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THE ALBERTA ELECTRICAL GRID: WHAT TO EXPECT IN THE NEXT FEW YEARS

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SUMMARY

The Alberta government has stated that it wants to make significant changes to the supply of electricity to the current electrical grid for the province. These changes include the phasing out of coal generation by 2030, the supply of 30 per cent of electricity from renewables by 2030 and the introduction of a so-called capacity market in addition to the current electrical energy market. The achievement of these objectives will require a number of fundamental changes to the existing electrical grid. This paper provides an overall description of these changes.

The paper first examines the current grid structure in which coal and gas provide the base load supply in the amount of 90 per cent of electricity demand, and renewables are a relatively small source of supply for the remaining 10 per cent. It then reviews the current simple energy market in Alberta that uses a single price auction to determine the wholesale price of electricity.

The paper then notes that the achievement of these changes will require a large amount of investment in the next 15 years to create new generating capacity that currently does not exist. The Alberta Electric System Operator (AESO) has forecast that by 2032, Alberta will need an additional 7,000 megawatts of gas generation, 5,000 megawatts of wind, 700 megawatts of solar and 350 megawatts of hydro. To put this in context, the Ontario grid currently has 4,213 megawatts of wind (11 per cent of total generating capacity) and 380 megawatts of solar (one per cent of generating capacity).

The Alberta government has made two fundamental changes in the electricity market to make this happen.

First, it has introduced a Renewable Energy Program (REP) to incent investment in renewables. They asked industry to bid on a 20 year contract for supply of electricity that offered a guaranteed fixed price that was independent of the existing wholesale market. The first round of bidding (REP 1) announced

in December 2017 resulted in 600 megawatts of new wind capacity at prices below expectations. No solar proposals were accepted in REP 1, a result that may cause the Alberta government to make new proposals (details still to come) that may permit solar participation. Two new rounds for 2018 (REP 2 for 300 megawatts and REP 3 for 400 megawatts) have requested bids on a similar basis. The one new feature is that REP 2 is limited to investors with an Indigenous equity position of at least 25 per cent.

Second, the Alberta government has proposed to introduce a capacity market that would compensate electricity suppliers for merely creating capacity to supply. The capacity market was requested by industry and was announced by the Government of Alberta in November 2016. It is intended to give additional compensation over and above the energy market compensation in order to make it economic for investment in future renewables if the REP guaranteed price structure is terminated, and in future base load and backup gas generation.

The paper then describes one possible solution using new storage battery technology as a means of providing backup generation for renewables.

Finally, the paper contrasts the proposed Alberta electrical grid with the current Ontario electrical grid. It notes that the current high electricity prices in Ontario have become a high profile political issue there, since consumers are paying all electricity costs. In contrast, the Alberta government has also stated that retail electricity prices will be capped at 6.8 cents per kilowatt hour until 2021. If retail rates exceed that amount, the Alberta government will use carbon tax revenues to pay the difference.

I. INTRODUCTION

There has been a significant amount of discussion in Alberta regarding the future of the supply of electricity in the province. By 2030, the government of Alberta wants to eliminate coal-fired electricity generation and have 30 per cent of its electricity from renewable sources.¹

In order to understand the implications of these changes, it is helpful to first look at the existing Alberta electrical grid.

II. CURRENT STATE OF THE ALBERTA GRID

(a) Overall capacity

The Alberta electrical grid serves an electrical demand with a higher industry component than most other grids. As a result, the fluctuation in demand is smaller. For 2016, average demand (referred to as Alberta Internal Load or AIL) was 9,057 megawatts (MW), with a peak load of 11,458 megawatts and a minimum load of 6,595 megawatts (AESO 2016).

One of the challenges of supplying electricity to a grid is matching supply with a demand load that fluctuates minute by minute. The party charged with achieving this matching is a government entity known as the Alberta Electric System Operator (AESO).

The data from the year 2016 show the following for the Alberta grid's capacity in megawatts as well as total electricity generated in gigawatt hours (Gwh).

GENERATING CAPACITY, 2016 ELECTRICAL ENERGY GENERATED, 2016

	MW	%	Gwh	%
Coal	6,289	38	38,486	48
Gas	7,555	45	33,842	42
Wind	1,445	9	4,402	6
Hydro and Other	1,322	8	2,830	4
Total	16,611	100	79,560	100

Source: AESO 2016, Annual Market Statistics.

It should be noted that in 2016 coal was responsible for 38 per cent of capacity and 48 per cent of electricity, while gas was responsible for 45 per cent of capacity and 42 per cent of electricity. These two facts show that coal and some gas capacity form the base load for electricity in Alberta. The rationale for this structure is that coal and some gas plants are usually large, and operate at their greatest efficiency by operating continuously. This is analogous to the Ontario system, where large nuclear plants and hydro facilities, such as those at Niagara Falls, provide the base load for that province's electricity grid.

(b) Gas generation

The reason why only some gas generation forms the base-load capacity is because gas generation is further subdivided into the three categories: (1) combined cycle, (2) simple cycle, and (3) cogeneration.

¹ Alberta Energy Department website, "Electricity," <http://www.energy.alberta.ca/AU/electricity/Pages/default.aspx>.

Combined-cycle gas generation is the most efficient form of thermal electrical generation, in that it generates the most amount of electricity per unit of thermal energy input. The reason for this is contained in the name “combined cycle” itself. When the gas is first combusted, the extremely hot fumes are run through a first turbine that turns and generates electricity. The exhaust from this first turbine is still hot, and the exhaust is then run through a heat exchanger to generate steam. This steam is run through a second turbine that turns and generates additional electricity. Hence the name combined cycle. These combined-cycle plants run best when they run continuously, and so are best used in base-load generation. The Alberta grid currently has six combined-cycle gas generators with a capacity of 1,700 megawatts that are in almost continuous use.²

Simple-cycle generation only has one cycle: gas is combusted and the hot fumes are used only to generate steam that is run through a turbine. Simple-cycle plants tend to be smaller, and are relatively easy to ramp up and down in electricity production. As a result, they are used to meet fluctuations in demand, in that they are brought on during increases in demand, and turned off during drops in demand. They are often referred to as “peaking” facilities. There are currently 26 such simple-cycle facilities in Alberta with a combined capacity of 1,000 megawatts. The AESO current supply and demand report shows that many of these are often turned off completely.³

Cogeneration facilities are facilities constructed by large industrial operators that have a significant need for industrial-grade steam in their operations. Examples are oil sands plants, refineries and chemical plants. The gas is combusted and the hot fumes are used to generate steam to turn a turbine and generate electricity. The exhaust steam from these turbines is not sufficiently hot enough or at high enough pressure to generate any more electricity, but is very suitable for use in the plant’s industrial process to heat bitumen, refine crude oil into petroleum products or manufacture chemical products. The thermal efficiency of the operation is increased because one combustion of gas cogenerates for two uses, namely electricity and industrial steam. These cogeneration facilities are often referred to as “behind the fence,” since all of the equipment is contained within the site of the industrial operation. There are currently 33 such cogeneration operations in Alberta with a capacity of about 4,500 megawatts. They also tend to be base load, since the industrial operators need to operate them continuously in order to provide steam for their industrial processes.⁴

(c) Wind generation

Wind-generated electrical power can be classified as reliable in the long term, but unpredictable in the short term. The utilization factor (sometimes also called the reliability factor) is a number that shows how much electricity a facility actually produces versus the maximum it could produce if it always operated at its nameplate (or full) capacity. Wind facilities in Alberta have an average utilization factor of 35 per cent (AESO 2016).

This means that a wind facility with a nameplate capacity of 100 megawatts would not generate 100 megawatt years of electricity in a year, but rather would only generate 35 megawatt years of electricity. The output of such a wind facility at any point in time could be as low as zero per cent, or as high as 95 per cent, depending on wind conditions.

² See Alberta Electric System Operator “Current Supply Demand Report,” http://ets.aeso.ca/ets_web/ip/Market/Reports/CSDReportServlet.

³ *ibid.*

⁴ *ibid.*

Given this unpredictability, wind is not viewed as a base-load supplier. In fact, there must be a backup facility to provide electricity when the wind does not blow. The simple-cycle gas plants mostly provide this backup.

(d) Other generation

The final components of electricity supply in Alberta are hydro, biomass, solar and other. These are small suppliers with limited capacity (about 1,343 megawatts in total). The only on-grid solar supply comes from the Brooks solar facility with a capacity of 15 megawatts (AESO 2016).

(e) Utilization factors

Coal facilities had a utilization factor of 68 per cent in 2016 and gas facilities had a utilization factor of 51 per cent. These higher utilization factors represent their use as base-load suppliers.

In 2016, the utilization factor of simple-cycle gas generation was only nine per cent. This result is consistent with the peaking operation of simple-cycle gas generation (AESO 2016).

III. EXISTING MARKET FOR SELECTING SUPPLY

The current system for generating and pricing electricity in Alberta is relatively straightforward. The hourly price of electricity in Alberta is determined according to the economic principles of supply and demand. The wholesale market system is operated by the AESO.

Parties wishing to supply electricity submit their bids to the AESO, specifying the amount of power they are prepared to supply and the price they wish to receive for such power. These parties are well-known utilities (TransAlta, Enmax, etc.), companies with cogeneration facilities (Syncrude, Imperial Oil, Suncor, etc.) and other smaller independent power producers. The AESO arranges these bids in an ascending-order list, starting with the lowest price and ending at the highest price bid. This is referred to as the merit order.

As described by the AESO, the offer price of power dictates its position in the merit order, which determines whether the AESO will select the unit to run. Market participants choose offer prices based on the operational characteristics of the unit, the price of fuel, and other considerations of the unit operator.

Base-load-generation technologies typically adopt a price-taker strategy: they offer energy to the market at a low price and produce energy in the majority of hours.

Peaking generation technologies adopt a scarcity-pricing strategy: they offer energy at a higher price and only produce energy when strong demand drives the pool price higher. The combustion turbines used in simple-cycle gas generation can halt and restart operation without incurring high costs, but they cost more to operate. These higher costs are reflected in higher offer prices, which position peaking-generation capacity late in the merit order. Peaking generation will only be dispatched to run during periods of high demand, after lower-priced generation has been completely dispatched. Peaking generation operates in fewer hours than base-load generation does but achieves higher average revenue (AESO 2016).

Wind generation is offered at very low prices, since the marginal cost to produce is minimal. This ensures that the wind power will be selected to run, since its bid price is at or near the bottom of the merit order.

The combination of offer strategy and market conditions determines the achieved price that each asset type receives.

After receiving these supply offers, the AESO then makes an assessment of the demand for power at that point in time. It then selects bidders from this merit order until the power amounts in the selected bids in total are sufficient to meet this electricity demand. Each selected bidder then supplies the amount of power in its bid. Successful bidders each receive the same price, namely the price bid by the last selected bidder. This price is referred to as the clearing price. Bidders that are not selected do not supply and receive no compensation. Readers will no doubt recognize that this is a classic auction process, which is sometimes referred to a single-price auction as there is one single clearing price given to all suppliers.

Since electricity demand constantly varies, the AESO must repeat the above process every minute to ensure that electricity supply exactly equals electricity demand. Clearing prices are determined every minute and are then averaged each hour to determine the price to be paid to the pool of suppliers who supplied in that hour.

To give readers a sense of what in-total prices result from this process, the average annual pool price in 2016 was 1.828 cents per kilowatt hour (kwh). This price is significantly below the corresponding 2013 average annual pool price of 8.019 cents per kilowatt hour (AESO 2016).

This large drop in electricity price is due to both a decrease in demand and an increase in supply. The decrease in demand is due to the drop in industrial activity caused largely by the drop in oil prices. The increase in supply is due to the construction of new suppliers, combined with the decrease in the price of natural gas (AESO 2016).

IV. CHANGES NEEDED TO ACHIEVE POLICY GOALS

In 2015 and 2016, the government of Alberta made several announcements regarding changes to the electricity market in Alberta. The key changes are as follows:⁵

- (1) The phase out of coal generation by 2030.
- (2) Approximately 2,400 megawatts of coal-fired generation will convert to natural-gas-fired units in the early 2020s.
- (3) The addition of 5,000 megawatts of renewable electricity generation by 2030.
- (4) The introduction of a capacity market in addition to the existing energy market. This capacity market is intended to encourage investors to build new electricity capacity in Alberta by providing additional revenue to them to build such capacity. This introduction of a capacity market was recommended by current and potential energy investors, external experts, consumer groups, and the AESO.
- (5) A cap of 6.8 cents per kilowatt hour on the Regulated Rate Option, which is the default electricity contract available to most Alberta electricity consumers. From June 1, 2017 to May 31, 2021, should the market price of electricity rise above 6.8 cents, consumers on the regulated rate will not see an increase on their bills.

The first question to be asked is, what will the generating capacity of the Alberta electrical grid look like in 2030?

⁵ See Alberta Energy Department website, “Electricity”; and Alberta Electric System Operator, “Long-Term Outlook,” 2017, www.aeso.ca/download/listedfiles/AESO-2017-Long-term-Outlook.pdf.

The AESO 2017 Long-Term Outlook sets out a base-case forecast showing the anticipated changes to the generating capacity in Alberta for 2032, as reproduced in the table below. The “coal to gas” line refers to the conversion of boilers in existing coal plants from burning coal to burning natural gas. The transition from 2017 to 2032 is as follows.

	2017 Capacity, MW	2032 Capacity, MW	Additional Investment, MW
Coal	6,299	0	-6,299
Gas cogen	4,934	5,204	270
Gas combined cycle	1,746	5,386	3,640
Gas simple cycle	916	1,486	570
Coal to gas	0	2,371	2,371
Wind	1,445	6,445	5,000
Solar	0	700	700
Hydro and Other	1,373	1,723	350
Total	16,713	23,315	6,602
Peak Load	11,458	13,486	

Source: Alberta Electric System Operator, “Long-Term Outlook,” 2017, www.aeso.ca/download/listedfiles/AESO-2017-Long-term-Outlook.pdf.

It is important to note that 12,901 megawatts of the anticipated capacity in 2032 does not currently exist in 2017. More specifically, this will require an additional 6,050 megawatts of renewables and 6,851 megawatts of gas generation. This new gas capacity is needed for two reasons: (1) to replace coal as a base-load supplier; and (2) to provide backup when wind and solar are not operating (the proverbial cold, windless January night).

This huge need for new generating capacity in 2032 will require significant steps to encourage the investment needed to create this new generating capacity.

The second question is, what changes to the pricing mechanisms will have to be made in order to encourage the investment in new generating facilities to achieve this new generating capacity? The short answer has two components:

- (1) a program to encourage renewables; and
- (2) the introduction of the capacity market.

The first change is the compensation for renewable energy investment. On March 31, 2017, the Alberta government launched its Renewable Electricity Program and updated the renewable electricity requirement to 5,000 new megawatts of capacity.⁶

Part V of this paper will describe the system for the first round of bidding that took place in the fall of 2017, as well as the proposed second and third rounds to take place in 2018.

The second change will be the use of a so-called capacity market, in which a producer is not only compensated for the electricity it produces, but also for the capacity that it provides to be available to the electrical grid. This compensation for capacity would be paid even if the supplier does not actually generate and sell electricity. Part VI of this paper will discuss this capacity market in more detail.

The third question is, how will the guaranteed price of 6.8 cents per kilowatt hour be paid?

In essence, it appears that the government of Alberta has proposed the following bargain to the consumers of electricity in Alberta. The consumer will not have to pay high electricity

⁶ Alberta Energy Department website, “Electricity.”

prices; any amounts in excess of 6.8 cents per kilowatt hour will not be paid by the consumer. Albertans will, however, have to pay a carbon tax, and the government will use that revenue to subsidize renewable energy and other related electricity costs. If market forces drive the price above 6.8 cents per kilowatt hour, then the government will pay a subsidy to electricity producers using public funds to ensure the cap of 6.8 cents per kilowatt hour is maintained. These subsidies will include payments to companies for stranded coal assets, as well as payments for renewable supply.

V. THE RENEWABLES PROGRAM

(a) Background

The AESO 2017 Long-Term Outlook forecasts an additional 6,050 megawatts of renewable energy sources by 2032. Specifically, it forecasts an additional 5,000 megawatts of wind, 700 megawatts of solar and 350 megawatts of hydro. To put this in context, Ontario currently has 4,213 megawatts of wind (11 per cent of total generating capacity) and 380 megawatts of solar (one per cent of generating capacity) on the Ontario grid. Wind supplies six per cent of electricity and solar 0.4 per cent.⁷

The policy objective of 30-per-cent renewable energy by 2030 is guided by certain engineering facts. As mentioned earlier in the paper, wind power in Alberta has an average utilization factor of 35 per cent. Locations in the south of Alberta may have higher-than-average utilization factors.

Solar power has a utilization factor that is dependent on location (the farther away the facility is from the equator, the lower the factor), as well as location conditions (cloud cover and snow will reduce the factor). Alberta's highest solar-utilization factors occur in the southeast part of the province.⁸ Ontario's experience for solar's utilization factor is 15 per cent.⁹

The implication of these engineering realities is that it will be difficult for solar energy to be competitive with wind energy on a straight-up price-per-kilowatt-hour basis. The recent auction for renewable power in Ontario in March 2016 bears this out. The price for wind was about 8.6 cents per kilowatt hour versus solar's price of 15.7 cents per kilowatt hour.

(b) The Renewable Electricity Program (REP 1)

The government of Alberta has given the task of implementing the Renewable Electricity Program to the AESO. The AESO requested a first round of bids to be submitted in the fall of 2017 to yield an installed capacity of 400 megawatts, a process called REP 1. The AESO indicated that REP 1 would ask bidders to bid a price that will be guaranteed for the life of the contract of 20 years. The actual term used is a "contract for difference," meaning that the AESO will pay the successful bidder an amount equal to the difference between the guaranteed price and the market price in the wholesale market for all other suppliers. Conversely, if the wholesale market price is higher than the guaranteed price, the renewable supplier must pay this excess difference back to the AESO.

⁷ See Ontario's Independent Electric System Operator website, "Supply Overview," <http://www.ieso.ca/en/power-data/supply-overview/transmission-connected-generation>.

⁸ See AESO, "Long-Term Transmission Plan."

⁹ See Ontario's Independent Electric System Operator website, "Supply Overview."

The AESO designed a three-stage process to deal with the many expected bidders.

The first stage was the Request for Expressions of Interest (REOI) by potential suppliers, which allowed the AESO to gauge the interest of industry in participating in this first round. This stage ended on April 21, 2017, and resulted in expressions of interest from about 80 parties. The expressions of interest were for both wind and solar, and came from parties in Alberta, in other parts of Canada and from outside of Canada.

The second stage was the Request for Qualifications (RFQ), which opened on April 28, 2017. In essence, the RFQ process was intended to ensure that the parties who would submit proposals are bona fide parties that meet the many non-price requirements required by the AESO to ensure that a proposer is properly qualified. These non-price requirements include things such as financial-capacity strength, previous experience in building renewable facilities, names of specific personnel and their expertise, confirmation that the proposers can have their supply operating by 2019, and other relevant considerations.

The third stage was for qualified bidders to submit bids based solely on price per megawatt hour (wholesale bidding is made in prices per megawatt hour, unlike consumer prices, which are per kilowatt hour). Bids were due by June 16, 2017, and results were announced on Dec. 13, 2017.

Twelve different bidders submitted bids for 26 projects with a capacity of 3,600 megawatts.¹⁰ The winning bidders were two companies based outside of Canada and one based in Edmonton. Bids amounting to almost 600 megawatts were accepted, all plans for facilities in southern Alberta. The capital cost for this 600 megawatts of capacity was about \$1 billion, or about \$1.6 million per megawatt.¹¹

This unit cost is less than existing wind projects, such as the \$2-million-per-megawatt unit cost for the 300-megawatt Blackspring Ridge facility built in 2014.¹² It would seem to support the view that capital costs for wind energy have dropped.

The winning bids and prices were as follows:

Capacity, MW	Winning Bidder	Unit Cost per MW
248	EDP Renewables (Spain based)	Not released
202	Capital Power (Edmonton)	\$1.6 million/MW
115	ENEL Spa (Italy based)	\$1.5 million/MW
31	ENEL Spa (Italy based)	\$1.5 million/MW

Sources: AESO (<https://www.aeso.ca/assets/Uploads/REP-Infographic.pdf>); Capital Power (<http://www.capitalpower.com/MediaRoom/newsreleases/2018/Pages/12-14-2017.aspx>); ENEL Spa (<https://www.enelgreenpower.com/media/press/d/2017/12/enel-to-build-146-mw-of-new-wind-capacity-in-canada-following-first-renewables-tender-win-in-the-country>).

The AESO release shows that the winning bids ranged from \$30.90 to \$43.30 per megawatt hour, with a weighted average price of \$37 per megawatt hour.¹³ The release from the Alberta government contrasted this price with the March 2016 auction price in Ontario of 8.5 cents per kilowatt hour (\$85 per megawatt hour) for wind power.¹⁴

¹⁰ AESO promotional release, “Alberta’s Renewable Electricity Program attracts lowest renewable pricing in Canada,” <https://www.aeso.ca/assets/Uploads/REP-Infographic.pdf>.

¹¹ Alberta government press release, “Alberta renewables auction record-setting success,” Dec. 13, 2017, <https://www.alberta.ca/release.cfm?xID=511572D67D28E-C09C-E3E6-BA37A772B4C34AF6>.

¹² See EDF EN Canada website, “Blackspring Ridge,” <https://www.edf-en.ca/project/blackspring-ridge-wind/>.

¹³ AESO, “Alberta’s Renewable Electricity Program attracts lowest renewable pricing in Canada.”

¹⁴ Alberta government, “Alberta renewables auction record-setting success.”

The interesting point to note is that there does not appear to be any public release as to the specific prices bid by the specific winning bidders. Perhaps this was done to protect the confidentiality of commercial information. It is very possible that these first-round bidders were prepared to take a lower return in the low single digits in order to be chosen as a winning bidder. A recent report from EDC Associates Ltd. released shortly after the results of REP 1 concludes that these winning bids may suffer from the so-called “winner’s curse” and that the AESO might anticipate that the REP 2 and REP 3 auction processes may result in prices higher than those in REP 1 (EDC Associates Ltd., 2017).

(c) Solar request for proposals

It is also interesting to note that no solar suppliers were chosen. As noted above, the lower utilization factor for solar versus wind (15 per cent versus 35 per cent) makes it more difficult for solar to be competitive with wind. To date, the only solar supplier to the Alberta grid is a 15-megawatt solar facility in Brooks. All other solar installations are small, off-grid residential and commercial projects, encouraged by various incentives from the government of Alberta.

With perhaps this point in mind, in May 2017 the government of Alberta issued a request for proposals (RFP) to provide solar power to about half of the more than 1,500 government-owned buildings and sites in Alberta that are currently being powered using non-solar renewable energy contracts that are expiring. The total consumption for the two contracts is 135,000 megawatt hours per year, which is approximately equivalent to 80 megawatts of solar capacity. This RFP is separate from the REP 1 process run by AESO. It appears that it is an effort by the government of Alberta to provide a separate opportunity for solar providers to achieve a successful bid without having to beat the price bid by wind suppliers.

The solar RFP is in process, but not yet complete. The government of Alberta has apparently invited submissions by June 2017 and was supposed to reduce these to a short list of five bidders or fewer by the end of 2017. It would then take the business plan submitted by this short list and negotiate with bidders to finalize the form of deal structure. It would then select the winning bids by the end of March 2018.¹⁵

In a recent development, the government of Alberta infrastructure group announced on Feb. 22, 2018 that the RFP for solar power had been cancelled. It further announced that a new program for solar power will be created that may use a combination of the contract-for-difference model, giving a guaranteed price for solar electricity, with the purchase of Renewable Energy Certificates (RECs) from the solar producer. This new program is to be announced by June 2018, with an estimated six-month process to reach a final award.

Lastly, as noted in a piece dated March 20, 2017 on the Alberta Power Market website:

“The solar industry was disappointed when the Province rejected its request that some of the procurement be carved out for solar. Instead, the Province maintained its position that at least this year’s procurement (REP 1) would be technology neutral... A solar carve out in the next procurement (this would be REP 2 and REP 3) is also a possibility. Clearly Alberta solar developers agree with us, given that there are currently 37 utility scale solar projects with an

¹⁵ Alberta Power Market blog, “Update On Alberta’s Solar PV Electricity Procurement,” June 5, 2017, <https://albertapowermarket.com/2017/06/05/update-on-albertas-solar-pv-electricity-procurement/>.

aggregate capacity of over 1450 megawatts under development in Alberta and that appear on the Project List maintained by the Alberta Electric System Operator.”¹⁶

It should be noted that the 37 utility-scale solar projects referred to above have not yet been approved for investment, let alone built. They are undoubtedly waiting for a pricing regime with a high enough price to make these projects economic. To date, such a pricing regime does not exist in Alberta.

(d) REPs 2 and 3

On Feb. 5, 2018 the government of Alberta announced REPs 2 and 3 as the next step towards the goal of 30-per-cent renewables by 2030. REP 2 will have a target of 300 megawatts, and will require a minimum 25 per cent indigenous equity ownership that must be maintained for a minimum of three years following commercial operation of the facility.¹⁷ REP 3 will have a target of 400 megawatts, and will be open to any bidder. The process for REP 2 and REP 3 will be similar to REP 1. Bids are due by October 2018 and selection will be made in December 2018. Target commercial operation date is June 30, 2021. All projects submitted in REP 2 and REP 3 must be able to connect to the existing transmission or distribution system.¹⁸

The inclusion of an Indigenous equity-ownership requirement has the goal, stated by the government, of creating jobs and economic benefits in Indigenous communities and across Alberta.¹⁹ The AESO has stated that a project may only compete in one of REP 2 and REP 3, but not both. Furthermore, REP 2 projects will be given priority in that projects participating in REP Round 2 will be assessed for their ability to connect to the existing system prior to a corresponding assessment being completed for REP Round 3 projects.²⁰ The government’s news release announcing the requirement does not describe how REP 2 bids will be evaluated versus REP 3 bids. In particular, it does not state if a bid in REP 2 will be selected even if it is at a higher price than a non-selected bid in REP 3.²¹ On February 2, 2018, the Alberta Minister of Energy asked the AESO to recommend certain terms for REP 2 and REP 3, including a pricing mechanism.²² On March 27, 2018, the Minister approved the AESO’s competition proposal and specifically directed the AESO to use the same price mechanism as in REP 1, namely a guaranteed price using an indexed renewable energy credit (referred to as an Indexed REC).²³ As with REP 1, the indexed portion means that 20% of the guaranteed price (representing an approximation of the percentage allocated to operation and maintenance costs) will be adjusted by any change in the Consumer Price Index for Alberta.²⁴

¹⁶ Alberta Power Market blog, “Sun is Rising on Alberta’s Solar Industry,” March 20, 2017, <https://albertapowermarket.com/2017/03/20/sun-is-rising-on-albertas-solar-industry/>.

¹⁷ <https://www.aeso.ca/market/renewable-electricity-program/rep-round-2/>

¹⁸ <https://www.aeso.ca/assets/Uploads/REP-Round-3-REOI-FINAL.pdf>

¹⁹ See Government of Alberta website, “Indigenous partnerships power renewable energy,” news release, February 5, 2018, <https://www.alberta.ca/release.cfm?xID=523590267E0EF-CD7B-06A1-90484C9730888A2E>.

²⁰ <https://www.aeso.ca/assets/Uploads/REP-Round-3-REOI-FINAL.pdf>

²¹ See Government of Alberta website, “Indigenous partnerships power renewable energy,” news release, February 5, 2018, <https://www.alberta.ca/release.cfm?xID=523590267E0EF-CD7B-06A1-90484C9730888A2E>.

²² Letter from Margaret McCuaig-Boyd, Alberta’s minister of energy, to David Erickson, president and CEO of the Alberta Electric System Operator, February 2, 2018, <https://www.aeso.ca/assets/Uploads/Alberta-Energy-direction-2018-02-02.pdf>.

²³ <https://www.aeso.ca/assets/Uploads/REP-Round-3-REOI-FINAL.pdf>

²⁴ <https://www.aeso.ca/assets/Uploads/03-29-18-Key-Provisions-of-the-RESA-R3>.

VI. THE CAPACITY MARKET

As manager of the Alberta electrical grid, the AESO has a key role in ensuring that there is always a supply of electricity that is adequate to meet electricity demand. It defines this key role in two ways.

First, it requires the Alberta grid to have a reserve margin of capacity so that the grid has a certain level of generating capacity. This concept is described in its recent 2017 Long-Term Outlook (LTO):

For the purposes of the 2017 LTO, a reserve-margin target of 15 per cent is assumed.

A reserve margin is a comparison of generation supply and demand in Alberta. It is a calculation of the firm-generation capacity that is in excess of annual peak AIL demand, expressed as a percentage of the peak demand. Firm generation is defined as installed and future generation capacity, adjusting for seasonal hydro capacity, and excludes wind and solar capacity.²⁵

Second, the AESO has set an objective for the amount of outages due to inadequate supply that it is prepared to tolerate in Alberta. It has rejected the tests of number of outages in a given time or the amount of megawatts not available per time. Instead, it has adopted a test of amount of unserved energy per year that is not supplied.

An initial working assumption of 100 megawatt hours per year of expected unserved energy was established. Following additional review of historical data, the AESO is revising this working assumption to 400 megawatt hours per year (AESO 2018b).

The specific response of the AESO to achieve this policy objective is to introduce the concept of a capacity market to the Alberta grid. The purpose of the capacity market is to ensure there will be an adequate supply of electricity to meet the province's demand (AESO 2017).

The capacity market was requested by industry and was announced by the government of Alberta in November 2016.²⁶

The stated rationale for introducing a capacity market is that the current energy-only market will not give sufficient incentive to investors to make the investments need to transition to the electrical grid of 2030 (i.e., no coal, 70-per-cent gas and 30-per-cent renewables). It will protect consumers from price volatility and provide a reliable supply of electricity at stable, affordable prices.²⁷

The AESO notes that (AESO 2017):

“Intermittent generation sources such as wind and solar do not provide the same level of reliability as non-intermittent sources such as simple-cycle or combined-cycle gas-fired generation. It is often the case that wind and solar resources will be unavailable during Alberta peak loads, and therefore wind and solar additions are not assumed to contribute towards the target reserve margin. This assumption is not intended to provide an indication of the eligibility of these resources for the in-development capacity market.”

The interesting point is that the AESO agrees that wind and solar are not reliable enough to provide supply when needed, which is the precise stated rationale for paying investors to invest in capacity. Yet it goes on to state that a capacity market will compensate investors for investing in capacity.

²⁵ AESO, “Long-Term Outlook,” 2017.

²⁶ See Government of Alberta website, “Electricity capacity market.”

²⁷ *ibid.*

Specifically, the AESO states that the capacity factor for renewables for a year will be the amount of electricity produced by the renewable capacity during the 100 tightest supply-cushion hours in that year. This capacity factor for the previous five years will be averaged and then multiplied by the nameplate capacity of the renewable facility to create the capacity number. For example, if the average five-year capacity factor were 35 per cent and the nameplate capacity were 100 megawatts, the capacity factor to be used in capacity-market bidding would be 35 per cent of 100 megawatts, or 35 megawatts (AESO 2018b).

The interesting point to note is that despite this calculation using past history, there is no guarantee that the renewable capacity would be available when it is actually needed. It is more likely that the real reason for introducing a capacity market is to provide additional compensation to both gas and renewable suppliers.

Renewable suppliers only produce electricity 35 per cent of the time (wind) or 15 per cent of the time (solar). Future renewable auctions may not use the contract-for-difference guaranteed price model used in REP 1. Since they may well be unable to compete with gas generation in a straight-up energy price market, the renewables will need additional compensation for investing in capacity in order to meet the Alberta government's objective of 30 per cent of electricity from renewables by 2030.

Gas producers could produce electricity for virtually 100 per cent of the time. Some gas will be used all the time as base-load supply. Gas capacity will be turned back when demand is low and/or renewables are producing. Such gas capacity will provide backup supply that is not needed that frequently but is required for peak demand periods. In Ontario for example, there is a gas plant at Lennox, Ont. near Kingston with a capacity of 2,100 megawatts that only operates a few days a year.²⁸

Simply stated, gas producers have stated that they require compensation for merely making the capacity available. In essence, this compensation is a form of insurance. It is similar to the financial concept in which a bank charges a standby fee when it makes a line of credit available to a borrower. The standby fee is paid even if the borrower never actually borrows money on the line of credit.

The actual mechanics of implementing this capacity-market feature are currently being designed. The AESO has engaged industry in a series of meetings and consultations. The AESO has published its current thinking in a document dated Feb. 13, 2018 called a Comprehensive Market Design (CMD).²⁹

The AESO believes that it will take two years to design the capacity market, another year to conduct the first procurement and an additional year to award the first capacity contract.

Simply stated, the current thinking is that energy producers with available capacity will bid in a single-price auction process similar to the energy market. The difference will be that producers in the capacity market will state that they will make capacity available (say, 100 megawatts) for a stated period of time (say, 12 months). In return, they will receive a payment for making this capacity available (for example, 1,200 megawatt months times \$X per megawatt months). This payment will be made even if the capacity bidder never produces a single kilowatt hour of electricity.

²⁸ See Ontario's Independent Electric System Operator website, "Supply Overview."

²⁹ See AESO website, "Comprehensive Market Design (CMD)," <https://www.aeso.ca/market/capacity-market-transition/comprehensive-market-design/>.

To get a sense of how much this capacity compensation might be, the CMD published by the AESO contained a table using \$139 per kilowatt year as a possible price for capacity.

Using this number would give the following energy-market compensation (assumed to be around the current 3.00 cents per kilowatt hour) and the following capacity-market compensation (cents per kilowatt hour) to gas and renewable suppliers. It shows that compensation from the capacity market would be a significant piece of producers' total overall compensation.

	Typical Gas Producer	Typical Wind Producer
Energy Amount	3.00	3.00
Capacity Amount	2.64	1.59
Total Amount	5.64	4.59

Source: AESO, "Alberta Capacity Market," January 26, 2018, <https://www.aeso.ca/assets/Uploads/Rationale-section-3.pdf>.

The capacity amount per kilowatt hour for the gas producer is higher than the capacity amount for the wind producer because the gas producer gets credit for its full nameplate capacity, whereas the wind producer only gets credit for its nameplate capacity multiplied by its utilization reliability factor (typically 35 per cent).

VII. THE BATTERY OPTION

As has been pointed out by countless energy analysts, the weakest aspect of wind and solar electrical energy is that these two sources are not reliable. The wind does not blow all the time and the sun does not shine all the time. Wind in particular is not only unreliable but unpredictable as well.

Up until now there has been no meaningful method of storing electricity. Any battery or other storage has been tiny in comparison to the required supply. As mentioned in Part VI, electrical-grid operators like the AESO and the IESO in Ontario have had to rely on gas-powered generation to provide backup electricity when renewables are not producing.

A recent development has been the introduction of large-scale storage batteries by Tesla in the United States. Tesla is best known as an electric-car manufacturer, and the recent introduction of its Model 3 car has received a lot of media coverage. But as its visionary president and CEO, Elon Musk, likes to say, Tesla also wants to change the way mankind generates energy, converting from fossil fuels to renewables. As a result, it has made a huge effort to increase the size and reduce the costs of lithium-ion batteries. Tesla has constructed a huge factory in Nevada that it calls its "Gigafactory" to produce a massive amount of lithium-ion batteries at a greatly reduced cost due to economies of scale.

These batteries were initially designed for use in Tesla's cars. Tesla then expanded their size for use as backup storage in residential homes, sold under the name "Powerwall." Tesla expanded the battery size yet again for use in utility electrical grids, with a product called a "Powerpack." Tesla has installed an 80-megawatt-hour Powerpack in a utility in southern California³⁰ and a 129-megawatt-hour Powerpack in South Australia.³¹ The Powerpack batteries will be charged

³⁰ Electrek news, "Tesla quietly brings online its massive – biggest in the world – 80 MWh Powerpack station with Southern California Edison," January 23, 2017, <https://electrek.co/2017/01/23/tesla-mira-loma-powerpack-station-southern-california-edison/>.

³¹ Tesla website, "Tesla Powerpack to Enable Large Scale Sustainable Energy to South Australia," news release, July 6, 2017, https://www.tesla.com/en_CA/blog/tesla-powerpack-enable-large-scale-sustainable-energy-south-australia.

using electricity from the grid during off-peak hours, when demand and prices are low, and then deliver electricity during peak hours when demand and prices are higher. This will help maintain the reliability of the grid and lower the utility's dependence on natural-gas peaking plants. More recently, in February 2018, Tesla proposed installing Powerwall batteries in 50,000 homes, offering combined storage capacity of about 650 megawatt hours in total.³² According to Tesla, the capital cost of these storage batteries is in the range of US\$500,000 per megawatt hour.³³

It is important to note that these three projects are still relatively small compared to the capacity needed for a large grid such as Alberta's. A simple calculation shows that backing up 3,000-megawatts capacity of wind generation with a 33-per-cent utilization factor would need a battery-storage capacity of about 16,000 megawatt hours. This calculation for a single day assumes a constant 1,000-megawatt demand, a production of 3,000 megawatts for eight hours of the day (one-third of the time reflecting the 33-per-cent utilization factor) that would supply the 1,000-megawatt demand and use the excess 2,000 megawatts to charge the batteries for the eight hours. This would put 16,000 megawatt hours of electricity into the battery. For the remaining 16 hours of the day when the wind did not blow, the 1,000-megawatt demand would be supplied by draining 1,000 megawatts for 16 hours from the 16,000 megawatt hours stored in the battery.

This would require a capital investment of about \$8 billion. Even this investment would only backup 1,000 megawatts of demand, or about 10 per cent of the Alberta grid demand of 10,000 megawatts.

The AESO has indicated that storage batteries will be eligible to participate in the capacity market if they can provide more than one megawatt for at least four hours (AESO 2018a).

More recently, Nova Scotia Power has started a pilot project to use Tesla's Powerpack batteries as a means of backup storage.³⁴ It is reasonable to assume that the planning people at the AESO are aware of these new developments in storage-battery capacity. It will be interesting to see if they pursue this concept further.

VIII. CONTRASTS BETWEEN THE ALBERTA AND ONTARIO ELECTRICAL SYSTEMS

Lastly, it is useful to compare Alberta's approach to the electricity market with the approach taken by Ontario.

The way Albertans think of their electrical future can perhaps be summed up in one phrase: "Whatever we do here in Alberta, please let us not do it like they did it in Ontario."

The first contrast between Alberta and Ontario is electricity pricing. As mentioned above, Alberta wholesale prices are currently in the range of two to three cents per kilowatt hour, with retail prices being about one cent higher at four cents per kilowatt hour. In 2016, retail prices in Ontario ranged from eight to 18 cents per kilowatt hour, depending on whether the electricity was consumed at peak periods, off-peak periods or periods between peak and off-peak.

³² Rich Smith, "Australia Doubles Down on Tesla," Yahoo Finance, February 25, 2018, <https://finance.yahoo.com/news/australia-doubles-down-tesla-164800647.html>.

³³ Inside EVs news, "Tesla Energy Reveals Powerpack Pricing, Starting From 200 kWh Of Storage," April 2016, <https://insideevs.com/tesla-energy-reveals-powerpack-pricing/>.

³⁴ Steve Silva, "Nova Scotia Power testing Tesla batteries in electrical system," Global News, February 8, 2018, <https://globalnews.ca/news/4014663/nova-scotia-power-testing-tesla-batteries-in-electrical-system/>.

These high prices were the cause of deep unpopularity of the Ontario government. More recently, the Ontario government has taken steps to reduce the prices to the range of 6.5 cents per kilowatt hour for off-peak and 13.2 cents per kilowatt hour for peak.³⁵

There are several reasons for these high Ontario prices. Much of Ontario's electricity comes from nuclear plants. The cost from the Bruce facility, for example, was 6.6 cents per kilowatt hour in 2016. Gas-fired supply averages 17 cents per kilowatt hour. Supply from wind (at 14 cents per kilowatt hour) and solar (at 48 cents per kilowatt hour) are a result of the government offering high-priced contract incentives for renewable suppliers. Still more charges come from the payment of debt-retirement charges for stranded debt left over after the break up of Ontario Hydro. Starting in 2016, residential customers are exempted from this charge.³⁶

The important thing to note is that all these higher prices in Ontario are paid for by the electricity consumer. The amounts show up in the bill they receive every month. The higher prices are very visible, and the Ontario consumers (who are also voters) have been very vocal in their reaction to these costs.

This is in direct contrast to the approach taken by the government of Alberta. Retail electrical prices are capped at 6.8 cents per kilowatt hour. Any costs in excess of this capped price will be paid by the taxpayers of Alberta through the payment of a carbon tax.

IX. CONCLUSION

The Alberta electrical grid is facing a number of fundamental changes in its future design. It will involve new players, the elimination of coal, an increase in renewables, a change in the form of compensation paid to producers, some potential new technology to provide backup power, and at least short-term price protection for consumers. Hopefully this paper has provided a roadmap for the reader to use as this future journey unfolds.

³⁵ See Ontario Energy Board website, "Historical electricity rates," <https://www.oeb.ca/rates-and-your-bill/electricity-rates/historical-electricity-rates>.

³⁶ See Bruce Power website, "Tools to help Ontarians get facts about electricity costs in the province," March 2, 2017, <http://www.brucepower.com/tools-electricity-costs/>.

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