Renewable Electricity Grids, Battery Storage and Missing Money: An Alberta Case Study

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In this study, we simulate a hybrid renewable energy system with battery storage to power the Alberta grid, to meet the province's goal of phasing out coal-fired power plants by 2030. In doing so, we study the optimal generation mix based on wind, solar, and load data, and we consider the so-called missing money problem in determining how Alberta will be able to facilitate a shift away from fossil fuels sustainably. We find that high carbon tax rates allow for higher levels of wind integration and introduce battery storage into the model, while solar energy remains economically infeasible. This allows the grid to depart from using combined-cycle gas plants to meet base load, though we find that combustion gas turbines are still necessary to act as peakers. One of economic consequence of this situation is that missing money problem is exacerbated, and then a compensation mechanism like the capacity market is necessary for the sake of electricity source adequacy and reliability. Despite this, renewable capacity factors in Alberta are potentially high, and as costs decline in the future, renewable energy will play a key role in meeting energy demand.

Acknowledegment:

JEL Codes: Q42, L94

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DRAFT: January 14, 2018

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Key Words: Renewable energy; missing money; generation mix; fossil fuels; capacity factor

JEL Categories: H41, L51, L94, Q42, Q48, Q54

1. Introduction

During the 21st Conference of the Parties (COP 21) in 2015, Canada's Prime Minister Justin Trudeau highlighted the key role that provincial and territorial governments would have in enabling Canada to achieve its lofty carbon emissions targets over the coming years (Office of the Prime Minister, 2015). While most Canadian provinces and territories have kept their greenhouse gas (GHG) emissions in check over the past 25 years, Alberta's emissions have risen to 274.1 megatons (Mt) of carbon dioxide (CO_2) equivalent as of 2015 – an increase of roughly 56% since 1990 (Government of Canada, 2017). This now comprises some 38% of Canada's overall emissions. Unchecked, Alberta's CO_2 emissions could rise to 320 Mt by 2030 (ECCC, 2012). The ability of Canada to meet its Paris commitment will require significant CO_2 reductions from Alberta.

Various industries can be targeted in such efforts. The bulk of Alberta's emissions come from its oil and gas industry, with more minor contributions coming from sectors such as agriculture and transportation. Although Alberta's natural resource sectors are large carbon emitters, much of their activity is designated as trade-exposed under international regulations. This means that policies aimed at reducing emissions in these industries may only serve to locate them elsewhere, resulting in continued CO_2 emissions at the cost of local economies. Emissions reduction efforts in these sectors may prove to be ineffective, or at the very least unpopular. In 2015, the electricity sector accounted for 17% of Alberta's total greenhouse gas (GHG) emissions. Most of these emissions came from coal-fired electricity generation. In the same year, coal and gas accounted for 38.6% and 44.3% of Alberta's total generating capacity, respectively (Table 1). In 2016, 62% of Alberta's power was generated by coal-fired power plants, which set the system marginal price in 69% of hours (Alberta Electric System Operator [AESO], 2017b)[1]. Regardless, the Alberta government has committed to eliminating its coal plants completely by 2030, in addition to replacing two-thirds of coal-generating capacity with electricity from renewable energy sources (Alberta Government, 2016).

In recent years, capacity additions in Alberta have been dominated by natural gas-fired facilities and wind turbines. Gas facilities have been built to support expansion in the Alberta oil sands. Many of these plants generate heat and use waste steam to generate electricity. This is referred to as cogeneration or combined heat and power (CHP; AESO, 2017a). Conversely, only six percent of Alberta's electricity currently comes from wind generation. Despite the relatively low level of installed capacity, Alberta has a long history of utilizing wind energy to generate electricity. The planned decommissioning of coal-fired power plants in Alberta presents an opportunity to further invest in wind power. The Canadian Wind Energy Association (CanWEA) notes that while

[1] In the Alberta wholesale electricity market, generators offer to sell electricity to the power pool (or spot market) and retailers bid to buy power, similar to an open stock market.

Alberta currently has an installed capacity of 1,445 megawatts (MW) of wind generation, at least 4,000 MW of new wind generating capacity will need to be built to compensate for the loss of capacity described above (CanWEA, 2017). AESO anticipates that removal of coal-fired capacity will lead to 5,000 MW of new wind capacity (Table 1).

The solar photovoltaic (hereafter referred to as "solar") energy market in Alberta is not as well developed, with an installed capacity of roughly 20.2 MW in 2016 (Howell, 2017). However, solar power has great potential in Alberta – a study undertaken by the Pembina Institute notes that solar irradiance levels in some parts of Alberta are as high as the sunniest parts of the United States (Hastings-Simon, 2016). Initially, the AESO did not anticipate significant increases in solar generating capacity to replace the loss of coal-fired power, but its most recent studies foresee 1,000 MW of installed solar PV capacity within two decades, compared with 5,000 MW of wind capacity (Table 1). From Table 1 and Figure 1 of Appendix A, it is shown that CC gas and wind will see the greatest increase in capacity over the next 20 years.

Table 1: Current and Anticipated Changes in Generating Capacity, Alberta Electric System (MW)[a]

Year	Coal	Cogen	CC gas	GT	Coal-to-Gas	Hydro	Wind	Solar	Other[b]	Total
2017[c]	6,299	4,934	1,746	916	0	894	1,445	0	479	16,713
2022	3,849	5,024	1,746	1,059	1,581	894	3,045	200	479	17,877
2027	2,904	5,114	2,656	1,249	2,371	894	5,045	400	479	21,112
2032	0	5,204	5,386	1,486	2,371	1,244	6,445	700	479	23,315
2037	0	5,339	6,751	2,769	790	1,244	6,445	1,000	479	24,817
Change	-6,299	405	5,005	1,853	790	350	5,000	1,000	0	8,104

[a] Cogen refers to cogeneration which is used primarily in industrial plants; CC gas provides baseload power; GT refers to fast-responding (peak load) gas turbines.
[b] Includes mainly biomass and possibly some solar.
[c] Future capacity as of the end of the year; existing capacity includes projects under construction.
Source: (AESO, 2017b)

A stumbling block in the development of renewable resources globally is the inherent problem of intermittency. Wind and solar sources cannot be reliable as either baseload sources of electricity or for addressing peak demand (van Kooten, Duan, & Lynch, 2016) and thus integration into the grid has proven problematic for many countries (Timilsina, van Kooten, & Narbel, 2013). One proposed solution for overcoming intermittency has been to store intermittent power behind hydroelectric dams or, if such storage is unavailable, in grid-scale batteries. Battery systems provide a wide range of support services for power systems such as frequency response, reserve capacity, black-start capability and other grid services. In the longer-term, grid-scale batteries can be used to store surplus power during off-peak times for use during periods of higher demand. This could be especially useful for electricity grids that rely significantly on such renewable energy sources, which would otherwise need to be sold at very low or even negative prices, like in Denmark where wind power generates over 100% of its electricity demand (Neslen, 2015).

If Alberta's government intends to replace 30% of its generating capacity (or more) with renewable sources, some form of energy storage technology will likely be necessary to maintain a reliable power supply throughout the province. Lithium-ion (Li-ion) batteries with a lifespan of 3 to 15 years are preferred for storing variable electricity because they have a high energy density, low self-discharge and high charging efficiency (Sabihuddin, Kiprakis, & Mueller, 2015). However, widespread adoption of such batteries has been hampered by often prohibitive costs. The world's largest grid-scale battery was constructed in South Australia in 2017. It has a capacity rating of 100 MW and can store 300 MWh of power or operate for three hours at maximum capacity. It cost between $150 - $180 million or $500 - $600 per kWh (Adams, 2017). Looking forward, Li-ion battery costs for stationary applications are expected to fall to below $200 per kWh by 2030 for installed systems. (Ralon, Taylor, & Ilas, 2017).

One of the economic consequences of the greater integration of renewable energy sources is the so-called missing money problem (Joskow, 2013). The marginal costs associated with renewables is very low, and higher integration lowers the market price of electricity so that conventional fossil-fuel assets, such as coal and gas plants, lose market share and can no longer recover fixed costs, especially when there is a market price cap such as that of Alberta ($1000/MWh; Pérez-Arriaga, 2013). In essence, there is a reduction in quasi-rent so investors have inadequate incentive to invest in fossil-fuel assets that are necessary as a capacity reserve in situations where the output from renewables is insufficient to meet demand. Additionally, there is growing concern over resource adequacy, as evidenced by shrinking reserve margins in Texas (Kleit & Michaels, 2013). One solution is to create a capacity market in which conventional fossil fuel plants are incentivized to provide needed capacity. (Hildmann, Ulbig, & Andersson, 2015). In Alberta, a capacity market is planned for 2019 to satisfy capacity adequacy requirements and to provide revenue to investors in addition to the earnings from energy markets (AESO, 2016). However, this may not be the most efficient approach. Indeed, evidence from the British experience shows that capacity payments could lead to excessive procurement (Newbery, 2016).

As costs continue to decline, renewables are expected to replace conventional base-load generators, but gas-fired generators will still be needed for reliability (instead of coal). Hybrid renewable energy systems (HRES) that combine intermittent wind and solar energy and battery storage have previously been employed as stand-alone power systems to meet small loads. Given the projected future downward trend in renewable energy and storage costs, it might be possible to configure such a system to meet Alberta's enormous demand for energy at reasonable prices, while accomplishing its medium-term goal of eliminating coal power entirely. In this study, we investigate the potential to use energy from wind and solar sources, with battery storage, to meet

Alberta's goal of eliminating coal plants without having to replace more than one-third of coal capacity with natural gas, and the ensuing issues related to this. If a system with even a small proportion of natural gas generation can succeed, the missing money and related capacity payment design problems may no longer be serious issues. With only a small amount of gas generation remaining in the system, the less money will be "missing", and the scale of capacity payments will be much smaller.

2. Methods

We begin by assuming that the independent AESO makes decisions regarding investments in electrical generating capacity, and then allocates generation in each hour in least-cost fashion to meet a pre-determined load. The operator's objective is to minimize total cost such that exogenous demand (D_t) is met in each period:

$$(1) \qquad \mathrm{TC} = \sum_{r\in\{w,s\}}\left[f_r N_r + \sum_{t=1}^{T} v_r N_r P_{r,t}\right] + \sum_{j\in\{GT,CC\}}\left[f_j K_j + \sum_{t=1}^{T}(\tau\varphi_j + v_j)\; P_{j,t}\right] + f_b K_b + \sum_{t=1}^{T} v_b b_t^- \,,$$

where TC refers to the total cost of the hybrid renewable energy system; T is the number of hours in a one-year time horizon (8,760); v_i and f_i (i=w, s, GT, CC, b) refer to the variable and fixed costs of obtaining power from wind (w), solar (s), open-cycle gas combustion turbines (GT), combined-cycle (CC) gas plants and battery storage (b) respectively; N_w and N_s refer to the number of wind turbines and solar modules to be installed, and K_j and K_b refer to the installed capacity of gas facilities (MW) and energy rating (size) of the battery[2] (MWh) to install, respectively; τ refers to the carbon tax used as an incentive to remove fossil-fuel capacity and invest in renewables and a battery; φ_j is the amount of CO_2 emitted (tons) when producing one MWh of electricity from energy source j; $P_{r,t}$ refers to the electricity produced by each renewable unit N_r, $P_{j,t,}$[3] refers to the amount of power produced from a gas source; and b_t^- refers to power provided out of battery storage.

Costs are determined exogenously for each energy source, while the energy provided each hour by one unit of wind and solar generation are exogenously determined (based on wind and solar data). The AESO decision maker chooses the number of wind turbines and solar panels to install. It also selects the size of the Li-ion battery and the flow of energy into and out of the battery in each hour, plus the overall capacity of gas generation and the hourly production of electricity from natural gas. These choices are naturally affected by the constraints facing the decision

[2] Since we examine a one-year period, fixed operation and maintenance costs are incorporated into the capital cost.

[3] $r \in \{w, s\}$; $j \in \{GT, CC\}$

maker.

The system constraints are as follows:

(2) $\sum_{r\in\{w,s\}} N_r P_{r,t} + \sum_{j\in\{GT,CC\}} P_{j,t} + b_t^- \geq D_t + b_t^+$ Demand is met every hour

(3) $V_t = V_{t\text{-}1} + \delta b_{t-1}^+ - b_{t-1}^-$ Battery operating equation

(4) $V_t \leq d_b K_b$ Energy stored in battery cannot exceed the capacity of the battery

(5) $b_t^+ \leq d_b K_b$ Charge to the battery cannot exceed the capacity of the battery

(6) $b_t^- \leq K_b$ Discharge from the battery cannot exceed the power rating of the battery

(7) $P_{j,t} \leq K_j \; \forall j$ Power produced by a gas source *j* cannot exceed available (endogenously-determined) capacity

(8) $P_{j,t} \leq P_{j,t\text{-}1} + r_j{*}K_j \; \forall j$ Ramping up constraints for all *j*

(9) $P_{j,t} \geq P_{j,t\text{-}1} - r_j{*}K_j \; \forall j$ Ramping down constraints for all *j*

In constraint (2), b_t^- denotes the discharge from the battery at time *t* to meet demand and b_t^+ denotes the flow of energy into the battery (charge) at *t* if there is too much power available to the grid – the Alberta load must be met in each hour. Constraint (3) is the dynamic equation that indicates the available energy in the battery at time *t* (V_t), where $\delta = 0.86$ is the roundtrip efficiency of the battery (Lazard, 2017b). The energy available in period *t* equals that of the previous period plus any loss or gain in charge, with gains in energy multiplied by the roundtrip efficiency (loss due to the operation of the battery). The battery cannot charge and discharge at the same time, which is satisfied via constraints (2) and (3). The variables in constraint (3) are all non-negative, which guarantees that discharge b_t^- from the battery cannot exceed the current energy V_t available in the battery. Constraints (4), (5) and (6) concern the battery's power rating and capacity (power rating times duration), where K_b is the power rating in MW, d_b is the battery's duration which is assumed to be eight hours (U.S. Energy Information Administration [EIA], 2017a). The term $d_b K_b$ is the battery's capacity in MWh. In equations (8) and (9), r_j is the ramping rate for fossil fuel generators. Advanced GT are assumed to ramp to their full capacity within an hour, while CC gas facilities are assumed to ramp up to 40% capacity per hour (Gonzalez-Salazar, Kirsten, & Prchlik, 2018). By solving the program given by equations (1) through (9), we find the optimal combination of wind turbines and solar modules to construct, the capacities of GT and CC gas facilities to install, and the size of the battery, given the exogenously determined parameters and data.

The capacities of wind turbines and solar panels vary by location. We divided the province into three wind profile regions (southwest, southeast and north) to reflect different average wind speeds, and three solar regions (south, central and north[3]), to reflect different latitudes. Optimal capacities of wind and solar to install are chosen for each of the respective regions, while choice of GT and CC gas facility capacities is not location-dependent.

These decisions are determined for each year over the period 2006-2015 as they depend on the observed load and actual wind profile and solar intensities for each year. Thus, optimal capacities, system costs and CO_2 output are determined for every year over the decade for which we have data. The ten years of data and ten separate models we run allow us to test scenarios (as described below) for a number of years, as it is likely in practice that renewable yield and energy demand may change from year to year.

Load

Total Alberta internal load (AIL) has risen by nearly 1.6% annually between 2006 and 2015. About a third of total AIL can be attributed to the industrial sector and a fifth to commercial activity, with the remainder to residential and farm customers.[4]

Annual peak demand usually during winter when electricity is required to run heaters, furnaces and lighting. Load data for 2006 through 2015 indicate peaks of about 11,500 MW occurring in December. During a given day, demand is highest in early evening hours and then falls into the night, rising again to a lower peak in the early morning. However, demand does not fluctuate as dramatically as in other regions because of Alberta's high industrial demand, which remains more or less constant throughout the day. Average hourly demands during daytime hover between 8,700 to 9,000 MW (AESO, 2017a). Additional details regarding AIL are found in

[3] The northern regions for wind and solar are not identical.

[4] Average AIL decreased slightly between 2015 and 2016, but winter peak load set a record at 11,458 MW. Slowing load growth since 2014 can be attributed to mild winter weather and decreased industrial activity throughout Alberta, particularly in the oil sands (AESO, 2017a).

Appendix A.

Costs

The levelized cost of electricity (LCOE) measures the net present cost of producing electricity ($/MWh) once overnight construction costs, fixed and variable operations and maintenance (O&M) costs and fuel costs are averaged over the expected lifetime output of a generator. This depends on forecasts of the generator's expected lifespan and capacity factor (CF)[5]. This measure accounts for differences in these factors to facilitate cost comparisons among generators. For instance, while fuel costs of wind and solar power are negligible, such assets are expensive to build and have CFs that can vary considerably with location. Nonetheless, LCOEs of intermittent renewables are gradually reaching the point at which they are equal to, or lower than, the cost of purchasing electricity from the grid (i.e. grid parity). The costs of intermittency cannot be adequately captured, however. These mainly involve the indirect costs that intermittent renewables impose on remaining assets as they are integrated into the grid (van Kooten, 2016). Estimates of the LCOE for the different sources of energy used in this study are provided in Table 2. We apply these estimates even though they largely originate in the U.S.

Table 2: Levelized Cost of Electricity Estimates for GT, CC Gas, Solar, Wind and Battery Power (US$2016 per MWh)

Type	Min. LCOE ($/MWh)	Max. LCOE ($/MWh)
GT [a]	70.7	174.7
CC gas[a]	36.4	42.4
Solar[a]	67.7	135.3
Wind[a]	40.4	180.8
Lithium-ion Battery[b]	261	338

[a] Source: "2017 Annual Technology Baseline (ATB) Cost and Performance Summary" (National Renewable Energy Lab [NREL], 2017). The original values are in US$2015 and are converted to US$2016 according to Bureau of Labor Statistics consumer price index.
[b] Source: Unsubsidized LCOE estimated to vary from $261-$338/MWh in US$2016 if battery serves as distribution devices, or $268-$347/MWh if the battery serves to replace peaker plant output (Lazard, 2017b).

[5] The capacity factor refers to the power actually produced over a year divided by the potential power that would be produced if the source operated at its nameplate capacity.

Before we proceed, a note on data is necessary. Considering the LCOE measure, renewable energy sources are nearly cost competitive with conventional fossil fuel generation. When social welfare measures like carbon footprints are considered, renewables are even more attractive. However, LCOE measures used are based on ideal production environments and CFs. The ability of renewables to achieve low LCOE depends on the design of the respective power systems. In our model, we use overnight building costs and fixed and variable O&M costs to compute the total costs of the power system. The better our model performs, the lower LCOE we can achieve. Bodies such as the EIA are continuously updating the cost estimations of new utility-scale plants. We use the most recent and optimistic evaluations of generation costs for our purposes.

Table 3: Cost of Electricity Estimates for GT, CC Gas, Solar, Wind and Battery Power (US$2016 per MWh)

Type	Overnight Capital Cost ($/kW)	Fixed O&M ($/kW/yr)	Variable O&M[c] ($/MWh)	Emissions[d] (tCO_2/MWh)	Facility Life[e] (years)
GT[a]	678	6.8	58.8	0.52	20
CC gas[a]	1,104	10	37.5	0.334	20
Solar[a]	2,534	21.8	0	0	30
Wind[b]	1,867	39.7	0	0	20
Lithium-ion Battery[b]	3,122[f]	40	8	0	20

[a] Source: "Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants" (EIA, 2016).
[b] Source: "Capital Cost Estimates for Additional Utility Scale Electric Generating Plants" (EIA, 2017a).
[c] Source: Variable O&M costs, including fuel-related costs, retrieved from "Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2017" (EIA, 2017b).
[d] Source: The emission is converted from 117 lb/MMBtu to t/MWh by using corresponding heat rates reported in "Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants" (EIA, 2016). The heat rates for GT is 9,800, and that of CC gas is 6,300. CC gas is more efficient than turbines.
[e] Source: "Lazard's Levelized Cost of Energy Analysis—Version 11.0" (Lazard, 2017a) and "Lazard's Levelized Cost of Storage Analysis—Version 3.0" (Lazard, 2017b).
[b] Source: "Capital Cost Estimates for Additional Utility Scale Electric Generating Plants" (U.S. Energy Information Administration (EIA), 2017a). The estimated cost of battery storage has increased from $2,813 to $3122/kW due to increases in battery duration from 2 to 8 hours.

Overnight costs are converted to annualized fixed capital costs by using a five percent discount rate. Annualized fixed capital costs and fixed O&M costs are combined into an overall annual fixed cost. In addition, Alberta has raised its carbon tax to $30/$CO_2$, and for large thermal power generators, a carbon tax is applied under Alberta's Carbon Competitiveness Incentive Regulation (Government of Alberta, 2018). Under this, a generating asset needs to pay for the difference between its CO_2 emissions and those of the cleanest gas plant (Howie et al., 2017). However, for simplicity, we assume that the $30 carbon tax (roughly US$24 using 2018 exchange rates) is directly imposed on the emission, thereby raising the variable cost of the fossil fuel generators. Consequently, we can examine how changes in carbon taxes influence the optimal generation mix.

Solar data

Despite Alberta's high latitude (which usually does not bode well for solar power potential), its sunny summers and cold (but also sunny) winters are conducive to solar cell performance (Eisenmenger, 2011). While Ontario is arguably the nation's leader in solar technology (for example boasting the Sarnia Photovoltaic Power Plant), Alberta's solar potential could be harnessed under a new renewable energy scheme. Indeed, the potential of total concentrating solar power (CSP) in Alberta is about 9,177 TWh/year (terawatt-hours per year) on land with slopes of less than four percent (Djebbar et al., 2013)[6].

Solar resources are most abundant in southeastern Alberta, with average annual direct normal irradiance (DNI; $kWh/m^2/y$) levels of over 1,800 in Lethbridge and Medicine Hat. Due to the sunny climate and proximity to various large transmission lines, several large solar plants are currently planned for southeastern Alberta. One such plant, located in Brooks, is worth $30 million and has a capacity of 15 MW (or 50,000 solar panels). This will be the largest solar project in Western Canada (Bakx, 2017).

In this study, we employ data from the Canadian Weather Energy and Engineering Datasets (CWEEDS), which provides annual data on a range of meteorological elements, recorded hourly at about 10 km grid spacing (Government of Canada, 2017a).[7] Based on this data, we determined the potential power output of a single 220W module in north, central, and southern Alberta; this is provided in Figure 1 for the each of the years in our time horizon (see also Appendix Table B1). The solar energy outputs were calculated by using the PVLIB package in Python, developed by Sandia National Laboratories (Holmgren et al., 2015)[8]. The choice of solar panel is expected to play a minor role in determining the optimal generating mix in the current study.[9]

[6] It would of course be unreasonable to expect all this land to be covered by solar panels. A large PV farm has a capacity-weighted average land use 7.9 acres/MW_{AC} (denoting nominal power output converted to AC) and a generation-weighted average land use 3.4 acres/GWh/yr (Ong et al., 2013).

[7] Given the slight mismatch with our data on load and wind (2006-2015), we use actual solar data for 2006-2014 but, for 2015, we use the 2005 solar irradiation profile.

[8] PVLIB Python is a community-supported tool that provides a set of functions and classes for simulating the performance of photovoltaic energy systems. PVLIB Python was originally imported from the PVLIB MATLAB toolbox developed at Sandia National Laboratories.

[9] The module we chose may not the best choice and it is relatively conservative, but we chose this module to account for other factors that will affect the module performance, such as shading and transmission loss.

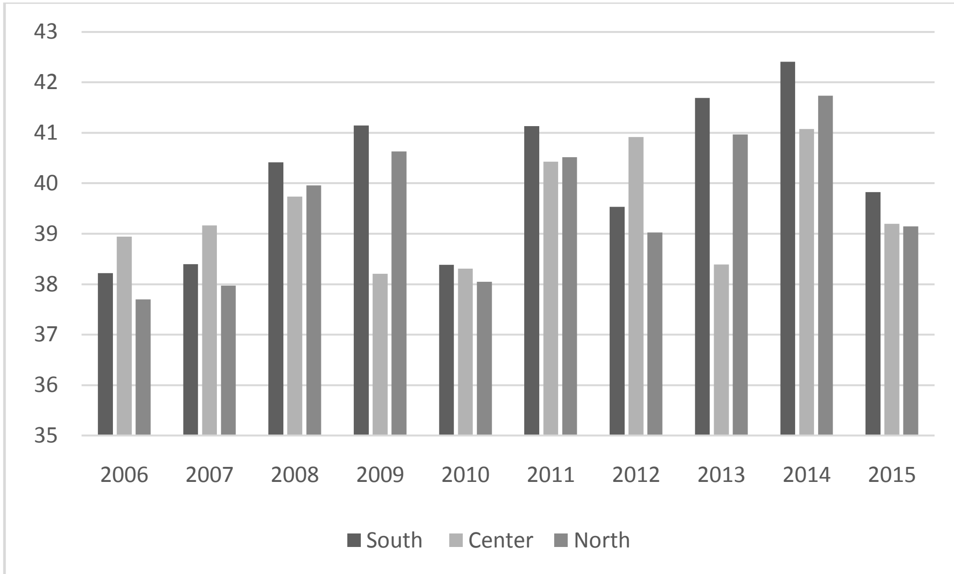

Figure 1: Potential Average Hourly Energy (W) Output of A 220W Solar Panel

The highest potential solar output occurs in southern Alberta. The average hourly CF in 2014 (over the five to six hours of daily sunlight on average) of this region was about 90%.

Wind data

Alberta has a long history of utilizing wind as an energy source. In 2017, Alberta was the third-largest wind market in Canada, with an estimated 1,445 MW of installed capacity (AESO, 2017b). However, more could be done to integrate additional wind generating capacity. In a 2017 auction, 600 MW wind power projects received a price of $37 per MWh in Alberta, which is the lowest price for wind power in Canada (although these projects were provided with subsidies from the Alberta government; Ward, 2017). For our purposes, wind speed data were collected from 17 locations in Alberta (Government of Canada, 2017b), and an average was taken across three regions (southwest, southeast and north) over a period of ten years, from 2006 to 2015. Conversion of the available mechanical energy (wind speed) to electricity is based on the technical specifications for a 3.5-MW capacity Enercon E-101 wind turbine (van Kooten et al., 2016).[10] Modelled values of wind power from a 3.5 MW turbine demonstrate that the average CF over the ten years of observed data was roughly 32%. To put that in perspective, the average CF of wind in California is about 20% (Rosenbloom, 2016).

The average hourly energy output for each of the ten years in our time horizon and for each region are provided in Figure 2. Potential wind generation was higher in 2013 than in any other year. Data also indicate that southwestern Alberta has the best wind profiles, with CFs almost

[10] More details are provided in Appendix B.

double than those anywhere else in the province.

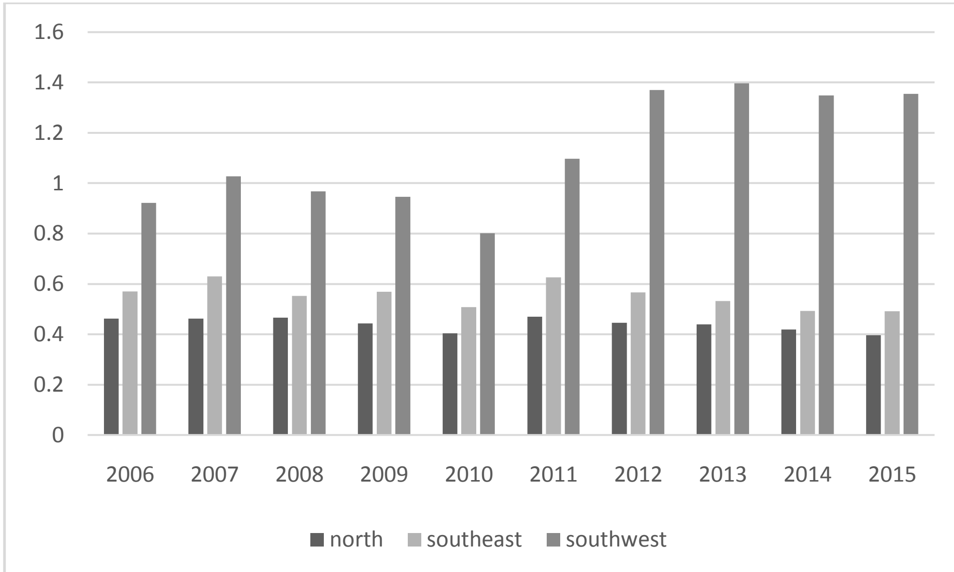

Figure 22 Potential Average Hourly Energy Output MWh for A 3.5 MW Wind Turbine

Energy Storage

Various types of energy storage technology exist today. For instance, pumped-hydroelectric storage works through the gravitational potential energy of water; it has existed for many years, there is significant installed capacity globally, and it is the best option for storing electricity in terms of efficiency and cost. However, there are limits to this option due to the availability of adequate sites – which Alberta lacks.[11] For our purposes, we focus on battery (electrochemical) storage technologies. Batteries have been used in small-scale (usually residential) applications, and its use in a utility-scale capacity has not yet been tested widely. One such example is the Tehachapi Energy Storage project in California that is designed to fulfil a total of 13 operational uses, including energy price arbitrage and frequency regulation (U.S. Department of Energy, 2014). In this study, we consider the extent to which batteries might back up renewable energy sources in place of conventional GT. We assume a series of Li-ion batteries that are known to be smaller, more advanced, and more efficient than many other types of conventional battery (including lead-acid batteries). The parameters associated with Li-ion batteries designed to fulfil the aforementioned applications are found in Lazard (2017b).

[11] In an earlier study, Benitez et al. (2008) assumed Alberta did indeed have suitable sites for developing pumped-hydroelectric storage; while such storage was limited in their model, no real storage is available.

According to EIA, the capital cost of a typical 50 MW battery storage has now declined to \$3122/kW of installed capacity, and the duration (operation at peak capacity) has increased from 4 to 8 hours (EIA, 2017a). Additionally, the price of utility-scale Li-ion batteries is forecasted to fall by as much as fifty percent by 2020 (Lazard, 2015). Finally, we assume that the cost of recharging a battery is effectively zero because it employs electricity from renewables.

3. Results

To explore the results of various carbon taxes on Alberta's generation mix, we will simulate two cases over a period of ten years. Due to limitations in data, we will regard each year of exogenous solar, wind and load observations as a representative year and as such, the results will be presented for representative years one through ten (regardless of the actual years they correspond with). This ignores changes in solar cycles, wind regimes, and differences in load past the last year, but for the sake of simplicity, we will use this as a starting point.

The Alberta government plans to achieve its target of phasing out coal-fired power and increasing reliance on renewables will be incentivized by a carbon tax of \$30/tCO_2 from 2018. The carbon tax on coal will be much higher than natural gas according to Alberta's Carbon Competitiveness Incentive Regulation. [12] This will promote renewable integration and elimination of coal power in the grid. Meanwhile, on October 3, 2016, the federal government announced that, unless provinces became more aggressive in their policies to reduce CO_2 emissions, it would implement a carbon tax that would start at \$10/tCO_2 beginning in 2017 and increase annually by \$10/tCO_2 until it reached \$50/tCO_2 in 2021(Government of Canada, 2016).

We first study the impact of current carbon tax levels of \$30 (or \$24 in 2018 U.S. dollars) on the generation mix over a period of ten years. Our results demonstrate that current carbon tax levels are not high enough to encourage renewable integration. Only 7 MW of installed wind capacity is introduced into the system in the eighth year when average wind speeds are particularly high. Neither solar capacity nor battery storage enters the system at all (Table 4). The CFs for CC gas in this base case reach ninety percent. As of 2017, the average annual CF of CC gas plants in the U.S. averaged 56% to 87%, compared to 55% to 85% for coal (NREL, 2017). While it may be expected that coal plants generally operate at a much higher CF, lower prices for natural gas as a result of fracking and explicit or implicit penalties on CO_2 emissions have led to increased reliance on gas plants instead of coal. In this case, barring adopting nuclear energy, gas

[12] Data from EIA show emissions of 95.35 kgCO_2 per million Btu from coal, and 53.07 kgCO_2 per million Btu from natural gas. (EIA, 2017). Other researchers find that the emission intensity of electricity production for coal is 820 gCO_2eq/kWh, and for gas-combined cycle is 490 (Schlomer et al., 2014).

dominates.[13] Renewable integration is far from our thirty percent target.

Table 4. Case 1: Configuration with Current Levies $US24.

Year	*Installed wind capacity (MW)*	*Installed GT capacity (MW)*	*GT capacity factor*	*Installed CC gas capacity (MW)*	*CC gas capacity factor*	*Net cost (Million USD 2016)*	*Carbon emissions (MtCO2)*	*Tax revenue (Million USD 2016)*
1	-	1064.4	0.03	8604.8	0.92	3922.35	23.22	557.28
2	-	1021.7	0.03	8684.3	0.91	3940.78	23.32	559.68
3	-	1171.6	0.03	8055.2	0.92	3688.11	21.79	522.96
4	-	1502.9	0.03	8731.8	0.91	3982.58	23.42	562.08
5	-	1248.9	0.04	8947.8	0.91	4071.29	24.04	576.96
6	-	1014.5	0.04	9212.3	0.91	4164.71	24.65	591.60
7	-	1177.5	0.04	9432.2	0.91	4271.87	25.24	605.76
8	7	1450.7	0.04	9682.5	0.91	4403.17	25.94	622.56
9	-	1122.5	0.04	10046.2	0.90	4527.88	26.77	642.48
10	-	1162.6	0.04	10066.7	0.91	4545.07	26.87	644.88

To encourage renewable integration, we may opt to raise the carbon tax. Carbon taxes are meant to capture the social costs of CO_2 emissions to correct the negative externality of pollution from fossil fuel use in electricity generation. However, if current carbon taxes are not high enough to capture the actual social cost, the market result of the generation mix is not optimal (suppose that optimal generation should have thirty percent renewable integration).

In the second case we consider, we increase carbon taxes by 700%, to $210 ($168 in 2018 U.S. dollars). When this happens, the battery utilization becomes feasible and wind capacity continues to grow. Wind energy achieves our thirty percent goal in nine out of ten years and averages 44% market share (Table 5) However, solar power never enters the generation mix.

[13] We also ignore electricity from wood biomass, because our purpose is to determine whether wind and solar power, with battery storage, is feasible. Furthermore, the AESO does not consider biomass to be a significant future source of power (see Table 1), and it has its own economic and ecological drawbacks (van Kooten, 2015).

Table 5. Case 2: Configuration with US$168 Carbon Levy.

Year	*Installed Battery capacity (MW)*	*Installed wind capacity (MW)*	*Installed GT capacity (MW)*	*GT CF*	*Installed CC gas capacity (MW)*	*CC CF*	*Net cost (Million USD 2016)*	*Carbon emissions (MtCO2)*	*Tax revenue (Million USD 2016)*
1	-	8625.0	998.7	0.02	8216.8	0.69	7013.9	16.61	2790.4
2	-	9058.8	1112.1	0.03	8323.6	0.64	6847.1	15.67	2632.5
3	-	8580.2	1155.9	0.02	7689.6	0.66	6498.3	14.93	2508.2
4	-	8859.2	1680.1	0.02	8424.9	0.66	7068.7	16.47	2766.9
5	-	2163.8	1183.5	0.02	9005.2	0.85	7525.1	22.54	3786.7
6	-	10700.5	1301.8	0.04	8745.3	0.59	7066.4	15.19	2551.9
7	326.89	15811.0	2031.3	0.08	7907.2	0.36	6393.9	9.06	1522.0
8	342.23	17278.5	3452.3	0.07	7016.4	0.35	6460.9	8.29	1392.7
9	407.59	18246.2	3207.8	0.08	7302.1	0.34	6756.6	8.58	1441.4
10	327.85	18045.2	3281.3	0.09	7303.5	0.35	6780.8	8.88	1491.8

With this high carbon tax, average emissions over ten years fall from 24.5 Mt to 13.6 Mt, but average total cost jumps from US$4,151 million to US$6,841 million, which will cause a significant increase in electricity market price. However, if the redistribution of government tax revenue is considered, the increase in tax revenue can make up the loss of electricity consumers. The difference of the average tax revenues between either case is US$1,700 million, which is large enough to recover the loss in total cost.

The effects of wind integration and battery storage on GT and CC gas usage work in different directions. Table 5 demonstrates that with higher wind integration comes lower CC gas utilization (average capacity falls from 9,146 to 7,993 MW) and higher GT usage (average capacity rises from 1,193 to 1,940 MW). During high wind potential years such as years seven to ten, average GT capacity even rises to 2,993 MW, which is almost triple the base case capacity. This provides compelling evidence that such an HRES configuration can replace CC gas capacity (base load supply), but instead of displacing GT (peak load supply). High levels of wind integration combined with battery storage result in the grid relying on more GT usage as a backup. Under current technological conditions, battery storage is not yet able to remedy the intermittency problem associated with renewables. The current cost, duration and capacity levels of available batteries limit the ability of such energy storage technology to replace GT.

Such a generation mix would further the economic burden on the power system. A high carbon tax and wind-battery HRES may seem to be a feasible option in terms of balancing total cost and government revenue; however, this does not consider the indirect cost of the missing money problem associated with renewables. An increase in GT capacity will increase the amount of "missing money" since GT usually only achieve four percent CF. Furthermore, a decrease in CC gas capacity seems to mitigate the missing money problem, but the average CFs of CC gas fall from 91% to 55%. Compared to a twelve percent decrease in CC gas capacity on average, the average CFs of CC gas decrease by 45%. In case 1, most of the time CC gas generators can make money by selling energy; while in case 2, CC gas generators are not able to do so nearly half of the time. The missing money problem is therefore exacerbated under the second case considered. To keep GT and CC gas in a system, a compensation mechanism such as capacity payment is necessary for Alberta to realize its thirty percent goal.

Battery storage is not able to replace GT, nor is it able to mitigate the missing money problem in our model. However, the presence of a battery does reduce total emissions significantly. In the second case, without a battery, average emissions from the first to the sixth year is 16.9 Mt, while with a battery, from the seventh to the tenth year, average emissions drop to 8.7 Mt. Furthermore, the utilization rate of battery in the same time periods are on average fifty percent, which means that the battery used provides fifty percent of its capacity for energy supply.

Discussion and Conclusion

Our model shows that it is possible for renewables to displace baseload supply to some extent, but peaker gas generators are still unreplaceable. The main economic consequence is that the missing money problem is not alleviated; rather, it is exacerbated. Alberta requires a capacity market to provide gas generators with revenues other than those gained from selling energy. Our model does not show that renewables are infeasible. The wind-battery HRES may not solve the missing money problem but is effective in reducing emissions with affordable cost.

It is noteworthy that in the case of high wind integration, more energy was produced than needed. The wasted renewable energy between the seventh and tenth years in the second scenario reached 5,978 MWh, accounting for ten percent of total wind output on average. Wasted renewable energy due to the intermittent nature of wind power should be expected in such a case and would need to be exported to neighbouring provinces and states. It would not be necessary (nor optimal) for battery capacities to be so high as to capture all the wasted renewable energy all the time due to the high cost and low utilization rate of the battery. Rather, priorities should be focused towards meeting the load in any given time period, as is the case in our simulation.

Additionally, it is very difficult to integrate solar energy into the Alberta grid due to its relatively higher LCOE. Only when this is decreased by eighty percent of its current level does solar power become cost competitive. This is not to say it has no place in Alberta; solar integration in residential and farm applications would be ideal, for example. Furthermore, the International Renewable Energy Agency (IRENA) expects that by 2020 all mainstream renewable energy source will have average costs at the lower end of the fossil fuel cost range, thereby allowing renewables to go head-to-head with fossil fuel-based power solutions to provide new capacity without financial support (IRENA, 2018). The key issue relating to solar applications in our model will soon be solved by this.

While other studies have simulated HRES successfully, these tend to be for microgrids or other small-scale purposes (Sinha & Chandel, 2015). In our case, we encounter problems due to the sheer size of Alberta's demand for electricity, in addition to economic viability issues that need to be considered from a policy perspective. However, where high taxes were applied in our simulation, renewable energy was able to supply over thirty percent of electricity and reduce CO_2 emissions, thus meeting one of the goals of Alberta's Climate Leadership Plan.

Additionally, our simulation merely captures the monetary aspects of renewable integration and energy storage, while ignoring many of the benefits that can accrue from such projects. As renewable and battery prices continue to drop, Alberta may see itself relying more on renewables in the near future. However, while renewables will undoubtedly play a large part in the future of Alberta's electrical grid, renewable energy will likely need to be backed up by some other more reliable source of energy (GT and CC gas, in our case), to meet peak and base load.

Appendix A: Additional Information on Alberta’s Load (2006-2015)

Table A1: Monthly Averaged Peak Loads, 2006-2015

Month	Peak/MW	Month	Peak/MW
January	11,229	July	10,520
February	10,956	August	10,515
March	10,743	September	9,909
April	9,783	October	10,074
May	9,512	November	11,020
June	10,319	December	11,458

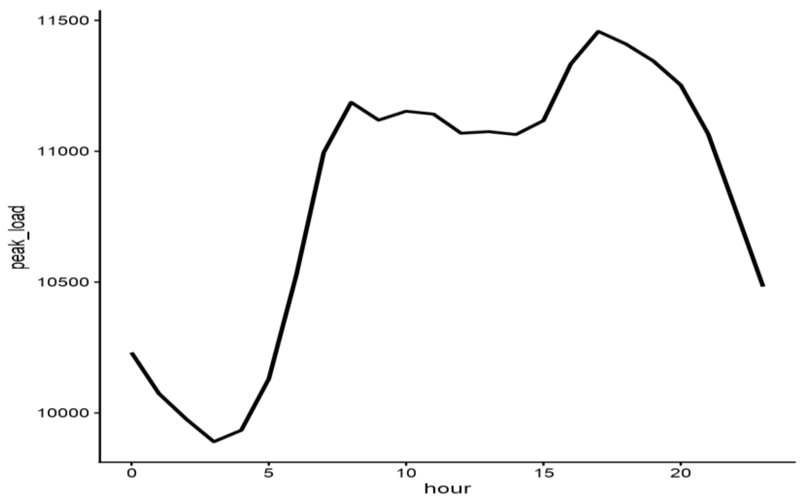

Figure A1: Average Daily Peak demand (2005-2016)

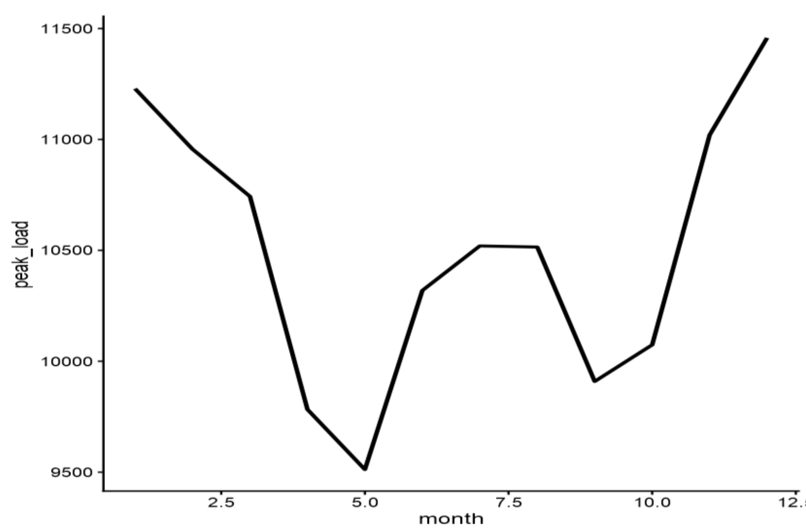

Figure A2: Average Monthly Peak Demand (2005-2016)

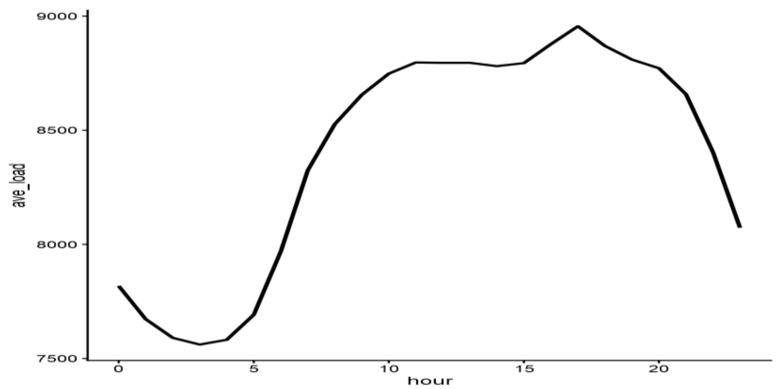

Figure A3: Average load over the day

APPENDIX B: Calculating Solar and Wind Energy

The choice of the solar panel may play a large role in determining the final cost and efficacy of the resulting RES. Crystalline silicon (mono- or poly-crystalline; the difference in efficiency is often negligible) panels are common in many solar applications. Thin-film solar panels, on the other hand, are very diverse in scope. Modules made of such materials often perform better in times of lower irradiance, and their temperature coefficients are lower (Sunbeam Communications 2014). These particular advantages may be useful for applications in Alberta but are left for future research.

Table B1: Technical Specifications for Canadian Solar CS5P-220M (220W) Solar Panel

Nominal maximum power (W/NOCT)[a]	Module efficiency (η_m)	Size (m^2)	Temperature coefficient (%/K)	NOCT (°C)
220	0.1294	1.919	-0.45	45

[a] Under Standard Test Conditions: an irradiance of 1000 W/m^2, module temperatures of 25°C, wind speeds of 1 m/s, and an air mass of 1.5. Then, the nominal maximum power is calculated as: $E = \eta_m \times A$, where E denotes electrical power in kWp (kilowatt-peak) and A denotes area of panel in m^2. NOCT denotes Nominal Operating Cell Temperature.

Wind power computation

Wind velocity (m/s) is a function of wind speed and turbine height (van Kooten et al., 2016):

$$V_{hub} = V_{data} \times (\frac{H_{hub}}{H_{data}})^{\alpha},$$

where V_{hub} is the wind velocity at the turbine hub; V_{data} is the observed wind velocity; H_{hub} is the height of the hub; H_{data} is the height at which the data was collected, and α is a wind shear component. We use our knowledge of the regions in the dataset to set values of α, which assume different values based on the type of terrain upon which the turbines are built. Wind power is a function of wind speeds, as represented by the following equation:

$$P_w = ½\beta v^3 \pi r^2,$$

where P_w is wind power (measured in watts); β is the density of dry air (assumed to be equal to 0.94, measured in kg/m^2); v is wind velocity (measured in m/s), and r is the radius of the rotor (measured in meters).

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