Investing in Alberta's clean energy future

How we can cut emissions, create jobs and deliver a reliable, cost-effective electricity grid

ALTALINK
A BERKSHIRE HATHAWAY ENERGY COMPANY

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1. VISION

When people think of Alberta's energy sector, they think first of oil and gas. But it has a third pillar—electricity—which can help change how the province's environmental performance is perceived elsewhere, make significant cuts to greenhouse gas (GHG) emissions, and spur capital investment even during a slump in oil prices.

AltaLink and its parent company, Berkshire Hathaway Energy, believe in Alberta. We share the goal of achieving real emission reductions by phasing out coal-generated electricity. We've helped other jurisdictions, such as Iowa and Nevada, move away from coal and toward renewable energy generation.

In the United States, Berkshire Hathaway Energy is a long-time investor in renewable energy. Today, it has invested over $15 Billion in wind and solar power, and is a signatory to President Obama's recent climate change commitment. It has the outlook, experience and resources to help Alberta transition away from coal, including in-depth local knowledge through its ownership of AltaLink.

AltaLink understands Alberta's electricity sector. It's all we do. So we know that reliable, affordable and environmentally sustainable electricity for Alberta's businesses and families depends on a diversified portfolio of resources that includes renewables, cogeneration and other gas-fired generation, energy efficiency, and strong access to regional markets.

Because of this knowledge and track record, we believe Alberta can retire approximately 1,000 MW of coal within five years and can convert an additional 3,000 MW to a reliable back-up operation before ultimately retiring them within 15 years. Renewable projects are ready to move forward before the international climate change meeting in Paris this year to help show how seriously Alberta takes our responsibilities.

Alberta can significantly reduce its GHG production through the retirement of or reduced output from its coal fleet and determine what generation replaces it while protecting Albertans from unnecessary costs. To deliver on this objective, a step change in Alberta's generation mix is required.

Here's how we can get there:

- **Spur capital investment in renewable generation** through a competitive procurement program that offers long-term contracts with reasonable revenue certainty to quickly and significantly increase renewable energy generation and move rapidly away from coal.
- **Encourage gas-fired cogeneration** by competitive procurement under long-term contracts. Cogeneration can replace existing baseload generation, has the lowest cost and GHG emission intensity among all gas-fired generation. It also helps turn the oil sands from a perceived environmental problem to being part of the climate solution. Encouraging cogeneration will also act as a boost for investment and jobs in Alberta's natural gas sector.

- **Better access larger regional markets with neighbouring jurisdictions** to ensure renewable energy's reliability and lower price.
- Support the **deployment of energy storage infrastructure** to optimize regional market participation and provide additional renewable energy back up.
- **Minimize the cost of coal retirement by making use of mothballed coal capacity** for reliability back-up, the firming of renewable resources and bridging to longer-term GHG efficient resources.
- **Embrace energy efficiency** to create jobs and help keep bills affordable.

Working as a package, the proposed changes allow Alberta to cut emissions while still preserving the market and allowing it to continue to provide competitive pricing signals. These proposed changes do not require redesigning the electricity market. Instead, less electricity will be subject to market prices and the volatility of the average Albertan's regulated rate option electricity bill will be reduced.

It's urgent that we act now because the last of Alberta's Power Purchase Arrangements (PPA) contracts expire at the end of 2020. Achieving these policy objectives requires decisive action. In the absence of change, uncertainly about the market and industry structure will either deter investment or miss opportunities to influence potential new investment decisions to help lower emissions. There is a one-time opportunity to replace coal with clean generation.

The table below shows it's possible to cut two million more tonnes in GHGs as well as save consumers almost $100 million a year, versus the business-as-usual approach. Indeed, replacing 1,000 MW of retired coal capacity by 2020 through our proposed policy package will deliver 50% more GHG emission reductions at 16% less cost. Detailed assumptions on the analysis can be found in Appendix B.

	GHG Emission Reductions (Million Tonnes)	Annual Cost ($M/Year)
Business-as-usual	3.78	$ 573
Policy Package	5.63	$ 479

2. UNDERSTANDING THE CHALLENGE

The electricity industry can help spur investment in Alberta while reducing emissions. Today, electricity generation produces about 45 million tonnes of CO2, or 17% of Alberta's total emissions. Reducing electricity related GHG emissions can be accomplished on both demand-side and supply-side measures.

On the demand side, measures such as energy conservation and efficiency programs are an important part of the solution for reducing electricity-related GHG emissions. Appropriately-designed financing and

other incentives targeted at residential, smaller commercial and farm customers are effective in overcoming market barriers and delivering cost-effective emissions reductions while creating new jobs across Alberta and lowering customer's bills. However, given the industrial sector accounts for more than 60% of total electricity consumption in Alberta, demand-side measures alone will not be able to achieve GHG reduction objectives.

On the supply side, coal-fired generation is responsible for 85% of the electricity sector's CO2 emissions. As such, delivering material GHG reductions requires a substantial reduction in coal generation on or before its normal retirement dates, and its replacement with clean, renewable electricity, including wind, solar, hydro, biomass, geothermal and lower-emission gas-fired generation.

To achieve significant reductions in GHG emissions in the electricity industry, Alberta's generation mix will require a step change over the next five to 10 years. An appropriate market and industry framework is essential to manage this transition and achieve the government's broad policy objectives. Key questions for government and stakeholders are:

- To what extent can we rely on today's market structure to facilitate this step change?
- What other policy changes are required to achieve the policy objectives?

This paper recommends a suite of policy changes to facilitate the step change in Alberta's generation mix to achieve material GHG emission reductions at an affordable cost, while supporting the new government's priorities of creating jobs and helping oil and gas compete globally.

3. POLICY OBJECTIVES

There are several overarching policy objectives that drive the vision for greening the grid, which spur investment and lower emissions. Focusing only on emissions may affect cost; focusing only on cost may affect emissions. We need to see the whole picture to ensure the best possible outcome for Albertans.

GHG reductions must be material

The framework must deliver significant GHG reductions, starting in the very near future and increasing with time. Relying on the market's response leaves too much to chance and is unlikely to achieve the greatest possible GHG reductions. A strategic and robust public policy approach is needed.

A reliable and efficient electrical system is critical to Alberta's economy

Our economy depends on a reliable and efficient electrical system to generate and deliver affordable electricity to homes, farms, businesses and industry. Uncertainty about new policy direction will threaten industry and investor confidence at a time when investment is most needed to help retire a large amount of baseload coal capacity. This uncertainty will in turn put the reliability of the electrical system at risk.

As well, integrating significant amounts of inherently intermittent renewable generation (the wind does not always blow; the sun does not always shine) requires changes in market and operational practices to keep the system reliable.

Albertans must be protected from significant cost impact

Alberta is already suffering from a severe drop in world oil prices, prices which threaten to remain low for some time. As Albertans' incomes plateau or fall and unemployment rises, people and businesses need to be protected from the potential cost increases that large GHG reductions in the electricity sector may bring. We should encourage the most cost-effective ways of transitioning our fuel mix to minimize the impact on electricity customers and the economy.

We must boost the economy as much as possible

As Alberta moves to cleaner generation mix, private investment can be achieved while creating jobs and increasing royalties to the government. Our natural gas industry has an important role in our economy and provides many jobs. Low natural gas prices mean significant volumes of natural gas are no longer exported. Encouraging the efficient use of additional natural gas for electricity generation takes advantages of low prices and creates economic benefit to the province by deriving new royalties for the government while supporting and creating jobs.

A change in Alberta's generation mix will also open new opportunities for employment in emerging renewable energy fields, a reality seen in jurisdictions where the renewable industry has created construction and operations jobs.

4. ISSUES OF RELYING ON CURRENT MARKET STRUCTURE

Existing energy market has delivered on its original intent

Investment in new electricity generation has and will be driven primarily by the competitive electricity market which was introduced in 1996. Generally speaking, the wholesale market has worked well in attracting a significant amount of private investment and produced competitive wholesale electricity prices. Since 2001, electricity supply has increased by more than 50 per cent and today, there are more than 100 generators operating in the market. This has also resulted in a diversified generation mix with large increases of natural gas-fired and wind generation. In fact, more than 1,300 MW of new wind generation has been added to the grid since the wholesale market was introduced.

A step change in generation mix is required to deliver material GHG reductions

The fact remains that coal-fired generation is a major part of Alberta's generation mix. It accounts for more than 55 per cent of total generation output and 85 per cent of total GHG emissions from the electricity sector. Due to its low cost, coal operates as baseload generation, running almost continuously, when available, to meet Alberta's electricity needs.

Despite its current role in Alberta, coal-fired generation must be significantly reduced soon and then phased out entirely to deliver required reductions in GHG emissions. Replacing that generation requires partners willing and able to invest, and a structure that encourages investment.

Relying on the market to fulfill GHG reduction target is a challenge

While it performed well in delivering its original objective of attracting private investment, Alberta's energy-only electricity market now faces an uphill battle to reduce GHG emissions as outlined below.

Wind generation is challenged in the energy only wholesale market

The economics of wind generation have deteriorated significantly over the last several years. As the installed wind capacity has grown, the "price discount" that wind generators receive in the market has grown relative to the average market price. As "price-takers", in 2014 wind generation took prices for their energy that was 34% lower than average market prices. Our small market and poor connections with other markets make this worse as wind output will be increasingly absorbed by the Alberta system. As a result, the development of new wind generation has largely stalled during the last several years.

Limited opportunity for long-term contracts limits investment and increases energy cost

As a result of insufficient interest from electricity customers to provide generators with price certainty through long-term Power Purchase Arrangements (PPA), very few opportunities exist for renewable generators to secure long-term arrangements with sufficient revenue certainty. In the absence of certainty, generation developers are forced to rely on market prices, which significantly limit the development of capital intensive generation, such as wind. Experience in other jurisdictions shows that alternatives such as PPAs are effective in supporting project financing and beneficial in reducing energy cost by removing the market risk premium.

Cogeneration opportunities are significant but constrained by market risks

Cogeneration is a low-cost source of generation with low GHG intensity. Alberta is uniquely positioned to maximize its benefits due to our oil sands projects, which require large amounts of steam. This significant cogeneration potential has gone unfulfilled because oil sands developers have not been willing to take the risk of the entering the competitive electricity market.

Combined cycle gas turbine generation (CCGT) will be the default choice to replace baseload coal generation

Under the existing market structure, coal will be largely replaced by combined cycle gas turbine generation, due to the likelihood of large volumes of low-cost natural gas remaining available for some time. While better than coal, CCGT still produces significant greenhouse gas emissions when compared to renewable or cogeneration sources.

Alberta is poorly interconnected and our connections are used primarily for trading

A well-connected system with other jurisdictions creates a large market, which in turn allows greater load and generation diversity. This makes renewable energy more feasible. Alberta, however, is poorly

connected with neighbouring jurisdictions, and no effective new intertie capacity has been added since the 1980s.

Our problem is that while there are opportunities to increase the existing intertie capacity, the current policy framework means any new capacity will be used for trading by market participants to optimize their market operations, instead of helping to "firm" renewable energy generation. As a result, the intertie is of limited benefit to Albertans.

Today's market structure will not meet Alberta's GHG reduction goals

In summary, even with an increase in the price of carbon, it is unlikely that the existing market structure will help the government deliver on the government's GHG policy objectives. As it now operates, the market will not produce sufficient fuel diversity in the generation mix to deliver significant GHG reductions. At the same time, Alberta customers will be exposed to the risk of significantly higher market prices and threatened system reliability during this transition.

5. PROPOSED CHANGES TO CUT EMISSIONS AND DELIVER A RELIABLE GRID AT AFFORDABLE COST

Simply put, Alberta's electricity-related GHG emissions can be significantly reduced by retiring and/or changing the coal generation fleet and substantially increasing lower-GHG emission generation, while maintaining a reliable electricity supply at a reasonable additional cost to consumers. Alberta can retire 1,000 MW of coal within five years and an additional 3,000 MW converted to a reliable back-up operation before ultimately retiring these megawatts within 15 years.

This vision can only be achieved with a number of changes to the electricity market to address the issues that have been identified in Section 4. These five changes include:

A. **Spur capital investment in renewable generation** through a competitive procurement program that offers long-term contracts with reasonable revenue certainty to quickly and significantly increase renewable energy generation and move rapidly but prudently away from coal.
B. **Encourage gas-fired cogeneration** by competitive procurement under long-term contracts. Cogeneration can replace existing baseload generation and delivers the lowest cost and GHG emission intensity among all gas-fired generation. It also helps turn the oil sands from a perceived environmental problem into part of the climate solution.
C. **Better access larger regional markets with neighbouring jurisdictions** to ensure renewable energy's reliability through "firming" and lower price for consumers.
D. Support the **deployment of energy storage infrastructure** to optimize regional market participation and provide additional renewable energy back up.
E. **Minimize the cost of coal retirement by making use of mothballed coal capacity** for reliability back-up, the firming of renewable resources and bridging to longer-term GHG efficient resources.

A. Renewable procurement with long-term revenue certainty

Long-term contracts enable large renewable development

As a result of its intermittent nature, the amount of renewable generation required to replace coal generation capacity is significant. For example, replacing 1,000 MW of coal-fired generation requires 2,500 MW of wind generation because wind power operates at a much lower "capacity factor" than coal. That is, it's not available all the time like a coal plant. To meet Alberta's emission reduction targets, large amounts of renewable generation must be added quickly. Many projects have already been sited, and with some changes to how permits are issued, renewable capacity can begin to be built in the immediate future.

The most effective solution is to provide increased revenue certainty to renewable generation developers through long-term contracts awarded in a competitive procurement process. There are two ways to do this: central procurement or renewable portfolio standards (RPS).

Central procurement is the best opportunity

1) Under a central procurement model, a central agency would be given the mandate to procure large-scale renewable generation under long-term contracts. Developers would compete in an RFP, offering the lowest-cost solution with minimal market risk. The resulting cost savings would then be passed on to ratepayers. It has several advantages:
    a. Large scale procurement of competitive renewable generation better captures economies of scale
    b. Lower costs to customers
2) It is an efficient program that lowers transaction costs
3) It is supported by strong government credit ratings that reduce risk premiums and overall cost to consumers; and
4) The low-cost renewable generation supply procured through long-term contracts can be made available to Regulated Rate Option (RRO) customers.

RPS approach is not an efficient model for Alberta

An RPS approach is essentially a quota system, which requires energy companies to procure a predetermined percentage of renewable generation. Implementing an RPS approach in Alberta is challenging for a number of reasons:

1) The Alberta market is relatively small and fragmented. Individual companies with small, inefficient procurement programs would be similar to what we now have for the regulated rate option (RRO).

2) Small procurement opportunities do not attract large competitive developers, and do not result in low costs to customers.

3) Load-serving entities such as small retailers and distribution facility owners may not have strong credit ratings, which increases the risk premium for electricity procured and therefore costs to customers.

4) Even for large retailers with stronger credit ratings, procuring electricity through PPAs still exposes them to the risks of electricity market price volatility due to "mark-to-market" accounting requirements. In turn, this impacts the company's credit rating and increases its cost to customers.

Encourage creative solutions for risk-sharing by developers

The proposed procurement program would result in a long-term contract with fixed and variable payments that appropriately shares risk between the developer and the contract underwriter so as to minimize costs to customers.

Under the proposed central procurement model, the RFP process and PPAs would encourage creative offers to allow appropriate allocation of risks between bidders and customers, including the sharing of market price risk.

Successfully implementing a central procurement program for renewable generation requires a robust planning process to set the pace and scale for the development of renewables and other sources of generation in Alberta. This program can and must meet the province's GHG reduction objectives while ensuring a reliable and cost-effective supply of electricity.

The new planning framework should also be long-term in nature and take into account forecasted load growth, the retirement of the existing coal fleet, alternative sources of generation and energy conservation. Where appropriate, the planning should also consider the best ways to integrate large amounts of renewable generation through maximizing the value of existing transmission and interties and new "firming" or "back-up" technologies such as energy storage. This planning framework is a natural extension of the AESO's planning mandate and is very similar to Integrated Resource Planning (IRP), a standard industry practice across North America.

B. Cogeneration procurement to help more low-emission generation

Cogeneration is a low-cost and low-emission baseload resource

To reduce GHG emissions, Alberta must replace coal-fired generation with other reliable capacity. Our oil sands producers can provide one such source given their significant as yet untapped resource for gas-fired cogeneration. As a result of higher efficiencies, better greenhouse gas emission performance and its high capacity factor, cogeneration is much better-suited to provide the replacement baseload capacity than gas-fired combined cycle generation.

Fulfilling cogeneration potential depends on policy

In the past, cogeneration has been primarily developed to power the industrial facility's onsite power needs, with little being built to meet broader customer market needs. The main barriers to better use of

this technology are the lack of long-term contracting opportunities and insufficient policy recognition of its higher efficiencies which result in superior greenhouse gas reductions.

Without deliberate policy action, however, new gas generation will be dominated by combined cycle projects, which deliver neither the most cost-effective baseload capacity nor the best greenhouse gas emission performance. Generally speaking, cogeneration is 15% - 20% less costly on a $/MWh basis and 30% - 40% lower in GHG emission in terms of tonnes of CO2 per megawatt hour output than combined cycle gas turbine generation.

A central procurement program should be created to foster cogeneration development

We recommend an appropriate block of baseload cogeneration be procured through competitive RFPs under long-term contracts. The timing of this can coincide with the retirement of some of the coal generation blocks. In addition, the introduction of carbon prices or a similar mechanism which provides the appropriate carbon cost signal to alternate forms of generation, could also stimulate cogeneration development by establishing a more accurate competitive balance between cogeneration and combined cycle.

Cogeneration development supports broad public interest

Building more cogeneration facilities at heavy oil sites delivers two public benefits:

- It reduces costs for oil sands operators rather than purchasing electricity in the market; and
- It helps the larger economy by supporting the natural gas sector, creating and maintaining jobs and delivering royalties to the government.

C. Accessing regional markets is critical to enabling renewable and low-cost electricity

Accessing a larger regional market is essential to allowing for significantly higher levels of renewable energy because the market broadens the generation mix and provides better back-up for when the wind is not blowing or the sun is not shining. Operating in a regional market also enhances competition, allowing Alberta consumers to have access to a more diverse range of suppliers, including those from outside the province.

Working with Berkshire Hathaway Energy, Nevada and Iowa have successfully demonstrated how highly interconnected systems can support greater penetration of renewable energy without jeopardizing reliability and market performance. Nevada leads all U.S. states in the number of wind and geothermal projects on public land since 2009 and, following the completion of new wind energy projects, Iowa will receive 57 per cent of its retail energy load from wind by 2017.

Alberta's small market presents a challenge to the government's GHG policy objective

Unlike most other jurisdictions in North America, Alberta is lightly interconnected with neighbouring electrical systems.

Additional intertie capacity is a key to adding significant new renewable generation in the foreseeable future because of its ability to "firm" the intermittent output from Alberta's renewable sources by taking advantage of the load and generation diversity of larger regional markets. While it would take many years to construct an entirely new intertie (10-15 years), there are opportunities to increase the capacity of the existing 500 kV tie with BC by approximately 500 MW.

To increase the existing intertie capacity would mean additional costs to be borne by Alberta electricity consumers. Consumers should therefore receive its benefits. However, under the present arrangements additional capacity would only provide increased opportunities and benefits to BC Hydro and energy traders. Put simply, this capacity would not be available to support the policy-driven, higher-value objectives of replacing coal generation with renewable energy.

Consumer value of the intertie has been reduced over time

When the original intertie with BC was constructed in the 1980s the benefits from increased reliability and the synergies between British Columbia's predominantly hydro system and Alberta's predominantly thermal system were shared by the two provinces. Alberta's electricity system was fully regulated. While Alberta as a whole has enjoyed the reliability benefits, since the competitive electricity market was introduced British Columbia has been able to capture a much higher share of the commercial benefits than was previously the case under the bilateral contracts. The remaining value accrues primarily to commercial entities, mainly energy traders.

By changing the framework to access a larger regional market, Albertans can recapture the original value of their intertie, ensuring reliable electricity and benefitting Alberta consumers through increased competition among generators.

Alberta needs to capture the value of a larger regional market

A new arrangement should be put in place to ensure that the currently-planned 500 MW of increased intertie capacity provides Alberta with a fair share of the benefits, and as importantly helps us transition away from coal. In summary:

- The 500 MW of new intertie capacity should be controlled by an appropriate Alberta agency (i.e. the Alberta Electric System Operator), with the authority to negotiate with BC Hydro how this new capacity would be utilized.
- The new capacity would only be available to commercial traders if and when it was not required to provide services under the bilateral contract.
- The contract with British Columbia would have the following principal terms.
    - BC Hydro's hydro storage would be used to "firm" Alberta wind generation.
    - In return, BC Hydro would have priority access to 500 MW of intertie capacity for wind energy arbitrage (store/send back to Alberta market).
    - Renewable "firming" would be done by Alberta having an option to call on capacity from British Columbia when needed.

- British Columbia would pay a typical transmission tariff for intertie access when buying and selling wind energy.

A contingency plan for firming renewable energy is prudent

It would also be prudent to pursue an alternative to the contract with British Columbia for firming wind generation as there is no guarantee such a contract could be negotiated. One possibility is a combination of gas-fired simple cycle generation and energy storage located in Alberta.

D. Storage infrastructure provides flexibility for integrating renewables

Energy storage is a valuable asset in a renewable energy future

As we generate more electricity through renewables, we will need more flexible resources to accommodate its intermittent output. Traditional generation technologies such as coal or combined-cycle gas turbine are not as efficient or effective in providing this flexibility. Greater market integration would help, but can be difficult to develop.

Energy storage, whether through the use of batteries, compressed air storage, thermal storage or pumped hydro power, is uniquely qualified to provide this needed flexibility for the integration of large amounts of renewable energy. Storage technology can quickly switch its operation from load to generation, depending on the system's needs. A wide variety of such technologies are available ranging from short duration, fast response storage to respond to immediate, short-term electricity requirements, to longer duration technologies better suited to store energy when there is surplus renewable generation and sent back to the grid when renewable output is low, or during peak hours when demand is high.

Energy storage has a particularly high value in Alberta with our single price, energy-only market given its potential to reduce the significant price volatility we currently see, and to some extent compensate for our lack of intertie capacity.

Energy storage has a valuable role in the vision for greening the Alberta grid

Energy storage is an essential element in greening the grid. It can support interties by "firming" renewable energy, enhancing market competition and efficiency, reducing price volatility and optimizing transmission development. Energy storage resource can also guard against the risk of not being able to arrange a satisfactory "firming" solution with BC.

Energy storage is a cost-effective solution for restoring intertie capacity

The Alberta Transmission Regulation requires the AESO to restore the BC intertie to its original design capacity, which would allow for the import of 1,000 MW and export of 1,200 MW of electricity. Today because of system stability concerns, the intertie is operated at capacity levels well below the designed capacity.

The AESO is currently procuring Load Shed Service for Import (LSSi) services from load customers to support increased import capacity on the BC intertie. LSSi requires load customers to be taken offline following a sudden loss of imported electricity as a result of a trip of the intertie. The tripping of these customers help maintain system integrity and reliability. LSSi is an expensive solution, given that load customers who provide LSSi service must operate during import hours when market prices are typically high. Energy storage can be a more cost-effective solution than LSSi as it doesn't incur significant cost while providing LSSi type of services.

Storage can effectively provide system flexibility to allow for renewable integration

Energy storage is an effective resource to meet the increasing requirement for various ancillary services (e.g. operating reserves) as we generate more renewable energy. As an example, California has renewable targets of 33% by 2020, rising to 50% by 2030. This has created a greater need for system flexibility; in particular the need for fast ramping capabilities to mitigate a sudden change of renewable output. As renewable energy replaces coal generation, our grid will also require more frequency response capabilities. These have traditionally been supplied by large thermal units such as coal generation, but energy storage technologies could be a more cost-effective solution.

Storage would enhance market competition and efficiency

Technologies that can store energy for several hours are an effective resource to optimize market efficiency since they store surplus energy during periods of low prices and release it during periods of higher prices, thus helping to reduce price volatility. This price or energy arbitrage operation enhances market competition and overall efficiency, and limits the market power of BC's hydro storage in Alberta's electricity market.

Storage can optimize transmission costs for renewable integration

Integrating renewables often requires additional transmission to be built to connect it to the grid. Strategically located energy storage assets can help optimize the timing and scale of this infrastructure, which reduces the overall cost of new transmission to customers. These storage facilities would also provide additional reliability benefits by assisting in managing various contingency or emergency events.

Storage can form part of the alternative solution to British Columbia "firming"

As indicated earlier, we could firm more renewable generation by relying on British Columbia's hydro system. However, energy storage resources offer the technical potential to provide all of these "firming" services as well, and can be part of an effective Plan B. Enhancing Alberta's storage resources would improve our bargaining position in negotiating a satisfactory business arrangement with BC Hydro.

Innovation should be encouraged for energy storage development

It should be noted that a variety of business approaches can be used to develop the needed energy storage facilities. The Brattle Group, a leading energy and economic consultant headquartered in Cambridge, Massachusetts, recently proposed a hybrid approach that could be used to maximize its

potential value. It suggests that a storage facility would be built, either as a regulated asset, or a tolling plant, whose storage capacity could then be auctioned off to market participants. [1]

It is recommended that an approach similar to that suggested by the Brattle Group should be critically examined for application in Alberta. This approach would provide a wide range of benefits, as well as support to the development of renewables at a favourable cost to customers.

E. Reduce coal generation output while preserving the value of its capacity as much as possible

Reduce but preserve is an ideal way to reduce Alberta's emissions

To achieve material reductions in greenhouse gas emissions, Alberta's coal generation output must be reduced as soon possible and replaced with renewables and low-carbon intensity cogeneration. There is a debate as to whether coal should be shut down immediately, continue to operate until the end of its useful life, or be converted to a different mode of operation.

We believe the existing coal generation with PPAs scheduled to expire in 2019 should be retired and decommissioned at that time or sooner if possible. Coal units operating after 2019 should be critically examined to ensure customers are not burdened with higher electricity costs, that the system remains reliable, and to actively manage the transition to a renewable future.

New roles for coal generation should be evaluated

There are a number short to medium-term uses for that coal capacity which could provide good value for customers with minimal GHG emissions:

- Some or all of the coal generation slated for retirement in 2029 (approximately 3000 MW) could be transitioned to a peaking or backup role, helping to firm up renewables and to keep the system reliable. While coal generation used in this way would not be immediately retired, it would run only a fraction of the hours compared to today, therefore cutting emissions substantially. This is similar to how Nevada uses its coal units.
- In a standby role, this generation could also be used as capacity to firm up secondary hydro energy in British Columbia to support firm energy sales. This could be part of the bilateral contract with BC Hydro, and a way of recouping some of the remaining value of this generation, with minimal production of GHG emissions as well as savings for Alberta consumers.
- Some of the coal generation might be used as a bridging resource until enough lower GHG resources such as storage and intertie arrangements with British Columbia are online. After which time, it would decommissioned.

[1] The Brattle Group. *The Value of Distributed Electricity Storage in Texas: Proposed Policy for Enabling Grid-Integrated Storage Investments* (prepared for Oncor). November 2014.

Potential commercial arrangements

For coal generation converted to a peaking or standby mode, its owners could be paid a capacity payment commensurate with its value as a firming resource for renewables and for any other benefits it provided to the grid.

6. PROPOSED CHANGES ARE COMPATIBLE WITH CURRENT MARKET DESIGN

Implementing this paper's proposed changes does not require a complete redesign of our existing energy-only market. However, there would be implications on the operations of the wholesale and retail markets in Alberta.

Hybrid market for investment

Under the existing market framework, investment in generation is exclusively driven by expected market prices and/or short-term bilateral contract arrangements. Under our proposed framework, market signals would be supplemented by competitive RFP procurement under long-term contracts, which in turn would drive generation investment towards lower-carbon fuels.

This new approach would play a significant role during a transition period over the next five to 10 years. Robust policy interventions would be needed to achieve substantial GHG emission reductions, while protecting consumers from significant price increases. However, the market would continue to play a critical role in delivering a competitive price that would guide how companies invest in the wholesale market, beyond that which is centrally procured.

Wholesale market operation

Contracted generation capacity procured through the competitive process would be required to offer into the market at zero dollars. Proceeds from the sale of contracted electricity would then be settled based on a contract-for-differences. Generators under the contract will only receive payments previously stipulated in the PPA.

It can be expected that the competitiveness of the market would be maintained and the electricity market would increasingly act as a balancing market during this transition period. This increased price volatility in the balancing market would likely attract more flexible generation and storage technologies. Smaller customers would be shielded from volatility by the contract generation procured centrally, to which they would have priority access. Today's market would move from being the central source of electricity pricing to a balancing market in which only imbalances to pre-purchased bulk procurement would be subject to market prices.

In addition, centrally procured contracts could be auctioned off to allow the market to decide the right price. This would be consistent with Alberta's PPA auction in 1998/99, which enabled the creation of Alberta's competitive wholesale electricity market.

Retail market operation

To ensure that customers benefit from the expected cost savings arising from contracted resources for renewable and cogeneration resources, it is essential that load customers have direct access to resources procured centrally. This can be done through changes to the existing retail market operation:

1) Each RRO service provider would be required to procure its RRO supply from the central procurement agency. It in turn would have to supply energy to meet the requested RRO load at the average cost of its portfolio.
2) Commercial and industry customers would have access to the contracted capacity also at cost, with priority given to small customers.
3) Retailers could purchase capacity and energy from a central agency to meet their contracted load, if surplus capacity is available.
4) Any net profit or cost accrued to the central agency's market and retail operations would be returned/charged to ratepayers.

7. IMPLEMENTATION

The proposed market changes have a compelling value proposition

As described, the electricity sector can make a significant contribution in supporting the government's policy objectives of material GHG emission reductions in Alberta. To deliver on this objective, a step change in Alberta's generation mix is required. Coal-fired generation output must be significantly reduced or eliminated entirely, and replaced with renewable and low-emission generation sources.

The current approach of relying on the existing energy-only market to facilitate such a change is not a viable option. That approach will be more costly, impose a risk on reliability, and will not meet the government's policy objectives.

The proposed changes outlined in this paper are intended to work together as a package in an integrated way to achieve the policy objectives, and supplement the existing market. These enhancements are expected to ensure the delivery of significant GHG emission reductions while preserving reliability, cost-effectiveness and economic growth.

There is an urgency to act now

While we believe the proposed changes will be effective and in the public interest, it is our view that we must act now or this one-time opportunity to replace coal with renewables and cogeneration will be lost. Given that all PPA contracts will have expired on before the end of 2020, the government must introduce policy changes as soon as possible. Lack of certainty on the market and industry structure will either deter investment in generation or miss this unique opportunity to influence investment decisions.

Berkshire Hathaway Energy Canada is ready and willing to support Alberta's renewable energy objectives

Berkshire Hathaway Energy has a long and successful history of developing renewable energy and supporting jurisdictions in transitioning from a coal-fired generation industry. The company is the only energy company to join President Obama's American Business Act on Climate Pledge, a demonstration of the U.S. private sector's commitment to taking on the global challenge of climate change. Berkshire Hathaway Energy has already invested more than US$15 billion in renewable energy generation projects that are under construction and in operation through 2014, and has pledged to invest up to an additional US$15 billion going forward.

Berkshire Hathaway Energy Renewables operates in six U.S. states and currently owns or has under construction more than 2,400 MW of renewable generation capacity, including:

- 1,272 MW of solar
- 681 MW of wind
- 338 MW of geothermal
- 138 MW of hydro

Berkshire Hathaway Energy's regulated utilities, including MidAmerican Energy, PacifiCorp and NV Energy are leaders in delivering reliable, low-cost, renewable energy to millions of customers in their service territories.

MidAmerican Energy owns more wind-powered generation capacity than any other U.S. rate-regulated utility. Renewable and other noncarbon resources currently make up 25 per cent of PacificCorp's close to 14,000 MW generation capacity. And NV Energy has more than 360 MW of cumulative installed solar capacity and 385 MW of geothermal capacity.

Berkshire Hathaway Energy companies also rank among the best in terms of customer service:

- Berkshire Hathaway Energy ranked first among U.S. holding companies in the TQS Research Associates study
- Three of its operating companies earned a very satisfied rating of 95 per cent or better from customers surveyed by TQS
- MidAmerican Energy Company was ranked first by three customer classes in J.D. Power and Associates' Midwest region survey
- Its gas pipeline companies ranked first and second, respectively, among 42 interstate natural gas pipelines in the Mastio & Company customer satisfaction index, and were first among major organizational groups for the ninth consecutive year

Berkshire Hathaway Energy's recent purchase of AltaLink is a sign of confidence in Alberta's electricity industry and it looks forward to investing in Alberta to deliver a greener future.

APPENDIX A – REVIEW OF ALBERTA MARKET STRUCTURE

The competitive wholesale electricity market opened in 1996. Together with the transmission regulation which was put in place in 2003, they represent the two key elements to the electricity market framework in Alberta. Generally speaking this structure has worked very well, and has produced the following benefits to Alberta customers:

- The generation market has delivered sufficient generation to ensure a reliable supply.
- The average wholesale market price of electricity has been stable. Net of inflation it has increased little since the market opened.
- Sufficient transmission has been built to ensure reliability and effective competition in the generation market.
- A reasonable level of fuel diversity has been maintained in the generation mix.
- Over 1,000 MW of renewable generation has been developed.
- New generation has attracted private investors who have borne the risk rather than customers. There has also been no need for any government support, in contrast to most other jurisdictions in Canada.

There have however been a number of areas in which the market has not performed as well, or has resulted in customer issues and dissatisfaction, as set out below.

- The existing generation fleet has a high level of greenhouse gas emissions, given the predominance of thermal coal and gas-fired generation.
- The economics of renewable generation have deteriorated significantly due largely to the market price discount that is received in the wholesale market.
- There is little opportunity for long-term contracts, due to the lack of credit worthy counterparties, which significantly restricts the development of capital intensive generation, such as wind or hydro.
- Retail competition has not been effective and small customers are reluctant to enter into fixed-price contracts offered by retailers, and thus suffer from market price volatility.
- High market price volatility, which is a fundamental characteristic of the market and has the greatest impact on small consumers given market complexity and their limited options.
- Cogeneration potential, which should be an effective resource in Alberta, has been unfulfilled largely due to lack of contracting opportunities.
- Alberta is poorly interconnected with neighboring jurisdictions, and no effective new interties have been added under the present system.

Looking forward there are also a number of looming issues and policy directions that the existing market structure is not well-suited to deal with economically or effectively.

- Significant new renewables are unlikely, given market fundamentals and difficulties in operating the system with higher levels of intermittent generation.
- To achieve any meaningful reduction in greenhouse gas emissions, coal generation must be retired as soon as possible and replaced by resources producing significantly lower emissions.
- Under the existing market structure coal would be largely replaced by gas-fired combined cycle, which, while better than coal, still produces significant greenhouse gas emissions.
- While some existing 500 kV intertie capacity can be economically increased, the existing market structure will not result in this capacity being available to support policy initiatives, such as additional renewables. Instead it will simply be used by traders, for additional commercial transactions, and provide limited benefits to Alberta customers.

Lack of contracting opportunities will continue to hamper the development of the appropriate generation mix to replace such a large block of baseload coal generation, effectively, economically and with a reasonable diversity of fuel risk.

APPENDIX B – QUANTIFICATION OF BENEFIT OF PROPOSED CHANGES

Approach/Analysis											
Coal Retirement	1,000	MW	7,446	GWh	GHG Emission	6.70	Million tonnes per year				
Two scenarios: (1) BAU assuming current market, and (2) Policy scenario assuming targetted RFP											
Comparing scenarios based on											
Emission reduction											
Total cost											
Show price impact to customers											
Objective: demonstrate Policy Scenario is more cost effective in delivering emission reduction, and less impact on customer price											

Key Value Drivers
Emission reductions: contracted mix of generation of renewables and co-gen
Cost efficiency: (1) avoiding market risk premium in the cost; (2) efficient use of intertie; (2) storage for intertie restoration

Scenarios	**BAU (Market)**					**Policy (Contract)**				
	Resources (MW)	Capacity Factor (%)	GWh	Levelized Cost ($/MWh)	GHG Emission (t/MWh)	Resources (MW)	Capacity Factor (%)	GWh	Levelized Cost ($/MWh)	GHG Emission (t/MWh)
Wind	300	35%	920	$ 80.0	-	1,000	35%	3,066	$ 65.0	-
Solar	50	18%	79	$ 120.0	-	200	18%	315	$ 100.0	-
Cogeneration	-		-	$ 65.0	0.29	450	85%	3,351	$ 60.0	0.29
CCGT	1,000	65%	5,694	$ 70.0	0.45	-		-	$ 70.0	0.45
GT/DG	350	20%	613	$ 100.0	0.58	100	20%	175	$ 100.0	0.58
Hydro	-		-		-	-		-		-
Intertie Use	500	4%	153	$ 195.7	-	500	12%	526	$ 57.1	-
Intertie Restoration	500		-		-	400	1%	35	$ -	-
Total			7,459	573	2,917			7,468	479	1,071
				$M/Year	1000 t/y				$M/Year	1000 t/y

Key scenario assumptions		
Wind	300 MW - higher penetration would result in heavier price discount	Policy driven, targeted RFPs Savings from the economy of scale and lower cost of capital
Solar	Largely not economic but will have some penetration either from gov't grant or early movers	Policy driven, targeted RFPs Savings from the economy of scale and lower cost of capital
Cogen	No addiitonal capacity built for market	Policy driven, targeted RFPs Savings from lower cost of capital
CCGT	1000 MW CCGT, 65% capacity factor	No additional CCGT
GT/DG	350 MW peaker, 20% capacity factor	100 MW peaker, 20% capacity factor Less need of peaking due to expanded use of tie
Hydro	No additional hydro	No additional hydro over the next 5 - 7 years
Intertie Use	Intertie use under current rules Primarily for trading by generators or retailers for portfolio optimization	Arrangement with BCH to optimize intertie use BCH has priority access to 500 MW restored capacity Captures wind arbitrage opportunities as price taker BCH gurantees firming services when AB needs AB mothballed coal units to support BC in dry years Value: Enable BCH to sell long-term contract Pricing: fixed payment for option, plus variable for energy delivered Intertie will be price taker/don't set price
Intertie Restoration	Use LSSi to restore intertie capacity to 12,000 MW About $30M annual payment for LSSi	Storage capacity to provide services equivalent to LSSi Also provide short-term peaking 400 MW with 15 minutes duration/$300 M investment No incremental cost over LSSi ($30M/yr) Other transmission reliability benefit Storage - price taker