POWER WORKERS' UNION

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November 2, 2023

Environment and Climate Change Canada
Electricity and Combustion Division
Ottawa, Ontario

Submitted via Email: ECD-DEC@ec.gc.ca with Exec Summary on
https://www.gazette.gc.ca/rp-pr/p1/2023/2023-08-19/html/reg1-eng.html

Re: Clean Electricity Regulations Gazette Part 1, Vol. 157, No. 33

The Power Workers' Union ("PWU") represents a large portion of the employees working in Ontario's electricity industry. Attached please find a list of PWU employers.

The PWU appreciates the opportunity to provide input on the Proposed Clean Electricity Regulations (CER). The PWU is a strong supporter of emission reduction strategies, climate change initiatives, and Canada's clean electricity objectives and has engaged in several federal consultations that support the prudent and rational reform of the electricity sector and the importance of low-cost, low-carbon energy to the competitiveness of Canada's economic sectors.

The PWU believes that new, low-carbon electricity infrastructure is the best way to help advance Canada's NZ objectives by 2050 in a way that supports workers, communities and the competitiveness of our economy.

The PWU finds that it is not possible for the CER to achieve its objectives anywhere in the country in the timeframe identified. The assessment provided here strongly suggests that the ECCC should reconsider the timelines contained in the CER given the higher electrification driven demand, the conclusions it is drawing from its modeling about the potential contribution of renewables, and the disconnects between its supply mix assumptions and those of provincial plans which may be related to invalid and/or inconsistent cost assumptions.

We hope you will find the PWU's comments useful.

Yours very truly,

Jeff Parnell
President

Encl.

cc. Deputy Prime Minister Freeland, Minister of Natural Resources Wilkinson, Minister of ECCC Guilbeault, Council for Clean and Reliable Energy, Ontario Minister of Energy Smith.

List of PWU Employers

Abraflex
Alectra Utilities (formerly PowerStream)
Algoma Power
AMEC Nuclear Safety Solutions
Aptum (formerly Cogeco Peer 1)
Atlantic Power Corporation - Calstock Power Plant
Atlantic Power Corporation - Kapuskasing Power Plant
Atlantic Power Corporation - Nipigon Power Plant
Bracebridge Generation
Brighton Beach Power Limited
Brookfield Power Wind Operations
Brookfield Renewable Power - Mississagi Power Trust
Bruce Power Inc.
Canadian Nuclear Laboratories (AECL Chalk River)
Chapleau Public Utilities Corp.
Centre Wellington Hydro
Collus Powerstream
Compass Group
Cornwall Electric
Corporation of the County of Brant
Covanta Durham York Renewable Energy Ltd.
Elexicon (formerly Whitby Hydro)
Enova (formerly Kitchener-Wilmot & Waterloo North)
Enwave Windsor
Epcor Electricity Distribution Ontario Inc.
Erth Power Corporation (formerly Erie Thames Powerlines)
Erth Corporation
eStructure
Ethos Energy Inc.
Great Lakes Power (Generation)
Greenfield South Power Corporation
Grimsby Power Incorporated
Halton Hills Hydro Inc.
Hydro One Inc.
Hydro One CSO (formerly Vertex)
Hydro One Sault Ste. Marie (formerly Great Lakes Power Transmission)
Independent Electricity System Operator
InnPower (Innisfil Hydro Distribution Systems Limited)
Kinectrics Inc.
Lakeland Power Distribution
Laurentis Energy Partners
London Hydro Corporation
Milton Hydro Distribution Inc.
Mississagi Power Trust
Newmarket Tey/Midland Hydro Ltd.
North Bay Hydro
Northern Ontario Wires
Nuclear Waste Management Organization
Ontario Power Generation Inc.
Orangeville Hydro Limited
Portlands Energy Centre
PUC Services
Quality Tree Service
Rogers Communications (Kincardine Cable TV Ltd.)
Sioux Lookout Hydro Inc.

SouthWestern Energy
Synergy North (formerly Kenora Hydro Electric Corporation Ltd.)
Tillsonburg Hydro Inc.
The Electrical Safety Authority
Toronto Hydro
TransAlta Generation Partnership O.H.S.C.
Westario Power

Power Workers' Union Submission on Canada's Proposed Clean Electricity Regulations (CER)
November 2023

The Power Workers' Union (PWU) is pleased to submit comments and make recommendations to Environment and Climate Change Canada (ECCC) regarding the proposed Clean Electricity Regulation (CER). The PWU remains a strong supporter and advocate for the prudent and rational reform of Ontario's electricity sector and recognizes the importance of planning for low-cost, low-carbon energy solutions to enhance the competitiveness of Ontario's economy. The PWU is a strong advocate of emission reduction strategies and has engaged in several federal consultations, including the SMR Action Plan, Hydrogen Strategy, National Infrastructure Assessment, Clean Fuel Standard (CFS), Carbon Capture Utilization and Sequestration (CCUS) tax credit, the 2030 Emission Reduction Plan, the Clean Electricity Standard (CES), the Sustainable Development Strategy and the Federal Investment Tax Credits.

Context

The PWU applauds the ECCC for having advanced the CER design and for addressing several concerns expressed by the PWU in its submission regarding the previous CER proposed frame:[1]

- Reinforced CER technology neutrality by eliminating the initial emphasis on "renewables" solutions and focusing instead on "non-emitting" solutions;
- Allowed for the continued use of existing natural gas-fired generation for meeting peak and reserve system reliability needs;
- Clarifying the independence of the CER from the Output-Based Pricing System (OBPS); and,
- Providing an objective communication of cost assumptions in the CES.

However, the PWU remains concerned that several of the risks identified in our previous CES submissions have not been addressed, including:[2]

1) The widely accepted challenges of achieving net zero electricity emissions by 2035 given the forecast demand growth from electrification;
2) The inherent challenges presented by the intermittent output from renewable technologies;
3) The dependence of regional interprovincial Tx Interconnections on the type and location of new non-emitting supplies; and,
4) The need to ensure federal tax credits and the Green Bond Framework (GBF) are technology agnostic and include nuclear. The PWU has separately provided feedback to Finance Canada on the ITCs.[3]

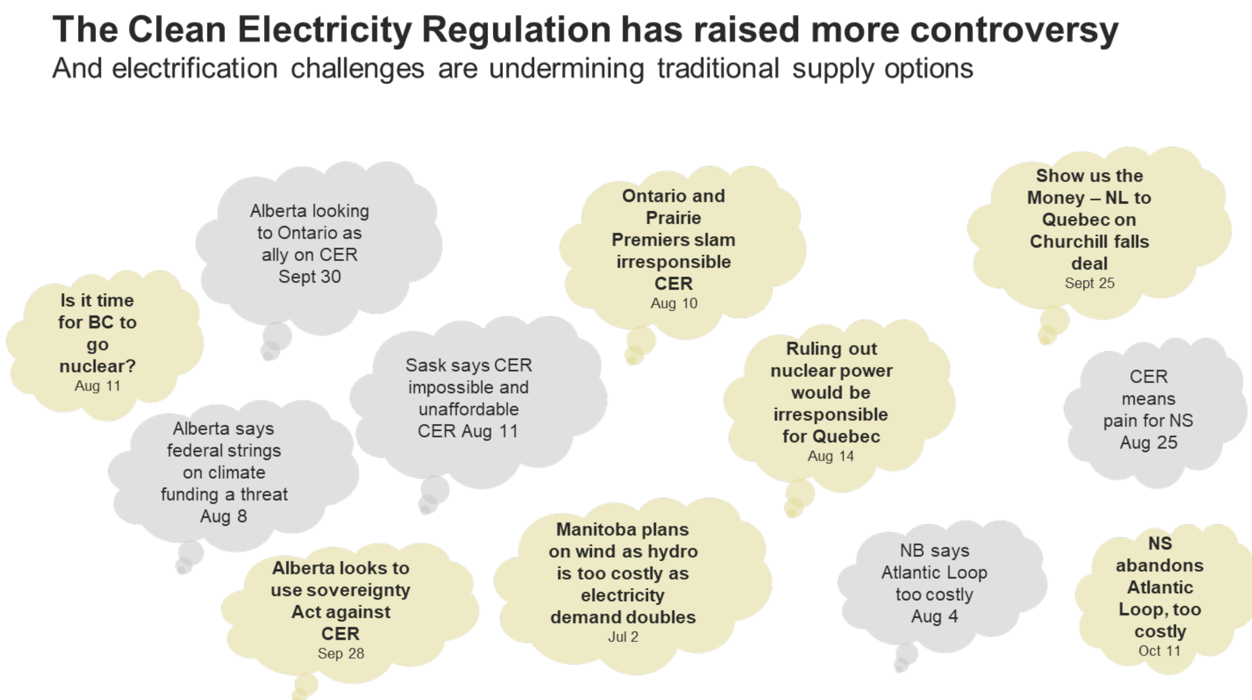
Many stakeholders share these concerns as respective provinces and territories continue to struggle to develop approaches that provide lower carbon energy for meeting future electricity demand.

The current high-profile feud between Alberta and the federal government over oil and gas and carbon policy has spilled over to debates on the proposed CER. Alberta is not alone on this. Ontario has also

[1] PWU submission to the ECCC regarding Canada's Proposed Frame for the Clean Electricity Regulations (CER), August 2022.
[2] Power Workers' Union Submission on Canada's Clean Electricity Standard Discussion Paper, April 2022.
[3] PWU submission on 2023 Budget Investment Tax Credits to the Department of Finance Canada, September 8, 2023.

expressed opposition and concerns have been voiced in Nova Scotia. These issues are playing out in the public domain as reflected by Alberta's recent ad campaign and headlines in the media over the last few months as summarized in Figure 1.

Figure 1



Clearly, the proposed Clean Electricity Regulation is at the center of the challenges in providing significant amounts of new, lower-carbon energy that Canada will need. Several unexpected developments have emerged:

- Calls for nuclear energy in Quebec and BC
- Manitoba is not considering more hydro given the higher cost
- Newfoundland and Labrador and Quebec have renewed discussions over Churchill Falls and,
- New Brunswick and Nova Scotia do not support the proposed Atlantic Loop transmission line.

All of the above lead to questions about the viability of the assumptions in the cost benefit analysis for the proposed CER and represent significant challenges for achieving an affordable and reliable energy transition by 2050. To help address these challenges, the PWU makes the following recommendations:

1 - The CER benefits case should be assessed against the full electrification demand to ensure policy makers appreciate the scale of the development challenge that the CER is imposing and recognize the requirement for substantial ongoing gas-fired generation to ensure a reliable transition to a net zero electricity system for Canadians;

2 - The potential contribution from renewables should be remodelled to address the flaws and risks in the underpinning modelling that overstates their potential contribution;

3 - Cost benefit of interregional transmission should be re-evaluated against realistic fundamental premises and assumptions; and,

4 - Modelling used to identify supply mix options and support the CER benefits case should be validated against provincial plans regarding viability, costs and cost impacts.

Recommendation #1 – The CER benefits case should be assessed against the full electrification demand to ensure policy makers appreciate the scale of the development challenge that the CER is imposing and recognize the requirement for substantial ongoing gas-fired generation to ensure a reliable transition to a net zero electricity system for Canadians.

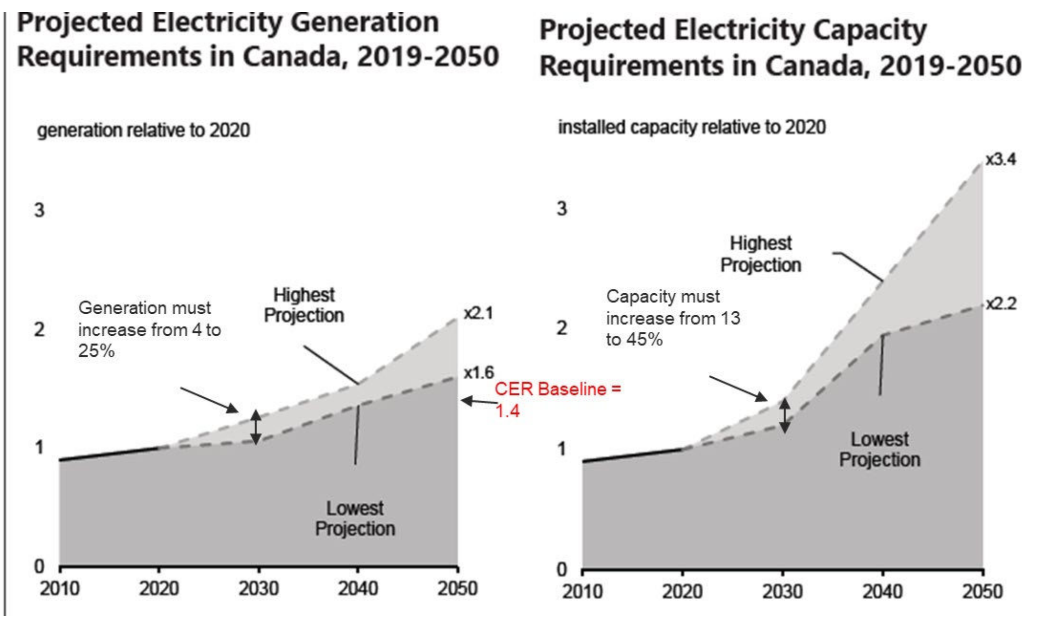
Three factors underscore the magnitude of the challenge facing the country in achieving the transition to a net zero economy:

- Demand growth will require a more significant and rapid buildout of capacity than contemplated by the CER;
- Outcomes of the CER scenario modeling reflect limited supply mix options; and,
- Forecasts indicate that the pace of demand growth will outstrip the ability to develop non-emitting solutions that comply with the CER.

Demand growth is more significant than contemplated by the CER

Canada's 2023 Federal budget stated that larger generation capacity and enhanced transmission networks are required to ensure the reliability of our electrical grids and refers to the charts in Figure 2 that show Canada's demand doubling by 2050 and generation capacity increasing by 2.2 to 3.4 times.

Figure 2



These projection ranges were assembled by the Canadian Climate Institute (CCI) from five 2021 reports and one released in early 2022 by the David Suzuki Foundation (DSF).[4] The Trottier Foundation singularly

[4] CER (2021); DSF (2022); CCI (2021); EPRI (2021); Jaccard and Griffin (2021); IET (2021); Stats Can (2022).

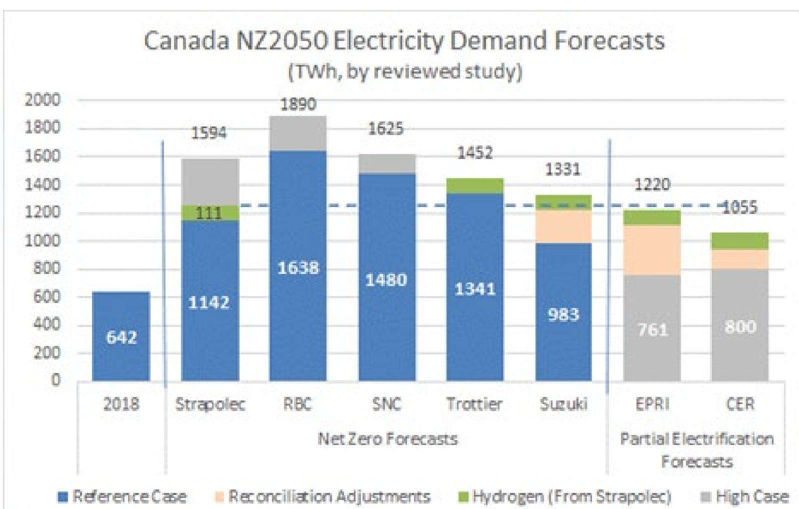
projected the highest while the others, including from the Canada Energy Regulator in 2021, were on the low end.

These reports were in the public domain when the Clean Electricity Regulation was developed and are cited in the proposed regulation materials. In fact, the analysis behind the Clean Electricity Regulation design used a growth range of 1.4x to 2.5x to bookend these projections. However, the high end was used only for sensitivity analysis and was disregarded because of the modelling tools used by the ECCC. Its models rely on coded actual policies which do not include a Net Zero model, a prerequisite for capturing the 2.5x case. The CER business case is predicated on 40% growth in demand by 2050.

There is a significant difference between the challenges of meeting a 40% growth in demand and those of achieving a 110% growth in demand in the same timeframe. The higher end requires almost triple the amount of needed new electricity generation compared to the business case in the proposed CER. As an example, the Canadian Climate Institute states that: "*total generation must increase from 4 to 25 per cent by 2030"* → a range of a factor of 6. This does not consider the lower forecast assumptions made by the ECCC in the CER cost benefit analysis or the need to displace existing fossil assets.

Furthermore, a closer inspection of the data supporting Figure 2 shows that, except for the Trottier Study, ***none of them*** were actually net zero studies. Aligning the assumptions would result in a demand forecast of around the 2.1x growth factor found by the Trottier study. In addition, subsequent, independent Net Zero studies have all aligned on a minimum demand growth of about 2.1x. These included reports by SNC Lavalin and the Council for Clean and Reliable Energy based on analysis by Strapolec. The comparative results are illustrated in Figure 3.[5] Differences in assumptions regarding carbon capture, electrolytic hydrogen, and biofuels net out to similar total demand forecasts.

Figure 3[6]



Similarly, the 2023 edition of the Canada Energy Regulator's Energy Future report confirms this expected demand range of 2.1x growth in needed electricity supply.

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[5] SNC Lavalin, Engineering Net Zero, 2021; CCRE, A National Energy Vision, 2021.

[6] Reconciliation adjustments applied to correct for conspicuous discrepancies from actuals and consensus assumptions.

To properly inform policy, the implementation challenges of this higher demand forecast must be considered to validate the viability of the CER-modelled supply mix pathways. The CER aims to ban most operations of natural gas plants by 2035 and is premised on two assumptions that must be achieved in just over 10 years: new non-emitting generation can be built to displace the gas-fired supply and the new demand; and, transmission systems can be upgraded to accommodate the new generation.

The amount of demand growth directly impacts the scale of new generation capacity required. Alarmingly, Figure 2 above indicates a growth range of 2.2x to 3.4x in required installed generation capacity by 2050. An increase of up to 45% could be required by 2030 alone. These capacity increases are much higher than the forecast growth in demand since they reflect the nameplate capacity of the supply options identified in the referenced reports, not derated values that would reflect their peak contribution.

Independent analyses show that growth in peak needs can be managed to roughly 2.0x, slightly less than overall demand growth.[7] The higher projected capacity growth factors identified in Figure 2 are due to extensive use of renewables in the cited reports. Also noteworthy is that the difference between a 2.0x and 3.4x in needed new capacity development would suggest a need for a 3.4x transmission capacity build-out. This would more than double the cost of incremental transmission required to connect that generation. It does not appear that the CER cost-benefit analysis has factored these cost implications into their assessments.

Outcomes of the CER scenario modeling reflect limited supply mix options with minimal impact

The analysis of the CER costs and benefits compared two scenarios: a baseline reference and a regulated scenario. The demand forecast for both scenarios is practically identical with growth of 43% to 2050 as mentioned above. The entire purpose of the CER is to encourage a reduction in unabated fossil fuels by 2035. The baseline scenario reflects a 38% or 33 TWh reduction in that type of generation. The CER regulated scenario reduces that by another 25 TWh, or about 3% of the predicted total generation in 2035 of 774 TWh.

The CER analysis used modelling tools to predict how the supply mix might change if the CER were introduced and then assessed the incremental cost.

The CER analysis shows the supply mix for both scenarios to be very similar with growth to about 260 GW by 2050 dominated by emitting resources, hydro and other non-emitting supplies, primarily wind, while the nuclear footprint shrinks. Under the CER regulations, by 2050 more of the emitting supplies would be equipped with carbon capture and 2 GW of new nuclear SMRs, 3 GW of new hydro, and 1 GW of storage is added to the supply mix to offset a reduction of about 4.5 GW of emitting supplies. These are very small changes considering that Canada's total system capacity is forecast at about 260 GW.

Both scenarios anticipate about 4 GW of new gas-fired generation by 2030, and about 8 GW of new hydro and less overall nuclear generation by 2035. The assumption that more hydro can be built and no large scale nuclear is anticipated contradicts Ontario's Provincial Outlook.[8] Furthermore, there is widespread acknowledgement by several Canadian energy ministers that new hydro options are limited, contrary to the 18.5 GW contemplated by 2050 under the CER regulated scenario. These contradictions

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[7] Strategic Policy Economics, Electrification Pathways for Ontario, 2021.
[8] IESO, Pathways to Decarbonization, Dec 2022

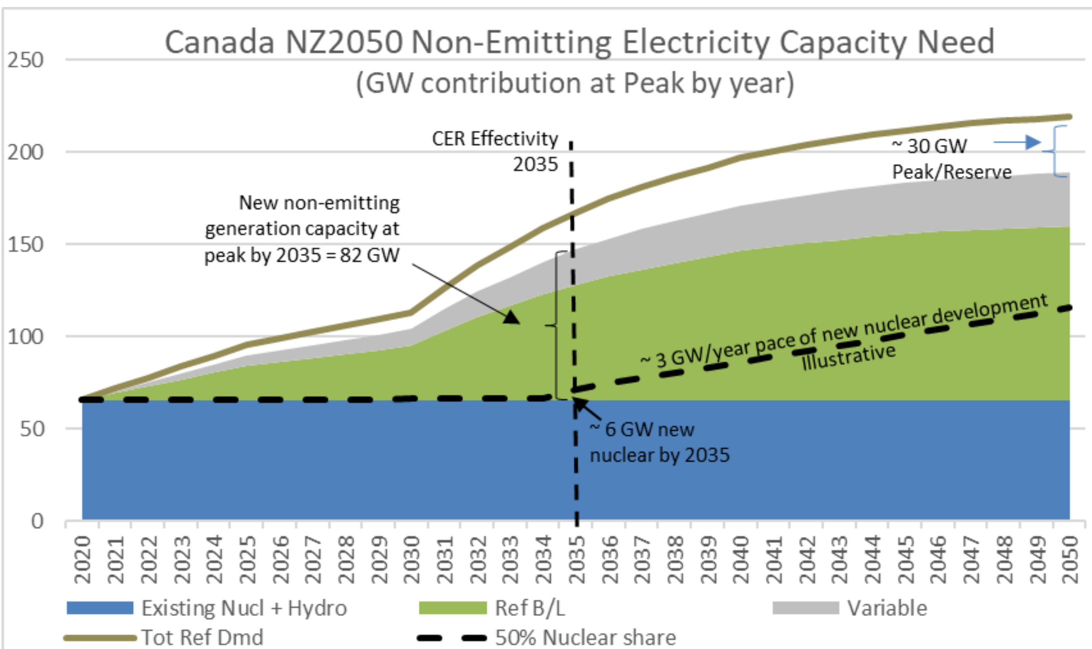
suggest the need to revisit the assumptions used to model the CER impacts to date. The challenges facing Canada's future supply options are further exacerbated by the higher demand noted and discussed above.

The pace of demand growth will outstrip the ability to develop non-emitting solutions that would comply with the CER.

As shown below, Figure 4 projects a 2.1x growth in demand requiring the development of an enormous amount of new non-emitting energy in the time available.[9]

Figure 4 projects the minimum required pace of development by year of new non-emitting baseload, intermediate and peak supplies[10] to meet the demand forecast and displace emitting resources to achieve Net Zero by 2050.[11] Note that this chart reflects the de-rated capacity of the supplies to reflect their contribution potential at peak, when renewables contribution is minimal.[12]

Figure 4



Analysis strongly suggests that demand will outpace the ability to develop energy resources to meet the need in the time required. Accelerating EV and heat pump adoption will drive the near-term shape of

[9] Total 2050 demand shown reflects the Strapolec forecast which is the lowest of the Net Zero forecasts reviewed.
[10] Baseload –The constant level of demand present 24x7 365 days per year. Going forward, emitting sources should not be considered for meeting baseload. Intermediate – Demand rises during the day and drops at night. Fossil-fuel generation has traditionally been used to meet intermediate demand. Peak – Represents the top 1-2% of the demand hours in a year, typically driven by consumer heating and cooling (air conditioning) demand. Reserve supply -- Rarely occurs as the estimates for peak demand already reflect worst case weather conditions. Reserve capacity is provided to assure system reliability against failures in load-serving generation supply.
[11] The shape of the demand curve reflects Canada's emission reduction objectives as captured by Navius 2021 and is similarly weighted to the growth anticipated by the CER analysis.
[12] ECCC Sept 2022 webinar on initial modeling suggested that solar should be awarded a zero contribution value at peak times and wind 17.5% of its capacity.

the curve – this is currently being aggressively incented by the federal government. Furthermore, demand can be expected to grow faster than illustrated due to new immigration, economic development, strategies such as critical minerals, as well as corporate net zero objectives. These are all factors that are not reflected in the currently available studies of demand forecasts.

With respect to capacity development, four factors are highlighted:

- Need to add up to 82 GW of non-emitting supply capacity to meet peak demand by 2035
- A hypothetical accelerated nuclear development schedule is unlikely to bring much nuclear online before 2035 and even building the equivalent of a new Darlington site every year for the subsequent 15 years will only supply 50% of the needed baseload.[13] It is unlikely that new hydro could be constructed faster to build as much capacity.
- There is a need for up to 30 GW of peak and reserve capacity throughout the timeline, which could be served by unabated gas-fired supply, as allowed for in the proposed CER.
- Most of the up to 82 GW of the new baseload and intermediate capacity needed by 2035 cannot be addressed by non-emitting resources in that timeframe. There are no known non-emitting solutions that can address it.

The CER modelling approach stated that when higher demand scenarios were considered, given the CER's cost assumptions, the needed capacities just scale in the simulation. The CER Regulated scenario identifies a need for 8 GW of new hydro by 2035. Adopting the more realistic option would require 2.5 times that amount for a total of 20 GW of new hydroelectric capacity by 2035. That's almost as much as Quebec's installed capacity today. The CER models would require 160 GW of renewables and 21 GW of CCS equipped gas-fired generation — all within 10 years. Experience shows that the required CCUS, hydro, nuclear and transmission cannot be built in the time required. This is a long game, the CER should be more focused on 2050 than on 2035. The ECCS's model and recommendations do not scale to the demand reality Canada is facing.

Canada is now at risk of brownouts across the country due to the rapidly advancing demand. The system will face higher risks and costs if existing assets are phased out too soon and new gas-fired generation is dis-incented, as currently planned by the CER.

Given the mammoth emerging capacity needs in the near term, policy makers must accept that the country has extremely limited options over the next 10-15 years for the significant amount of reliable affordable supply that must be built relatively quickly – with the exception of more gas-fired generation. Ontario is procuring new gas-fired generation and will use it to augment baseload and intermediate supply in the long run until sufficient non-emitting resources are built.[14] Ontario's IESO has advised the ECCC that natural gas will be needed at least until 2043 – and that is based on modest Ontario demand forecasts. Partial emission reductions from the required new gas-fired generation may be possible with more renewables. However, the integrated operations and potential for extended dependence on gas-fired generation should be carefully considered.

[13] SNC Lavalin's 2021 Engineering for Net Zero report estimates that an aggressive development with minimal hurdles could achieve 55 MW by 2050.
[14] Power Workers' Union Submission on Canada's Clean Electricity Standard Discussion Paper, April 2022.

Recommendation #2 – The potential contribution from renewables should be remodelled to address the flaws and risks in the underpinning modelling that overstates their potential contribution.

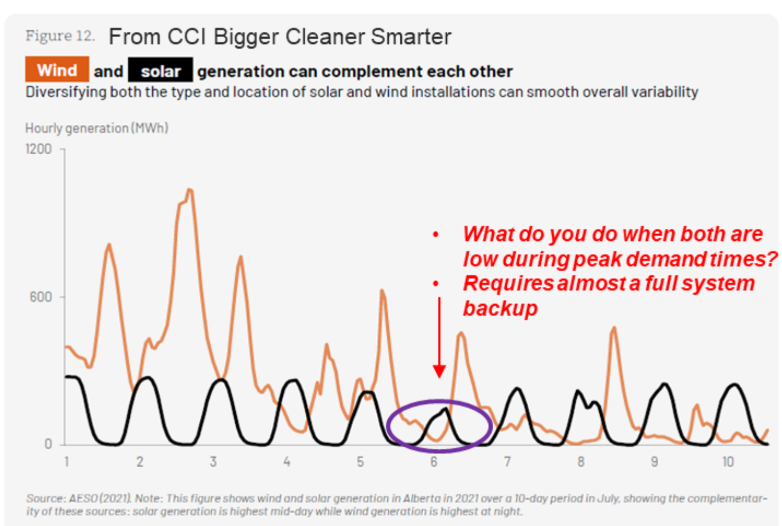
The PWU previously submitted extensive commentary and analysis to the ECCC on how to accurately model the contribution of renewables to the electricity system.[15] In that submission, the PWU recommended that the CES treatment of renewables should clearly recognize the challenges of relying on these resources to achieve its goals and cautioned that the modelling of renewables is pivotal to properly understanding the operational and cost implications for the electricity system.

There is significant misinformation being communicated about the contribution of renewables to the electricity system. This is important because the CER and many Net Zero studies anticipate that wind will provide much of Canada's new generation e.g., CER's 2023 Energy Future report identifies need for over 100 GW of new renewables. It is notable that this is substantially less than the 160 GW that would be forecast in the CER model for the high demand scenario.

Deficient forecast demand and supply mix modelling has provided a complex minefield of conflicting results underscoring the need for comprehensive, transparent data sharing, common assumptions, and modelling. The following two examples highlight this need—recent reports from the Canadian Climate Institute (CCI)[16] and David Suzuki Foundation (DSF).[17]

The CCI argues that wind and solar generation can complement each other as shown by their illustration in Figure 5. However, the implications of misalignment with demand are overlooked. For example, wind peaks at night but demand does not.

Figure 5



[15] Power Workers' Union Submission on Canada's Clean Electricity Standard Discussion Paper, April 2022.
[16] Canadian Climate Institute, Bigger, Cleaner, Smarter - Pathways For Aligning Canadian Electricity Systems With Net Zero, May 2022.
[17] David Suzuki Foundation, May 2022.

As further annotated in the figure, what happens when both supplies are low due to weather induced intermittency? It is well understood that renewables need a reliable backup supply option → the question becomes how much.

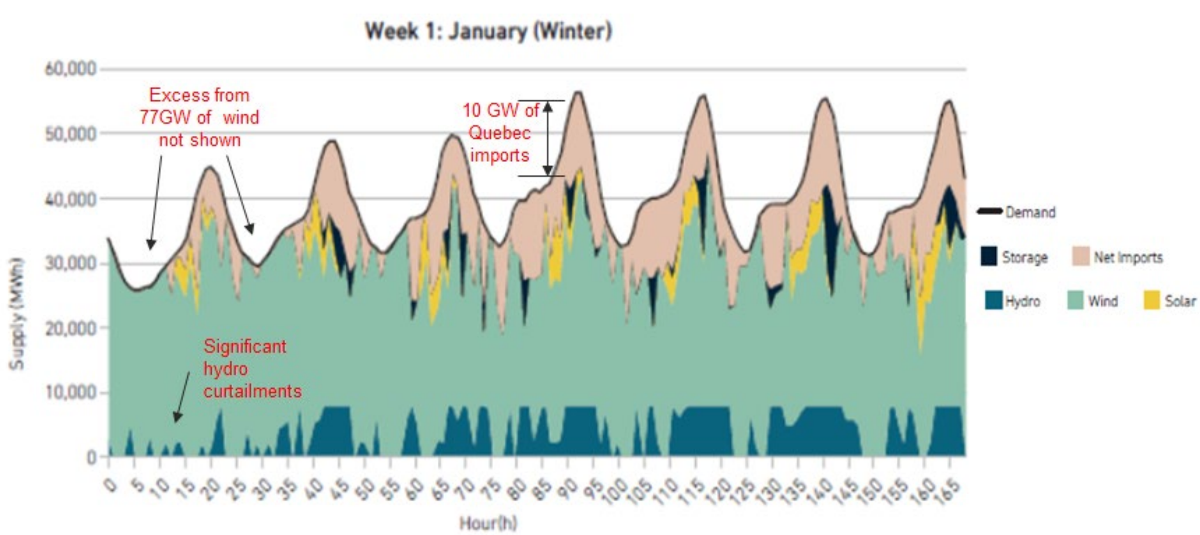
Figure 5 also illustrates how 5-6 days of storage would be required to store the required back up early in the week in anticipation of lower output later in the week. Such a low duty cycle significantly increases costs. It is also important to recognize that during winter, solar values are significantly reduced.

Robust modelling is a prerequisite for informing decision makers with the best information about the limitations of intermittent renewable supply options. Previous PWU submissions have referenced significant independent academic research that demonstrates inadequate model fidelity can overestimate the cost benefits and contribution of renewables.[2]

Most models, including DSF's and the NextGrid model used by Environment and Climate Change Canada (ECCC) to assess the Clean Electricity Regulation make averaging assumptions that mask the intermittent consequences of renewables as well as real peak energy demand needs. The DSF renewables-only solution for Ontario highlights several pitfalls of inadequate modelling, as illustrated by Figure 6 from that report.[18]

- The DSF model assumes 10 GW of Quebec imports, in winter. Quebec does not have this capacity and will not build it to just meet Ontario's demands for a couple of months of the year. Quebec's supply challenges are further discussed in Recommendation 4.
- Hydro is curtailed to minimize "wasted" renewables generation. This is not a viable approach for Ontario as its hydro resources are not reservoir backed and their curtailment leads to spilled water which results in higher costs.
- There is no identified curtailment or forecast "wasted" electricity from renewables, an impossible likelihood given the wind production could spike as high as its nameplate capacity of 77 GW which would be off the scale of the chart.

Figure 6

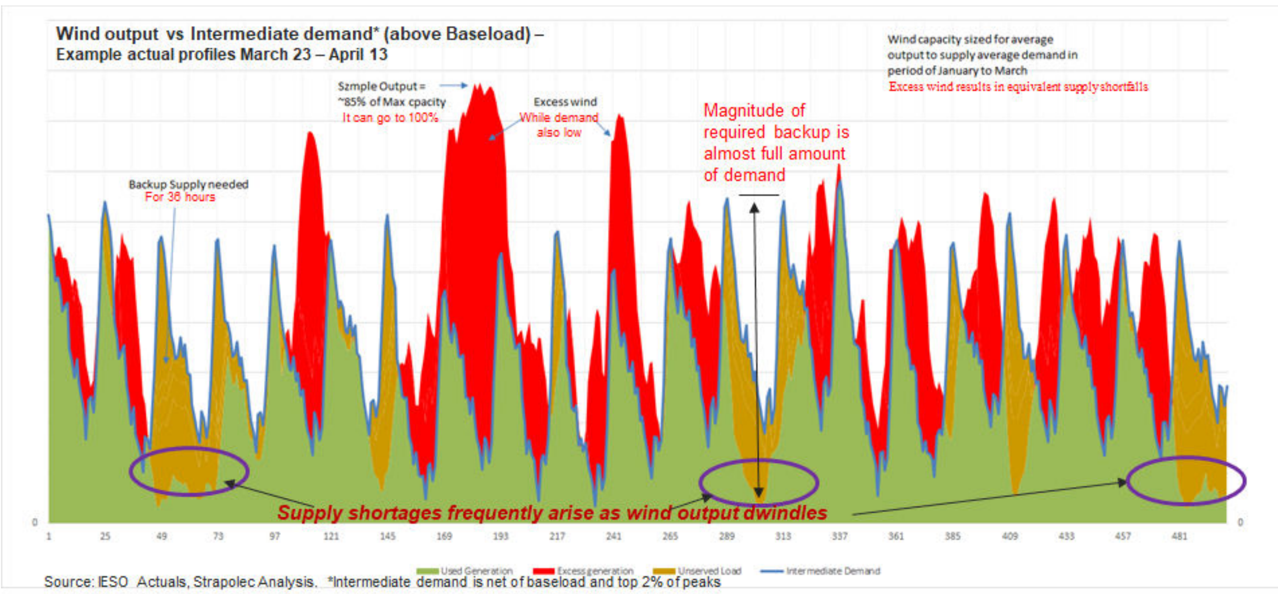


[18] The model has 77 GW of wind, 4 hours of storage at about 25% of demand (net of hydro supply), and some solar.

These observations are supported by available actual data. Figure 7 shows actual Ontario profiles of wind output and intermediate demand above baseload for three weeks beginning at the end of March. The wind capacity has been scaled to match the average expected wind output to the average amount of demand over the months of January to March. The figure illustrates the volatility of wind intermittency in the context of the variability of demand.

The green colour highlights the amount of wind that is directly used to meet demand. Demand is the blue line that rises and falls with each day. The excess wind energy that is shown in red is significant and leads to a need for an equivalent backup supply (brown) to balance the energy demand. The wind output can frequently drop quite low to less than 10% of its capacity and stay there for over 36 hours. Since this low output can persist for some time, equivalent backup generation capacity to meet full demand is required. This backup capacity must also be very flexible. Wind can work very well with thermal generation, e.g., CCS equipped natural gas in Alberta or with reservoir hydro like Quebec's. These options are not suitable for Ontario.

Figure 7



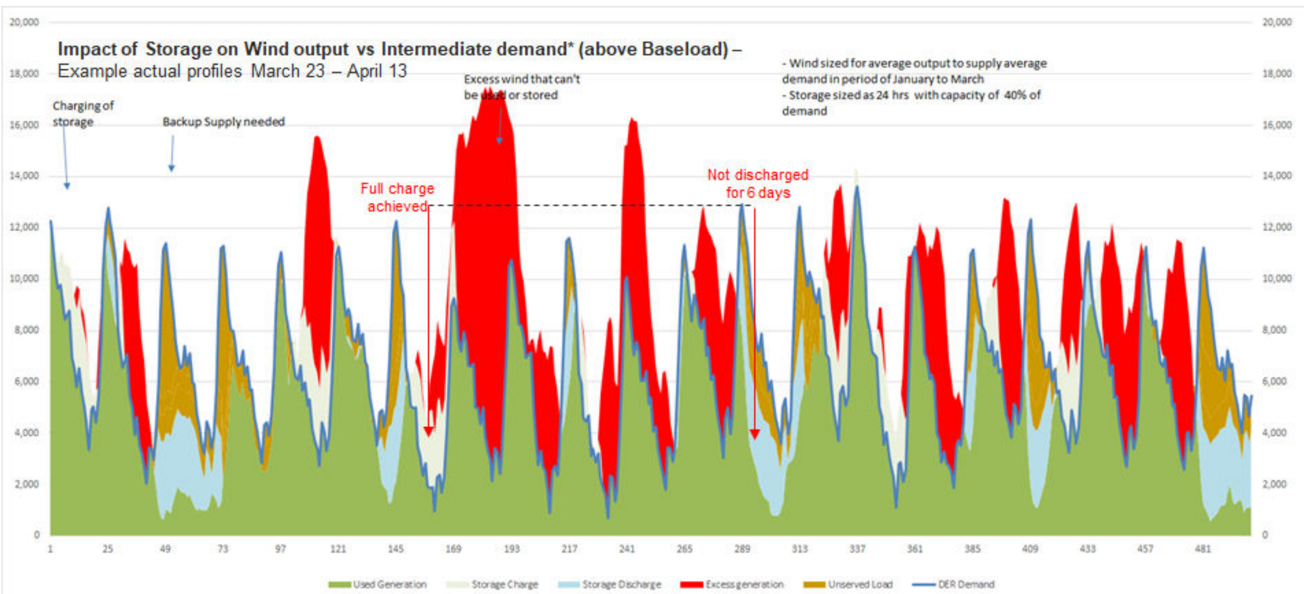
Many argue that storage can be used to smooth the intermittency of renewables. Figure 8 illustrates the behavior of storage against these actual demand and supply profiles by adding 24 hours of storage with a capacity to supply 40% of demand, a large amount. At 15% of wind capacity, this is double the amount modelled by the CER and in the DSF reports. The storage discharge is in light blue and charging in white. The results show a need for significant flexible backup and substantial "waste". Furthermore, the duty cycle between charging and discharging the storage could be 6 days, making the unit energy cost of the storage very expensive plus a 15% to 35% loss premium.

Additional analysis of Ontario and Alberta wind data shows that there can be very low wind output for up to 20 days. Renewables-based solutions require some ***substantial*** mix of flexible supply like storage and natural gas. In considering the supply mix contemplated by the CER analysis, the wind capacity is much higher than the flexible supply capacity and the relative storage capacity is much lower than illustrated in Figure 7. This suggests that the ECCC's CER modeling suite is not accurately modeling the renewables and should be adjusted to reflect these challenges, risks, and costs.

In the end, the analyses for Ontario conclude that the need for flexible backup capacity, even with substantial storage, is relatively undiminished at over 90% of intermediate demand. Even with storage, the thermal backup will still need to supply almost 30% of demand and operate with a capacity factor of over 13%, which would be non-compliant with the CER rules that would only allow up to a 5% capacity factor.

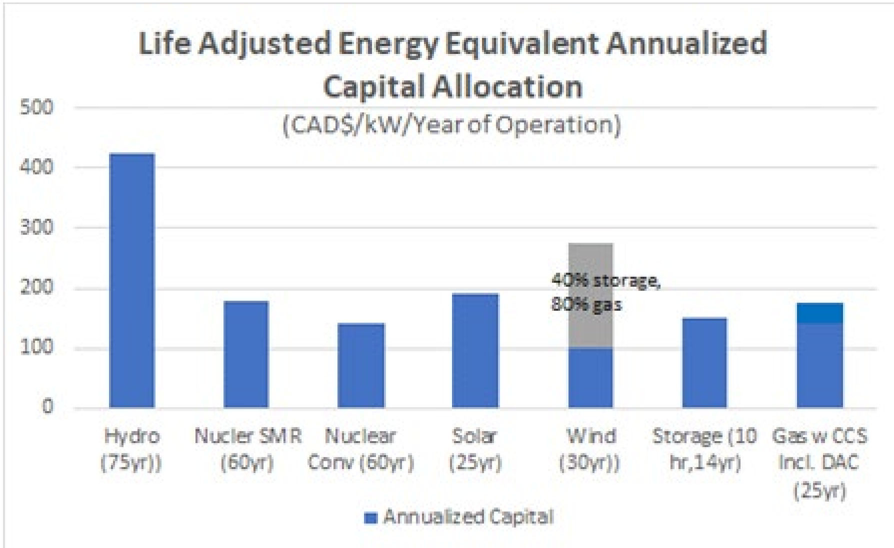
As a result, the conclusions arising from the analyses that support the CER should not be used by decision makers until this critical element of enabling a net zero electricity grid is adequately and properly validated.

Figure 8



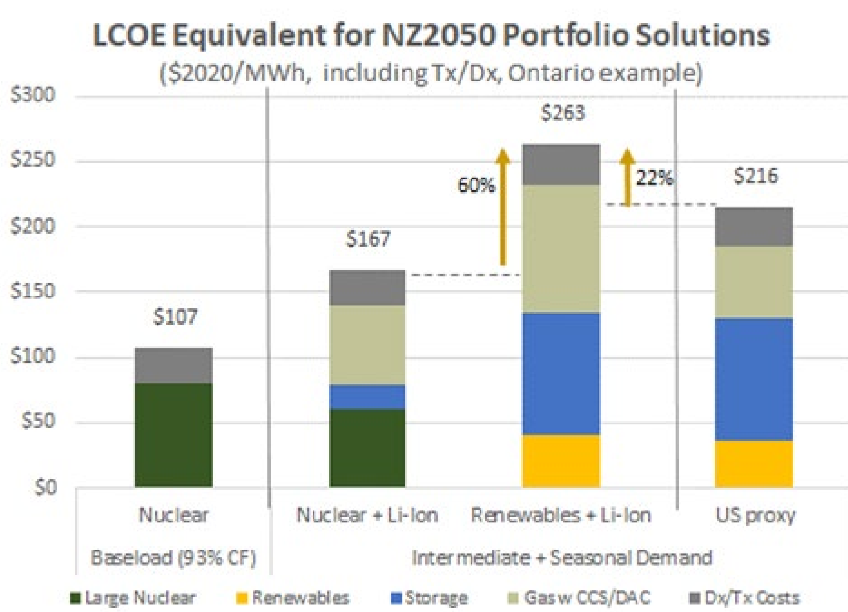
Many argue that renewables are low cost and that nuclear is high cost. Figure 9 illustrates the life adjusted energy equivalent capital costs of common generation options including storage. The figure reflects the capacity factor and the different economic life of the assets. These annualized equivalent investments are very similar. However, wind also needs 40% of the storage capacity and 80% of the gas capacity, making those portfolio solutions the highest capital cost (gray).

Figure 9



However, net costs are better compared by an LCOE of the requisite integrated system costs for meeting demand, as shown in Figure 10. The LCOE includes not only capital costs, but also financing and operating costs over the life of the asset. To analyze system costs, solutions must be measured against their ability to reliably serve real baseload and intermediate demand.

Figure 10



Baseload options such as hydro, nuclear, or gas equipped with CCS (nuclear is illustrated) appear to be straightforward and may also be addressed with portfolio solutions similar to those for meeting intermediate demand. To supply intermediate demand, all generation options require additional investments in storage and back up gas-fired generation. This applies to nuclear solutions (middle bar) as well as for the renewables-based solutions.

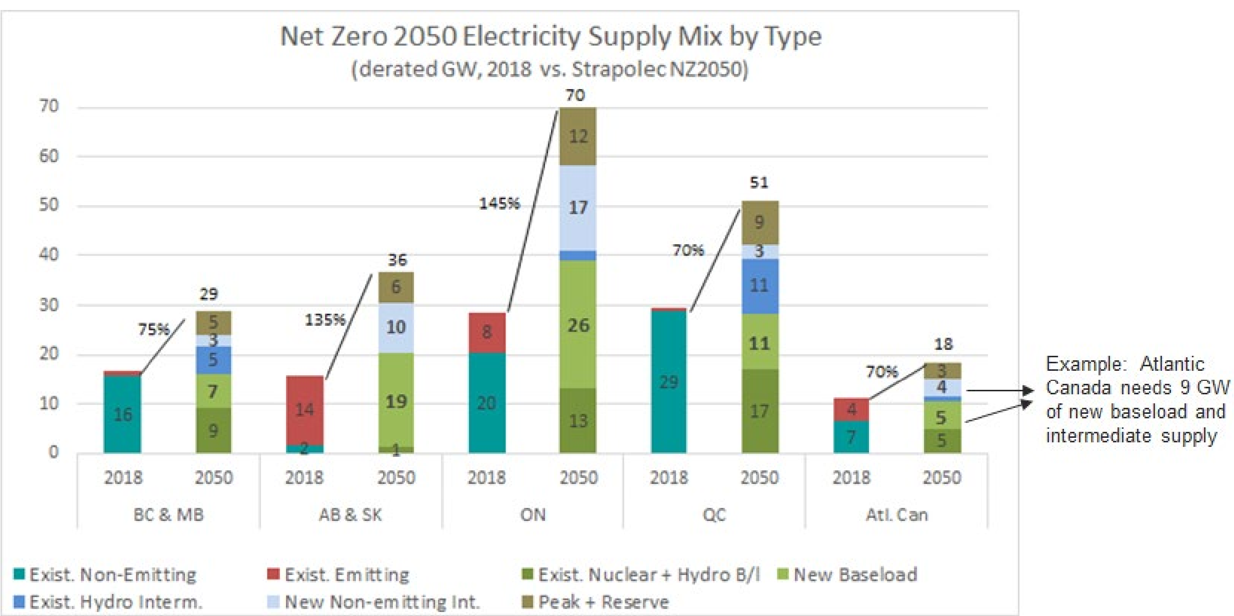
Ontario modeling shows that integrated renewables solutions could be 60% more costly than nuclear based solutions, even for meeting intermediate demand which is not a traditional function of nuclear. A renewables-based solution could make Ontario's electricity costs over 20% higher than those in the U.S.

This is a critical policy matter since the cost of electricity will drive the pace of decarbonization. The affordability of Canada's energy transition relies on finding the electricity generation mix with the lowest available integrated ***system*** LCOE. Proper modelling of the contribution of renewables to the system is very material to the scenarios and outcomes that the CER may consider.

Recommendation #3 – Cost benefit of interregional transmission should be re-evaluated against realistic fundamental premises and assumptions.

The negative impacts of under forecasting demand on the CER policy are evident when considering the provincial requirements for new supplies. Figure 11 shows the capacity contribution required to meet peak 2050 demand for each province by supply type. Red represents existing fossil supply, and light green and blue the new baseload and intermediate supplies. The darker green and blue reflect the existing hydro and nuclear assets which are assumed to be maintained through to 2050. Needs vary from 70% growth in Atlantic Canada to 145% growth in Ontario. A mitigating factor in sourcing supply is that reserve and peak supplies (brown) are rarely used and may be suitable for unabated natural gas fired generation, at least in the transition, with minimal emission consequences, as provided for by the CER.

Figure 11



Provincial needs differ due to their specific industrial mix and the degree to which electrification has already occurred – e.g., electric heating already exists in Quebec. The dramatic increase in demand in every province means that without new generation there will be no surplus in any province to help support reliability through regional transmission connections. For example, the Atlantic Loop could only have worked if Quebec were to build large amounts of new hydro or other supply to produce surplus electricity for export.

A lack of recognition of the challenge of insufficient supply in each of these jurisdictions represents an inherent flaw in the federal government's approach. Ontario, Alberta, and Saskatchewan face the greatest demand challenges and need for new supply, including the replacement of existing emitting fossil assets. Alberta and Saskatchewan may need 19 GW of new clean baseload, not including the needs of the oil patch which has been assumed to shrink by 75% by 2050.[19] Ontario could need 26 GW of new baseload, or three times the capacity of Ontario's refurbished nuclear fleet. Even Quebec will need 11 GW of new baseload, equivalent to the capacity of an additional James Bay Complex. The DSF model that assumes 10 GW from Quebec supports the fantasy of Ontario depending upon imports.

While there are limited options beyond new nuclear for most provinces, this supply option does not figure prominently in the CER analysis. Despite the hyperbole over renewables, renewables need either reservoir hydro (e.g. Quebec) or variable generation with carbon capture (e.g. Alberta) to be viable as previously discussed in Recommendation #2.

The potential for Saskatchewan and Alberta to build out substantial carbon capture-based solutions paired with renewables remains to be proven. The hydro-rich provinces: BC, Quebec, Manitoba, and NL already recognize the limit of new hydro development and it is unlikely that even the CER modelling assumptions of 18 new GW of hydro can be realistically achieved.

Canada's current high voltage transmission network connects its population centers to the country's hydro resources, which are for the most part located some distance away. This north/south oriented infrastructure also helps facilitate electricity exports to neighbouring U.S. jurisdictions. Future expansion of the capacity of these interprovincial transmission lines is dependent upon each province siting its new generation options. Locating generation as close as possible to demand centers lowers costs. The costs of interregional electricity exchanges can be mitigated by strategically siting new generation including the cost for building new transmission lines. The provinces must determine where the new required generation will be sited and only then can it be determined if the substantial costs to build transmission lines is warranted. It is noteworthy that transmission costs rise substantially for low capacity factors such as integrating output of intermittent renewables. In the future, optimally locating renewables and hydro resources will be more challenging given their large land footprints and other locational constraints, e.g. wind speeds.

While the CER modeling purports to optimize locational generation with transmission costs, it fails to consider real world constraints facing the development of new generation options-e.g., commercially viable hydroelectric. While it is unclear from the reviewed materials as to how much transmission has been included in the baseline scenario to accommodate the CER regulations, Ontario is proposed to have the most incremental interprovincial transmission lines at 2000 MW with Quebec and 666 MW with Manitoba, more than doubling existing interconnections. The next largest is a 2100 MW BC

[19] This assumption was made in the 2021 CCRE Commentary as well as the recent 2023 Energy Futures report by Canada's Energy Regulator.

transmission line to support Alberta. These are modelled to be in service by 2035 (2040 for Quebec) and premised on ample hydroelectric power capacity in BC, Manitoba, and Quebec.

Canada's real challenge in the near term may be less about securing new non-emitting supplies and more urgently about developing generation to avoid blackouts across the country. The CER should be looking at 2050 ambitions to achieve net zero, not 2035, and planners and policy makers should be better informed about the jurisdictional circumstances in each province.

Recommendation #4 – Modelling used to identify supply mix options and support the CER benefits case should be validated against provincial plans regarding viability, costs, and cost impacts.

The CER modelling suggests that the impacts of the legislation will have very specific implications for each jurisdiction. More specifically, 85% of the costs to 2035 are identified to be borne by Alberta, Ontario, and Nova Scotia.

Alberta is modelled as incurring a net cost of over $19.5 B by 2035, out of a total Canadian cost of $35B. This investment is primarily for CCS equipped natural gas facilities and the transmission lines to BC. These costs support the view that Alberta faces the greatest challenge among provinces and natural gas options are required that support renewables.[20] However, the transmission connections with BC may not be warranted as discussed above.

Ontario is modelled as incurring a net cost of over $5.5B by 2035, primarily for new hydro facilities and transmission with Manitoba. Ontario then has an additional $10B by 2040, or 71% of the cost impacts in that timeframe. This is at odds with Ontario's energy transition plan that includes significant amounts of new nuclear with negligible hydro and no discussion of interconnection additions with Quebec.[21]

Rounding out the top three is Nova Scotia with $5.2 B by 2035, primarily for biomass equipped with CCS. Nova Scotia has recently balked at the Federal government's Atlantic Loop plan, which was included in the CER modelling. Quebec has confirmed it does not have the capacity that Nova Scotia requires to close coal generation– firm energy available for sale to meet its winter peak needs. Nova Scotia instead will rely on renewables, primarily wind, enhanced ties with New Brunswick to help with renewables and fast response dispatchable generation.[22] There is no mention of new biomass generation.

Quebec has acknowledged that it will need over 100 TWh of new generation in the future and that it has insufficient hydro resources. As mentioned above, the Atlantic Loop project cancellation was related to Quebec not having the power. It is now considering new nuclear as mentioned earlier.

These provincial plans reflect significant deviations from the scenarios modeled to assess the CER, questioning the viability of the conclusions offered by the ECCC. Besides not reflecting these provincial strategies, the CER cost assumptions are not current and as aligned with provincial assumptions as the ECCC has suggested. Ontario's IESO has assumed hydro costs that are double those assumed in the CER

[20] AESO, Technical Briefing on Proposed Clean Electricity Regulations, September 28, 2023.
[21] IESO, Pathways to Decarbonization, Dec 2022; Ontario Ministry of Energy, Powering Ontario's Growth: Ontario's Plan for a Clean Energy Future, July 2023.
[22] Nova Scotia Department of Natural Resources and Renewables, Nova Scotia's 2030 Clean Power Plan.

modelling and wind costs that are 30% higher.[23] The IESO's assumptions are consistent with the findings of the recent report from Clean Energy Canada on wind and solar costs in Alberta and Ontario.[24]

Finally, the CER is already having unanticipated cost impacts. The recent Ontario procurement by the IESO's LT1 RFP included provisions that the gas contracts must expire by 2040, shortening the expected economic life of the assets to 15 years instead of 20 to 25. This has resulted in much higher than standard gas fired generation capacity costs on the order of $280K/MW per year, purely due to the uncertainty introduced by the draft CER.[25] These higher costs did not dissuade the procurement decision to move forward.

Closing

The assessment provided here strongly suggests that the ECCC should reconsider the timelines contained in the CER given the higher electrification driven demand, the conclusions it is drawing from its modeling about the potential contribution of renewables, and the disconnects between its supply mix assumptions and those of provincial plans which may be related to invalid and/or inconsistent cost assumptions. The PWU's comments and recommendations are supportive of Canada's clean electricity objectives. We will continue to work with the ECCC and other stakeholders to help achieve Canada's climate goals. The PWU is committed to the following principles: create opportunities for sustainable, high-pay, high-skill jobs; ensure reliable, affordable, and environmentally responsible electricity; build economic growth for Canadian communities; and, promote intelligent reform of Canada's energy policy.

[23] IESO, Pathways to Decarbonization, assumptions spreadsheet.
[24] Clean Energy Canada, Cost of Renewable Generation in Canada, Dec 2022.
[25] IESO webinar, March 2023; IESO, Expedited Long-Term RFP (E-LT1 RFP) – Final Results, Sept 2023.