ALBERTA 10 YEAR GENERATION OUTLOOK

Prepared for

ALBERTA ELECTRIC SYSTEM OPERATOR

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SUMMARY

This document presents scenarios of generation additions to the Alberta system over the next ten years to facilitate the AESO's obligation to maintain a long term transmission outlook.

The scenarios are based on the load forecast prepared by the AESO which forecasts the peak Alberta load to increase by 3,280 MW from 9,580 MW in 2005 to 12,860 MW in 2016. The average growth rate over this period is 2.6% per annum and 1,600 MW of the 3,280 MW increase is behind the fence load that is served by behind the fence generation.

Based on this load growth, the need to provide reserve capacity and the projected retirements of Wabamun Unit 4 and Battle River Units 3 and 4, it is estimated that 2,300 MW of new generation capacity will be installed by 2011 and 4,100 MW by 2016.

It is expected that new generation capacity will comprise:

- Behind the fence cogeneration additions that will meet the 1,600 MW of largely oil sands behind the fence load growth.
- Small additions to the grid including upgrades at existing coal-fired plants, gas-fired peaking units and cogeneration, hydro and wind that are included based on their effective capacity, and other small additions that will add 1,100 MW over the ten year period.

The likely candidates for providing the remaining generation, which will be approximately 500 MW in 2011 and 1,500 MW by 2016, are additional coal-fired units at the Keephills and Genesee plants, Integrated Gasification Combined Cycle (IGCC) plants fired with coke that could be located in the Fort Saskatchewan or Fort McMurray area, additional cogeneration and a new two unit coal-fired plant at Bow City near Brooks.

A Northern Scenario, Southern Scenario and Northern & Fort McMurray Scenario are presented in the tabulation below, assuming unit additions of 500 MW and shown as cumulative MW installed:

	Scenario 1			Scenario 2			Scenario 3	
	Northern			Southern			Northern & Fort McM	
Major Additions	2011	2016		2011	2016		2011	2016
Coal Units - KH3 and GN4	500	1,000		500	500		500	1,000
Fort Sask IGCC or KH4		500						
Coal at Bow City					1,000			
Fort McM. IGCC or Cogen								500
Total of Major Additions	500	1,500		500	1,500		500	1,500

- Scenario 1 - Northern Generation comprises adding Keephills Unit 3 by 2011 and by 2016 Genesee Unit 4 and either Keephills Unit 4 or a coke-fired IGCC plant using Fort Saskatchewan coke.
- Scenario 2 - Southern Generation comprises adding Keephills 3 by 2011 and then adding the two Bow City units by 2016.

- Scenario 3 - Northern & Fort McMurray Generation comprises adding Keephills Unit 3 by 2011 and then by 2016 Genesee Unit 4 plus 500 MW in the Fort McMurray area of either coke-fired IGCC generation or a combination of IGCC generation and gas-fired cogeneration.

Sensitivity analyses are prepared to determine the impact on Scenarios 1 and 2 in 2016 of accelerated wind development, lower behind the fence generation and higher industrial loads. The first sensitivity analysis has the potential of reducing the need for the other major additions and the second and third increase the need for major additions:

- The scenarios on the previous page are based on 1,200 MW of wind being added by 2016 which is estimated to contribute 240 MW of additional effective capacity. The sensitivity analysis examines the impact of an additional 1,700 MW (340 MW effective) by 2016 which brings the total installed wind capacity to 3,200 MW by the end of the ten year period. This additional wind capacity does not fundamentally change the need for major additions as shown in the tabulation on the previous page.
- Scenarios 1 and 2 on the previous page are based on behind the fence generation additions meeting behind the fence load growth and, as part of the 1,100 MW of small additions, supplying 150 MW to the grid. The sensitivity analysis examines the effect of the behind the fence generation additions being 500 MW lower and instead of supplying 150 MW to the grid, the grid will need to supply 350 MW to meet behind the fence load growth. This extra 500 MW of grid generation in 2016 is assumed to be met by adding Bow City Unit 1 to Scenario 1 and Genesee Unit 4 to Scenario 2 in the tabulation on the previous page.
- The AESO load forecast, which is used to prepare this generation outlook, is based largely on the forecast rate of provincial GDP growth. The AESO also tabulates the loads of all the planned industrial projects as forecast by the proponents of those projects. By 2016 the individually forecast industrial loads served by the grid, and the individually forecast behind the fence loads, are both about 1,000 MW higher than the GDP based forecasts. Including the loads of these industrial projects as currently forecast by their proponents adds 1,000 MW to the generation to be met by major additions to the grid and brings the total to 2,500 MW in 2016. The major additions that are assumed to meet this higher grid requirement in 2016 are shown below:

Major Additions	Scenario 1	Scenario 2
Coal Units - KH3 and GN4	1000	1000
Coal Unit - KH4	500	500
Fort Saskatchewan Coke-fired IGCC	500	
Coal at Bow City	500	1000
Total of Major Additions	2500	2500

It is assumed that the additional 1,000 MW of behind the fence load is met by an additional 1,000 MW of behind the fence generation.

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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 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 years into the future.

In this report the analysis 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 presents an estimate of the amount of new generation that will be developed over the next 10 years based on the AESO’s load forecast and projected generating unit retirements; Section 2 presents a review of Alberta’s electric generation resources; Section 3 compares the costs of 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

Alberta's installed generating capacity, as set out on the AESO's website, at the end of 2005 was made up of 5,840 MW of coal-fired plant, 4,170 MW of gas-fired plant, 869 MW of hydro, 251 MW of wind and 178 MW of other for a total installed capacity of 11,308 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 3,500 MW of additions to the system since the mid-1990s is 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 is part of the BC and western United States synchronous system, and has a smaller 150 MW DC tie with Saskatchewan which provides a limited connection to central and eastern North America.

The restructuring of the Alberta power sector in 1996 created a power pool for trading electric energy and provided open access for all 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 to third parties in Power Purchase Arrangements (PPAs) with durations of up to 20 years. Of the total 5,840 MW of coal-fired generation in place, 5,390 MW is held as PPAs; and of the 869 MW of hydro generation,789 MW is held as a PPA.

1.2 Load Forecast

The estimates of new generation requirements described in Section 1.3 are based on the AESO's 2006 load forecast titled "Future Demand and Energy Requirements".

Table 1.1 presents the actual 2005[1] and forecast 2011 and 2016 Alberta Total Peak Demand (line 1) and Alberta Grid Peak Demand (line 2) together with the behind the fence Peak Demand (line 3) which is the difference between the total and grid peak loads. The Total Peak Demand is forecast to increase at 2.6% per annum and the Grid Peak Demand is forecast to increase at 1.7% per annum.

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[1] Whereas the AESO document uses 2005/06, and the same format in subsequent years, to denote the winter peak that may ocurr near the end of 2005 or beginning of 2006; this document uses only the calender year, that is the 2005 used here corresponds to 2005/06 in the AESO report. The terms "Total", "Grid" and "behind the fence" Peak Demand are as defined in the AESO document with behind the fence load being that load that is served by behind the fence generators.

1.3 Reserve Margin and New Generation Capacity

Prior to restructuring the question of how much generation capacity was required to reliably meet the load would have been addressed using a generation planning model which simulated the operation of the system. This analysis 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) or Estimated Unserved Energy (EUE) criterion. The results of the LOLP and EUE

Table1.1 Alberta Peak Load and Installed Capacity (MW)

	2005	2011	2016
PEAK LOAD			
1. Grid Load	8,158	8,910	9,844
2. Behind the Fence Load	1,422	2,557	3,016
3. Total Alberta Load	9,580	11,467	12,860
PEAK LOAD + RESERVE			
4. Total Alberta Load + 10% Reserve	10,538	12,614	14,146
GENERATION CAPACITY			
5. Total Effective Capacity in 12/2005	10,574	10,574	10,574
6. Retirements	0	279	575
7. Capacity Net of Retirements	10,574	10,295	9,999
SURPLUS (SHORTFALL)			
8. Total Surplus (Shortfall)	36	(2,319)	(4,147)
9. Increase in Behind Fence Load	0	1,135	1,594
10. Grid Surplus (Shortfall)	**36**	**(1,184)**	**(2,553)**

analyses also provided an estimate of the amount the generation capacity needed to exceed the peak demand, known as the reserve margin.

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 and market conditions. 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 effective generation capacity that is available to meet the load and then using that definition of effective capacity to select a reserve margin that is expected to occur over the longer term with Alberta's market structure.

1.3.1 Effective Capacity

The calculation of Total Effective Capacity of 10,574 MW shown in Table 1.1 for the end of 2005 is calculated by (i) starting with Total Installed Capacity on the Alberta system of 11,308 MW from the AESO website, (ii) subtracting the 209 MW capacity of the Rossdale plant which although included in the 11,308 MW is no longer available for the purposes of merit order dispatch, (iii) de-rating the hydro to the capacity that is likely to be available during the winter when the peak load occurs and (iv) de-rating the wind to take into account its low capacity factor and variable output.

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 Effective Capacity (MW)

Installed Capacity December, 2005	11,308
Less: Rossdale Capacity	-209
Small Hydro Derate	-64
PPA Hydro Derate	-260
Wind Derate	-201
Total Effective Capacity	10,574

Hydro

Alberta's hydro plants have limited storage and cannot operate at full 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 to take into account their limited reservoir storage and their primary use to augment the supply of water for irrigation during the summer months and;
- The 789 MW of the larger previously regulated hydro is de-rated by 260 MW or 33% to reflect their output in a peaking operation mode in December through February.

Wind

Wind generation in Alberta typically has a capacity factor in the 30% to 35% range with output being higher in the winter at the time of system peak. Although the wind generation may not actually be available at the time of system peak as an energy producer it does contribute to the overall reliability of the system and its impact on pool price does delay the installation of other types of generation. For the purposes of this study wind is included at a capacity value of 20%, which means that the 251 MW on the system at the end of 2005 is de-rated by 80 percent, or by 201 MW. Similarly each 100 MW of wind added to the system in the future is assumed to contribute 20 MW of effective capacity, or put differently, to displace 20 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 effective capacity that will be installed to meet the Total Alberta 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 effective capacity falls to approximately 10% as a result of load growth.

The 10% reserve margin used here is based on the definition of effective 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 effective 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 15.5% if the total 2005 installed, rather than effective, hydro and wind capacity is included and is equivalent to a reserve margin of about 24.5% if the full 2005 capacity of the BC and Saskatchewan inter-ties of 865 MW is also included.

The tabulation below summarizes how the "effective capacity reserve margin" of 10% used in this study compares to the other two definitions.

Definition	Equivalent Margins
1. Effective Capacity Reserve Margin	10%
2. Margin including the installed hydro and wind capacity	15.5%
3. Margin including the installed hydro and wind capacity and interties	24.5%

1.3.3 Retirements

The effective capacities net of retirements in 2011 and 2016 are calculated by subtracting the projected retirements from the effective capacity in 2005. These retirements include Wabamun Unit 4, 279 MW, at its planned retirement date of 2010 and Battle River Units 3 and 4, totaling 296 MW, in 2013 consistent with the termination of their PPA.

1.3.4 Surplus and Shortfall

The Total Surplus (Shortfall) in Table 1.1 is simply the difference between the Total Effective Capacity and the Total Alberta Load plus the 10% Reserve. The estimated surplus in 2005 of 36 MW falls to a shortfall of 4,147 MW for all of Alberta, as shown on line 8, by 2016 and to a shortfall of 2,553 MW for the grid.

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

2. ALBERTA ELECTRIC GENERATION RESOURCES

This discussion identifies the generation resources that are likely to be developed over the next ten years, and together with a comparison of the costs of the likely major generation additions in Section 3, provides the basis for the generation scenarios developed in Section 4.

The resources are discussed in the order that they were developed historically in Alberta– hydro, coal, gas, wind, followed by other types of resources.

2.1 Hydro

2.1.1 Existing Hydro

Of the total of 869 MW of hydro, 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, these plants were covered under a Power Purchase Arrangement (PPA). Table 3.1 provides a breakdown of the installed capacities at the PPA hydro plants.

Table 2.1 PPA Hydro Plants

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.

The remaining "small" hydro capacity reported by the AESO totals 80 MW, and is located at five separate plants, is shown in Table 3.2.

Table 2.2 Small Hydro Capacity

Plant	Installed Capacity (MW)
Oldman River	32
Chin Chute	11
Irrican Hydro	7
Raymond Reservoir	18
Taylor Hydro	12
Total Small Hydro	80

2.1.2 Potential Hydro Projects

In the past 30 years, two large hydro projects in the province have been studied in some detail:

- The Dunvegan Project on the Peace River just upstream of where Highway 2 crosses the Peace River, between Grande Prairie and Fairview which was studied in the mid-1970s. The preferred layout at the time would impound a reservoir which would flood water back approximately 130 km to the Alberta/BC boundary and would have an installed capacity of some 900 MW.
- The Slave River Hydro Project on the Slave River at the boundary between Alberta and the Northwest Territories which was studied in the early 1980s. The project would flood back to the outlets of the Peace-Athabasca Delta and have an installed capacity of some 2,000 MW.

However both these projects have construction periods of 8 to 10 years which would be in addition to the time required to carry out environmental studies and get the necessary approvals, and therefore are not candidates for the ten year timeframe examined here.

The only known hydro project that is likely to come on over the next 10 years is a much smaller alternative run-of-river project at Dunvegan that Glacier Power applied to the EUB to develop in 2000. The application was rejected 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 addressing these concerns and is currently preparing its next submission.

The project, which is expected to be completed in 2012, would develop approximately 6 m of head with an installed capacity would be about 100 MW. It is assumed to contribute 50 MW of effective capacity at the time of system peak.

2.2 Coal

Currently there are seven coal-fired plants operating in Alberta of which four are located near Wabamun Lake 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.

With the exception of HR Milner at Grande Cache, 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 sub bituminous, 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 best deposits in terms of seam thickness, strip ratios and low sulphur content are in the Wabamun Lake area where most of the generation is currently concentrated.

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 in November of 2003 and the two 65 MW units 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 has subsequently been increased by approximately 40 MW. 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 13 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, in March 2005.

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 the new generation that will be built it is assumed, in the absence of a declaration by their owner to the contrary, that these units are retired when their PPAs expire.

The two unit Sheerness plant is located approximately 30 km south of the Town of Hanna and some 200 km east of Calgary. Each unit has a capacity of 378 MW with the capability of going higher. 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.

2.2.3 Maxim Power Plant

The HR Milner plant, which was originally owned by ATCO and is now owned by Maxim Power Corp., 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 continue to operate to 2016 since the owner has not made any statement about retiring this plant.

2.2.4 Upgrades at Existing Plants

Upgrades similar to the one completed at Sundance Unit 6 are possible for Sundance Units 3, 4 and 5 and somewhat smaller increases at Keephills and Genesee Units 1 and 2. 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. Two more upgrades of the Sundance units of 40 MW each are assumed in the period to 2011 and a further total of 80 MW of upgrades are included in the 2012 to 2016 period.

2.2.5 Major Additions

Alberta has very substantial coal resources that form a large arc from west and northwest of Edmonton to southeast of Calgary. Over the years, more than twenty individual coal properties have been investigated to some degree for the purposes of providing coal for coal-fired plants.

The lead time for bringing on a coal-fired plant at a new mine will typically be about eight years and will involve a substantial investment even before all necessary regulatory approvals are obtained. Currently there are 2,500 MW which can be brought on in a shorter timeframe:

- Two additional units at Keephills and a fourth unit at Genesee; and
- Two units at Bow City which is south east of Calgary near Brooks.

Given that the total requirement for new grid generation is about 2500 MW over the next ten years it is likely that the portion of this that is coal-fired will come from these more advanced properties. Current and possible future coal-fired generation technologies are presented in Appendix A and the costs of coal-fired generation are compared to the costs of other possible major additions to the system in Section 3.

2.3 Natural Gas

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

These gas-fired generation additions have been either gas turbine, combined cycle or cogeneration plants. 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.[2]

2.3.1 Gas Turbines

Gas turbines, together with the hydro plants with storage, provide peaking capacity for the system. After restructuring ATCO added gas turbine capacity in the northwest of the province but very little other peaking capacity has been added and, with the retirement of the Clover Bar and removal of Rossdale from the energy market, the proportion of peaking capacity on the system has declined. The combined cycle plants, discussed in Section 2.3.2 below, generally operate in a mid range role but essentially all the other types of generation discussed in this report, and expected to be added over the next ten years, are designed to operate as base load.

In August of this year EPCOR applied to the EUB to install 245 MW of gas turbine peaking capacity at its Clover Bar site over the period 2007 to 2010. Others are also considering peaking capacity.

Given this announcement, and the need for a balance of peaking and base load additions, 300 MW of new peaking capacity are projected to be added by 2011 plus an additional 100 MW by 2016.

2.3.2 Combined Cycle Plants

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 250 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

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[2] Natural gas can also be used to fuel steam electric plants similar to the Clover Bar and Rossdale plants which have been, or are about to be, retired. This technology is not competitive with current gas prices and is not considered here.

efficiency of greater than 50% can be achieved. High efficiency combined with higher proportion of hydrogen in natural gas as compared to coal results in CO2 emissions of about 0.40 tonnes/MWh, or less than half a new pulverized coal fired plant such as Genesee 3.

The costs of combined cycle plants are compared with other sources of generation in Section 3.

2.3.3 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.

Recent Additions

The most popular gas turbine 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, 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 will be used 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; and the GE 7FB, and "G" class machines offered by Siemens or Mitsubishi are being considered.

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. These facilities provide electric power and thermal energy to the host facility and can also supply electric power surplus to the host's needs into the grid.

Oil sands 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.

Future Additions

Planned oil sands developments in Alberta are constrained by limited engineering, manpower and transportation capacity. The focus of developers is on the production of oil and in most cases their approach to power is only to install sufficient generation capacity to meet their demand and to do so using well proven and readily implemented technologies.

Information submitted by developers to the AESO show an overall balance of their new loads and their additional behind the fence generation during the period to 2009 in which their plans are fairly firm. Their current plans beyond 2009 show a modest increase in generation relative to load but these longer term estimates of projects' loads, generation and the balance of the two tend to be fluid and subject to frequent changes.

Based on this trend, additions in behind the fence cogeneration are projected to exceed behind the fence load growth by 50 MW by 2011 and by 150 MW by 2016. The possibility of more cogeneration is examined together with possible coke-fired IGCC generation in the Fort McMurray area in Section 4.

2.4 Oil Sands By-products

Currently there are two instances in which oil sands by-products are being used, or are about to be used, as an energy source in Alberta:

- 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, primarily to produce process steam; and
- OPTI Nexen is installing an asphaltene gasification unit as part of its Long Lake upgrader to provide hydrogen to the hydrocracker and synfuel for power and steam generation. Two GE 7EA gas turbines will provide sufficient power for facility use and have up to about 60 MW available for grid export. The term "polygeneration" has been coined for plants such as Long Lake which generate more than two useful products, that are electricity, steam and hydrogen.

Although the OPTI Nexen project, which will start production next year, might be seen to be setting a trend of gasifying asphaltene to produce power for internal use and sales to the grid, it is unlikely that this will be a significant source of new generation over the ten year timeframe of this study.

The reasons for this are as follows:

- A major gasification plant will cost $2 billion, making power generation with syngas more capital intensive, and will place greater demands on scarce engineering, manpower and transportation resources than installing natural gas-fired turbines.
- When gasifiers are installed and syngas is produced, hydrogen for the production of transportation fuels and petrochemicals has highest value in the hierarchy of uses and power generation is among the lowest.

The plans of oil sands developers bear this out. Table A.1 in Appendix A shows that the owners of new upgraders planning to produce and gasify asphaltene will, with the exception of OPTI Nexen, either use the syngas internally or to sell it as a feedstock.

The remaining oil sands by-product is coke. In Fort McMurray the Suncor and Syncrude plants have coke stock piles from operations to date and continue to produce coke. Syncrude produces a fluid coke and stores it in ponds, while Suncor produces sponge coke which is either stored on site, sold when possible or burnt in convention boilers for its own energy needs. Suncor currently produces approximately 3 million tonnes of coke per year of which about 900,000 tonnes are used to fire boilers, 300,000 tonnes are marketed and the remaining production is largely stored or used for construction projects. Suncor continue to consider greater use of coke for power and steam generation but are currently installing gas fired generation as part of their ongoing expansion.

As the Table in Appendix A shows, as many as four new upgraders are planned for the Fort Saskatchewan area of which the Petro-Canada Fort Hills upgrader will be major coke producer. The use of coke for power generation to supply the grid is more likely at this location, or some other location given the proximity to rail and coke's high heating value that makes transportation viable, than in Fort McMurray. The coke from the Fort Hills upgrader alone could fuel a 1,500 MW power plant.

The cost of coke-fired IGCC generation, as described in Appendix A, is compared with the costs of other options in Section 3.

2.5 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 about 250 MW is connected to the transmission system and forms part of the 11,308 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 capacity factors of new wind generators are 35% on an annual basis 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.

There is considerable interest in wind development in Alberta with some 3,000 MW of new generation currently at various stages of development. However, in April of 2006 the AESO established an operational threshold of 900 MW of wind under current system conditions.

For the purposes of this study it is assumed that an additional 600 MW of wind capacity will be installed by 2011. For the second five year period it is assumed that the threshold will be raised and another 600 MW will be installed bringing the total installed wind capacity to 1,500 MW in 2016.

In recognition of the magnitude of the wind resource and the considerable interest, a sensitivity analysis is undertaken in which a total wind installation of 3,200 MW by 2016 is examined.

2.6 Other

Of the 3,500 MW of new generation capacity that has been added to the system since 1996 approximately 20% is from generators that are smaller than 50 MW. These plants, which are largely gas-fired plants plus a smaller amount of biomass, have not been addressed in the foregoing discussion which has focused for the most part on plants between 100 and 500 MW.

It is expected that this phenomenon of small additions will continue in the future but, it most of it is small gas-fired or biofuel-fired plants and fuel prices continue to be high, will represent a smaller portion of the total additions. It is estimated that such generation will amount to additions of 50 MW by 2011 and another 50 MW between 2011 and 2016.

2.7 Conclusions

Based on the review of the generation resources and the announced intentions of generators it is concluded that the likely small generation additions over the next ten years will be:

- One 100 MW hydro plant, probably in 2012, contributing 50 MW to effective capacity.
- Two more upgrades of Sundance units totaling 80 MW in the period to 2011 and a further 80 MW of upgrades in the 2012 to 2016 period.

- Gas Turbine additions to provide peaking generation of 300 MW by 2011 and an additional 100 MW by 2016.
- Increases in behind the fence cogeneration exceeding increases in behind the fence load by 50 MW in 2011 and by an additional 100 MW in 2016.
- Wind generation additions of 600 MW by 2011 and a further 600 MW by 2016, contributing 120 MW of additional effective capacity in each five year period, and bringing the total installed wind capacity to approximately 1,500 MW by 2016.
- Other small generation of 50 MW by 2011 and an additional 50 MW by 2016.

These small additions, using the effective capacity of hydro and wind, add up to 600 MW by 2011 and, with an additional 500 MW between 2011 and 2016, 1,100 MW in the ten year period.

The conclusions of the review with respect to major additions are that:

- The likely candidates for new coal-fired units are two additional units at Keephills, a fourth unit at Genesee and a new two unit plant at Bow City.
- Cogeneration additions by oil sands developers are currently constrained by factors other than the relative economics of power generation and most of the cogeneration that is being installed will likely be gas-fired rather than using the oil sands by-products asphaltene and coke.
- Coke-fired generation, using the planned Fort Saskatchewan coke production or possibly the Fort McMurray coke, could contribute to meeting the grid load growth over the next ten years.
- The other possible major contributor to serving the growth in the grid load is gas-fired combined cycle plants.

3. COMPARISONS OF MAJOR GENERATION OPTIONS

This section presents a cost comparison of the coal, gas and coke-fired thermal plants and wind generation discussed in the previous Section. The objective in setting out the relative lifetime costs of these types of generation is to identify the likely candidates for providing major additions to meet the load growth to 2016.

3.1 Cost Comparisons

Table 3.1 presents a comparison of the levelized costs of:

Coal - a super-critical pulverized coal unit similar to Genesee 3.

Natural Gas - a combined cycle plant that could be located almost anywhere in the province

- cogeneration plant assumed to be installed as part of oil sands development.

Coke – an IGCC plant comprising a gasifier and a combined cycle fuelled with the syngas.

Wind – a typical wind farm comprised of turbines of about 2 MW each.

Cost of Fuel

Line 1 of Table 3.1 presents estimates of prices for coal, gas and coke that will fuel the thermal 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 prospective, but unnamed, sites in Alberta. The costs varied from a low of $0.75/GJ, which reflected the costs at the existing Highvale mine serving Keephills and the Genesee mine, to a high of a $1.96/GJ. Thirteen of the 20 sites had costs between $1.00 and $1.20/GJ. A cost of $1.00/GJ is selected as being generally representative of the cost of fuel for additional units at Keephills and Genesee. A green field site could be higher.

AECO-C gas price forecasts prepared in mid 2006 by Sproule and Gilbert Laustsen Jung Associates Ltd. are in the range of $6.00/GJ to $7.00/GJ over the next ten years, expressed in constant 2006 dollars. A price of $7.00/GJ has been selected for the base case analysis here and sensitivity analyses are presented at $6.00 and $8.00/GJ.

As noted in Section 2, coke that is currently being produced in the province is largely being stockpiled. In the absence of an established market, a handling/limited opportunity cost of $10/tonne, which is equivalent to $0.30/GJ, is selected assuming the power plant is located near the upgrader producing the coke.

Heat Rates and Fuel Costs

The second line in Table 3.1 presents each plant's heat rate in terms of the amount of energy in the form of fuel that is required to produce a megawatt hour of electrical output. The heat rate for a super-critical coal-fired unit is 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 lower heat rates. The heat rates given in Table 3.1 for the combined cycle plant and cogeneration plant are considered to be representative of plants that are being installed in Alberta. In addition to variations resulting from different types of equipment, the heat

Table 3.1 Comparison of Unit Power Costs

	COAL	GAS	GAS	COKE	WIND
	Pulverized	Combined	Cogeneration	IGCC	Wind
	Coal	Cycle			Turbine
COST ANALYSIS					
1. Cost of Fuel ($/GJ)	1.0	7	7	0.3	0
2. Heat Rate (GJ/MWh)	9.5	6.5	5	8.5	na
3. Fuel Cost ($/MWh)	10	50	39	3	0
4. 0&M ($/MWh)	6	5	4.5	9	10
5. Capacity Factor (%)	90	95	95	90	35
6. Project Life (years)	30	20	20	20	20
7. Station Service (%)	6	3	0.6	20	nil
8. Capital ($/kW)	2000	800	700	2300	2000
($/MWh)	29	12	10	45	68
9. Generation Cost ($/MWh)	45	67	53	57	78
10. CO2 Offsets ($/MWh)	5	0	0	4	-4
11. Total Generation Cost	50	67	53	61	74
Incl. CO2 ($/MWh)					
SENSITIVITY ANALYSIS					
Gas Price at $6/GJ	50	60	47	61	74
Gas Price at $8/GJ	50	74	58	61	74
CO2 Offsets at $20/tonne	55	67	53	65	70
Notes:					
1. Since the price of natural gas is based on its Higher Heating Value and the Heat Rates of the gas-fired plants on the Lower Heating Value, the product is multiplied by 1.1 to get fuel cost in $/MWh					
2. Capital costs in $/kW are based on gross output and exclude Interest During Construction, IDC is included in $/MWh based on four year construction/procurement for the coal and coke plants and two years for the rest.					
3. Capital costs are expressed in $/MWh based on the lives, capacity factors and station service shown; financing of 60% debt at 6% and a 15% return on equity; 2% escalation and CCAs of 50% for cogen, IGCC and wind and 8% CCA for other plants.					
4. Costs are in mid 2006 $.					

rates of both types of plant will vary slightly with the altitude and temperature at the site and the cogeneration heat rate will vary with the configuration of equipment and the nature of the steam host.

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 is taken into account by multiplying the product of the two by 1.1.

Operation and Maintenance (O&M) Costs

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-2006 dollars and are assumed to escalate at a general level of inflation of two percent per year over the life of the project.

Capital Costs

The capacity factors, project lives and station service in lines 5 through 7 are taken into account in converting the capital cost estimates in $/kW into $/MWh.

The $/kW on line 8 are based on the gross outputs of the plants, are in mid 2006 dollars and exclude interest during construction (IDC) which is based on the construction periods for each type of plant[3].

The capital cost of a 500 MW super-critical pulverized coal-fired unit is estimated to be $2,000/kW. This estimate is considered to be generally representative of the costs of additional units at the existing Keephills and Genesee plants. A green-field site could be slightly more.

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 about 250 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 $700/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 is based on the incremental capital cost of the cogeneration facilities relative to the costs of the facilities needed to raise steam, and as such, excludes the cost of the HRSG.

The $2,300/kW coke-fired IGCC capital cost estimate is for a 500 MW plant and includes the cost of the gasifier and a combined cycle plant designed for the syngas produced. The capital

[3] Including IDC in the capital cost and using net rather than gross output would result in $/kW estimates that are higher than those shown in Table 3.1. For example, the coal plant estimate of $2000/kW in Table 3.1 is between $2400 and $2500/kW when IDC is included in the estimate and the plant capacity is based on net output. Including the escalation that will ocurr during construction would result in higher unit costs. The $/MWh figures presented below the $/kW figures on line 8 include IDC and are based on net output but, being expressed in mid 2006 $, do not include future escalation.

cost of the wind turbine of $2,000/kW is considered representative of the costs of a wind farm with the turbines of about 2 MW that are typically being installed in Alberta.

Converting $/kW to $/MWh

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 plant has a four year construction period, 30 year life, 6% station service and operates at a 90 percent capacity factor;
- The gas-fired plants have a two year construction period, 20 year life, 3% station service for the combined cycle and 0.6% for cogeneration and operate at a 95 percent capacity factor;
- The coke-fired IGCC plant has a four year construction period, 20 year life, 20% station service because of the high electrical requirements of the gasifier and operates at a 90 percent capacity factor;
- The wind turbine capital costs are incurred over a two period and the facility has a 20 year life, operates at a 35% percent capacity factor and receives a $10/MWh subsidy for the first ten years of operation which, for the purposes of the calculations here, is levelized over the life of the plant;
- 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 and IGCC plants and wind turbine and 8 percent for the other plants and the combined federal and provincial tax rate is 31 percent; 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 2006 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 capacity 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 of power for each plant in line 9 is the sum of the operating and fuel costs and the levelized capital charges and is expressed in 2006 dollars.

CO_2 Offsets

The cost of CO_2 offsets is included in line 10 in Table 3.1. The coal-fired plants are equipped with scrubbers to reduce SO_2 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 CO_2, which would increase the capital and operating costs substantially, the cost of buying CO_2 offsets is included as a charge to the coal and coke fired plants. The charge is based on an offset cost of $10.00/tonne of CO_2 and is applied to the coal and coke fired plants to the extent that their CO_2 emissions exceed those of the combined cycle plant. For example a super-critical coal-fired plant produces about half a tonne more CO_2

per MWh than a combined cycle so that offsets of $10/tonne increase the costs of the coal-fired plant by $5/MWh. Wind on the other hand produces no CO_2 and is given a credit.

Comparison of Total Costs

The pulverized coal-fired units similar to Genesee 3 have the lowest levelized lifetime costs, including CO_2 offsets, at $50/MWh, as shown on line 11. The cost of gas-fired cogeneration, representing the generation configuration typically installed by oil sands developers, has the next lowest cost at $53/MWh, followed by the coke-fired IGCC plant at $61/MWh, the combined cycle at $67/MWh and wind is the most costly at $74/MWh.

Sensitivity to Gas Prices and Higher Offset Costs

The sensitivity analysis examines the effect of using gas prices of $6 and $8/GJ and increasing the cost of CO_2 offsets from $10 to $20 per tonne. A gas price of $6/GJ reduces the difference in the costs between the combined cycle plants and the coal and coke plants and results in cogeneration being the lowest cost option. Conversely a gas price of $8/GJ increases the costs of both the combined cycle and cogeneration options.

Increasing the cost of CO_2 offsets to $20 per tonne increases the costs of the coal and coke options, reduces the cost of wind generation, and, as in the case of $6/GJ natural gas, results in cogeneration being the lowest cost option.

3.2 Technologies to Reduce CO_2 Emissions

The foregoing analysis has been based on buying CO_2 offsets since the technologies to reduce emissions of CO_2 below the levels currently being achieved are not expected to be available and commercially accepted in North America until near the end of the ten year timeframe of this study.

The status of the technologies that would actually reduce the CO_2 emitted from the coal and coke options are summarized below:

- Ultra super-critical coal-fired plants are now in operation in certain parts of the world and have efficiencies of about 45% and CO_2 emissions of 0.75 tonnes/MWh as compared to 1.0 tonnes/MWh for a sub-critical plant such as Keephills and 0.9 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 such as Genesee 3 included in the cost comparison in Table 3.1 but at this time none have been installed in North America.
- Methods to capture the remaining CO_2 emissions from these coal plants, such as amine scrubbing, are at an early stage of development and the facilities required to capture and sequester the CO_2 would substantially increase the cost of power from these plants. Although considerable research is underway in North America and worldwide, these technologies are not expected to be commercially available until about 2012.
- Reducing CO_2 emissions from an IGCC plant will be possible once gas turbines have been developed that will burn a hydrogen rich fuel. However, like the amine scrubbing, these units are not expected to be available until about 2012 and the power produced would be significantly more expensive.

The most likely steps to be taken with these technologies in the 10 year timeframe to reduce CO_2 emissions are the possible installation of an ultra super-critical unit towards the end of the period and/or the installation of an IGCC plant that would be designed so that it could be converted at a later date to capture the CO_2. Technologies to reduce CO_2 are discussed further in Appendix A.

3.3 Conclusions

The comparison of costs of large generating plants shows that pulverized coal units similar to Genesee 3 are likely the lowest cost option and the most likely major additions to the system over the next ten years. Gas-fired cogeneration ranks next in the base case analysis and is the lowest cost option in two of the sensitivity analyses. As noted in Section 2, gas-fired cogeneration is the likely source of generation to meet the behind the fence loads but with the current practice of oil sands developers matching their new generation to just meet their new load, cogeneration is unlikely to make a significant contribution to meeting the grid requirements in the timeframe being examined. Coke-fired IGCC ranks next and could become a major source of new generation.

4. GENERATION SCENARIOS

This section presents scenarios of the likely major generation additions expected to be added over the next ten years. The amount of generation to be met with major additions by 2011 and by 2016 is calculated in Table 4.1.

Table 4.1 Generation Met by Smaller and Major Grid Additions (Cumulative MW)

	2011	2016
1. New Grid Generation	1,184	2,553
2. Less Small Additions to Grid		
2.1 Small Hydro (@50%)	0	-50
2.2 Upgrades at Coal Plants	-80	-160
2.3 Gas Turbine Peaking	-300	-400
2.4 Gas-Fired Cogeneration	-50	-150
2.5 Wind (@20%)	-120	-240
2.6 Other	-50	-100
2.7 Total Smaller Additions	-600	-1,100
3. To be Met by Major Grid Additions	584	1,453

Table 4.1 starts with the grid shortfalls of 1,184 MW in 2011 and of 2,553 MW in 2016 as calculated in Table 1.1. The remaining steps in developing the scenarios of major additions are to:

- Deduct the contribution to effective capacity that will be made by the smaller additions to the grid;
- Develop three scenarios of major additions that could meet the remaining generation shortfall; and
- Conduct sensitivity analysis.

4.1 Smaller Grid Additions

As set out in Sections 2.1 through 2.6 and summarized in Section 2.7, the smaller grid additions comprise:

- One 100 MW hydro plant, probably in 2012, contributing 50 MW to effective capacity.
- Two more upgrades of Sundance units totaling 80 MW in the period to 2011 and a further 80 MW of upgrades in the 2012 to 2016 period.

- Gas Turbine additions to provide peaking generation of 300 MW by 2011 and an additional 100 MW by 2016.
- Increases in behind the fence cogeneration exceeding increases in behind the fence load by 50 MW in 2011 and by an additional 100 MW in 2016.
- Wind generation additions of 600 MW by 2011 and a further 600 MW by 2016, contributing 120 MW of additional effective capacity in each five year period, and bringing the total installed wind capacity to approximately 1500 MW by 2016.
- Other small generation additions totaling 50 MW by 2011 and an additional 50 MW by 2016.

These small additions, using the effective capacity of hydro and wind, add up to 600 MW by 2011 and, with an additional 500 MW between 2011 and 2016, 1,100 MW in the ten year period. As shown in line 3 in Table 4.1, subtracting these levels of smaller additions from the grid requirements leaves 584 MW to be met by major additions by 2011 and 1,453 MW by 2016.

Assuming that the major unit additions will be approximately 500 MW each, one unit is required by 2011 and a total of three units by 2016.

4.2 Scenarios of Major Additions

Based on the review of generation resources in Section 2 and the cost comparisons in Section 3, the major addition candidates are:

- A total of five coal-fired units comprising a third and fourth unit at the Keephills plant, a fourth unit at the Genesee plant and a new two unit plant at Bow City;
- Coke-fired IGCC generation using the planned Fort Saskatchewan coke production or possibly the Fort McMurray coke; and
- Possibly additional cogeneration in the Fort McMurray area.

Based on the current status of these projects, Keephills Unit 3 is the only major addition that is expected to meet a 2011 in service date. It is expected that Bow City Unit 1 could be in service by 2012 which, in the analysis here that only considers 2011 and 2016, means showing it being available to meet the 2016 load. The lead times of the other additions are such that they could be commissioned in the 2012 to 2016 period but likely not before.

Three scenarios of major additions have been developed:

- Scenario 1 - Northern Generation, in which all the units are located in the Wabamun Lake and Edmonton area, comprises adding Keephills Unit 3 by 2011 and Genesee Unit 4 and either Keephills Unit 4 or a coke-fired IGCC plant using Fort Saskatchewan coke by 2016.
- Scenario 2 - Southern Generation comprises adding Keephills Unit 3 by 2011 and then adding the two Bow City units by 2016. In other words the Southern Generation Scenario includes two southern units and one northern unit.
- Scenario 3 - Northern and Fort McMurray Generation comprises adding Keephills Unit 3 by 2011 and then by 2016 adding Genesee Unit 4 plus 500 MW in the Fort McMurray area comprising either a coke-fired IGCC plant or a combination of IGCC generation and gas-fired cogeneration.

These scenarios are presented in Table 4.2.

Table 4.2 Generation Scenarios (Cumulative MW)

	Scenario 1			Scenario 2			Scenario 3	
	Northern			Southern			Northern & Fort McM	
Major Additions	2011	2016		2011	2016		2011	2016
Coal Units - KH3 and GN4	500	1,000		500	500		500	1,000
Fort Sask IGCC or KH4		500						
Coal at Bow City					1,000			
Fort McM. IGCC or Cogen								500
Total of Major Additions	500	1,500		500	1,500		500	1,500

4.3 Sensitivity Analyses

Sensitivity analyses are prepared to determine the impact of:

- Accelerated wind development;
- Lower behind the fence generation; and
- Higher industrial loads.

These sensitivity analyses address the impacts on the Northern and Southern Scenarios in 2016. The first sensitivity analysis has the potential of reducing the need for the major additions and the second and third increase the need for major additions.

4.3.1 Accelerated Wind Development

It is assumed in the first sensitivity analysis that an additional 1,700 MW of wind are installed by 2016 bringing the total wind installation to 3200 MW by the end of the 10 year period. As shown in Table 4.3, using the factor of 20% to calculate the effective capacity, this additional wind reduces the generation to be met by major additions by 340 MW to 1,113 MW in 2016. Using a criterion that 500 MW units are added when the shortfall exceeds 100 MW results in three 500 MW units still being needed in 2016. In other words with this criterion, the additional wind does not affect the units added by 2016 as shown in Table 4.2.

Table 4.3 Impact of Additional Wind on Shortfall to be Met by Major Additions in 2016 (MW)

Type of Generation	MW
Met by Major Additions in Base Case	1,453
Met by 1700 MW of Additional Wind (@ 20%)	-340
Met by Major Grid Additions	1,113

4.3.2 Lower Behind the Fence Generation

The analysis leading to the need for 1,500 MW of major grid additions, as shown in Table 4.2, is based on increases in behind the fence generation exceeding increases in behind the fence load growth by 150 MW by 2016. This second sensitivity analysis examines the effect of the behind the fence generation being 500 MW lower and instead of 150 MW being supplied to meet grid load growth, the grid will need to supply 350 MW to meet behind the fence load growth.

As shown in Table 4.4 the extra 500 MW to be supplied by the grid is assumed to be met by adding Bow City Unit 1 to Scenario 1 and Genesee Unit 4 to Scenario 2.

Table 4.4 Impact on Scenarios 1 and 2 in 2016 of 500 MW less Behind the Fence Generation (MW)

Major Additions	Scenario 1	Scenario 2
Coal Units - KH3 and GN4	1,000	1,000
Fort Saskatchewan IGCC or KH4	500	
Coal at Bow City	500	1,000
Total of Major Additions	2,000	2,000

4.3.3 Higher Industrial Loads

The AESO load forecast set out in Section 1.2 of this report, which is the basis of the estimated generation additions, is based largely on the forecast rate of GDP growth in the province. Through discussions with individual project proponents the AESO also tabulates the forecast loads of all the planned industrial projects as forecast by the proponents. The totals of these individually forecast loads are greater than the corresponding components of the GDP based forecast. By 2016 the individually forecast behind the fence loads and large industrial loads served by the grid are both about 1,000 MW higher than the GDP based forecasts.

The third sensitivity analysis examines the impact of those industrial projects proceeding as currently planned. The additional 1,000 MW of grid generation brings the total to be served by major additions to 2,500 MW in 2016.

Table 4.5 Impact on Scenarios 1 and 2 in 2016 of 1000 MW Higher Grid Load (MW)

Major Additions	Scenario 1	Scenario 2
Coal Units - KH3 and GN4	1,000	1,000
Coal Unit - KH4	500	500
Fort Saskatchewan Coke-fired IGCC	500	
Coal at Bow City	500	1,000
Total of Major Additions	2,500	2,500

As shown in Table 4.5, the major additions in Scenario 1 are assumed to be the three additional units at the Keephills and Genesee plants, an IGCC plant fired with Fort Saskatchewan coke and the first unit at the Bow City plant. Scenario 2 is the same except that the second Bow City unit replaces the IGCC plant fired with Fort Saskatchewan coke.

In addition to the extra 1,000 MW of grid generation the behind the fence generation load is also 1,000 MW higher and is assumed to be met by behind the fence generation.

The three scenarios of major additions presented in Section 4.2 and the three sensitivity analyses presented above are considered to provide a reasonable range of generation additions for the purposes of transmission planning.

APPENDIX A - GENERATION TECHNOLOGIES AND PLANNED GASIFIERS IN ALBERTA

A.1 Characteristics of 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 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 unit to reduce SO_2 emissions and fabric filters to control particulate emissions, to comply with emission regulations at the time the unit was installed.

The current "Alberta Air Emission Standards for Electricity Generation" provides emission limits for SO_2, NO_X and particulates 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 if required to further reduce NO_X emissions.

The Government of Alberta has developed a regulation that requires existing plants to reduce their mercury emissions by 70%. This emission requirement will also apply to new plants. It is expected that the flue gas desulphurization, selective catalytic reduction and fabric filters installed to reduce emissions of SO_2, NO_X and particulates on new plants will also reduce mercury emissions to, or close to, this level. Further reductions in mercury can be achieved by injecting a material that absorbs mercury, such as activated carbon, upstream of the particulate collector such as a bag house or electrostatic precipitator.

The cost estimates of the coal-fired plants presented in Section 3 include environmental controls to meet the current standards for SO_2, NO_X and particulates and sufficient funds for adding an absorbent to further reduce mercury if required.

In addition to installing environmental control equipment, owners of new coal-fired plants in Alberta have also been required to purchase CO_2 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 CO_2 offsets is included as part of the cost comparisons presented in Section 3. Options for actually reducing CO_2 emissions are discussed in Section A.3.

A.2 Technologies to Generate Power from Coke

As noted in Section 2 of the report, coke is the most likely oil sands by-product to be used for power generation. The two likely technologies to be used to generate power from coke are:

) Integrated Gasification Combined Cycle (IGCC) plants which have the following basic components:

- Fuel handling;
- Oxygen separation;
- Coke (or Coal) gasifier;
- Gas (syngas) coolers and syngas clean-up and wastes;

- Combined cycle unit; and
- Plant infrastructure and ancillary systems.

IGCC plants have the advantage of low NOx and SO2 emissions, capturing heavy metals in an unleachable slag, producing saleable by-products such as sulphur and the slag that can be used for road beds, CO2 emissions of 0.82 tonnes/MWh and the potential to separate and capture CO2.

b) Steam electric plants using Circulating Fluidized Bed (CFB) boilers, which are preferable to conventional boilers for the high sulphur coke that will be produced. CFB boilers are capable of using a wide range of fuels and by adding limestone with the fuel the suphur is captured in the ash. However the CFB boilers produce 30 to 40 times as much ash as IGCC technology and although their NOx and SO2 emissions can be kept within the prescribed limits they are higher than for an IGCC plant and CO2 emissions are slightly higher at 0.87 tonnes/MWh with limited potential to retrofit the plant to capture that CO2.

The costs of the two technologies are similar. The IGCC plant is likely to have a slightly higher capital cost but better heat rate, greater flexibility in that the option exists to sell some of the syngas that is produced and lower emissions. It is assumed for the purposes of this study, and in the cost comparisons of generation from coal, natural gas, coke and wind in Section 3, that coke will be used to fire an IGCC plant.

A.3 Technologies to Reduce CO_2

There are several initiatives underway in Canada to address the CO_2 issue. One of the most significant is the program of the Canadian Clean Power Coalition (CCPC). Their objective is "to demonstrate that coal-fired electricity generation can effectively address air quality issues projected in the future, including greenhouse gas". In September 2006 CCPC, Alberta Energy Research Institute and EPCOR announced a $33 million research project to find the cleanest ways to generate power from coal.

The two main options for reducing CO_2 are (i) further efficiency improvements in plants that may be combined with post-combustion capture of CO_2, which would apply to coal-fired steam electric plants; and (ii) the removal of CO_2 prior to combustion which could apply to either coal or coke-fired IGCC plants.

Efficiency improvements and post-combustion capture of CO_2

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 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 sub bituminous coal is about 44% which further reduces CO_2 emissions. Typically the CO_2 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 CO_2 from the dilute flue gas stream, capturing and sequestering it or finding a CO_2 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 CO_2 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 CO_2 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 that reduce the overall efficiency of the plant. 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 CO_2 is compressed to pipeline pressure for use/sequestration.

Once captured and compressed, the CO_2 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 CO_2

Whereas the foregoing has discussed post-combustion capture of CO_2 from the flue gas, in an IGCC plant the CO_2 can be removed prior to combustion. The IGCC technology has been applied for over two decades and several plants are in operation.

The gasification process produces a syngas comprising mainly CO and Hydrogen that can be burnt cleanly in gas turbines. This technology keeps emission levels of SO_2 and NO_X below required limits and offers the potential to significantly reduce CO_2 emissions. Shift convertors can be used to react the CO fraction of the syngas with water to produce CO_2, that can be captured, and hydrogen which can become the fuel for the gas turbine. Gas turbines capable of being fired with hydrogen are under development and are expected to be available for large scale commercial operation by about 2012.

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.

There are several technology vendors that can supply suitable processes for the gasification of coal and coke. These include Shell, who developed their own technology; General Electric, who purchased the Chevron Texaco technology; Conoco-Phillips, who purchased the E-Gas technology; Siemens, who purchased the Future Energy technology; and Sasol-Lurgi, who developed their own technology.

In Alberta the coke that is produced as a by-product of oil sands upgrading, which has a heating value almost twice the plains coal, is the more likely candidate to fuel an IGCC plant.

A.4 Upgraders and Gasifiers in Alberta

A list of planned Upgraders, and the Gasifiers that are planned to be part of those Upgraders, is presented in Table A.1 on the following page.

Table A.1 Upgraders and Gasifiers in Alberta

Company Name	Project	Upgrader Location	Feedstock to upgrader	upgrading process	capacity in bbl/day	Feedstock to Gasifier	Gasification Technolgy Supplier	Gasification Products Produced	Usage	timing of first production
BA Energy	Phase 1, Heartland Upgrader	Strathona County	merchant	hydrogen addition	75,500	-	no plans announced	tbd	tbd	2008
BA Energy	Phase 2,3, Heartland Upgrader	Strathona County	merchant	hydrogen addition	157,500	-	no plans announced	tbd	tbd	after Phase 1 completed
CNRL	Horizon-Phase 1	Wood Buffalo	Horizon-Phase 1	tbd	125,000	tbd	no plans announced	tbd	tbd	proposed
CNRL	Horizon-Phase 2,3	Wood Buffalo	Horizon-Phase 2	tbd	108,000	tbd	no plans announced	tbd	tbd	2021
Husky Energy	Bitumen Upgrader	Lloydminster	Lloydminster area	delayed coking	5,000	tbd	rfp out for gasification	tbd	tbd	2010
Northwest Upgrading Inc	Northwest Upgrader-Phase 1	Ft. Saskatchewan	merchant	hydrogen addition	75,000	Resid HC residue	Lurgi	hydrogen	internal usage for upgrading	2009
Northwest Upgrading Inc	Northwest Upgrader-Phase 2	Ft. Saskatchewan	merchant	hydrogen addition	75,000	Resid HC residue	Lurgi	hydrogen	internal usage for upgrading	2010-2015
Northwest Upgrading Inc	Northwest Upgrader-Phase 3	Ft. Saskatchewan	merchant	hydrogen addition	75,000	ashphaltenes	Lurgi	hydrogen	internal usage for upgrading	2010-2016
Opti-Nexen	Long Lake-Phase 1	Ft. McMurray	SAGD	hydrogen addition	70,000	asphaltenes	Shell	Power, hydrogen and SAGD energy	internal use for upgrading, excess, excess power to the grid	2007
Opti-Nexen	Long Lake-Phase 2	Ft. McMurray	SAGD	hydrogen addition	70,000	asphaltenes	Shell	Power, hydrogen and SAGD energy	proposed	2008-2010
Peace River Oil	Blue Sky	Peace River	Merchant	slurry hydrocracking	25,000	Resid HC residue	tbd	hydrogen + power (maybe)	hydrogen for upgrading	2012
Peace River Oil	Blue Sky	Peace River	Merchant	slurry hydrocracking	eventually to 75000	Resid HC residue	tbd	hydrogen + power (maybe)	hydrogen for upgrading	proposed
Petro-Canada/Tech/UTS Energy	Sturgeon Upgrader	Sturgeon County	Fort Hills	delayed coking	50,000	petroleum coke	gasification to be considered in the future	tbd		2011
Petro-Canada/Tech/UTS Energy	Sturgeon Upgrader, Phase 2	Sturgeon County	Fort Hills	delayed coking	90,000	petroleum coke	gasification to be considered in the future	tbd		proposed
Petro-Canada	Refinery	Strathcona County	MacKay River & 3rd parties	delayed coking	135,000	petroleum coke	coke will be marketed			2008
Shell Canada	Scotford Refinery Expansion	Strathcona County	Albian Sands Energy	hydrogen addition	150,000	Resid HC/SDA residue	no plans announced			2010
Shell Canada	Scotford Refinery Expansion	Strathcona County	Albian Sands Energy	hydrogen addition	500,000	Resid HC/SDA residue	no plans announced			proposed
Suncor Energy	Voyageur Project	Ft. McMurray	Steepbank Mine and Firebag 1-4	delayed coking	235,000	delayed coke	tbd	gasifier to consume 20% of the petcoke produced		2010
Suncor Energy	Millineum Coker Unit Project	Ft. McMurray	Steepbank Mine and Firebag 1-4	delayed coking	increasing to 350,000 bpd	delayed coke	tbd			2008
Syncrude Canada Ltd.	Upgrader Expansion 2	Wood Buffalo	Aurora Mine train 3	fluid coking	180,000	fluid coke	no plans announced			2010
Synenco Phase 1	Northern Lights-Phase 1	Sturgeon County	Northern Lights-Phase 1	hydrogen addition	57,250	SDA residue	General Electric	hydrogen, syngas no power at the present time	have a MOU for a long term contract to sell hyrogen, nitrogen, sulphur and CO2 to Agrium in Ft Sask	2010
Synenco Phase 2	Northern Lights-Phase 2	Sturgeon County	Northern Lights-Phase 2	hydrogen addition	57,250	SDA residue	General Electric	hydrogen, syngas		2012