during the period to 2024. If such development should occur it is expected to be towards the end of the 20-year period. The long lead times of these two projects would mean that the transmission planning and construction to tie either of them into the grid could proceed in parallel with the planning, design and construction of the hydro project.

2.2 Coal

Currently there are seven coal-fired plants operating in Alberta of which four are located near Lake Wabamun approximately 50 km west Edmonton, two are east of Red Deer and Calgary and one is located at Grande Cache near the BC border northwest of Edmonton.

2.2.1 Wabamun Lake Area Plants Owned by TransAlta and EPCOR

The Wabamun plant on the north side of the lake was TransAlta's first coal-fired plant. When completed in 1968 it comprised two 65 MW units, which were initially fired with gas and later

converted to coal, a 140 MW unit and a 279 MW unit. The 140 MW unit was retired at the end of 2003 and the two 65 MW were retired at the end of 2004. The remaining 279 MW unit is scheduled to be retired in 2010. The Wabamun plant is supplied by the Whitewood Mine which is also on the north side of the lake and which has significant remaining coal reserves to the west of the area currently being mined.

The 2,018 MW Sundance plant is located on the south side of the lake and has six units that were commissioned from 1970 to 1980. The capacity of Sundance Unit 6 was subsequently increased by approximately 40 MW in 2000. The 762 MW Keephills plant is located to the southeast of the Sundance plant and has two units that were commissioned in 1983 and 1984. The Sundance and Keephills plants are also both owned by TransAlta and both are supplied by the adjacent 12 million tonne per year Highvale Mine.

EPCOR's 1,218 MW Genesee plant is to the southeast of the Keephills plant. The first two units were commissioned in 1989 and 1994 and the third unit, which is the only coal-fired unit built since industry restructuring and not subject to a PPA, at the end of 2004.

The coal reserves in the vicinity of the Highvale and Genesee mines are more than sufficient to fuel the existing Sundance, Keephills and Genesee plants beyond 2024/25, plus two new units at Keephills and another unit at Genesee. For the purposes of arriving at the amount of generation in 2024/25, it is assumed that:

- The Sundance plant continues to operate, or is replaced by a similar plant in the area;
- The existing two units at Keephills and three units at Genesee are also operating in 2024/25;
- Two additional units at Keephills and a fourth unit at Genesee are considered candidates for meeting load growth over the 20-year period; and
- Wabamun Unit 4 is retired in 2010 as is currently planned and, as discussed in Section 1, is included with the plant retirements in arriving at the 7,864 MW of new generation identified. However the Wabamun site is also considered as one of the possible sites for new generation.

2.2.2 ATCO Power Plants

ATCO's two major coal-fired plants are Battle River which is due east of Red Deer and Sheerness which is south of Battle River and east of Calgary.

At the time of its completion in 1981, the Battle River plant comprised five generating units with a total installed capacity of 724 MW. Units 1 and 2, each with 30 MW capacity, were commissioned in 1956 and 1964 and are now retired. Unit 3 was commissioned in 1969, Unit 4 in 1975 and Unit 5 in 1981. The PPAs for Units 3 and 4 expire in 2013 and the PPA for Unit 5 expires in 2020. For the purposes of estimating new generation that will be built it is assumed that these units are retired when their PPAs expire. However, as in the case of Wabamun, Battle River is also considered as a possible site for new generation either as a result of:

- Unit 5 being life extended and fired with coal from the existing mine; or
- Potentially a new plant being built and coal brought in from a new mine about 20 km away.

The Sheerness plant is located approximately 30 km south of the Town of Hanna and some 200 km east of Calgary. The installed capacity of each of its two units, including the recent capacity increases, is about 390 MW each. Unit 1 was commissioned in 1986 and Unit 2 in 1990.

There are sufficient coal reserves to fuel the two units for their full 40 year life but not sufficient to fuel a third unit. It is assumed that these two units will operate for at least their 40-year lives and therefore will be operating in 2024/25.

The HR Milner plant is located about 20 km north of the Town of Grande Cache in west-central Alberta. The 143 MW single unit plant, commissioned in 1972, was built to use waste coal from the Smoky River Mine and more recently has used coal imported to the site. It is assumed that the plant will be retired in 2012.

2.2.3 New Sites

With the exception of HR Milner, the coal-fired plants in Alberta are located adjacent to open pit mines that have been developed specifically to serve these power plants. The coal from these dedicated mines varies somewhat in quality but is typically ranked as subbituminous, classified as B or C, and referred to as plains coal. The “as received” heat content ranges from approximately 16 to 20 GJ/tonne and the sulphur content ranges from about 0.2% to 0.6%.

The major coal zones in Alberta form a large arc from northwest of Edmonton to southeast of Calgary. The north and north-central deposits are part of the Ardley coal zone of the Scollard Formation, the south-central deposits are part of the Drumheller coal zone of the Horseshoe Canyon Formation, and the southeastern deposit are part of the Lethbridge coal zone of the Oldman Formation.

Over the years, twenty or more individual coal properties in these formations have been investigated to some degree for the purposes of providing coal for coal-fired plants. In 1981 the Electric Utility Planning Council in its report “Power Generation in Alberta [1981-2005]” discussed 11 sites. These sites, their approximate location and the potential capacity of the power plant based on the coal reserves, are:

South and East of Calgary

Blackfoot, 100 km southeast of Calgary, potential capacity to 1500 MW

Bow City – Kitsim, 20 km southwest of Brooks, 1,000 MW

Between Calgary and Edmonton

Camrose – Riley, 30 km northeast of Camrose, 2,250 MW

Pipestone, 60 km south of Edmonton, 1,500 MW

Ardley, 40 km east of Red Deer, 1,500 MW

Trochu – Three Hills, located between Three Hills and the Red Deer River, 750 MW

North and West of Edmonton

Lesser Slave Lake, on the lake about 3 km west of the Town of Slave Lake, 750 MW

Judy Creek, 60 km north of Whitecourt, 2,250 MW

Fox Creek, 25 km northeast of the town of Fox Creek, 750 MW

Picardville, 50 km northwest of Edmonton, 750 MW

Isle Lake, northwest of Wabamun, 1,500 MW

The other sites that have been investigated tend to be more to the north and west of Edmonton, rather than south of Edmonton. The best sites in terms of seam thickness, strip ratios and low

sulphur content are in the Lake Wabamun area where most generation is currently concentrated.

2.2.4 New Coal-fired Plants

It is expected that the next coal-fired generation additions in Alberta will be similar to the recently completed Genesee Unit 3 which includes a super-critical pressure steam cycle and clean air technologies to enhance operational and environmental performance.

The higher temperature and steam pressure in a super-critical boiler (implementing once-through technology), combined with a high-efficiency steam turbine result in a more efficient conversion of thermal energy to electricity. The net efficiency of a super-critical unit such as Genesee 3, based on the higher heating value of coal, is 38.4% as compared to 35% in a sub-critical unit such as Genesee 1 and 2 and the Keephills units. Genesee 3 is fitted with environmental controls which include low NO_x burners to reduce NO_x emissions, a dry flue gas desulphurization (FGD) unit to reduce SO₂ emissions and fabric filters to control particulate emissions.

In January 2003, the federal Department of the Environment reported “New Source Emission Guidelines” in the Canada Gazette. These guidelines supercede the former “Thermal Power Generation Emissions – National Guidelines for New Stationary Sources” which were issued in 1993. These guidelines provide emission limits for SO₂, NO_x, particulates and opacity and can be met with low NO_x burners, flue gas desulphurization and fabric filters similar to those installed at Genesee 3 plus selective catalytic reduction (SCR) to further reduce NO_x emissions. The cost estimates of the coal-fired plants presented in Section 3 include these environmental controls.

The Government of Alberta is currently developing regulations for Mercury emissions in parallel with similar initiatives elsewhere. The current state of Mercury removal technology is addressed in the EPRI article “Mercury controls for coal-fired power plants – status and challenges” in the May 2005 issue of Modern Power Systems. That article notes that “mercury control technologies offering sustainable performance and known applicability, impact, and cost are still in the future”. However it also points out that flue gas desulphurization, selective catalytic reduction and fabric filters installed to reduce emissions of SO₂, NO_x and particulates can also substantially reduce Mercury emissions but that the extent of those reductions depends on the the coal burned and the chemistry of the flue gas.

Whether the SO₂, NO_x and particulates emission control facilities noted above and included as part of the cost estimates presented in Section 3 will be sufficient to meet the Mercury emission regulations that will be set, or whether additional, and at this time unknown, equipment will need to be added, cannot be determined at this point.

In addition to installing environmental control equipment, owners of new coal-fired plants in Alberta are also required to purchase CO₂ offsets for the amount that the carbon dioxide emissions of their coal-fired plant exceed those of a combined cycle plant. The cost of purchasing the CO₂ offsets is included as part of the cost comparisons presented in Section 3. Options for actually reducing CO₂ emissions are discussed in the next section.

2.2.5 Emerging Coal Technologies

There are several initiatives underway in Canada to address the CO₂ issue. One of the most significant is the program of the Canadian Clean Power Coalition. Their objective is “to demonstrate that coal-fired electricity generation can effectively address air quality issues

projected in the future, including greenhouse gas”. Their goal is to “construct and operate a full-scale demonstration project to remove greenhouse gas and all other emissions of concern from a new coal-fired power plant by 2010 to 2012 time frame”.

The two main options for reducing CO₂ are (i) further efficiency improvements to coal fired plants that may be combined with post-combustion capture of CO₂, and (ii) the removal of CO₂ prior to combustion.

Efficiency improvements and post-combustion capture of CO₂

As with the progression from sub-critical to super-critical coal-fired power plants, the next efficiency improvement is the advancement from the super-critical steam cycle to the the ultra super-critical (USC) cycle .

USC power plants have been operational in Europe and Japan for the past decade. Published data indicate that the operating results have been good as the development into the USC concept has been a stepwise progress from well-proven super-critical systems. There have been no major problems in terms of water/steam process, pulverized fuel combustion or heat transfer. EPRI reports that USC is now the baseline state-of-the-art for power plant developments in Europe and Japan.

The estimated efficiency for an USC plant using Alberta subbituminous coal is about 45% which further reduces CO₂ emissions. Typically the CO₂ emissions are 0.99 tonne/MWh for a sub-critical plant, 0.88 tonne/MWh for a super-critical plant and 0.75 tonne/MWh for an ultra super-critical plant.

Further reduction requires separating the CO₂ from the dilute flue gas stream, capturing and sequestering it or finding a CO₂ user such as an Enhanced Oil Recovery (EOR) facility. Advancements are being made in the technologies to achieve this but they are still very costly and require technical demonstration on a large scale.

Separation of CO₂ from the flue gases can be accomplished by absorption after contact with amine-based solvents, by adsorption on activated carbon, by passing the gas through special membranes, or by cryogenic separation.

The most advanced technology for power plant application is the amine scrubbing process. The technology has been under development for over 20 years and Fluor Daniel markets it as the ECONOMINE FG process. After cooling the flue gas in a dry contact cooler (DCC), the CO₂ is removed in an absorption tower. There is also a significant amount of ancillary equipment as the system includes an amine regeneration loop. The system has high auxiliary utility loads. The regeneration loop includes a reboiler which consumes a substantial amount of steam from the power plant, flue gas fan power is increased to compensate for additional pressure drops in the system and the captured CO₂ is compressed to pipeline pressure for use/sequestration.

Once captured and compressed, the CO₂ can be utilized to enhance oil recovery by injection into a reservoir; to displace methane from coal seams, resulting in the use of the methane as a fuel for heating or electricity generation; or can be sequestered in geological formations such as depleted oil or gas reservoirs, deep and un-mineable coal formations, and deep saline aquifers.

Pre-combustion capture of CO₂

Whereas the foregoing has discussed post-combustion capture of CO₂ from the flue gas, in technologies such as the Integrated Gasification Combined Cycle (IGCC) the CO₂ can be removed prior to combustion. The IGCC technology has been applied for over two decades and several plants are in operation.

The basic components in the IGCC power plant are as follows:

- Fuel handling;
- Oxygen separation;
- Coal (fuel) gasifier;
- Gas (syngas) coolers and syngas clean-up and wastes;
- Combined cycle unit; and
- Plant infrastructure and ancillary systems.

There are several technology vendors that can supply suitable processes for the gasification of coal. These include Shell, General Electric (formerly Texaco), E-Gas and others.

IGCC power plants provide distinct advantages in comparison to conventional coal-fired power plants. The gasification process produces a gas (syngas) that can be burnt cleanly in gas turbines. It is possible to keep emission levels of SO₂ and NO_x below required limits and significantly reduce CO₂ emissions. To remove the CO₂ from the synfuel prior to combustion, water gas shift reactors are used to react the CO fraction with water to produce CO₂ and hydrogen that can be captured.

Some of the IGCC plants that are in commercial operation capture CO₂ from the synfuel and some do not. The Dakota Gasification Company IGCC plant at Beulah, North Dakota, is an example of a plant which does capture CO₂ which in turn is shipped by pipeline to Weyburn Saskatchewan for enhanced oil recovery.

Views on the future role of IGCC as a source of power generation are changing. In 2004, the Northwest Power and Conservation Council reported that “a coal gasification plant could be ordered and built today. However, relatively few demonstration plants have operated for extended periods and numerous technical difficulties have been experienced with these demonstration projects, especially during the first years of operation. This experience has led to concerns regarding plant cost and reliability, which coupled with the lack of overall plant performance warranties appear to preclude financing.”

In early 2005, the National Energy Technology Laboratory (NETL) of the U.S. Department of Energy reported positively on recent moves towards commercialization of IGCC. They indicated that, in 2004, several major energy corporations (including American Electric Power, Cinergy, First Energy, Consol, General Electric and Bechtel) had expressed strong interest in building IGCC power plants. The mounting interest in IGCC reflects a convergence of three changes in the electric utility marketplace:

- The increasing maturity of gasification technology;
- The extremely low emissions from IGCC, especially air emissions, and the potential for lower cost control of greenhouse gases than other coal-based systems; and
- The recent dramatic increase in the cost of natural gas-based power, which is viewed as a major competitor to coal-based power.

2.3 Natural Gas and Oil Sands Byproducts

Of the approximately 3,500 MW of new generation that has been added to the Alberta system over the past five years, some 2,500 MW is gas-fired.

The gas-fired generation additions are either combined cycle or cogeneration plants and the principal building block for both is a gas turbine. The gas turbines are linked to a heat recovery steam generator (HRSG) which drives a steam turbine in the case of the combined cycle plant and provides process steam in the case of cogeneration.

This section first examines the combined cycle and cogeneration plants that have recently been installed and then goes on to examine emerging technologies using oil sands by-products to produce power.

2.3.1 Combined Cycle

Equipment configuration can vary widely for a combined cycle plant. A one-on-one plant consists of a single gas turbine, HRSG and steam turbine. A two-on-one plant consists of two gas turbines, two HRSGs and a single steam turbine. Other variations of the numbers of gas turbines and steam turbines in a combined cycle configuration are also available.

A typical combined cycle merchant power plant operating in Alberta is the Calgary Energy Centre developed by Calpine. This plant has been in operation since 2003 and provides a nominal base load capacity of 252 MW.

For potential future merchant combined cycle power plants developed in Alberta, similar types of configurations to the Calgary Energy Centre are envisaged. Typically a one-on-one configuration with a General Electric Frame 7FA and a GE steam turbine has a nominal rating of 262 MW.

As a combined cycle plant utilizes the waste heat from the gas turbine to produce steam which is further converted to electric power in the steam turbine generator, an overall thermal efficiency of greater than 50% can be achieved.

2.3.2 Cogeneration

Cogeneration, which is simply defined as the simultaneous generation of electric power and thermal energy, is widely used in northern Alberta's oil sands. The use of the waste heat to produce steam or hot water leads to very high operating efficiencies for a cogeneration plant. Often the waste heat recovery unit is also provided with duct firing to further increase the steam or hot water output of the unit. Duct firing does not improve efficiency, however it is a means of adding thermal generating capacity at a relatively low additional capital cost.

The gas turbine unit selected for each of the various projects is dependent on the type and size of facility and the contractual arrangement under which the cogeneration is developed.

The most popular GTG utilized at oil sands facilities over the past decade has been the General Electric Frame 7EA, a nominal 85 MW unit. Two of these units are installed at the Syncrude Aurora Mine (one of them currently under construction), two are installed at the Albian Sands Muskeg River Mine and one is planned for installation at the CNRL Horizon Project. These units have also been utilized at heavy oil and SAGD projects such as Primrose and are planned at the Long Lake Project.

The GE 7EA continues to be a favoured workhorse in the oil sands development due to its operating history and reliability, but also the fact that the amount of recoverable exhaust heat matches the demands of oil sands projects.

Some oil sands developments have also used larger gas turbines. The facility at MacKay River has a General Electric Frame 7FA, a nominal 172 MW unit. The Suncor Plant has two ABB Frame 11N2 units, rated at nominal 115 MW each.

Oil sands developers such as Syncrude own and operate their cogeneration facilities and produce enough power to meet their mining and upgrading needs. Some of the other oil sands developments have arrangements with independent power producers (IPPs) for the delivery of power and heat for the oil processing operations. At Muskeg River and Primrose, ATCO Power owns and operates the cogeneration plant; at MacKay River, TransCanada Power is the IPP; and at Suncor, TransAlta owns and operates the Poplar Creek Power Plant. Each of these facilities provides electric power and thermal energy to the host facility, typically on a cost-of-service basis, and can also supply electric power surplus to the host's needs into the grid.

Oilsands projects that are currently under development are trending towards the oil sands developer owning and operating the cogeneration plants, as opposed to forming alignments with IPPs and, with the exception of OPTI Nexen, are generally sizing power facilities to meet only their own behind the fence needs.

2.3.3 Emerging Technologies Using Oil Sands Byproducts

The gasification of oil sands by-products, particularly asphaltenes and petroleum coke, is expected to gradually replace the use of natural gas as the source of fuel for new oil sands cogeneration.

OPTI Nexen is installing a gasifier at their Long Lake Project – the first to be integrated into an oil sands development. In October 2004, an update of the project was presented at the Gasification Technologies Conference in Washington D.C. The Long Lake Project uses a unique combination of technologies to provide a solution to the natural gas supply and cost issue. A key advantage of the development is the integration of an asphaltene gasification unit into the upgrader system to provide hydrogen to the hydrocracker and synfuel for power and steam generation. The facility development includes the installation of two GE 7EA gas turbines which will provide sufficient power for facility use and have up to 58 MW available for grid export. Depending on power pool prices, the gas turbines will either operate at full load and export power, with natural gas used to make up the total fuel demand, or operate at reduced load to consume all synfuel, and meet on-site power requirements only.

The term “polygeneration” has been coined for plants such as Long Lake which generate more than two useful products, that is electricity, steam and hydrogen.

Suncor currently utilizes coke for the generation of high pressure steam in conventional boilers, which have been retrofitted with FGD systems to reduce the SO_x emissions, and has indicated that coke gasification is being considered as part of its expansion plans.

2.4 Wind

Southern Alberta provides an attractive regime for wind generation. Since the mid 1990s some 300 MW of new wind generation has been installed of which 250 is connected to the transmission system and forms part of the 11,940 MW of existing generation listed on the AESO website.

Wind generation is sold to “green” customers wishing to purchase a renewable source of power, to coal-fired generators buying carbon dioxide offsets and directly to energy customers or into the pool. The annual plant factors of new wind generators are 35% or better and higher in December and January at the time of system peak. Generators receive a subsidy from the federal government of \$10/MWh during the first 10 years of operation.

Over the next five years wind generators plan to install as much as an additional 1,000 MW to the system. The longer term potential along the southern strip of the province is estimated to be

around 3,000 MW taking into account the various constraints such as population density, the environment, current technology and the market. The technology continues to change with the use of higher towers and larger turbines resulting in improved plant capacity factors.

It is estimated, for the purposes of this study, that 2000 MW of new wind generation will be installed over the next twenty years.

2.5 Other

The foregoing discussion has included a review of the major potential additions to the Alberta system over the next twenty years. With the exception of wind and small hydro, all of these single additions are more than 50 MW and most are between 100 and 500 MW.

Of the 3,500 MW of new generation capacity that has been added to the system since the start of restructuring approximately 20% is from generators that are smaller than 50 MW. These are largely gas-fired plants plus a small amount of renewables other than wind.

It is expected that this phenomenon will continue in the future but will represent a smaller portion of the total additions. Significantly less new generation from small gas-fired plants, because of continued high gas prices and a low system heat rate, is expected to be offset in part by distributed generation which has not yet occurred to any significant extent. For the purposes of the forecasts it is estimated that such generation will amount to between 300 and 800 MW over the next twenty years and an estimate of 500 MW is included in the forecast.

3. COMPARISONS OF MAJOR GENERATION OPTIONS

The review of Alberta's generation resources presented in Section 2 indicates that major hydro development is unlikely; that wind will continue to be installed at a rapid rate but, as discussed in Section 1, will only make a small contribution to firm capacity and that other small generators will have a smaller role than in the past. As a result the likely candidates for major additions to the Alberta system are expected to be coal- and gas-fired thermal generation in the short term and emerging technologies that will utilize coal and by-products of oil sands development in the longer term.

This section presents a cost comparison of the coal- and gas-fired technologies that are currently installed in Alberta and a qualitative comparison of the emerging technologies.

3.1 Cost Comparison of Coal and Gas Technologies Currently Installed in Alberta

Table 3.1 presents a comparison of the levelized costs of:

- A 450 MW coal-fired super-critical unit (s) similar to Genesee 3 that would be added at either Keephills or Genesee;
- A 450 MW coal-fired super-critical unit (s) at a green-field site;
- A 260 MW natural gas-fired combined cycle plant that could be located almost anywhere in the province; and
- A 170 MW natural gas-fired cogeneration plant that is assumed to be installed as part of oil sands development at Fort McMurray

The top line of Table 3.1 presents estimates of prices for coal and gas that will fuel the power plants.

The coal price is based on information from a presentation made by TransAlta Utilities Corporation, on behalf of the Canadian Clean Power Coalition in May 2004 in Lexington, Kentucky. That presentation showed the \$/GJ coal costs for a total of twenty perspective, but unnamed, sites in Alberta. The prices varied from a low of \$0.75/GJ to a high of a \$1.96/GJ. Thirteen of the 20 sites had costs between \$1.00 and \$1.20/GJ.

Based on those estimates, and other work that has been done, the comparison of power costs described here is based on a cost of \$0.80/GJ for the expansion of the mines serving the Keephills and Genesee power plants and \$1.20/GJ at a green-field site.

The year to date AECO-C gas price in Alberta as of May 4, 2005 was \$6.40/GJ. Gas price forecasts prepared at the beginning of 2005, when the prices were slightly lower, by Sproule and Gilbert Laustsen Jung Associates Ltd. forecast that prices, expressed in constant 2005 dollars, would decline to about \$5.00/GJ over the next ten years. A price of \$6.00/GJ has been selected for the base case analysis here and sensitivity analyses are presented at \$5.00 and \$7.00/GJ.

The second line in Table 3.1 presents the plants' heat rates, that is the amount of energy in the form of fuel that is required to produce a megawatt hour of electrical output. The heat rates for the super-critical coal-fired plants are 9.5 GJ/MWh.

Since the gas-fired combined cycle and cogeneration plants utilize the waste heat from the gas turbine, either to generate electricity in a steam turbine or to provide process heat, they are more efficient and have a lower heat rates. The heat rate given in the Table for the combined

cycle plant is the ISO heat rate as quoted in the Gas Turbine World 2004-05 GTW Handbook. The actual unit performance will vary depending on site selection, the auxiliary equipment design and temperature throughout the year. Use of the ISO data provides results which are well within the accuracy limits of the requirements of this study.

Table 3.1 Comparison of Unit Costs of Coal and Gas-fired Plants

	Coal-fired (KH3, KH4, GN4)	Coal-fired (Greenfield)	Combined Cycle	Cogeneration (Fort McMurray)
COST ANALYSIS				
1. Cost of Fuel (\$/GJ)	0.8	1.2	6	6
2. Heat Rate (GJ/MWh)	9.5	9.5	6.5	5.2
3. Fuel Cost (\$/MWh)	8	11	43	34
4. O&M (\$/MWh)	6	6	3.5	3
5. Capital (\$/kW)	1,900	2,100	800	1,000
(\$/MWh)	26	29	12	14
6. Total Cost (\$/MWh)	40	46	58	51
7. CO ₂ Offsets (\$/MWh)	5	5	0	0
8. Total Cost Incl. CO ₂ Offsets (\$/MWh)	45	51	58	51
SENSITIVITY ANALYSIS				
Gas Price \$/GJ				
\$5.00	45	51	51	45
\$7.00	45	51	65	57
CO ₂ Offsets at \$20/tonne	50	56	58	51

The cogeneration plant heat rate of 5.2 GJ/MWh allows for the efficiency of the steam to host and condensate recovery. Since the equipment configuration of a cogeneration facility depends on the nature of the steam host, the plants can vary widely from site to site and result in performance, in terms of heat rate, and capital costs as shown on line 6, that vary from the numbers presented here. The numbers presented in Table 3.1 are however considered representative of expected performance and costs.

Each plant's fuel cost per MWh of output in line 3 is the product of the fuel price and plant's heat rate. In the case of the coal-fired plants, the fuel cost is simply the multiplication of the two values. However in the case of the gas-fired plants the fact that the gas price is quoted in terms of gas's higher heating value and the heat rates quoted by manufacturers are in terms of gas's lower heating value has to be taken into account by multiplying the product of the two by 1.1.

The operation and maintenance costs are shown in terms of \$/MWh figures for each of the plants. In fact the operation and maintenance for the coal-fired plants are largely fixed, and independent of the level of output, and the operation and maintenance costs for the gas-fired plants are generally proportional to the level of output.

The fuel and operation and maintenance costs are all estimated in terms of mid-2005 dollars and are assumed to escalate at a general level of inflation of two percent per year over the life of the project.

The \$/kW capital cost estimates in line 6 include the complete design, procurement, construction (direct and indirect), commissioning and Owners' costs of each plant. A high voltage substation is included, but the transmission line to the grid is excluded. The estimates are in mid-2005 dollars. Interest during construction (IDC) and escalation are not included in the \$/kW costs but are taken into account in the \$/MWh costs on the next line.

The capital cost of a single 450 MW super-critical coal-fired unit, as described in the previous section, is estimated to be \$2,100/kW for a green-field site and \$1,900/kW for a unit expansion on an existing site such as Keephills or Genesee. The slightly lower cost at the existing site is the result of being able to use common access and infrastructure facilities that are already in place.

The estimated capital cost for the combined cycle plant of \$800/kW is for a one-on-one GE Frame 7FA installation with a nominal capacity of 260 MW. In addition to the gas turbine the estimate includes the HRSG, steam turbine, condenser cooling system with mechanical draft cooling tower and all ancillary systems.

The \$1,000/kW estimated capital cost of a cogeneration plant is for a single unit installation of a GE Frame 7FA with a nominal capacity of 170 MW. The estimate includes the gas turbine, the HRSG with duct firing, ancillary systems to support the requirements of the cogeneration system and interconnections to the process plant. Redundant steam generation capacity (auxiliary boilers) is not included.

As a point of reference (but not shown in Table 3.1), the current choice of most of the oil sands developers – a two-unit GE Frame 7EA installation with two HRSGs and also a nominal capacity of 170 MW, is estimated to cost \$1,250/kW.

The capital costs are expressed in terms of \$/MWh costs using a financial model. The key input parameters to the financial model are:

- The coal-fired plants have a four year construction period, 30 year life and operate at a 90 percent capacity factor;

- The gas-fired plants have a two year construction period, 20 year life and operate at a 95 percent capacity factor;
- All capital is financed with 60 percent debt at a cost of debt of 6% and 40 percent equity with the return on equity of 15%;
- The capital cost allowances (CCAs) are 50 percent for the cogeneration plant and 8 percent for the other plants and the tax rate is 20.5 percent consistent with the recent federal budget; and
- Inflation, which would apply to all costs and revenues, is assumed to be two percent per year.

These parameters are used to calculate the annual capital-related costs of each plant on a cost-of-service basis over its life and then those annual costs are levelized in constant 2005 dollars.

A revenue stream equal to the levelized cost, increasing at the rate of inflation of two percent per year, times the plant's output at the load factors indicated would recover the capital costs, taxes, interest charges and provide a 15% return on equity over the lives of the plants. The use of a single levelized value results in a return on equity that is lower than 15% in the earlier years and higher in the latter years.

The total cost for each plant in line 6 is the sum of the operating and fuel costs and the levelized capital charges and is expressed in 2005 dollars.

The cost of CO₂ offsets is included in line 7 in Table 3.1. The coal-fired plants are equipped with scrubbers to reduce SO₂ emissions, low NO_x burners and SCRs to reduce oxides of nitrogen emissions, and baghouses which remove in excess of 99 percent of particulate matter. Rather than include a means to capture CO₂, which would increase the capital and operating costs substantially, the cost of buying CO₂ offsets is included as a charge to the coal-fired plants. The charge is based on an offset cost of \$10.00/tonne of CO₂ and is applied to the coal-fired plants to the extent that their CO₂ emissions exceed those of the gas-fired plants. A super-critical coal-fired plant such as the one examined here produces just under one tonne of CO₂ per MWh of output and the gas-fired technologies produce just under half a tonne. The cost difference of half a tonne of CO₂ per MWh offsets increases the costs of the coal-fired plants by \$5/MWh.

The additional coal-fired units at the existing sites have a total levelized cost including CO₂ offsets of \$45/MWh that is slightly lower than the other three options examined. The cost of coal-fired generation from a green-field site and the cost of cogeneration from Fort McMurray are both \$51/MWh and the combined cycle is the most costly at \$58/MWh.

3.1.1 Sensitivity to Gas Prices and Higher Offset Costs

The sensitivity analysis examines the effect of using gas prices of \$5 and \$7/GJ and increasing the cost of CO₂ offsets from \$10 to \$20 per tonne. A gas price of \$5/GJ reduces the cost of the cogeneration to the same level as the coal-fired additions at the existing sites and the combined cycle to the same level as coal-fired generation from a green-field site. Conversely a gas price of \$7/GJ pushes the costs of both the gas-fired combined cycle and cogeneration above the two coal-fired options.

Increasing the cost of CO₂ offsets to \$20 per tonne increases the cost of the additional coal-fired units at existing sites to essentially the same level as cogeneration at Fort McMurray.

3.2 Emerging Technologies

This section summarizes the key features of the emerging technologies that were discussed in Section 2 and provides some indicative costs. It is expected that these technologies would be primarily implemented to address CO₂ emissions and diminishing gas resources, that is the likelihood that natural gas will not be used for base load power generation in the longer term.

- Ultra super-critical coal-fired plants are now in operation in certain parts of the world, and have efficiencies of about 45% and CO₂ emissions of 0.75 tonnes/MWh as compared to 0.99 tonnes/MWh for a sub-critical plant such as Keephills and 0.88 tonnes/MWh in a super-critical unit such as Genesee 3. Ultra super-critical coal-fired plants are not significantly more costly than the super-critical units included in the cost comparison in Table 3.1.
- Methods to capture the remaining CO₂ emissions from these coal plants, such as amine scrubbing, are at an early stage of development and the facilities required to capture and sequester of CO₂ could as much as double the cost of power. However, considerable research is underway in North America and worldwide with the objective of making these technologies commercially viable.
- CO₂ emissions can also be reduced with the use of Integrated Gasification Combined Cycle (IGCC) plant, in which coal is first gasified and then used to fuel a combined cycle plant. CO₂ can be captured from the gasifier which reduces emission levels to those of a natural gas-fired combined cycle plants. IGCC plants are some 50% more expensive than the coal-fired plants included in Table 3.1 but, with high natural gas prices, are now the subject of considerable interest.
- Gasification of oil sands by-products such as asphaltenes, as is currently being undertaken by OPTI Nexen, or coke to generate power and produce steam and hydrogen are less costly than coal gasification and will allow oil sands developers to stop using natural gas.

These findings provide a guide for selecting the major power additions in the second half of the 20-year outlook. As discussed in Section 4.2.3, it is expected that gasification of oil sands by-products will become a major source of generation in the longer term.

4. GENERATION SCENARIOS

In this section the electric generation options discussed in Sections 2 and 3 are used to meet the projected future load growth and replace retired plants as set out in Section 1. The various sources of generation selected to meet this requirement are tabulated in Table 4.1 and the basis for selecting each of the components is discussed below.

Table 4.1 starts with the 7,864 MW of new generation that is estimated to be needed by 2024/25, as was developed in Table 1.1. The first step is to subtract the increase in behind the fence load which will be served by behind the fence generation. Between 2004/05 and 2024/25 the behind the fence load increases by 2,640 MW. Subtracting this increase in behind the fence generation from the total shortfall results a grid shortfall is 5,224 MW.

The analysis of how the 5,224 MW of generation will be met:

- Starts with estimates of the contribution to firm capacity of the smaller additions to the grid; and then
- Develops two scenarios of major additions that could meet the remaining generation shortfall.

4.1 Smaller Grid Additions

4.1.1 Wind

As set out in Section 2.5 it is assumed that 2,000 MW of new wind generation will be installed. Using the criterion developed in Section 1 to arrive at wind's contribution to capacity, the addition of 2,000 MW will provide 300 MW of firm capacity to the system.

4.1.2 Small Hydro

As noted in Section 2.6 it is considered unlikely that either the large Dunvegan or the Slave River projects will be developed in the 20-year period. A low head 100 MW Dunvegan project is actively being pursued and there is the potential for other small projects being developed, particularly on the Peace River. Based on this assessment 200 MW of run-of-river capacity, providing 100 MW of firm capacity is included in the 20-year period.

4.1.3 Upgrades at Sundance and Keephills Coal-Fired Plants

The capacity of Sundance Unit 6 has been increased by approximately 40 MW. Similar upgrades are possible for Sundance Units 3, 4 and 5 and Keephills Units 1 and 2 providing an aggregate of 200 MW. Such upgrades typically have a cost per kW which is well below the cost per kW of a new coal-fired plant and, because part of the upgrade is in effect an efficiency improvement, the heat rate of the upgrade is better than the heat rate of the overall plant.

4.1.4 Other

A significant part of the new generation installed since restructuring has been small non-oil sands cogeneration, other types of gas-fired generation and renewables other than small hydro and wind.

It is expected that these types of generation will continue to be added in the future but, because of high gas prices and a low system heat rate, will represent a smaller portion of the total additions than in the past. It is estimated that 500 MW of such generation will be installed over the next twenty years.

4.2 Scenarios of Major Additions

The projected additions of wind, small hydro, upgrades at Sundance and Keephills and other generation capacity total 1,100 MW which leaves approximately 4,100 MW to be met by major additions to the grid.

As shown in the bottom half of Table 4.1, two scenarios of major additions are developed:

- Predominately Coal and Southern Generation; and
- Predominately Cogeneration and Northern Generation.

The general bases for selecting the major additions in these scenarios are:

Short to medium term – Within the next 10 years

It is assumed that:

- Coal-fired plants commissioned within the next 10 years will be able to buy CO₂ offsets; and
- Natural gas will continue to be a fuel source for base load generation, but will be expensive.

The levelized costs shown in Table 3.1, which are based on these assumptions, are used as a guide in selecting the generating plants in the two scenarios recognizing that:

- Levelized costs are useful in ranking the lifetime costs of plants but actual investment decisions may be based more on the projected returns in the earlier years of the plant's life and on factors such as the fuel cost risk over the life of the plant; and
- In addition to the relative costs and risks of the options available, the plants that will actually be built will also depend on the willingness of their proponents to make the required investments and to capitalize on the "first mover" advantage, that is being the first to announce and proceed with their project.

Longer term – After 10 years

It is assumed that new coal-fired power plants built in the second half of this 20-year outlook will have to capture CO₂ emissions and, because of diminishing gas resources, that natural gas will not be used for base load power generation.

Rather than using the results of Table 3.1, the choice of the new plants to be built in the longer term is based more on the review of emerging technologies presented in Sections 2.2.5 and 2.3.3 and compared in Section 3.2.

4.2.1 Additional Coal-Fired Units at Keephills and Genesee

As the analysis in Table 3.1 shows, additional units at Keephills and Genesee similar to Genesee 3 are a competitive source of power in the short to medium term. These additions have a capital cost per kW that is approximately twice that of the gas-fired alternatives, resulting in higher financing requirements and potentially lower returns in earlier years, but have the advantage of locked in fuel costs.

In the longer term new coal generation at these sites could be either ultra super-critical units possibly with some method of CO₂ capture, or coal gasification fuelling combined cycle plants (IGCC plants) in which CO₂ is captured from the gasifier. As in the case of the existing

technology, the lower cost of fuel and established Keephills and Genesee sites will provide an advantage for these new technologies over a green-field site.

The unit size for these plant additions, and new units elsewhere, would likely be similar to the 450 MW Genesee 3 unit if they are build in the short term, could be somewhat smaller if they are IGCC plants or larger if they are a later generation of a ultra super-critical plant. Unit sizes of 500 MW have been assumed – and with two units at Keephills and one unit at Genesee the total capacity is 1,500 MW.

This 1,500 MW of coal-fired capacity is included in both scenarios.

4.2.2 Coal-fired plants At Other Sites

Plants at green-field sites are expected to have slightly higher capital and fuel costs than additions at Keephills and Genesee and will typically have longer lead times. Until recently the higher cost of a green-field site located in the south would have been largely offset by a lower raw loss factor, which is a component of the transmission charges and is based on plant location. However the loss factors that are currently proposed largely eliminate that differential and in essence remove the offsetting transmission advantage for a southern plant. As a result a green-field site could be anywhere in the major coal formation running from the southeast of Calgary to the northwest of Edmonton.

Over the past 30 years several sites have been examined as possible locations for new coal-fired power plants but at this point in time the Bow City site near Brooks is the only one being actively pursued.

The most likely competition for Bow City is not necessarily a coal-fired plant at another green-field site but rather new units at either the Wabamun or Battle River sites. As noted in the discussion of retirements in Section 1, and further in Section 2, the last remaining unit at Wabamun (Unit 4) is assumed to be retired in 2010 as is currently planned and the last remaining unit at Battle River (Unit 5) is assumed to shut down in 2020 at the end of its PPA. Wabamun could easily be a site for new generation and Battle River Unit 5 could be life extended and/or new capacity added.

A 1,000 megawatt coal-fired plant, in addition to the 1,500 megawatts at Keephills and Genesee, is included in the Coal Scenario but not in the Cogeneration Scenario.

4.2.3 Cogeneration to Serve Grid Load

A large portion of the 3,500 MW of new capacity that has been installed since the start of restructuring in Alberta is gas-fired cogeneration. Part of this generation has been installed by the oil sands companies themselves, such as Syncrude, and part by generation companies who have contracts with the oil sands companies, or other industrial hosts, to supply steam and power and sell power surplus to the hosts' needs into the grid. These contracts were made by the generation companies at a time when gas prices were well below, and the system heat rate above, present levels. Oil sands cogeneration that is currently being installed is owned largely by the oil sands companies themselves, rather than contracted with generation companies, and only a small portion of this generation will be available to the grid.

A change from this current trend of installing essentially no excess capacity for export to the grid will likely require either lower gas prices, a higher system heat rate, or bitumen or coke being fully viable and widely used fuels. Gas prices below \$5.00/GJ, which are required to make cogeneration more economic than coal-fired generation, are not considered likely. Also, with coal plants setting the pool price a significant portion of the time, the system heat rate is not

expected to increase significantly in the short term. Substantial amounts of cogeneration, surplus to on-site needs, therefore, are unlikely to occur until the longer term when bitumen and coke are expected to be more widely used. Once this point is reached, oil sands cogeneration will likely again be a major source of new generation to the grid.

Given the likely improved economics for cogeneration in the longer term, all of the remaining requirement of 2,600 MW (the difference between line 6.5 and 6.1 in Scenario 2 in Table 4.1) is assumed to be cogeneration in the Cogeneration Scenario and 1,100 MW is assumed to be cogeneration in the Coal Scenario.

4.2.4 Mid Range and Peaking Generation

A power system such as that in Alberta is made up of base load, mid range and peaking plants.

The new coal-fired units have a minimum output capability of about 40 percent of their installed capacity and in theory could operate in a mid range role. However these new units would likely have the lowest variable operating costs of any of the thermal plants on the system and therefore will operate at base load.

Cogeneration plants are typically designed to operate at base load so as to provide a continuous steam supply to their steam hosts. This characteristic of cogeneration plants has meant that many of the ones installed in Alberta have lost money during the off peak period when pool prices are low and they have to continue to operate to provide steam to their hosts. As a result of this experience, it seems likely that in the future when new cogeneration plants are installed to provide significant amounts of power to the grid that the heat recovery steam generators will be designed so that they have sufficient duct firing so that the gas turbines can be backed off during times of low prices. This feature would allow them to operate as a mid range plant, albeit with some loss of efficiency, when off peak pool prices fall below the incremental operating and fuel costs of the gas turbines.

Thus the candidates for mid range and peaking plants are:

- Cogeneration plants designed to possibly fill this role and are forced into it by low off peak pool prices;
- Combined cycle, or possibly simple cycle gas turbine, plants that are designed for and intended to be used as mid range and peaking capacity; and
- Existing base load plants that will be “pushed up” the stacking order by new more-efficient coal-fired plants.

An analysis of the role of the existing generation that has not retired and varying amounts of base load and mid range/peaking generation for 2024/25 indicates that about a 1,000 MW of new mid range/peaking capacity is required to allow the existing and new base load plants to operate in a reasonable manner within their design parameters.

In the Coal Scenario it is assumed that 500 MW of this requirement will come from the new cogeneration plants and that the remaining 500 MW will come from combined cycle plants. In the Cogeneration Scenario it is assumed that all of the mid range/peaking capability will be provided by the cogeneration plants.

A comparison of differential generation costs for combined cycle/gas turbine mid range/peaking plants due to temperature/elevation differences between Calgary or Edmonton relative to the location-based loss factor for the two cities indicates that the Calgary loss factor advantage is offset by Edmonton's efficiency advantage. As a result these plants could be located in either

city. Given that this capacity is required in the Coal and Southern Generation Scenario, it is assumed that it will be located in the south near Calgary.

Table 4.1 Generation Scenarios (MW) (Most Probable Forecast)

1. Total New Generation	7,864	
2. Cogeneration Seving Behind the Fence Load	-2,640	
3. New Grid Generation	5,224	
4. Less Smaller Additions to Grid		
4.1 Wind (2,000MW@15%)	-300	
4.2 Small Hydro (200MW@50%)	-100	
4.3 Upgrades at KH and SD	-200	
4.4 Other	-500	
5. Remaining New Grid Generation	4,124	
6. Scenarios of Major Additions	Scenario 1 Coal and Southern Generation	Scenario 2 Cogen and Northern Generation
6.1 New Coal Units at KH and GN	1,500	1,500
6.2 Coal from other site(s)	1,000	0
6.3 Cogen Exported from Fort Murray	1,100	2,600
6.4 Mid Range/Peaking near Calgary	500	0
6.5 Total of Major Additions	4,100	4,100

4.3 Sensitivity to Load Growth

The foregoing discussion and the scenarios in Table 4.1 are all based on the most probable load forecast as prepared by the AESO. Table 4.2 presents the generation scenarios for the high forecast prepared by the AESO and Table 4.3 presents the scenarios for the low forecast.

The generation scenarios for the high and low forecasts are developed from the scenario for the most probable forecast in Table 4.1. In doing so the wind, small hydro and upgrades at existing plants are not changed since these developments are considered to be independent of the rate of load growth; other generation is increased and decreased using the range that was set out in Section 2.5; and the coal, cogeneration and mid range/peaking capacity is generally increased and decreased in proportion to the levels of the high and low forecasts relative to the most probable forecast.

Table 4.2 Generation Scenarios (MW) (High Forecast)

Total New Generation	11,482		
Cogeneration Seving Behind the Fence Load	-3,788		
3. New Grid Generation	7,694		
4. Less Smaller Additions to Grid			
4.1 Wind (2000MW@15%)	-300		
4.2 Small Hydro	-100		
4.3 Upgrades at KH and GN	-200		
4.4 Other	-800		
5. Remaining New Grid Generation	6,294		
6. Scenarios of Major Additions	Scenario 1	Scenario 2	
	Coal and Southern	Cogen and Northern	
	Generation	Generation	
6.1 New Coal Units at KH and GN	1,500	1,500	
6.2 Coal from other site(s)	2,500	1,000	
6.3 Cogen Exported from Fort M.	1,500	3,800	
6.4 Mid Range/Peaking near Calgary	800	0	
6.5 Total of Major Additions	6,300	6,300	

Table 4.3 Generation Scenarios (MW) (Low Forecast)

Total New Generation Requirement	4,247		
Cogeneration Seving Behind the Fence Load	-1,492		
3. New Grid Generation	2,755		
4. Less Smaller Additions to Grid			
4.1 Wind (2000MW@15%)	-300		
4.2 Small Hydro	-100		
4.3 Upgrades at KH and GN	-200		
4.4 Other	-300		
5. Remaining New Grid Generation	1,855		
6. Scenarios of Major Additions	Scenario 1	Scenario 2	
	Coal and Southern Generation	Cogen and Northern Generation	
6.1 New Coal Units at KH and GN	1,000	500	
6.2 Coal from other site(s)	0	0	
6.3 Cogen Exported from Fort M.	600	1,400	
6.4 Mid Range/Peaking near Calgary	300	—	
6.5 Total of Major Additions	1,900	1,900	

Appendix B - Scenario Summaries and Bubble Diagrams

Appendix B - Scenario Summaries and Bubble Diagrams

B.1 Forecasted Generation Additions by Location

The AESO engaged the services of an independent consultant to assist in identifying generation development opportunities in Alberta and their most probable locations. Two generation development scenarios achieving the required amount of new generation were prepared for the Low, Most Likely and High load growth scenarios for a total of six different generation development scenarios. Tables B-1 through B-6 below provide a breakdown of the regional distribution of the total generation for the six scenarios.

As described in the consultant's report contained in Appendix A, all of the scenarios developed assumed that the behind-the-fence load increases would be served by corresponding increases in behind-the-fence generation. This generation is included in the "Base" generation for all scenarios. All coal generation is also included in the "Base" block.

The "Peaking Thermal" block includes all of the existing and future combined cycle gas plants as well as cogeneration plants as discussed in the consultant's report.

All simple cycle gas turbines are included in the "Super Peaking Thermal" block.

Table B-1: Generation Location by Region – Scenario 1

Generation as of 2025					
Scenario 1	Region				
Type	North East	North West	Edmonton & North Central	Central & Calgary	South
Wind	-	-	-	-	2,255
Base	3,418	482	5,335	451	902
Peaking Hydro	-	-	-	202	-
Peaking Thermal	648	116	-	969	156
Super Peaking Thermal	144	202	100	81	106
Super Peaking Hydro	-	-	-	592	-
Total	4,211	800	5,435	2,295	3,419

Table B-2: Generation Location by Region – Scenario 2

Generation as of 2025					
Scenario 2	Region				
Type	North East	North West	Edmonton & North Central	Central & Calgary	South
Wind	-	-	-	-	2,255
Base	3,938	482	4,835	451	902
Peaking Hydro	-	-	-	202	-
Peaking Thermal	928	116	-	669	156
Super Peaking Thermal	144	202	100	81	106
Super Peaking Hydro	-	-	-	592	-
Total	5,011	800	4,935	1,995	3,419

Table B-3: Generation Location by Region – Scenario 3

Generation as of 2025					
Scenario 3	Region				
Type	North East	North West	Edmonton & North Central	Central & Calgary	South
Wind	-	-	-	-	2,255
Base	4,841	382	5,835	451	1,902
Peaking Hydro	-	-	-	202	-
Peaking Thermal	973	141	-	1,194	156
Super Peaking Thermal	144	202	125	81	131
Super Peaking Hydro	-	-	-	592	-
Total	5,959	725	5,960	2,520	4,444

Table B-4: Generation Location by Region – Scenario 4

Generation as of 2025					
Scenario 4	Region				
Type	North East	North West	Edmonton & North Central	Central & Calgary	South
Wind	-	-	-	-	2,255
Base	5,816	382	5,835	451	902
Peaking Hydro	-	-	-	202	-
Peaking Thermal	1,498	141	-	694	156
Super Peaking Thermal	144	202	125	81	131
Super Peaking Hydro	-	-	-	592	-
Total	7,459	725	5,960	2,020	3,444

Table B-5: Generation Location by Region – Scenario 5

Generation as of 2025					
Scenario 5	Region				
Type	North East	North West	Edmonton & North Central	Central & Calgary	South
Wind	-	-	-	-	2,255
Base	6,134	482	6,335	1,451	1,902
Peaking Hydro	-	-	-	202	-
Peaking Thermal	1,228	216	-	1,569	156
Super Peaking Thermal	144	202	200	81	206
Super Peaking Hydro	-	-	-	592	-
Total	7,507	900	6,535	3,895	4,519

Table B-6: Generation Location by Region – Scenario 6

Generation as of 2025					
Scenario 6	Region				
Type	North East	North West	Edmonton & North Central	Central & Calgary	South
Wind	-	-	-	-	2,255
Base	7,629	482	6,835	451	902
Peaking Hydro	-	-	-	202	-
Peaking Thermal	2,033	216	-	769	156
Super Peaking Thermal	144	202	200	81	206
Super Peaking Hydro	-	-	-	592	-
Total	9,807	900	7,035	2,095	3,519

B.2 Bubble Diagrams

'Bubble' diagrams are a common method used in the power industry for depicting in a simplified yet understandable way how energy is expected to flow between regions for an assumed system loading and generation dispatch condition. In order to assess the transmission requirements contemplated in this 20-Year Outlook Document the transmission grid and associated transmission paths within Alberta are divided into five major regions, each represented by a bubble. Major transmission paths between regions are defined by using "cut-planes" which are hypothetical lines "cutting" through all of the transmission circuits at a given location. This permits the system to be evaluated based on the total capability of multiple transmission circuits interconnecting regions of the system and under the loading conditions which most stress these circuits. The cut-planes and associated transmission paths used for creating the five major regions of the bubble diagrams are shown in Figure B-0 below.

The estimated range of operational transfer capability for the existing system are shown in Figure B-0 below for the major transmission paths. The approved major system additions shown in the diagram were taken into account when estimating the path capabilities. Path capabilities will vary depending on the time of year, dispatch conditions and system loading conditions. For this reason some of the ranges are quite wide. But the capacities do provide some sense of the shortfall expected by 2024 on the major paths within Alberta.

Bubble diagrams have been created for each of the six load and generation scenarios. Because the time of day and system conditions for which different sections of the transmission system are most stressed do not necessarily coincide, different system conditions must be checked when assessing the path capabilities required. For each scenario, three different system operating conditions have been modeled to heavily stress the different transmission paths for a total of eighteen bubble diagrams.

The three loading conditions assessed are:

- (a) Winter Peak Load, No Wind, No Import/Export
- (b) Summer Daytime Load, No Wind, Exports
- (c) Spring Load, Maximum Wind, Imports

The winter peak loading condition represents the winter peak hour with no production from the wind generation due to calm wind conditions and no imports into Alberta. A forced outage of a large generator in the south is assumed in order to increase northern dispatched generation and, as a result, further stress the paths which move energy from northern Alberta to the south. Because the generation

scenarios have assumed a significant portion of the "Peaking" plants will be constructed as cogeneration, the north to south flows are expected to be very heavy during the peak loading periods in the summer and the winter. This is different than the peak loading conditions of today for which the majority of the "Peaking" generation is supplied from southern generation and imports. The "Central and Calgary" and "South" regions contain more load than generation in all of the scenarios and therefore require additional supplies from the north.

The summer daytime export condition represents moderate early summer daytime loading in Alberta combined with an export of energy out of Alberta. No wind has been assumed and southern base load generation has been reduced for planned maintenance to increase the stress on all the paths from the north through to B.C.

To stress the south to north paths, a spring load condition has been used in combination with full wind production, imports from B.C. and all base load plants in the south available.

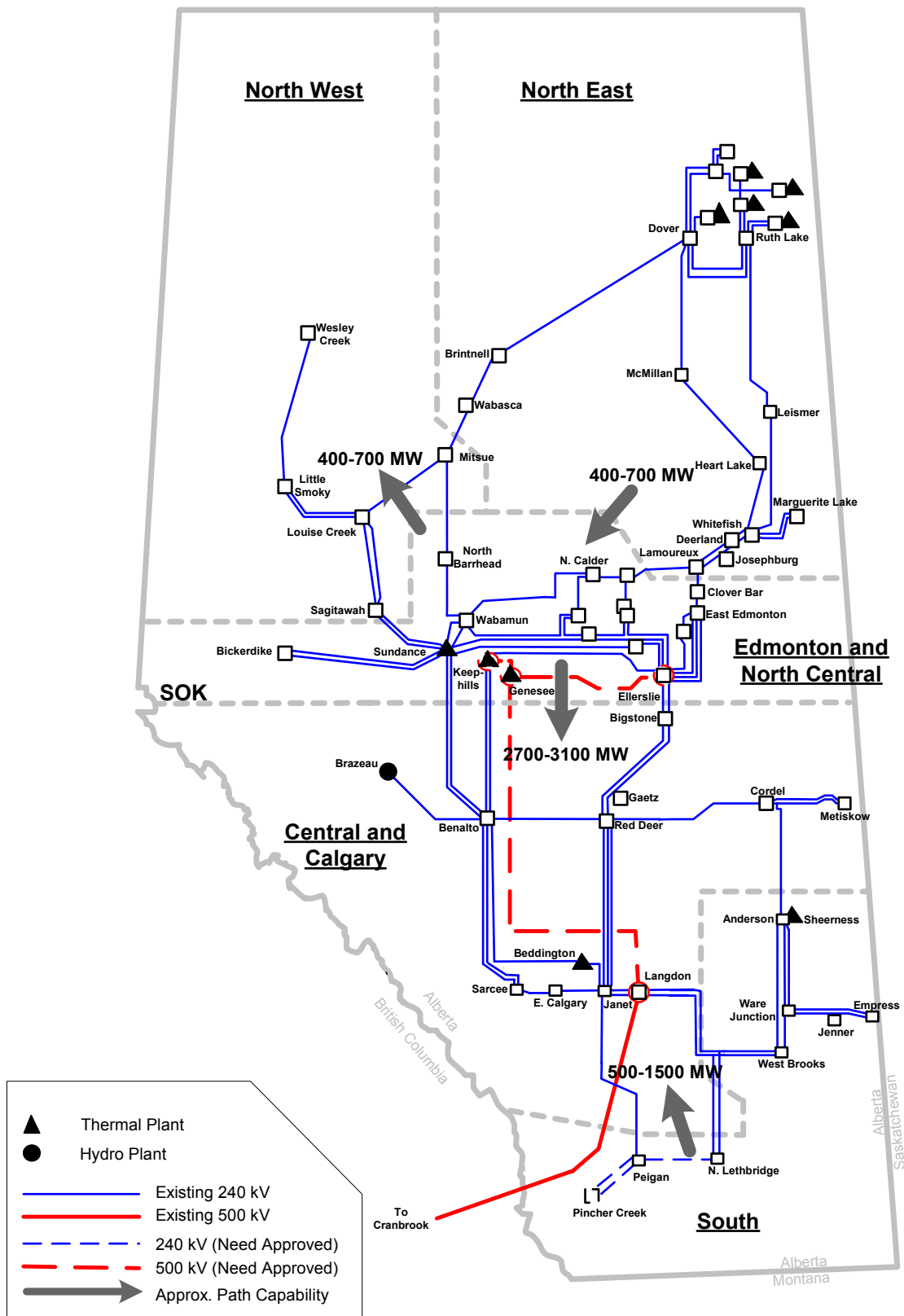
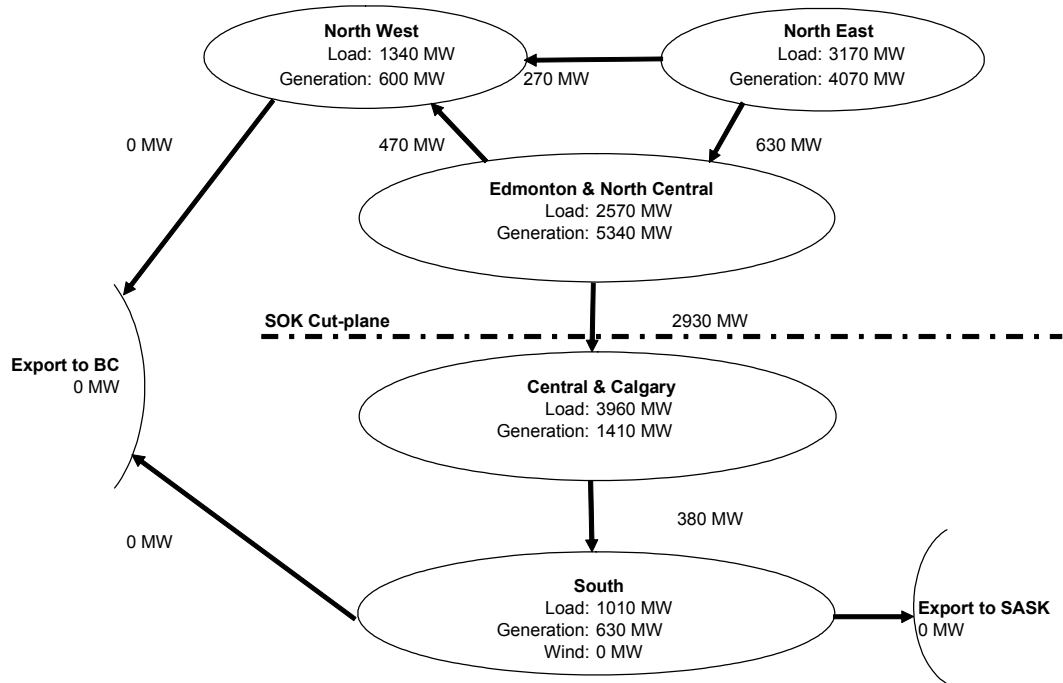


Figure B-0: System Map – Regional Areas



AIL Generation

North of SOK	2025 Available Capacity	Dispatch
Base	9,235	100%
Peaking Thermal	765	100%
Super Peaking Hydro	-	0%
Super Peaking Thermal	446	0%

South of SOK	2025 Available Capacity	Dispatch
Wind	2,255	0%
Base	1,353	53%
Peaking Hydro	202	100%
Peaking Thermal	1,125	100%
Super Peaking Hydro	592	0%
Super Peaking Thermal	187	0%
Total	16,160	

AIL Load	2025 Available Capacity	Dispatch
AIES	9,069	100%
On-Site	2,855	90%
Losses	408	4.5%
Total	12,332	

Scenario 1 - Bubble Diagram A

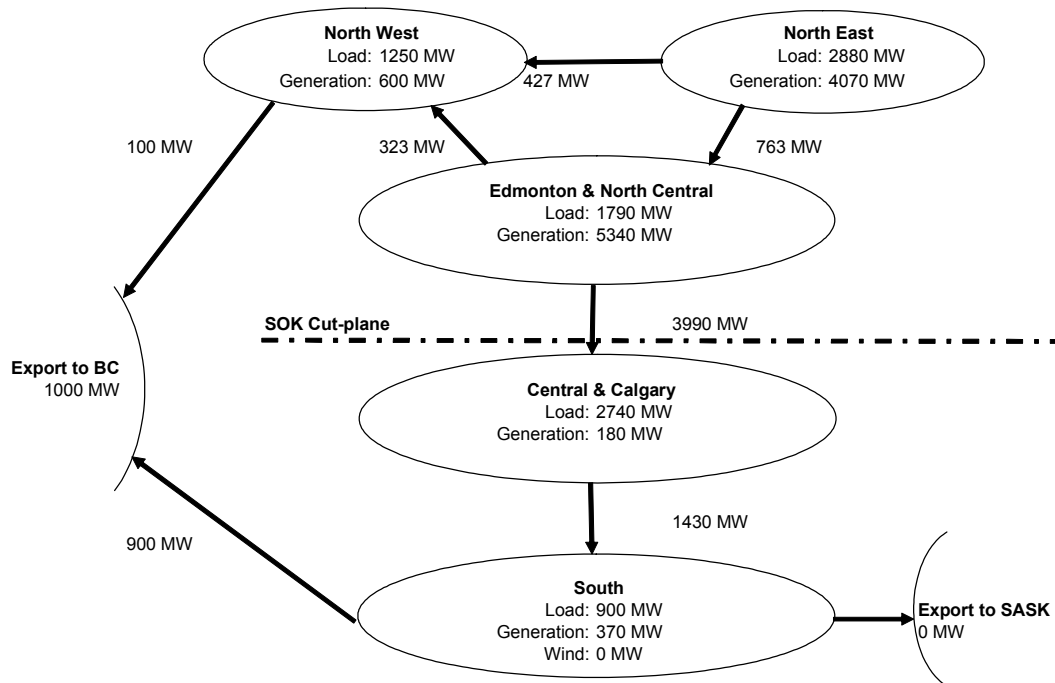
Generation Scenario: Coal and Southern

Load Forecast: Low

System Condition: Winter Peak 2024/2025, No Wind, No Import/Export

Figure B1-A: Bubble Diagram - Scenario 1 Winter Peak

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AIL Generation

	2025 Available Capacity	Dispatch
North of SOK		
Base	9,235	100%
Peaking Thermal	765	100%
Super Peaking Hydro	-	0%
Super Peaking Thermal	446	0%

South of SOK		
Wind	2,255	0%
Base	1,353	41%
Peaking Hydro	202	0%
Peaking Thermal	1,125	0%
Super Peaking Hydro	592	0%
Super Peaking Thermal	187	0%
Total	16,160	

AIL Load		
AIES	6,819	75%
On-Site	2,855	85%
Losses	307	4.5%
Total	9,980	

Scenario 1 - Bubble Diagram B

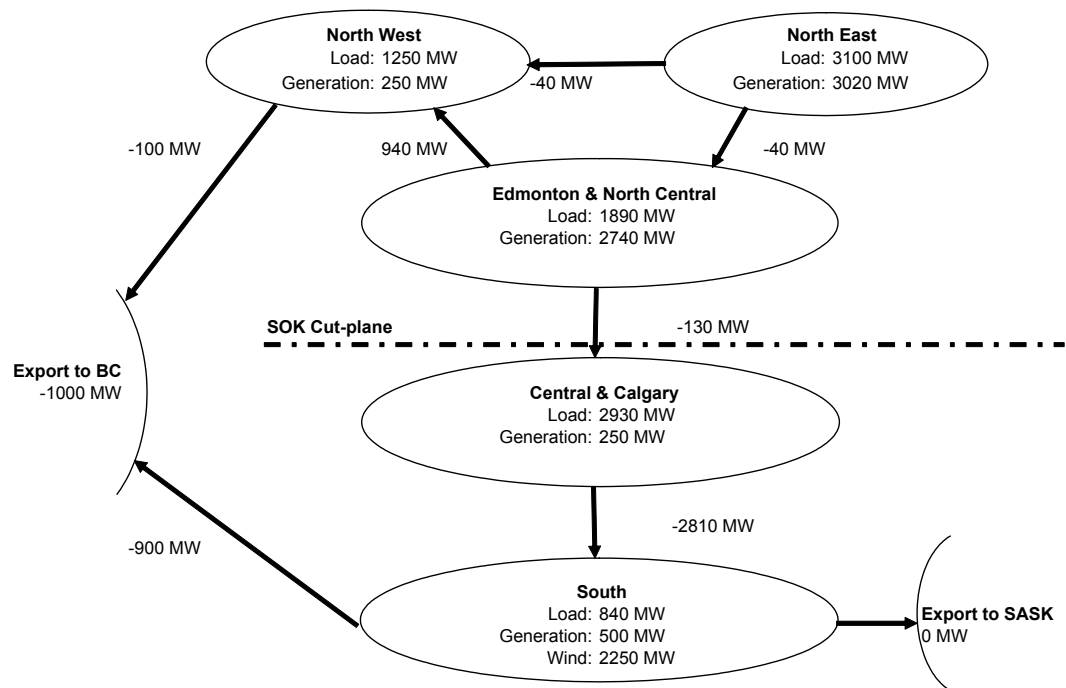
Generation Scenario: Coal and Southern

Load Forecast: Low

System Condition: Summer 2024 Daytime Export, No Wind

Figure B1-B: Bubble Diagram - Scenario 1 Summer Export

20-Year Outlook Document (2005 – 2024)



AIL Generation

	2025 Available Capacity	Dispatch
North of SOK		
Base	9,235	51%
Peaking Thermal	765	0%
Super Peaking Hydro	-	0%
Super Peaking Thermal	446	0%
South of SOK		
Wind	2,255	100%
Base	1,353	55%
Peaking Hydro	202	0%
Peaking Thermal	1,125	0%
Super Peaking Hydro	592	0%
Super Peaking Thermal	187	0%
Total	16,160	

AIL Load

AIES	7,118	78%
On-Site	2,855	90%
Losses	320	4.5%
Total	10,292	

Scenario 1 - Bubble Diagram C

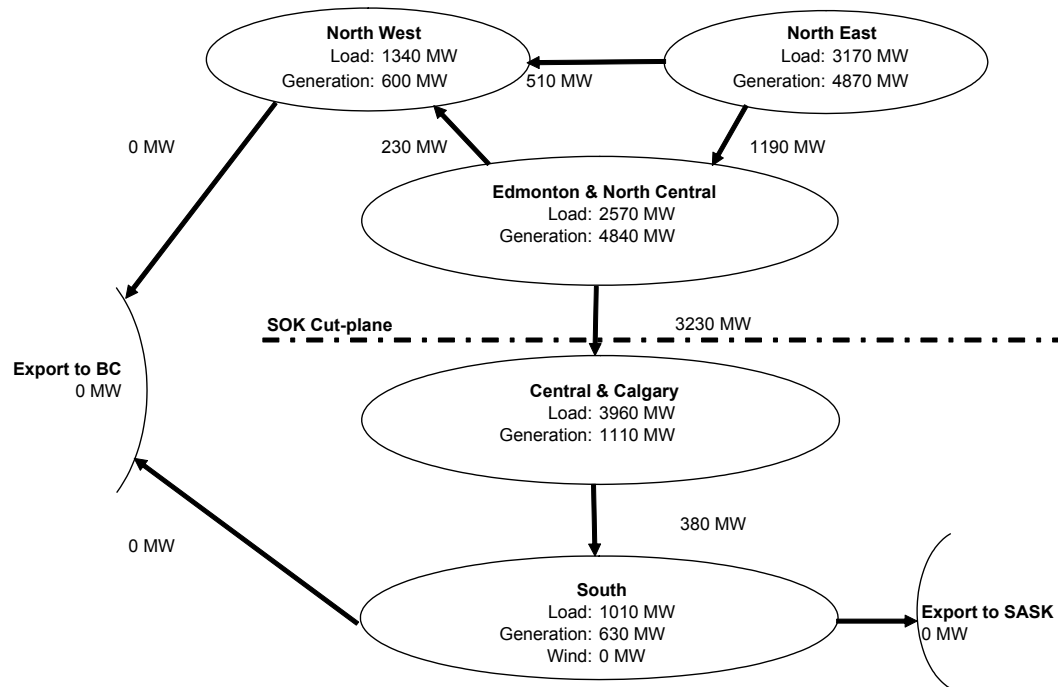
Generation Scenario: Coal and Southern

Load Forecast: Low

System Condition: Spring 2024 Maximum Wind & Hydro Import

Figure B1-C: Bubble Diagram - Scenario 1 Spring Import

B.1 Scenario 2



AIL Generation

	2025 Available Capacity	Dispatch
North of SOK		
Base	9,255	100%
Peaking Thermal	1,045	100%
Super Peaking Hydro	-	0%
Super Peaking Thermal	446	0%
South of SOK		
Wind	2,255	0%
Base	1,353	53%
Peaking Hydro	202	100%
Peaking Thermal	825	100%
Super Peaking Hydro	592	0%
Super Peaking Thermal	187	0%
Total	16,160	

AIL Load

AIES	9,069	100%
On-Site	2,855	90%
Losses	408	4.5%
Total	12,332	

Scenario 2 - Bubble Diagram A

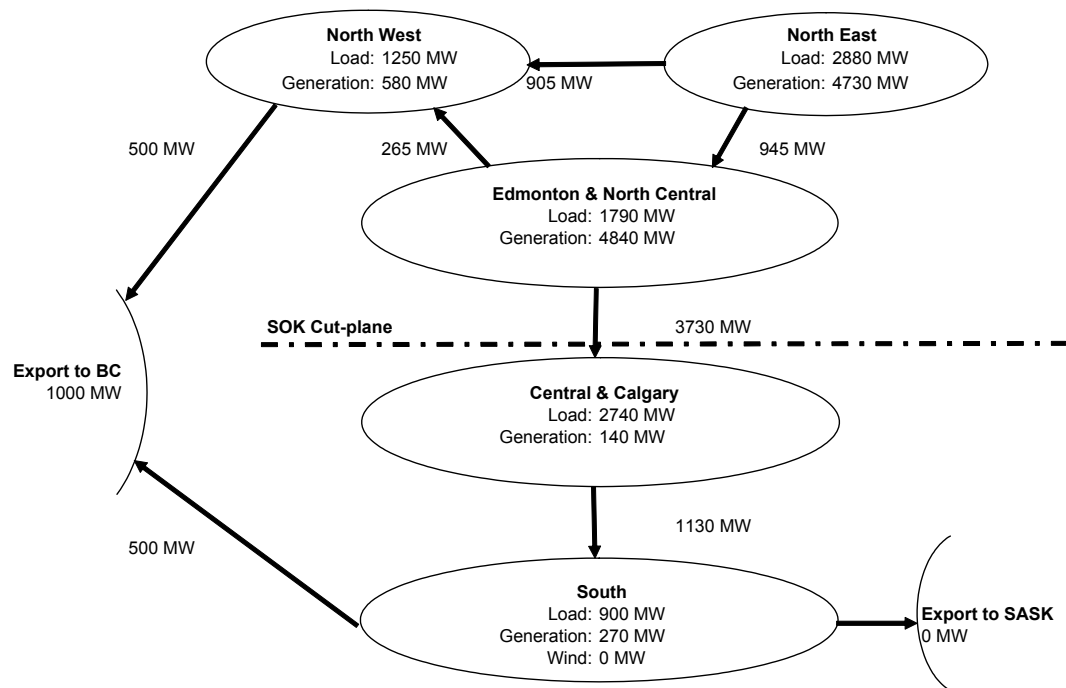
Generation Scenario: Cogen and Northern

Load Forecast: Low

System Condition: Winter Peak 2024/2025, No Wind, No Import/Export

Figure B2-A: Bubble Diagram - Scenario 2 Winter Peak

20-Year Outlook Document (2005 – 2024)



AIL Generation

	2025 Available Capacity	Dispatch
North of SOK		
Base	9,255	100%
Peaking Thermal	1,045	85%
Super Peaking Hydro	-	0%
Super Peaking Thermal	446	0%
South of SOK		
Wind	2,255	0%
Base	1,353	30%
Peaking Hydro	202	0%
Peaking Thermal	825	0%
Super Peaking Hydro	592	0%
Super Peaking Thermal	187	0%
Total	16,160	

AIL Load

AIES	6,819	75%
On-Site	2,855	85%
Losses	307	4.5%
Total	9,980	

Scenario 2 - Bubble Diagram B

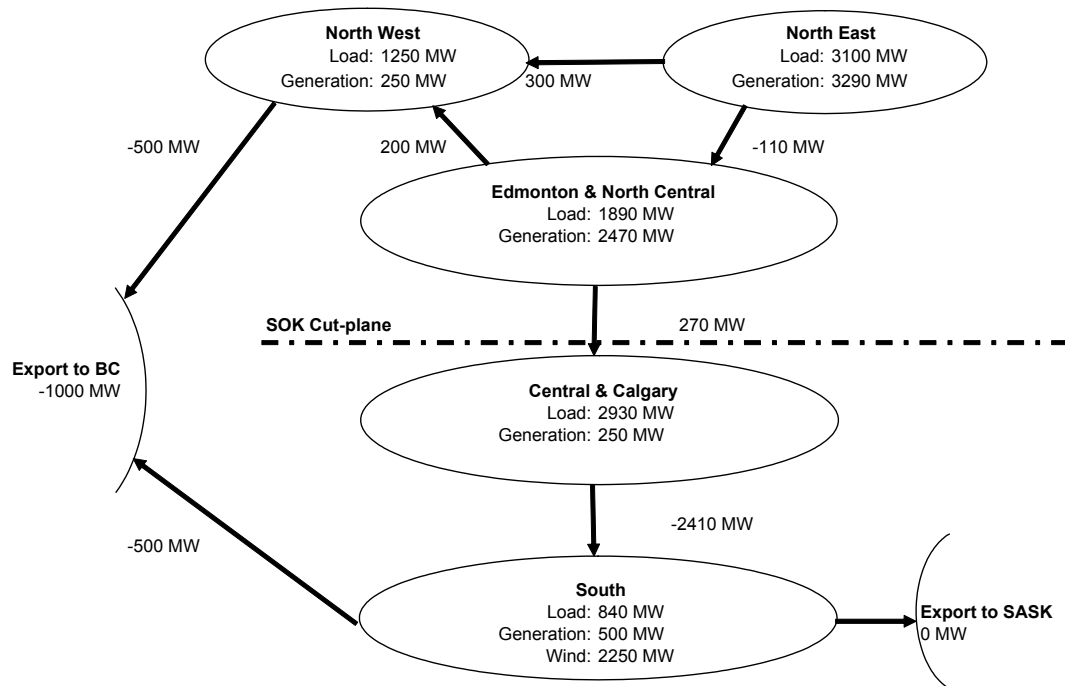
Generation Scenario: Cogen and Northern

Load Forecast: Low

System Condition: Summer 2024 Daytime Export, No Wind

Figure B2-B: Bubble Diagram - Scenario 2 Summer Export

20-Year Outlook Document (2005 – 2024)



AIL Generation

	2025 Available Capacity	Dispatch
North of SOK		
Base	9,255	51%
Peaking Thermal	1,045	0%
Super Peaking Hydro	-	0%
Super Peaking Thermal	446	0%
South of SOK		
Wind	2,255	100%
Base	1,353	55%
Peaking Hydro	202	0%
Peaking Thermal	825	0%
Super Peaking Hydro	592	0%
Super Peaking Thermal	187	0%
Total	16,160	

AIL Load

AIES	7,118	78%
On-Site	2,855	90%
Losses	320	4.5%
Total	10,292	

Scenario 2 - Bubble Diagram C

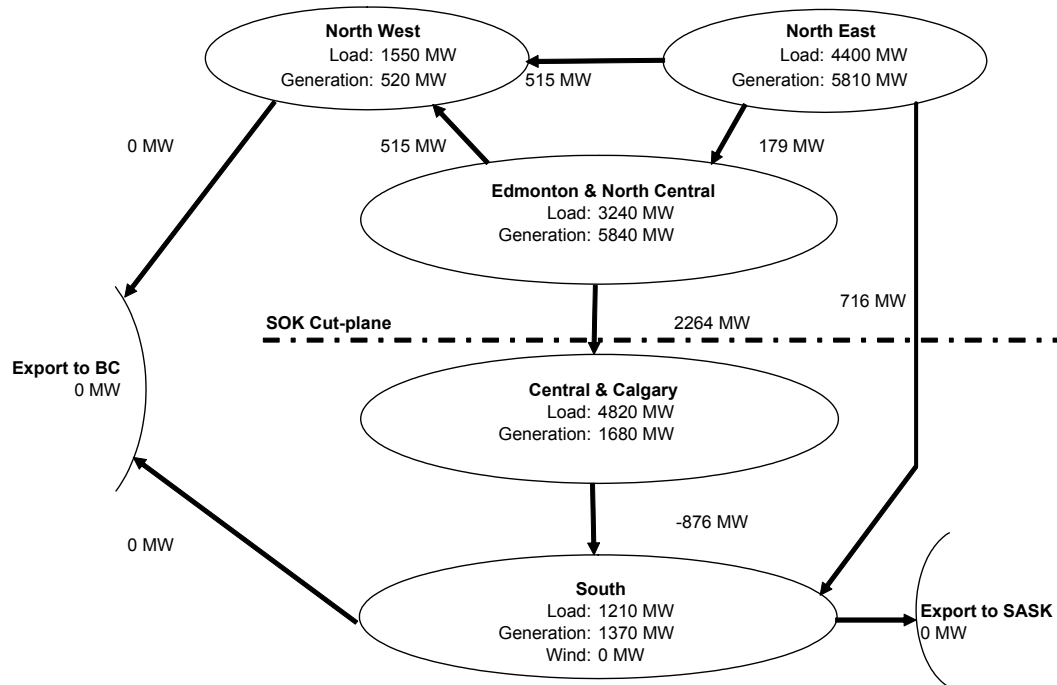
Generation Scenario: Cogen and Northern

Load Forecast: Low

System Condition: Spring 2024 Maximum Wind & Hydro Import

Figure B2-C: Bubble Diagram - Scenario 2 Spring Import

B.2 Scenario 3



AIL Generation

	2025 Available Capacity	Dispatch
North of SOK		
Base	11,058	100%
Peaking Thermal	1,114	100%
Super Peaking Hydro	-	0%
Super Peaking Thermal	471	0%

South of SOK		
Wind	2,255	0%
Base	2,353	64%
Peaking Hydro	202	100%
Peaking Thermal	1,350	100%
Super Peaking Hydro	592	0%
Super Peaking Thermal	212	0%
Total	19,608	

AIL Load		
AIES	11,117	100%
On-Site	4,003	90%
Losses	500	4.5%
Total	15,620	

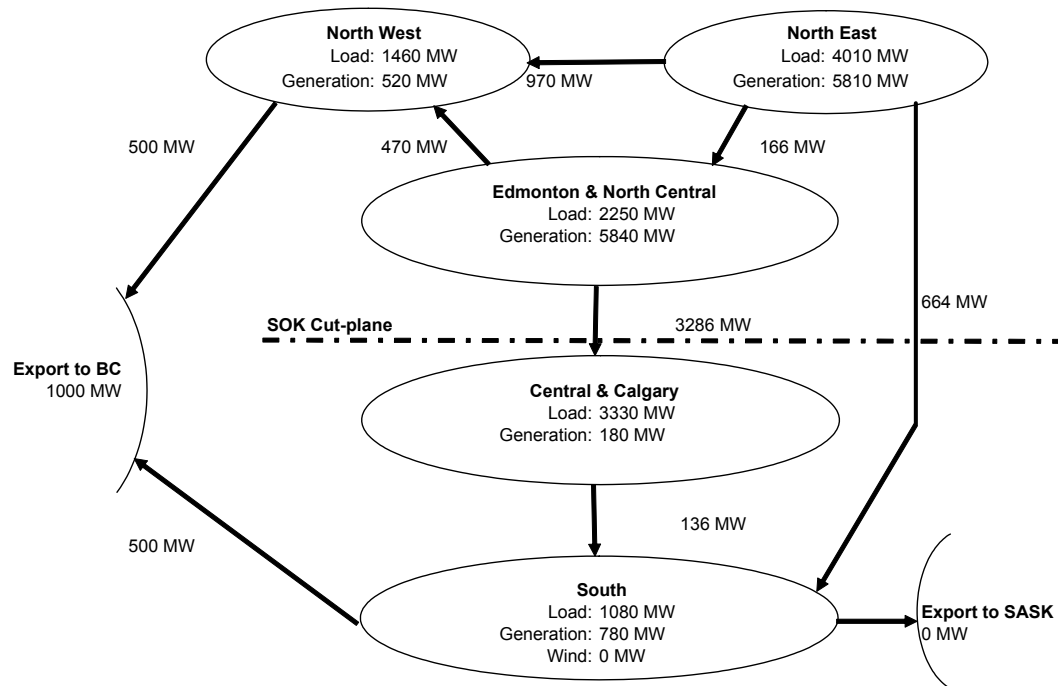
Scenario 3 - Bubble Diagram A

Generation Scenario: Coal and Southern

Load Forecast: Most Likely

System Condition: Winter 2024/2025 Peak, No Wind, No Import/Export

Figure B3-A: Bubble Diagram - Scenario 3 Winter Peak



AIL Generation

	2025 Available Capacity	Dispatch
North of SOK		
Base	11,058	100%
Peaking Thermal	1,114	100%
Super Peaking Hydro	-	0%
Super Peaking Thermal	471	0%
South of SOK		
Wind	2,255	0%
Base	2,353	41%
Peaking Hydro	202	0%
Peaking Thermal	1,350	0%
Super Peaking Hydro	592	0%
Super Peaking Thermal	212	0%
Total	19,608	

AIL Load

AIES	8,343	75%
On-Site	4,003	85%
Losses	375	4.5%
Total	12,720	

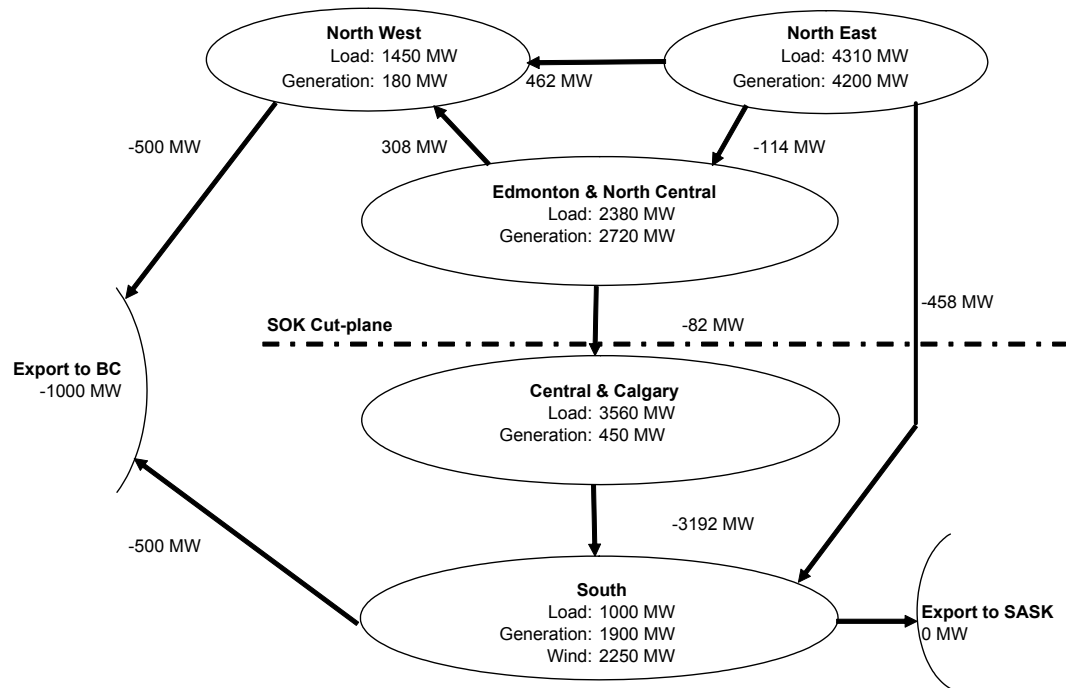
Scenario 3 - Bubble Diagram B

Generation Scenario: Coal and Southern

Load Forecast: Most Likely

System Condition: Summer 2024 Daytime Export, No Wind

Figure B3-B: Bubble Diagram - Scenario 3 Summer Export



AIL Generation

	2025 Available Capacity	Dispatch
North of SOK		
Base	11,058	47%
Peaking Thermal	1,114	0%
Super Peaking Hydro	-	0%
Super Peaking Thermal	471	0%
South of SOK		
Wind	2,255	100%
Base	2,353	100%
Peaking Hydro	202	0%
Peaking Thermal	1,350	0%
Super Peaking Hydro	592	0%
Super Peaking Thermal	212	0%
Total	19,608	

AIL Load

AIES	8,714	78%
On-Site	4,003	90%
Losses	392	4.5%
Total	13,108	

Scenario 3 - Bubble Diagram C

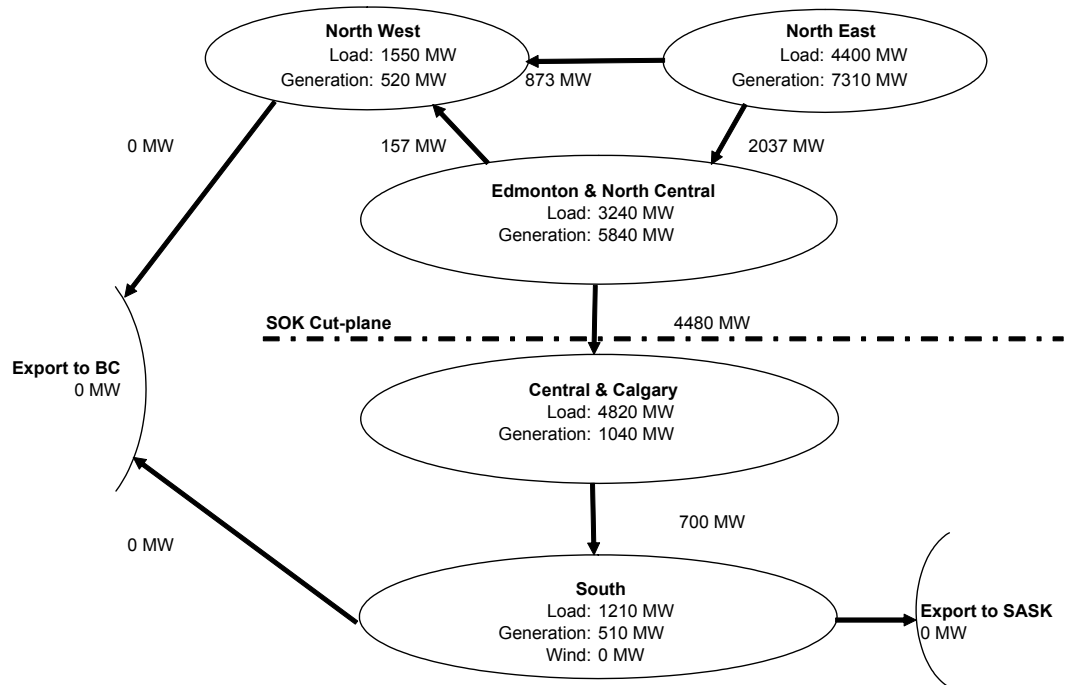
Generation Scenario: Coal and Southern

Load Forecast: Most Likely

System Condition: Spring 2024 Maximum Wind & Hydro Import

Figure B3-C: Bubble Diagram - Scenario 3 Spring Import

B.3 Scenario 4



AIL Generation

	2025 Available Capacity	Dispatch
North of SOK		
Base	12,033	100%
Peaking Thermal	1,639	100%
Super Peaking Hydro	-	0%
Super Peaking Thermal	471	0%

South of SOK		
Wind	2,255	0%
Base	1,353	41%
Peaking Hydro	202	100%
Peaking Thermal	850	94%
Super Peaking Hydro	592	0%
Super Peaking Thermal	212	0%
Total	19,608	

AIL Load		
AIES	11,117	100%
On-Site	4,003	90%
Losses	500	4.5%
Total	15,620	

Scenario 4 - Bubble Diagram A

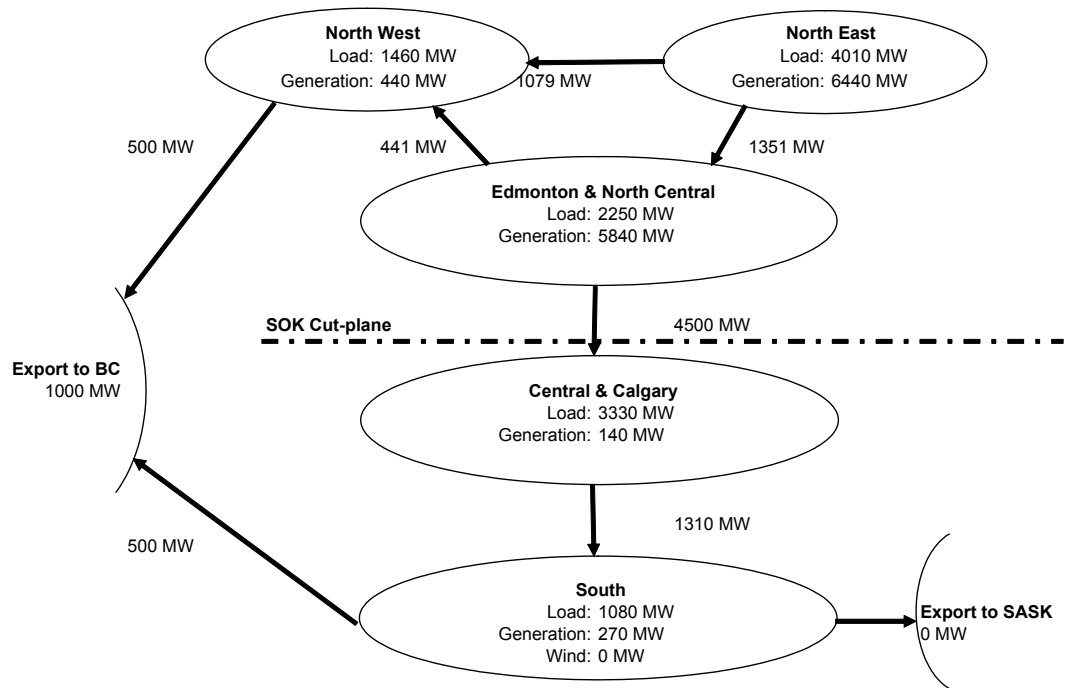
Generation Scenario: Cogen and Northern

Load Forecast: Most Likely

System Condition: Winter Peak 2024/2025, No Wind, No Import/Export

Figure B4-A: Bubble Diagram - Scenario 4 Winter Peak

20-Year Outlook Document (2005 – 2024)



AIL Generation

	2025 Available Capacity	Dispatch
North of SOK		
Base	12,033	100%
Peaking Thermal	1,639	42%
Super Peaking Hydro	-	0%
Super Peaking Thermal	471	0%
South of SOK		
Wind	2,255	0%
Base	1,353	30%
Peaking Hydro	202	0%
Peaking Thermal	850	0%
Super Peaking Hydro	592	0%
Super Peaking Thermal	212	0%
Total	19,608	

AIL Load

AIES	8,343	75%
On-Site	4,003	85%
Losses	375	4.5%
Total	12,720	

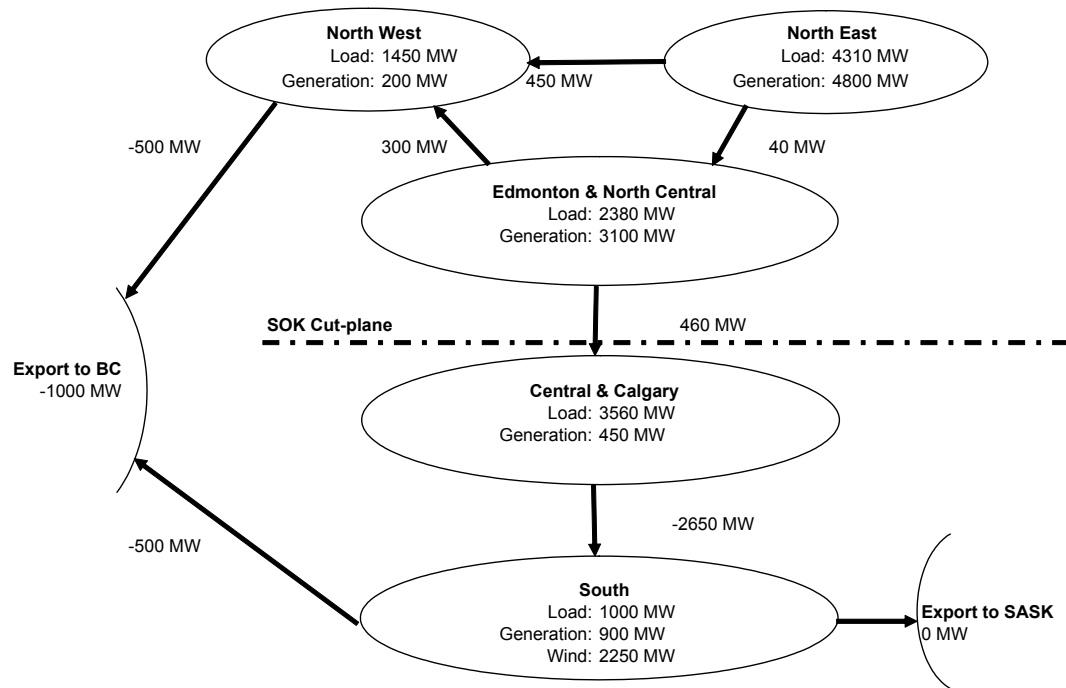
Scenario 4 - Bubble Diagram B

Generation Scenario: Cogen and Northern

Load Forecast: Most Likely

System Condition: Summer 2024 Daytime Export, No Wind

Figure B4-B: Bubble Diagram - Scenario 4 Summer Export



AIL Generation

	2025 Available Capacity	Dispatch
North of SOK		
Base	12,033	53%
Peaking Thermal	1,639	0%
Super Peaking Hydro	-	0%
Super Peaking Thermal	471	0%
South of SOK		
Wind	2,255	100%
Base	1,353	100%
Peaking Hydro	202	0%
Peaking Thermal	850	0%
Super Peaking Hydro	592	0%
Super Peaking Thermal	212	0%
Total	19,608	

AIL Load

AIES	8,714	78%
On-Site	4,003	90%
Losses	392	4.5%
Total	13,108	

Scenario 4 - Bubble Diagram C

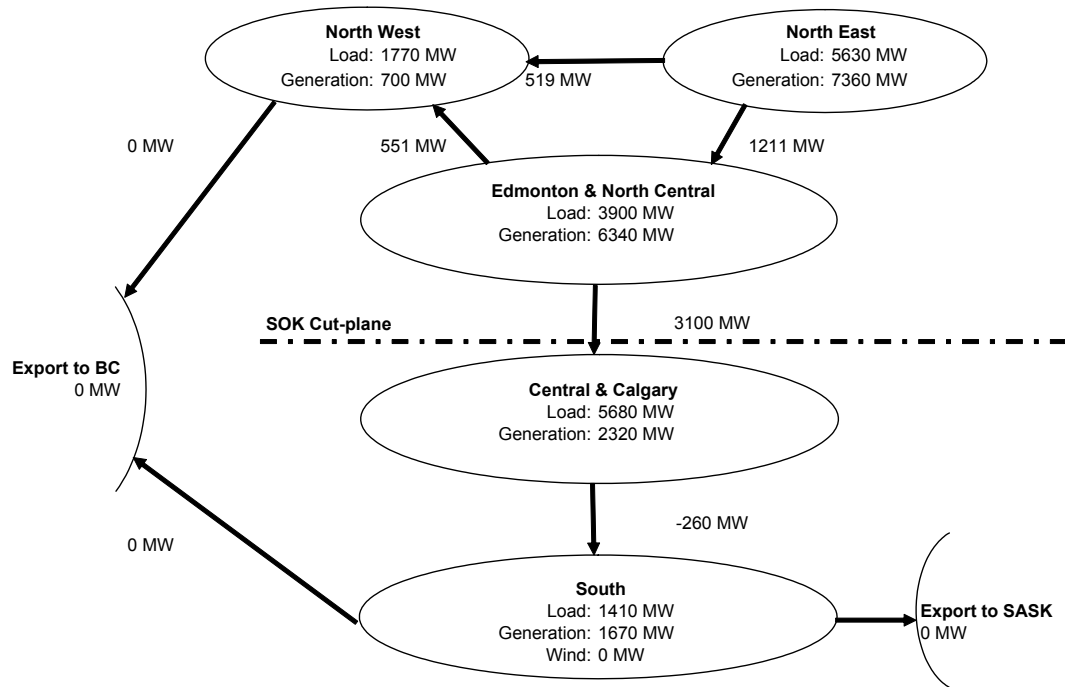
Generation Scenario: Cogen and Northern

Load Forecast: Most Likely

System Condition: Spring 2024 Maximum Wind & Hydro Import

Figure B4-C: Bubble Diagram - Scenario 4 Spring Import

B.4 Scenario 5



AIL Generation

North of SOK	2025 Available Capacity	Dispatch
Base	12,951	100%
Peaking Thermal	1,444	100%
Super Peaking Hydro	-	0%
Super Peaking Thermal	546	0%

South of SOK	2025 Available Capacity	Dispatch
Wind	2,255	0%
Base	3,353	83%
Peaking Hydro	202	100%
Peaking Thermal	1,725	58%
Super Peaking Hydro	592	0%
Super Peaking Thermal	287	0%
Total	23,356	

AIL Load	2025 Available Capacity	Dispatch
AIES	13,165	100%
On-Site	5,151	90%
Losses	592	4.5%
Total	18,908	

Scenario 5 - Bubble Diagram A

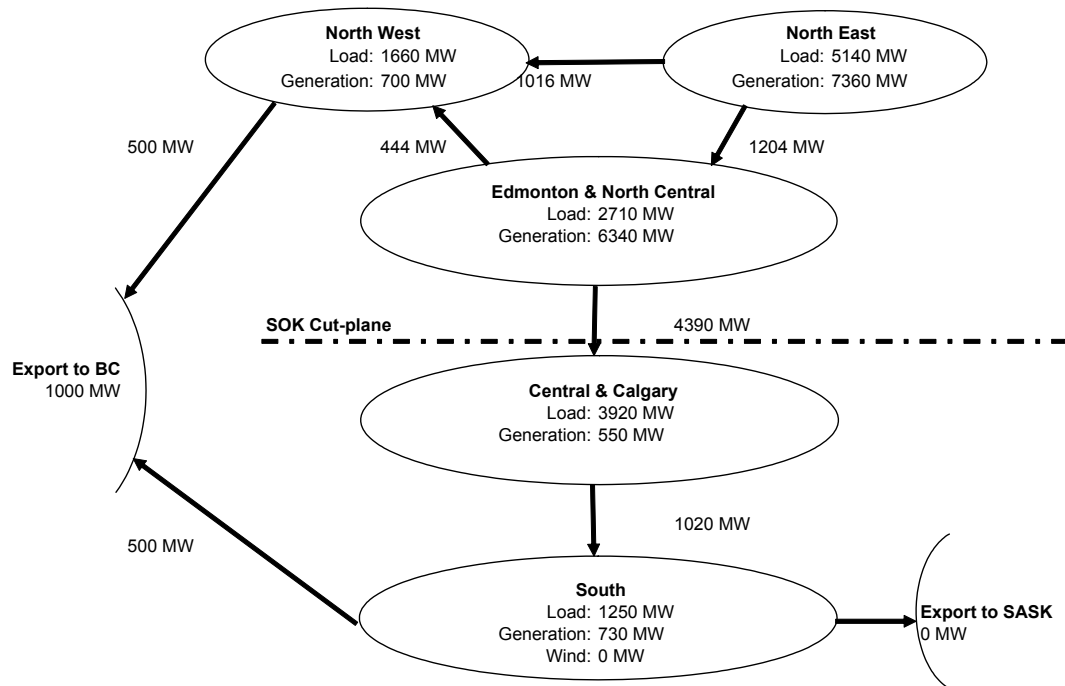
Generation Scenario: Coal and Southern

Load Forecast: High

System Condition: Winter 2024/2025 Peak, No Wind, No Import/Export

Figure B5-A: Bubble Diagram - Scenario 5 Winter Peak

20-Year Outlook Document (2005 – 2024)



AIL Generation

	2025 Available Capacity	Dispatch
North of SOK		
Base	12,951	100%
Peaking Thermal	1,444	100%
Super Peaking Hydro	-	0%
Super Peaking Thermal	546	0%
South of SOK		
Wind	2,255	0%
Base	3,353	38%
Peaking Hydro	202	0%
Peaking Thermal	1,725	0%
Super Peaking Hydro	592	0%
Super Peaking Thermal	287	0%
Total	23,356	

AIL Load

AIES	9,866	75%
On-Site	5,151	85%
Losses	444	4.5%
Total	15,461	

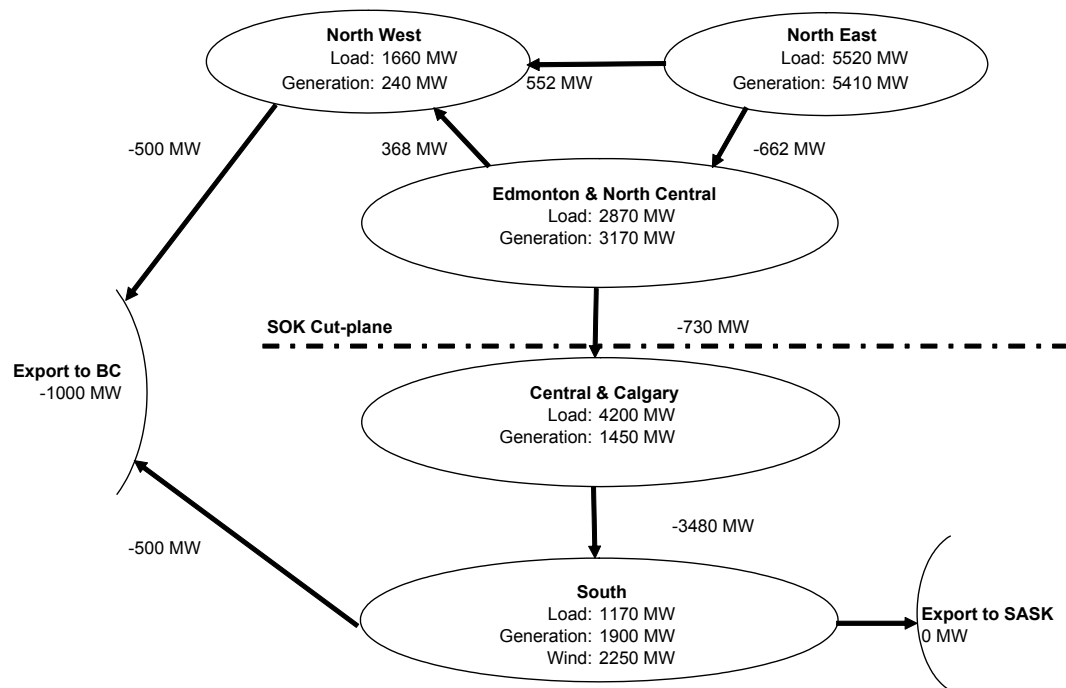
Scenario 5 - Bubble Diagram B

Generation Scenario: Coal and Southern

Load Forecast: High

System Condition: Summer 2024 Daytime Export, No Wind

Figure B5-B: Bubble Diagram - Scenario 5 Summer Export



AIL Generation

	2025 Available Capacity	Dispatch
North of SOK		
Base	12,951	50%
Peaking Thermal	1,444	0%
Super Peaking Hydro	-	0%
Super Peaking Thermal	546	0%
South of SOK		
Wind	2,255	100%
Base	3,353	100%
Peaking Hydro	202	0%
Peaking Thermal	1,725	0%
Super Peaking Hydro	592	0%
Super Peaking Thermal	287	0%
Total	23,356	

AIL Load

AIES	10,313	78%
On-Site	5,151	90%
Losses	464	4.5%
Total	15,927	

Scenario 5 - Bubble Diagram C

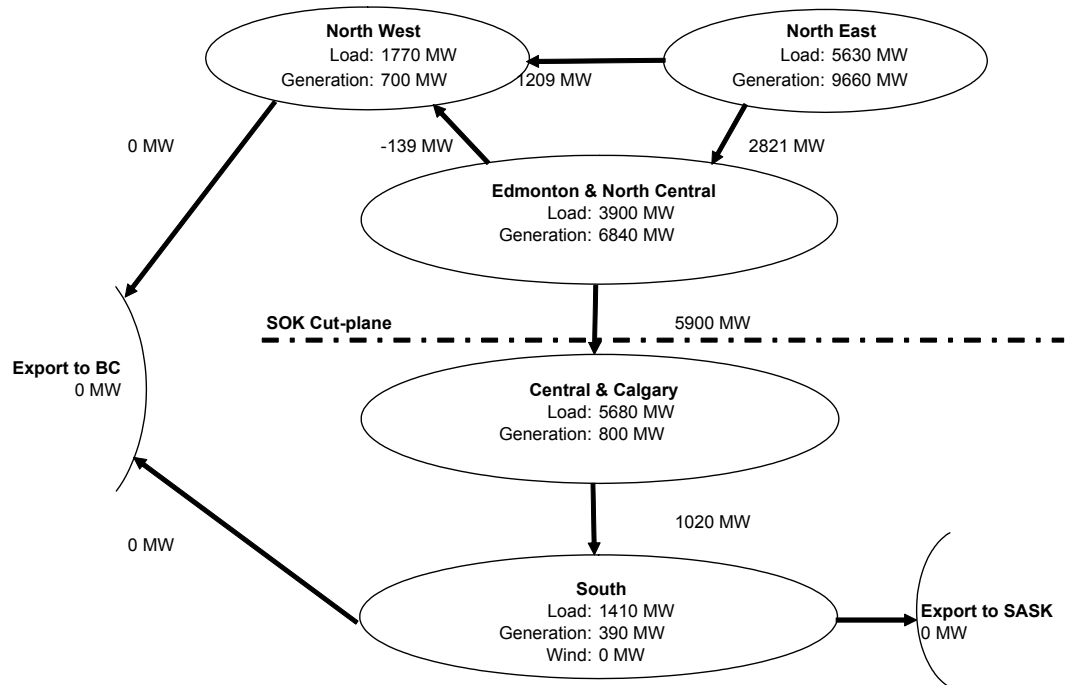
Generation Scenario: Coal and Southern

Load Forecast: High

System Condition: Spring 2024 Maximum Wind & Hydro Import

Figure B5-C: Bubble Diagram - Scenario 5 Spring Import

B.5 Scenario 6



AIL Generation

North of SOK	2025 Available Capacity	Dispatch
Base	14,946	100%
Peaking Thermal	2,249	100%
Super Peaking Hydro	-	0%
Super Peaking Thermal	546	0%

South of SOK	2025 Available Capacity	Dispatch
Wind	2,255	0%
Base	1,353	34%
Peaking Hydro	202	100%
Peaking Thermal	925	58%
Super Peaking Hydro	592	0%
Super Peaking Thermal	287	0%
Total	23,356	

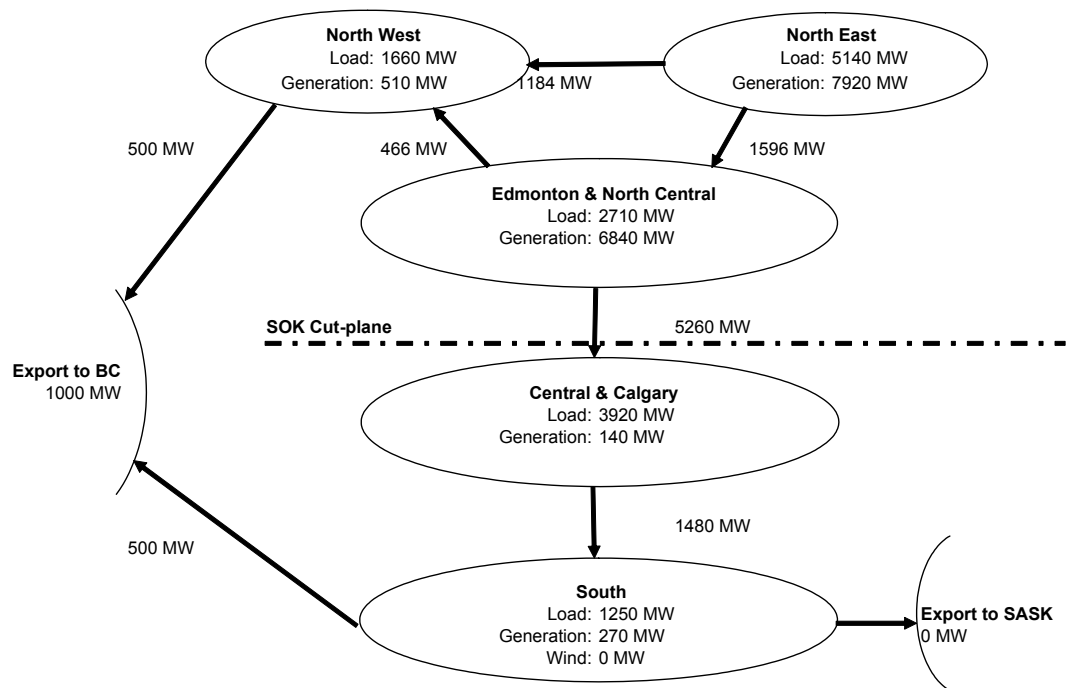
AIL Load	2025 Available Capacity	Dispatch
AIES	13,165	100%
On-Site	5,151	90%
Losses	592	4.5%
Total	18,908	

Scenario 6 - Bubble Diagram A

Generation Scenario: Cogen and Northern
Load Forecast: High
System Condition: Winter 2024/2025 Peak, No Wind, No Import/Export

Figure B6-A: Bubble Diagram - Scenario 6 Winter Peak

20-Year Outlook Document (2005 – 2024)



AIL Generation

	2025 Available Capacity	Dispatch
North of SOK		
Base	14,946	100%
Peaking Thermal	2,249	14%
Super Peaking Hydro	-	0%
Super Peaking Thermal	546	0%
South of SOK		
Wind	2,255	0%
Base	1,353	30%
Peaking Hydro	202	0%
Peaking Thermal	925	0%
Super Peaking Hydro	592	0%
Super Peaking Thermal	287	0%
Total	23,356	

AIL Load

AIES	9,866	75%
On-Site	5,151	85%
Losses	444	4.5%
Total	15,461	

Scenario 6 - Bubble Diagram B

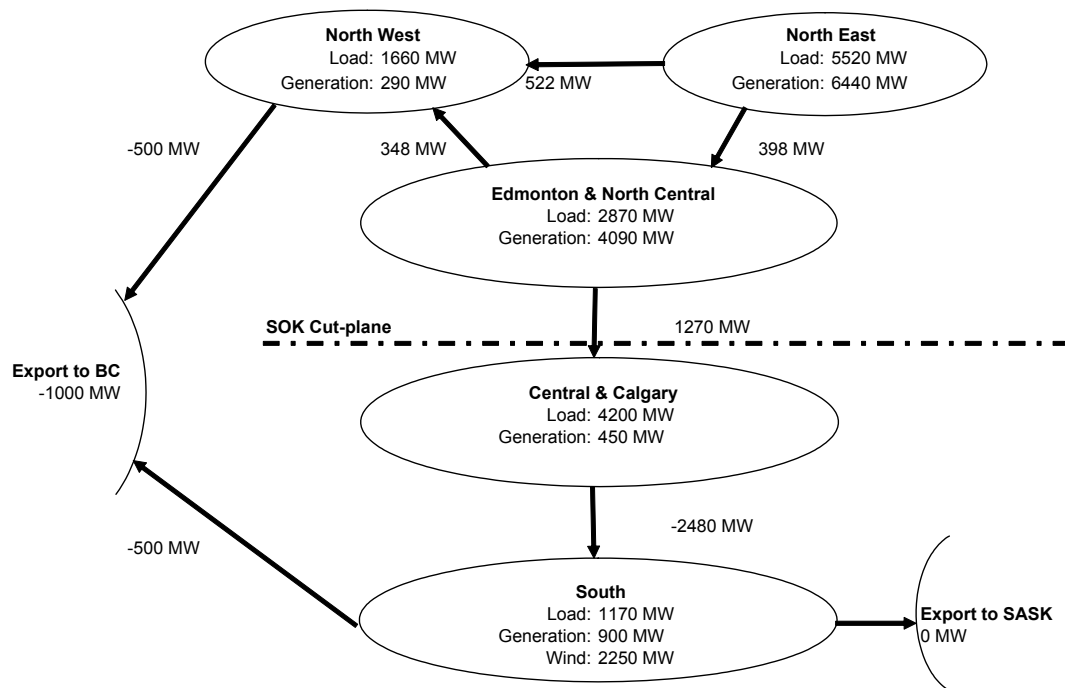
Generation Scenario: Cogen and Northern

Load Forecast: High

System Condition: Summer 2024 Daytime Export, No Wind

Figure B6-B: Bubble Diagram - Scenario 6 Summer Export

20-Year Outlook Document (2005 – 2024)



AIL Generation

	2025 Available Capacity	Dispatch
North of SOK		
Base	14,946	60%
Peaking Thermal	2,249	0%
Super Peaking Hydro	-	0%
Super Peaking Thermal	546	0%
South of SOK		
Wind	2,255	100%
Base	1,353	100%
Peaking Hydro	202	0%
Peaking Thermal	925	0%
Super Peaking Hydro	592	0%
Super Peaking Thermal	287	0%
Total	23,356	

AIL Load

AIES	10,313	78%
On-Site	5,151	90%
Losses	464	4.5%
Total	15,927	

Scenario 6 - Bubble Diagram C

Generation Scenario: Cogen and Northern

Load Forecast: High

System Condition: Spring 2024 Maximum Wind & Hydro Import

Figure B6-C: Bubble Diagram - Scenario 6 Spring Import

Appendix C - Transmission Regulation and Reliability Criteria

APPENDIX C - Transmission Regulation and Reliability Criteria

Transmission is a long-term investment that plays a vital role in ensuring Alberta's competitive market continues to provide reliable and competitively priced electricity to consumers now and in the future. Through transmission interconnections to neighbouring jurisdictions, transmission also provides access to the rest of the North American electricity grid enhancing both reliability and commercial opportunities.

Long-term planning for transmission infrastructure in a competitive market poses several challenges:

- 1) Generation is no longer centrally planned, which makes the location and timing of generation uncertain.
- 2) Transmission investments tend to be "lumpy"; i.e. they tend to come in large increments.
- 3) Transmission project lead times are generally long and often unpredictable due to the regulatory process and siting challenges.
- 4) Major power plants can often be delivered in a considerably shorter time frame than the associated major transmission grid infrastructure.

These challenges were recognized in the development of the Transmission Development Policy and subsequently in the Transmission Regulation. The intent of the Transmission Regulation is to ensure the development of an unconstrained transmission system in Alberta and to assure an effective, competitive electricity market.

C1. Transmission Development Policy and Regulation

Both the Transmission Development Policy and Transmission Regulation are intended to provide specific direction for transmission planning, as well as for the development of transmission infrastructure in Alberta. This 20-Year Outlook Document recognizes the following key principles imbedded in the Policy and Regulation, although it is also recognized that some of these principles are more significant than others within the context of this 20-Year Outlook:

- 1) The AESO must make assumptions about load demand forecast and generation development taking into consideration the timing of such development and appropriate generation reserve levels.
- 2) Transmission development must meet North American Electric Reliability Council ("NERC") and Western Electricity Coordinating Council ("WECC") reliability criteria and standards.

- 3) Transmission development must be proactive and must lead load growth and generation development. Transmission should not be a barrier to generation development.
- 4) Transmission internal to Alberta should be reinforced so that under normal system operating conditions the existing interconnections can import and export power on a continuous basis according to their design capabilities.
- 5) Transmission must serve and facilitate a competitive wholesale market.
- 6) Under normal system conditions, with all existing and new transmission facilities in service and the dispatch of all anticipated in-merit generation, the system shall be capable of operating so as to withstand the next single contingency without transmission congestion.
- 7) Transmission system adequacy should be measured on an annual, system-wide basis so that under abnormal system conditions (some transmission facility out of service and the system operated to withstand the next critical single contingency) 95 per cent of in-merit transactions can take place.
- 8) Using Remedial Action Schemes (“RAS”) and Transmission Must Run (“TMR”) generation to meet system reliability requirements are short-term solutions. The Regulation allows the AESO flexibility and discretion with respect to the use of TMR and the duration of such use.
- 9) The strategy imbedded in the Transmission Regulation is for transmission system development to be proactive and prudent and to occur in advance of projected needs. This facilitates unconstrained load growth, generation development and import and export transactions with neighbouring markets in a timely, reliable and cost effective manner.

The AESO can initiate pre-construction activities such as engineering, design, route and site selection and right-of-way acquisition at an early stage, deferring actual project decisions and construction until the need is established. This will reduce lead times and provide flexibility and adaptability to meet future needs, while managing the risk of unnecessary expenditures or stranded investments and assets. The AESO recognizes that major projects with long lead times and significant expenditures must be monitored and appropriate actions taken as circumstances change to ensure investment risks are managed.

C2. Reliability Criteria

The AESO's role is to ensure adequate transmission facilities are available so that the transmission system can operate in a safe, reliable and economic manner, and to facilitate a fair, efficient and openly competitive market for electricity.

The AESO is a member of the WECC and a signatory to its Reliability Management System ("RMS") Agreement. As such the AESO has agreed to follow the NERC/WECC Reliability Criteria and Standards for planning and operating the Alberta system and its interconnections.

Planning criteria are designed to ensure that 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.

The operation of Alberta's existing transmission system must adhere to criteria developed by NERC/WECC. The NERC/WECC reliability standards and criteria are also central to assessing the adequacy of the future transmission system. With an adequately planned system and prudent operating criteria, the AESO can operate the Alberta Interconnected Electric System ("AIES") reliably while facilitating an open and competitive market.

Reliability criteria provide a set of important inputs whether planning future developments or operating the AIES and represent a minimum standard to which the AIES is planned and operated. There are a wide variety of other considerations that must also be taken into account. Planning and operating decisions must be made with due regard for the costs to meet the criteria, impact on stakeholders and the risks associated with not meeting the criteria.

For details concerning the AESO's reliability criteria, please refer to the AESO's website, www.aeso.ca, for documentation of the reliability criteria and standards used in planning and operating the transmission system.

To ensure the adequacy and reliability of the transmission system, studies are carried out applying the NERC/WECC reliability criterion. The nature of this 20-Year Outlook Document is such that extensive analytical studies were not conducted to analyze the performance of the transmission system alternatives outlined. These studies will be conducted, and system performance measured against the reliability

criteria, in greater detail when warranted by better information regarding system load and generation parameters.

Appendix D – Overview of The Electricity System

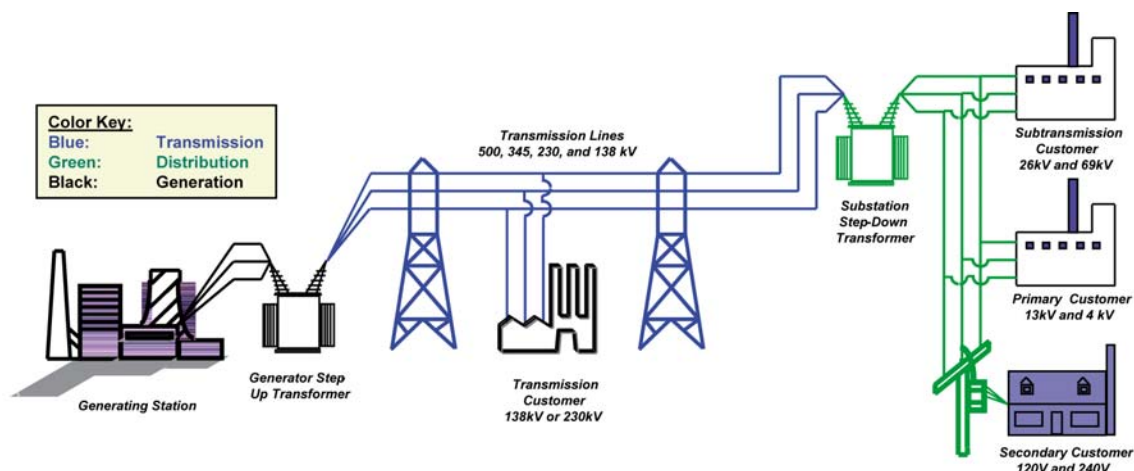
APPENDIX D – Overview of The Electricity System

Albertans depend on reliable electricity for services that are critical to their jobs, lifestyles and well-being. The AESO has a major responsibility for meeting these electricity needs. Part of that responsibility is planning an adequate transmission system to meet future requirements.

D1. Components of the Electricity System

A delivery system is required to transport electricity from generating stations where it is produced to areas across the province where it is consumed.

Figure D1-1 Basic Structure of the Electric Delivery System



The basic structure of the electric delivery system is shown in Figure D1-1. Electricity is produced at lower voltages, typically in the range 10 kV to 25 kV, and is stepped up to higher voltages, typically in the range 240 kV to 500 kV, for transmission in bulk to regional centres.

Transmission of power at these higher voltages reduces conductor heating losses and allows for economic bulk transfer of power over longer distances.

At regional centres the electricity is stepped down to voltages in the range of 69/72 kV to 138/144 kV. Area supply lines transmit the power to area supply transformer stations located in the vicinity of the load. Distribution lines then transmit the power in smaller quantities to large customers and distributing stations in or near population centres at voltages in the range of 13.8 kV to 25 kV.

The final stage is the distribution of power to groups of customers and to individual customers at 600 volts to 4,160 volts for light industries and 120/240 volts for small commercial and residential customers.

D2. Alberta's Transmission System

The AIES is a vital component of the electric industry and provides the platform for a competitive wholesale electricity market. The AIES connects generators to loads over a wide 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 interconnections with neighboring jurisdictions the AIES also provides access to the entire North American electric grid. In addition to providing mutual assistance during emergencies, transmission interconnections are an essential part of a competitive market and provide Alberta with a way to import energy when needed and to export energy that is surplus to the province's needs.

D2.1 *Historical Overview of Generation and Bulk Transmission System Development in Alberta*

Early transmission-connected generating plants in Alberta were usually hydro-powered and transmission lines were energized at voltages up to 138 kV. As load grew during the 40's and 50's hydro-powered generation continued to be added and, in the later part of this period, significant gas-fired generation, later to be converted to burn coal, was added. Transmission development continued at lower voltage levels.

Development of Alberta's bulk 240 kV transmission system began in the late 1950s and early 1960s. The early circuits emanated from the main generation sources at the time, including the Lake Wabamun and Bow Valley regions, and went to Edmonton and Calgary. The lines were primarily wood pole "H" frame construction and included lines such as 904L Wabamun 19S-East Edmonton 38S and 150L Ghost 20S-Sarcee 42S.

Generation development tended toward larger, coal-fired generators with the commissioning of Wabamun Unit 3 in the mid 1960s. More 240 kV developments occurred, particularly between Edmonton and Calgary. 190L was constructed at that time as a direct feed from Wabamun to Sarcee 42S, which was the first 240 kV substation in the Calgary area. 190L was subsequently terminated at the new Benalto 17S substation around 1967, when the Brazeau hydro station was

commissioned and connected to Benalto 17S via the 240 kV circuit 995L.

Electric generation development in the Lake Wabamun area exploded through the 1970s and into the 1980s to meet Alberta's increasing load demand, with annual load growth per cent in the low to mid teens. This load growth was spurred by the rapid development of conventional oil and gas industry pumping loads and increases in population and later by petrochemical processing facilities around Fort Saskatchewan and Red Deer. The 240 kV transmission system developments continued apace, connecting the Lake Wabamun area coal-fired steam plants east to the Edmonton and Cold Lake areas, north and west to Grande Prairie and Edson and south to Calgary and southern Alberta. First one and then a second 240 kV transmission line was extended to the Fort McMurray area. At this time, constructing single-circuit lines was felt to be unsustainable when considering the land use impacts of the transmission system development required to meet the rapid load growth. With rights-of-way becoming increasingly difficult to obtain, construction of double-circuit 240 kV transmission lines became a common practice.

Also during this time the Battle River generating station was expanded and the new Sheerness generating station built to supply growing load, primarily in central and southern Alberta. 240 kV transmission lines were extended south to Lethbridge and east to the gas pipeline compression loads at Empress.

With load growth projected at the time to continue at annual percentage rates in the teens, 500 kV transmission lines were designed for the early phases of the Keephills power station. Although initially operated at 240 kV, 1202L and 1203L were designed to operate at 500 kV and envisioned to directly connect Keephills 320P and Ellerslie 89S. When the Genesee generating station was developed it was also interconnected via these lines.

D2.2 *Historical Development of Transmission Interconnections*

Currently, Alberta has two transmission interconnections to other provinces. The interconnection to British Columbia ("B.C.") (also part of the WECC) consists of 500 kV and 138 kV circuits. The interconnection to Saskatchewan, part of the Mid-Continent Area Power Pool ("MAPP") is a back-to-back High Voltage Direct Current ("HVDC") terminal.

The 500 kV interconnection to B.C. was planned in the late 1970s and constructed in the early 1980s. The lower voltage 138 kV

interconnection existed for several years prior to the construction of the 500 kV interconnection and provided limited interchange capability or support in case of system contingencies.

The 500 kV interconnection was built to B.C. for several reasons. Economic justification was based on the interconnection permitting the indefinite deferral of 300 MW of gas fired peaking capacity in Alberta. The interconnection was seen to provide several other benefits including economic interchange of Alberta thermal-based energy with British Columbia's hydro-based energy and access to B.C. and U.S. energy markets. The 500 kV interconnection, along with the underlying 138 kV interconnection, is the major control area interconnection with British Columbia and the Pacific Northwest. The current operational interchange limits vary depending on prevailing system load conditions.

The HVDC interconnection between Alberta and Saskatchewan was planned in the early 1980s and constructed in the late 1980s. Alberta Power (now ATCO Electric) and Saskatchewan Power Corporation (SPC, now SaskPower) jointly initiated the project based on Alberta initially deferring 125 MW of gas-fired peaking generation. Today export from Alberta to Saskatchewan on the HVDC interconnection is limited due to system capacity constraints in Alberta.

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