IPPSA News: Thought Piece On Achieving Net Zero, Reliability, Affordability and Market Design

Achieving Net Zero emission in Alberta is challenged by the need to reconcile – simultaneously - four key variables:

1) Reducing emissions in the largest thermal market in Canada in a very short period of time
2) Ensuring the system remains reliable
3) Ensuring that the cost of electricity remains affordable
4) Recognizing that supply in Alberta is at investor risk, that the current market requires a level playing field among competitors and that the current market has driven generators and consumers to make multi-billion decisions which can be undermined by poor policy decisions.

This article reflects dialogue on the Net Zero challenge that IPPSA has been having with its Board and Power Members over the last number of months. It highlights the challenge of achieving Net Zero and concludes with some questions for policy-makers.

It should be noted - *with great emphasis* - that IPPSA and its members do not contest the 'what' of achieving Net Zero. The goal is admirable and Alberta generators have been decarbonizing the grid for some time. In 2014, Alberta had more natural gas installed generation than coal. The last of Alberta's coal-fired generation will cease in 2023. Alberta remains the easiest jurisdiction to add renewable energy in Canada thanks to its open market and strong solar and wind regime. Given its strides to decarbonize, Alberta's power sector is forecast to reduce GHGs 61% from 2005 levels by 2030[1].

What IPPSA and its members are focused on is the 'how.'

To IPPSA's knowledge, and at this time, there are no commercially available Net Zero generation technologies that are proven at a significant enough scale and that can be built by 2035 to ensure supply adequacy for Alberta.

1) Carbon Capture Utilization and Storage (CCUS), Hydrogen (H2), Direct Air Capture (DAC) and Small Modular Reactors (SMR) are not proven at the scale needed.
2) Hydro and interties (and the requisite non-emitting supply to serve Alberta's load that interties need to connect to) cannot be built by 2035.
3) Renewables and storage alone are unlikely to provide supply adequacy for the duration or the scale needed to meet Alberta's demand.
4) Scale is a critical consideration. Alberta is Canada's third largest power market with a winter peak of 12,187 megawatts (MW). For context, BC's winter peak is 10,302 MWs and Saskatchewan's is 3,868 MWs. Alberta's thermal supply equals approximately 14,500 MWs of installed generation and generation under construction.

Because of the lack of commercially available Net Zero technologies at the appropriate scale, increasing carbon prices under the Clean Electricity Regulation (CER) will - inescapably – drive up Alberta's power prices. EDC Associates estimates that the cost impact to Alberta of the CER versus 'business as usual' totals $40 billion over 2023-2036.

Given the foregoing, Net Zero by 2035 represents a risk to electricity reliability and electricity affordability for Albertans.

We also submit that policy-makers need to recognize that emissions reduction, market design and transmission policy in Alberta are now inexorably linked. To the point, changing the transmission policy

[1] Alberta Electric System Operator, 2021 Long Term Outlook

too dramatically may impede the development of renewable energy (wind, solar, hydro, pumped storage). And it may also precipitate a market design discussion that could delay investment decisions around CCUS or H2 infrastructure.

The concern over policy-stability isn't hyperbole. It's lived experience in Alberta.

In the late 1990s, the inability to reconcile a path to mitigating the market power of incumbent utility generators deterred new entrant supply. Simple as that. In the twenty teens, the capacity market debate, along with PPA cancelations, also deterred generation investment. In both circumstances, demand grew, supply was short and prices rose.

This article discusses the challenge of achieving Net Zero by highlighting the magnitude of the reliability and affordability challenge and concludes with some high-level questions for policy-makers

1.0 The Reliability Challenge Associated with Net Zero:

Market-Based Renewables are a Profound Alberta Success Story, But Baseload and Dispatchable Gas-Fired Generation is Required for Reliability for the Near Term

In terms of wind and solar generation, IPPSA expects Alberta's electricity market to continue to add wind and solar because of the following four key factors:

1) Wind and solar cost less to operate than do natural gas units and even more so as natural gas supply faces increasing carbon prices. Given that markets reward efficiency, wind and solar are forecast to remain profitable in Alberta's market as long as higher cost natural gas generation continues to influence power prices.
2) Alberta has a profoundly strong wind and solar regime. Wind and solar operate more frequently in our province than they do in most other provinces (higher capacity factors). The greater the volume of production, the greater the opportunity to earn revenue and provide a return on and of capital.
3) Rising carbon prices have driven - and will continue to drive - consumers to contract with wind and solar for emissions offsets, given that wind and solar production is metered and therefore easily verifiable. Alberta's open market allows consumers to contract with renewable developers and they continue to do so; either by adding on-site renewables or via financial contracts.
4) Alberta's open market is 'plug and play'. Wind and solar generators can build freely in response to price signals and customer choice. In every other province, supply is added in response to crown corporation or government programs.

As proof of the appeal of Alberta's market to renewable developers, the Alberta Electric System Operator's November 2022 Long-Term Adequacy report states:

- Of the 6839 MWs under construction, 52% are renewable.
- Of the 4475 MWs with regulatory approval, 53% are renewable.
- Of the 25,372 MWs of announced projects, 64% or 16,141 MWs are renewables.

As noted above, while zero emitting technologies such as wind and solar are essential to reducing GHGs, equally important is Alberta's gas fleet's essential role in ensuring reliability.

As an example, wind and solar production remain limited when the market needs energy the most. The following is from the Market Surveillance Administrator's Q3 2022 report and highlights supply response during three Energy Emergency Alerts in 2022, the first during a cold snap and the latter two during heat waves[2]:

Table 4: Comparison of relevant market metrics during certain hours of recent EEA events

	Dec 27, 2021 (EEA2 event)	Sep 27, 2022 (EEA3 event)	Sep 28, 2022 (EEA3 event)
Hour ending	21	19	17
Pool price ($/MWh)	$999.99	$999.99	$999.99
Demand (AIL) (MW)	11,137	9,978	10,305
Calgary Temperature (°C)	-30	26	28
Wind generation (MW)	217	145	111
Solar generation (MW)	0	93	569
Thermal outages[10] (MW)	2,875	2,982	2,911
Net Imports (MW)	511	60	0

Wind's output of 217 MWs, 145 MWs and 111 MWs reflected a small percentage of wind's installed capacity of 2,469 MWs at the time. Solar generation of 0 MWs, 93 MWs and 569 MWs also reflected a small percentage of solar's installed capacity of 1165 MWs at the time.

During normal market conditions, Alberta's combined cycle and cogeneration assets operate at capacity factors of approximately 85 to 90%. Capacity factor represents how much a unit *actually* produces against its *capacity* to produce. It is usually measured on an annual basis. In Alberta, wind's capacity factor averages ~35% and solar's ~20%.

When renewables are not operating, Alberta's power demand is almost entirely met by the province's combined cycle, simple cycle, converted coal and cogen natural gas-fired generation. Again, natural gas generation is essential to meet demand in Alberta.

There are additional complexities associated with incorporating intermittent wind and solar supplies in Alberta's market, namely frequency response, inertia, system strength, and net demand variability. More detail about those complexities is found in the appendix of this article.

Given the foregoing concerns with regard to ensuring reliability in Alberta, IPPSA supports the Alberta Electric System Operator's (AESO) assessment from its July 7, 2022 Net Zero Emissions Pathway Report that ***"Risk is unacceptable in all scenarios if legacy unabated gas units exit the market and are not replaced by supply with similar operating characteristic."***

2.0 The Affordability Challenge

$40 Billion Estimated Cost Impact of Clean Electricity Regulation (CER)

At this time, there are no commercially available technologies at a sufficient scale to replace Alberta's baseload and dispatchable natural gas fleet by 2035.

[2] Market Surveillance Administrator, Quarterly Report for Q3 2022, November 15, 2022, page 15

Therefore, Alberta will experience rising carbon compliance costs until sufficient technologies (CCUS/H2) emerge to offset the emissions of Alberta's natural gas fleet or that replace the fleet with equal characteristics (SMR, large-scale hydro). In the meantime, Alberta's power prices will rise.

The market price impact of rising carbon pricing is significant. EDC Associates estimates that the cumulative cost impact of market pricing under the Clean Electricity Regulation to be $40 billion more than its 'business as usual' case over the period 2022-2036. That estimated is driven by rising carbon prices upon Alberta's natural gas fleet. If carbon prices were to entirely flow through to natural gas generation, the following price impacts would occur[3]:

- $170/T represents a $63/MWh increase to the operating cost of a natural gas combined cycle unit. ($170/T times an emissivity of 0.37 T/MWh = $63/MWh). This carbon price impact alone is equivalent to ¢6.3/kWh.
- $170/T represents a $102/MWh increase to the operating cost of a converted coal unit. ($170/T times an emissivity of 0.6 T/MWh = $102/MWh). This carbon price impact is equivalent to ¢10.2/kWh.

As noted above, natural gas units are required to meet demand and, as such, will need to flow these carbon costs through to consumers in the form of higher market prices or else they will not be able to operate. Financially deterring the operation of Alberta's natural gas generation would only accelerate the reliability concerns raised in the reliability section above.

Carbon costs will continue until each natural gas-fired unit in Alberta that is required to meet demand abates its emissions. The above are just CER compliance costs. These costs do not include the impact of rising natural gas price on gas-fired generation, variable operating and maintenance costs, fixed operating and maintenance cost and a return of and on the capital costs of generation.

These costs do not include the reliability products that the AESO has identified to integrate intermittent supply and that are described in the appendix to this article. Adding the cost of cost of transmission and distribution wires, it is foreseeable that Alberta's delivered cost of electricity under CER will detrimentally impact Albertans, Alberta's public services (operating costs of hospitals, schools, water treatment, municipalities) and Alberta's farm, commercial and industrial power consumers.

Technological options to meet Net Zero by 2035 are limited:

- Applying CCUS is estimated to cost $1.4 million/MW[4]. At ~14,500 MW of existing gas supply in Alberta, abating all of Alberta's natural gas supply via CCUS would equate to $20.3 billion. It is also fair to say that CCUS has not been contemplated at this scale.
- Applying Direct Air Capture to the forecast 20MT of emissions from Alberta's electricity sector by 2030 at $779M/MT - $1.126 B/MT[5] would equal a carbon cost of $15.58-$22.52 billion. It's also fair to say that DAC has not been contemplated at this scale.
- Expansion of interties is a long-term option given a) the lead time of building large interprovincial or international transmission, b) the lead time of building new large scale, non-emitting generation to produce the power to meet Alberta's needs that would flow on those lines to replace Alberta's current

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[3] IPPSA understands that the Government of Canada has endorsed the Government of Alberta's TIER regime, which includes a declining stringency (to 0.3108 T/MWh by 2030) and a carbon price of $170/T by 2030. However, the rate of decline of stringency between 2030 and 2035 is unknown. At 0.3108 T/MWh and $170/T, the carbon price impact on an NGCC (at 0.37 T/MWh) equals **$11.60/MWh** ((0.37 T/MWh – 0.3108 T/MWh) * $170/T). The impact on converted coal unit (at 0.6 T/MWh) equals **$49.16/MWh** ((0.6T/MWh-0.3108 T/MWh) * $170/T).

[4] EDC Associates

[5] [A Process for Capturing CO2 from the Atmosphere: Joule (cell.com)]

gas fleet (14,500 MWs), and c) the need to resolve seems issues between Alberta's at-risk, competitive market and neighbouring crown corporations.

- Commercially available storage is principally battery-based with four hours of discharge time. Weather events - such as extreme heat or extreme cold – require supply availability for days and which usually correspond with demand peaking resulting in further requirement for supply to be available and operating. Renewables plus storage simply cannot meet demand during these circumstances. Long duration storage is not proven and nor is available at the scale needed.

3.0 Support for Market Approaches:

Unique among most Canadian provinces, Alberta's power supply was always provided by companies, and not crown corporations. In the mid-1990s Alberta was also unique in Canada by embracing competition – and not central-planning – as the driver for electricity generation investment and innovation. The migration to a competitive, market-based approach to electricity generation investment and production was predicated on the belief that:

- markets best ensure efficiency,
- markets shift investment risk to generators and off of ratepayers,
- markets best enable customer choice,
- markets best enable the downward pressure of competition,
- markets allow for the easier entry of new technologies as the decisions for adopting new technologies are decentralized to market participants (generators and consumers) themselves and not directed by governments or regulators.

IPPSA supports the price signal as the principal mechanism to attract supply, demand response investment, and consumer choice in Alberta's power market. If left unfettered, the energy market's price signal, combined with the carbon price signal, will work to drive emissions reduction behavior on the part of Alberta consumers and producers.

Given the reliability and affordability concerns pertaining to net zero by 2035 discussed earlier in this paper, it's also true that industry is seeking wisely designed policy-supports and funding supports that help alleviate affordability concerns, but that are also aligned with Alberta's FEOC market.

4.0 Questions for Policy-Makers:

To begin a dialogue on solutions to achieve Net Zero reliability and affordability, IPPSA proposes the following questions:

- Can the timeframe for Net Zero by 2035 be changed? A delay to the electricity sector's Net Zero by 2035 target will allow the potential for new abatement technologies to emerge and the potential for unit costs of abatement technologies to fall. Would a commitment to a Net Zero power grid by 2045 be palatable? Moving the power sector's target date would not impact the overall Canadian goal of Net Zero by 2050. A 2035 target effectively limits Alberta's abatement choices to CCUS or DAC; two technologies untested on the scale required to achieve Net Zero in Alberta.
- Will Alberta continue to adopt the Government of Canada's carbon tax and stringency? And what will happen to TIER stringency after 2030? Certainty in emissions reduction regime is critical as generators and consumers make multi-billion dollar – at-risk – decisions to respond to Net Zero goals. How will the Government of Alberta and the Government of Canada manage carbon price risk/stranded cost risk should the current trajectory of carbon pricing change?

- In addition to existing Investment Tax Credit supports, will public dollars be available to offset the cost of abating Alberta's natural gas fleet? To the point, if the market price impact of CER is $40 billion, wouldn't ~$20 billion in public support for CCUS and/or DAC and/or other cross-cutting emission reduction investments leave consumers better off? Can a program be created to allocate any such funding in a manner that is consistent with Alberta's legislation and 'level-playing field' principles?
- Will transmission policy in Alberta change and how? Will locational signals change to increase transmission utilization/optimization and if so, by how much? Given the inexorable nature of GHG reductions, market design and transmission policy, will Alberta honour its policy commitment to resolve existing constraints faced by renewable supply? Can the Canadian Infrastructure Bank play a role in providing lower cost debt to Alberta's wires utilities as a means to reduce intra-Alberta wires costs?
- Would policy makers consider commencing regional efforts to resolve intertie seams between Alberta and jurisdictions that have or that can construct baseload and dispatchable non-emitting supply? Some seams issues include: mitigation of market power of crown corporation supply, reciprocal access to compete for consumer, creation of a level playing field on taxation, among others.

The timeframe to decarbonize Alberta's electricity supply promises to be the most dynamic twelve years in the history of electricity in this province. IPPSA and its members are keen to engage with policy-makers and consumers to understand how this goal can be achieved while ensuring reliability, affordability and respect for all the billions of dollars worth of 'at-risk' decisions that generation companies and power consumers have made and need to make in the years to come.

APPENDIX: Operational Challenges Associated with Intermittent Supply

The following is a summary of the challenges identified by the Alberta Electric System Operator in its August 11, 2022 presentation, *Maintaining Reliability During the Transition*:

1) Frequency Response - relates to the need for electricity to flow at or near 60 Hertz. Minor deviations in frequency (measured in decimal place reductions in frequency) and over small amounts of time (measured in seconds) can cause consuming or generating assets to trip offline. The AESO states,
    - *"Primary frequency response (PFR) has declined from 2019 to 2021 and is expected to continue to decline as renewable penetration continues to increase*
    - *The time per year is growing where there is frequency response capability risk of Underfrequency Load Shed (UFLS), following a contingency*
    - *UFLS events are a violation of our reliability standards*
    - *Frequency deviations can result in cascading events, with broader reliability impact*
    - *Increasing number of UFLS events are already occurring due to declining primary frequency response (PFR) and inertia*
    - *Higher renewables will increase the risk of more UFLS events as PFR and inertia decline further*
    - *UFLS events trip a large number of customers"*
2) System Inertia –is created by large rotating motors associated with combined cycle natural gas fired generation. The AESO states,
    - *"Inertia levels will continue to decline with growing renewables; expect growing challenges"*

3) System Strength – relates to the short circuit ratio (SCR)
   - *"In regions of high renewable penetrations, SCR can decline considerably*
   - *Weaker system strength (lower SCR) in regions can cause reliability challenges (Voltage instability, system protection mis-operation, plant control instability, plant tripping for disturbances)"*
4) Net Demand Variability - relates to the sudden reduction in energy as wind stops blowing or as the sun sets. The larger the volume of wind and solar ramping down, the more the market has to call upon dispatchable supply – primarily gas supply in Alberta – to meet system demand. The AESO states,
   - *"Net demand ramp sizes increase and the frequency of occurrences per year increases as renewable penetrations grow*
   - *Increasing ramp sizes and frequency may require improved ramping capability in order to effectively match supply with demand"*
5) Maximum Single Severe Contingency – relates to the largest-sized generation unit the AESO is comfortable to permit in Alberta, given the AESO needs to operate the system should that unit trip. Currently, Alberta's MSSC is set at 466 MW. The AESO states,
   - *"Internal Alberta frequency response, including inertia response, must be sufficient to offset loss of MSSC and recover the frequency*
   - *Higher renewable penetrations will result in declining inertia and frequency response capability*
   - *As a result, the existing MSSC Limit will be harder to reliably absorb when islanded*
   - *Existing import levels will require more LSSi (Load Shed Service for imports) to offset the declining frequency response capability)"*