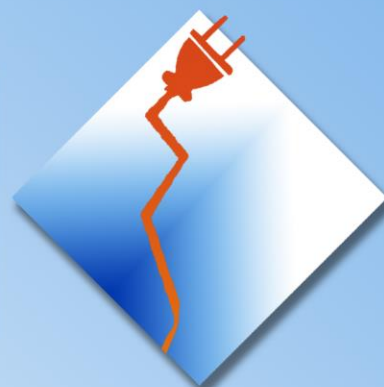
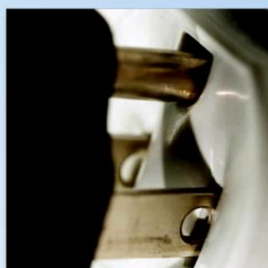
Electricity Framework
5 Year Review 2013
Phase I Report





Results and Analysis prepared for:

Clean Air Strategic Alliance (CASA)

Ms. Robyn-Leigh Jacobsen

10th Floor, 10035 – 108 Street

Edmonton, Alberta T5J 3E1

Issued: April 8, 2014

Disclaimer

The information and data provided in this report has been obtained or prepared from sources that are believed to be reliable and accurate but has not necessarily been independently verified. EDC Associates Ltd. makes no representations or warranties as to the accuracy or completeness of such information and data nor the conclusions that have been derived from its use. Further, the data in this report is generally of a forecast nature and is based on what are believed to be sound and reasonable methodologies and assumptions, however cannot be warranted or guaranteed with respect to accuracy. Therefore, any use of the information by the reader or other recipient shall be at the sole risk and responsibility of such reader or recipient.

The information provided in this report and the facts upon which the information is based as well as the information itself may change at any time without notice subject to market conditions and the assumptions made thereto. EDC Associates Ltd. is under no obligation to update the information or to provide more complete or accurate information when it becomes available.

EDC Associates Ltd. expressly disclaims and takes no responsibility and shall not be liable for any financial or economic decisions or market positions taken by any person based in any way on information presented in this report, for any interpretation or misunderstanding of any such information on the part of any person or for any losses, costs or other damages whatsoever and howsoever caused in connection with any use of such information, including all losses, costs or other damages such as consequential or indirect losses, loss of revenue, loss of expected profit or loss of income, whether or not as a result of any negligent act or omission by EDC Associates Ltd.

The opinions and conclusions contained in this report are the views of EDC and may not represent the view of CASA or the Electricity Project Team members.

EDC Associates Ltd.

Suite #310, 505-8th Avenue SW
Calgary, AB T2P 1G2
www.EDCAssociates.com

Table of Contents

List of Figures

List of Tables

Executive Summary

On November 27, 2013, the Clean Air Strategic Alliance (CASA) contracted EDC Associates Ltd. (EDCA) to provide a detailed review of the assumptions that produced two past Generation and Emissions Forecasts:

1) The 2003 NS-1 Scenario (2003 Model),

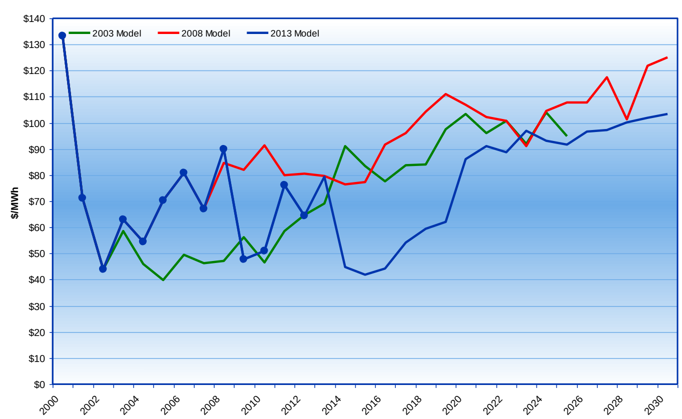
2) The 2008/2009 Base Case (2009 Model) and,

3) The EDCA's Q4-2013 Quarterly Forecast Update.

Although each of the 3 models incorporate the "*thinking of the day*" respecting their key underlying assumptions, the actual values of these fundamentals departed from the original forecast over time, ultimately bringing about differing supply/demand relationships, pool price expectations and emission forecasts between the models. For example, in 2003, the model assumed the Alberta's economy would be fairly strong, with real GDP growth forecast to average 3.4% between 2004 and 2008. In actuality, GDP growth averaged 5.4%, almost twice the expectation, driven primarily by a substantial increase in the price of crude oil and natural gas. This brought about unprecedented drilling for natural gas and expedited the development of Alberta's oil sands projects. The 2009 model assumed an acceleration of the robust demand growth and natural gas prices, unaware of the impending fall in AIES energy sales of 0.4% and 2.8% in late-2008 and 2009, respectively, before resuming its growth, albeit at a slower pace. Gas prices collapsed from a monthly average peak of $10.60/GJ in June 2008 to a low of $1.59/GJ in April 2012, as game-changing technological advances (multi-bore horizontal drilling, down-hole seismic and fracking) revived a gas supply growth that easily outpaced demand growth and promised to keep gas prices low and less volatile indefinitely.

Figure 1 presents the pool price forecasts from the 3 models, with blue dots representing historical values. On top of the weaker AIES demand and lower natural gas forecast, in September 2012 the new Federal GHG regulations extended coal-fired retirement dates by an average 3.5 years[1], which, if expected earlier may have helped to stall some of the new generation builds that have contributed to the expected upcoming supply glut. The commissioning of several large wind farms (e.g., Enbridge/EDF's 300 MW Blackspring Ridge) and ENMAX/Capital Power's 800 MW Shepard Energy Centre, are expected to keep pool prices depressed over the next 5 years. The 2013 model predicts a 5-year average price (2014-2018) of $48.90/MWh, well down from the $89.16/MWh in the 2009 model and $84.00/MWh in the 2003 model in that same timeframe.

Figure 1 – Comparison of 3 Pool Price Forecasts ($/MWh)



---

[1] From a previously floated federal proposal in August 2011, which proposed a 45-year end of life for coal plants. Depending on whether a unit was governed by a cut-off date based on their year of service (2019 (pre-1975) or 2029 (pre-1985)) or the end of their 50th year, units moved more or less than the full 5 years, averaging 3.5 additional years across the fleet.

In the long-term (2019 to 2025), the predominant source of new baseload generation will shift away from coal towards combined cycle gas-fired generation, as coal capital costs soar, emissions compliance costs expand and gas prices remain subdued. At the lower gas prices, the anticipated life-cycle pool price can be lower than before and still incent the construction of new generation, pushing the 2013 model below the prior models, averaging $87.12/MWh, as compared to $98.42/MWh in the 2003 model and $103.48/MWh in the 2009 model.

The CO_2 emission intensity of gas-fired generation is less than half that of coal plants. As gas-fired generation makes up a progressively larger percentage of the fleet capacity and production, total emissions will spontaneously drop from the forecasts in prior studies, even without changes to carbon costs and lower total expected electricity production. As CO_2 regulation forces coal unit closures and thus lowers CO_2 emissions, it also reduces the other emissions (NOx, SOx, Hg, PM, currently only addressed in provincial legislation) from those same coal units that would otherwise have been produced by those coal plants if they had continued to run indefinitely.

Changes in federal legislation have also had an impact on emissions, directly for $CO_{2,}$ but also indirectly for certain Criteria Air Contaminants ("CACs": NOx, SOx, Hg and Particulate Matter (PM)). Although the regulations are effective as of September 2012, the federal government is likely to add further features to the emissions rules, including as yet undetermined "Equivalencing" between the provincial and federal regimes, other fuel types than coal, and other emissions.

Throughout the report, the various assumptions change across the three study periods. Table 1 summarizes the main changes. Most assumption changes affect the overall electricity production and the fleet mix. Individual assumed unit Intensities do not change much between 2003 and 2008, but are typically lower than actuals. Generally, compliance fee changes are not large enough do not change the merit order significantly.

Table 1 -Summary of Model Changes

Assumption	2003	2008-09	2013
Oil Price/Economy	Low $30 Oil/$5 Gas, $CDN=0.75	Very High $100 Oil/$10 Gas, Very Optimistic	Strong $95 Oil, $6 Gas, Slump in 2009-10, strong in 2014
Load Growth	Steady, good growth	Very optimistic growth	Much more subdued
Coal Retirements	45 Years	45 Years	Old coal retires 3.5 years later
Gen Additions	Cogen to dominate, some new coal, less wind	Coal Dominates, strong wind, some hydro	Combined Cycle dominates, KH3 last coal, Strong wind
Pool Price	Low '04-'14	High Throughout	High '06-08, low '14-'20
GHG	3.5% Renewables	High GHG Compliance Fees, SGER	September '12, Mandatory Coal Retirements
NOx, SOx, Hg, PM	Same Factors, Lower than Actuals, slow conversions, minimal effect on dispatch	Same Factors, Lower than Actuals faster Conversions, minimal effect on dispatch	May revise factors

Project Background and Scope of Work

Background

The Clean Air Strategic Alliance (CASA) is currently reviewing elements of the Emissions Management Framework for the Alberta Electricity Sector (Alberta Framework) developed by the Electricity Project Team in 2003. This is the second Five-Year Review and is in accordance with Recommendation 29 from the Alberta Framework.

The Electricity Framework Review Project Team directed a working group to:

- Develop a base case for the emissions profile expected under the Alberta Framework, and
- Update the emission forecast undertaken in 2009.

The consultant, EDC responded to the working group's request for proposal based on the scope of work described below.

Services Required

The project scope is divided into two phases. Phase 1, the subject of this report, provides the CASA task group with detailed information about the assumptions used to carry out previous modeling for CASA. Upon completion of Phase 1, the task group will make a determination if Phase 2 is needed and will advise the consultant. Phase 2, if it proceeds, will update the 2008/09 emissions and generation forecast submitted to CASA in 2009. The details of Phase 1 and 2 are itemized below:

Phase 1

The first phase of work provides a detailed comparison of the key assumptions for the following:

- 2003 Generation and Emissions Forecast prepared by EDCA for CASA
- 2009 Generation and Emissions Forecast prepared by EDCA for CASA
- Alberta's Annual Electricity Study 2013: Power Struggle – How wind and co-gen volatility interact.

In addition to the macro economic assumptions previously provided by EDCA, the key assumptions provided for each of the model runs above include the following:

1) How is compliance with the Alberta Framework (CO_2, NOx, SOx, Hg and PM) and the Federal GHG Regulation (only CO_2) assumed to be achieved?
    a. What is the assumed environmental legislation compliance cost (capital and operating) for each pollutant?
    b. How does the model allocate these costs to affected units (i.e. one time cost, vs. adding to levelized costs; and over what time period are the costs assumed to be amortized)?
    c. How are emissions credits accounted for in the projections?
2) What are the assumed future emission / BATEA standards?
3) What are the primary triggers for unit shut downs in the various scenarios?
4) How does the model deem investment decisions to be made (i.e. does it consider a rate of return, reserve margin, etc.)?

Where assumptions were made in historical forecasts that didn't reflect actual values seen, the comparison should also comment on whether this meant material differences in the forecast.

Phase 2

The second phase of work would actually update the 2008/09 emission and generation forecast.

Report Layout

This report lays out the track of assumption changes across the three vintages of reports (2003, 2009, 2013). The 2013 report is in the process of being developed and so contains the proposed assumptions, subject to review by the steering group. The assumptions are presented in five different sections. The first section describes the changing view of global, Canadian and provincial macroeconomics, with emphasis on the price of oil and gas, the main drivers of the Alberta economy.

The second section translates these economic variables into EDCs changing view of the long-term strip of Alberta electricity demand from the changing perspective of the successive 5 year review dates.

The third section translates this electricity consumption into a corresponding change in EDC's view of the fleet makeup by year over the study period, both additions and retirements, by fuel type (coal, gas (cogen, combined cycle and simple cycle), wind and hydro) and in terms of maximum capacity and estimated annual production, given that changing fleet mix and the changing offer strategies of each generator, partially reflective of their differential changes in fuel (e.g. coal vs natural gas escalation) and other operating costs, including emissions compliance costs.

The fourth section compares the assumed changes in implementation mechanics of both federal (CO_2 only) and provincial (CO_2, NOx, SOx, Hg, particulate Matter (PM)) emission compliance rules and prices and how they are implemented in the model. This section also compares the assumed pre- and post-mitigation emission intensities (e.g. t/MWh) and planned and actual conversion dates, by pollutant in terms of:

a) Legislated Targets,
b) Model Assumptions, and
c) Observed actuals.

Because the 2013 work is still to be performed, the report occasionally must venture into the Phase 2 scope, which is the actual running of the model, to highlight differences between the analyses amongst the three time perspectives. For example, this report speculates on how the 2013 Phase 2 report will handle the capital costs of mitigation devices already in place versus those that will eventually be needed after a significant number of units meet their respective "end of design life" and are forced by permit caveats to meet tighter BATEA standards.

Throughout the report, graphs typically assign the green line to 2003 values, red to 2009 and blue to 2013.

Macroeconomic Forecast

This section reviews changes between the 3 study timeframes in the major macroeconomic variables that influence Alberta's future GDP growth. Since GDP and electricity consumption are closely correlated, they help provide a context for the energy demand forecast. Of several scenarios run in 2003, the only demand scenario used as a comparator in the 2008/9 update was the scenario termed "Optimized Case -NS1", an adjustment to the "Reference Case" to reflect the likely impacts of the Kyoto Protocol on the overall economic climate in Canada and Alberta. The effects of implementing Kyoto on the Alberta economy were expected to be felt not only through lower overall national economic activity but through lower investment in the oil sector, particularly oilsands production. It was assumed that the emission restrictions would be stringent enough to delay or reduce investment in the refining and upgrading sector. A less than offsetting effect was expected from higher anticipated natural gas prices, as environmental issues were expected to increase the demand for that cleaner burning fuel.

Global and United States Economy

2003

Although US showed stellar productivity gains at 4.7%, it was at the cost of net job losses of 0.9% in 2002, with the economy growing at 2.4%. Expenditures kept the economy afloat, as consumer spending grew by 3.1% and government expenditure by 4.4%. However, business investment dropped for a second year in a row, hitting 5.7%, reflecting the weak equity markets, high levels of spare capacity and strained business investment growth. The Iraq war, provoked by the September 2001/9/11 attack, rocked the financial markets and increased debt levels. At that time, no one anticipated it would linger until 2011 and many expected the economy to benefit from it. US President Bush started a long series of fiscal and monetary stimulus measures to resuscitate the flagging economy, which was expected to increase personal income growth in the third quarter of 2003 and first quarter of 2004.

2009

The subprime lending issue led to a nationwide credit crisis. Weakness in financial and housing markets and low real GDP growth contributed symbiotically to the impending recession. Consumer spending issues, home foreclosures and bank failures, rising domestic unemployment and increasing food and fuel prices all compromised the US ability to weather the financial storm.

Job losses grew through the remainder of 2008 and into 2009 with no end in sight. High unemployment depressed personal income which, in turn, reduced credit and domestic consumption. Financial market losses eroded personal net worth and curbed consumer spending. During the first quarter of 2008, Congress passed a fiscal stimulus package aimed at boosting consumer spending. Corporate bailouts further taxed the federal flexibility.

2009-13

The National Bureau of Economic Research declared the US recession, which lasted officially from December 2007 to June 2009, as the longest since WWII. During the next five years, the world teetered on the brink of a financial catastrophe, with successive European countries facing imminent default on sovereign debt (e.g. Greece, Portugal, Spain, Ireland). The US Federal Reserve Bank (US Fed) instituted an aggressive monetary policy and successive stimulus packages and cut its overnight lending rate to near zero, all the while running successive $Trillion budget deficits. Unemployment hovered in the 10% range until late 2009. Scores of banks went bankrupt in 2009 and 2010 and several hundred more were on watch, as the US introduced the first round of Quantitative Easing (QE1). House prices fell to negative equity levels for a large fraction of homeowners and unsold inventories rose, with only a temporary respite during a first-time home buyer's tax credit in 2009-10. The US credit rating was down-graded by S&P in August 2011, citing the cumbersome and uncertain process of extending the debt ceiling and unprecedented deficit spending.

The unemployment rate finally dropped in 2011 to 9.0% and again to 8.1% in 2012. Only 16 banks failed during the first half of 2013, although the list of "problem banks" was still over 650. In June, the Federal Reserve Bank announced its intentions to moderate its monetary stimulus policy, showing guarded optimism for recovery. The 2014 GDP growth is expected to be 2.7%, up from the frail 1.6% in 2013.

The only bright light was the persistent yearly 8-10% economic expansion in China and India.

Canada

2003

Canada's economy was much healthier in 2003 than the US economy. Canada experienced its highest job growth rate since 1987, at 3.7%. Further, GDP grew at 3.4%, above the estimated long-term sustainable level and was partly to blame for a January inflation rate of 4.5%, its highest level in more than 11 years. Housing activity reached a 13-year high annual pace in February. Although Canadian productivity performance improved for the year as a whole (at 2.2%) it fell in the last quarter of 2002 for the first time in two years, already trailing far behind the US for the third year in a row. The Bank of Canada responded with a series of interest rate hikes to 3.25%. The 3-month T-Bill rate was expected to reach 5.5% in the long run. The Canadian dollar started the year at US$0.635 but rallied to around US$0.74, supported by Canada-US short-term interest rate spreads, rising non-energy commodity prices, Canada's large current account surplus and the supposedly unsustainable US trade deficit. By early March, the US$ had depreciated by 19% against the Euro and by 7% against the Canadian dollar. The long-term expected Canada / US exchange rate was expected to be $0.70 US/$Cdn.

Housing activity reached a 13-year high annual pace in February. Job growth flourished and merchandise exports and factory shipments rose 3.7% to reach their highest level in two years, in spite of the international uncertainty. Canadian companies were expected to be slow in building up inventories. A pattern of high energy prices and depressed non-energy exports was expected in the first half of 2003. An 11.5% growth in the Canadian Federal budget was expected to spur spending, its highest level since 1996-1997 at 12.2%. EDC expected GDP to grow at 3% for 2003, 3.5% for 2004 and then 3% for the long-term. The unemployment rate was expected to trend downward for 4 years to a long-term sustainable level of 6.8%.

2009

The US economy directly impacted Canada export sales. In spite of signals of modest economic growth for the Canadian market, low unemployment and average wage growth allowed for only modest gains in the domestic economy, levelizing real GDP growth. The Bank of Canada (BOC) lowered the overnight rate 3% in attempts to thwart the cross border effects of a longer and more pronounced US economic slowdown.

The BOC expected the domestic economy to remain strong despite tightening credit conditions and slowing business and consumer spending. The decrease in GST and the increased competition from imports through the higher exchange rate both contributed to lower prices for retail domestic goods. As a result, inflation hovered near the BOC's target rate of 2%, with gasoline prices and mortgage costs as the main contributing factors.

2009-2013

The Loonie peaked in October 2007 at 1.10US$/C$ and then fell to parity with the American dollar where it remained throughout much of 2008. The historical positive correlation with the price of oil and the early 2008 oil price escalation supported the strong Loonie. However, after peaking in July 2008, oil and gas prices began their precipitous drop. By the end of 2008, after the CASA emissions study was cast, the economy was slowing down, despite strong domestic retail sales, low unemployment and healthy hourly wage growth. Total unemployment peaked at 8.7% in mid-2009.

2012 housing starts were 25% over 2010 and 2011 levels to 215,000, but were expected to fall again into the 180,000 range for 2013-14. The exchange rate reached parity in 2012 but sagged in 2013 to 0.96$US/$Cdn, with a long-term expectation of $0.99US/$Cdn. For 2013, inflation is still below the policy target 2%. Unemployment is expected to reach 7.1% in 2013 and 6.8% in 2014. Canadian real GDP is expected to be a moderate 1.8% in 2013 and 2.4% in 2014.

Alberta

2003

2003 GDP growth in Alberta was forecast at 4.5%, supported by an expectation of strong housing starts and growing oil and gas exports. The very strong growth was expected to continue into 2004 (at 3.5%). The annual average growth was forecast at 3.2% annually, with exports rising at an annual rate of 4.6%, largely driven by oil and natural gas exports and a generous lineup of oilsands projects. The provincial unemployment rate was forecast at 5.1% for 2003 and was expected to average 5.3% from 2003 to 2020. The lower unemployment rate in Alberta relative to the rest of the country was expected to continue to encourage fulsome net in-migration, averaging 48,600/year across the forecast period.

2009

Even with 88% of Alberta's exports destined for the flagging US market, tight unemployment, a real GDP growth at almost twice Canada's average and large increases in non-conventional production, exports hit their highest monthly figure in history. Over the previous five years, Alberta's population had grown by 2.2%, with inter-provincial immigration accounting for the majority of increases. Alberta was expected to top 3.5 million people by the end of 2008.

Building permits were down from 2007, but were explained away by some of the huge one-off projects that were issued building permits in 2007, such as the $1.1 billion Bow Tower in Calgary.

The Albertan economy was cooling down slightly from a high of 7.0% real GDP growth in 2006, with the 2008 forecast calling for real GDP growth of 3.7% and 3.8% in 2008 and 2009, respectively, most of it from capital intensive oil and gas related projects. Over the forecast period, real GDP growth was expected to average 4.0% as real GDP growth was expected to rise in the later years of the forecast period. From this perspective, the 2009 report was still painting a rosy picture, with GDP and electricity demand growth well above what had been assumed in the 2003 CASA report.

2009-13

Oil prices moved down to the $55/bbl range through the first three quarters of 2009, setting the stage for project cancellations and deferrals in 2010. By 2010, Alberta still enjoyed a country-leading 3.6% unemployment rate and oil prices were headed back up to the $75/bbl level. Net migration returned to the positive side, but GDP contracted for the first time since 1986, by 4.5%. The GDP then grew at about 4%/year from 2010-2012. Building permits were up and unemployment fell from 6.1% to 4.6 in that same period, as in-migration rebounded to 86,000 for 2012. Land sales set records in 2010 and 2011 but languished in 2012 and 2013. Even at that, electricity demand did not recover to 2008 levels until 2011, most of the decline coming from the Oil and Gas and related Commercial sectors.

Oil Production and Price

2003

Oil prices had been dominated by political events over the previous months, especially as the conflict with Iraq came to a head. With an expectation of a resolution, crude oil prices come down from the US$35-38/bbl to in February and March of 2003 to below US$30/bbl in April. NYMEX futures were indicating prices between US$25/bbl and US$28/bbl over the summer months. Prices were forecast to fall to US$22/bbl by 2006, and then remain relatively constant in real terms. It was even speculated that Iraq might leave OPEC and reduce the cartel's influence on price.

Alberta's oil production was expected to increase dramatically between 2003 and 2009, from 100 million m^3/year in 2003 to just over 150 million m^3/year in 2009. Alberta's production of conventional crude was expected to continue its decline while bitumen and synthetic crude would make up the vast majority of production by 2009. The relative share for these classes was expected to increase throughout the forecast horizon.

2009

In 2008, the price of WTI had escalated dramatically to US$126/bbl, still driven by the "peak oil" mindset. Between 2008 and 2013, the WTI average price was forecast to average US$89.04/bbl, reaching

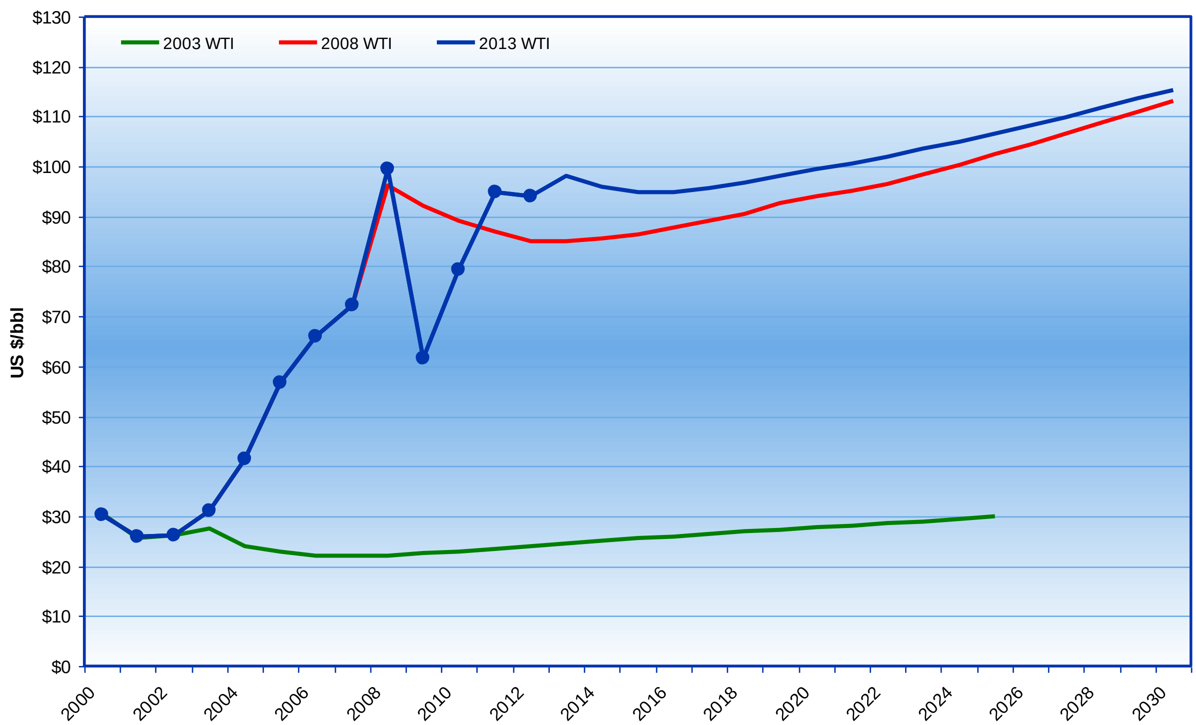
US$113.07/bbl by 2030, with no end in sight to $100/bbl plus WTI prices. This bullish oil price forecast ($60/bbl higher than 2003) generated considerable differences in both expected load growth and behind the fence generation projections.

2009-2013

Just after the 2009 analysis was finalized, both oil price and natural gas prices collapsed from their mid-summer highs to only $62/bbl in 2009, finally finding some stability around $80/bbl in 2010. The OPEC cartel, still the most influential seller, felt comfortable targeting a $70-85/bbl oil price. By 2011, China and India were emerging as major new sources of sustained demand growth. Oil prices averaged $94/bbl for both 2011 and 2012. However, differentials between heavy and light oils were contracting to the point that many Alberta upgrader projects were being deferred or cancelled. New drilling technologies (horizontal, down-hole seismic, fracking) were making a surprising impact on US on-shore production, significantly reducing US dependence on imported oil, but still allowing $100/bbl oil and plenty of room for Alberta oil, albeit slightly constrained by takeaway pipeline capacity.

This return to high-priced oil has put Alberta back on a solid growth trajectory, albeit with at least a 3 year lag from the 2009 study and a slightly slower growth rate.

Figure 2 – Nominal WTI Prices ($US/bbl)



Natural Gas Production and Price

2003

AECO–C Natural gas daily spot prices ranged from a low of $5.42/GJ to a high of $15.29/GJ in the first half of 2003 and became unconnected with oil price. The driving force behind the run-up was the below-average US storage levels. In April, stocks were 46% below the 5 year average and 57% below the same month in the prior year, the result of a very cold US winter. Natural gas stocks were expected to recover somewhat as the low storage levels and associated high prices provoked record forecast drilling in 2003. For example, the Petroleum Services Association of Canada (PSAC) forecast a total well count of 18,300 in Canada for the year. Of these wells, 63% (11,352) were expected to be natural gas, still using conventional drilling.

With this correction in exploration, complemented with frontier (arctic and off shore) gas and Liquefied Natural Gas (LGN) imports, the price of gas was expected to fall to an average $6/GJ range over the forecast.

Figure 3 – AECO-C Natural Gas Price ($/GJ)

2009

Contemporaneous to the 2009 CASA report, 2008 natural gas prices averaged C$8.23/GJ, an increase of 34% from the 2007 average. The low 2007 prices slowed rig activity in 2007, resulting in significantly lower WCSB production. The reduction in production supported higher prices and stronger upticks in the forward natural gas market price which was expected to encourage activity in the WCSB.

The forecast at that time called for Alberta natural gas prices averaging $7.91/GJ between 2008 and 2013 and $8.96/GJ over the entire forecast period 2008 to 2030, $3/GJ higher than 2003 estimates.

2009-2013

After natural gas prices peaked in mid-2008, AECO-C prices plummeted to $3.80/GJ for 2009 and 2010 and fell further to average only 2.27/GJ for all of 2012, as storage levels consistently beat the 5-year maximum curve. At these prices, US electricity generators began substituting natural gas for coal, only partially tempering the drop in gas price. Reduced US industrial demand did not deter new shale oil and gas drilling, which kept adding more capacity to an already flush market, partly to comply with development obligations and partly to exploit well-priced associated NG liquids. High gas pipeline tariffs temporarily widened the Alberta/Chicago gas prices until a recent tariff refiling, coincident with the start of a colder than normal heating season, reduced Alberta storage levels and allowed some relief from the dismal sub-$2/GJ AECO-C price.

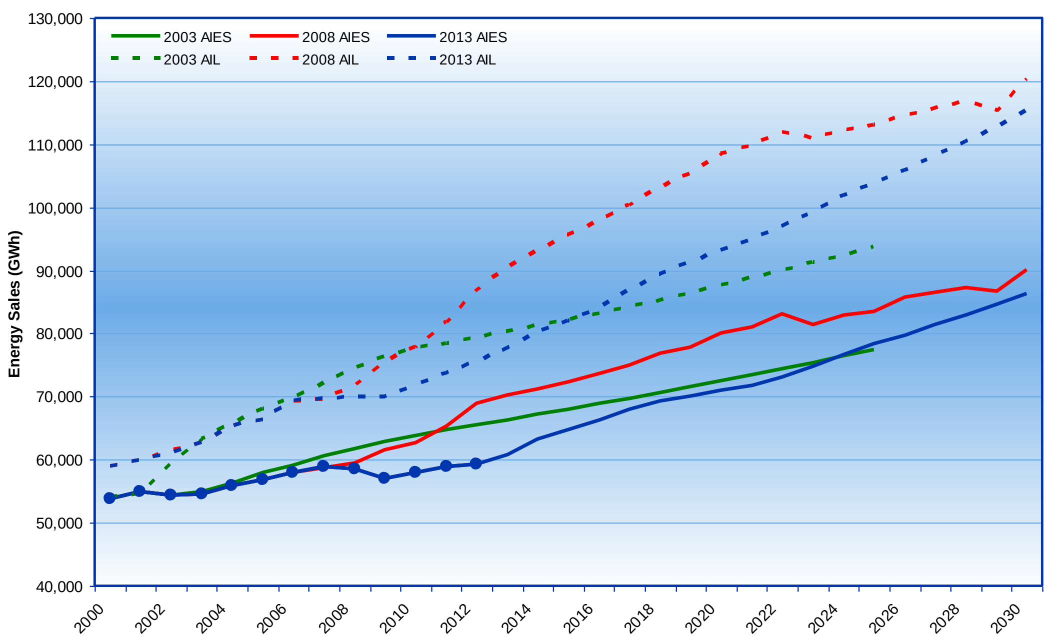
The single biggest contributor to the continued soft prices and rising production levels was the emergence of shale gas recovery techniques, a phenomenon not even contemplated during the 2009 report timeframe. Alberta is just now beginning to join other Canadian and US producing regions (e.g. BC Horn River, Saskatchewan Bakken, Marcellus, Eagle Ford, Haynesville) in the exploitation of shale gas reserves. Gas producers are actively encouraging the development of new uses for this abundance of gas (LNG vehicles, electricity generation, high-horsepower motors), but the production costs are such that these lower prices are likely to continue.

Electric Energy and Demand Forecast

2003

AIES demand fell in 2003, some from a redefinition of behind the fence load and some from the beginning of a gradual reduction in overall exports, which has continued through to 2013. In 2002, prices in neighboring jurisdictions were relatively low and as a result, AIES exports fell from 2,294 GWh in 2001 to only 616 GWh in 2002. It was assumed that the tie-line capacities would not be expanded but that by 2025, annual exports would still attain a level of more than 1,230 GWh.
Residential consumption reflected the strong growth in population and households, as well as additional average usage, tempered by an expectation of meagre energy efficiency gains. Residential sales were expected to grow at an average compounded growth rate of 2.3%, from an estimated 7,530 GWh in 2003 to 12,441 GWh by 2025. Commercial AIES energy sales were forecast to grow at an annualized rate of 3.1%, from 11,539 GWh in 2003 to 22,088 GWh in 2025.
Total oil and gas AIES energy sales were expected to grow at a modest 1.6%, from 17,360 GWh for 2003 to 25,278 GWh by 2025. However, that did not include the growing volumes of on-site loads fed by onsite generation, which increasingly characterized this customer class, with the expectation that AIL demand would rise by 9%. Energy sales to the Other Industrial category, including the chemical, forestry, cement, coal, food processing and manufacturing sectors, were forecast to grow annually by 1.3%, from 12,090 GWh in 2003 to 16,229 GWh by 2025. AIES peak demand was forecast to grow at an annual rate of 1.9% over the forecast horizon, from 7,727 MW in 2003 to 11,750 MW by 2025. In the Optimized Cases, efficiency, measured as the amount of electricity per million dollars of GDP, was expected to fall from an estimated 538 MWh per million dollars in 2002 to 426 MWh per million dollars in 2025, implying slightly more than 1% gains in efficiency on an average compounded annual basis.

Figure 4 – AIES & AIL Energy Sales (GWh)



2009

Given the massive increase in demand expected in the blossoming oil and gas sectors, AIES energy sales were expected to grow by 3.5% annually between 2008 and 2013, compared to a 1.5% annual average growth rate in the 2003 forecast. Over the entire forecast period (2008-30), the average expected annual growth rate was similarly boosted from 1.6% in the 2003 study to a very aggressive 2.5% in the 2009 study, and from a higher kickoff point reflecting the unprecedented run-up of actual demand preceding 2008. AIL load growth was expected to grow annually by 4.9% between 2008 and 2013 and by 3% out to 2030 compared to the much meeker 1.8% and 2% used in the 2003 AIL forecast.

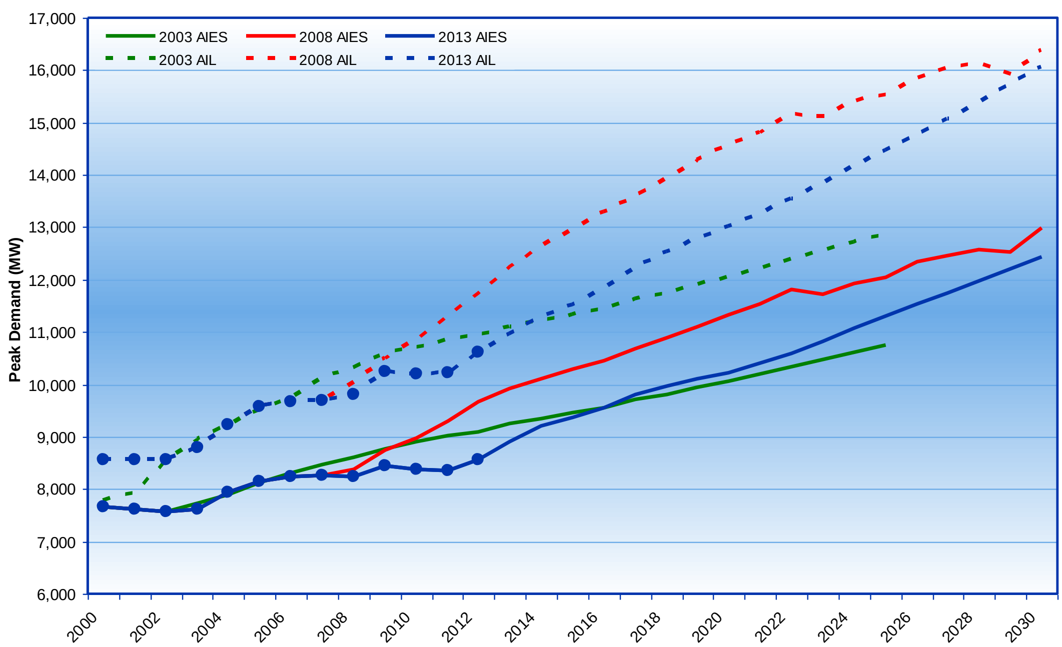
The difference between AIES and AIL demand represents the load being served “behind the fence” by on-site generators, mostly at oil and gas sector plants, both of which were anticipated to increase production in the anticipated higher commodity price environment. The extent of on-site generation was forecast to be much larger in 2009 than 2003, on the expectation that production of bitumen and synthetic oil would more than triple by 2030.

2013

By the year after the 2009 analysis, average hourly domestic AIES demand had deteriorated by 175 MW and did not return to 2008 levels until 2011. Oil and gas prices had discouraged the aggressive expansion plans of the oil patch and all its downstream benefactors, to such an extent that in-migration turned negative for a year. Besides starting from a much lower point in 2009, the estimated rate of AIES energy consumption growth slowed to 2.1% from the 2008 estimate of 2.4%. Alberta Industrial Load (including behind the fence) dropped in similar fashion, slightly mitigated by an accompanying drop in on-site generation. Exports all but dried up from 2008 to 2013, as Alberta pool prices rose compared to BC, Mid-C and Saskatchewan prices.

Figure 5 compares the corresponding peak demand (MW) for the three years, which follow roughly the same trend as energy growth. Pool prices and advances in technology may also affect the way customers respond to pool price (load responsiveness or direct load control), potentially impacting load only at the time the system peaks. The peak demand statistic records the single largest hour experienced in a calendar, so is not as precise a predictor of emissions as is total energy consumed.

Figure 5 – AIES & AIL Peak Demand (MW)



This major reduction in overall expected energy from 2008 to 2013 shows up as a reduction in total emissions, even if the fleet were to remain unchanged. Changes in fleet makeup, detailed in the following section create further reductions in emissions. The effect of changes in emissions compliance cost rules are detailed in a subsequent chapter.

Supply Resource Forecast

The following section outlines the differences between the 3 study timeframes in key assumptions about the timing and extent of future resource additions, and the changing mix of different generation technologies, cost structures and development constraints in response to load growth and regulatory changes.

Although this section focuses on the heavy-runners in Alberta's market – coal, gas, hydro and wind – EDCA's forecasting models do include imports/exports and other smaller forms of generation (primarily biomass and nuclear).

Discussions involving gas-fired generation relate to total generation (i.e., net-to-grid capacity/generation plus behind-the-fence capacity/generation). The majority of EDCA's reports focus on net-to-grid figures as this is the value that makes it to the intersection of supply and demand when setting pool price. However, any type of emission forecasting must also include behind-the-fence values as these are a significant contributor to Alberta's total electricity usage. Although natural gas cogeneration is very efficient, it still has associated GHG and NO_x emissions. An electricity sector emissions forecast would be understated without this component.

Generation Additions

Generation is added to the EDCA dispatch model in two ways over time.

First, publicly announced projects are assigned a probability and a completion date based on their level of development and an assessment of their economic viability. These "named" projects tend to occur during the near/mid-term of the forecast (the next 4-6 years). As projects become more likely to proceed (based on company news or economic conditions) their in-service date is advanced forwards and/or their probability is increased. Conversely, probability and commissioning date are reduced on negative news. The use of probability-weighted generation allows EDCA to include all viable projects in its forecast without picking "winners or losers" while still limiting the total envelope of new generation to a sustainable level. As an example, in EDCA's most current model, several large combined-cycle facilities (Sundance #7, Capital Power's Energy Centre, TransCanada's Saddlebrook and ATCO's proposed Heartland Power Station) are vying to commission in the 2020-2022 range of the forecast. The current load growth would not sustain all 4 projects at once. Second, when necessary, generic capacity is added to total supply in order to meet incremental demand and capacity retirements, preventing prices from surging to uneconomic levels.

2003

In the 2003 model, generic gas-fired capacity was added whenever the reserve margin reached a critical level (13%) deemed necessary to maintain system stability and reliability, while respecting a 3.5% renewable energy target in place for 2008. Given the low forecast capital and fuel cost and emissivity of natural gas generation and the tendency in 2003 for northern Alberta industrial loads to build incremental capacity in excess of their on-site needs, natural gas generation gained preference over coal for the majority of replacement and growth capacity, promising both low cost energy production and reduced emissions.

2009

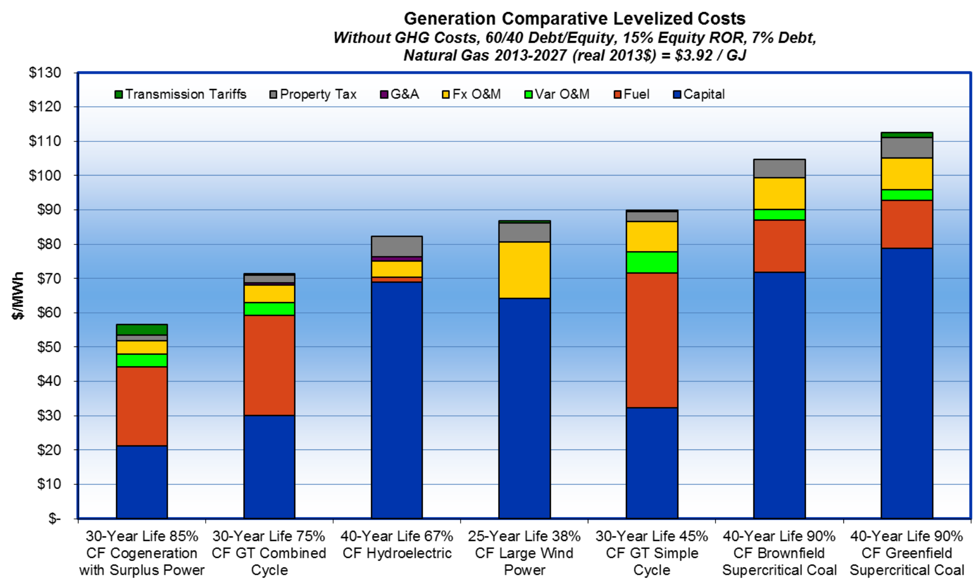
In the 2009 and 2013 models, timing of new generation additions was based on the relationship between the pool price forecast and the levelized cost of the cheapest source of base-load power. In the 2003 model the generator of choice for replacing retirements and meeting new load growth was cogeneration, but in the 2009 model, although it did include some generic net-to-grid gas-fired capacity, generic coal-fired generation returned to favor. Very high gas prices and very low electricity prices had created unavoidable losses to the non-dispatchable cogeneration, which was forced to run at a loss to meet the host steam needs. This provoked a return to coal in spite of the uncertainty surrounding the future cost of carbon emissions. Future capital costs of coal generators were still expected to mimic the very low 2004 Genesee #3 experience.

2013

In 2011, the reported Keephills 3 coal unit capital costs set the unit cost per kW of capacity at a significantly higher mark, enough so that combined-cycle clearly became the least expensive source of new baseload generation. The levelized cost line shows the price line at which a combined cycle unit could be expected to earn enough return to incent a developer to build. The more prices are forecast to be substantially above the levelized cost line, the more generators are incented to build.

EDC calculates a levelized cost for each candidate technology. When new generation is needed to replace retirements or meet load growth, it adds the technology with the cheapest levelized cost, that price that an investor would have to expect over the project's lifetime to earn an adequate return on the invested capital (blue area) after covering all operating costs, including fuel (red area). Cogen is currently the cheapest on a $/MWh basis, but it is limited by the number of interested steam hosts. EDC presumed that the prevailing sizing method would continue, namely that cogen candidates (mostly oilsands plants) would tend to size their generator to their electric load rather than their steam needs (three times as large). The next cheapest generation is combined cycle. Coal, because of its large capital costs and emission cost risk, is far out of the money and is not expected be installed in the future in the current EDCA model.

Figure 6 - Comparative Levelized Costs of Various Technologies (before Emissions Fees)



Average monthly AECO-C natural gas price peaked at $10.60/GJ in June 2008, after which prices rapidly retraced as unexpected increases in natural gas drilling productivity overshot demand growth. The unprecedented and unanticipated technological successes of the last decade enabled producers to drastically increase output and book massive potential reserves, leading to low gas prices. The new technology also had the positive side-effect of reducing gas price volatility. Gas-fired generation was once again the cheapest source of base-load power, this time predominated by combined-cycle rather than cogeneration. However, unlike 2003 when cogeneration developers were burnt by the combination of low electricity prices and high gas prices, are now expected to more closely match generation with on-site load requirements, minimizing merchant risk. Besides coal's huge capital cost disadvantage, new coal builds are now strongly disadvantaged by current Federal environmental policies which require any coal facilities built after July 1, 2015 to meet stringent GHG emission intensity performance standards equal to natural gas-fired combined-cycle technology.

Figure 7 presents EDCA's 2013 forecast of generation additions, from 2004 to 2030. Given the soft prices forecast over the next several years, the earliest it makes economic sense for large new combined-cycle projects to commission would be 2020. As such, pre-2020 contains a variety of announced projects (although heavily weighted towards cogeneration and one large combined-cycle facility), while 2020 onwards is predominately populated by large generic combined-cycle capacity. Almost 1,800 MW of gas-fired generation is being added to the forecast in 2030 to support the 2029 retirement of four large coal facilities (Sundance #6, Battle River #5, Keephills #1 and Keephills #2) plus natural load growth.

Coal

Coal has always been the dominant source of electricity generation in Alberta, accounting for 63.5% of total generation (net-to-grid plus behind-the-fence) in 2004, and 49.7% in 2012. As the most emissive technology, it also dominates the contribution to emission tonnage, having twice the GHG intensity of cleaner-burning gas units. Wind and hydro generation are considered emission-free.

Figure 7 – Total Capacity Additions in the 2013 Model

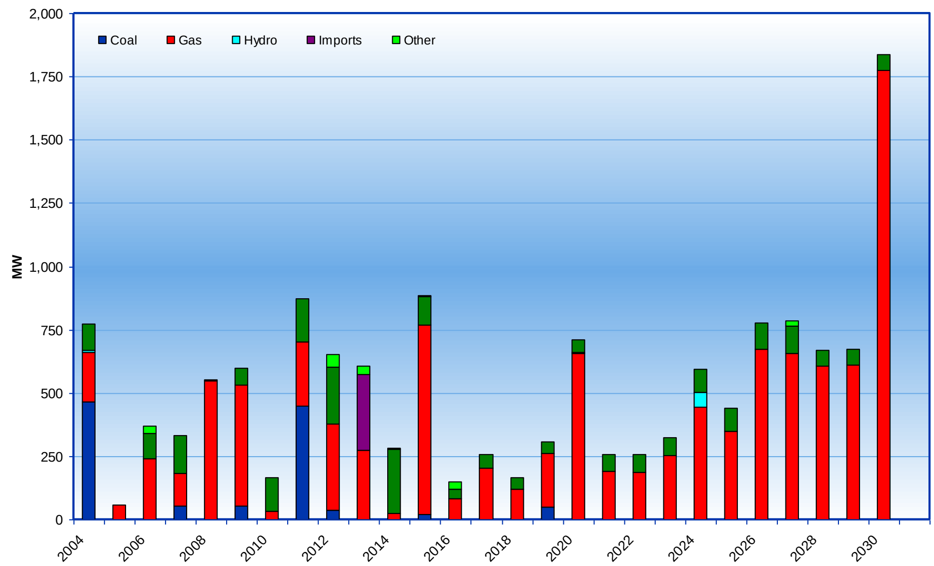
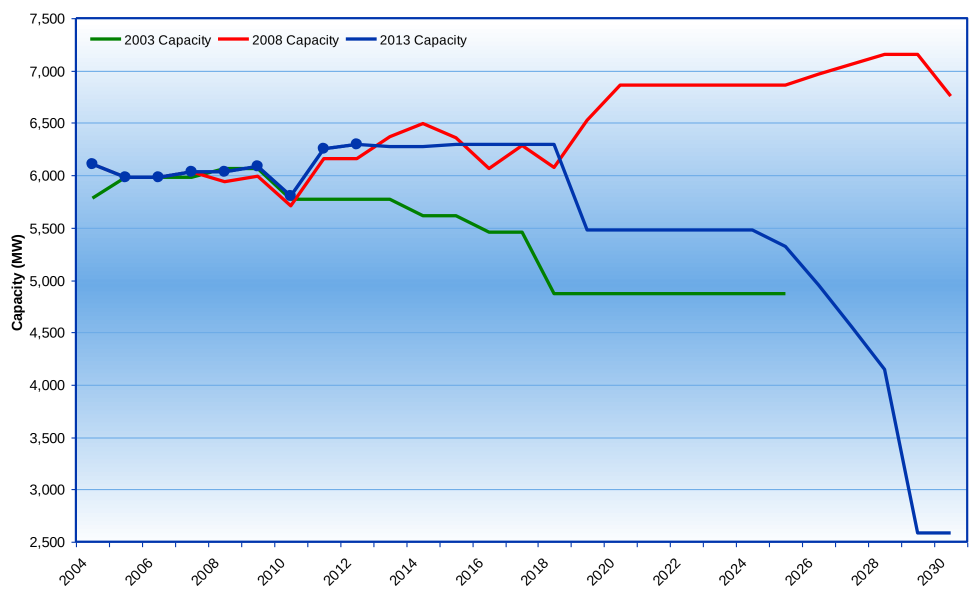


Figure 8 depicts the coal-fired capacity forecasts from the 3 models. Retirement and addition assumptions were radically different between the three studies, with 2013 showing by far the largest reduction.

Figure 8 – Coal-Fired Capacity (MW)



2003

The 2003 forecast (green line) assumes the developers of low cost, cleaner-burning natural gas-fired cogenerators would size their generation much in excess of their load. Therefore, future coal-fired additions were minimal, with only Genesee #3 and Keephills #3 forecast to commission. These newer coal-fired units were expected to last at least 35 years (retiring outside the forecast period). Older units were expected to retire after 50 years of service, with the exception of HR Milner (assumed to retire at the beginning of 2009, reflecting the announced intention of the facility's new owners to only procure coal supply for 2004 through 2008), Battle River #3 and #4 (the beginning of 2014 and 2016 respectively) and Sundance #1 and #2 (the beginning of 2018). The Battle River and Sundance units were forecast to retire at the expiration of their PPA. Coal was forecast to account for 5,610 MW in 2015, then stay at 4,864 MW from 2020 to 2025.

2009

In the 2009 model, in spite of the uncertainties surrounding future environmental costs, the then presumed low future capital cost of coal (based on a well-negotiated and executed commissioning of Genesee #3) and a robustly priced natural gas environment favored coal as the primary choice for future additions, accounting for 6,355 MW in 2015, followed by 6,862 MW in 2020 and 6,758 MW in 2030. Between 2017 and 2020, almost 1,400 MW of coal-fired additions were forecast to meet load growth and retirements. The 2009 model utilized similar retirement assumptions as the 2003 model, with the exception that HR Milner was now forecast to retire at the end of 2015 (the expiration of its fuel supply agreement), while Battle River #3 would not retire until 2016. With proposed Federal legislation then expected to come into effect by 2012, some consideration was given to older plants retiring around that time. However, with the potential to trade emission credits, it was assumed new environmental standards would trigger only retirements that were already contemplated.

Table 2 – Coal-Fired Retirement Assumptions

Coal-Fired Retirement Assumptions					
Unit	ISD Year	2003 Model	2008 Model	2013 Model	Reason
Battle River #3	1969	*2014*	*2016*	2019	50th Year
Sundance #1	1970	*2018*	*2018*	2019	2019 is before 50th Year
Sundance #2	1973	*2018*	*2018*	2019	2019 is before 50th Year
HR Milner	1972	*2005*	*2015*	2019	2019 is before 50th Year
Battle River #4	1975	*2016*	*2016*	2025	50th Year
Sundance #3	1976	*2026*	*2026*	2026	50th Year
Sundance #4	1977	*2027*	*2027*	2027	50th Year
Sundance #5	1978	*2028*	*2028*	2028	50th Year
Sundance #6	1980	*2030*	*2030*	2029	2029 is before 50th Year
Battle River #5	1981	*2031*	*2031*	2029	2029 is before 50th Year
Keephills #1	1983	*2033*	*2033*	2029	2029 is before 50th Year
Keephills #2	1984	*2034*	*2034*	2029	2029 is before 50th Year
Sheerness #1	1986	*2036*	*2036*	2036	50th Year
Genesee #1	1989	*2039*	*2039*	2039	50th Year
Sheerness #2	1990	*2040*	*2040*	2040	50th Year
Genesee #2	1994	*2044*	*2044*	2044	50th Year
Genesee #3	2004	*2040*	*2034*	2054	50th Year
Keephills #3	2011	*2043*	*2041*	2061	50th Year

2013

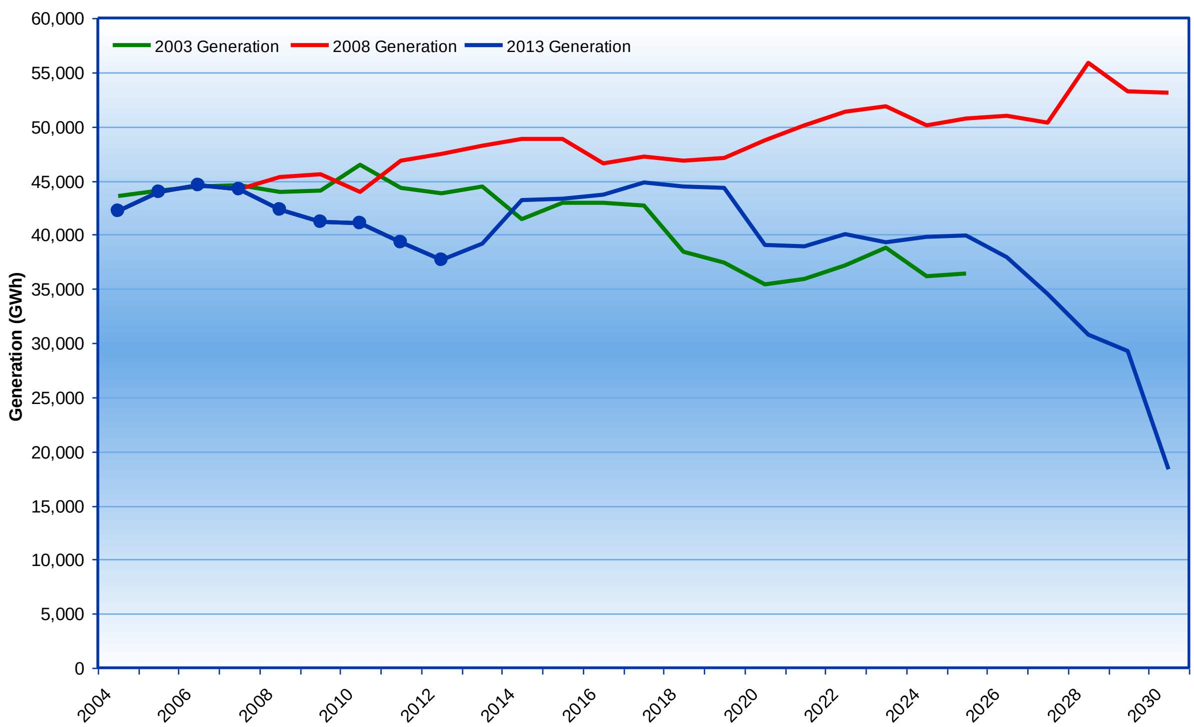
The 2013 coal-fired capacity remains fairly close to the 2009 model until 2019, after which it steadily drops from 6,294 MW in 2015 to 5,473 MW in 2020 and finally 2,580 MW in 2030. First, given depressed natural gas prices, gas-fired generation (combined-cycle) once again becomes the cheapest source of base-load power, pre-empting the 2009 model's preference for coal. Second, the "*Reduction of Carbon Dioxide Emissions from Coal-Fired Generation of Electricity Regulations*" announced on September 5, 2012, requires that any coal-fired facility built after July 1, 2015, must meet a stringent GHG emission intensity performance standard equivalent to natural gas-fired combined-cycle technology. The only future coal plant that could possibly meet this deadline is the HR Milner expansion. Even this unit seems unlikely in light of Maxim Power's announced intention to amend their filings to develop a gas-fired facility. Previously, coal unit lives were based on 50 years of economic life, or in the case of HR Milner, Battle River #3, #4 and Sundance #1 and #2, special exceptions (e.g. end of fuel service agreements and/or PPA expiration).

The 2013 model further shifted retirement assumptions based on the September 5, 2012 Federal GHG regulations. Treatment will be different for units commissioned before or after 1975 and after 1985. The pre-1975 units must retire on the earlier of their 50th birthday or 2019 (e.g. built in 1969, retire in 2019; built in 1974, 2019) or meet strict new GHG emission intensity targets set at 0.42 t/MWh, compared to typical intensities of 0.9 to 1.2 t/MWh for existing coal units. Units commissioned between 1975 and 1984 must retire on the earlier of their 50th anniversary year or 2029, and units built after 1985, at their simple 50 year date. Current market research suggests that all companies intend to run their plants as long as possible, so all facilities (including HR Milner, Battle River #3, Battle River #4, Sundance #1 and Sundance #2) were aligned with the federal legislation. Table 4 compares the retirement assumptions (and rationale for them) across the three models.

Figure 9 compares coal-fired generation from the 2013 Study to the 2003 and 2009 studies. The 2013 model (blue line, with markers for actuals) shows a sharp downward trend after 2024, as retirements easily overpower the one potential addition (HR Milner expansion). The 2009 model (red) shows very strong, growing generation levels because coal was the presumed primary source of new base-load power. Neither the 2003 (green) nor the 2009 model could have anticipated the extended Sundance #1 and #2 outages (December 2010 to Q4-2013).

Softer than forecast coal generation levels will result in lower emission levels. This downward revision to coal-fired generation, combined with the reduced forecasted demand will significantly reduce post-2014 emission results.

Figure 9 – Coal-Fired Generation (GWh)



Coal's capacity factor (average hourly production divided by nameplate capacity) has also significantly reduced. The generator outputs used in the calculation of credits were very genericized, unchanging across time and generally overstated (~4%), being based on a presumed capacity factor and the nameplate capacity, not a calculated dispatch based on generation offers and hourly load. EDC calculated the 5-year strip of actual capacity factors for comparison (2006-2010). Using these lower actual volumes, emission calculations would be lower and the cost of credits higher for the 2013 study.

Table 3 – Comparison of Assumed and Actual Capacity Factors

	Capacity Factor (%)				
	2003	2009	2006-2010 Weighted Average	Report Differences	CASA vs Actual Differences
H.R. Milner	61.6%	61.6%	67.7%		-6.1%
Battle River 3	83.7%	83.7%	83.4%		0.3%
Battle River 4	87.3%	87.3%	82.8%		4.4%
Genesee 3	90.0%	90.0%	84.9%		5.1%
Sundance 1	75.2%	75.2%	76.2%		-1.0%
Sundance 2	84.2%	84.2%	77.3%		6.8%
Sundance 3	89.4%	89.4%	74.7%		14.7%
Sundance 4	90.6%	90.6%	76.7%		13.8%
Sundance 5	91.3%	91.3%	80.1%		11.2%
Sundance 6	93.7%	93.7%	80.3%		13.3%
Battle River 5	89.5%	89.5%	80.2%		9.3%
Keephills 1	93.8%	93.8%	88.3%		5.5%
Keephills 2	95.7%	95.7%	85.3%		10.4%
Sheerness 1	92.4%	92.4%	79.3%		13.1%
Genesee 1	91.6%	91.6%	89.3%		2.3%
Sheerness 2	91.6%	91.6%	79.2%		12.4%
Genesee 2	93.3%	93.3%	88.6%		4.8%
Wabamun 1	88.0%	88.0%			
Wabamun 2	80.6%	80.6%			
Wabamun 3	80.6%	80.6%			
Wabamun 4	86.6%	86.6%	82.8%		3.8%

Gas

2003

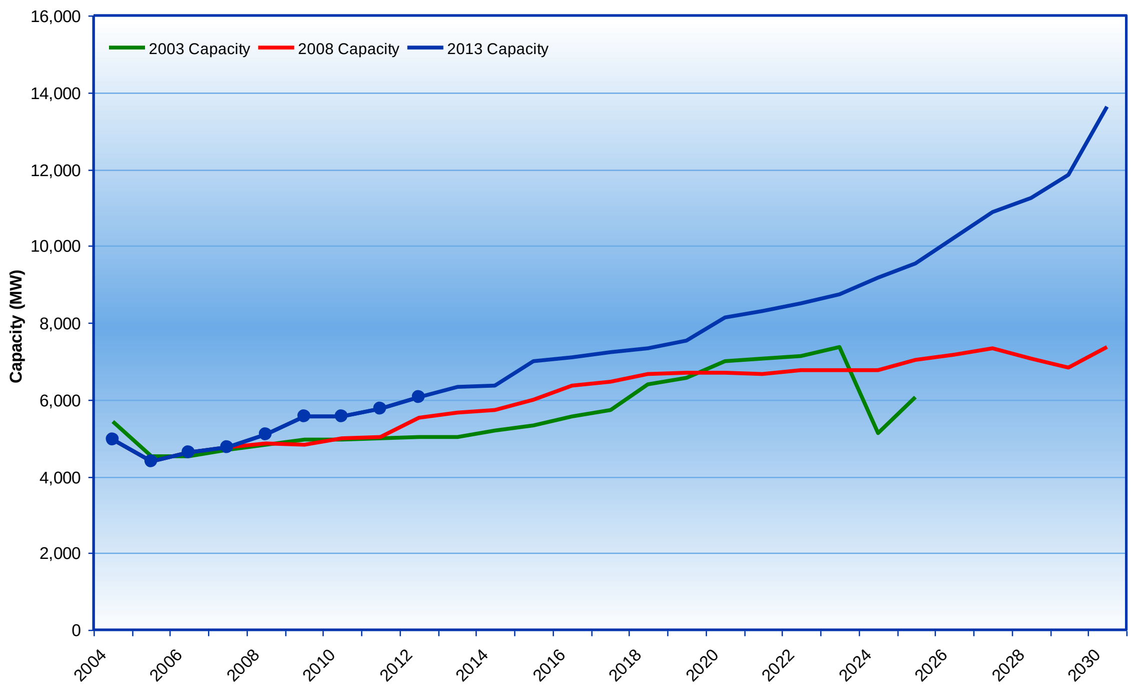
In the 2003 model, cogeneration, mostly serving oilsands projects in northern Alberta, was expected to be the primary source of future base-load power, given the presumption of relatively low gas prices. As depicted in Figure 10, gas-fired capacity was forecast to grow steadily from 5,428 MW in 2003 to 7,350 MW in 2023 (with an anomalous drop to 6,069 MW in 2025). The majority of gas units were assumed to have an economic life between 20 and 30 years, depending on the size of the unit. The original gas-fired steam turbine Clover Bar #1-4, Rossdale #8-10, Sturgeon #1-2 and Rainbow #1-3 were assumed to retire at the end of 2005.

2009

Although the assumptions made in the 2003 model made sense at the time, unexpected natural gas price increases and falling electricity prices created large losses in power sales for the non-dispatchable units that had to run in losing hours when production steam was needed. Significant cost overruns at the larger oil sands projects incented developers to scale back their cogeneration plans to roughly equal their onsite load. Given that coal was still considered the cheapest source of base-load power, in spite of future environmental cost uncertainties, gas-fired capacity was dialed back in the 2009 model. Still, the 2009 model forecast showed such robust AIL demand growth (e.g., a forecast 2015 internal load of 23,302 GWh in the 2009 model versus 14,077 GWh in the 2003 model) that even though the mix of gas generation was lower, total 2008 gas-fired capacity is actually above the 2003 model (see Figure 10).

The 2009 retirement assumptions were left mostly the same as in the 2003 model, with the exception of several larger units (Dow, Syncrude and Suncor) which were extended to 50 years of life. Clover Bar was retired in 2005, Rossdale was retired in 2008 and Rainbow and Sturgeon were assumed to remain operational for TMR services until the northwest transmission system upgrade was completed.

Figure 10 – Gas-Fired Capacity (MW)



2013

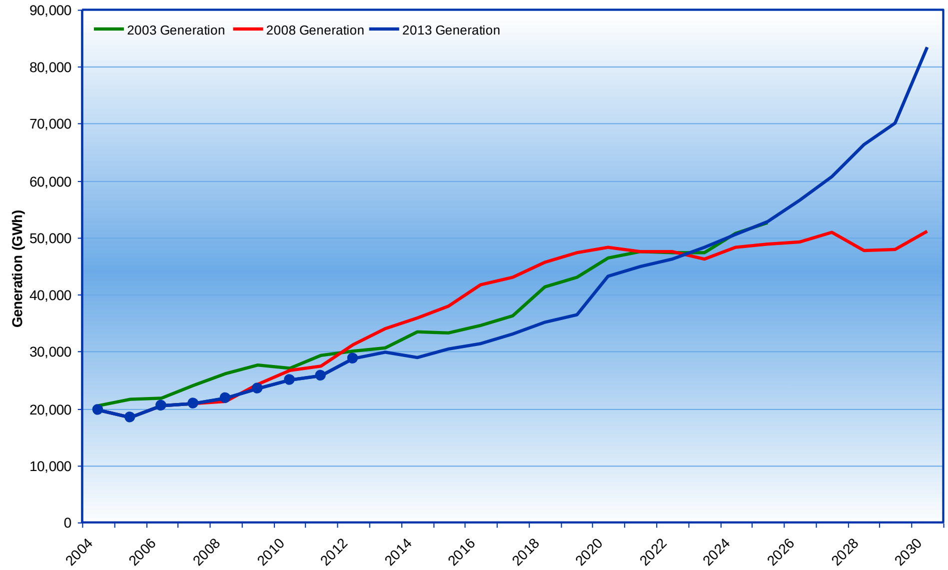
The 2009 model did not anticipate the revolution in gas production and prices, assuming AECO-C price would remain in the $7/GJ range between 2008 and 2012, as compared to the actual drop from $7.74/GJ to $2.27/GJ. This post-2008 low gas price environment, coupled with environmental cost uncertainty, provoked much more gas-fired generation between 2008 and 2012 than forecast, and virtually no new coal. Including future coal retirements and load growth, gas-fired generation (combined-cycle) capacity could now grow from 6,335 MW in 2013 to 7,012 MW in 2015, to 8,120 MW in 2020 (when the first tranche of coal-fired retirements occur) and ultimately 13,635 MW by 2030.

In addition to combined-cycle, the forecast includes several new oil sands cogeneration facilities (e.g., Imperial Oil's Nabiye and Kearl), as well as a few simple-cycle peaking units (e.g., Deerland). At the end of the forecast 2013 assumes almost twice as much (6,159 MW) gas-fired capacity as there was in the 2009 model, including almost 1,800 MW of additional gas-fired capacity just to meet a large tranche of coal-fired retirements at the end of 2029. Retirement assumptions for gas-fired units, including Rainbow and Sturgeon, parallel the 2009 model's assumptions.

Figure 11 compares the forecast energy production (GWh) between the 3 models. In the mid-term (2014 to 2020) the 2013 model (blue line) produces less gas-fired generation despite having significantly more capacity. First, in the 2013 model, near/mid-term AIES demand was forecast to be almost 8,000 GWh/year lower than the 2009 model, requiring less total generation, including gas units. Second, the assumed on-site load in the 2013 model was well below the 2009 model (e.g., in 2015, 17,119 GWh, compared to 23,302 GWh in 2008), requiring a larger amount of behind-the-fence generation. The back half of the most recent forecast follows the expected pattern (with the 2013 model producing roughly 60% more gas-fired generation than the 2009 model).

The 2013 model has an upward inflection in 2020, when more gas-fired generation is needed to meet the first 2019 tranche of coal-fired retirements (HR Milner, Battle River #3, Battle River #4, Sundance #1 and Sundance #2). Post-2020, gas-fired capacity creeps upwards to meet load growth and unit retirements, with a sizeable uptick occurring in 2030, for the 2029 tranche of large retirements (Sundance #6, Battle River #5, Keephills #1 and Keephills #2).

Figure 11 – Gas-Fired Generation (GWh)



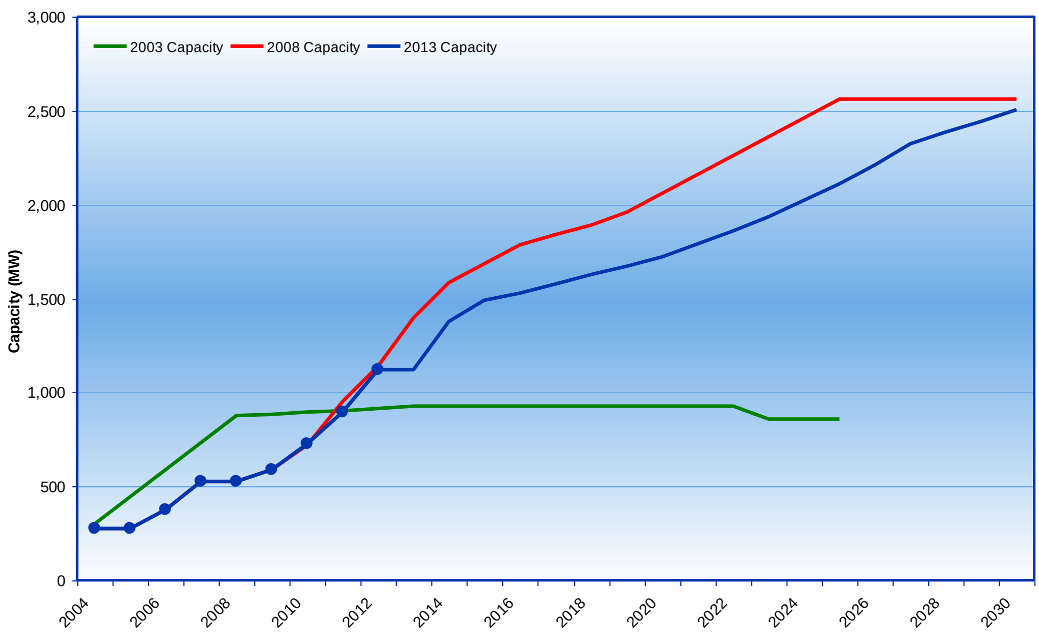
Retirements are based on the unit's economic life, with some special exceptions (e.g., Rainbow #1-3 provides TMR until the northwest transmission system upgrade is commissioned).

Wind

2003

In 2003, it was assumed that there would be a run-up in wind development over several years in order to meet a 3.5% renewable source policy requirement in 2008, and then no growth as subsidies dried up and wind generators could no longer fully recover costs. Wind farms were expected to have a 30 year service life.

Figure 12 – Wind Capacity (MW)



2009

In the 2009 model, potentially lucrative emission credits were expected to incent significant growth in wind farms, given the policy direction of environmental regulation. Wind's ultimate share of total *net-to-grid* capacity by the end of the forecast was targeted at 15% (although the 2009 model was fairly generous with additions and overshot this target by several percent). This target limit was chosen for two reasons. First, there are physical transmission constraints to wind growth; although this may be less of a concern in the future with market policy changes, improved wind forecasting and firming technologies. Second, the discount from pool price tends to increase as the wind fleet grows, having a negative impact on wind project economics. Service lives of farms ranged between 30 and 50 years in the 2009 model.

2013

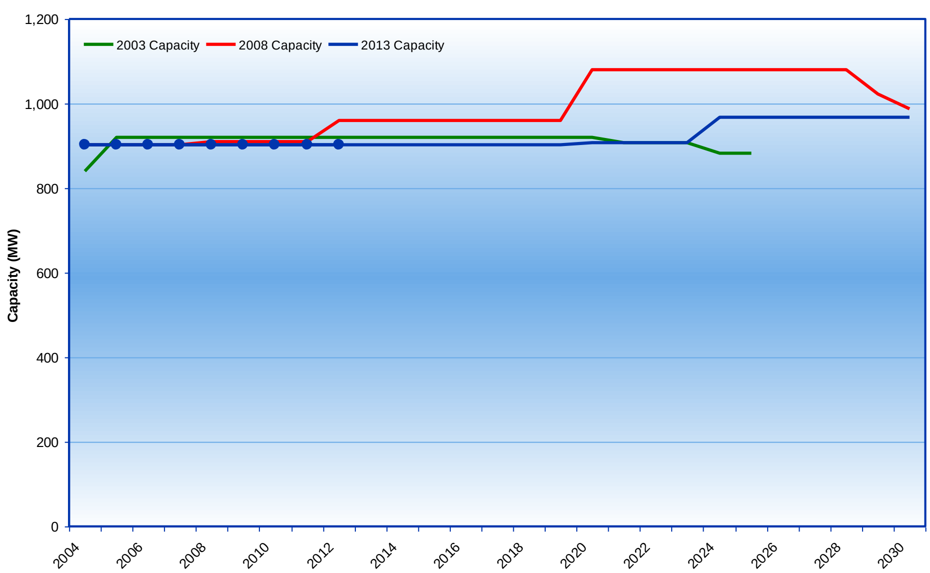
A weaker demand forecast in the 2013 model, coupled with softer pool prices and more current developer information, indicated a subdued wind capacity forecast, now only growing from 1,122 MW in 2013 to 1,489 MW in 2015, 1,723 MW in 2020 and ultimately 2,505 MW in 2030, close to the 15% target. Mainstream's 46 MW Oldman River wind farm and Enbridge/EDF's 300 MW Blackspring Ridge farm should commission in 2014. Although almost 40 wind farms could potentially commission between 2015 and 2019, less than 10% of proposed farms typically reach fruition. EDCA probability weights each project such that the database includes all potential projects while still respecting the limited envelope of total sustainable generation. The service life of wind farms is now uniformly set at 50 years.

Wind remains the primary source of renewable energy in Alberta, although capacity and generation levels are below those forecast in the 2009 model due to weaker demand and pool price expectations.

Hydro

Hydro generation is the second form of renewable generation in Alberta. Of the 902 MW of existing hydroelectric capacity in Alberta, approximately 800 MW is owned and operated by TransAlta. Most existing hydroelectric generation facilities are found in the west-central and southwestern portions of the province. These units are by far the most aged generation type in Alberta, many dating back to the 1950s, and some as far back as the early 1910s. With no retirements and only a few minor additions, the forecast capacity growth for these units has remained relatively stable across the years, as shown in Figure 13. The primary difference between the 2009 and 2013 models is that in 2009 study, Dunvegan commissioned sooner (2012, as compared to 2020) and at a much higher probability (50%, as compared to 5%). In addition, ATCO's 1,200 MW Slave River also seemed more likely in 2009 (10%, commissioning in 2020, as compared to 5% in 2024 in the 2013 model).

Figure 13 – Hydro Capacity (MW)

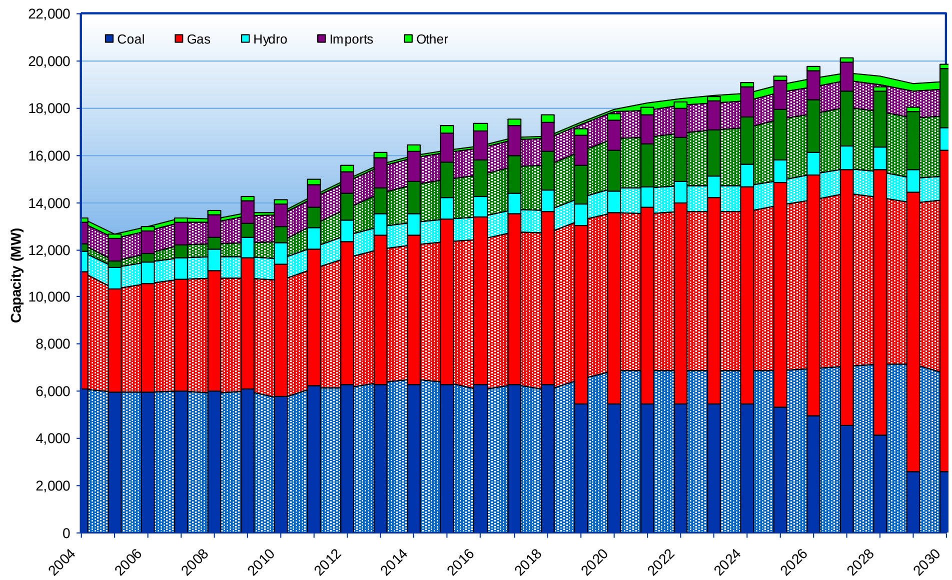


2009 vs 2013 Supply Forecast Summary

Capacity (MW)

Figure 14 and Figure 15 compare the differences in fleet capacities (MW) and production (GWh) between the 2009 and 2013 model, for all fuel types (including imports and others). Solid bars represent the most current model (2013), while shaded area behind the bars depicts the 2009 model.

Figure 14 – 2009 vs 2013: Capacity Forecast (MW)



In the 2013 model, coal capacity gradually tapers off due to retirements stipulated in the latest Federal GHG emission intensity legislation. In the 2009 model, coal capacity grew over time (forecast to be the primary source of future base-load power). Gas-fired capacity increases in both models, but in the 2013 model, combined-cycle is expected to be the technology of choice to meet retirements and load growth, and more cogeneration is built to take advantage of cogeneration efficiency. In the absence of incentives, the lower forecast pool prices in the 2013 forecast discourage renewable forms of generation. Economic, environmental and social constraints make development of any new hydro facilities unlikely.

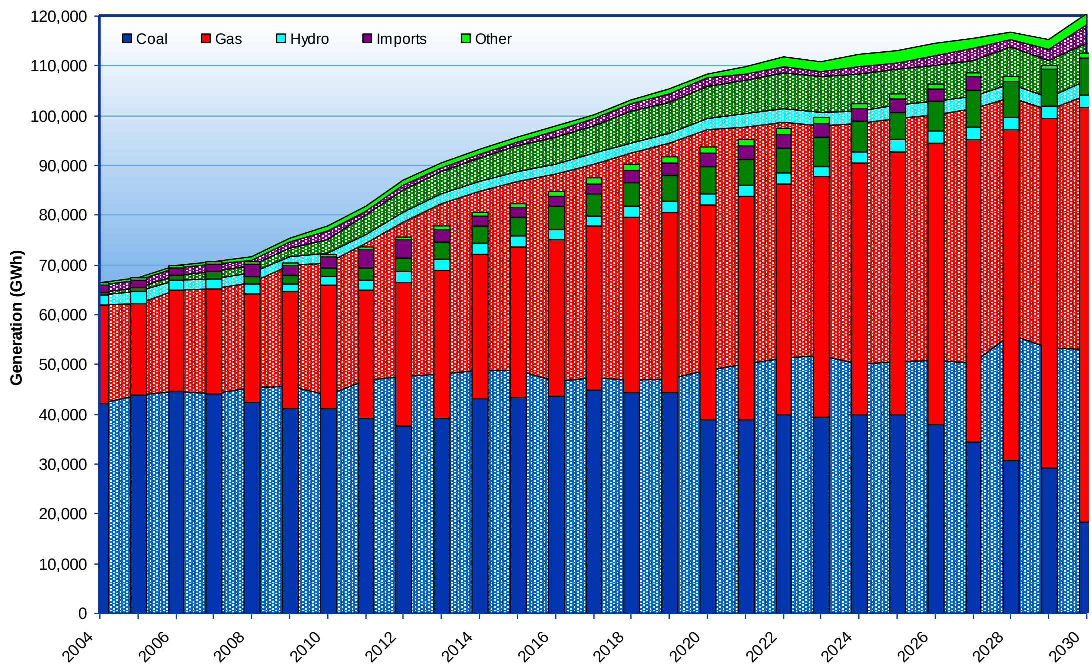
Both forecast have a similar amount of imports, although the 2009 model assigns a lower probability (65%) to the Montana/Alberta Transmission Line than in 2013 (100%). The 2009 forecast includes more nuclear technology ("Other"). The probability of nuclear power in Alberta was greatly reduced in the 2013 model, serving merely as a placeholder should the technology ever manage to gain traction.

Energy (MWh)

The total energy production (GWh) level (net-to-grid plus behind-the-fence generation) drops in the 2013 model to reflect the significantly weaker AIES & AIL demand forecast. In the 2009 model, AIL generation was forecast at 93,124 GWh in 2014, growing to 95,600 GWh in 2015, 108,419 GWh in 2020 and ultimately 120,404 GWh in 2030. The 2013 model (stacked columns) forecasts 80,328 GWh in 2014, 81,906 GWh in 2015, 93,156 GWh in 2020 and finally 115,251 GWh in 2030.

In the 2013 model, coal-fired generation dips harder than 2009, as units begin to retire, as compared to slowly growing in the 2009 model. In the mid-term, higher domestic and internal demand in the 2009 model requires the dispatch of more gas generation than the 2013 model. However, as coal units begin to retire in the 2013 model, combined-cycle growth picks up and surges, such that by the end of the forecast period (2030), gas-fired generation is expected to account for roughly 60% more generation in the 2013 model than in the 2009 model. The 2009 model shows greater output from Alberta's primary sources of renewable energy (hydro and wind) as their growth was forecast to occur sooner and harder (more MWs) than in the 2013 model. Despite higher power prices in the 2009 model, generation from imports is below the 2013 model due to technical changes in the modeling of how imports (and exports) function within the dispatch model. All these demand and generation changes create a downward pressure on emissions. The interactions are complex as factors pull in different directions and have to be explicitly modeled to be properly quantified. The 2013 model has weaker demand (and thus less total generation) and a much richer blend of clean-burning natural gas fired generation, but also has less renewable energy (hydro and wind).

Figure 15 – 2009 vs 2013: Generation Forecast (GWh)



Alberta and Federal GHG and Pollutants Emission Compliance Assumptions

EDC was required to answer the following questions:

1) How is compliance with the Alberta Framework and the Federal GHG Regulation assumed to be achieved?
    a. What is the assumed environmental legislation compliance cost (capital and operating) for each pollutant?
    b. How does the model allocate these costs to affected units (i.e. one time cost, vs. adding to levelized costs; and over what time period are the costs assumed to be amortized)?
    c. How are emissions credits accounted for in the projections?
2) What are the assumed future emission / BATEA standards?
3) What are the primary triggers for unit shut downs in the various scenarios?
4) How does the model deem investment decisions to be made (i.e. does it consider a rate of return, reserve margin, etc.)?

EDC forecast the costs and emissions of both Greenhouse Gases (GHG) and other pollutants (NOx, SOx, HG, and Particulates) at both the provincial and federal level. The federal plan is currently restricted to coal plants and GHG's (primarily CO_2 and CH_4, but it is EDC's view that that is not the end game). This next section outlines EDCA's current understanding of the rules and fees associated with the various emissions of both types. After that overview section, EDCA compares the treatment of the emissions in the three study vintages.

Greenhouse Gas (mostly CO_2) Emission Costs

2003

In the 2003 Study, the GHG fleet emission intensity was calculated at 0.61t/MWh for 2010, with a further reduction to 0.41t/MWh in 2020, all assumed to be met by offset purchases. The Mercury emission abatement technology was expected to be installed by December 31, 2009 for all coal generators except those who would commit to shut down by a specified date, namely, Battle River #3 & 4 by 2015 and Sundance #1 & 2 by 2017. The policy also set a 3.5% target for new renewable energy production.

The model assumed a required target GHG reduction of 6% from 2010-2019, then 26% thereafter. Any emissions above that would be charged $9/t until 2015, then $12/t and finally $15/t after 2020. Coal end of design life was 40 years and gas 30 years, each requiring physical controls at BATEA 10 years thereafter.

2009

The 2009 model assumed a required lower target GHG reduction of 4% from 2010-2019, then 24% thereafter. Any emissions above that would be charged $5/t until 2015, then $7.50/t and finally $15/t after 2020. Coal end of design life was 40 years and gas 30 years, each requiring physical controls at BATEA 10 years thereafter. After 2020, the gas design life was changed to 40 years and BATEA at 50 years, although this looks to be a model logic error.

By 2008, both federal and Alberta provincial governments had introduced plans to limit GHG and other emissions. The provincial plan has been operational and essentially unchanged since July 1, 2007, governed by the Climate Change and Emissions Management Act, Specified Gas Emitters Regulation. Under the provincial Regulation, a plant must either reduce CO_2 emissions by 12% from a 2004-2006 baseline or buy credits from a Technology Fund at $15/t or from an entity that has created credits.

Federal

Over time, the federal government has also floated a series of widely divergent proposed policies, beginning with the complicated "Turning the Corner" draft policy that was announced in the spring of 2007, with a proposed effective date of January 1, 2010. That proposal, which made little forward progress, discriminated harshly between different vintages and technologies of generation. On August 19, 2011, then federal Minister of the Environment, Peter Kent, announced the Canadian government's proposed regulations for the coal-fired electricity sector; *Reduction of Carbon Dioxide Emissions from Coal-Fired Generation of Electricity Regulations,* which would have fallen under the *Canadian Environmental Protection Act*. However, in January 2012, the Minister floated yet another proposed amendment to the regulations that would pass the problem back to the provinces. Each province would create their own custom provincial rules that would meet the equivalent 2020 federal emission targets in whatever manner that province saw fit.

Existing coal-fired unit intensities were based on the Alberta Electricity Generation System's Average Greenhouse Gas Emission Intensity Report by the KEFI-Exchange. Future coal units were assumed at 0.88 t/MWh. Future cogen units had varied intensities around the 0.30 t/MWh mark. Simple-cycle additions, such as Deerland, were around 0.50 t/MWh and combined-cycle, such as the Shepard Energy Centre, around 0.37 t/MWh. Assumptions about the emission intensities of future units did not vary much from those used in the 2013 model. Assumptions regarding a few existing units did change based on more recent information, such as HR Milner's move from 2.35 t/MWh in the 2009 model to 1.31 t/MWh in the 2013 model.

As outlined in Table 4 the 2009 model methodology was more an intensity-based rule than the 2013 permit style rule. 2008 was also significantly more aggressive, with GHG charges ending the forecast at $82.44/t (as compared to $23.00/t in the 2013 model) and the target reduction growing to 38% (as compared to 12% in the 2013 model).

Table 4 – 2008 Model GHG Components

2008 Model Federal (after 2010) GHG Component		
Year	**Tech Fund Prices ($/t)**	**Prov. Reduction %**
2009	$15.00	12.0%
2010	$25.00	18.0%
2011	$25.00	20.0%
2012	$25.00	22.0%
2013	$29.32	24.0%
2014	$34.38	26.0%
2015	$40.31	28.0%
2016	$47.27	30.0%
2017	$55.43	32.0%
2018	$65.00	34.0%
2019	$66.30	36.0%
2020	$67.63	38.0%
2021	$68.98	38.0%
2022	$70.36	38.0%
2023	$71.77	38.0%
2024	$73.20	38.0%
2025	$74.66	38.0%
2026	$76.16	38.0%
2027	$77.68	38.0%
2028	$79.23	38.0%
2029	$80.82	38.0%
2030	$82.44	38.0%

The assumptions made with respect to 2009 to 2013 were, in hindsight, too aggressive and too early. Those past assumptions yielded much higher total environmental costs, which flowed to generators' offers and significantly raised overall pool price, providing a strong incentive to move away from coal, especially the later vintages, which were particularly harshly treated. In the absence of legislation, coal plants that were fully depreciated but still functional would only have to cover their marginal costs (e.g. fuel, transmission losses, compliance costs). Compared to gas unit marginal costs, coal marginal costs would be small and coal plants would likely be profitable indefinitely without emissions legislation.

Future renewable generation additions and imports were assumed to have zero emissions in all studies.

2013

Provincial

The 2013 model uses a straightforward set of GHG assumptions, as detailed in Table 5. It assumes the provincial reduction percentage on emission intensities, currently at 12%[2], remains static throughout the forecast. Provincial GHG charges grow from the current $15/t in 2014 to $17/t in 2015, then by $2/t every 5 years, roughly accounting for inflation. The sensitivity of a more or less aggressive rise in either the target % reduction or the stipulated cost per tonne from the current 12%/$15/t regime is easily accommodated in the model. The model does not use any flat carbon taxes or credits.

Unit CO_2 emission intensities (t/MWh) for existing units were derived using the 2010 SGER report, as well as through consultation with generators. The current EDC estimate is shown in Table 5. Emission intensities for future additions of coal (two small uprates and potentially the HR Milner expansion facility) are assumed at 0.89 t/MWh, 0.369 t/MWh for combined-cycle, 0.25 t/MWh for cogen, between 0.50 t/MWh and 0.55 t/MWh for simple-cycle (depending on the size of the unit) and 0 t/MWh for renewable sources of energy and imports. The 0.369 t/MWh is fairly aggressive for combined-cycle, given the Calgary Energy Centre was at 0.38 t/MWh in the 2010 SGER report.

Table 5 – 2013 Model GHG Components

2013 Model Provincial GHG Component		
Year	**Tech Fund Prices ($/t)**	**Prov. Reduction %**
2014	$15.00	12.0%
2015	$17.00	12.0%
2016	$17.00	12.0%
2017	$17.00	12.0%
2018	$17.00	12.0%
2019	$17.00	12.0%
2020	$19.00	12.0%
2021	$19.00	12.0%
2022	$19.00	12.0%
2023	$19.00	12.0%
2024	$19.00	12.0%
2025	$21.00	12.0%
2026	$21.00	12.0%
2027	$21.00	12.0%
2028	$21.00	12.0%
2029	$21.00	12.0%
2030	$23.00	12.0%

2013

Provincial

The provincial framework is currently under review and will likely be updated by September 2014, to be effective January 1, 2015. EDC is anticipating that the current target 12% of baseline will be increased to a higher value, likely between 20 and 30%. For each tonne (t) of non-compliant emission (i.e. above the baseline minus the targeted reduction), an emitter will have to buy credits at a cost that changes over time, likely above the current $15/t, perhaps between $18-35/t. This specific compliance fee is added to each generator's offer, which affects their relative positions in the merit order stack, and therefore ultimately affects their respective hourly dispatch and the pool price.

EDC presumes that the provincial legislation will indefinitely continue to allow emitters to buy their way out of CO_2 non-compliance and continue to run a non-compliant plant and assumes that all units will pay the fee rather than actually reduce emissions. It is also aware that provincial and federal agencies are currently negotiating and could eventually operationalize some type of "Equivalencing" such that the province will be delegated control of all emissions regulations in Alberta to a level supportive of federal policy targets. Although not reflected in the current modeling, depending on the severity of the final implementation design, this

---

[2] New units are granted a 3 year holiday after which they grow up to the 12% at 2% per year. If the 12% reduction changed to, say 20%, the approach rate might be increased, e.g. 3.3%/year). This is a Phase 2 decision. Unofficial regimes of 20%/$20 and 30%/$30 have been rumored.

equivalencing could significantly alter the conclusions of the 2013 report.

Federal

On September 5, 2012, the Federal government announced its latest and supposedly final GHG regulation, "*Reduction of Carbon Dioxide Emissions from Coal- Fired Generation of Electricity Regulations*", focusing, for the moment, strictly on coal units, but with passing indications that gas-fired generators would eventually also be regulated and that the list of emissions would include both CO_2 and other emissions (p. 36, March 14, 2008 briefing presentation).

The latest Federal GHG legislation stipulated coal-fired retirement dates and discouraged the future growth of coal. Treatment will be different for units commissioned before or after 1975 and after 1985. The pre-1975 units must retire on the earlier of their 50th birthday or 2019 (e.g. built in 1969, retire in 2019, built in 1974, 2019) or meet strict, and likely uneconomical new targets set at 0.42 t/MWh, compared to typical intensities of 0.9 to 1.2 t/MWh for existing coal units. Units commissioned between 1975 and 1984 must retire on the earlier of their 50th anniversary year or 2029, and units built after 1985, at their simple 50 year date.

The federal plan is a permit-based rule only, without any actual fees, so it does not generate any marginal costs for the generator and thus no change in offers or movement in the merit order and thus no effect on which units are dispatched in an hour.

Since 2009, the EDC Hourly Electricity Load and Pricing (HELP) model has been modified to perform the GHG compliance fee calculation explicitly in each hour rather than by post-processing as was done in the 2003 and 2009 versions. EDC would recommend removing the 2003 and 2009 logic for GHG calculations and substituting a more explicit calculation of GHG

Other Emissions

In addition to the federal CO_2 regulations, the province created rules, contained in the Environmental Protection and Enhancement Act, Emissions Trading Regulation, which were previously negotiated by the Clean Air Strategic Alliance (CASA).

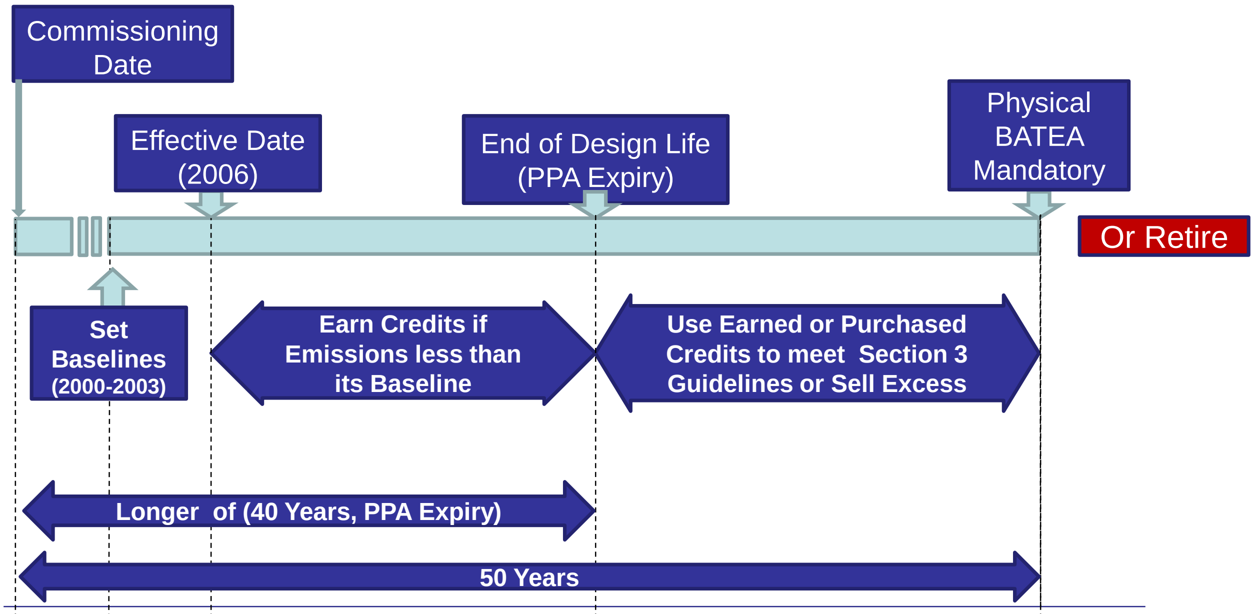
2003

In 2003, an industry team studied alternate approaches to the mitigation of these emissions. The team prepared a proposed method which was largely adopted and implemented on January 1, 2007. Each generation unit has specified NO_X and SO_X, emission targets, set from an individualized baseline calculated from their individual 2000-2003 performance. Hg and particulate standards were not based on past actuals. Until the end of the "design life" of a facility (defined as the longer of their PPA expiry date or 30 years for gas units and 40 years for coal units), if a unit performs better than its target intensity, it earns tradable credits. If it fails to beat its baseline in a year, it will not earn credits, nor will it be required to use up credits, it will just not accumulate further credits until it does improve. If credits are not used for 2 years, they are discounted to 90% and added to the credit bank.

Improvements could come from using cleaner fuel, improving operating practices or actually installing BATEA level controls or mitigation devices before being required to do so. Units need not spend credits until they pass their "design life", and the credits can be sold to anyone, albeit only within a pollutant and within an industry. Once the unit reaches its "design-life" (i.e., the longer of the expiration of a coal unit PPA or 40 years), the facility would either have to meet the increasingly stringent "post design-life standard" BATEA targets by physical remediation, use up its accumulated compliance credits and/or buy credits from someone else. This market-minded system has already substantively mitigated emission for NOx and SOx. Earned credits can be traded with other units, but not across pollutants or industries.

After the unit's 50th year (40th year for gas units), it must physically comply with a then current, vintaged BATEA target (currently 0.8 kg/MWh of SOX and 0.69 kg/MWh of NOX, based on 2005 Alberta Air Emission Standards For Electricity Generation policy) which becomes more stringent over time. ESRD is implementing the consensus based new BATEA coal unit emissions standards from the May 2010 final report.

Figure 16 - CASA Coal Timelines



If there were not enough accumulated credits to keep up with the expanding need, or holders of excess credits withheld them, this requirement could theoretically trump the federal GHG emission intensity regulation as the constraining factor controlling the advancement of the retirement date of some coal units, depending on each owner's economics for installing SO_X and NO_X abatement devices and the accumulated credits available for trading and application. While withholding is quite possible, the EDC modeling exercise assumed that the market would eventually find a price which would incent a viable credits market. Generally, sunk capital costs are not considered when setting a generator's hourly offer, since the dollars spent will not vary by a change in the hourly dispatch. However, if the generator must buy credits when it does not comply, those costs will vary in the hour and will be considered in their offers. Also, if a generator owns an excess of credits, by using them on its own MWh of production, it makes them unavailable to sell to another buyer who requires them to meet the covenants of his operating permit. This gives an implied emissions cost to that operator for running. That cost will help determine where each generator is in the electricity pool price merit order and therefore how often he will be dispatched and what the price will settle at with compliance costs included. It will also be useful in determining the total dollars of compliance fees that will be generated by unit and by the total fleet.

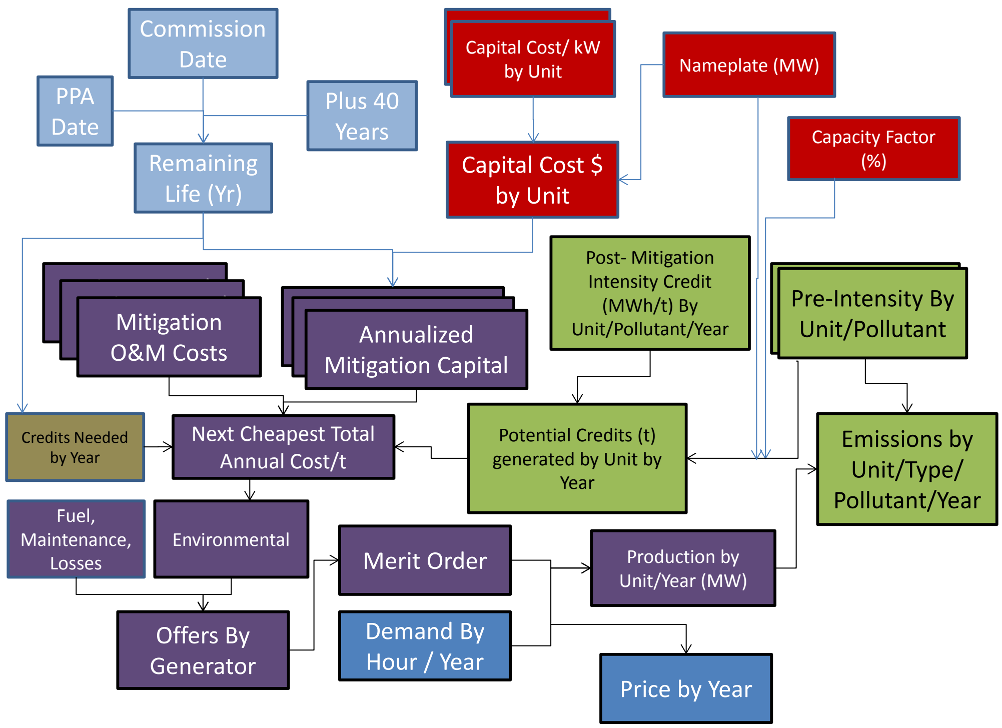
That leaves the task of estimating what a unit of credit for each pollutant is likely to sell for in different years of the study period. This is a classic supply and demand problem. At present, most generators have not reached their design life, as defined in the regulations, and so have no need or desire to buy credits just yet. However, in each successive year, more generators will have to buy credits to meet more stringent post design-life targets for each pollutant. At the moment, it appears that the current cache of earned credits will carry the generators through until about 2019, subject to vetting by the committee members and presuming the generators will then trade amongst themselves at some price.

EDC assisted in this quantification effort, using emission intensity data provided by CASA at the individual plant level, to calculate an electricity industry-wide estimate of emissions for each emission type and generator type across the study horizon, based on the expected annual production levels of each unit and their unique intensity. The model also tracks the changes in unit revenues and profits created by the compliance costs. The intensities are specified for each unit, depending on whether or not they have already installed mitigation devices. However, the production of each generator, that is, the level at which the unit is dispatched, is influenced by its offers into the power pool. One of the components that affect their offer is the marginal cost of emissions compliance. If a unit is already converted, it may be earning credits, which lowers its marginal costs. If a "post-design life" unit is not yet converted, it might have to buy credits from another unit.

The model must, therefore determine when additional credits are going to be needed, which unit would be the next most appropriate source of the additional credits and what the charge would likely be. The first step is to determine what credits are already available and how they are being earned year over years.

Eventually, a unit passes its "design life" threshold and begins to need credits. Over a short period of time, all the available accumulated credits will have been used, as the need for new credits relentlessly rises as more units pass their design-life threshold.

Figure 17- Schematic of Emissions Model



NOx

NOx dates and allowance costs are different in 2003 and 2009, because the estimate of total required NOx credits comes earlier in 2009 than 2003. Also, Suncor is not used as a source of credits in 2009.

Table 6 - NOx Reduction Source and Cheapest Unit

NOx Reduction Source and Cheapest Unit						
	Source			Allowance Cost		
	2003	2009	Difference	2003	2009	Difference
2012	Calpine	Calpine, GN1, GN2	Y	$921	$1,886	$965.08
2013	Calpine	Calpine, GN1, GN2	Y	$969	$1,886	$916.32
2014	Calpine	Calpine, GN1, GN2, SH2	Y	$1,038	$2,042	$1004.59
2015	Calpine	Calpine, GN1, GN2, SH2	Y	$1,140	$2,042	$902.19
2016	Calpine	Calpine, GN1, GN2, SH2, SH1	Y	$1,311	$2,502	$1191.78
2017	Calpine	Calpine, GN1, GN2, SH2, SH1, KH2	Y	$1,652	$2,656	$1003.62
2018	Calpine	Calpine, GN1, GN2, SH2, SH1, KH2	Y	$1,874	$2,502	$628.73
2019	Calpine	Calpine, GN1, GN2, SH2, SH1, KH2	Y	$1,883	$2,042	$158.87
2020	Calpine	Calpine, GN1, GN2, SH2, SH1, KH2	Y	$1,894	$2,502	$608.58
2021	Calpine, Suncor, GN1, GN2	Calpine, GN1, GN2, SH2, SH1, KH2	Y	$2,114	$2,502	$388.47
2022	Calpine, Suncor, GN1, GN2	Calpine, GN1, GN2, SH2, SH1, KH2	Y	$2,114	$2,502	$388.47
2023	Calpine, Suncor, GN1, GN2	Calpine, GN1, GN2, SH2, SH1, KH2	Y	$2,114	$2,502	$388.47
2024	Calpine, Suncor, GN1, GN2, SH2	Calpine, GN1, GN2, SH2, SH1, KH2	Y	$2,377	$2,502	$125.30
2025	Calpine, Suncor, GN1, GN2, SH2, SH1	Calpine, GN1, GN2, SH2, SH1, KH2	Y	$2,765	$2,502	-$263.05

In the 2003 model, it was assumed that NOx credits would first begin to be applied in 2006 (UoA), then 2009 (AMACO for 2 years, Suncor for 3 years and Syncrude for 1 year), then DOW 1 & 2 in 2010 for 10 years. This first tranche of needed credits was presumed to be provided by accumulated credits from early retirement of Clover Bar (1-4) and HR Milner (assumed to have been retired by 2006) and earned credits from the Calgary Energy Centre. In 2021, four coal units were expected to pass their design life threshold (Sundance 3-6), followed by Battle River 4 in 2022, requiring virtually all the remaining credits that had heretofore accumulated.

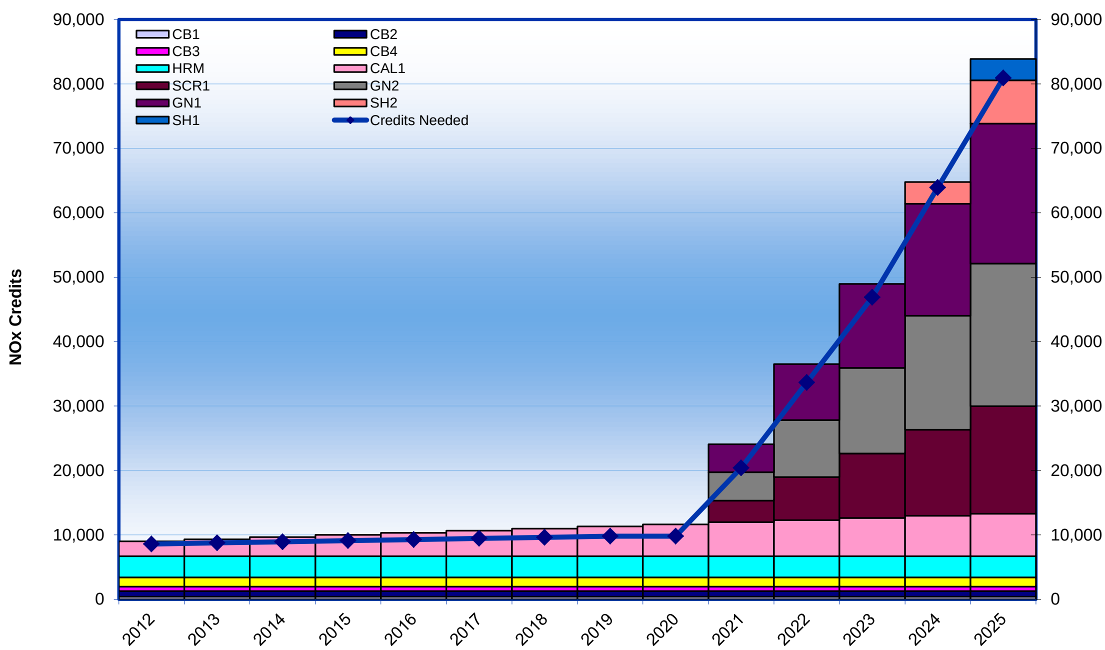
Table 7 – Schedule of Assumed Needed Credits (2006-2025, from 2003 Study)

Unit	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
U of A	(239)	(239)	(239)	(239)	(239)															
Amaco				(1,018)	(1,018)															
Suncor				(657)	(657)	(657)														
Syncrude				(2,862)																
DOW1					(87)	(87)	(87)	(87)	(87)	(87)	(87)	(87)	(87)	(87)						
Dow 2					(87)	(87)	(87)	(87)	(87)	(87)	(87)	(87)	(87)	(87)						
Sundance 3																(2,516)	(2,516)	(2,516)	(2,516)	(2,516)
Sundance 4																(2,548)	(2,548)	(2,548)	(2,548)	(2,548)
Sundance 5																(2,569)	(2,569)	(2,569)	(2,569)	(2,569)
Sundance 6																(2,979)	(2,979)	(2,979)	(2,979)	(2,979)
Battle River 5																	(2,626)	(2,626)	(2,626)	(2,626)
Keephills 1																			(3,790)	(3,790)
KeepHills 2 (self-supplied)																				
Sum	(239)	(239)	(239)	(4,776)	(2,087)	(831)	(173)	(173)	(173)	(173)	(173)	(173)	(173)	(173)	-	(10,612)	(13,238)	(13,238)	(17,028)	(17,028)

This would necessitate the conversion of more plants, which would fulfil the growing need for credits from 2021 until 2024, when a further unit would have to be converted, followed by another in in 2025. Not every unit must convert to produce enough credits to meet the fleet requirements.

Each time it was determined that more credits would be needed, the model searched for the next best unit, i.e. cheapest in terms of $/t. In 2003, Genesee 1 and 2 and Suncor were expected to be the cheapest in 2021, then Sheerness 2 in 2024 and Sheerness 1 in 2025 (see Figure 18). Although the model presumed that the owner of the cheapest next unit would be willing to step up to the task, that was by no means a certainty. If that unit did not step up, one of the many other units in the fleet possibly would, but at some higher price.

Figure 18 - Cumulative NOx Credits, Source and Application, from 2012 Onwards (2003 Report)



The cheapest next unit in 2021 was calculated as follows. From an uninflated, global estimate of capital cost (($/kW), as provided by CASA (see red squares in Figure 17 and numbers in Table 8), the model calculates the total capital cost of converting every one of the candidate generators.

Table 8 - Global Cost Parameters (2003 & 2009)

Model Assumptions						
	Capital Costs ($/KW)		Operating Costs ($/t)		Operating Costs ($/MWh)	
	2003	2009	2003	2009	2003	2009
Mercury	$52	$52	-	-	$1.20	$1.20
SOx	$225	$225	$900	$900	-	-
NOx - Coal	$125	$125	$1,500	$1,500	-	-
NOx - Gas	$40	$40	-	-	$2	$2

Each generator has a different expected life before it would have to be retired (light blue squares, Figure 17 and Amortization Period in Table 9), usually its 50th birthday or the end of life (now set by the September, 2102 federal GHG policy, but unknown at that time).

The model simply divides the capital cost by its remaining life (i.e., with a 0% return) to create an annualized capital cost (purple squares in, Figure 17 and rightmost column in Table 9). The capital allocation is a purely straight-line allocation, spread evenly across the remaining years until it reaches its 50th year, with no time value of money or return on capital included.

This treatment is different in the 2009 study, which spreads the NOx capital cost only over the remaining time until the design life is reached. The latter is probably the more appropriate, since after the end of design life, the unit would be required to meet a BATEA target. It would therefore not be able to generate any additional credits in those post-design life years and therefore would not be receiving additional revenues to support the capital it spent on mitigation. EDC would recommended only spreading the capital cost over years which could likely generate additional credits, that is, to the end of the design life, the shorter period.

Table 9- Calculation of Annualized NOx Capital Cost in 2021, from 2003 Study

Example of Calculating Annualized Capital Costs for NOx from 2003 Report in Year 2021							
						Capital Related Costs	
						$	
Unit	Nameplate (MW)	Capacity Factor (%)	Output (MWh)	Year Control Must be Installed By*	Amortization Period (Yrs)	Raw Capital Cost at $125/KW Coal, $40/KW Gas	Annualized Capital Cost in 2021
H.R. Milner	143	61.6%	771,114	2012	0		
Battle River 3	148	83.7%	1,085,336	2019	0		
Battle River 4	148	87.3%	1,131,221	2025	4	$18,500,000	$4,625,000
Genesee 3	490	90.0%	3,863,160	2055	34	$61,250,000	$1,801,471
Sundance 1	280	75.2%	1,843,918	2020	0		
Sundance 2	280	84.2%	2,064,293	2023	2	$35,000,000	$17,500,000
Sundance 3	353	89.4%	2,764,962	2026	5	$44,125,000	$8,825,000
Sundance 4	353	90.6%	2,800,190	2027	6	$44,125,000	$7,354,167
Sundance 5	353	91.3%	2,823,163	2028	7	$44,125,000	$6,303,571
Sundance 6	399	93.7%	3,273,381	2030	9	$49,875,000	$5,541,667
Battle River 5	368	89.5%	2,885,785	2031	10	$46,000,000	$4,600,000
Keephills 1	381	93.8%	3,132,215	2033	12	$47,625,000	$3,968,750
Keephills 2	381	95.7%	3,193,357	2034	13	$47,625,000	$3,663,462
Sheerness 1	378	92.4%	3,057,980	2036	15	$47,250,000	$3,150,000
Genesee 1	384	91.6%	3,080,504	2039	18	$48,000,000	$2,666,667
Sheerness 2	378	91.6%	3,033,209	2040	19	$47,250,000	$2,486,842
Genesee 2	384	93.3%	3,139,570	2044	23	$48,000,000	$2,086,957
Wabamun 1	65	88.0%	500,857	2008	0		
Wabamun 2	65	80.6%	459,204	2006	0		
Wabamun 3	139	80.6%	981,990	2012	0		
Wabamun 4	279	86.6%	2,116,004	2018	0		

To this annualized capital cost for each unit, an estimated operating cost is added to create a total annual mitigation cost, which is then divided by the total annual tonnes of credits generated to create a $/t price (rightmost column, Table 10), as if that particular unit was the one converted in that year. From that list, the cheapest unit would be assumed to be the provider of additional needed credits and its price would be used for that year's cost calculations.

Table 10- Calculating the NOx Annual $/t for a Potential Converted Unit

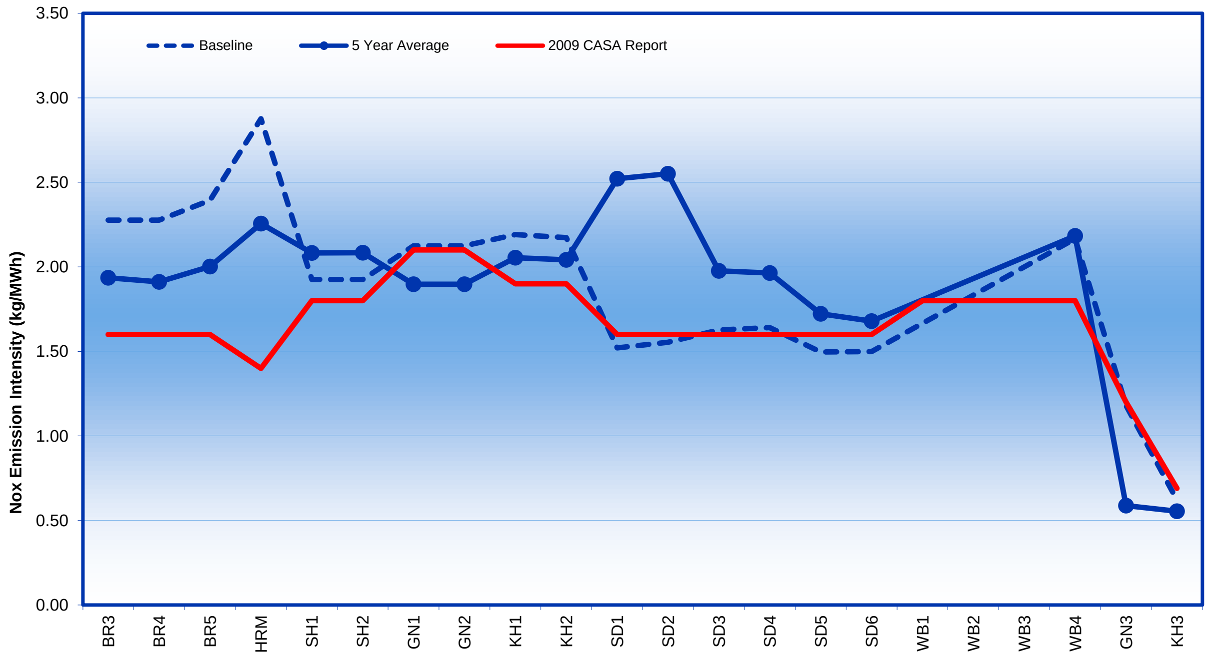
Example of Calculating Annualized Capital Costs for NOx from 2003 Report in Year 2021										
		Period Costs						Capital Related Costs		Total Costs
		Current		Target				$		$/t
Unit	Output (MWh)	Current NOx Intensity (kg/MWh)	Current Emissions (t)	Target NOx Intensity (kg/MWh)	Emissions at NOx Target (t)	Potential NOx Reduction (t)	Annual Operating Cost at $1500/t Coal, $2/MWh Gas ($)	Annualized Capital Cost in 2021	Annualized Total Costs in 2021	Total Annualized Cost in 2021
H.R. Milner	771,114									
Battle River 3	1,085,336									
Battle River 4	1,131,221	1.60	1,810	0.69	781	1,029	$1,544,117	$4,625,000	$6,169,117	$5,993
Genesee 3	3,863,160	1.18	4,559	0.69	2,666	1,893	$2,839,423	$1,801,471	$4,640,893	$2,452
Sundance 1	1,843,918									
Sundance 2	2,064,293	1.60	3,303	0.69	1,424	1,879	$2,817,760	$17,500,000	$20,317,760	$10,816
Sundance 3	2,764,962	1.60	4,424	0.69	1,908	2,516	$3,774,173	$8,825,000	$12,599,173	$5,007
Sundance 4	2,800,190	1.60	4,480	0.69	1,932	2,548	$3,822,260	$7,354,167	$11,176,426	$4,386
Sundance 5	2,823,163	1.60	4,517	0.69	1,948	2,569	$3,853,618	$6,303,571	$10,157,189	$3,954
Sundance 6	3,273,381	1.60	5,237	0.69	2,259	2,979	$4,468,165	$5,541,667	$10,009,832	$3,360
Battle River 5	2,885,785	1.60	4,617	0.69	1,991	2,626	$3,939,096	$4,600,000	$8,539,096	$3,252
Keephills 1	3,132,215	1.90	5,951	0.69	2,161	3,790	$5,684,970	$3,968,750	$9,653,720	$2,547
Keephills 2	3,193,357	1.90	6,067	0.69	2,203	3,864	$5,795,944	$3,663,462	$9,459,405	$2,448
Sheerness 1	3,057,980	1.80	5,504	0.69	2,110	3,394	$5,091,536	$3,150,000	$8,241,536	$2,428
Genesee 1	3,080,504	2.10	6,469	0.69	2,126	4,344	$6,515,267	$2,666,667	$9,181,934	$2,114
Sheerness 2	3,033,209	1.80	5,460	0.69	2,093	3,367	$5,050,292	$2,486,842	$7,537,134	$2,239
Genesee 2	3,139,570	2.10	6,593	0.69	2,166	4,427	$6,640,191	$2,086,957	$8,727,147	$1,971
Wabamun 1	500,857									
Wabamun 2	459,204									
Wabamun 3	981,990									
Wabamun 4	2,116,004									

Once the allowance costs for each of the four pollutants (NOx, SOx, Hg, GHG).is determined, by generator, for credits bought or sold, the costs of the four pollutants are added together and averaged across their respective outputs to get a composite $/MWh cost for each unit. That total emissions cost is then added to each generator's other marginal costs (fuel, losses, etc.), to influence each generator's offer. This stack of offers is aggregated into a fleet merit order (see purple squares in Figure 17, and also Appendix 5). When the EDC HELP model runs, it uses the intersection of demand with this merit order to determine the actual dispatch of each unit, in each hour of each year. Then by multiplying the output of each unit by its respective intensities, the total tonnes of each pollutant is calculated, and then aggregated annually by unit, generator type and total fleet emissions tonnes and ultimately fleet intensity (t/MWh).

Intensities

The 2003 and 2009 studies shared common estimated NOx intensities, save a handful of small gas units. These were generally lower than their respective baselines, which in turn were lower than the five year average of actuals (see Figure 19 and Appendix 1). Besides the coal intensities, Appendix 1 also shows the gas unit intensities as well as the actuals for both from 2006 to 2012 and the calculation of their 5 and 7-year averages.

Figure 19 - Comparison of Actual, Baseline and Assumed (2003/9 Study) Coal NOx Intensities



SOx

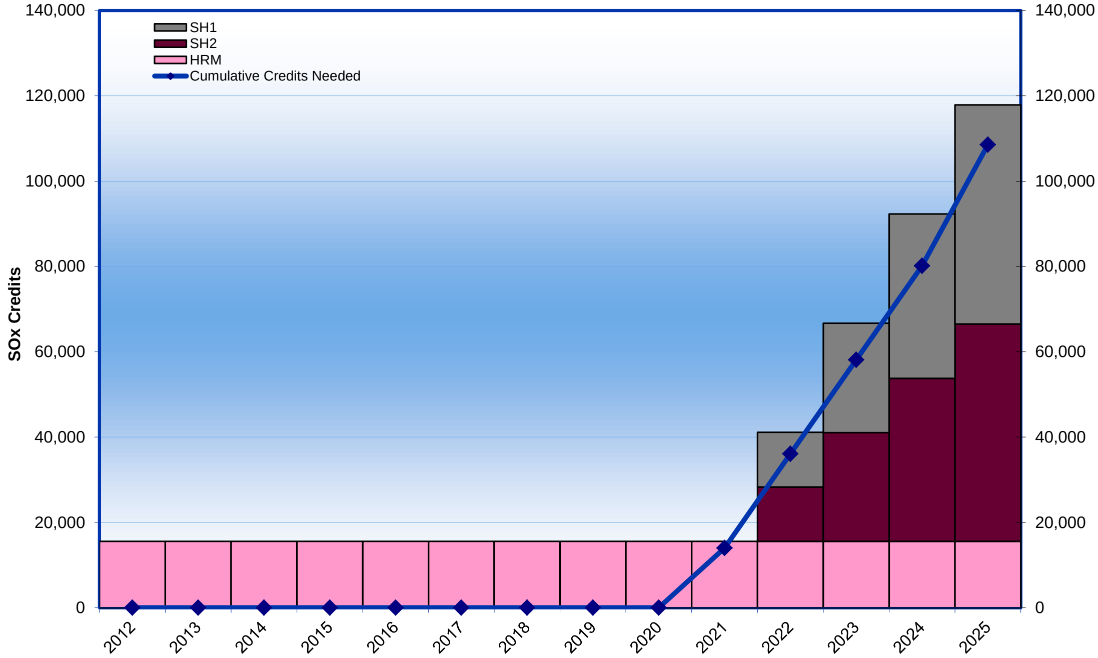
SOx mitigation dates and the yearly allowance costs are identical in 2003 and 2009.

Table 11 -- SOx Reduction Source and Cheapest Unit

SOx Reduction Source and Cheapest Unit						
	Source			Allowance Cost		
	2003	2009	Difference	2003	2009	Difference
2012	HRM	HRM		$1,138	$1,138	
2013	HRM	HRM		$1,147	$1,147	
2014	HRM	HRM		$1,157	$1,157	
2015	HRM	HRM		$1,167	$1,167	
2016	HRM	HRM		$1,178	$1,178	
2017	HRM	HRM		$1,190	$1,190	
2018	HRM	HRM		$1,203	$1,203	
2019	HRM	HRM		$1,218	$1,218	
2020	HRM	HRM		$1,234	$1,234	
2021	HRM	HRM		$1,251	$1,251	
2022	SH2, SH1	SH2, SH1		$1,373	$1,373	
2023	SH2, SH1	SH2, SH1		$1,373	$1,373	
2024	SH2, SH1	SH2, SH1		$1,373	$1,373	
2025	SH2, SH1	SH2, SH1		$1,373	$1,373	

Similar to the NOx calculations, costs of the required and provided SOx credits were estimated for the 2003 study, from CASA provided capital and operating cost characteristics (see Table 8, above). This exact curve was used in the 2009 Study as well.

Figure 20 - Cumulative SOx Credits, Source and Application, 2012 Onwards (2003 or 2009)



The order in which generators were converted was similarly derived by determining the next least expensive provider, given its unique baseline, post-mitigation intensity and remaining life. Similar to 2003 NOx, the SOx capital cost is annualized by dividing it by the remaining life. However, unlike the 2009 NOx calculation, that method is carried over to the 2009 SOx, i.e., allocating over the remaining life, not the design life.

Given the pattern of retirements and the credits created especially by the expected early HR Milner retirement assumed by the 2003 study, the need for new SOx credits did not emerge until 2022. At that time, the model added Sheerness 1 and 2, which generated sufficient new annual credits to cover needs out to 2025.

Table 12- Calculating Annualized SOx Capital Cost from 2003 or 2009 Study

Example of Calculating Annualized Costs for SOx from 2003 or 2009 Report in Year 2022								
						Capital Related Costs		
						$		
Unit	Nameplate (MW)	Capacity Factor (%)	Output (MWh)	50th Year	Amortization Period (Yrs)	Raw Capital Cost at $225/KW	Annualized Capital Cost in 2022	Annualized Total Costs in 2022
Genesee 3	490	90.0%	3,863,160	2055	0			
H.R. Milner	143	61.6%	771,114	2022	0			
Battle River 3	148	83.7%	1,085,336	2019	0			
Battle River 4	148	87.3%	1,131,221	2025	3	$33,300,000	$11,100,000	$13,950,677
Sundance 1	280	75.2%	1,843,918	2020	0			
Sundance 2	280	84.2%	2,064,293	2023	1	$63,000,000	$63,000,000	$65,229,436
Sundance 3	353	89.4%	2,764,962	2026	4	$79,425,000	$19,856,250	$22,842,409
Sundance 4	353	90.6%	2,800,190	2027	5	$79,425,000	$15,885,000	$18,909,205
Sundance 5	353	91.3%	2,823,163	2028	6	$79,425,000	$13,237,500	$16,286,516
Sundance 6	399	93.7%	3,273,381	2030	8	$89,775,000	$11,221,875	$14,757,127
Battle River 5	368	89.5%	2,885,785	2031	9	$82,800,000	$9,200,000	$16,472,177
Keephills 1	381	93.8%	3,132,215	2033	11	$85,725,000	$7,793,182	$10,612,175
Keephills 2	381	95.7%	3,193,357	2034	12	$85,725,000	$7,143,750	$10,017,772
Sheerness 1	378	92.4%	3,057,980	2036	14	$85,050,000	$6,075,000	$17,634,163
Genesee 1	384	91.6%	3,080,504	2039	17	$86,400,000	$5,082,353	$8,686,543
Sheerness 2	378	91.6%	3,033,209	2040	18	$85,050,000	$4,725,000	$16,190,528
Genesee 2	384	93.3%	3,139,570	2044	22	$86,400,000	$3,927,273	$7,600,570
Wabamun 1	65	88.0%	500,857	2008	0			
Wabamun 2	65	80.6%	459,204	2006	0			
Wabamun 3	139	80.6%	981,990	2012	0			
Wabamun 4	279	86.6%	2,116,004	2018	0			

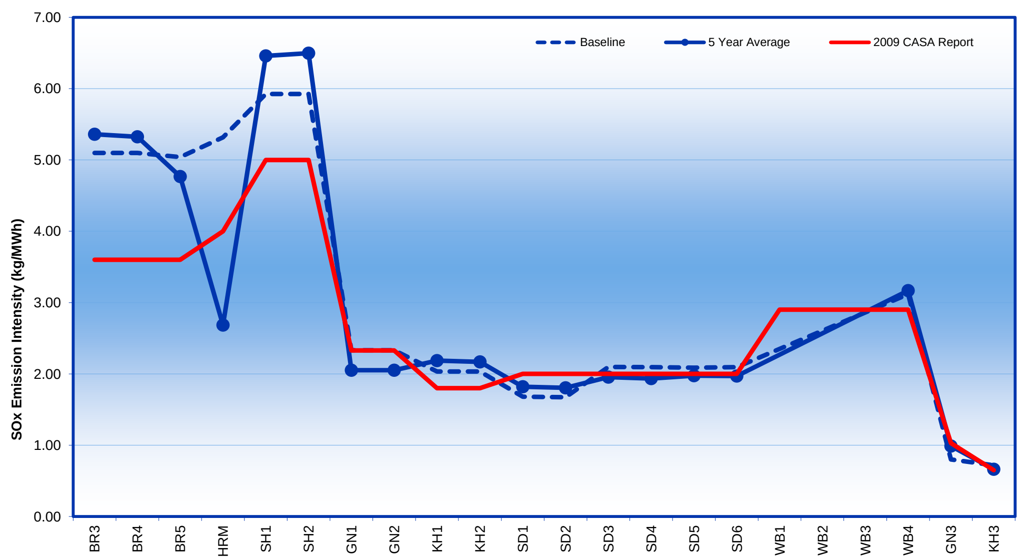
To that annualized cost, annual operating and maintenance costs are added to yield a total annual cost and total annual cost per tonne, if that until were to be chosen for mitigation. The generator with the lowest total annual cost/t was assumed to be the converted unit (Sheerness 2=$1,271/t, Sheerness 1=$1,373/t). Those units happen to have a high baseline that generates more credits /MWh than other units, and a long remaining life over which to spread those lower costs.

Table 13- Calculating the SOx Annual $/t for a Potential Converted Unit

Example of Calculating Annualized Costs for SOx from 2003 or 2009 Report in Year 2022										
		Period Costs						Capital Related Costs		Total Costs
		Current		Target				$		$/t
Unit	Output (MWh)	Current SOx Intensity (kg/MWh)	Current Emissions (t)	Target SOx Intensity (kg/MWh)	Emissions at SOx Target (t)	Potential SOx Reduction (t)	Annual Operating Cost at $900/t ($)	Annualized Capital Cost in 2022	Annualized Total Costs in 2022	Total Annualized Cost in 2022
Genesee 3	3,863,160									
H.R. Milner	771,114									
Battle River 3	1,085,336									
Battle River 4	1,131,221	3.60	4,072	0.80	905	3,167	$2,850,677	$11,100,000	$13,950,677	$4,404
Sundance 1	1,843,918									
Sundance 2	2,064,293	2.00	4,129	0.80	1,651	2,477	$2,229,436	$63,000,000	$65,229,436	$26,332
Sundance 3	2,764,962	2.00	5,530	0.80	2,212	3,318	$2,986,159	$19,856,250	$22,842,409	$6,884
Sundance 4	2,800,190	2.00	5,600	0.80	2,240	3,360	$3,024,205	$15,885,000	$18,909,205	$5,627
Sundance 5	2,823,163	2.00	5,646	0.80	2,259	3,388	$3,049,016	$13,237,500	$16,286,516	$4,807
Sundance 6	3,273,381	2.00	6,547	0.80	2,619	3,928	$3,535,252	$11,221,875	$14,757,127	$3,757
Battle River 5	2,885,785	3.60	10,389	0.80	2,309	8,080	$7,272,177	$9,200,000	$16,472,177	$2,039
Keephills 1	3,132,215	1.80	5,638	0.80	2,506	3,132	$2,818,994	$7,793,182	$10,612,175	$3,388
Keephills 2	3,193,357	1.80	5,748	0.80	2,555	3,193	$2,874,022	$7,143,750	$10,017,772	$3,137
Sheerness 1	3,057,980	5.00	15,290	0.80	2,446	12,844	$11,559,163	$6,075,000	$17,634,163	$1,373
Genesee 1	3,080,504	2.10	6,469	0.80	2,464	4,005	$3,604,190	$5,082,353	$8,686,543	$2,169
Sheerness 2	3,033,209	5.00	15,166	0.80	2,427	12,739	$11,465,528	$4,725,000	$16,190,528	$1,271
Genesee 2	3,139,570	2.10	6,593	0.80	2,512	4,081	$3,673,297	$3,927,273	$7,600,570	$1,862
Wabamun 1	500,857									
Wabamun 2	459,204									
Wabamun 3	981,990									
Wabamun 4	2,116,004									

Assumed SOx intensities (see Figure 21 and Appendix 2) varied only slightly from their baselines and from 5-year average actuals. The 2003 and 2009 studies shared a common set of SOx intensities except for small differences in Genesee 1, 2 & 3).

Figure 21 - Comparison of Actual, Baseline and Assumed (2003/9 Study) Coal SOx Intensities

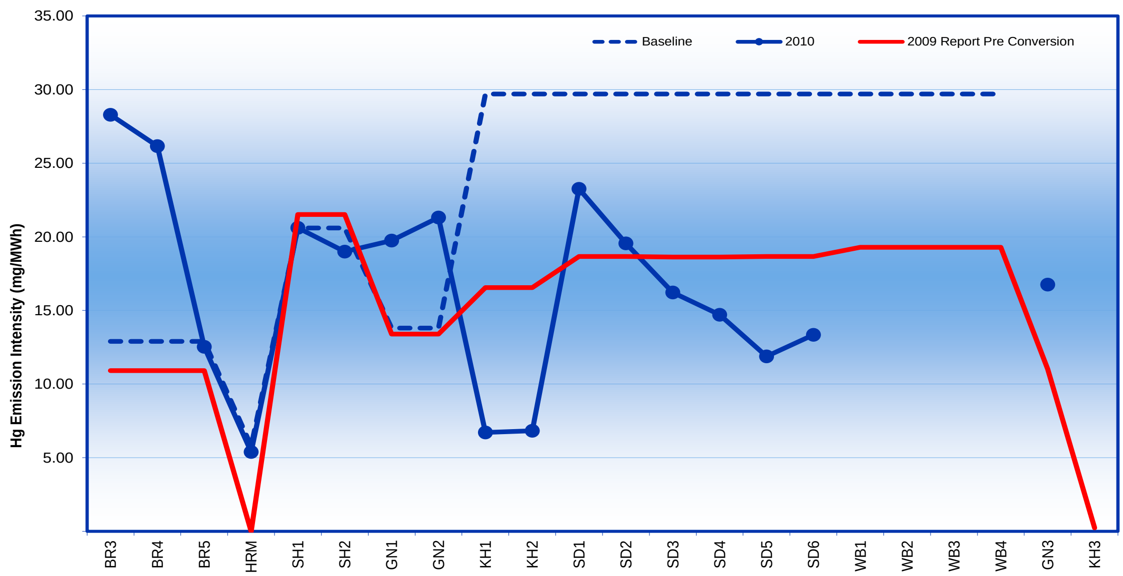


Hg

The unit cost per MWh ($1.2/MWh, of Hg was an unchanging inputted amount (see, above and Appendix 5.1)) and did not vary across the 2003 to 2009 study periods. The intensity varied by unit, but the schedule did not change across the study periods. There were two hard overwrites (Battle River 3 & 4 both changed from 10.92

to 12.00 mg/MWh; Sundance 1& 2 changed from 18.66 to 34 and 39 mg/MWh) The baselines and actuals are significantly different from the assumed intensities (see Figure 22 and Appendix 3).

Figure 22- Comparison of Hg Presumed (2003 and 2009) and Actual Coal Unit Intensities



HG

Some HG parameters change between the 2003 and 2009 versions.

Table 14 - Mercury Capital and Operating Costs

Mercury Capital & Operating Costs												
	Year Installed		Capital Costs ($Millions)			Annual Capital Costs ($Millions)			Annual Operating Costs ($Millions)			
	2003	2009	2003	2009	Difference	2003	2009	Difference	2003	2009	Difference	
H.R. Milner	2010	2011	$7.44	$7.44		$0.62	$0.68	$0.06	$0.93	$0.93		
Battle River 3	2010	2011	$7.70	$7.70		$0.86	$0.96	$0.11	$1.30	$1.30		
Battle River 4	2010	2011	$7.70	$7.70		$0.51	$0.55	$0.04	$1.36	$1.36		
Genesee 3	2010	2011	$25.48	$25.48		$0.57	$0.58	$0.01	$4.64	$4.64		
Sundance 1	2010	2011	$14.56	$14.56		$1.46	$1.62	$0.16	$2.21	$2.21		
Sundance 2	2010	2011	$14.56	$14.56		$1.12	$1.21	$0.09	$2.48	$2.48		
Sundance 3	2010	2011	$18.36	$18.36		$1.15	$1.22	$0.08	$3.32	$3.32		
Sundance 4	2010	2011	$18.36	$18.36		$1.08	$1.15	$0.07	$3.36	$3.36		
Sundance 5	2010	2011	$18.36	$18.36		$1.02	$1.08	$0.06	$3.39	$3.39		
Sundance 6	2010	2011	$20.75	$20.75		$1.04	$1.09	$0.05	$3.93	$3.93		
Battle River 5	2010	2011	$19.14	$19.14		$0.91	$0.96	$0.05	$3.46	$3.46		
Keephills 1	2010	2011	$19.81	$19.81		$0.86	$0.90	$0.04	$3.76	$3.76		
Keephills 2	2010	2011	$19.81	$19.81		$0.83	$0.86	$0.04	$3.83	$3.83		
Sheerness 1	2010	2011	$19.66	$19.66		$0.76	$0.79	$0.03	$3.67	$3.67		
Genesee 1	2010	2009	$19.97	$19.97		$0.69	$0.67	-$0.02	$3.70	$3.70		
Sheerness 2	2010	2011	$19.66	$19.66		$0.66	$0.68	$0.02	$3.64	$3.64		
Genesee 2	2010	2009	$19.97	$19.97		$0.59	$0.57	-$0.02	$3.77	$3.77		
Wabamun 1	N/A	2011	$0.00	$0.00		$0.00	$0.00		$0.00	$0.00		
Wabamun 2	N/A	2011	$0.00	$0.00		$0.00	$0.00		$0.00	$0.00		
Wabamun 3	N/A	2011	$0.00	$0.00		$0.00	$0.00		$0.00	$0.00		
Wabamun 4	N/A	2011	$0.00	$0.00		$0.00	$0.00		$0.00	$0.00		

The model keeps track of the amount of credits that will be necessary in total across the whole fleet.

Then the model picks from amongst all the generators to see which one would have the lowest annual cost of allowances (SOx, NOx but not Hg, which is all converted already) if that unit were to install mitigation. That generator becomes the chosen provider of credits for the rest of the generators for that year and until even more credits are needed. As soon as that additional generator does not produce enough credits for the whole fleet, the cheapest next generator is added. The calculated dates when each new mitigation device is added are compared below for 2003 and 2009 for SOx and NOx:

Particulates

It was agreed that the particulate matter policy is in sufficient flux that it will not be analyzed in this report.

2009

The pattern of plant retirements was generally significantly delayed for 2009 over 2003 (see Table 15), resulting in a more aggressive conversion pattern to keep up with the increased need for NOx and SOx credits in the face of fewer expected earned credits for early retirement. Table 15 shows a much delayed retirement of Suncor (2017 vs. 2011 in the 2003 study), much larger and longer credit shortfalls for Dow and Amaco, new credit needs for Sundance 1 & 2, Keephills 1 and Battle River 3, and earlier credit needs for the remaining Sundance units,

Table 15 - Schedule of Assumed Needed Credits (2006-2030, from 2009 Study)

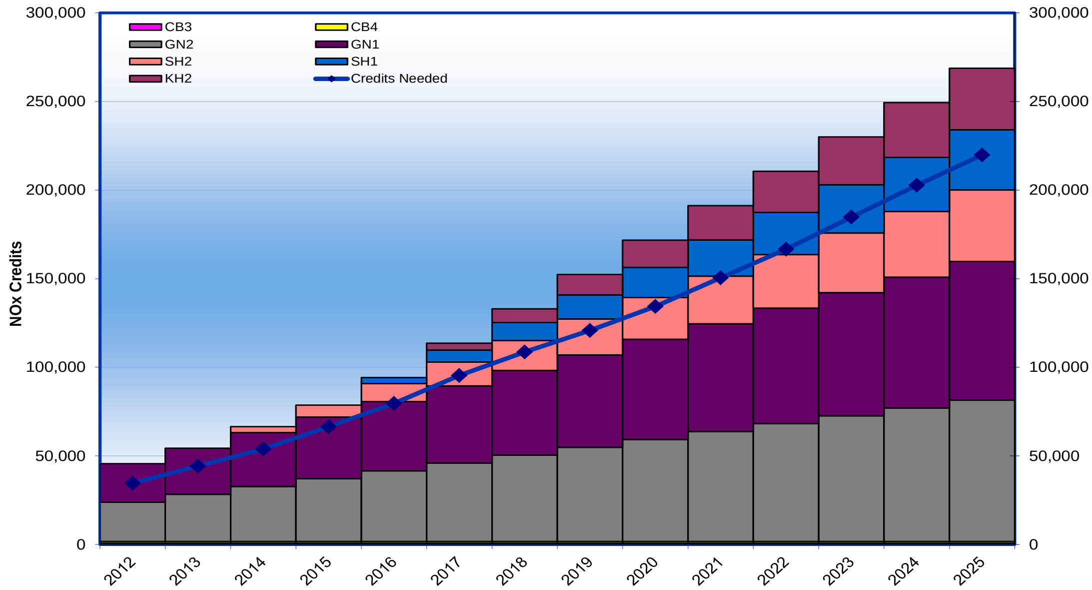
Unit	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Rainbow #1	(6)	(6)																							
Rainbow #2	(8)	(8)	(8)	(8)																					
Rainbow #3	(4)	(4)	(4)	(4)																					
Suncor			(657)	(657)	(657)	(657)	(657)	(657)	(657)	(657)	(657)	(657)													
Syncrude			(3,090)	(3,090)	(3,090)	(3,090)	(3,090)	(3,090)	(3,090)	(3,090)	(3,090)	(3,090)													
DOW1			(343)	(343)	(343)	(343)	(343)	(343)	(343)	(343)	(343)	(343)													
Amaco			(1,018)	(1,018)	(1,018)	(1,018)	(1,018)	(1,018)	(1,018)	(1,018)	(1,018)	(1,018)													
Battle River 3				(988)	(988)	(988)	(988)	(988)	(988)	(988)	(988)	(988)	(988)												
Sundance 1					(1,678)	(1,678)	(1,678)	(1,678)	(1,678)	(1,678)	(1,678)	(1,678)	(1,678)	(1,678)											
Sundance 2								-1878.5	-1878.5	-1878.51	-1878.51	-1878.51	-1878.51	-1878.51	-1878.51	-1878.51	-1878.51								
Genesee 3 (Self Supplied)										-1892.95															
Battle River 4										-1029.41	-1029.41	-1029.41	-1029.41	-1029.41	-1029.41	-1029.41	-1029.41	-1029.41	-1029.41						
Sundance 3											-2516.12	-2516.12	-2516.12	-2516.12	-2516.12	-2516.12	-2516.12	-2516.12	-2516.12	-2516.12					
Sundance 4												-2548.17	-2548.17	-2548.17	-2548.17	-2548.17	-2548.17	-2548.17	-2548.17	-2548.17	-2548.17				
Sundance 5													(2,569)	(2,569)	(2,569)	(2,569)	(2,569)	(2,569)	(2,569)	(2,569)	(2,569)	(2,569)	-	-	-
Sundance 6															-2978.78	-2978.78	-2978.78	-2978.78	-2978.78	-2978.78	-2978.78	-2978.78	-2978.8	-2978.8	
Battle River 5																-2626.06	-2626.06	-2626.06	-2626.06	-2626.06	-2626.06	-2626.06	-2626.1	-2626.1	-2626.1
Keephills 1																		-3789.98	-3789.98	-3789.98	-3789.98	-3789.98	-3790	-3790	-3790
KeepHills 2 (self-supplied)																									
Sum	(18)	(18)	(5,120)	(6,107)	(7,773)	(7,773)	(7,773)	(9,652)	(9,652)	(12,574)	(13,197)	(15,745)	(13,207)	(12,219)	(13,520)	(16,146)	(16,146)	(18,058)	(18,058)	(17,028)	(14,512)	(11,964)	(9,395)	(9,395)	(6,416)

In 2009, the choice and timing of generators that would have had to convert to sufficiently generate the larger number of required credits was calculated using a similar methodology as 2003, but with significantly different results. Most of the nameplate and capacity factor data is identical. The capital and operating cost parameters were the same (per Table 8) but the year in which each conversion was necessary is much sooner in the 2009 study, first additional unit needed in 2008).

Table 16- Annualized Capital Cost from 2009 Report, (Needed in 2008)

Example of Calculating Annualized Capital Costs for NOx from 2009 Report in Year 2008							
						Capital Related Costs	
						$	
Unit	Nameplate (MW)	Capacity Factor (%)	Output (MWh)	Greater of Design Life or PPA	Amortization Period (Yrs)	Raw Capital Cost at $125/KW Coal, $40/KW Gas	Annualized Capital Cost in 2008
H.R. Milner	143	61.6%	771,114	2012	4	$17,875,000	$4,468,750
Battle River 3	148	83.7%	1,085,336	2013	5	$18,500,000	$3,700,000
Battle River 4	148	87.3%	1,131,221	2015	7	$18,500,000	$2,642,857
Genesee 3	490	90.0%	3,863,160	2045	37	$61,250,000	$1,655,405
Sundance 1	280	75.2%	1,843,918	2017	9	$35,000,000	$3,888,889
Sundance 2	280	84.2%	2,064,293	2017	9	$35,000,000	$3,888,889
Sundance 3	353	89.4%	2,764,962	2020	12	$44,125,000	$3,677,083
Sundance 4	353	90.6%	2,800,190	2020	12	$44,125,000	$3,677,083
Sundance 5	353	91.3%	2,823,163	2020	12	$44,125,000	$3,677,083
Sundance 6	399	93.7%	3,273,381	2020	12	$49,875,000	$4,156,250
Battle River 5	368	89.5%	2,885,785	2021	13	$46,000,000	$3,538,462
Keephills 1	381	93.8%	3,132,215	2023	15	$47,625,000	$3,175,000
Keephills 2	381	95.7%	3,193,357	2024	16	$47,625,000	$2,976,563
Sheerness 1	378	92.4%	3,057,980	2026	18	$47,250,000	$2,625,000
Genesee 1	384	91.6%	3,080,504	2029	21	$48,000,000	$2,285,714
Sheerness 2	378	91.6%	3,033,209	2030	22	$47,250,000	$2,147,727
Genesee 2	384	93.3%	3,139,570	2034	26	$48,000,000	$1,846,154
Wabamun 1	65	88.0%	500,857	2003	0		
Wabamun 2	65	80.6%	459,204	2003	0		
Wabamun 3	139	80.6%	981,990	2003	0		
Wabamun 4	279	86.6%	2,116,004	2008	0		

Figure 23 – Cumulative NOx Credits, Sources and Application from 2012 Onwards (2009 Study)



From the graph, it appears that the conversion of Keephills in the 2009 study was not actually needed as early as it was planned.

2013

EDC has not refreshed the various capital and operating cost and emission intensity input data since the 2003 study and only has direct visibility of data in the public domain. 2003 and 2009 intensity assumptions were almost identical for each pollutant, but not reflective of observed actuals. EDC would expect CASA to review the current assumptions and determine the extent to which a refresh is required. The choice of the intensities to use in the Phase 2 2013 model is the subject of current committee discussion, but can be informed by Appendix 1-4 which shows the gas and coal unit intensities as well as the actuals from 2006 to 2012 and a calculation of 5 and 7-year averages for each pollutant.

For Phase 2 of the 2013 study, EDC, with critical review from the steering committee, will update the calculation of market-based costs of additional required credits for each pollutant, reflecting more current capital and operating costs of converting existing generators, ranked in the order they mostly likely would consider investing in additional mitigation equipment, to generate and sell new credits on a merchant basis, as the need for increases over time.

Besides the intensity and production data shown above, other actual 2009-2013 data is now available that had not yet come to pass in either the 2003 or the 2009 study.

Actual Accumulated Credits to the End of 2013

EDCA recently did a preliminary electricity industry-wide estimate of already accumulated credits for NOx/SOx credits under the Emission Trading Regulation over time. EDC scraped the Alberta Environment and Sustainable Resource Development Website (see: http://www.environment.alberta.ca/apps/etr/Credits.aspx) and created a full breakdown, by unit, of earned credits by year and pollutant (XL file available). Of a total of undiscounted[3] 89,732 credits claimed to date, 55,300 are for NOx and 34,432 are for SOx. EDC estimated what the totals would accumulate to, by unit, from 2013 to 2035, by extending that creation, where probable, at a similar speed to prior accumulation, assuming published baselines, actual intensities and average capacity factors for each unit. Preliminary work (subject to review by committee members) suggests that, by the end of

[3] i.e. Before application of the prescribed 10% discount for credits held longer than 2 years

2013, if everyone (including small contributing gas-fired plants) reported everything they will have probably already earned by then[4], the nominal stockpile of credits will actually be larger than what is already reported, possibly 105,000 NOx credits and 45,000 SOx credits. By 2015, they will have accumulated (with expected additions) as follows (before application to "post-design life" units):

Table 17 -Summary of Estimated Accumulations of NOx and SOx credits

Type of Emission	Current Accumulated Claimed Credit	Estimated to end of 2013 (if all claimed)	End of 2015
NOx	55,300	104,933	131,309
SOx	34,432	42,409	65,087
Total	89,732	147,342	196,396

This accumulation is larger than anticipated in either the 2003 or 2009 Study (see Table 7 and Table 15).

Estimating Future Creation and Application of NOx/SOx Credits

This section outlines how EDC would estimates the future creation and application of NOx/SOx credits under the Emission Trading Regulation and assesses the likely balance of future credits vs. future required SOx credits over time. EDCA is prepared to do a similar analysis for NOx emissions. EDCA made a series of assumptions regarding coal-fired retirements, delaying the retirement of all coal units back to the new Federal dates based on the earlier of 50 years or the specified latest year (2019 or 2029) for the three bands of vintages (pre-1975, pre-1985, post-1985).

In their 'post-design life" phase (indicated by a cell with a red outline), each unit will have to meet stringent and tightening BATEA (Best Available Technology Economically Achievable) standards for their respective technology. In 2013, HR Milner was assumed to be the first of existing units to start using up credits (1,461/year) to meet their more stringent BATEA level NOx and SOx requirements, while many others will continue to generate credits until their respective design lives are reached (see Table 7 and Table 15). EDC's preliminary analysis estimates that, shortly thereafter, in 2014 and 2015 respectively, each successive Battle River unit would likely need to use about 5,000 credits per year to comply with their "post design life" BATEA emission level if they continue to emit at their average baseline emissivity.

Since HR Milner and Battle River 3 & 4 would be the only ones needing credits until about 2018 (assuming no tie-in to new Federal GHG life extensions), the existing pool of credits would be sufficient, in fact in a large enough surplus position (see Figure 24) that the credits might not command a price anywhere near the fully-allocated cost of the already installed scrubbers. After 2015, EDC estimates that addition of credits will be in the order of 13,200/year for NOx and 4,000/year of SOx until some unit(s) decides it would be financially beneficial to install scrubbers and other mitigation devices to earn merchant credits. For each unit in its pre-design life phase, the model calculates its allowed emissions of each pollutant (baseline intensity (kg/MWh) times average production (MWh) compared to its average (2008-2012) actual emissions (average production (MWh) time average actual intensity). If its actual emissions are less than its allowed emissions, that unit earns credits. Ten years after the end of design life it is assumed a unit will not earn any further credits.

[4] Which they are not obligated to report immediately, but still earn the credits

Table 18 - Estimated Current Accumulations of NOx and SOx Credits to 2013

Coal SOx BATEA Target (kg/MWh): 0.80

Legend: Retired | Purchase Credits to meet BATEA | SOx Install

									2026	Yearly SOx Credits							
										8760	8760	8784	8760	8760	8760	8784	8760
Unit	Nameplate (MW)	Retirement Year (by end of)	2008-2012 Capacity Factor	BATEA Year (by end of)	SOx Baseline (kg/MWh)	Avg. Sox Intensity (kg/MWh)	Year Control Installed	Post-Control Intenisty (kg/MWh)	Amortized Cost to Install in 2026	2006	2007	2008	2009	2010	2011	2012	2013
Battle River #3	149	2019	84.3%	2013	5.10	5.36				179	140	81					
Battle River #4	155	2025	81.5%	2015	5.10	5.32				183	162	71					
Battle River #5	385	2029	79.3%	2021	5.04	4.77			$2,720	987	1,854	1,387	780	27		732	730
Genesee #1	400	2039	89.1%	2029	2.33	2.05			$1,772	848	794	1,156	1,043	787	514	873	870
Genesee #2	400	2044	89.0%	2034	2.33	2.05	2025	0.80	$1,281	799	819	1,156	1,110	729	545	872	870
Genesee #3	466	2054	80.5%	2044	0.80	0.99			$5,994								
HR Milner	144	2019	61.0%	2012	5.32	2.69				2,417	2,130	1,878	2,445	1,899	1,693	2,031	-1,451
Keephills #1	395	2029	83.7%	2023	2.03	2.19			$7,377								
Keephills #2	395	2029	83.6%	2024	2.03	2.17			$7,484								
Keephills #3	466	2061	85.9%	2051	0.72	0.66									83	195	195
Sheerness #1	390	2036	75.4%	2026	5.93	6.46	2021	0.80	$602								
Sheerness #2	390	2040	74.8%	2030	5.93	6.50	2018	0.80	$431								
Sundance #1	288	2019	73.9%	2017	1.68	1.82											
Sundance #2	288	2019	73.2%	2017	1.67	1.80											
Sundance #3	362	2026	69.6%	2020	2.10	1.95						348	207	149	610	318	317
Sundance #4	406	2027	73.5%	2020	2.10	1.94			$30,759			383	363	238	778	420	419
Sundance #5	406	2028	74.8%	2020	2.09	1.97			$14,620			543	56	160	138	301	300
Sundance #6	389	2029	76.1%	2020	2.09	1.97			$9,616			566	146	154	238	322	321
Credits Earned That Year										5,413	5,899	7,569	6,150	4,143	4,599	6,064	2,571
Raw Cumulative Total (No Discount)										5,413	11,312	18,881	25,031	29,174	33,773	39,837	42,409

For the future, the analysis calculates each unit's requirement for credits or earned credits and keeps a running tally of cumulative balance of credits. Once a unit is retired (grey cells), it no longer uses or generates credits.

Some units (still without full mitigation installed), have very high NOx/SOx baselines and long remaining lives. If such units were to install a mitigation device, they would be able to generate credits at a high rate and for a much longer time before they reach their design life than a unit nearer retirement or with a lower baseline. Eventually, several units would have to add mitigation equipment to keep up with the demand for credits. Since the credits do not expire, they would have some value already, as they could be sold later at an expectedly higher price, less carrying costs. Because the cost of earning new credits would be different for each unit, a market should develop wherein the least expensive additional source needed to clear the market would set the price. So even if a unit could build new credits for some price, if that did not create enough credits to meet the market demand, a more expensive provider would have to also be incented to build, but at a price higher yet, which the first unit would likely shadow-price. This set of progressively more expensive new additions would continue to expand until all demand for credits was filled. However, some generating units may not be motivated to build mitigation devices at any price, for example, because of difficulties negotiating around existing contracts (e.g. PPA terms) or for other portfolio related reasons.

Table 19 - Summary of Possible Used and Earned Credits

Yearly SOx Credits

Coal SOx BATEA Target (kg/MWh): 0.80

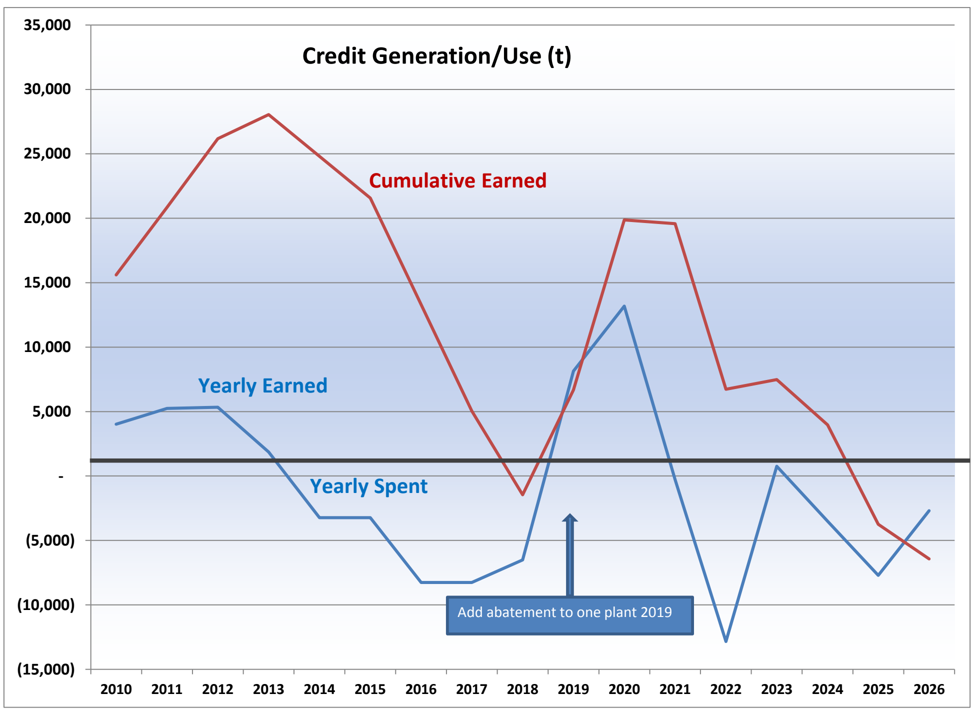
Legend: Retired | Purchase Credits to meet BATEA | SOx Install

		8784	8760	8760	8760	8784	8760	8760	8760	8784	8760	8760	8760
Unit	Retirement Year (by end of)	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Battle River #3	2019			-5,018	-5,018	-5,032	-5,018	-5,018	-5,018				
Battle River #4	2025					-5,024	-5,010	-5,010	-5,010	-5,024	-5,010	-5,010	-5,010
Battle River #5	2029	732	730	730	730	732	730	730	730	732	730	-10,614	-10,614
Genesee #1	2039	873	870	870	870	873	870	870	870	873	870	870	870
Genesee #2	2044	872	870	870	870	872	870	870	870	872	870	870	870
Genesee #3	2054												
HR Milner	2019	2,031	-1,451	-1,451	-1,451	-1,455	-1,451	-1,451	-1,451				
Keephills #1	2029												
Keephills #2	2029												
Keephills #3	2061	195	195	195	195	195	195	195	195	195	195	195	195
Sheerness #1	2036											13,203	13,203
Sheerness #2	2040								13,090	13,126	13,090	13,090	13,090
Sundance #1	2019							-1,902	-1,902				
Sundance #2	2019							-1,854	-1,854				
Sundance #3	2026	318	317	317	317	318	317	317	317	318	-2,549	-2,549	-2,549
Sundance #4	2027	420	419	419	419	420	419	419	419	420	-2,970	-2,970	-2,970
Sundance #5	2028	301	300	300	300	301	300	300	300	301	-3,124	-3,124	-3,124
Sundance #6	2029	322	321	321	321	322	321	321	321	322	-3,034	-3,034	-3,034
Credits Earned That Year		6,064	2,571	-2,447	-2,447	-7,477	-7,457	-11,213	1,878	12,135	-932	926	926
Raw Cumulative Total (No Discount)		39,837	42,409	39,962	37,515	30,038	22,582	11,369	13,247	25,382	24,450	25,376	26,303

		8784	8760	8760	8760	8784	8760	8760	8760	8784	8760	8760	8760
Unit	Retirement Year (by end of)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Battle River #3	2019												
Battle River #4	2025	-5,024	-5,010										
Battle River #5	2029	-10,643	-10,614	-10,614	-10,614	-10,643	-10,614						
Genesee #1	2039	873	870	870	870	873	870	-3,907	-3,907	-3,918	-3,907	-3,907	-3,907
Genesee #2	2044	872	870	4,774	4,774	4,787	4,774	4,774	4,774	4,787	4,774	4,774	
Genesee #3	2054												
HR Milner	2019												
Keephills #1	2029	-4,027	-4,016	-4,016	-4,016	-4,027	-4,016						
Keephills #2	2029		-3,959	-3,959	-3,959	-3,969	-3,959						
Keephills #3	2061	195	195	195	195	195	195	195	195	195	195	195	195
Sheerness #1	2036	13,239	13,203	13,203									
Sheerness #2	2040	13,126	13,090	13,090	13,090	13,126	13,090	13,090					
Sundance #1	2019												
Sundance #2	2019												
Sundance #3	2026	-2,556	-2,549	-2,549									
Sundance #4	2027	-2,978	-2,970	-2,970	-2,970								
Sundance #5	2028	-3,133	-3,124	-3,124	-3,124	-3,133							
Sundance #6	2029	-3,042	-3,034	-3,034	-3,034	-3,042	-3,034						
Credits Earned That Year		-3,098	-7,048	1,866	-8,787	-5,833	-2,693	14,152	1,062	1,065	1,062	1,062	-3,712
Raw Cumulative Total (No Discount)		23,205	16,157	18,023	9,236	3,402	709	14,861	15,923	16,988	18,050	19,112	15,400

EDC prepared a preliminary analysis of SOx puts and takes (for review by CASA). The chart is based on the latest expected retirement dates, most, other than HR Milner and Battle River, after 2019. EDC suggests modeling the early years with significant discounts, which would diminish within a year of when the next new emission control device retrofit would be required to meet the rising demand for credits. As more units pass their design life threshold, the pace of credit consumption will accelerate and finally surpass the credit generation from existing equipment (2018). At that stage, one or more units would have to convert early in order to generate credits (blue squares). It is likely that the price of credits will then begin to track the levelized cost of the new abatement costs. There is some debate as to whether the ESRD will follow the Federal GHG guidelines for determining "design life", since the Feds extended all coal generation to 2019 (for plants built before 1975) and 2029 (for plants built before 1985). For this exercise, EDC has assumed the current parameters for "design life" will remain unaltered. At some point, enough units retire (grey squares) and enough units are converted that progressively fewer credits are used. By experimenting with different conversion dates, a schedule of conversions can be found that will create an early stockpile of credits that very nearly runs out just as the last unconverted units retire. Figure 24 presents a graphical illustration of how one pattern would generate and use credits over time. As additional generators periodically convert and earn pre-design life credits for units which are in their post-design phase. A similar chart for NOx puts and takes could be developed by a similar process.

Figure 24 - Puts and Takes of SOx Credits Estimate (Preliminary)



Abatement devices may have significant capital and operating costs which would likely vary widely by generator. EDC used the originally estimated capital costs for such devices, the same figures used in its 2003 and 2009 studies. However, the EDC models would easily accommodate revised capital costs in its levelized cost calculation if CASA was able to canvass its members for such data, which appears to under-estimate their likely cost.

EDC also would envisage creating a more inclusive "levelized cost" calculation than that in the 2003 or 2009 studies, essentially amortizing the capital costs rather than simply depreciating them, that is, including not just repayment of capital but also return on capital. Then, adding on the yearly or per MWh variable operating costs would yield a price per avoided tonne of emissions which any person needing credits would be expected to pay. Ideally, the calculation above would serve as a legitimate proxy for a market-set price, reflecting the supply and demand of such credits.

Determining Total Emissions and Associated Compliance Costs

EDCA's dispatch model (for determining which generators will run in which hours), uses a forecast of each generator's marginal cost. This value is tempered by observed actual merit order offers and some game theory, to construct the price/quantity offer pairs that determine the intersection of supply and demand (and thus hourly dispatched generation, pool price and resultant emissions) (see purple boxes in Figure 17).

Unit marginal costs are based on individual capital, fuel, environmental and variable (O&M and miscellaneous components like the AESO trading charge) costs, modified by either individual unit or area-specific loss factors. The environmental component ($/MWh) for GHG s is generally calculated by the product of Unit Emission Intensity * Target Reduction % * $/t GHG Charge. As these costs are included in the marginal cost for each unit, they flow through to unit offer strategies, thus having a direct impact on power prices (increasing them) and respective hourly dispatch of units (units with higher intensity may move past other units adjacent to them in the merit order).

For the 2003 and 2009 studies, EDC had developed a matrix of composite costs and credits that each unit was presumed to apply in each year. These numbers did reflect some of the capital costs spent to earn credits by early adoption and to reduce their individual unit's intensities closer to their ultimate target. They also included the expected operating costs that would be included each year (e.g. activated carbon, bag-house power, chemicals and repairs).

EDC researched its archives to verify the buildup of these figures. Generally, they are not large enough to substantially change the merit order enough to materially affect the respective dispatch of generators or, even less likely, to damage their profitability enough to provoke an early retirement. Therefore, the total tonnes and intensity by pollutant, by unit and for the fleet are not likely to be changed substantially in the short run.

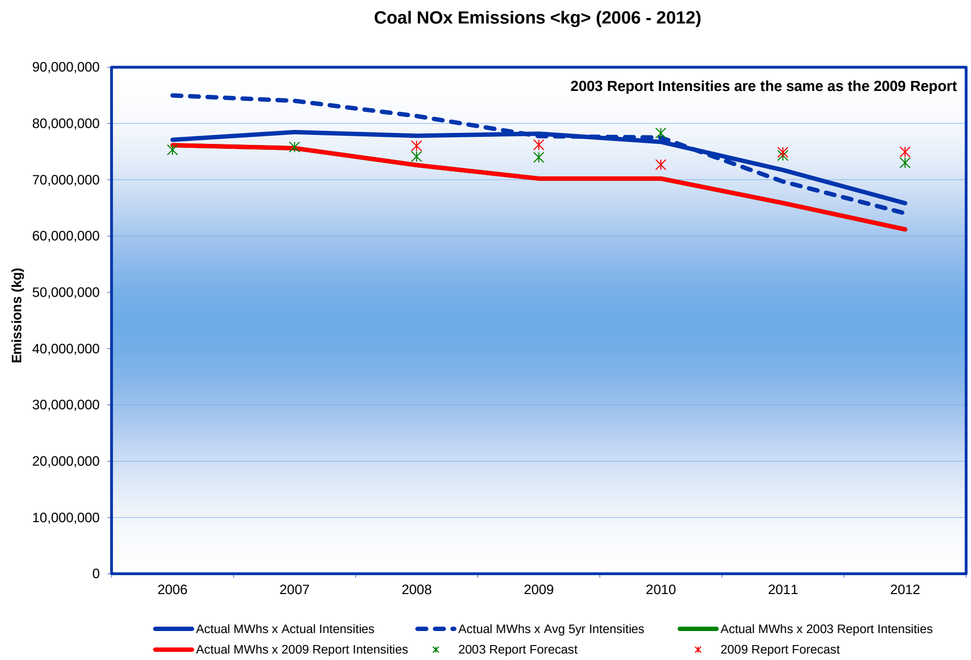
2013 NOx, SOx Forecast

For Phase 2 of the 2013 study, in a manner similar to the method used in the 2003 and 2009 studies, but with updated cost figures, EDC, with critical review from the steering committee, will endeavour to develop a market-based cost of credits for each pollutant, reflecting the expected capital and operating costs of the existing generators, to create a list of generators, ranked in the order they mostly likely would consider investing in additional mitigation equipment, that would create new credits to sell on a merchant basis, as the need for additional credits increases over time. It is expected that this will yield an analog to the electricity merit order, where successive tranches of credits will cost more than the previous one. The steering committee agreed to drop PM calculations from the model.

Preliminary Test of 2013 Methodology

Although technically a Phase 2 task, EDC did a preliminary estimate of the progression of annual NOx and SOx tonnage from 2006-2012, comparing the 2003 and 2009 forecasts to different combinations of previous or current actuals of the intensities of each unit and their respective production. This allows the effects of different changes to be segmented (e.g. generation volume variance versus intensity variance). The current generation production actuals are lower in each year than their estimated values in 2003 and 2009, but the NOx intensities are higher, based on observed actuals (see Figure 19 and Appendix 1). The two variances partly cancel each other out, but the increase in total NOx emissions cause by higher actual intensities is greater than the reduction caused by the lower volumes of generation needed to match the reduced demand for electricity. On balance, therefore, the total actual NOx emissions, although still falling over time, are about 10% higher than predicted in either 2003 or 2009, using this preliminary analysis. The model is set up to do a similar analysis for each pollutant.

Figure 25 – Preliminary Phase 2 Estimate of NOx Emissions (2006-2012)



Price Forecast

Each of the 3 models incorporated "*thinking of the day*". As such, although the expectations that were modeled were plausible, changes in market conditions would result in different outcomes than forecast. The landscape of the Alberta electric industry has changed dramatically across forecast periods in response to underlying fundamentals and unforeseen policy and technology changes.

For example, the 2003 model had enough wind additions to meet a 3.5% renewable energy target, then held growth flat. In actuality the wind fleet has grown quite noticeably (from 174 MW in 2003 to 1,122 MW in 2012) and is forecast to continue to grow as developers are able to secure credits from outside sources, such as California, making their projects viable despite soft prices in the near/mid-term. This will result in greater emission-free electricity generation at the cost of system stability (wind farms are typically only able to operate at about 35% capacity factor and, when coupled with the fact that most farms are clustered together, can add significant price volatility). The 2009 model captured and utilized this information, albeit at too aggressive a pace; the 2013 model continued the 2009 model's assumptions, but toned down.

As another example of a shift in fundamentals, the 2003 model expected the Alberta economy to be fairly strong (with a real GDP growth forecast averaging 3.4% from 2004 to 2008). However, a substantial increase in the price of crude oil and natural gas spurred unprecedented levels of drilling for gas and the development of northern Alberta's oil sands, driving Alberta's real GDP growth to actually average 5.4% in that time period, almost twice what was expected. The 2009 model utilized this information and forecasted a continuation of the strong demand growth and robust natural gas prices, leading to greater total electricity generation and coal being the primary source of future additions (in spite of the uncertainty surrounding its future environmental costs). In actuality, demand fell in 2008 and 2009 before resuming growth (albeit at a slower pace). Natural gas prices collapsed from a monthly average peak of $10.60/GJ in June 2008 to a low of $1.59/GJ in April 2012 as technological advances led to gas supply easily outpacing demand. The net effect of these changes was a decrease in the amount of electricity forecast to be generated in Alberta, in addition to combined-cycle now being the cheapest source of future base-load power.

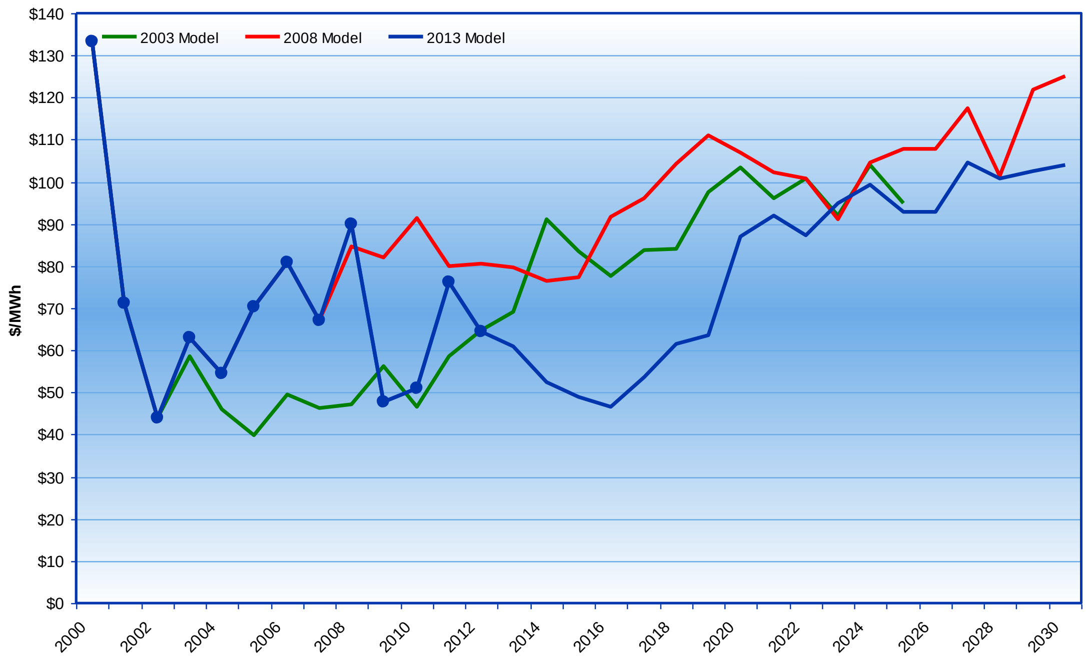
Beyond fundamental changes to the market, the model has undergone vast technical changes over the last decade. Although the core of the model is still the same (intersect forecast demand with forecast supply in order to produce an accurate generation, price and emissions forecast), how the various components are forecast has changed. For example, in past models, generator's offer behavior had to be implied based on an analysis of their metered volume output and assumed marginal costs. In 2009, the AESO began publishing the raw merit order data which shows, hour-by-hour, the offer structure generators with offer control implemented. As such, EDCA was able to refine its price/quantity offer pairs using actual historical data and linking them to dynamic market events (e.g., supply cushion responsiveness).

Figure 26 presents the pool price forecasts from the 3 models, with blue dots representing historical actuals. The 2003 model undershot actuals as it did not forecast the high commodity price environment that was experienced. Conversely, the 2009 model did not foresee the upcoming recession and negative demand growth, resulting in its forecast prices being too aggressive. Although its prices came close to converging with actuals in 2011, that was primarily due to the market reacting to the sudden loss of Sundance #1 and #2 (586 MW of total generation) in late December 2010.

The 2013 model averages $48.90/MWh between 2014 and 2018, as compared to $89.16/MWh in the 2009 model and $84.00/MWh in the 2003 model. In the long-term (2019 to 2025), softer market fundamentals cause the pool price forecast in the 2013 model to remain below the other models, averaging $87.12/MWh, as compared to $103.48/MWh and $98.42/MWh in the 2009 and 2003 models, respectively.

In the 2013 model, despite an expectation of robust domestic AIES demand growth and stronger AECO-C natural gas prices, pool prices are expected to soften from an actual average price of $80.19 in 2013 to $44.90/MWh in 2014. The full-year return of Sundance #1, Sundance #2 and Keephills #1 (which had been offline for most of 2013 due to a winding failure), coupled with the commissioning of Enbridge/EDF's 300 MW Blackspring Ridge wind farm and the first full year of operation of MEG Energy's newest cogen and increased MATL imports will depress the 2014 forecast. It is expected the new MEG unit act as a pure price taker, similar to MEG's existing facility. Although MATL will not add any new Available Transfer Capacity, it should provide additional imports when BC imports do not fully utilize their allocated capacity (but only when 1201L is available, as MATL requires the support of this line in order to flow power).

Figure 26 – Pool Price Forecasts ($/MWh)



Following 2014, a supply glut will be created by the potential commissioning of several additional large wind farms, such as BluEarth's Bull Creek, and base-load units, the largest of which is ENMAX/Capital Power's 800 MW Shepard Energy Centre. Extended coal-fired retirement dates due to the more liberal current GHG assumptions for coal units will exacerbate the situation, with pool prices averaging $49.89/MWh between 2015 and 2018.

Minimal generation additions are forecast between 2016 and 2019, which will allow prices to slowly recover on demand growth. Multiple coal-fired retirements in 2019 (Battle River #3, Sundance #1, #2 and HR Milner) make 2020 the first year capable of absorbing large capacity additions, potentially either Sundance #7, the first part of Capital Power's proposed Energy Center, TransCanada's Saddlebrook or the initial piece of ATCO's proposed Heartland facility. Current forecast demand growth and supply expectations make it uneconomical for these large combined-cycle units to commission earlier than 2020.

There is always the outside chance that AIES demand will snap back to pre-2009 levels and put upward pressure on prices. However, the current leading indicators (oil price, building permits and exchange rate) do not signals strong growth. Similarly, another long-term major plant failure or a significant (but unlikely) construction delay at Shepard, would spike prices. The upside price risk from unexpectedly high levels of coincident base-load outages, unforeseen changes in pool participant behaviors, or construction delays is much stronger than the downside risk of weaker demand or greater supply.

From 2020 onwards, the pool price oscillates slightly above the levelized cost of natural gas-fired combined-cycle generation (the lowest cost alternative for base-load power). When pool prices are below the levelized cost line, generators are not incented to build. Eventually, ever-increasing demand and retirements use up existing supply and prices rise. Conversely, when prices are above the line, generators have incentive to build, which causes supply to eventually outpace demand, and lower prices. The levelized cost line itself may go through a similar cycle. For example, if more North-American natural gas-fired generators build, equipment (e.g., turbines) may become more expensive as equipment manufacturers try to take advantage of any temporary supply scarcity.

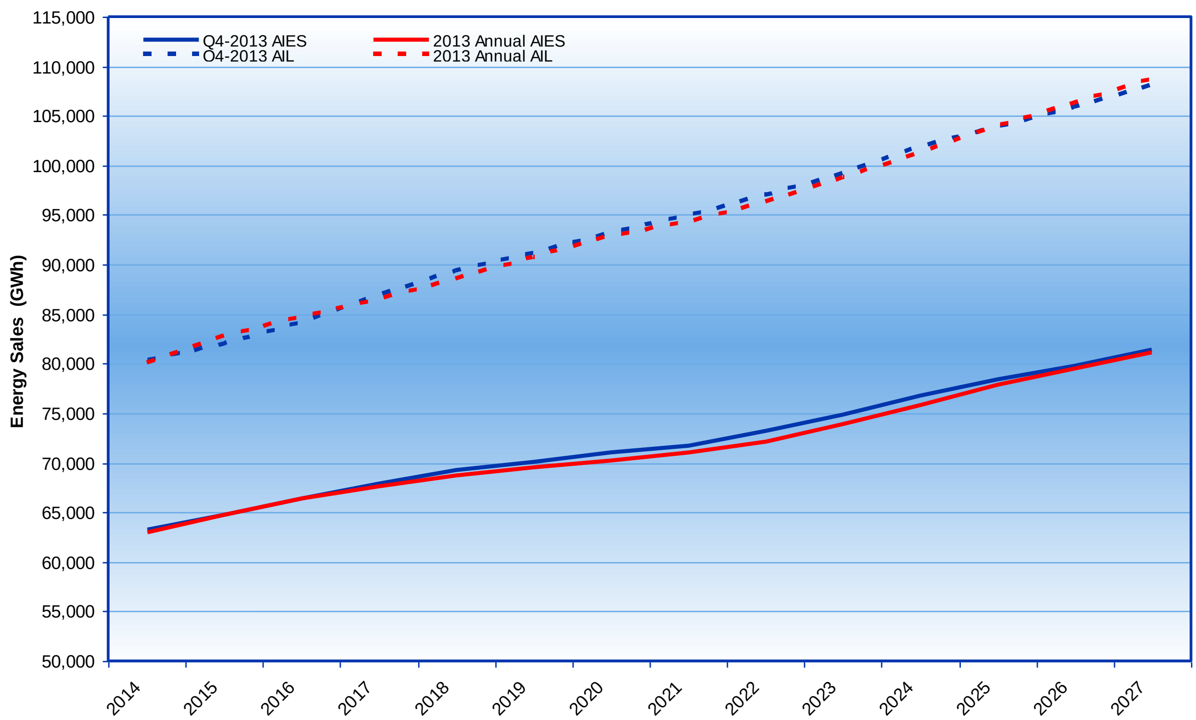
Q4-2013 vs 2013 Annual Study

CASA had originally tasked EDCA with comparing the assumptions from the 2003 model and the 2009 model against EDCA's most recent Annual Study (2013 Annual). However, given that some of the information presented in the Annual Study is now outdated, as well as the fact that past emission forecasts were constructed using 'Quarterly' assumption sets, Q4-2013 was expected to provide a more straightforward and meaningful comparison to past studies.

As CASA members have not had the opportunity to review the Q4-2013 Report, this section presents a very high level overview of the changes between the two Studies. There are no changes between the two Studies that would result in different conclusions in the previous sections of this report.

Figure 27 compares the AIES and AIL energy sales forecast between the Q4-2013 and 2013 Annual Study models. The Q4 model is slightly higher than the Annual Study in the mid-term of the forecast, driven predominately by stronger oil prices.

Figure 27 – Changes between AIES and AIL Energy Sales Forecasts (GWh)

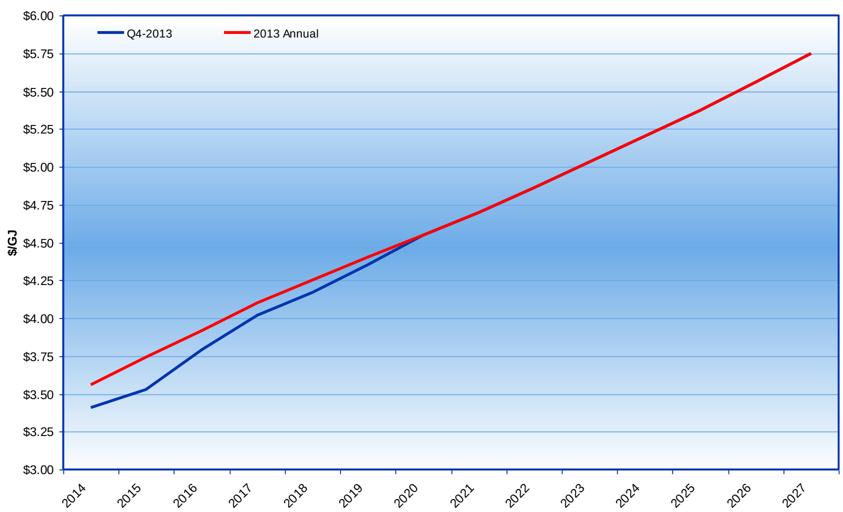


As depicted by Figure 28, AECO-C natural gas price expectations parallel each other post 2019, although the near/mid-term (2014-2019) sees slightly weaker prices, averaging $3.88/GJ in the Q4-2013, as compared to $4.00/GJ in the Annual Study. The front-end of EDCA's natural gas forecast is more heavily weighted towards the market forwards (which have softened over the last several months), as compared to the back-end, which places more emphasis on institutional forecasts and market fundamentals.

With respect to near/mid-term supply assumptions, several small unofficial derates/uprates were to made to coal-fired generators' capacity in order to better reflect information presented on the AESO's CSD page. Several gas-fired units, such as MEG Energy's Christina Lake Phase 3 and Surmount, in addition to small Genalta simple-cycle units, were added into the forecast. The largest change to short-term gas-fired generation, MEG Energy's newest facility (Christina Lake Phase 2B) was in the Annual Study half-way through 2014 at 65% probability, sending first power to the grid in September 2013.

Assumptions were changed for multiple wind farms, including raising Blackspring Ridge's probability to 80% (from 45% in the Annual Study) on refreshed progress reports, doubling the probability of Mainstream's Oldman River wind farm to 30% after they secured project financing, adding ATCO's recently proposed Heartland Power Station and tweaking the timing of generic combined-cycle units to follow the marginally higher domestic demand expectations.

Figure 28 – Changes between AECO-C Natural Gas Price Forecasts ($/GJ)



Unit retirement assumptions were not changed. Combined-cycle is still expected to be the primary source of generation additions throughout the forecast, meeting load growth and unit retirements. The methodology used to forecast future ATC levels was recalibrated and loss factors were changed to reflect the AESO's most recently published values.

Figure 29 summarizes the impact of these changes on the capacity forecast for the Q4-2013 model in solid bars against the 2013 Annual Study model (shaded area curve). As can be seen from the graph, the two capacity forecasts are not significantly different from each other.

Figure 29 – Changes between Capacity Forecasts (MW)

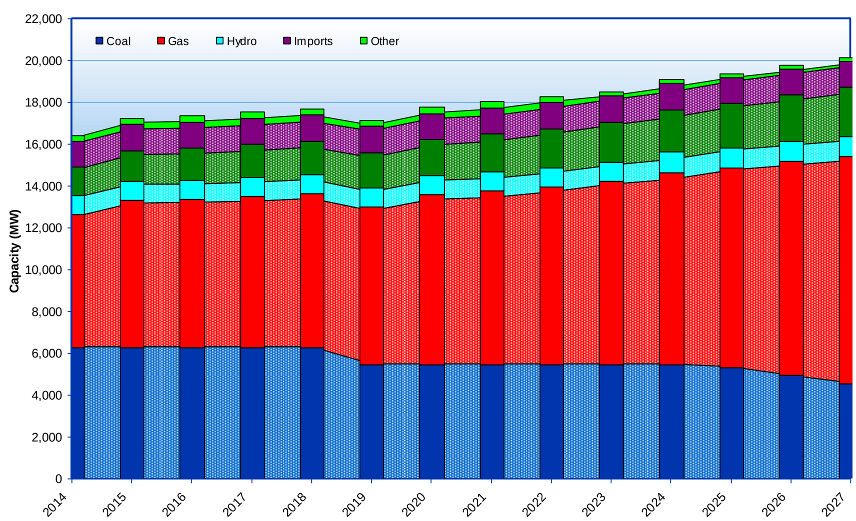
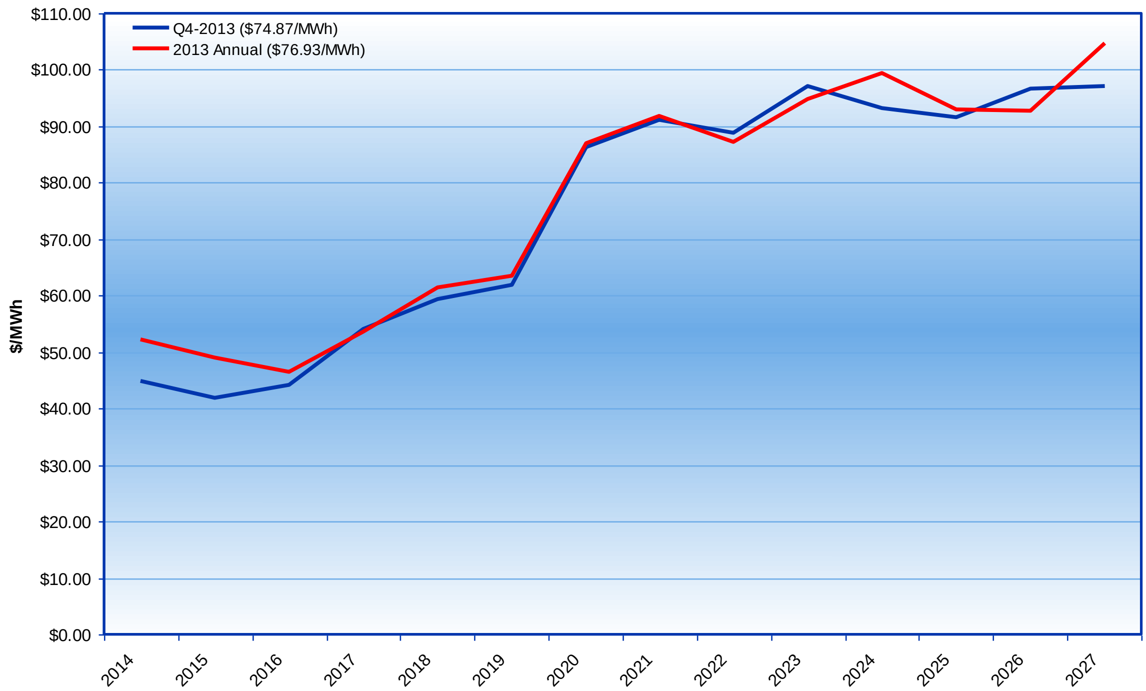


Figure 30 presents the P50 pool price forecasts from the Q4-2013 and the 2013 Annual Study. For the most part the price curves follow each other fairly closely.

Figure 30 – Changes between Pool Price Forecasts ($/MWh)



Noticeable differences in 2014 and 2015 are due to revised supply assumptions, primarily the changes to MEG Energy's Christina Lake Phase 2B cogen (increased probability to 100%, with commissioning in 2013). The years towards the end of the forecast (2024 onwards) vibrate through each other and are fairly close. EDCA's forecasting model uses a Monte-Carlo technique. This probability based "stochastic" model will produce slightly different results each time it is run. In the near/mid-term, the difference in results between runs is very small. In the long-term, due to greater uncertainty surrounding supply and demand assumptions, the difference between runs can increase to several dollars. As such, one would expect two similar forecasts to vibrate through each other, as they are in Figure 30. Over the next 5 years (2014-2018), the Q4-2013 model averages $48.90/MWh, as compared to $52.59/MWh in the Annual Study. In the long-term (2019-2027) the Q4-2013 model averages $89.30/MWh, as compared to $90.45/MWh in the Annual Study.

Qualifications

For over 20 years in Alberta, EDCA has been continually engaged by a wide variety of electric industry participants including loads, generators, power marketers, legislators and implementing agencies, to provide its professional judgment and opinion in respect of asset valuation, market impact assessments and recommendations for purchases and sales of electricity, and to provide evidence in written format and as oral expert witness testimony for court litigations and quasi-judicial regulatory proceedings in the electricity industry.

EDCA also publishes weekly, monthly, quarterly and annual reports for hundreds of subscribers, which include 2-20 year forecasts of expected supply, load, hourly electricity pool price and gas price (see www.edcassociates.com for product line and client list). For these reasons, EDCA represents itself and is often retained as an industry expert, as outlined in Section 620 of the Handbook of International Auditing, Assurance, and Ethics Pronouncements, 2010 Edition, for the purpose of evaluating the fair market value of the ESA as contemplated in the IFRS, Section IAS 39: Financial Instruments: Recognition and Measurement.

Incorporated in 1992, EDC Associates Ltd. (EDCA) is an independent energy-consulting firm based in Calgary, Alberta, Canada that provides consulting services with respect to electric energy pricing, generation economic development, electric energy and natural gas procurement, regulatory and legal issues, and electric industry training.

EDCA's Experience and Qualifications

EDCA has designed, developed and continually updates and maintains an integrated suite of computer models that are used to provide very detailed quantitative analysis in support of its consulting services. These models are based on robust forecast methodologies to assess intricate market fundamentals and have been recognized as being leading edge, comprehensive and the "barometer" of energy (electricity and natural gas) pricing used by industry and market participants. More specifically, these models are used to analyze electric energy market fundamentals to produce both short and long-term hourly forecasts of expected supply, load, hourly electricity pool price and heat rate, typically from 1 to 30-years, which EDCA publishes weekly, monthly, quarterly and annually for hundreds of subscribers. EDCA has been the premier supplier of independent electricity price forecasts and generation energy production simulations in Alberta since the start of the electric energy industry re-structuring in 1996. As part of this detail quantitative analysis, EDCA also closely follows and analyzes world oil and North American natural gas markets as they relate to and impact on the Alberta energy markets.

As part of the energy pricing consulting services provided by EDCA, the company has been retained to prepare case by case client specific market analysis and forecasts for a wide range of electricity industry participants including marketers, retailers, generation developers, industrial customers, regulators and governmental departments and also publishes several multi-client studies, newsletters and reports on its own volition that are widely circulated to industry clients on a fee for service basis.

As part of the generation economic development services provided by EDCA, the company has been retained by its clients to provide independent and rigorous analysis with respect to generation feasibility and economic modeling used by those considering generation development, value optimization, acquisition or divestiture. EDCA incorporates Monte-Carlo analysis with respect to quantifying volume, price and other key risk components related particularly to asset valuation, energy production, ancillary services revenues and risk/hedging analysis as part of any generation economic or options study.

As part of the energy procurement consulting services provided by EDCA, the company has been retained by energy suppliers and consumers to facilitate energy procurement or sale processes for electricity and natural gas. EDCA provides services in regards to: requests for quote and proposal development, purchase/sale recommendations, purchase/sale strategies and portfolio monitoring services, budget assistance and reporting. EDCA has made recommendations and negotiated vendor contract terms in respect of electricity and natural gas over-the-counter agreements up to 20 years in length.

As part of its regulatory and legal consulting services provided by EDCA, the company has on many occasions prepared and filed evidence in both legal and regulatory proceedings in Alberta and other provincial jurisdictions. EDCA staff has been prepared as an expert witness on approximately 10 occasions on behalf of several clients and proceedings with several appearances in front of the then AEUB (now AUC).

EDCA's Independence and Objective Professionalism

EDCA maintains strict neutrality between commodity suppliers, generation developers, marketers and equipment suppliers. EDC owns no generation assets or capacity rights and has no preferred commodity suppliers. This neutrality ensures our actions and advice are always independent and unbiased.

EDCA's client list further exemplifies the fact that our services are industry neutral, with services being provided to all segments of the market from consumers to suppliers, marketers, retailers, utilities, governments and other impartial and regulatory agencies.

The following quotations from an AEUB (now AUC) Decision 2005-096 (dated August 28, 2005) regarding the Alberta Electric System Operator's 2005/2006 General Tariff Application (Application No. 1363012) also serves to underscore EDC's recognized credibility and professionalism, specifically in the Alberta electricity market.

On page 6, section 4.2.1:

"The AESO noted the EDC commodity price forecast has been used by the AESO and predecessor organizations since at least 2002 for the following reasons:

- The EDC forecast is a credible, industry accepted standard.
- A third-party or arm's length forecast is less contentious.
- Purchasing the EDC forecast is more cost–effective than producing an internal forecast.

The AESO noted that in Information Response BR.AESO-030, the AESO stated that in the future it will use the most recent EDC bi-weekly forecasts regarding ancillary service forecasts.",

and on page 7, section 4.2.1:

"Furthermore, during cross-examination, the Alberta Direct Connect Consumer Association (ADC) panel stated that some ADC members used EDC forecasts and noted that EDC is a credible and professional organization."

See Attachment 1 for CV's of contributing EDCA staff.

Appendix 1 – Used ('03, 09) and Actual NOx Intensities by Unit and Year ('06-12)

Historical NOx Assumptions (kg/MWh)															
ID	Name	Baseline	2003 CASA Report	2006	2007	2008	2009 CASA Report	2009 vs 2003 CASA	2009	2010	2011	2012	2013	5 Year (08-12) Average	7 Year Average
BR3	Battle River #3	2.28	1.60	1.88	1.84	1.91	1.60		1.85	1.87	1.92	2.12		1.94	1.91
BR4	Battle River #4	2.28	1.60	1.88	1.78	1.84	1.60		1.84	1.87	1.88	2.13		1.91	1.89
BR5	Battle River #5	2.39	1.60	2.01	1.94	1.87	1.60		1.96	1.53	2.35	2.31		2.00	1.99
HRM	H.R. Milner	2.88	1.40	2.59	2.73	2.94	1.40		2.27	2.15	2.15	1.77		2.26	2.37
SH1	Sheerness #1	1.93	1.80	2.07	2.26	2.02	1.80		2.01	2.05	2.13	2.20		2.08	2.10
SH2	Sheerness #2	1.93	1.80	2.07	2.25	2.01	1.80		2.03	2.03	2.12	2.23		2.08	2.11
GN1	Genesee #1	2.13	2.10	1.95	1.76	1.83	2.10		1.90	1.87	2.01	1.87		1.90	1.88
GN2	Genesee #2	2.13	2.10	1.95	1.76	1.83	2.10		1.90	1.87	2.01	1.87		1.90	1.88
KH1	Keephills #1	2.19	1.90	1.95	1.84	1.85	1.90		2.21	2.19	2.12	1.89		2.05	2.01
KH2	Keephills #2	2.17	1.90	1.99	1.84	1.86	1.90		2.16	2.20	2.15	1.85		2.04	2.01
SD1	Sundance #1	1.52	1.60	1.54	1.98	2.32	1.60		2.67	2.57				2.52	2.22
SD2	Sundance #2	1.55	1.60	1.53	1.98	2.31	1.60		2.66	2.67				2.55	2.23
SD3	Sundance #3	1.63	1.60	1.64	1.80	1.86	1.60		1.88	2.00	1.95	2.20		1.98	1.90
SD4	Sundance #4	1.64	1.60	1.66	1.77	1.86	1.60		1.87	1.98	1.93	2.17		1.96	1.89
SD5	Sundance #5	1.50	1.60	1.43	1.55	1.75	1.60		1.78	1.64	1.69	1.75		1.72	1.66
SD6	Sundance #6	1.50	1.60	1.39	1.54	1.65	1.60		1.67	1.63	1.65	1.80		1.68	1.62
WB1	Wabamun #1		1.80				1.80								
WB2	Wabamun #2		1.80				1.80								
WB3	Wabamun #3		1.80				1.80								
WB4	Wabamun #4	2.17	1.80	2.11	2.00	2.06	1.80		2.28	2.21	n/a	n/a		2.18	2.13
GN3	Genesee #3	1.18	1.20	0.57	0.54	0.59	1.20		0.57	0.60	0.58	0.60		0.59	0.58
KH3	Keephills #3	0.62	0.69				0.69				0.55	0.56		0.55	0.55
Past/Current Coal Uprates			0.00				0.00								
All Future Coal Units			0.00				0.47								
ALS1	Air Liquide (Shell Scotford Refinery	0.20	0.50	0.11	0.11	0.12	0.50		0.12	0.13	0.12	0.13		0.12	0.12
MKR1	ATCO/Shell Lease 13 Muskeg Rive	0.20	0.30	0.07	0.08	0.09	0.30		0.10	0.09	0.09	0.09		0.09	0.09
PR1	Primrose #1		0.30				0.30								
JOF1	Joffre		0.30				0.30								
PH1	Poplar Hill #1	0.22	0.30	0.60	0.55	0.49	0.30		0.51	0.43	0.77	0.90		0.62	0.61
RB5	Rainbow #5	0.63	0.53	0.68	0.79	0.73	0.53		0.88	1.15	0.73	0.50		0.80	0.78
RL1	Rainbow Lake #1	1.22	0.50	0.33	0.56	0.39	0.50		0.35	0.30	0.43	0.43		0.38	0.40
GOC1	Maxim Gold Creek (Ormat)		0.50				0.50								
DOW1	Dow Chemicals		0.50				0.50								
DOWG	Dow Chemicals		0.50				0.50								
EC01	Encana Cavalier Phase II (IBOC)	0.57	0.30	0.44	0.50	0.62	0.30		0.64	0.57	0.56	0.47		0.57	0.54
NX01	Encana/Nexen Balzac (IBOC)	0.54	0.30	0.62	0.60	0.63	0.30		0.56	0.46	0.45	0.41		0.50	0.53
IOR1	IOL (Mahkeses - Phase 11 to 13)		0.30				0.30								
ME01-05	Maxim Power		0.30				0.30								
FNG1	Fort Nelson (new combined cycle)		0.50				0.50								
SCR1	Suncor Tar Island		1.32				1.32								
SCR6	Suncor Stage 3 Utilities (Firebag St		1.32				1.32								
SCR7	Suncor Firebag Stage 4		1.32				1.32								
SCL1	Syncrude Mildred Lake		0.50				1.32	0.82							
BCRK	Bear Creek #1 & #2	0.28	0.30	0.31	0.26	0.28	0.30		0.30	0.43	0.50	0.52		0.41	0.37
TC01	TCP Carsland/Agrium (IBOC)	0.20	0.30	0.16	0.19	0.16	0.30		0.13	0.13	0.13	0.11		0.13	0.14
TC02	TCP Redwater	0.20	0.30	0.14	0.10	0.10	0.30		0.14	0.10	0.14	0.19		0.13	0.13
ST1	Sturgeon #1		11.00				0.30	-10.70							
ST2	Sturgeon #2		11.00				0.30	-10.70							
CG1	Cloverbar (Old) #1		2.50				2.50								
CG2	Cloverbar (Old) #2		2.50				2.50								
CG3	Cloverbar (Old) #3		2.50				2.50								
CG4	Cloverbar (Old) #4		2.50				2.50								
RB1	Rainbow #1	5.12	2.50	7.40	0.00	0.00	2.50			0.00	0.00	0.00		0.00	1.23
RB2	Rainbow #2	5.33	2.50	8.13	7.83	7.51	0.30	-2.20	7.89	8.75	8.64	7.08		7.97	7.98
RB3	Rainbow #3	5.43	2.50	0.00	0.00	0.00	2.50			0.00	0.00	0.00		0.00	0.00
RG10	Rossdale #10		2.50				2.50								
RG9	Rossdale #9		2.50				2.50								
RG8	Rossdale #8		2.50				2.50								
APS1	ATCO/Shell Scotford (Upgrader)	0.31	0.30	0.09	0.21	0.17	0.30		0.17	0.18	0.07	0.29		0.18	0.17
CAL1	ENMAX Calgary Energy Centre	0.20	0.11	0.15	0.15	0.15	0.11		0.05	0.07	0.06	0.05		0.08	0.10
EC04	ENCANA Foster Ck		0.30				0.30								
MKRC	MacKay River	0.20	0.30	0.12	0.15	0.11	0.30		0.10	0.13	0.14	0.12		0.12	0.12
NPC1	Northstone		0.30				0.30								
ENC1	Cloverbar (New) #1	0.30					0.30		0.49	0.33	0.39	0.38		0.40	0.40
ENC2	Cloverbar (New) #2	0.20					0.30		0.25	0.22	0.22	0.27		0.24	0.24
ENC3	Cloverbar (New) #3	0.20					0.30		0.25	0.22	0.22	0.24		0.23	0.23
CRS1	Crossfield #1	n/a							0.27	0.22	0.24	0.28		0.25	0.25
CRS2	Crossfield #2	n/a							0.19	0.18	0.17	0.16		0.18	0.18
CRS3	Crossfield #3	n/a							0.22	0.19	0.24	0.26		0.23	0.23
NPP1	Northern Prairie Power	n/a							0.16	0.36	0.27	0.27		0.27	0.27
Historical Unnamed Gas Units			0.30				(*)								
Future Gas Units			0.30				(*)								

(*) Gas-fired units commissioned before 2011 assumed to be 0.3 kg/MWh
2011+ Peakers are either 1.008 kg/MWh (<=25 MW), 0.4 kg/MWh or 0.5 kg/MWh (100 MW+)
2011+ Non-Peakers are (Heat Rate*0.01) + 0.6(<25 MW) or 0.09 (>= 25MW)

Appendix 2 – Used ('03, 09) and Actual SOx Intensities by Unit and Year ('06-12)

Historical SOx Assumptions (kg/MWh)

ID	Name	Baseline	2003 CASA Report	2006	2007	2008	2009 CASA Report	2009 vs 2003 CASA	2009	2010	2011	2012	2013	5 Year Average	7 Year Average
BR3	Battle River #3	5.10	3.60	4.94	5.03	5.07	3.60		5.14	5.65	5.61	5.33		5.36	5.25
BR4	Battle River #4	5.10	3.60	4.94	4.89	4.98	3.60		5.13	5.64	5.54	5.33		5.32	5.21
BR5	Battle River #5	5.04	3.60	4.67	4.39	4.52	3.60		4.77	5.03	4.82	4.69		4.77	4.70
HRM	H.R. Milner	5.32	4.00	2.43	3.03	2.71	4.00		2.70	2.92	3.11	1.99		2.69	2.70
SH1	Sheerness #1	5.93	5.00	7.30	7.54	6.60	5.00		6.02	6.26	6.43	6.98		6.46	6.73
SH2	Sheerness #2	5.93	5.00	7.30	7.46	6.74	5.00		6.04	6.26	6.38	7.07		6.50	6.75
GN1	Genesee #1	2.33	2.10	2.07	2.08	1.94	2.33	0.23	1.99	2.09	2.17	2.07		2.05	2.06
GN2	Genesee #2	2.33	2.10	2.07	2.08	1.94	2.33	0.23	1.99	2.09	2.17	2.07		2.05	2.06
KH1	Keephills #1	2.03	1.80	2.12	2.08	2.04	1.80		2.22	2.42	2.19	2.06		2.19	2.16
KH2	Keephills #2	2.03	1.80	2.10	2.08	2.04	1.80		2.17	2.41	2.20	2.02		2.17	2.15
SD1	Sundance #1	1.68	2.00	1.42	1.62	1.75	2.00		1.80	1.91				1.82	1.70
SD2	Sundance #2	1.67	2.00	1.41	1.64	1.69	2.00		1.79	1.93				1.80	1.69
SD3	Sundance #3	2.10	2.00	1.98	2.05	1.96	2.00		1.99	2.03	1.83	1.95		1.95	1.97
SD4	Sundance #4	2.10	2.00	1.99	1.96	1.97	2.00		1.94	2.00	1.82	1.95		1.94	1.95
SD5	Sundance #5	2.09	2.00	1.85	1.76	1.87	2.00		2.06	2.04	2.04	1.87		1.97	1.93
SD6	Sundance #6	2.09	2.00	1.85	1.80	1.85	2.00		2.04	2.04	2.00	1.92		1.97	1.93
WB1	Wabamun #1		2.90				2.90								
WB2	Wabamun #2		2.90				2.90								
WB3	Wabamun #3		2.90				2.90								
WB4	Wabamun #4	3.12	2.90	3.39	3.23	3.16	2.90		3.15	3.19				3.17	3.22
GN3	Genesee #3	0.80	0.80	0.99	1.05	1.10	1.03	0.23	0.90	0.99	0.94	1.02		0.99	1.00
KH3	Keephills #3	0.72	0.80				0.65	-0.15			0.65	0.67		0.66	0.66
Past/Current Coal Uprat			0.00				0.00								
All Future Coal Units			0.00				0.65								

Appendix 3 – Used ('03, 09) Hg Intensities by Unit and Year

		2003 Mercury (mg/MWh)					2008 Mercury (mg/MWh)					2014 Mercury (mg/MWh)		
ID	Name	Mercury Installed	Pre-Installation CASA	Post-Installation CASA	Pre-Installation Hard-Overwrite	Post-Installation Hard Overwrite	rcury Insta	Pre-Installation CASA	Post-Installation CASA	Pre-Installation Hard-Overwrite	Post-Installation Hard Overwrite	Mercury Installed	Pre-Installation	Post-Installation
BR3	Battle River #3	2010	10.92	3.24	12.00	12.00	2011	10.92	3.30					
BR4	Battle River #4	2010	10.92	3.24	12.00	12.00	2011	10.92	3.41					
BR5	Battle River #5	2010	10.92	3.24			2011	10.92	4.07					
HRM	H.R. Milner	2010	0.00	0.00			2011	0.00	0.00					
SH1	Sheerness #1	2010	21.51	3.16			2011	21.51	6.65					
SH2	Sheerness #2	2010	21.51	3.18			2011	21.51	6.49					
GN1	Genesee #1	2010	13.40	3.69			2009	13.40	3.52					
GN2	Genesee #2	2010	13.40	3.69			2009	13.40	3.75					
KH1	Keephills #1	2010	16.55	5.91			2011	16.55	6.48					
KH2	Keephills #2	2010	16.55	6.47			2011	16.55	8.07					
SD1	Sundance #1	2010	18.66	10.47	34.00	34.00	2011	18.66	9.39	34.00	34.00			
SD2	Sundance #2	2010	18.66	9.36	39.00	39.00	2011	18.66	9.39	39.00	39.00			
SD3	Sundance #3	2010	18.63	8.43			2011	18.63	9.73					
SD4	Sundance #4	2010	18.63	8.32			2011	18.63	9.73					
SD5	Sundance #5	2010	18.66	8.89			2011	18.66	9.93					
SD6	Sundance #6	2010	18.66	7.66			2011	18.66	8.79					
WB1	Wabamun #1	2010	19.29				2011	19.29						
WB2	Wabamun #2	2010	19.29				2011	19.29						
WB3	Wabamun #3	2010	19.29				2011	19.29						
WB4	Wabamun #4	2010	19.29				2011	19.29						
GN3	Genesee #3	2010	11.01	7.64			2011	11.01	0.23					
KH3	Keephills #3						2011	0.23	0.23					
SD4/5/6U	SD4/5/6 Uprates	2010	(various)	(various)	0.00	0.00	2011	(various)	(various)	0.00	0.00			
Other Future Coal		**All other future coal has 0mg/MWh Hg emissions**					**All other future coal has 0.23mg/MWh Hg emissions**							

Appendix 4 – Used ('03, 09) Particulate Matter Intensities by Unit and Year

		2003 Particulate Matter (kg/MWh)					2008 Particulate Matter (kg/MWh)					2014 Particulate Matter (kg/MWh)		
ID	Name	PM Installed	Pre-Installation CASA	Post-Installation CASA	Pre-Installation Hard-Overwrite	Post-Installation Hard Overwrite	PM Installed	Pre-Installation CASA	Post-Installation CASA	Pre-Installation Hard-Overwrite	Post-Installation Hard Overwrite	PM Installed	Pre-Installation	Post-Installation
BR3	Battle River #3	2009	0.23	0.095	0.23	0.23	2009	0.23	0.095	0.23	0.23			
BR4	Battle River #4	2009	0.23	0.095	0.23	0.23	2009	0.23	0.095	0.23	0.23			
BR5	Battle River #5	2009	0.23	0.095			2009	0.23	0.095	0.23	0.23			
HRM	H.R. Milner	2009	0.81	0.095			2009	0.81	0.095	0.81	0.81			
SH1	Sheerness #1	2009	0.13	0.095			2009	0.13	0.095	0.13	0.13			
SH2	Sheerness #2	2009	0.13	0.095			2009	0.13	0.095	0.13	0.13			
GN1	Genesee #1	2009	0.14	0.095			2009	0.14	0.095					
GN2	Genesee #2	2009	0.14	0.095			2009	0.14	0.095					
KH1	Keephills #1	2009	0.11	0.095			2009	0.11	0.095					
KH2	Keephills #2	2009	0.11	0.095			2009	0.11	0.095					
SD1	Sundance #1	2009	0.11	0.095	0.11	0.11	2009	0.11	0.095					
SD2	Sundance #2	2009	0.11	0.095	0.11	0.11	2009	0.11	0.095	0.11	0.11			
SD3	Sundance #3	2009	0.11	0.095			2009	0.11	0.095	0.11	0.11			
SD4	Sundance #4	2009	0.11	0.095			2009	0.11	0.095					
SD5	Sundance #5	2009	0.11	0.095			2009	0.11	0.095					
SD6	Sundance #6	2009	0.11	0.095			2009	0.11	0.095					
WB1	Wabamun #1	2009	0.45				2009	0.45						
WB2	Wabamun #2	2009	0.45				2009	0.45						
WB3	Wabamun #3	2009	0.45				2009	0.45						
WB4	Wabamun #4	2010	0.45				2010	0.45						
GN3	Genesee #3	2009	0.095	0.095			2009	0.095	0.095					
KH3	Keephills #3	2009	0.095	0.095			2009	0.066	0.066					
SD4/5/6U	SD4/5/6 Uprates	2009	(various)	(various)	0	0	2009	(various)	(various)	0	0			
Other Future Coal		**All other future coal has 0kg/MWh PM emissions**					**All other future coal has 0.066kg/MWh PM emissions**							

Appendix 5.0 – Total $/MWh for NOx, SOx, Hg, PM in EDC HELP Model ('05-'31)

Unit Name	CASA UNIT NAME	EDC Unit Code	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
HRM	H.R. Milner	HRM	$ -	$ -	$ -	$ -	$ -	$ (0.13)	$ -	$ -	$ -	$ (5.23)	$ (5.97)	$ -	$ -	$ -	$ -	$ -	$ (24.79)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BR3	Battle River 3	BR3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4.39	$ 4.42	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BR4	Battle River 4	BR4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
GN3	Genesee 3	GN3	$ 2.01	$ 2.01	$ 2.01	$ 2.01	$ 1.20	$ 1.20	$ 1.20	$ 2.01	$ 2.01	$ 2.01	$ 2.75	$ 2.75	$ 2.75	$ 2.75	$ 2.75	$ 2.75	$ 2.75	$ 2.75	$ 2.75	$ 2.75	$ 2.75	$ 1.20	$ 1.20	$ 1.20	$ 1.20	$ -	$ -
SD1	Sundance 1	SD1	$ -	$ -	$ -	$ -	$ -	$ -	$ 3.41	$ 3.41	$ 4.13	$ 4.27	$ 4.38	$ 4.80	$ 2.73	$ 3.80	$ 3.38	$ 3.74	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SD2	Sundance 2	SD2	$ -	$ -	$ -	$ -	$ -	$ -	$ 3.41	$ 3.41	$ 4.13	$ 4.27	$ 4.38	$ 4.80	$ 2.73	$ 3.80	$ 3.38	$ 6.02	$ 6.02	$ 6.02	$ 2.54	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SD3	Sundance 3	SD3	$ -	$ -	$ -	$ -	$ 1.20	$ 1.20	$ 1.41	$ 1.41	$ 1.41	$ 1.41	$ 1.52	$ 3.79	$ 2.73	$ 5.29	$ 5.02	$ 7.64	$ 7.64	$ 7.64	$ 6.00	$ 6.00	$ 6.00	$ 1.20	$ 1.20	$ 1.20	$ 1.20	$ 1.20	$ 1.20
SD4	Sundance 4	SD4	$ -	$ -	$ -	$ -	$ 1.20	$ 1.20	$ 1.41	$ 1.41	$ 1.41	$ 1.41	$ 1.52	$ 1.52	$ 2.73	$ 5.29	$ 5.02	$ 7.64	$ 7.64	$ 7.64	$ 6.00	$ 6.00	$ 6.03	$ 1.20	$ 1.20	$ 1.20	$ 1.20	$ 1.20	$ 1.20
SD5	Sundance 5	SD5	$ -	$ -	$ -	$ -	$ 1.20	$ 1.20	$ 1.40	$ 1.40	$ 1.40	$ 1.40	$ 1.50	$ 1.50	$ 0.30	$ 5.28	$ 5.01	$ 7.55	$ 7.55	$ 7.55	$ 5.90	$ 5.90	$ 5.95	$ 1.20	$ 1.20	$ 1.20	$ 1.20	$ 1.20	$ 1.20
SD6	Sundance 6	SD6	$ -	$ -	$ -	$ -	$ 1.20	$ 1.20	$ 1.40	$ 1.40	$ 1.40	$ 1.40	$ 1.50	$ 1.50	$ 0.30	$ 3.00	$ 3.15	$ 7.55	$ 7.55	$ 7.55	$ 5.90	$ 5.90	$ 6.32	$ 1.20	$ 1.20	$ 1.20	$ 1.20	$ 1.20	$ 1.20
BR5	Battle River 5	BR5	$ -	$ -	$ -	$ -	$ 1.20	$ 1.20	$ 1.42	$ 1.42	$ 1.42	$ 1.42	$ 1.53	$ 1.53	$ 0.33	$ 1.53	$ 5.37	$ 7.68	$ 9.96	$ 9.96	$ 6.12	$ 6.12	$ 6.22	$ 1.20	$ 1.20	$ 1.20	$ 1.20	$ 1.20	$ 1.20
KH1	Keephills 1	KH1	$ -	$ -	$ -	$ -	$ 1.20	$ 1.20	$ 1.39	$ 1.39	$ 1.39	$ 1.39	$ 1.49	$ 1.49	$ 0.29	$ 1.49	$ 1.49	$ 3.53	$ 4.90	$ 4.90	$ 6.56	$ 6.56	$ 6.96	$ 1.20	$ 1.20	$ 1.20	$ 1.20	$ 1.20	$ 1.20
KH2	Keephills 2	KH2	$ -	$ -	$ -	$ -	$ 1.20	$ 1.20	$ 1.39	$ 1.39	$ 1.39	$ 1.39	$ 1.49	$ 1.49	$ 13.37	$ 3.31	$ 3.31	$ 5.34	$ 5.34	$ 6.72	$ 5.34	$ 5.34	$ 5.34	$ 1.20	$ 1.20	$ 1.20	$ 1.20	$ 1.20	$ 1.20
SH1	Sheerness 1	SH1	$ -	$ -	$ -	$ -	$ 1.20	$ 1.20	$ 1.42	$ 1.42	$ 1.42	$ 1.42	$ 1.53	$ 11.70	$ (12.93)	$ 2.30	$ 3.41	$ 3.85	$ 1.79	$ (1.05)	$ 0.64	$ 0.64	$ 1.05	$ 1.20	$ 1.20	$ 1.20	$ 1.20	$ 1.20	$ 1.20
GN1	Genesee 1	GN1	$ -	$ -	$ -	$ -	$ 1.20	$ 1.20	$ 1.45	$ 1.45	$ 0.30	$ (5.65)	$ 0.73	$ 0.08	$ (1.33)	$ 0.08	$ 0.73	$ 2.16	$ 2.16	$ 2.16	$ 2.16	$ 2.16	$ 1.76	$ 1.20	$ 1.20	$ 1.20	$ 1.20	$ 1.20	$ 1.20
SH2	Sheerness 2	SH2	$ -	$ -	$ -	$ -	$ 1.20	$ 1.20	$ 1.42	$ 1.42	$ 1.42	$ 8.86	$ 0.62	$ (9.05)	$ (0.95)	$ 0.42	$ (1.13)	$ 0.83	$ 0.74	$ 0.74	$ 2.73	$ 2.73	$ 2.46	$ 1.20	$ 1.20	$ 1.20	$ 1.20	$ 1.20	$ 1.20
GN2	Genesee 2	GN2	$ -	$ -	$ -	$ -	$ 1.20	$ 1.20	$ 0.85	$ 0.85	$ 0.85	$ 0.63	$ 0.73	$ 0.08	$ (1.33)	$ 0.08	$ 0.73	$ 2.16	$ 2.16	$ 2.16	$ 2.16	$ 2.16	$ 1.68	$ 1.20	$ 1.20	$ 1.20	$ 1.20	$ 1.20	$ 1.20
WB1	Wabamun 1	WB1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
WB2	Wabamun 2	WB2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
WB3	Wabamun 3	WB3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
WB4	Wabamun 4	WB4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
ALS1	Air Liquide Scotford #1	ALS1	$ -	$ -	$ -	$ -	$ -	$ -	$ 19.26	$ 19.26	$ 19.26	$ 19.26	$ 19.30	$ 19.30	$ 19.30	$ 19.30	$ 18.10	$ 16.80	$ 16.80	$ 15.60	$ 15.60	$ 15.60	$ 15.60	$ 15.60	$ 15.60	$ 15.60	$ 15.60	$ -	$ -
SMR	Muskeg River1	SMR	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.08	$ 0.08	$ 0.08	$ 0.08	$ 0.13	$ 0.13	$ 0.13	$ 0.13	$ 0.13	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PR1	Primrose #1	PR1	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.08	$ 0.08	$ 0.08	$ 0.08	$ 0.13	$ 0.13	$ 0.13	$ 0.13	$ 0.13	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
JOF1	Joffre #1	JOF1	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.10	$ 0.10	$ 0.10	$ 0.10	$ 0.10	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PH	Poplar Hill #1	PH	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ 0.17	$ 0.17	$ 0.17	$ 0.17	$ 0.17	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
ST3	Rainbow #5	ST3	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ 0.16	$ 0.16	$ 0.16	$ 0.16	$ 0.16	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
HRL	Rainbow Lake #1	HRL	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.08	$ 0.08	$ 0.08	$ 0.08	$ 0.13	$ 0.13	$ 0.13	$ 0.13	$ 0.13	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Gold Creek Facility		$ -	$ -	$ -	$ -	$ -	$ -	$ 0.08	$ 0.08	$ 0.08	$ 0.08	$ 0.13	$ 0.13	$ 0.13	$ 0.13	$ 0.13	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DOW2	DOW1	DOW2	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.07	$ 0.07	$ 0.07	$ 0.07	$ 0.10	$ 0.10	$ 0.10	$ 0.10	$ 0.10	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CAV2	EnCana #1	CAV2	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.08	$ 0.08	$ 0.08	$ 0.08	$ 0.12	$ 0.12	$ 0.12	$ 0.12	$ 0.12	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
EAL503	Nexen Inc #1	EAL503	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.08	$ 0.08	$ 0.08	$ 0.08	$ 0.12	$ 0.12	$ 0.12	$ 0.12	$ 0.12	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
IOL	lahkeses Central Plant	IOL	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.10	$ 0.10	$ 0.10	$ 0.10	$ 0.10	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SPEC605	Maxim Energy #2	SPEC60(	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.12	$ 0.12	$ 0.12	$ 0.12	$ 0.17	$ 0.17	$ 0.17	$ 0.17	$ 0.17	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Maxim Energy #3		$ -	$ -	$ -	$ -	$ -	$ -	$ 0.12	$ 0.12	$ 0.12	$ 0.12	$ 0.17	$ 0.17	$ 0.17	$ 0.17	$ 0.17	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Maxim Energy #4		$ -	$ -	$ -	$ -	$ -	$ -	$ 0.12	$ 0.12	$ 0.12	$ 0.12	$ 0.17	$ 0.17	$ 0.17	$ 0.17	$ 0.17	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SPC2	Suncor #1	SPC2	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.10	$ 0.10	$ 0.10	$ 0.10	$ 0.15	$ 0.15	$ 0.15	$ 0.15	$ 0.15	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Suncor #2		$ -	$ -	$ -	$ -	$ -	$ -	$ 0.08	$ 0.08	$ 0.08	$ 0.08	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SYNA1	Syncrude #1	SYNA1	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.08	$ 0.08	$ 0.08	$ 0.08	$ 0.13	$ 0.13	$ 0.13	$ 0.13	$ 0.13	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
EAL508	Bear Creek Cogen1	EAL508	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.10	$ 0.10	$ 0.10	$ 0.10	$ 0.10	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
AGCC2	Carseland Cogen	AGCC2	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.08	$ 0.08	$ 0.08	$ 0.08	$ 0.13	$ 0.13	$ 0.13	$ 0.13	$ 0.13	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TCRW	Redwater Cogen	TCRW	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.10	$ 0.10	$ 0.10	$ 0.10	$ 0.10	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
ST1	Sturgeon #1	ST1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
ST2	Sturgeon #2	ST2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CG1	Clover Bar #1	CG1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CG2	Clover Bar #2	CG2	$ -	$ (4.91)	$ (5.03)	$ (5.17)	$ (5.00)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CG3	Clover Bar #3	CG3	$ -	$ (0.99)	$ (1.01)	$ (1.04)	$ (7.89)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CG4	Clover Bar #4	CG4	$ -	$ -	$ -	$ -	$ (10.81)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RB1	Rainbow #1	RB1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RB2	Rainbow #2	RB2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RB3	Rainbow #3	RB3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RG10	Rossdale #10	RG10	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RG8	Rossdale #8	RG8	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RG9	Rossdale #9	RG9	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SSU	O/Shell Scotford (Upgr	SSU	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.08	$ 0.08	$ 0.08	$ 0.08	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CAL	Calpine Energy Centre	CAL1	$ 2.00	$ 2.00	$ 2.00	$ 2.00	$ 1.15	$ 1.77	$ 2.10	$ 2.10	$ 2.10	$ 2.10	$ 2.14	$ 2.15	$ 2.15	$ 2.15	$ 2.14	$ 2.04	$ 2.04	$ 2.04	$ 2.04	$ 2.04	$ 2.04	$ -	$ -	$ -	$ -	$ -	$ -
FCK	Encana Foster Creek	FCK	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.10	$ 0.10	$ 0.10	$ 0.10	$ 0.10	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PCFM	P Petro Can McKay R	PCFM	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.10	$ 0.10	$ 0.10	$ 0.10	$ 0.10	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SYNA2	ıcrude (Future Expans	SYNA2	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.07	$ 0.07	$ 0.07	$ 0.07	$ 0.10	$ 0.10	$ 0.10	$ 0.10	$ 0.10	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
ANG	Northstone	ANG	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ 0.16	$ 0.16	$ 0.16	$ 0.16	$ 0.16	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
ALTK	Altec Power Corp.	ALTK	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.08	$ 0.08	$ 0.08	$ 0.08	$ 0.12	$ 0.12	$ 0.12	$ 0.12	$ 0.12	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PCS	Encana Saamis	PCS	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.08	$ 0.08	$ 0.08	$ 0.08	$ 0.12	$ 0.12	$ 0.12	$ 0.12	$ 0.12	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PW1	Hunt Power	PW1	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.08	$ 0.08	$ 0.08	$ 0.08	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OPTI1	Opti Canada	OPTI1	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.08	$ 0.08	$ 0.08	$ 0.08	$ 0.13	$ 0.13	$ 0.13	$ 0.13	$ 0.13	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
AES	AES Merchant	AES	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.08	$ 0.08	$ 0.08	$ 0.08	$ 0.12	$ 0.12	$ 0.12	$ 0.12	$ 0.12	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OPTI2	Opti Canada	OPTI2	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.08	$ 0.08	$ 0.08	$ 0.08	$ 0.13	$ 0.13	$ 0.13	$ 0.13	$ 0.13	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
KH3	Centennial		$ -	$ -	$ -	$ 0.81	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1.20	$ 1.20	$ 1.20	$ 1.20	$ -	$ -
GN4	Genesee 3		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1.20	$ 1.20	$ 1.20	$ 1.20	$ -	$ -
FD1	Brooks		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1.20	$ 1.20	$ 1.20	$ 1.20	$ -	$ -
KH4	Centennial		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1.20	$ 1.20	$ 1.20	$ 1.20	$ -	$ -
FD2	Brooks		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1.20	$ 1.20	$ 1.20	$ 1.20	$ -	$ -
FD3	Brooks		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1.20	$ 1.20	$ 1.20	$ 1.20	$ -	$ -
FD4	Brooks		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1.20	$ 1.20	$ 1.20	$ 1.20	$ -	$ -
FD5	Brooks		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1.20	$ 1.20	$ 1.20	$ 1.20	$ -	$ -

Appendix 5.1 – Total $/MWh for NOx, SOx, Hg, PM in EDC HELP Model ('12-'20)

	2012				2013				2014				2015				2016				2017				2018				2019				2020				2021				2022			
	Hg	NOx	SOx	GHG	Hg	NOx	SOx	GHG	Hg	NOx	SOx	GHG	Hg	NOx	SOx	GHG	Hg	NOx	SOx	GHG	Hg	NOx	SOx	GHG	Hg	NOx	SOx	GHG	Hg	NOx	SOx	GHG	Hg	NOx	SOx	GHG	Hg	NOx	SOx	GHG	Hg	NOx	SOx	GHG
H.R. Milner				$0.27																																			-$22.71				-$0.63	
Battle River 3	$1.20	$1.72		$0.44	$1.20	$1.72		$0.22	$1.20	$1.86		$0.22	$1.20	$1.86		$0.33	$1.20	$2.28		$0.33	$1.20	$2.42		$0.33	$1.20	$2.28		$0.33	$1.20			$0.33												
Battle River 4	$1.20			$0.44	$1.20			$0.22	$1.20			$0.22	$1.20	$1.86		$0.33	$1.20	$2.28		$0.33	$1.20	$2.42		$0.33	$1.20	$2.28		$0.33	$1.20	$1.86		$0.33	$1.20	$2.28		$2.64	$1.20	$2.28		$2.64	$1.20	$2.28		$2.64
Genesee 3	$1.20		$0.81		$1.20		$0.81		$1.20		$0.81		$1.20	$1.00	$0.81		$1.20	$0.74	$0.81		$1.20	$0.74	$0.81		$1.20	$0.74	$0.81		$1.20	$0.74	$0.81		$1.20	$0.74	$0.81		$1.20	$0.74	$0.81		$1.20	$0.74	$0.81	
Sundance 1	$1.20	$1.72		$0.42	$1.20	$1.72		$0.21	$1.20	$1.86		$0.21	$1.20	$1.86		$0.32	$1.20	$2.28		$0.32	$1.20	$2.42		$0.32	$1.20	$2.28		$0.32	$1.20	$1.86		$0.32	$1.20			$2.54								
Sundance 2	$1.20			$0.42	$1.20	$1.72		$0.21	$1.20	$1.86		$0.21	$1.20	$1.86		$0.32	$1.20	$2.28		$0.32	$1.20	$2.42		$0.32	$1.20	$2.28		$0.32	$1.20	$1.86		$0.32	$1.20	$2.28		$2.54	$1.20	$2.28		$2.54	$1.20	$2.28		$2.54
Sundance 3	$1.20			$0.42	$1.20			$0.21	$1.20			$0.21	$1.20			$0.32	$1.20	$2.28		$0.32	$1.20	$2.42		$0.32	$1.20	$2.28		$0.32	$1.20	$1.86		$0.32	$1.20	$2.28		$2.52	$1.20	$2.28	$1.50	$2.52	$1.20	$2.28	$1.65	$2.52
Sundance 4	$1.20			$0.42	$1.20			$0.21	$1.20			$0.21	$1.20			$0.32	$1.20			$0.32	$1.20	$2.42		$0.32	$1.20	$2.28		$0.32	$1.20	$1.86		$0.32	$1.20	$2.28		$2.52	$1.20	$2.28	$1.50	$2.52	$1.20	$2.28	$1.65	$2.52
Sundance 5	$1.20			$0.40	$1.20			$0.20	$1.20			$0.20	$1.20			$0.30	$1.20			$0.30	$1.20			$0.30	$1.20	$2.28		$0.30	$1.20	$1.86		$0.30	$1.20	$2.28		$2.42	$1.20	$2.28	$1.50	$2.42	$1.20	$2.28	$1.65	$2.42
Sundance 6	$1.20			$0.40	$1.20			$0.20	$1.20			$0.20	$1.20			$0.30	$1.20			$0.30	$1.20			$0.30	$1.20			$0.30	$1.20			$0.30	$1.20	$2.28		$2.42	$1.20	$2.28	$1.50	$2.42	$1.20	$2.28	$1.65	$2.42
Battle River 5	$1.20			$0.44	$1.20			$0.22	$1.20			$0.22	$1.20			$0.33	$1.20			$0.33	$1.20			$0.33	$1.20			$0.33	$1.20			$0.33	$1.20			$2.64	$1.20	$2.28		$2.64	$1.20	$2.28	$3.84	$2.64
Keephills 1	$1.20			$0.39	$1.20			$0.19	$1.20			$0.19	$1.20			$0.29	$1.20			$0.29	$1.20			$0.29	$1.20			$0.29	$1.20			$0.29	$1.20			$2.33	$1.20			$2.33	$1.20			$2.33
Keephills 2	$1.20			$0.39	$1.20			$0.19	$1.20			$0.19	$1.20			$0.29	$1.20			$0.29	$1.20	$13.08		$0.29	$1.20	$1.82		$0.29	$1.20	$1.82		$0.29	$1.20	$1.82		$2.33	$1.20	$1.82		$2.33	$1.20	$1.82		$2.33
Sheerness 1	$1.20			$0.44	$1.20			$0.22	$1.20			$0.22	$1.20			$0.33	$1.20	$10.17		$0.33	$1.20	-$13.26		$0.33	$1.20	$0.77		$0.33	$1.20	$1.67		$0.33	$1.20	$0.42		$2.64	$1.20	-$1.64		$2.64	$1.20	-$1.64	$0.22	$2.64
Genesee 1	$1.20	$0.05		$0.40	$1.20	-$1.10		$0.20	$1.20	-$7.05		$0.20	$1.20	-$0.76		$0.30	$1.20	-$1.41		$0.30	$1.20	-$1.63		$0.30	$1.20	-$1.41		$0.30	$1.20	-$0.76		$0.30	$1.20	-$1.41		$2.38	$1.20	-$1.41		$2.38	$1.20	-$1.41		$2.38
Sheerness 2	$1.20			$0.44	$1.20			$0.22	$1.20	$7.44		$0.22	$1.20	-$0.91		$0.33	$1.20	-$10.58		$0.33	$1.20	-$1.28		$0.33	$1.20	-$1.11		$0.33	$1.20	-$0.67		$0.33	$1.20	-$1.02		$2.64	$1.20	-$1.11		$2.64	$1.20	-$1.11	-$1.99	$2.64
Genesee 2	$1.20	-$0.54		$0.40	$1.20	-$0.54		$0.20	$1.20	-$0.76		$0.20	$1.20	-$0.76		$0.30	$1.20	-$1.41		$0.30	$1.20	-$1.63		$0.30	$1.20	-$1.41		$0.30	$1.20	-$0.76		$0.30	$1.20	-$1.41		$2.38	$1.20	-$1.41		$2.38	$1.20	-$1.41		$2.38
Wabamun 1																																												
Wabamun 2																																												
Wabamun 3																																												
Wabamun 4																																												
Air Liquide Scotford #1				$0.13				$0.06				$0.06				$0.10				$0.10				$0.10				$0.10				$0.10												
Muskeg River1				$0.17				$0.08				$0.08				$0.13				$0.13				$0.13				$0.13				$0.13												
Primrose #1				$0.17				$0.08				$0.08				$0.13				$0.13				$0.13				$0.13				$0.13												
Joffre #1				$0.13				$0.06				$0.06				$0.10				$0.10				$0.10				$0.10				$0.10												
Poplar Hill #1				$0.22				$0.11				$0.11				$0.17				$0.17				$0.17				$0.17				$0.17												
Rainbow #5				$0.21				$0.11				$0.11				$0.16				$0.16				$0.16				$0.16				$0.16												
Rainbow Lake #1				$0.17				$0.08				$0.08				$0.13				$0.13				$0.13				$0.13				$0.13												
Gold Creek Facility				$0.17				$0.08				$0.08				$0.13				$0.13				$0.13				$0.13				$0.13												
DOW1				$0.14				$0.07				$0.07				$0.10				$0.10				$0.10				$0.10				$0.10												
EnCana #1				$0.16				$0.08				$0.08				$0.12				$0.12				$0.12				$0.12				$0.12												
Nexen Inc #1				$0.16				$0.08				$0.08				$0.12				$0.12				$0.12				$0.12				$0.12												
Mahkeses Central Plant1				$0.13				$0.06				$0.06				$0.10				$0.10				$0.10				$0.10				$0.10												
Maxim Energy #2				$0.23				$0.12				$0.12				$0.17				$0.17				$0.17				$0.17				$0.17												
Maxim Energy #3				$0.23				$0.12				$0.12				$0.17				$0.17				$0.17				$0.17				$0.17												
Maxim Energy #4				$0.23				$0.12				$0.12				$0.17				$0.17				$0.17				$0.17				$0.17												
Fort Nelson				$0.20				$0.10				$0.10				$0.15				$0.15				$0.15				$0.15				$0.15												
Suncor #1				$0.15				$0.08				$0.08				$0.11				$0.11				$0.11				$0.11				$0.11												
Syncrude #1				$0.17				$0.08				$0.08				$0.13				$0.13				$0.13				$0.13				$0.13												
Bear Creek Cogen1				$0.13				$0.06				$0.06				$0.10				$0.10				$0.10				$0.10				$0.10												
Carseland Cogen				$0.17				$0.08				$0.08				$0.13				$0.13				$0.13				$0.13				$0.13												
Redwater Cogen				$0.13				$0.06				$0.06				$0.10				$0.10				$0.10				$0.10				$0.10												
Sturgeon #1				$0.21																																								
Sturgeon #2				$0.23																																								
Clover Bar #1				$0.12																																								
Clover Bar #2				$0.12																																								
Clover Bar #3				$0.12																																								
Clover Bar #4				$0.11																																								
Rainbow #1				$0.16																																								
Rainbow #2				$0.17																																								
Rainbow #3				$0.17																																								
Rossdale #10				$0.13																																								
Rossdale #8				$0.14																																								
Rossdale #9				$0.13																																								
ATCO/Shell Scotford (Upgrader)				$0.15				$0.08				$0.08				$0.11				$0.11				$0.11				$0.11				$0.11												
Calpine Energy Centre		$2.03		$0.15		$2.03		$0.07		$2.03		$0.07		$2.03		$0.11		$2.04		$0.11		$2.04		$0.11		$2.04		$0.11		$2.03		$0.11		$2.04				$2.04				$2.04		
Encana Foster Creek				$0.13				$0.06				$0.06				$0.10				$0.10				$0.10				$0.10				$0.10												
TCP Petro Can McKay River				$0.13				$0.06				$0.06				$0.10				$0.10				$0.10				$0.10				$0.10												
Syncrude (Future Expansion)				$0.14				$0.07				$0.07				$0.10				$0.10				$0.10				$0.10				$0.10												
Northstone				$0.21				$0.11				$0.11				$0.16				$0.16				$0.16				$0.16				$0.16												
Altec Power Corp.				$0.16				$0.08				$0.08				$0.12				$0.12				$0.12				$0.12				$0.12												
Encana Saamis				$0.16				$0.08				$0.08				$0.12				$0.12				$0.12				$0.12				$0.12												
Hunt Power				$0.15				$0.08				$0.08				$0.11				$0.11				$0.11				$0.11				$0.11												
Opti Canada				$0.17				$0.08				$0.08				$0.13				$0.13				$0.13				$0.13				$0.13												
AES Merchant				$0.16				$0.08				$0.08				$0.12				$0.12				$0.12				$0.12				$0.12												
Opti Canada				$0.17				$0.08				$0.08				$0.13				$0.13				$0.13				$0.13				$0.13												
Suncor		$4.15		$0.17		$4.15		$0.08		$4.49		$0.08		$4.49		$0.13		$5.51		$0.13		$5.84		$0.13																				
Syncrude		$4.48		$0.17		$4.48		$0.08		$4.85		$0.08		$4.85		$0.13		$5.94		$0.13		$6.31		$0.13																				
DOW1		$0.71		$0.12		$0.71		$0.06		$0.77		$0.06		$0.77		$0.09		$0.94		$0.09		$1.00		$0.09																				
Amaco		$4.15		$0.12		$4.15		$0.06		$4.49		$0.06		$4.49		$0.09		$5.51		$0.09		$5.84		$0.09																				

(cont'd)

Appendix 5.1 (cont'd)–$/MWh NOx, SOx, Hg, PM, by component, in EDC Model ('24-'30)

	2023				2024				2025				2026			
	Hg	NOx	SOx	GHG	Hg	NOx	SOx	GHG	Hg	NOx	SOx	GHG	Hg	NOx	SOx	GHG
H.R. Milner																
Battle River 3																
Battle River 4	$1.20	$2.28		$2.64	$1.20	$2.28		$2.64	$1.20			$2.64	$1.20			
Genesee 3	$1.20	$0.74	$0.81		$1.20	$0.74	$0.81		$1.20	$0.74	$0.81		$1.20			
Sundance 1																
Sundance 2				$2.54												
Sundance 3	$1.20	$2.28	$1.65	$2.52	$1.20	$2.28	$1.65	$2.52	$1.20	$2.28	$1.65	$2.52	$1.20			
Sundance 4	$1.20	$2.28	$1.65	$2.52	$1.20	$2.28	$1.65	$2.52	$1.20	$2.31	$1.65	$2.52	$1.20			
Sundance 5	$1.20	$2.28	$1.65	$2.42	$1.20	$2.28	$1.65	$2.42	$1.20	$2.33	$1.65	$2.42	$1.20			
Sundance 6	$1.20	$2.28	$1.65	$2.42	$1.20	$2.28	$1.65	$2.42	$1.20	$2.70	$1.65	$2.42	$1.20			
Battle River 5	$1.20	$2.28	$3.84	$2.64	$1.20	$2.28	$3.84	$2.64	$1.20	$2.38	$3.84	$2.64	$1.20			
Keephills 1	$1.20	$3.03		$2.33	$1.20	$3.03	$1.37	$2.33	$1.20	$3.43	$1.37	$2.33	$1.20			
Keephills 2	$1.20	$1.82		$2.33	$1.20	$1.82		$2.33	$1.20	$1.82	$1.37	$2.33	$1.20			
Sheerness 1	$1.20	-$3.20	-$0.41	$2.64	$1.20	-$3.20	-$0.41	$2.64	$1.20	-$2.79	-$3.25	$2.64	$1.20			
Genesee 1	$1.20	-$1.41		$2.38	$1.20	-$1.41		$2.38	$1.20	-$1.82		$2.38	$1.20			
Sheerness 2	$1.20	-$1.11	-$1.99	$2.64	$1.20	-$1.11	-$1.99	$2.64	$1.20	-$1.38	-$1.99	$2.64	$1.20			
Genesee 2	$1.20	-$1.41		$2.38	$1.20	-$1.41		$2.38	$1.20	-$1.89		$2.38	$1.20			
Wabamun 1																
Wabamun 2																
Wabamun 3																
Wabamun 4																
Air Liquide Scotford #1																
Muskeg River1																
Primrose #1																
Joffre #1																
Poplar Hill #1																
Rainbow #5																
Rainbow Lake #1																
Gold Creek Facility																
DOW1																
EnCana #1																
Nexen Inc #1																
Mahkeses Central Plant1																
Maxim Energy #2																
Maxim Energy #3																
Maxim Energy #4																
Fort Nelson																
Suncor #1																
Syncrude #1																
Bear Creek Cogen1																
Carseland Cogen																
Redwater Cogen																
Sturgeon #1																
Sturgeon #2																
Clover Bar #1																
Clover Bar #2																
Clover Bar #3																
Clover Bar #4																
Rainbow #1																
Rainbow #2																
Rainbow #3																
Rossdale #10																
Rossdale #8																
Rossdale #9																
ATCO/Shell Scotford (Upgrader)																
Calpine Energy Centre		$2.04				$2.04				$2.04						
Encana Foster Creek																
TCP Petro Can McKay River																
Syncrude (Future Expansion)																
Northstone																
Altec Power Corp.																
Encana Saamis																
Hunt Power																
Opti Canada																
AES Merchant																
Opti Canada																
Suncor																
Syncrude																
DOW1																
Amaco																

	2027				2028				2029				2030			
	Hg	NOx	SOx	GHG	Hg	NOx	SOx	GHG	Hg	NOx	SOx	GHG	Hg	NOx	SOx	GHG
H.R. Milner																
Battle River 3																
Battle River 4	$1.20				$1.20				$1.20				$1.20			
Genesee 3	$1.20				$1.20				$1.20				$1.20			
Sundance 1																
Sundance 2																
Sundance 3	$1.20				$1.20				$1.20				$1.20			
Sundance 4	$1.20				$1.20				$1.20				$1.20			
Sundance 5	$1.20				$1.20				$1.20				$1.20			
Sundance 6	$1.20				$1.20				$1.20				$1.20			
Battle River 5	$1.20				$1.20				$1.20				$1.20			
Keephills 1	$1.20				$1.20				$1.20				$1.20			
Keephills 2	$1.20				$1.20				$1.20				$1.20			
Sheerness 1	$1.20				$1.20				$1.20				$1.20			
Genesee 1	$1.20				$1.20				$1.20				$1.20			
Sheerness 2	$1.20				$1.20				$1.20				$1.20			
Genesee 2	$1.20				$1.20				$1.20				$1.20			
Wabamun 1																
Wabamun 2																
Wabamun 3																
Wabamun 4																
Air Liquide Scotford #1																
Muskeg River1																
Primrose #1																
Joffre #1																
Poplar Hill #1																
Rainbow #5																
Rainbow Lake #1																
Gold Creek Facility																
DOW1																
EnCana #1																
Nexen Inc #1																
Mahkeses Central Plant1																
Maxim Energy #2																
Maxim Energy #3																
Maxim Energy #4																
Fort Nelson																
Suncor #1																
Syncrude #1																
Bear Creek Cogen1																
Carseland Cogen																
Redwater Cogen																
Sturgeon #1																
Sturgeon #2																
Clover Bar #1																
Clover Bar #2																
Clover Bar #3																
Clover Bar #4																
Rainbow #1																
Rainbow #2																
Rainbow #3																
Rossdale #10																
Rossdale #8																
Rossdale #9																
ATCO/Shell Scotford (Upgrader)																
Calpine Energy Centre																
Encana Foster Creek																
TCP Petro Can McKay River																
Syncrude (Future Expansion)																
Northstone																
Altec Power Corp.																
Encana Saamis																
Hunt Power																
Opti Canada																
AES Merchant																
Opti Canada																
Suncor																
Syncrude																
DOW1																
Amaco																

Appendix 6 – CV's of Contributing Personnel

Duane Reid-Carlson, P.Eng.

President and CEO

Suite #310, 505-8th Avenue SW, Calgary, AB T2P 1G2

(403) 648-0631 dcarlson@edcassociates.com

PROFESSIONAL EXPERIENCE

President and CEO

Duane Reid-Carlson has 24 years' experience working in the oil and gas, petrochemical and electric industries. He is currently the President of EDC Associates Ltd—a company that he founded in 1992. Since that time Mr. Reid-Carlson has led a team of energy economic analysts responsible for providing electric energy supply, demand and price forecast information, energy procurement, risk management, generation economic and regulatory analytical services. These services and information is generally used by participants in the energy industry to help support short and long-term energy procurement and investment decisions.

Mr. Reid-Carlson holds a B.Sc. degree in Electrical Engineering from the University of Alberta, Canada.

Following graduation he gained direct oil, gas, pipeline and petrochemical experience working on projects in the Middle East and later in the UK. Working in Alberta, he has led numerous electric utility planning forecast studies used to assess the need and timing of generation, transmission and distribution facilities. In electricity price forecast matters, he has been instrumental in the development of software used internally, as well as commercially by clients, to assess future marginal and imbedded electricity pricing in Alberta and other jurisdictions in the US.

Mr. Reid-Carlson has authored a series of studies concerning the fundamentals of several electricity jurisdictions, most notably for the Alberta market, that have been utilized by government agencies, industry participants, utilities, generation developers and marketers/retailers to aid in their energy procurement and capital project decision making processes. He has presented the findings of these studies at many industry conferences and regularly facilitates an introductory course on electric industry operation and restructuring.

Mr. Reid-Carlson has developed evidence and provided expert witness testimony in the electric industry with respect to several legal and regulatory proceedings and is currently a Director on the Board of the Independent Power Producers Society of Alberta (IPPSA).

Allen Crowley

Vice-President, Regulatory & Market Studies

Suite #310, 505-8th Avenue SW, Calgary, AB T2P 1G2

(403) 648-0632 allen@edcassociates.com

Professional Experience

Allen Crowley has over 35 years' experience in the electricity, telecommunication and water industries. He has held widely varied, senior corporate positions and consulted in electricity, telecommunications, water, sewage and solid waste utilities in the areas of:

- Electricity market design, utility rate making, regulation;
- Retail and wholesale marketing and sales of energy and derivative hedging products;
- Strategic marketing and strategic planning;
- Complex financial modelling, forecasting and engineering economic studies;
- Process re-engineering, performance measurement and benchmarking;
- Customer service improvement and surveying, Delphi Nominal Group Technique;
- Evaluation of Potential Alberta Direct Load Control (Demand Side Management)

Mr Crowley has participated in hearings before rate tribunals and consultative sessions in several utilities and jurisdictions (on behalf of telephones, water and power utilities, energy marketing companies, government agencies, industry associations and large and small generation developers). He has an in-depth knowledge of the proposed FERC SMD NOPR and the Alberta Energy Transmission Policy. He has developed numerous complex financial models including valuation for the sale of a retail electrical distribution company, evaluation and bidding strategy for Alberta PPA's, numerous co-gens and hedging strategies including weather and structured products, and various rate designs. He prepared several successful comprehensive applications for BC Hydro's "Power for Jobs" and "Real Time Pricing" programs for major mining, chemical and lumber companies. He developed a unique operating lease financing process for Customer-Owned Substations, installing several in BC at a 20% savings and built the first customer-owned substation in Alberta.

Relevant Publications:

"Fill-Adjusted Sinking Fund Depreciation", Engineering Economist, Summer '84
"Real Time Pricing", The Electric Line, 1998

Speaking Engagements:

- Numerous guest speaking engagements with Phoenix Gas Seminar, Canadian Institute, Institute of International Research, IPPSA, CERI in BC, Alberta and Ontario

Education and Professional Development

MBA - Quantitative Methods Thesis: "Fill-Adjusted Sinking-Fund Depreciation for Utilities"	University of Alberta	1983
BA - Economics and Philosophy	University of Alberta	1974
Banff School of Advanced Management, #62, McPhee Award		1988

Numerous Engineering Economics, Law and Regulatory Courses and Seminars

Alex Markowski

Sr. Energy Market Analyst

Suite #310, 505-8th Avenue SW, Calgary, AB T2P 1G2

(403) 648-0633 alex@edcassociates.com

PROFESSIONAL EXPERIENCE

Mr. Markowski holds a B.Sc in statistics (actuarial science minor) from the University of Calgary and brings over a decade of quantitative forecasting/data management/modeling experience from multiple industry settings.

His present role at EDCA focuses on the creation of short and long-term price forecasts for the Alberta power market, in addition to generation economic development, energy procurement, cash flow analysis, PPA valuations and GHG sensitivity scenario modeling for a variety of industry clientele.

Further to the above, Mr. Markowski is responsible for the development and implementation of EDCA's data architecture that warehouses, disseminates and analyzes key electricity and natural gas data. He is also responsible for the coding of proprietary in-house models and toolsets in a variety of object-oriented and database-centric programming languages.

Mr. Markowski authors several industry-leading publications, including the weekly Alberta kWh Newsletter, the weekly Electricity SMP Predictions (ESP) Forecast Report, the monthly Alberta Wind Energy Report and the annual Alberta Electricity Industry Statistics Report. He co-authors the monthly Alberta Electricity Update, the quarterly Alberta Market Forecast Update and the annual Alberta Electric Industry Study.

Previous roles have seen him serve as investment counsel for a hedge fund trading closed-end funds and as a consultant within the bio-fuel industry. Mr. Markowski currently sits on the Board of Directors of a local investment management corporation.