

Supporting Co-Generation Through Alberta's Climate Leadership Plan



Prepared for the Oil Sands Community Alliance (OSCA)
A Division of the Canadian Association of Petroleum Producers (CAPP)

August 3, 2017

Executive Summary

Alberta has shown environmental leadership with the Alberta Climate Leadership Plan (CLP) to take action on climate change and protect the province's health, environment and economy.¹ The implementation of the CLP will require billions of dollars of capital investment to replace coal fired generation with non-emitting renewable generation sources (e.g. wind, solar, hydro) and clean burning natural gas.

Co-generation is the simultaneous production of electricity and heat for use in industrial processes. Co-generation is used throughout the world and Alberta is a leader in the utilization of this technology. Desiderata Energy believes that additional electricity production from co-generation will provide Alberta with lower emissions, lower costs and more reliable electricity, while supporting the province's CLP and environmentally responsible development of Alberta's oil sands industry. Co-generation offers the following benefits to Alberta and its CLP:

Lower Emissions

Co-generation produces 29% less CO₂ than state of the art combined cycle facilities and 62% less CO₂ than existing coal plants once converted to natural gas. To the extent Alberta requires additional natural gas fired generation to support renewables and replace coal, co-generation should be Alberta's first technology choice to minimize CO₂ emissions. **Utilizing co-generation versus coal to gas conversions could reduce Alberta's total CO₂ emissions by 2030 by an additional 3 MT.**

Low Cost

Industry experts agree that co-generation is the lowest cost supply option for Albertans. Co-generation facilities operate continuously and many facilities have surplus, low cost power that helps Alberta's electricity grid to be reliable and low cost.

Co-generation Flexibility Supports Renewables

Many co-generation facilities have the flexibility to ramp up and down to support intermittent renewables generation sources like wind. **Alberta co-generators have over a 20 year proven track record of supporting Alberta's electricity system.**

Co-generation Makes Oil Sands More Competitive

The oil sands industry is currently confronted with significant challenges and risks from a competitiveness perspective, particularly in the North American context. **Co-generation provides both in-situ and mining oil sands operations with low cost heat and power, while minimizing CO₂ emissions.** Alberta oil sands operations need to minimize their carbon footprint, while maintaining cost competitiveness with other oil producing regions. Alberta's oil sands industry remains an important part of Alberta's economy, even in times of economic challenges, providing significant economic benefits to Albertans.

Co-generation Potential

There is significant potential for additional co-generation capacity in Alberta, from both new and expansions at existing facilities. Based on a survey of the oil sands industry, in addition to the 5,160 MW of existing co-generation (29% of Alberta's total capacity), an additional 500 to 900 MW is forecast to be developed by 2022. **Co-generation should be Alberta's first choice to replace coal plants for base load capacity.**

¹ See <https://www.alberta.ca/climate-leadership-plan.aspx>

Challenges

Investing in co-generation facilities is a complex investment decision as these facilities are capital intensive and subject to considerable revenue uncertainty. A stable and predictable electricity industry and market structure helps reduce investment risks. Desiderata Energy is of the view that co-generation developers have elected not to build co-generation, or have limited the size of their facilities to primarily supply their on-site load, and not to build excess capacity, due to risks and revenue uncertainty around transmission, electricity markets and emissions policies and pricing. Due to these barriers, only 16% of the potential oil sands related co-generation capacity has been developed in Alberta.² In the absence of a policy framework complementary to the development of co-generation, this is a lost opportunity.

Government Support for Co-generation

The author submits that the restructuring of the electricity industry in the 1990s was done primarily to take advantage of the significant benefits co-generation could, and subsequently has, provided to Alberta.³ Desiderata Energy encourages the Government of Alberta (GOA) and the Alberta Electric System Operator (AESO) to consider the significant benefits co-generation has and can continue to provide to Alberta.

In light of the pending coal generation phase out and our recommendations that co-generation should be the first choice natural gas fired generation to minimize emissions and keep electricity costs low, policy makers need to encourage co-generation development. Desiderata Energy recommends that the GOA and the AESO provide:

- clear and consistent transmission policies and timely transmission additions,
- streamlined regulatory approval processes and reduced timelines for connections,
- regulations codifying net metering and peak demand avoidance provisions in the AESO's transmission tariff,
- stable and predictable electricity markets, guided by market forces with limited government interference, and
- clear and timely emissions policy that reflects the lower emissions benefits from co-generation.

Alberta Capacity Market

All generation developers, regardless of technology employed, require a more stable revenue stream than the current electricity markets are forecast to provide. The GOA understands this need and has directed the AESO to develop a capacity market. **Alberta's co-generators should be allowed to fully compete in the proposed capacity market.** This participation and the reliability the new industry structure brings will help oil sands developers invest and build additional co-generation capacity.

With respect to the proposed capacity market, Desiderata Energy recommends:

- Co-generation should be allowed to fully participate in the capacity market.
- Continue the same treatment in the capacity market model where a co-generation or facility with behind the fence generation is treated as a net to grid supplier.
- The AESO is the logical entity to procure capacity on behalf of load customers. In Alberta's deregulated retail business electricity is procured through retailers on behalf of their customers or directly by larger loads. The credit requirements to back stop these purchases has, in the

² A Review of Co-generation in Alberta, EDCA, September 29, 2015, Executive Summary

³ Please see Appendix A

author's view, limited the development of retail markets and not allowed Alberta to obtain all of the benefits of deregulation envisioned when these markets were created in the late 1990s.

- For settlement, the AESO has suggested a one month period, which this report supports.⁴

⁴ Ibid, page 16

Table of Contents

- Executive Summary 2**
 - Lower Emissions2
 - Low Cost2
 - Co-generation Flexibility Supports Renewables.....2
 - Co-generation Makes Oil Sands More Competitive2
 - Co-generation Potential.....2
 - Challenges3
 - Government Support for Co-generation3
 - Alberta Capacity Market3
- Supporting Co-generation Through Alberta’s Climate Leadership Plan 7**
 - What is Co-generation?.....7
 - Climate Leadership Plan Objectives8
- Lower Emissions 8**
 - Base Load 10
 - Mid-Merit 10
 - Peaking 10
- Low Cost 13**
- Co-generation Flexibility Supports Renewables..... 16**
- Co-generation Makes Oil Sands More Competitive 17**
- Co-generation Potential 18**
- Generators Require Revenue Stability – Alberta Capacity Market 19**
- Co-Generation Challenges..... 20**
 - Transmission20
 - Market Stability21
 - Emissions21
- Recommendations:..... 21**
- Appendix A: History of Deregulation and Alberta Electricity Markets 23**
 - Vertically Integrated to 1996.....23
 - Industry Restructuring 1996 to 200023
 - Energy Only Markets 2001 to present.....25
 - Alberta Co-generators25
 - Inter-Provincial Electricity Transfers26

Appendix B: Revenue From Alberta Electricity Markets..... 27

- 1. Energy Only Market27
- 2. Ancillary Services Market.....27
- 3. Over the Counter Markets28
- 4. Power Purchase Agreements (Competitive PPAs)28
- 5. Legislated Power Purchase Arrangements (Legacy PPAs).....29

Appendix C: About the Author 30

Figures

- Figure 1- Co-generation Schematic7
- Figure 2 – Generation Technologies CO₂ Emissions Intensity (Tonnes/MWh) and Alberta Average...9
- Figure 3 – Historical and Forecast Alberta Demand and Supply12
- Figure 4 - Estimated Levelized Cost by Generation Technology (EDCA).....14
- Figure 5 - Estimated Levelized Cost by Generation Technology (Solas Energy)15
- Figure 6 – Alberta Co-Generators Capacity, Behind the Fence Load and Net to Grid.....16
- Figure 7 – Alberta Co-generation Behind the Fence Generation Capacity17
- Figure 8 – AESO Capacity Market Development Timeline19
- Figure 9 – Annual Power Pool Payments27
- Figure 10 - Annual Power Pool and Ancillary Service Payments28

Tables

- Table 1 – Emissions from 5,000 MW Coal Generation and 5,000 MW Wind Generation with Natural Gas Firming Options11
- Table 2 – 2016 Alberta Generation Capacity and Forecast 2030 Alberta Generation Capacity13

Supporting Co-generation Through Alberta's Climate Leadership Plan

The Oil Sands Community Alliance (OSCA) commissioned this paper to assist the Government of Alberta (GOA) and the Alberta Electric System Operator (AESO) to better understand the role co-generation has played in the development of Alberta's electricity industry and markets, and the great potential co-generation has to participate in the capacity market and meet the CLP objectives.

What is Co-generation?

Co-generation, or industrial co-generation in the context of this paper, is the simultaneous production of electricity and heat for use in industrial processes for oil sands projects. Oil sands extraction methods range from mining operations to in-situ steam assisted gravity drainage production, with varying on-site electricity and heat demands. Oil sands co-generation applications include the use of large gas turbines to drive electric generators. The exhaust heat from gas turbines are captured in a boiler or Heat Recovery Steam Generator (HRSG) to produce steam for injection in in-situ operations or process heat for oil sands mining operations. Co-generation is more efficient at producing electricity and steam or hot water when compared with other technologies (e.g. coal or natural gas fired facilities) and standalone boilers.⁵

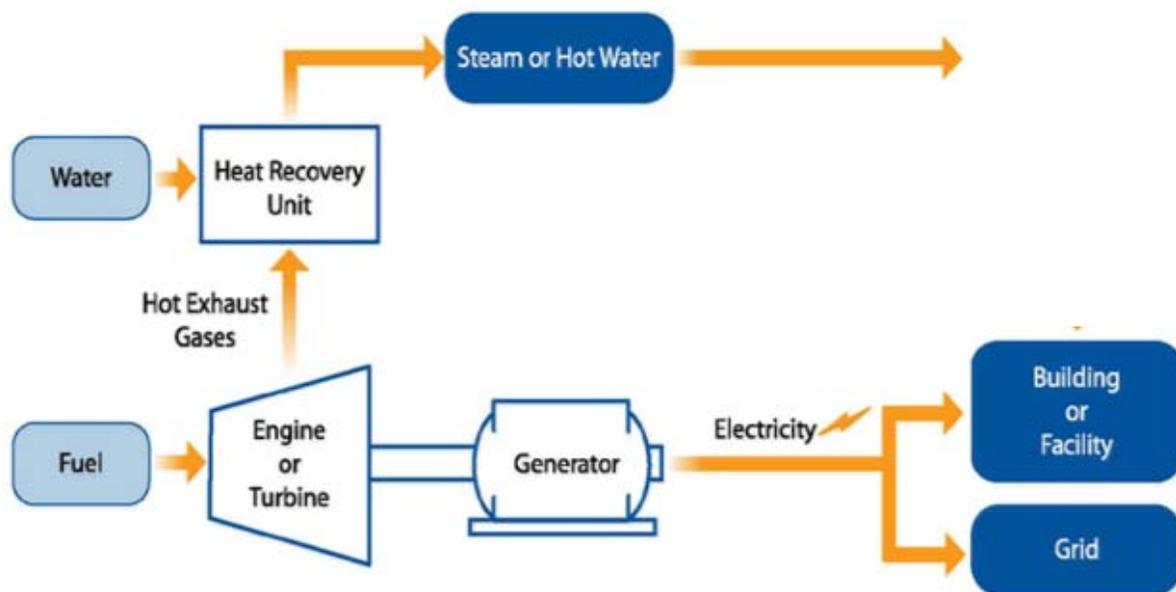


Figure 1- Co-generation Schematic⁶

The result is that the electricity production from co-generation is up to 85% efficient, compared to up to 60% efficiency for natural gas combined cycle plants. The conversion of coal plants to burn natural gas would result in efficiencies under 35%.

Co-generation has been used by the oil sands industry to assist with the production of bitumen since the mid 1970's. Over the past 40+ years, co-generation capacity has grown as more oil sands projects have come on-line and seek self-sufficiency, improved electric reliability, and optimization of on-site steam and electricity needs. Despite the efficiencies and other benefits associated with co-generation, not all oil sands operators elect to install co-generation as part of their oil sands facilities. In fact, due

⁵ Additional information on Canadian Co-generation at: <http://powerforthefuture.ca/electricity-411/electricity-fuel-source-technical-papers/co-generation/>

⁶ Schematic from <https://www.c2es.org/technology/factsheet/Co-generationCHP>

to economic factors, electricity transmission constraints, uncertain emissions policies, the requirement for incremental generation capacity in Alberta and related concerns, only about 16% of the oil sands co-generation potential in Alberta has been developed.⁷

Climate Leadership Plan Objectives

There are two key components of Alberta's Climate Leadership Plan (CLP) that will impact the type of electricity generation technology that will be utilized in the coming decades:⁸

1. Phasing-out coal pollution. Pollution from about 6,300 MW of coal-fired plants will be phased out by 2030 and replaced with cleaner energy sources such as natural gas, wind, hydro, solar and biomass.
2. Developing Renewable Energy, which will primarily be accomplished under the Renewable Electricity Program (REP). This program calls for 5,000 MW of renewable energy to be added in Alberta by 2030.

Co-generation is well suited to assist the GOA in achieving these objectives. As coal generation is phased out, co-generation can provide low cost, base load generation that can supply Alberta consumers 7/24/365. Co-generation is the lowest cost option for natural gas based electricity generation.

Alberta co-generators have a proven history of providing incremental generation capacity during times when it is needed to meet consumer demand. The notion that co-generators do not have generation capacity flexibility is not correct. Some Alberta co-generators increase their output daily in response to consumer demand and market opportunities. This operational flexibility will continue to support the development of intermittent renewables.

Lower Emissions

The replacement of coal fired generation with wind or solar does not result in the elimination of the equivalent coal fired emissions. For example, if a coal unit was operating 80% of the time and is replaced with wind generation that operates 40% of the time, there is a requirement for another generation option to operate 40% of the time to ensure the same quantity of electricity continues to be available when required. Hence, other generation units are required to "firm" the wind (or solar) generation. Options include:

- Co-generation – natural gas fired turbine and heat recovery, with heat utilized in an industrial process, up to 85% efficient.
- Hydro with storage – larger hydro projects, both in Alberta or imported from BC and/or Manitoba, can provide electricity and quick acting capacity to support renewables. Unlike coal or natural gas fired options that have an essentially limitless supply of source energy, hydro facilities are limited by the amount water nature provides and can be stored behind a dam.

⁷ [A Review of Co-generation in Alberta](#), EDCA, September 29, 2015, Executive Summary:

Despite its many benefits, only an estimated 16% of the total oil sands steam requirements is being produced through co-generation. Developers of co-generation face a number of challenges that have impeded it from reaching its full potential. Some are related to market fundamentals, like the uncertainty of future prices of natural gas and electricity. Others arise from individual development policies at the corporate level, including access to the incremental capital that co-generation requires versus steam boilers. Finally, government policy makers can play a decisive role in enabling and encouraging fulsome development of co-generation, such as providing timely clarity on future greenhouse gas emissions compliance obligations, reducing barriers and development timelines for the connection and approval process, and ensuring adequate transmission capacity is developed on time for industry requirements.

⁸ See <https://www.alberta.ca/climate-leadership-plan.aspx>

- Combined cycle – natural gas fired turbine and heat recovery, with waste heat un-utilized, up to 60% efficient
- Simple cycle – natural gas fired turbine with no heat recovery, up to 35% efficient
- Coal to gas conversions – retrofit old coal fired plants to burn natural gas, up to 35% efficient

It is anticipated that all of the above generation options will be utilized to some extent to replace coal fired generation in Alberta. However, co-generation produces 29% less CO₂ than state of the art combined cycle facilities and 62% less CO₂ than existing coal plants once converted to natural gas.⁹ To the extent Alberta requires additional natural gas fired generation to support renewables and replace coal, co-generation should be Alberta’s first choice to minimize CO₂ emissions. The following chart shows the emissions intensity of generation technology options for Alberta.¹⁰

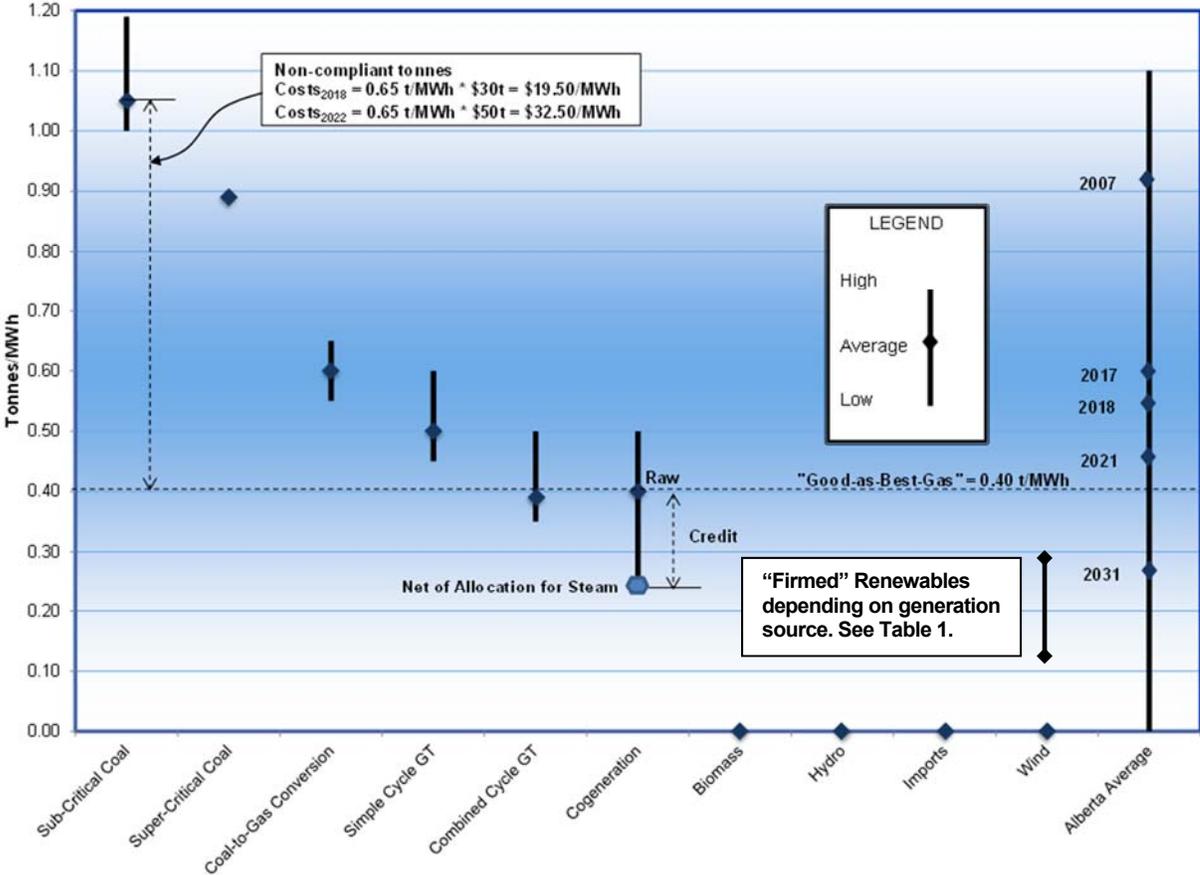


Figure 2 – Generation Technologies CO₂ Emissions Intensity (Tonnes/MWh) and Alberta Average

The high emissions intensity of coal fired generation options was likely part of the rationale under the CLP to phase out all coal fired related pollution by 2030. For co-generation, a significant part of the

⁹ What makes co-generation so efficient for electricity generation is the hot turbine exhaust provides most of the energy to create the steam or heat needed for the industrial process; hence, the incremental natural gas required to produce, and allocated to electricity, has few emissions.

¹⁰ A Review of Co-generation in Alberta, EDCA, September 29, 2015, prepared for OSCA, Figure 8 updated by EDCA June 2017. Please see OSCA web site for a copy of EDCA’s report.

energy (about half) can be allocated to steam production; a proportional amount of the fuel and the emissions can be similarly allocated to steam production, such that the net effective emission rate allocated to electricity is virtually half of the simple-cycle GT emission intensity. Typically, oil sands co-generation applications are calculated at the lower end of the range (0.25 t/MWh), given their operational efficiencies and the substantial allocation of emissions to steam production.¹¹

When considering overall emissions, one needs to consider how often each type of generation technology can or should run to minimize overall emissions from electricity generation. Typically, the following types of non-renewable generation capacity can be utilized:

Base Load

Base load generation typically has high capital costs and low operating costs. Operating continuously over many years, base load generation provides the lowest overall cost of electricity. Historically, base load generation in Alberta has come from coal fired plants and natural gas fired co-generation. A much smaller portion of generation comes from other base load plants like biomass or generation utilizing free or low cost natural gas.¹²

Base Load generators typically operate at their capacity greater than 80% of the time.

Mid-Merit

Mid-merit plants are designed with more operational flexibility to ramp up and down based on consumer demand. These facilities typically are less efficient, but also have lower capital costs. Examples of mid-merit plants are natural gas combined cycle facilities.

Mid-Merit generators typically operate at their capacity between 30% and 80% of the time.

Peaking

Facilities designed to operate less frequently require lower capital costs, with the trade-off being higher operating costs. Examples include natural gas fired turbines (without heat recovery, called simple cycle) and large internal combustion engines.

Peaking generators typically operate at their capacity less than 30% of the time.

Alberta is unique with a relatively flat load profile, with the peak demand being about 10% higher than the average load. There are of course daily and seasonally variations. This flat load profile has lead Alberta to mainly develop base load generation with smaller quantities of Mid-Merit and Peaking generation.

The introduction of 5,000 MW of renewable generation and the phase out of 6,300 MW of coal fired generation by 2030 will represent a significant change in the mix of generation types in Alberta. Very little of the expected new renewable generation capacity will be based loaded,¹³ requiring a significant amount of new base load capacity and some additional peaking capacity. Options to provide most of the required new base load capacity are co-generation, combined cycle plants and coal plants converted to natural gas.

¹¹ Ibid, page 12-13

¹² For example, utilization of natural gas that would otherwise be flared.

¹³ The addition of large batteries or energy storage could make renewables act like base load generation by storing energy when renewables are generating and release electricity when they are not. Not only is energy storage currently very expensive, the amount of renewable generation that would have to be built to provide energy into storage would at least double the Alberta renewables target to over 10,000 MW.

The large incumbent generators in Alberta have all proposed new large combined cycle plants to provide new base load capacity.¹⁴ As noted in the chart above, these plants will produce higher emission than co-generation facilities and should not be constructed to provide base load capacity. Co-generation should be considered as the first option to supply new base load capacity. To the extent Alberta may need more mid-merit capacity, combined cycle could be a viable alternative.

Converting the existing coal plants to burn natural gas will result in significantly higher emissions if these plants are operated continuously. Considering that the majority of capital costs of the coal plants have already been paid for by electricity consumers, operating some coal plants for peaking may be a good use for these assets. Note that coal plants converted to natural gas have similar emissions intensity to simple cycle natural gas fired turbines.

Considering the example noted above assuming natural gas units are required to “firm” the wind generation, if a coal unit was operating 80% of the time and is replaced with wind generation that operates 40% of the time, there is a requirement for natural gas fired generation to operate 40% of the time to ensure the same quantity of electricity continues to be available when required. Numerically, consider Table 1 below where wind is firmed with coal to gas conversions, combined cycle and co-generation:

		2017	2031 Coal to Gas	2031 Combined Cycle	2031 Co-generation
Generation:		Coal	Wind	Wind	Wind
MW		5,000	5,000	5,000	5,000
Capacity Factor		80%	40%	40%	40%
Electricity	GWh	35,040	17,520	17,520	17,520
Emission Intensity	t/MWh	0.95	0	0	0
CO2 Emissions	MT	33.29	-	-	-
Generation:			Coal to Gas	Combined Cycle	Co-generation
MW			5,000	5,000	5,000
Capacity Factor			40%	40%	40%
Electricity	GWh		17,520	17,520	17,520
Emission Intensity	t/MWh		0.55	0.4	0.24
CO2 Emissions	MT		9.64	7.01	4.20
Total Electricity	GWh	35,040	35,040	35,040	35,040
Total Emissions	MT	33.29	9.64	7.01	4.20
Emission Intensity	Tonnes/MWh	0.95	0.28	0.20	0.12

Table 1 – Emissions from 5,000 MW Coal Generation and 5,000 MW Wind Generation with Natural Gas Firming Options

While the replacement of coal with wind and natural gas provides a significant reduction in emissions, utilizing co-generation versus coal to gas conversions to firm renewables could reduce emissions much further. Alberta will be better off, from an emissions reduction and cost perspective, if additional co-generation is built rather than combined cycle natural gas or converting inefficient coal plants to burn natural gas.

We note that while the current government policy is to replace coal with renewables and firming capacity, a significant reduction in emissions could also be obtained by replacing coal with co-generation alone. From a cost perspective, co-generation is considerably lower cost than renewables.

¹⁴ As of June 2017, Capital Power is proposing a 1,010 MW of new combined cycle generation at Genesee and ATCO Power is proposing a 510 MW of new combined cycle generation at Heartland (Ft. Saskatchewan). Source ATCO project Connection Queue: <https://www.aeso.ca/assets/Uploads/Final-July-2017-Project-List.xls> TransAlta and others have also proposed new combined cycle plants; however, these projects are not in the current AESO queue to be connected to the grid.

Perhaps there is an appropriate trade-off between CO₂ emissions reductions and electricity cost to Alberta consumers / Alberta industrial competitiveness.

EDCA has forecast that a total of 12,593 MW of new generation will be required by 2030, as shown in the following chart:

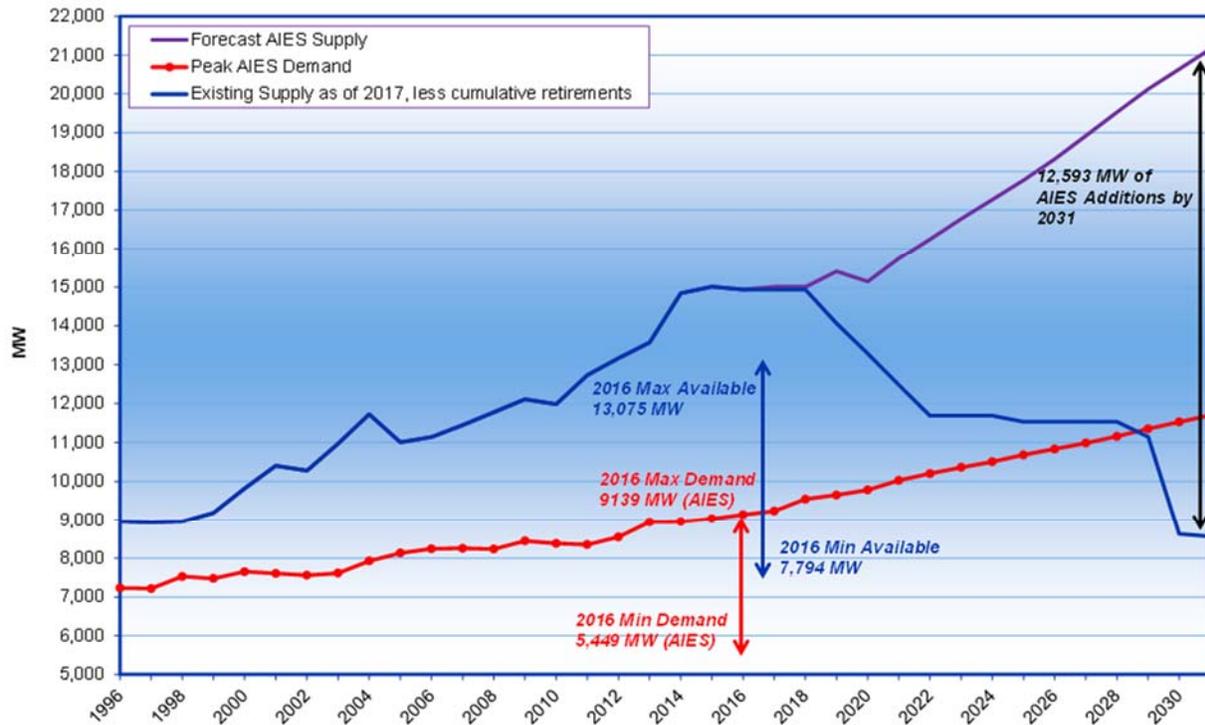


Figure 3 – Historical and Forecast Alberta Demand and Supply

It is anticipated that coal fired generation and load growth over the next 13 years will be provided by a combination of different generation technologies. EDCA has provided a view of the forecast 2030 generation mix:¹⁵

¹⁵ 2016 Capacity from <http://www.energy.alberta.ca/electricity/682.asp> and internal data sources; 2030 Capacity from EDCA

Generator Type	2016 Capacity (MW)	2030 Capacity (MW)	Capacity Changes (MW)
Coal	6,267	0	(6,267)
Cogen	5,160	5,535	375
Combined Cycle	1,151	4,053	2,902
Simple Cycle	770	3,535	2,765
Hydro	902	902	0
Imports	1,250	1,250	0
Wind	1,491	6,812	5,321
Coal to Gas	0	2,371	2,371
Biomass	424	284	(140)
Other	97	97	0
Total	17,512	24,839	7,327

Table 2 – 2016 Alberta Generation Capacity and Forecast 2030 Alberta Generation Capacity

Desiderata Energy submits that Alberta will be better off, from an emissions reduction and cost perspective, if additional co-generation is built rather than combined cycle natural gas or converting inefficient coal plants to burn natural gas. For example, the above forecast suggests 2,765 MW of new combined cycle by 2030 and 2,371 MW of coal to gas conversions, whereas only 375 MW of new co-generation is forecast to be built by 2030.¹⁶ If half of the proposed combined cycle capacity and coal to gas was instead more efficient and lower cost co-generation, Alberta's annual CO₂ emissions could be reduced by 3 MT per year by 2030.¹⁷

Low Cost

Industry experts such as EDCA and Solas Energy agree that co-generation is the lowest cost supply option for Alberta. The following chart shows EDCA's estimates of the total cost of generation technologies.¹⁸

¹⁶ Note that the 2016 industry survey conducted for OSCA suggests 500 to 900 MW of new co-generation will be built by 2022; significantly more than the EDCA estimate of 375 MW by 2030.

¹⁷ With corresponding capacity factor adjustments to equate electricity production.

¹⁸ A Review of Co-generation in Alberta, EDCA, September 29, 2015, Figure 10, updated by EDCA, based on the following assumptions:

EDCAA calculated a levelized cost for various generator types, revised for slight changes in assumptions. Levelized cost is a simple metric which calculates a single real (i.e., deflated) price which, if received for every MWh produced over the life of an asset, would just earn a developer an adequate rate of return, including covering all their operating costs plus recovery and return on their capital (blue area). For this generalized analysis, EDCAA makes certain assumptions about capital and operating costs and financing costs. All these measures are based on a 60:40 debt:equity ratio, with a debt interest rate of 7% and an after-tax return on equity of 15%. Each generator has different capacity factors and service lives, which changes how much of each dollar of capital must be recovered in each year.

Actual financing will be different for different developers and locations, depending on their own circumstances. For this refresh, coal units were assumed to never be built again, so are excluded. In their place, two different levelized costs are presented for a coal-to-gas conversion, assuming two different capital costs, either 10% (\$185/kW) or 20% (\$370/kW) of the capital cost of a combined cycle cost unit (\$1,850). These are higher than figures quoted by TransAlta, but similar to other sources. Unlike the previous version, these numbers include the levelized GHG costs. These amounts are expressed in "real" (deflated) terms. That single "first year" value would have to be inflated at 2% each year to determine the "nominal" values.

EDCAA has assumed that the carbon price will rise quickly to \$50/t according to the provincial and federal proposals, then escalate at inflation of 2%/year (i.e., \$30, 30, 30, 40, 50, 51, 52...\$/t). For example, a simple cycle unit would have to pay \$6/MWh in the first year, rising to \$8/MWh by 2031. A combined-cycle unit would have no compliance costs because it sets the "good-as-best-gas" standard. Cogeneration units and renewables earn a credit. The "Net" arrow shows the levelized cost for those units after the credit is applied.

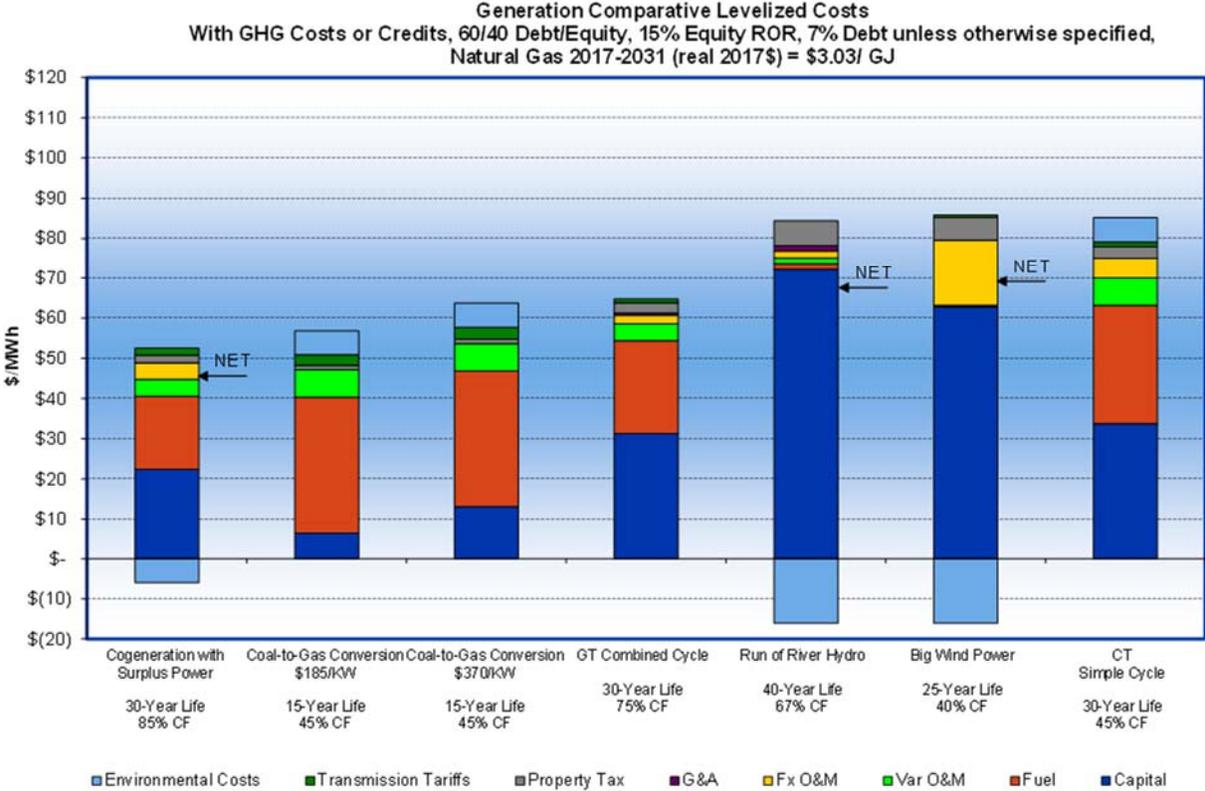


Figure 4 - Estimated Levelized Cost by Generation Technology (EDCA)

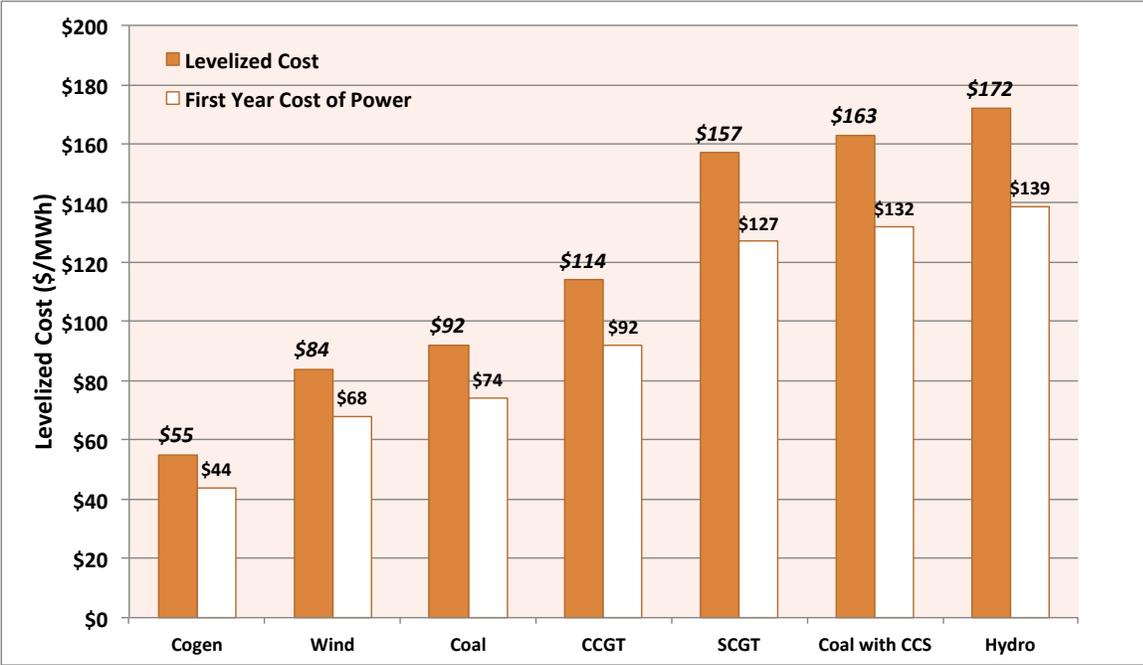
Co-generation has net levelized cost of about \$45/MWh, compared to about \$65/MWh for combined cycle and coal to gas conversions. While there are many variables and plant specific factors,¹⁹ it is clear that co-generation is the lowest cost option.

A report commissioned by the Canadian Wind Association also found that co-generation has lower costs (excluding emissions costs) than combined cycle (CCGT) or simple cycle (SCGT) options.²⁰

Note that these numbers show the average price each generator type would have to earn to breakeven economically, assuming their own particular capacity factor (e.g., wind at 40%, CCGT at 75%). However, the pool price required to earn that average received revenue can be very different by unit. For example, a simple cycle unit earns about a 32% premium to pool price, since it only runs in high-priced hours. A wind unit experiences a 10-30% discount to pool price, so if it needed to earn \$85/MWh, the average pool price would have to be \$120/MWh (at 30% discount), for them to break even.

¹⁹ For example, building at an existing industrial site with transmission and pipeline infrastructure could be lower cost than building at a new green-field site.

²⁰ A WindVision for Alberta – Technical Overview Report, Solas Energy Consulting Inc., May 2013., <http://canwea.ca/pdf/Solas-CanWEA-WindVision-29APR2013.pdf> Proposed larger wind turbines have purported levelized costs similar to co-generation.



Levelized Cost and First Year Cost of Power (2016)

Figure 5 - Estimated Levelized Cost by Generation Technology (Solas Energy)

The Canadian Wind Association’s report concludes that co-generation has the lowest long-term electricity costs of all current generation technologies, including renewables. Other technologies like wind and solar have seen significant cost reductions in recent years due to technology advances, mass production factories and economies of scale. Co-generation has also seen significant cost reductions and more are expected in the future due to the development of larger and more efficient gas turbines and economies of scale.

In-situ oil sands technology was felt to be a natural fit for co-generation application as large amounts of steam are required to heat the oil sands reservoirs. However, a typical SAGD²¹ operation of 25,000 BOPD²² requires about 10 MW of electricity; whereas a co-generation unit sized to meet the steam load would generate well over 100 MW of electricity. Co-generation units sized for in-situ steam recovery, or “steam match”, result in significant amounts of surplus generation, which results in a risk of surplus generation that was typically sold without a long-term contract (and hence limited revenue certainty). Please see Appendix B for a more complete explanation.

A second option was to size the co-generation unit for the on-site load, or “power match”. Unfortunately, smaller co-generation units (e.g. 10 MW) lack the economies of scale necessary to be economic in Alberta. As a result, most in situ oil sands developers elected not to add a co-generation unit with every 25,000 BOPD in-situ phase, but rather relied primarily on boilers for steam production, and added co-generation units for some phases, or not at all.²³ The risk of obtaining adequate revenue for surplus generation in addition to uncertainty in GHG policy, delays associated with connection and

²¹ Steam Assisted Gravity Drainage. For example, see <http://www.capp.ca/canadian-oil-and-natural-gas/oil-sands/oil-sands-development>

²² Barrels of oil equivalent per day

²³ For oil sands mining operations, the heat and electricity requirements are a better match for co-generation and all of Alberta’s oil sands mining operations have co-generation.

approval processes, and access to adequate transmission capacity, has resulted in a significant loss of co-generation potential in Alberta.²⁴

Co-generation Flexibility Supports Renewables

Many co-generation facilities have the flexibility to ramp up and down to support intermittent renewables generation sources like wind.²⁵ Alberta co-generators have a history of supporting Alberta’s electricity system. The following shows the existing Alberta industrial co-generation facilities and the quantity of capacity that surplus to on-site needs or Net-to-Grid.²⁶

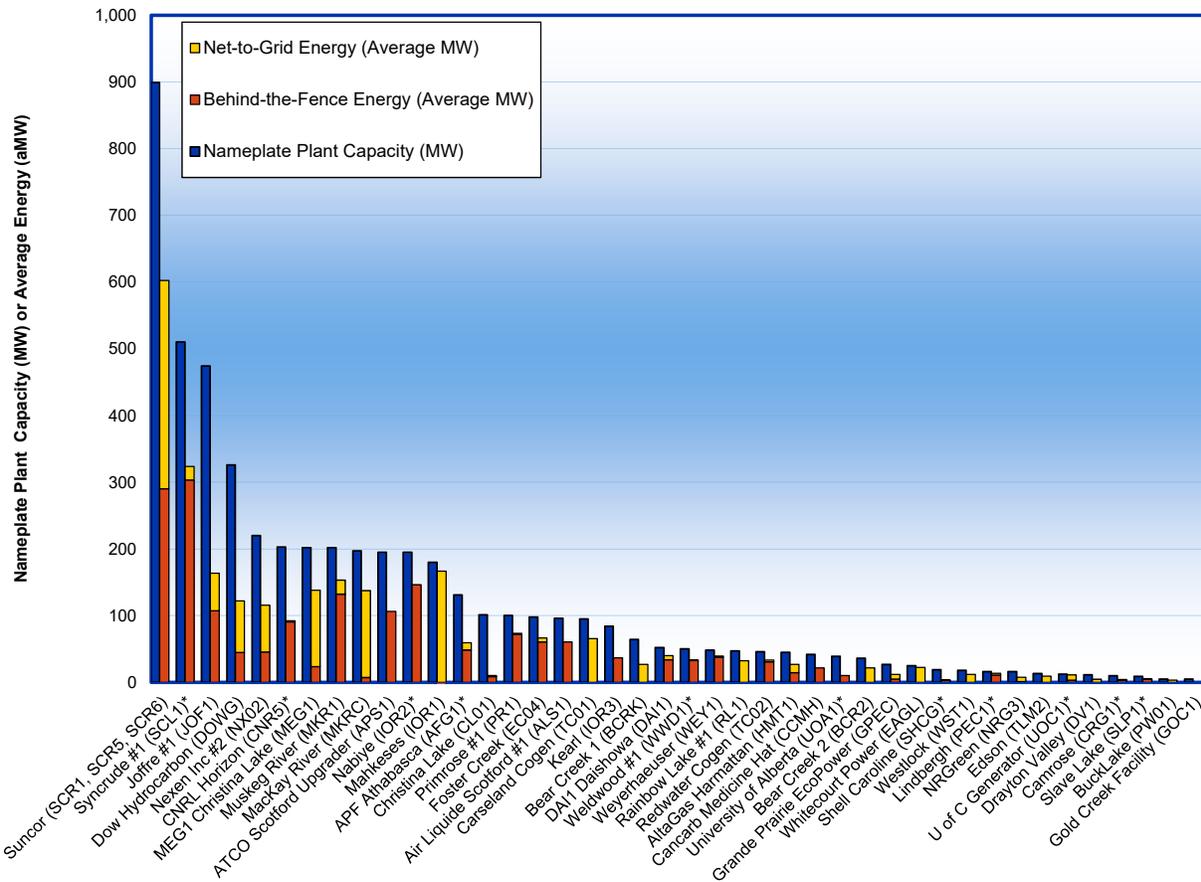


Figure 6 – Alberta Co-Generators Capacity, Behind the Fence Load and Net to Grid

Current co-generation capacity from 40 facilities in Alberta is 5,160 MW (29% of Alberta total). The total Net-to-Grid capacity for co-generators is approximately 2,040 MW, or 14% of Alberta’s total net-to-grid generation capacity. On average, about 1,150 MW of this surplus capacity is sold into the

²⁴ In Saskatchewan, for example, SaskPower purchased surplus generation under long term contracts allowing for a high proportion of the co-generation potential in the province to be developed.

²⁵ Each oil sands operation has unique attributes with varying amounts of excess generation capacity and flexibility, and with operational differences between mining and in-situ oil sands facilities.

²⁶ A Review of Co-generation in Alberta, EDCA, September 29, 2015, Figure 3 updated by EDCA.

Alberta Power Pool energy only market,²⁷ with the remaining either offered into the Ancillary Service markets or not produced.

The following chart shows a breakdown of the behind the fence generation capacity from January 2014 to March 2017:²⁸

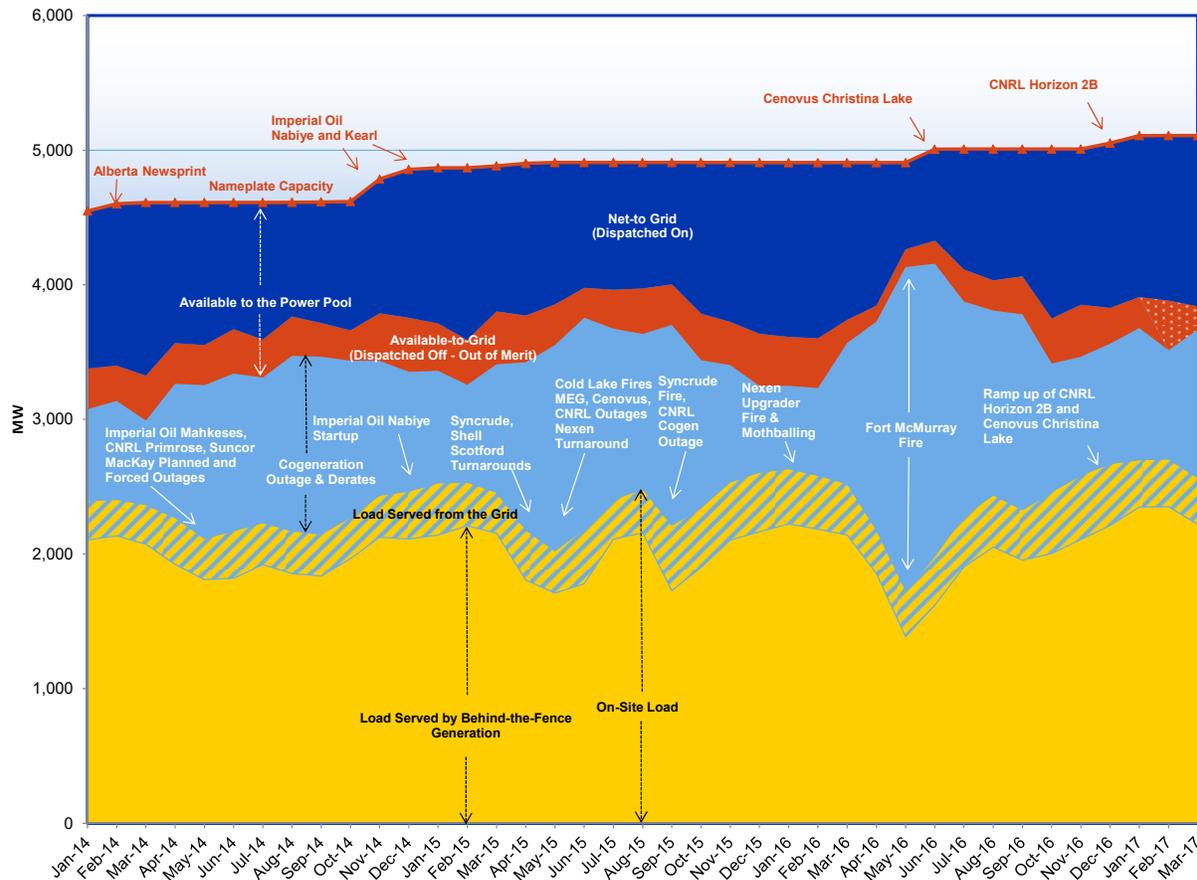


Figure 7 – Alberta Co-generation Behind the Fence Generation Capacity

The dark blue and red areas at the top of the chart represent co-generation capacity that was available to provide electricity to the grid, but did not. With more intermittent renewables to be added in Alberta, the need for additional generation capacity that can ramp up and down on a moment’s notice will be required. Co-generation can provide some of the “firming” generation Alberta will require, and at lower cost than combined cycle, simple cycle or coal plants converted to burn natural gas.

Co-generation Makes Oil Sands More Competitive

Co-generation provide both in-situ and mining oil sands operations with low cost heat and power, while minimizing CO₂ emissions. Alberta oil sands operations need to minimize their carbon footprint, while

²⁷ Based on Metered Generation volume data provided by the AESO for the period from Jan 1, 2015 to Sep 30, 2016. See <https://www.aeso.ca/market/market-and-system-reporting/data-requests/hourly-metered-volumes-by-generation-q1-2015-to-q3-2016/>

²⁸ Provided by EDCA. The hatched blue/yellow area shows energy used on site and provided from the grid. The light blue area is co-generation capacity that was not available due to operational issues (outages or de-rates).

maintaining cost competitiveness with other oil producers. Competitive oil sands operations provide economic benefits to all Albertans.

In addition, more co-generation will lower the overall emissions from Alberta's resource industries, including forestry, chemicals and in particular oil sands. More co-generation will allow additional oil sands production while adhering to the 100 MT/y emissions cap.²⁹

Recent reports by Canada Energy Systems Analysis Research (CESAR) suggest that Alberta could simultaneously achieve two of its biggest energy objectives – accelerating the phase-out of coal-fired power and reducing greenhouse gas emissions from oil sands crude production using co-generation.³⁰ A recent CESAR report concludes that co-generation can put in-situ oil sands production on par with conventional oil from an emissions perspective:

One objective of the Alberta government's 'Climate Leadership Plan' is to regain public support for the oil and pipeline industries that have been such important drivers for both the provincial and national economies. Concerns about oil sands production, especially from the steam assisted gravity drainage (SAGD) technology, have focused on the high GHG emissions associated with recovery when compared with more conventional types of crude oil. Reducing the GHG intensity associated with producing a barrel of SAGD oil is essential in the effort to regain public support for Alberta's oil sands operations.

This study shows how, over the next 14 years, the existing and planned SAGD operations in Alberta could use off-the-shelf technology to achieve the early retirement of coal from the electrical grid, make space for 12 TWh of new renewable generation, stabilize electricity prices and reduce GHG emissions by 170 Mt CO₂. If assigned to oil sands production, these emission reductions would reduce the GHG footprint of SAGD production to less than, or equivalent to, conventional oil.³¹

Co-generation Potential

There is significant potential for additional co-generation capacity in Alberta, from both new and expansions at existing facilities. Based on a survey of the oil sands industry prepared for OSCA, in addition to the 5,160 MW of existing co-generation, an additional 500 to 900 MW could be developed by 2022.

The author submits that the restructuring of the electricity industry in the 1990s was done primarily to take advantage of the significant benefits co-generation has provided to Alberta.³² Co-generation must be a meaningful part of the next phase of Alberta's electricity industry development to ensure these current and future benefits are maintained and obtained for Albertans.

Surplus generation from co-generation facilities has been called a "by-product" as the main purpose of co-generation facilities is to provide heat to support industrial processes. While heat generation is the primary function of industrial co-generation, in Alberta there is significant potential to build co-generation facilities that have surplus generation capability over on-site needs to provide capacity and electricity to Albertans. "Upsizing" co-generation facilities to generate more electricity than is required

²⁹ See <https://www.alberta.ca/climate-oilsands-emissions.aspx>

³⁰ <http://www.cesarnet.ca/blog/sagd-co-generation-strategy-would-shrink-carbon-footprint-both-alberta-electrical-grid-and-oil>

³¹ SAGD CO-GENERATION: REDUCING THE CARBON FOOTPRINT OF OIL SANDS PRODUCTION AND THE ALBERTA GRID, CESAR SCENARIOS Volume 1 • Issue 4 • October 2016. Available at: <http://www.cesarnet.ca/sites/default/files/CESAR-Scenarios-SAGD-Cogeneration-Reducing-Carbon-Footprint-Oil%20Sands-Grid.pdf>

³² Please see Appendix A

by the host industrial process will result in more efficient production, lower emissions and lower cost electricity.

Generators Require Revenue Stability – Alberta Capacity Market

All generation developers require a more stable revenue stream than the current electricity markets are forecast to provide, as outlined in Appendix B. The GOA has directed the AESO to develop a capacity market that is intended to provide stable revenues to generators and ensure there is adequate generation capacity for Alberta consumers.

The AESO recommended a capacity market for the following reasons:

- Ensures reliability as Alberta’s electricity system evolves
- Increases stability of prices
- Provides greater revenue certainty for generators
- Maintains competitive market forces and drives innovation and cost discipline
- Supports implementation of Climate Leadership Plan initiatives and is adaptable to future policy evolution

The AESO will ensure this transition supports other CLP initiatives; namely the Renewable Electricity Program and the phase-out of emissions from coal-fired generation by 2030. The AESO is responsible for designing and implementing the capacity market. This process is expected to take three years and a capacity market is anticipated to be in place by 2021.³³



Figure 8 – AESO Capacity Market Development Timeline

Co-generation participation in the proposed Alberta capacity market will help Alberta oil sands developers to justify additional co-generation capacity. It is estimated that only 16% of the potential co-generation capacity at oil sands facilities has been utilized to date.

On May 12, 2017, the AESO published their “straw dog” capacity market design. The AESO suggested that “As a starting point, it is proposed that the same treatment continues in the capacity market model where a co-generation or facility with behind the fence generation is treated as a net to grid supplier.”³⁴ Desiderata Energy supports this proposed capacity market design as it aligns with the current net to grid treatment under Alberta’s electricity markets and the AESO’s transmission tariff.

With respect to who should buy the capacity, the AESO paper also suggests that “The assumed starting point for discussion is a model of centralized procurement of capacity by the ISO acting on behalf of load, with the potential for self-supply in some cases.”³⁵ Desiderata Energy agrees that the AESO is logical entity to procure capacity on behalf of load customers. In Alberta’s deregulated retail

³³ From AESO website: <https://www.aeso.ca/market/capacity-market-transition/>
³⁴ Straw Alberta Market (SAM 1.0) – Proposal for discussion (Errata), AESO, May 12, 2017 (Errata), page 6. Available at: <https://www.aeso.ca/assets/Uploads/Straw-Alberta-Market-Proposal-formatted-FINAL-errata.pdf>
³⁵ Ibid, page 5-6

electricity market, electricity is procured through retailers on behalf of their customers or directly by larger loads. The credit requirements to back stop these purchases has, in the author's view, limited the development of retail markets and not allowed Alberta to obtain all of the benefits of deregulation envisioned when these markets were created in the late 1990s.

Similarly, if retailers or load customers were required to procure capacity directly, the credit issues would unnecessary increase, to the detriment of Albertans and Alberta consumers. The AESO is much better positioned to manage risks associated with capacity procurement via a central procurement, similar to how ancillary services are currently procured in Alberta.

Industrial facilities that have co-generation have invested tens of millions of dollars to have a reliable on-site electricity source. Desiderata Energy supports the AESO's suggestion that capacity market self-supply for these types of facilities should be an option.

Regarding how much customers will pay for capacity, the AESO suggests "As a starting point, it is assumed that allocation of capacity costs will be separate from the allocation of other costs in the ISO tariff, such as wires costs and ancillary services costs. It is also assumed that costs will be allocated considering consumption during periods of system stress (capacity performance periods) and seasonal coincident peaks." The allocation of costs needs to take into consideration the net-from-grid load requirements of industrial consumers with co-generation.

For settlement, the AESO has suggested a one month period, which we also support.³⁶

Co-Generation Challenges

Investing in co-generation facilities is a complex investment decision as these facilities are capital intensive and subject to considerable revenue uncertainty. A stable and predictable electricity industry and market structure helps reduce investment risks. As noted, only about 16% of the potential oil sands related co-generation capacity has been developed in Alberta. Desiderata Energy believes more co-generation has not been developed due to the following factors:

Transmission

The development of new high voltage transmission lines is a complex process that can take many years, typically longer than the 2 to 3 years required to develop a co-generation facility. Hence generation developers may not have certainty that there will be transmission capacity available to transport excess electricity to markets.

For example, in the Fort McMurray area, there is significant co-generation potential from oil sands operations; however, transmission capacity out of the Fort McMurray area is limited and plans to develop additional transmission lines have been delayed many times by many years. This is the classic "chicken and egg" strategy problem where co-generation developers will not commit to build surplus capacity without transmission lines to markets, and the GOA and the AESO will not commit to build new transmission lines until additional co-generation is developed and there is a clear need. A potential solution is that the AESO needs to commit to build the second 500 kV transmission line to Ft. McMurray with a certain completion date, as per the AESO's 2020 plan, which will give co-generation developers some certainty to build capacity

The operation of transmission systems is complex, especially where there is limited capacity available. Unlike pipelines that are "point to point" and parties can contract for pipeline capacity, the transmission system is more of a web and electricity can flow over several different pathways. In Alberta customers cannot obtain rights to transmission capacity and hence there is the risk that transmission capacity may not be available. For the AESO striking the balance

³⁶ Ibid, page 16

between operational requirements and commercial fairness to all customers is complex and often results in unanticipated consequences that may be perceived as unfair or ambiguous.

Most co-generators in Alberta have an Alberta Utilities Commission (AUC) approved Industrial System Designation that allows for load and generation within an oil sands facility to be net metered. AESO's transmission tariff net metering and the avoidance of peak demand charges provides the correct price signal for co-generators to reduce the need for new transmission investment, which helps lower transmission tariff costs for all Albertans. These tariff provisions come under review every 3 to 4 years and could be altered or eliminated, to the financial detriment of Alberta's co-generators. Hence, how co-generators are charged for the use of the transmission system is another source of uncertainty and risk that limits co-generation development.

Desiderata Energy is of the view that the above noted risks associated with transmission development and tariffs has been the main deterrent to additional co-generation development in Alberta.

Market Stability

Alberta's energy only market has been in place since 1996; however, there have been several significant GOA policy changes that impact how the electricity markets function, how market prices are determined and subsidies to certain sectors of the industry. While the GOA has tried to maintain a clear commitment to electricity de-regulation and competitive electricity markets, major changes have and are anticipated to continue to be made every few years that create risk and uncertainty.

For example, the implementation of the CLP has resulted in abnormally low power prices in 2016 and 2017, and anticipated for several more years, with the turn back of the legislated Power Purchase Arrangements to the Balancing Pool and the GOA providing financial support to the Balancing Pool to subsidize coal fired generation. The impact of the stability of Alberta's electricity markets may have been an unintended consequence of the CLP; however, the ability of the GOA to impact electricity markets imposes financial risks and limits co-generation investment.

Emissions

As noted, co-generation has the lowest level of emissions of all the natural gas fired generation options. This benefit has been recognized under the current CO₂ emission pricing system in Alberta³⁷ and has provided a small economic incentive for co-generation development. At the time of writing this paper in mid-2017 it is still unclear how CO₂ emission pricing will be applied to co-generators in 2018 under the CLP. This is an example of the uncertainty and risks that dissuade co-generation investment.

The above noted risk factors have, in Desiderata Energy's experience, lead co-generation developers to limit the size of their facilities to primarily supply their on-site load, and not to build excess capacity. In light of the pending coal generation phase out, these factors need to be addressed by policy makers to encourage co-generation developers to build surplus capacity to support renewables and reduce overall emissions.

Recommendations:

As outlined in Appendix A, Alberta's electricity industry was re-structured the 1990's to take advantage of the potential benefits co-generation could provide. History has shown that co-generation has provided the anticipated benefits. Co-generation can provide additional benefits to Alberta, which align

³⁷ SGER, or Specified Gas Emitters Regulation, which has been in place since 2007.

with the CLP objectives. Allowing co-generators to sell their net to grid capability into Alberta's capacity market will improve revenue certainty.

Desiderata Energy encourages the GOA and the AESO to consider the significant benefits co-generation has and can continue to provide to Alberta. For co-generation to realize its full potential for Alberta we recommend:

- Alberta's co-generators should be allowed to fully compete in Alberta's proposed capacity market;
- The AESO should procure capacity on behalf of all Alberta electricity consumers;
- Capacity market charges from industrial consumers with co-generation should be based on net-from-grid requirements;
- Capacity market payments to industrial consumers with co-generation should be based on net-to-grid supply; and
- GOA emission policies and pricing should encourage efficient co-generation development over other less efficient natural gas generation options, specifically by providing:
 - clear and consistent transmission policies and timely transmission additions,
 - streamlined regulatory approval processes and reduced timelines for connections,
 - regulations codifying net metering and peak demand avoidance provisions in the AESO's transmission tariff,
 - stable and predictable electricity markets, guided by market forces with limited government interference, and
 - clear and timely emissions policy that reflects the lower emissions benefits from co-generation.

Appendix A: History of Deregulation and Alberta Electricity Markets

Vertically Integrated to 1996

Prior to 1996 both municipally owned and investor owned vertically integrated utilities operated in Alberta and provided customer services, distribution, transmission and generation, under tariffs developed based on cost of service principles. The main utilities were TransAlta, Alberta Power (now ATCO Electric), Edmonton Power (now Capital Power) and City of Calgary (now ENMAX).

In this vertically integrated model there were some larger industrial generators, primarily forestry companies, with on-site generation that was less than their on-site load, and hence exports to the grid were rare.

In the early 1980's Alberta embarked upon a significant generation build with six coal fired units³⁸ under construction in light of rosy economic forecasts. The National Energy Program (NEP) and economic downturn in 1983/84 significantly reduced the forecast need for this new generation, and several of the units were delayed, creating significant carrying costs for these coal fired units until they were all eventually placed into rate base in the early 1990s. In hindsight, likely only three of the six units should have started construction in the early 1980s, with the other units phased in over the next 15 years. The construction delays and carrying costs made these coal units significantly more expensive than planned, resulting in higher end use rates to consumers.

During this same time period, the Alberta government had a policy of averaging transmission and generation costs across the province. The result was annual cash transfers from TransAlta to Edmonton Power and Alberta Power. As the size of these "equalization" payments grow sentiments of southern Alberta subsidizing northern Alberta grew and the issues became politically charged.

In the 1980s significant advancements were being made in reducing the cost of gas turbine generation technologies, specifically the development of co-generation projects. With natural gas prices between \$1 and \$2/GJ, and with surplus natural gas production in Alberta, and limited export pipeline capacity, the use of gas turbines for power generation became more compelling. A study prepared for the Alberta Government in 1992 suggest there was about 6,000 MW of co-generation development potential in Alberta that could be brought on at a lower cost than coal, in smaller quantities (to avoid the over built issues), and with non-regulated investment to reduce the internal provincial subsidization issues.³⁹

As a result, the Alberta government in 1994 started to modify its policies related to coal fired generation for base load capacity and embarked upon re-structuring the electric energy industry to allow for co-generation units to be more readily developed.

Industry Restructuring 1996 to 2000

In order to capture the perceived benefits of co-generation the government made three changes to the industry structure, essentially ending the vertical integration of the utilities:

1. Generation Deregulation

All electricity generation developed after January 1, 1996 was deregulated, meaning that:

- All capital would come from private sources, with no cost recovery through end user rates
- The government would not approve new generation for need – investors were at risk of developing generation and selling their output

³⁸ Keephills 1 & 2, Sheerness 1 & 2, Genesee 1 & 2

³⁹ Potential for Cogeneration and Generation from Waste in Alberta, 1992, available at <https://archive.org/details/potentialforcoge00orma>

2. Power Pool

The Power Pool was created to allow for the development of electric markets, where surplus electricity generation could be sold, the price of which would be set hourly by the generation supply available and consumer demand present. Co-generators would be able to build generation projects that were larger than their on-site load, and more cost efficient, and have a market to sell the surplus generation. For oil sands projects, the steam requirements dictated that co-generation projects sized to meet steam loads would produce significantly more power than the oil sands facility required.⁴⁰

3. Transmission Administrator

To allow co-generators unfettered access to the transmission grid, the Transmission Administrator (TA) was established to plan, operate and manage all the transmission assets in Alberta. While the underlying assets would remain regulated and owned by the utilities, the TA would ensure open access and develop a province wide tariff with uniform pricing to all market participants.

Customer Services and Distribution remained regulated.

During the first year of the Power Pool the price averaged below \$15/MWh, significantly less than the cost of new generation. Alberta still had surplus generation from the coal overbuild and the design of the Power Pool resulted in the Power Pool price reflecting the highest variable cost generator each hour. In addition, since customers remained captive to the regulated distribution utilities, co-generators found it hard to find buyers to sell their potential surplus generation at attractive prices.

There were also concerns with the potential for market power. With TransAlta owning about 60% of the generation in the province, other generators were concerned that TransAlta could unfairly manipulate Power Pool prices.⁴¹

By 1998 it was becoming clear that significant new generation development would require additional industry restructuring and/or deregulation. The Alberta government embarked upon a bold plan to transfer offer control of utility generation built prior to 1996 to marketers and deregulate the Customer Service portion of the industry.

The first part required the development of legislated Power Purchase Arrangements (Legacy PPAs). The Legacy PPAs offered the generation owners (utilities) recovery of their capital and operating costs based on formula and indices, rather than annual regulator approvals. The PPAs were intended to mimic cost of service recovery over the up to 20-year life, while providing appropriate incentives for the utilities to prudently operate the assets and to reduce regulatory oversight costs. The holders (or buyers) of the PPAs were provided offer control and entitled to most of the output from the generation units.⁴²

The PPAs were developed from 1998 to 2000 and the rights to the PPAs were auctioned off in the summer of 2000. The PPAs were intended to reduce the market power concerns with any one party having no more than about 25% offer control.

The second part deregulated the Customer Service portion of the business and allowed for retailers to compete for customers. The intent was that retailers would help make markets, by buying power from generators and selling to end use customers. In the era of ENRON's heyday in the late 1990's, common wisdom was that liquid markets would emerge that were efficient and drive down the cost of electricity for consumers.

⁴⁰ Called "steam match" projects, as discussed in the main body of the document

⁴¹ The incumbent utilities controlled most of the non-committed generation capacity

⁴² The PPAs contained availability and incentive payments whereby the utilities had the obligation to maintain the units to a certain level of reliability and had the opportunity to earn additional revenues from surplus generation.

Energy Only Markets 2001 to present

The restructuring and deregulation efforts of the Alberta Government resulted in the development of a significant amount of co-generation, with the first co-generation unit being commissioned in 1998. A total of about 2,400 MW was developed and brought on stream between 1998 and 2005.

As the province's demand grew in the 2000s, primarily due to oil sands developments and the related supporting infrastructure and economic spins offs, additional generation was developed, including 1,100 MW during a second round of co-generation development from 2008 to 2016.

Arguably, the electric industry and markets developed in the 1990s were successful. Generally, during periods of tight supply, pool prices increased sending the economic signal for additional generation to be developed. When there was excess supply, lower power pool prices sent the signal that new generation was not required. In reality, markets are more complex and a number of factors influenced developer's decisions to build generation; however, generation was built and Alberta's consumers were served at reasonable prices.

Currently Alberta has surplus generation and low Power Pool prices. In 2012 the Sundance 1 & 2 coal units (600 MW) were shut down due to boiler issues. The industry anticipated that these units would not return to service and a total of 1,600 MW of new generation was bought on line in 2014. However, an arbitration panel ruled that the Sundance 1 & 2 units should be returned to service, which contributed to the current over supply.

The combination of oversupply, low Power Pool prices and the pending implementation of the Climate Leadership Plan lead the PPA holders to turn back the PPAs to the Balance Pool in late 2015. While current Power Prices are very low, the prospect for more robust prices with additional coal plant being decommissioned, provides the opportunity for additional co-generation development in Alberta.

Alberta Co-generators

In the vertically integrated industry model prior to 1996 there were some larger industrial generators, primarily chemical and forestry companies, with on-site generation that was less than their on-site load, and hence exports to the grid were rare. Prior to industry restructuring and the enactment of the *Electric Utilities Act (EUA)* on January 1, 1996, there was about 1,400 MW of non-utility generation in Alberta.

The first co-generation unit commissioned in 1998 under the *EUA* was an 85 MW gas turbine owned by ATCO Power and heat recovery boiler owned by Amoco (now Canadian Natural Resources). Steam was utilized for oil sands recovery and electricity supplied surface facilities with surplus electricity sold Power Pool.

In-situ oil sands recovery was felt to be a natural co-generation application as large amount of steam are required to heat the oil sands reservoirs. However, a typical SAGD⁴³ operation of 25,000 BOPD⁴⁴ required about 10 MW of electricity; whereas a co-generation unit sized to meet the steam load would generate over 100 MW of electricity. Co-generation units sized for in-situ steam recovery, or "steam match", resulted in significant amount of surplus generation, which resulted in risk for the generation developer as the surplus generation was typically sold without a long-term contract (and hence revenue certainty)⁴⁵.

A second option was to size the co-generation unit for the on-site load, or "power match". Unfortunately, smaller co-generation units (e.g. 10 MW) lacked the economics of scale necessary to be feasible in Alberta. As a result, most oil sands developers elected not to add a co-generation unit

⁴³ Steam Assisted Gravity Drainage. For example see http://www.energy.alberta.ca/OilSands/pdfs/FS_SAGD.pdf

⁴⁴ Barrels of oil equivalent per day

⁴⁵ See Appendix C

with every 25,000 BOPD phase, but rather relied primarily on boilers for steam production, and added co-generation units for some phases, or not at all. The risk of obtaining adequate revenue for surplus generation resulted in a significant loss of co-generation potential in Alberta.⁴⁶

Inter-Provincial Electricity Transfers

In the vertically integrated industry model prior to 1996 Alberta and British Columbia had various agreements whereby base load coal fired generation was exported to BC during off-peak periods and hydro based generation was provided to Alberta on-peak. These arrangements took advantage of the surplus generation Alberta had at night and the flexible hydro capacity BC enjoyed. The benefits to the two provinces are estimated to be tens of millions per year.

After 1996, Alberta had market based prices for imports and exports whereas BC's prices were subject to regulatory factors. While electricity imports and exports flowed between the two jurisdictions, the transactions were often the subject of political and regulatory oversight and reviews.

A second major transmission connection between BC and Alberta has been proposed for decades,⁴⁷ and recently has surfaced again in the form of a 500 kV DC line from Site C to northern Alberta, which could be part of the Western Canadian transmission connection between BC and Manitoba. This line, if built, could expand the benefits of quick ramping hydro generation to firm renewables in Alberta. Unfortunately, hydro generation is limited to the amount of water that can flow past the dam. The author is of the view that hydro generation from BC and Manitoba would not be sufficient to fully replace base load coal generation in Alberta and Saskatchewan – natural gas firming generation will still be required.

⁴⁶ In Saskatchewan, for example, SaskPower purchased surplus generation under long term contracts allowing for a high proportion of the generation potential in the province to be developed.

⁴⁷ The current major transmission line between BC and Alberta is a 500 kV AC line that runs from Calgary, through the Crowsnest Pass to Cranbook.

Appendix B: Revenue From Alberta Electricity Markets

Similar to other industries, capital intensive investments like electricity generation require a secure source of revenue for capital cost recovery. Investors and debt holders require a certain level of revenue certainly before they will invest, and the higher the risk of obtaining the return of and on capital, the higher the level of return investors will require and the higher the cost of debt.

Under the prior vertically integrated, cost of service industry model in place prior to 1996, generators obtained fixed cost recovery, regardless of the amount electricity that was actually produced. For generators built after 1996, capital cost recovery was intended to come from several sources, including:

1. Energy Only Market

All generation of material size is required to offer output in excess of on-site consumption into the Alberta Power Pool. This market clears every minute at the price of the last generation offer dispatched to meet consumer demand. The average of the 60 minute prices each hour is the hourly Power Pool Price. All generation that clears the Power Pool is paid the Power Pool Price. Payments from the AESO each hour are the volume of energy produced times the hourly Pool Price - this market is often call the Energy Only Market.⁴⁸

Over the past five years, revenue from the energy only market to generators and importers has averaged \$3.8 billion/y; however, the range was a high of \$6.2 billion in 2013, down to \$1.5 billion in 2016. The low prices experienced in 2016 are forecast to continue for several years, putting significant financial pressure on some generators.

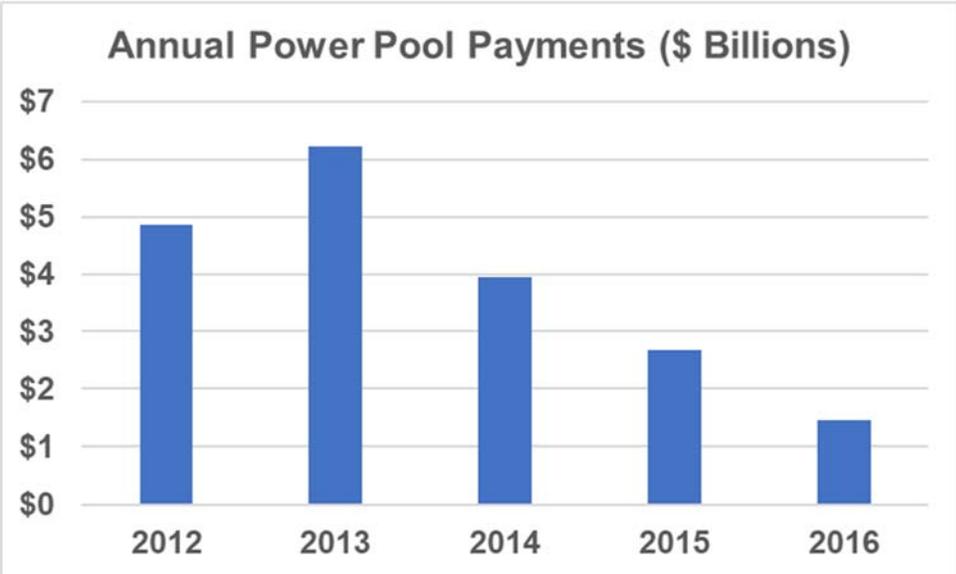


Figure 9 – Annual Power Pool Payments

2. Ancillary Services Market

In order to ensure there is adequate generation available at all times to meet consumer demand, the AESO procures varies types of ancillary services. Most of these services are provided by generators; however, larger, flexible loads can also provide services.⁴⁹ Some

⁴⁸ As opposed to a capacity market where generators are paid for being available (having capacity) to generate electricity when needed

⁴⁹ For some ancillary services, paying a generator to ramp up during a reliability event is equivalent to paying a load customer to ramp down.

ancillary services are procured directly by the AESO under contract, while others are procured via third party market called WATT-X.

Over the past five years, the AESO has provided revenue for ancillary services to generators and load averaging \$222 million/y, ranging from \$370 million in 2013 to \$67 million 2016.

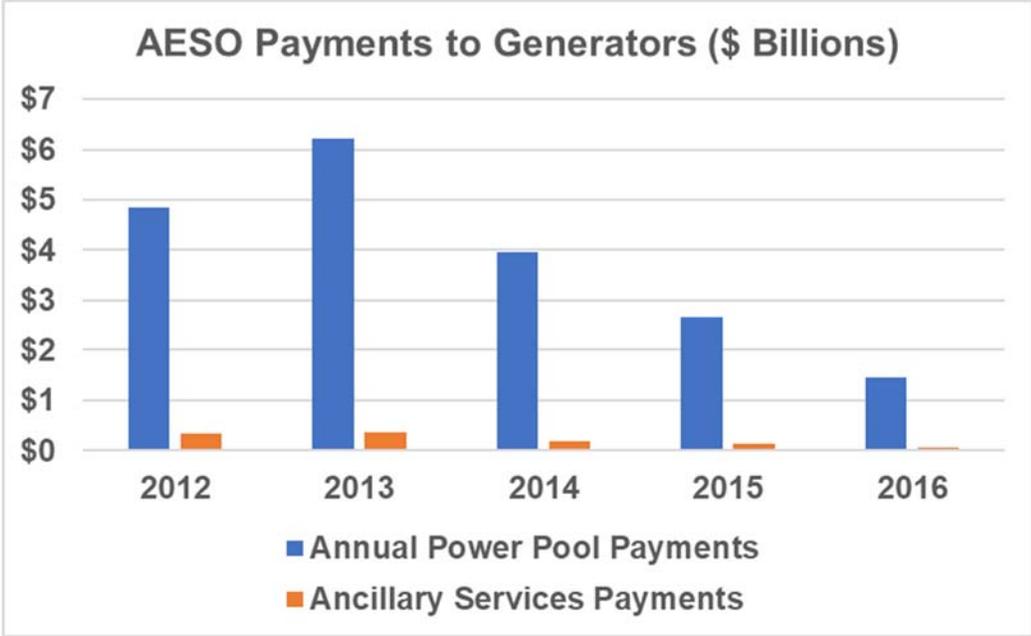


Figure 10 - Annual Power Pool and Ancillary Service Payments

3. Over the Counter Markets

Generators and load customers (or their retailers, marketers or agents) can contract around the Alberta Power pool to effectively set prices that are different from the Alberta Power Pool price. These financial arrangements can include capacity and energy type revenue streams to generators. When the current market structure was designed, it was envisioned that over the counter markets would become competitive and liquid, providing opportunities for generations to obtain fixed revenue streams to support capital investments. In reality, these markets are thinly traded and are mainly used by the larger generators to risk manage their portfolios.

Over the long run, over the counter markets should not provide incremental revenue to generators. However, these markets were intended to provide greater revenue certainty if generators could contract a portion of their output under longer term contracts. The author submits that in the post ENRON era over-the-counter markets have not provided the revenue certainty envisioned when electricity deregulation was designed in the late 1990s.

4. Power Purchase Agreements (Competitive PPAs)

Long term contracts between generators and loads that provide capacity payments are common between co-generation developers and host customers. Competitive PPAs have allowed for many of the co-generation projects to be built in Alberta. For some generation projects, Competitive PPAs exist between generators and large retailers (e.g. Capital Power and ENMAX for the Sheppard Energy Centre).⁵⁰

⁵⁰ <http://www.capitalpower.com/generationportfolio/CA/Pages/shepard.aspx>

Within a corporate entity, a virtual Competitive PPA can exist, for example when a large industrial customer builds surplus co-generation to effectively supply other facilities in Alberta or when a large generator is also a large retailer (i.e. one part of the company supplies the other). Where over the counter markets have failed, incumbent Alberta generators have relied on the strength of their balance sheets and internal virtual Competitive PPAs to finance generation facilities.

5. Legislated Power Purchase Arrangements (Legacy PPAs)

The Legacy PPAs provide capacity payments to the coal fired plants built prior to 1996 under the prior vertically integrated, cost of service industry structure. All of the Legacy PPAs will expire by January 1, 2021.⁵¹

Since 1996, a total of over 7,500 MW of generation has been developed in Alberta. The above sources of revenue (1 to 4) have obviously been sufficient for developers and investors to build billions of dollars' worth of generation capacity.

However, both industry and the Alberta government generally agree that these existing revenue sources will be insufficient to provide financial incentives for both the development of 5,000 MW of renewable generation by 2030, replace 6,400 MW of coal fired generation and encourage additional generation to support renewables, widely expected to be natural as fired generation.

⁵¹ The Legacy PPAs have been turned back to the Balancing Pool, hence the Balancing Pool is still paying the coal plant owners monthly capacity payments

Appendix C: About the Author

Dale Hildebrand is President of Desiderata Energy Consulting Inc., a management consulting firm specializing in electric energy. Desiderata's clients include industrial, commercial, institutional and residential customers, government agencies and regulators. Desiderata has assisted clients with generation project development, economic evaluations, grid connections, regulatory approvals and electric energy industry advisory services. Mr. Hildebrand has testified 15 times before regulatory tribunals and is an expert in electric energy tariff design.

A significant portion of Mr. Hildebrand's career has focused on co-generation. He has assisted several co-generation developers with feasibility studies, commercial advise, regulatory approvals and financial settlement services.

Dale has worked in the Alberta electric energy industries for 30 years. He earned an MBA in 1991 and a BSc in Mechanical Engineering, with distinction, in 1986, both from the University of Alberta.

For more information on Desiderata Energy and Mr. Hildebrand's resume please visit www.desiderataenergy.com.