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Electric Interties Between Provinces to Strengthen Canada's Energy Infrastructure

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Abstract:

The Van Horne Institute (VHI) is a Canadian not-for-profit think tank focussed on physical and regulatory issues related to transportation, trade and infrastructure. Over the last 24 months, VHI has hosted several discussions related to electric interties between provinces in Canada. The author has summarized this discussion and provides learnings based on his experience, and the VHI discussion, as follows:

1) Interties between provinces (or states or countries) result in greater overall reliability, lower overall generation costs, and enable overall increased greenhouse gas (GHG) reductions.
2) Maximizing the benefits of interconnections between provinces is challenging because adjacent provinces (or states or countries) have different electric market designs that do not always integrate well with each other.
3) There is urgent need for the federal government to fund and manage exploration of increased integration of provincial electric systems. There is no Canadian oversight related to interprovincial commercial and reliability management.

Discussion Summary:

VHI specifically examined the relationship between British Columbia (BC) and Alberta as an example of intertie issues. It then expanded such discussion conclusions to implications of stronger interconnections across Canada.

Electric systems require load to be balanced by generation every second of the year. Failure to keep balance cause outages – load/lines tripping, and escalating outages. Planning reliability requires having sufficient load following generation (hydro with unused capacity in the moment, gas turbines running at minimum with ability to increase generation, and instantaneous import from interties running at less than maximum capacity), in addition to base load generation and must run generation operating. Generally, thermal predominant systems (Alberta) manage their system by having large gas generation running at lower than full output which are capable of increasing output to respond to generators or tie lines tripping off. Systems like Alberta manage their risk by choosing a maximum exposure, i.e. 466 MW, that they can withstand in the event of a generation or line trip. Beyond this threshold, load is required to be tripped to keep the system from escalating to system wide outages.

Hydro predominant systems generally have an easier time to manage hour by hour reliability because hydro inherently has ample capacity compared to peak load. A hydro predominant system must manage their annual energy (water above dam) risk because they can have low rain/snow years. They manage their energy risk by buying energy off peak or at night from surplus neighbouring jurisdictions, or by running their underused thermal generation units. Similar to that of a battery, this allows them to store their water levels (energy) and gives them the flexibility to use this hydro to generate the power they need when it is desirable to do so.

Alberta

Alberta is basically at the end of a long chain of interconnect jurisdictions, in the Pacific Northwest of North America. Alberta has a weak connection to Saskatchewan (150 MW DC) and Montana (300 MW AC), and a strong connection (1,200 MW on a 12,300 MW peak system) with BC.

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Alberta has a high average load (average MW used divided by peak MW for the year) of 80% compared to about 60% in BC because of Alberta's industrial base. Historically, because of its high average load, Alberta has built a large portion of base load generation (that runs continuously) and a significant portion of generation that can cycle up and down to meet the peak (gas turbine generation supplemented by limited hydro generation).

In the 1990s, Alberta, in pursuit of efficiency and fairness to all generators, transitioned from several integrated electric utilities (companies that owned generation, transmission and distribution with captive areas) to an open market design. Alberta deregulated the industry so that distribution was split from transmission and generation. Currently, there are several large distribution companies in large municipalities and rural areas (Fortis in rural southern Alberta, ATCO in rural northern Alberta) which take care of connecting the transmission system directly to medium and small consumers. There are also several large transmission companies (AltaLink, ATCO) who take care of connecting generation to distribution, large customers, and jurisdictions.

The Alberta generation market is deregulated such that many generation companies build and sell generation into a pooled market, where all parties receive the same price in any given hour based on the highest last generation bid accepted. While there is no requirement for a particular generation company to ensure sufficient generation at all hours of the year, the government instituted an independent entity, Alberta Electric System Operator (AESO), to manage the grid and market to ensure reliability and efficient market competition by making and enforcing rules and planning the dispatch of generation.

In the last decades, with the realization that the world is increasingly producing significantly more greenhouse gases (CO_2, methane), Alberta has been transitioning from carbon intensive generation (coal) to green generation (wind, solar) such that Alberta has transitioned from 5% green generation (hydro) to 25% green generation with the addition of about 20% solar & wind generation.

Currently, Alberta has experienced several challenges with its market design due to the high market penetration of GHG reducing generation. Wind and solar generation are only available when the wind blows or the sun shines, respectively. Although Alberta has hydro generation, it is already fully used, thus there is no significant incremental energy storage available in Alberta. Wind and solar generation are relatively difficult to forecast because wind may decline, or sun may be clouded based on unpredictable hours.

In 2024, Alberta experienced many hours in the coldest months of the year, where wind and solar generation was severely limited, and had to take measures to reduce load by requesting voluntary and involuntary reductions, to not have a system collapse. Alberta now is in a situation where they either need larger reliable interconnections, more certain voluntarily load reductions, more gas turbines running at minimum, or intraseasonal and inter-period storage solutions – in order to enable much more GHG friendly generation.

Storage is currently very expensive and the storage that is available is not sufficient to move large quantities from periods of excess (e.g. fall/spring or night) to peak periods. Thus, GHG reducing generation requires either higher reliability connections and contracting with other jurisdictions or expensive duplication of generation capacity.

British Columbia

British Columbia (BC) has an integrated electric utility system (BC Hydro owns the majority of generation, transmission and distribution). BC Hydro (a provincial Crown corporation) is responsible for ensuring load is met, transmission is planned, and distribution is provided throughout BC.

BC has extensive existing, and significant future, hydro generation. Approximately 90% of its generation capacity is based on hydro. Hydro generation is very flexible. Water can be held back in the night to generate in the day. Water can also be held back in the fall/spring to generate in the summer/winter.

BC Hydro has multi-year risks in that its energy is dependent on rain and snow fall that can vary significantly from year to year. BC Hydro has the ability to move energy from year to year but relies on the opportunity to buy energy from interconnected regions (US Pacific Northwest or Alberta) to manage its energy risks. For example, according to the Fiscal 2024 Annual Report to BC Utilities Commission, BC Hydro imported approximately 20% of its electricity from outside the province, at a cost in the order of

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$1 billion, which was higher than anticipated largely in response to lower-than-average precipitation.

<u>Intertie Benefits – Alberta & British Columbia</u>

Although BC and Alberta are somewhat similar in total energy needs, BC has a different pattern of consumption than Alberta. Whereas, Aberta has large average load of 80%, BC has an average load of 60%. Whereas, BC has large hydro capacity, Alberta has significant base load (gas generation, cogeneration gas capacity) and significant solar and wind generation.

The result of Alberta and BC being adjacent and different (load and generation) is there are significant potential synergies between the jurisdictions. When wind and solar produce maximum output above Alberta needs (solar in the daytime and summer months and wind when the wind blows), BC has the ability to back off their water generation (hold water) and produce generation in daytime and peak times (daytime and winter/summer). Alberta has the ability to produce more energy from peaking units (gas, and night generation). Alberta has flatter wide open spaces that are agreeable to solar and wind, as compared to BC that is relatively mountainous.

Greater integration of BC and Alberta has the prospect of encouraging more GHG friendly generation in Alberta, reducing costs by taking advantage of BC's greater flexibility in storing energy in off peak hours to return it in on peak hours, and increasing reliability of both regions.

BC and Alberta are currently connected by a 500 KV interconnection that runs from southeastern BC to the Calgary area with transfer capacity of 1,200 MW import capacity to and 1,000 MW export capacity from Alberta. Alberta currently limits its reliance on BC to approximately 400 MW of capacity to protect the Alberta grid. Alberta does not use the entire 1,200 MW of potential capacity from BC because it would put too much reliance on one single source that could fail in key hours (lightning strikes or wind or other issues in BC or Alberta transmission systems).

Integrating an integrated electric system (e.g. BC – BC Hydro controls generation, transmission and distribution) that is predominantly hydro based with a deregulated system (e.g. AB - multiple separate generation, distribution, and transmission

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companies) is challenging because even though there are net benefits of combined systems, in some cases such benefits would not naturally be achieved.

For example, Alberta has surplus wind (and gas) energy in the night and in spring and fall. Alberta's market design is that when there is surplus energy, the prices are very low. BC Hydro would naturally buy very low energy prices in the night and fall/spring and sell surplus energy in the daytime winter/summer peak periods, back to Alberta or the US PNW. Generation in Alberta might not make enough profit to justify building more generation. Thus, without some commercial (or regulatory) arrangements and an increase in intertie capacity, GHG friendly generation in Alberta is not encouraged as much as it could be. Further, without agreements between Alberta and BC, BC might either sell its surplus energy to the US Northwest or effectively raise the price it offers energy into Alberta (by holding the energy for a higher price period) to an extent that it is not maximizing Alberta and BC synergies. In addition, for example, BC recently contracted for energy in GHG friendly generation in BC, at a higher cost than was available in Alberta which did not achieve lowest cost for both jurisdictions.

There is the ability to build more interconnections between Alberta and BC, but the reliability of the connections must be sufficient that Alberta load is not exposed to disproportionate single source risk and allows for flexible capacity. For example, an additional 500 kV line from BC could be built such that Alberta could raise its BC import capacity from 400 MW to 1,200 MW (since the second line would provide contingency for the existing line); or possibly there are technology solutions that would allow more reliability of the existing 500 kV line; or there are technology solutions that tie interruptible load in Alberta to automatically ramp up.

In summary, between Alberta and BC, there are large potential gains arising from integration (larger more numerous interconnections) that are limited by technology (one single connection with implications to reliability) and disparate market designs (BC Hydro ownership of generation, transmission, and distribution vs Alberta deregulated model).

Further Intertie Opportunities Across Canadian East-West Corridors

As described above, VHI intended to explore the benefits of greater integration of jurisdictions first by examining Alberta and BC; and then expanding the discussion to

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include other provinces. There are also benefits of integrating BC, Alberta, Saskatchewan and Manitoba.

Saskatchewan is similar to BC in that it has one large integrated utility (SaskPower) that is accountable for generation, transmission and distribution. However, unlike BC, its generation assets are more like Alberta, in having significantly less hydro generation and more base load generation and gas peaking generation. It also has similar high average load like Alberta. It has weak AC connections (~300 MW) to Manitoba Hydro and a small (150 MW) DC connection to Alberta.

Manitoba is similar to BC in that it has one large integrated utility (Manitoba Hydro) that is accountable for generation, transmission and distribution. It also has load similar to BC with proportionately higher generation capacity (hydro) than average generation and large storage capability. Manitoba Hydro has small AC connections (150 MW) to Saskatchewan and Ontario, but very large connections (1,400 MW) to the USA. Manitoba Hydro takes similar advantage of its hydro storage facilities and periodic surplus of hydro to buy and sell energy to the USA. Manitoba has large new hydro opportunities that are limited by interprovincial (and intercountry) transmission capacity.

There is an opportunity to create a transmission interconnection spanning from BC to Alberta, to Saskatchewan, to Manitoba. Such transmission interconnection might bring greater reliability and lower costs and encourage greater GHG reducing generation. It might also solve some of the market issues related to integrated systems relying on deregulated systems.

For example, with respect to encouraging GHG friendly generation, Alberta and Saskatchewan have surplus generation at night and fall/spring. Manitoba and BC could gain greater year to year reliability of energy; and the ability to sell more to the US. Alberta and Saskatchewan might gain more confidence in the usage of unpredictable wind and solar generation, which might encourage greater usage of such technology resulting in lower GHG impacts.

Additionally, for example, with respect to the economic issues caused by differing market designs (Alberta deregulated vs BC, Saskatchewan and Manitoba being regulated), a stronger more robust connection between BC and Manitoba, would create

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competition between Manitoba and BC, likely providing an incentive for generators to build additional facilities thereby increasing reliability and benefitting consumers. Higher market prices for fall/winter/night would encourage more GHG friendly generation in Alberta.

A strong east west BC-MB connection would be helpful to increase Alberta prices because a dual market (e.g. Manitoba and BC competing for storage) is likely to yield higher prices than single market (e.g. Alberta relying just on BC for storage) for competitive price setting. It is still likely that Alberta and Saskatchewan would not have sufficient confidence to rely more on BC and Manitoba, e.g. Manitoba and BC might have coincident needs for surplus energy – and the higher prices off peak/fall/winter might not be sufficient to attract new generation investment which is necessary to increase reliability and lower consumer prices over the long term. BC, Alberta, Saskatchewan, and Manitoba would likely have to agree to commercial terms on a long-term basis in order to encourage maximum gains in GHG reduction, prices and reliability. Given that Alberta is not centrally controlled, there is not sufficient motivation for any specific party to negotiate more integration. Even if there were sufficient motivation, it might not be legal for industry to cooperate. Arguably, the Canadian federal government could or should lead this discussion given the current mandate of the Canadian Energy Regulator. Currently, there is no government regulatory agency pursuing integration of interprovincial electric systems in Canada.

While VHI limited itself to extensive thinking about BC and Alberta; and then expanded the conversation to BC and Manitoba, there are likely to be similar synergies between Ontario (more similar to Alberta) and Quebec (more similar to BC). Further, we expect that the Maritime Provinces (New Brunswick, Nova Scotia, PEI, and Newfoundland) would have significant synergies and challenges.

It is also worth noting that with the current emphasis in the USA, to have less trade between the USA and Canada, it seems like now is the time to explore greater synergies between provinces in the electric systems.

Much of the discussion summarized above is conceptual based on experience and understanding of multiple industry participants as understood and summarized by a 4-decade expert in the field. There are obvious benefits of increased reliance on interties in terms of cost, reliability and GHG reductions. However, there are many important factors that need to be weighed in balancing the integration benefits versus the costs, such as identifying:

- What physical changes are possible that would enable greater reliance on existing interconnections.
- What are the costs associated with building and enhancing interties between jurisdictions.
- What are the regulatory constraints (e.g. funding, ownership, unpredictability of regulatory process, environmental issue, acquiring right of way, accommodating First Nations rights, and interprovincial regulation) in building tie lines from BC to Manitoba (or further to other regions in Canada), for example.
- What commercial and regulatory policy changes are needed in order to encourage thermal/must-run jurisdictions to cooperate with hydro/ample capacity jurisdictions in Canada.
- How and who should manage the discussions between provinces and industry to advance this conversation.

Funding and organization are needed to explore how the benefits of increased reliance on interties can be enhanced. It is also necessary that some government entity should be charged with the responsibility to examine opportunities that encourage such benefits.

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Conclusions:

Each province in Canada has created different regulatory regimes to deal with differing geographic (hydro vs thermal opportunities) and consumption patterns, associated with electric usage.

VHI has not conducted rigorous mathematical modelling of the benefits and costs associated with greater integration of the electric systems in Canada. However, it is likely that there is the opportunity to strengthen Canada's energy infrastructure by:

- Greater integration of disparate (load / generation / market design) provinces to create lower generation costs and lower GHG emissions on a combined jurisdiction basis.
- Greater integration, which requires larger and more numerous interconnections.
- Greater integration, which also requires solving the interplay of monopoly-controlled regions with deregulated regions through commercial contracts and regulatory discussions.
- There is urgent need for the federal government to fund and manage exploration of increased integration of provincial electric systems. The government of Canada should designate a government entity with this responsibility.

Disclaimer:

The author of this report, D. Scott Stoness, has over 40 years of experience in the electric and regulated pipeline industry including Alberta, BC, Federal Canadian, USA states and FERC experience. He has participated in integrated utilities (TransAlta Utilities in the 1980's to early 1990's, BC Hydro in the 1990's), integrated large municipal electric utility (Enmax), deregulated electric utility (Enron), and most recently regulated inter-jurisdictional oil pipelines (Trans Mountain from in the 2000's). He is an electrical engineer with an MBA with primary focus on commercial and regulatory matters.

Much of the conclusions and facts discussed are based on the Author's past experience, influenced by the discussions held by VHI over the last 24 months.

The opinions expressed in this report are the Author's and should not attributed to any specific VHI participant. Any errors or omissions are the sole responsibility of the Author. The Author thanks the VHI members and guests, including academic researchers and knowledgeable practitioners, for their thoughts, discussions, reviews and suggested edits.