PWU Submission to NRCan on Achieving Net Zero Goals in Electricity
January 24, 2024

Natural Resources Canada (NRCan) has asked for comments regarding barriers to and solutions for achieving Canada's net zero goals for the electricity sector. NRCan is especially interested in feedback to questions for the Canada Electricity Advisory Council (CEAC). The PWU remains a strong supporter and advocate for the prudent and rational reform of the electricity sector and recognizes the importance of planning for low-cost, low-carbon energy solutions that enhance the competitiveness of Canada's economy.

The PWU believes the questions posed are of strategic importance regarding how to: improve the planning of electricity systems; build electricity infrastructure in a timely manner; attract capital investments while maintaining electricity affordability during the transition; enhance regional cooperation; and, enable electricity sector innovation while reducing cost and maintaining grid reliability.

The PWU is a strong advocate of cost-effective emission reduction strategies. Our organization has engaged in several relevant federal consultations, including: Environment and Climate Change Canada's (ECCC) Clean Electricity Regulation (CER) and Standard (CES); Finance Canada's Federal Investment Tax Credits (ITCs); Infrastructure Canada's National Infrastructure Assessment regarding infrastructure needs, vision, coordination and financing; and, NRCan's consultation on Electricity Grid Modernization. The latter sought information similar to this consultation, on barriers and opportunities for accelerating electrification and electricity grid modernization to meet Canada's net zero goals. The PWU's recommendations provided in those submissions are relevant to the questions posed here and the submissions are attached hereto, in Appendices A-E, forming part of this submission.

Canada's complex and interrelated energy, climate and economic challenges require holistic and strategic solutions that are driven and directed by clear and cost-effective federal policy. It begins by recognizing and addressing the regional distribution of energy resources and different perspectives. This foundational policy process can be accomplished by focusing on three areas: creating a national energy vision; securing consensus on regional costs and benefits, affordability, effectiveness, competitiveness and trade balance; and, alignment of infrastructure development timelines with achievable emission reduction targets.

The PWU makes the following recommendations on these three areas:

A. Development of a consensus-based national energy vision that includes Canada's diverse provincial, territorial and indigenous stakeholders.
    1. Embrace regional diversity and autonomy for establishing the pathways to achieve Net Zero.
    2. Consider the implications of climate policy on Canada's position in the global economy.
    3. Set provincially defined, achievable goals with proposed milestones for each emissions producing sector of the regional economies.
    4. Support relevant integration initiatives for collaborating regions.

B. Ensure a common understanding of the achievability of electricity system solutions in each region including the reliability, cost, and affordability implications.
    5. Validate the modelling, cost and efficacy of renewables operations.

6. Encourage the use of robust benefit costs analyses (BCAs) by the local distribution companies for the assessment of distributed energy resources (DERs).

C. Assess the efficacy and alignment of current federal climate related programs for the development of electricity infrastructure with achievable nationwide emission reductions.

7. Identify realistic options and timelines for the development of affordable, non-emitting long life baseload resources for the future bulk system.
8. Develop and incent an affordable transition plan that reflects the timelines for long lead time, large-scale, non-emitting bulk system assets that secure a reliable electricity system for Canadians while incenting electrification accordingly.

Area A: Development of a consensus-based national energy vision that includes Canada's diverse provincial, territorial and indigenous stakeholders.

NRCan's consultation discussion guide recognizes that several factors are necessary for achieving net zero goals in Canada's electricity sector:

- Improve electricity system planning
  - Planning tools to identify and pursue least cost paths to net zero, that are credible and independent and updated regularly, and that reflect the unique conditions of the respective jurisdictions
- Build infrastructure in a timely manner
  - Address the lack of clear, net zero aligned energy strategies across regions
  - Consider the potential of the electricity sector to advance indigenous economic reconciliation
  - Foster effective engagement to encourage thorough project assessments as recommended by the Council
  - Recognize that some project assessments involve multiple jurisdictions and the need to streamline approvals and address federal/provincial overlaps
- Attract capital investment
  - Eliminate policy uncertainty that creates investment risk
- Enhance regional cooperation
  - Regional disparities represent complex challenges that warrant comprehensive regional planning and integration
  - Strengthened interconnection ties could drive economic development
- Enable innovation
  - Regional energy resource diversity requires different innovation(s)
  - Establish long-term financial predictability

The PWU makes the following recommendation to help address these above noted factors.

Recommendation #1 – Incorporate regional diversity and autonomy to establish the pathways to Net Zero.

The PWU previously recommended to the Federal government that it develop a national energy vision.[1] This recommendation was based on the work of the Council for Clean and Reliable Energy (CCRE). It included a set of guiding principles for developing a "vision" driven policy framework that could help address Canada's energy diversity dilemma.[2] The principles included: transparency; advancing reconciliation with Indigenous Peoples; fact and science-based decision-making; fulfilling Canada's climate change goals; reasonable and defined transformation period(s); affordability; and equitable sharing of the benefits and costs.

Such a national vision could provide clear and sustainable policy guidance that helps eliminate policy uncertainty and investment risk. The vision's sustainability would depend upon the scope and integrity of the collaborative process with provincial, territorial and indigenous peoples e.g., the extent to which consensus is achieved on common interests and the equitable sharing of benefits and costs.

The vision development must recognize the constitutional right of the provinces and territories to manage their diverse energy infrastructure objectives and focus the federal government's role on facilitating where collaboration is warranted. Provinces have the constitutional authority to determine their own electricity system and have adequately developed their own mandates for regulators, system operators and utilities. Recognizing constitutional and treaty rights in the vision development would mitigate many of the barriers to progress that have emerged to face federal policies. For example, the lack of consideration of regional differences in the federal carbon pricing policies and ECCC's draft CER has fueled significant provincial-federal disputes.[3]

The development of a national vision would, by design, require early and active engagement of all provincial, territorial, and Indigenous community stakeholders.[4]

The biggest gaps in electricity sector regulatory structures and policy levers in driving the development of technology innovation are policy makers' uninformed decisions that cause friction among stakeholders.

Recommendation #2 – Consider the implications of climate policy on Canada's position in the global marketplace.

Canada's climate policies impact its position in the global economy, specifically, its industrial competitiveness, contribution to reducing global emissions, trade balance and place in the world's supply chain for growing technologies.[5]

The cost and affordability of clean electricity during Canada's transition to NZ will have a significant impact on our country's industrial competitiveness. The relative cost of electricity in the economies of Canada's major trading partners is a major factor in Canada's industrial competitiveness.

[1] PWU submissions and recommendations: Grid Modernization Rec #1; ITCs Rec #5; Infrastructure Assessment Rec #s 1 &4.

[2] K. Taylor, CCRE Commentary, A National Energy Vision for Canada: A Principled Approach, 2021.

[3] PWU submission on the CER, Figure 1.

[4] Strategic Policy Economics, A National Energy Vision: Canada Hitting Above its Weight on Global Emissions Reduction, 2021; M. Brouillette, CCRE Commentary, Towards a National Energy Vision: Canada's Low-Carbon Energy Infrastructure Opportunity in a Global Net Zero Future, 2021.

[5] PWU submissions and recommendations: ITCs Recs #1 & 4; Infrastructure Assessment Rec #s 1 to 6.

For example, recent energy policy in the United States profoundly impacted the cost of electricity and the competitiveness of US industry as outlined in a report from Ontario's Green Ribbon Panel.[6] Regional differences in the costs of electrification within Canada should also be considered in the development of a national energy vision.

Canada's low-carbon energy assets and technological expertise can help achieve its NZ targets while helping other countries achieve emission reductions. A national energy vision should analyze this opportunity, including "credits" for Canadian-enabled reductions in other jurisdictions, especially countries with carbon trading mechanisms.[7] The regional distribution of Canada's energy assets, their economic competitiveness and emissions performance should also be addressed in a national energy vision for Canada.

Achieving consensus on a national energy vision will not happen without addressing the economic impacts of Canada's energy transition on each region and ensuring an equitable distribution of the economic and job benefits. Additionally, such a vision should ensure Canada's economic competitiveness and a healthy trade balance. This requires focusing on the domestic content of the eligible non-emitting energy options, especially those providing the most economic benefits to Canada, including nuclear, hydroelectric, transmission and potentially storage based on Canada's investments in a domestic EV and battery storage manufacturing and related mining projects.

Similarly, cost competitive non-emitting energy technologies could play a role in global supply chains and offer export opportunities in new global sectors that Canada has an advantage in, both in non-emitting energy and in exports of technology. Nuclear is obvious, carbon capture may become a potential lever, and hydrogen is becoming a significant opportunity in the east coast.

Recommendation #3 – Set provincially defined, achievable goals with proposed milestones for each emission producing sector within the regional economies.

There is an apparent consensus among Canadians on the need to reduce emissions to address climate change. However, there is evident concern that reducing emissions must be affordable and effective. Achieving meaningful consensus will require addressing these major challenges.

The federal government has the authority to set national targets and standards in accordance with Canada's international commitments. However, developing a consensus-based national energy vision provides the opportunity for an inclusive collaboration of all of Canada's affected stakeholders to develop and implement effective compliance actions. Such a consensus-built national energy vision should result in more equitable, regional-specific cost/benefit sharing plans that are integrated strategically with Canada's NZ program for the benefit of all Canadians.[8] Developing pathways for clear energy policy frameworks in each province can help accelerate progress, reduce and manage perceived

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[6] Green Ribbon Panel, Clean Air, Climate Change and Practical, Innovative Solutions: Policy Enabled Competitive Advantages Tuned for Growth, 2020.

[7] Strategic Policy Economics, A National Energy Vision: Canada Hitting Above its Weight on Global Emissions Reduction, 2021; M. Brouillette, CCRE Commentary, Towards a National Energy Vision: Canada's Low-Carbon Energy Infrastructure Opportunity in a Global Net Zero Future, 2021.

[8] PWU submissions and recommendations: CES Recs #8; CER Recs #1 & 4; Infrastructure Assessment Rec #s 1 to 6; Grid Modernization Rec #3.

risks and advance regional collaboration and integrated plans that meet Canada's economic and environmental goals.

A national energy vision has the potential to facilitate integrated efforts by federal, provincial and territorial governments to cooperatively streamline project assessments, approvals and permitting to shorten in/service timelines.,

Municipal and community support for these projects could be encouraged by communications from the federal government in support of regional collaborations that clearly outline the benefits of a national energy vision.

Recommendation #4 – Encourage the integration of collaboration-based regional energy initiatives.

The federal government has been advocating for deeper regional planning and integration and the expansion of interregional transmission infrastructure. The analyses supported by PWU suggest that this approach should consider the implications of the distribution of Canada's major population centers and the high cost of transmission assets.[9]

The need for interregional transmission will largely depend upon the location of the most cost-effective non-emitting generation resource. This falls within the jurisdiction of the provinces and territories and is typically most cost-effective when the generation resources are located close to demand centers in order to reduce transmission costs. For example, the transmission costs for potential wind farms north of Lake Superior to supply Toronto could double to triple the costs of this wind generation.

The federal government supported the development of the Atlantic Loop. However, the Atlantic provinces decided not to participate given the high transmission costs compared to other available options.

The federal government should work with the provinces as they develop their own plans, and then support the exploration of interregional connections when the provinces identify a potential benefit and indicate a need for support. Analysis suggests that, for reliability purposes, the existing intertie capacities may be sufficient to provide grid stability.[10] Other analyses show that when provinces search for alternatives to existing options, e.g. hydro development, then collaboration across technologies and regional intertie expansion may be appropriate to enable export opportunities and optimization of existing assets.[11]

<u>Area B – Establish a common understanding of the achievability of electricity system solutions in each region, including reliability, cost and affordability implications.</u>

NRCan's discussion guide recognizes several factors relevant to identifying achievable regional electricity solutions including the need for:

- Planning tools that identify and pursue least cost paths to net zero, and reflect the unique conditions of the respective jurisdictions and affordability implications;

[9] PWU submissions and recommendations: CES Rec #9; CER Rec #3; Infrastructure Assessment Rec #4.
[10] Strategic Policy Economics, Electrification Pathways for Ontario, 2021.
[11] M.Brouillette, CCRE Commentary, Towards a National Energy Vision Case Study: Ontario and Quebec, 2022;

- Perspectives on the balance of traditional investment vs risk capital investments for emerging technologies;
- Guidance on the role of public funding in electricity system innovation.

The discussion guide also contains other statements that require further consideration and attention:

- Enhancing regional cooperation requires assessing variable renewables.
- Enabling innovation:
    - New technology is cost effective at solving problems
    - Understanding market differences is crucial
    - Need operational agility and flexibility

Identifying the lowest cost solutions that helps accelerate Canada's energy transition to NZ should be the federal government's primary policy imperative. Canada's bulk electricity system will continue to be pivotal for the building of large-scale, non-emitting generation and the delivery of electricity to its population and load centers. Investment in large-scale infrastructure will be needed to provide for the significant forecast growth in electricity demand, adapt to climate change and maintain system reliability.

Local distribution companies can optimize costs by implementing demand-side management to smooth load enabling bulk system assets to meet baseload demand and provide cost-effective use of transmission assets.[12] Analyses suggests that market structures have no bearing on the underlying costs of available technologies. For example, Ontario's Independent Electricity System Operator (IESO) and the Ontario Energy Board (OEB) contract or regulate 95% of the province's generation without market-based parameters. The PWU has argued that electricity markets are not suitable to the non-emitting generation options needed now and in fact only increase the cost.[13]

The PWU makes the following recommendations to help address these shortcomings:

Recommendation #5 – Validate the modelling, cost and efficacy of renewables operations.

Valid electricity system models are needed to assess the impact of Canada's decarbonization and electrification strategies.

The PWU's experience suggests that more attention should be given to modelling the electricity system options with sufficient temporal fidelity to identify reliability needs and, specifically, the extent to which storage can support renewables and the extent to which additional flexible backup generation is needed.[14]

The recent draft CER provides an example of the risks. The CER is predicated on the ability of renewables to meet the electricity needs from Canada's decarbonizing economy. The PWU's CER submission noted that several of the CER's objectives are questionable given weak underlying modelling that overstates

[12] Strategic Policy Economics, Electrification Pathways for Ontario, 2021.
[13] Strategic Policy Economics, Electricity Markets in Ontario, 2019.
[14] PWU submissions and recommendations: CES Recs #5; CER Recs #1, 2, & 4; Infrastructure Assessment Rec #3b; Grid Modernization Recs #1 & 3; ITCs Rec #5

their contribution and understates the costs. Additionally, Electricity Canada made similar critical comments in its submission to the ECCC.[15]

A consensus on the best modelling approach should be a prerequisite for electricity policy decision-making.

Based on the PWU's investigation there is a critical scarcity of models with sufficient temporal fidelity to address the previously discussed issues. At the recent Energy Modelling Hub (EMH) forum, most utility participants noted the issue of inadequate temporal fidelity for assessing grid reliability. The NRCan-funded EMH is conducting an exercise to compare various models and their outcomes.[16] NRCan has also recently issued a new call for modeling expertise.[17] Collaboration between these two exercises should be encouraged.

High fidelity models are necessary to properly assess affordability which is best indicated by the total system levelized cost of energy (LCOE). PWU analyses have established that under most scenarios the total system LCOE from renewables-based solutions exceeds that of other bulk system technologies e.g., nuclear. Intermittent renewables require storage and backup generation compared to nuclear and hydroelectric which do not.

Recommendation #6 – Encourage the use of robust benefit costs analyses (BCAs) by the local distribution companies for the assessment of distributed energy resources (DERs).

Many myths regarding the cost effectiveness of DERs stem from a lack of validation analysis or due to the above-noted modelling limitations must be addressed. The OEB and its Framework for Energy Innovation Working Group (FEIWG) investigated the need for BCAs as a critical step for DER adoption. The PWU provided detailed recommendations regarding the evaluation of the potential roles for DERs in a broad electricity system planning framework and the factors that should be considered when conducting a BCAs.[18]

The IESO's DER Potential Study provides an example of how modeling deficiencies can significantly misinform policy makers such as by overstating the usefulness solar technology. The PWU's submission identified the analytical deficiencies and strongly recommended that the findings of the report as they relate to solar technologies not be communicated to policy makers as written.[19]

Area C: Assess current federal climate related programs for their efficacy when aligned with the development of electricity infrastructure intended to achieve emissions reductions nationwide.

NRCan's discussion guide recognizes that:

- Policies need to align energy system outcomes with decarbonization goals to improve planning of the electricity system; and,

[15] Electricity Canada, Clean Electricity Regulations: Electricity Canada Response, Nov 2023.
[16] https://cme-emh.ca/en/see-open-call-for-projects/#project2
[17] https://natural-resources.canada.ca/science-and-data/funding-partnerships/opportunities/grants-incentives/energy-innovation-program/energy-innovation-program-national-energy-systems-modelling-call/25515
[18] PWU submission to the OEB on the FEIWG and BCA recommendations, Jan 2023.
[19] PWU submission to the IESO on the DER Potential Study, 2022.

- Polices must consider: the diversity of provinces; ability to attract capital investment; market size; sustaining affordability during the transition; and, the cost risks for the economy, including the impacts on industrial competitiveness of trade exposed sectors.

The PWU has consistently recommended that Canada's climate policy be better aligned with the pace of infrastructure development of reliable and affordable electricity. Emission reduction programs should not be over-incenting electrification adoption before electricity assets can be built.[20]

The essential policy question in NRCan's discussion guide is as follows: "*What policies, programs, or other structural changes would support affordable and competitive electricity rates for all Canadians and businesses as Canada progresses through the energy transition?*"

There are three fundamental challenges with the current federal policy framework:

1) The emissions targets and associated incentive programs for the adoption of non-emitting technologies are not realistically aligned with the development timelines required.

    - Federal policies are incenting EV and heat pump adoption.
    - Canada's emission targets suggest the need to develop new non-emitting supply to meet 82 GW of new peak demand by 2035. However, bulk system assets of the scale required take 10-15 years to develop and building 82 GW of new supply is simply not achievable in that time frame.
    - There are limited bulk system options, e.g., nuclear, hydroelectric and transmission, and development decisions should be made today.
    - Robust modelling is expected to confirm that renewables cannot on their own address Canada's electricity system needs.

2) The draft CER inhibits the use of natural gas in the transition to a net zero future by restricting its use before other options are available.

    a. Renewables can play an important role in reducing the use of natural gas-fired generation while the gas-fired generation capacity is needed for reliability during the transition. However, renewables cannot eliminate its use in the near-term and could exacerbate the need for gas-fired back-up in the longer term. This will make a net zero system unachievable for some time.

3) Carbon pricing comes with a long lag time before it achieves behavioral change and for many of the alternatives the carbon price must exceed the current price of $170/tonne for 2030.[21]

    - Many Canadians are not in a financial position to make carbon price driven fuel switching decisions, e.g., the type of heating in their home.
    - Business innovation, such as technology advances to reduce emissions, is typically enabled by applicability on the scale of the global economy. The presence of carbon pricing in Canada and not in its trading partners undermines this scale and hence the ability to justify innovation investments.

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[20] PWU submissions and recommendations: CES Recs #1 & 7; CER Rec #1; Infrastructure Assessment Rec #4; Grid Modernization Rec #2; ITCs Rec #1.

[21] Strategic Policy Economics, Ontario's Emissions and the Long-Term Energy Plan, Phase 2: Meeting the Challenge, Dec 2016.

- The US through its *Inflation Reduction Act* has elected to provide direct incentives instead of carbon pricing to promote adoption of lower carbon energy options.

The following two PWU recommendations would: prioritize the addition of new non-emitting bulk system assets; provide incentives to encourage the adoption of affordable and reliable decarbonization energy options; and, provide policy clarity to accelerate investment.

Recommendation #7 – Identify realistic options and timelines for the development of affordable, non-emitting long life baseload resources for the future bulk system.

Canada can provide policy certainty and accelerate investment by recognizing: the urgency presented by the transition; the nature of the potential electricity system pathways; and, the long-term benefits of assets with long economic life.

Policy makers need improved data and analysis about the energy assets that can be built in the desired timelines, including the differing regional opportunities to develop affordable and reliable electricity infrastructure for the long-term. This will best position Canada in a competitive position, i.e., the lowest cost system.

Given the pressing timelines, ready to deploy, tested options will be the most attractive while waiting for those technologies in the early stages of development are proven to be commercially viable at scale. It is important to recognize that "early-stage" technologies are influenced by global markets. Canada does not need to bear the development risk unless it positions Canada in a leadership role as discussed earlier. Collaborative development suggests a better path, e.g., Ontario Power Generation (OPG) Small Modular Reactor development agreements with the U.S. and other countries.

The federal government has the opportunity to collaboratively leverage the available options and their applicability regionally and nationally to enable the national energy vision policy and implementing framework. Strategically driven investment decisions show lower capital costs and greater investment security for the selected pathway(s) and options.

Recommendation #8 – Develop and incent an affordable transition plan that reflects the timelines for long lead time, large-scale, non-emitting bulk system assets that secure a reliable electricity system for Canadians while incenting electrification accordingly.

Policies with a focus on the long-term needs of Canada's bulk system can be optimized to ensure that the transition in the near and medium-term remains reliable and affordable. The transition policies will involve the use of natural gas-fired generation supported by:

- Innovation that minimizes the operation of these gas-fired assets e.g., renewables;
- Reductions in carbon intensity e.g., Renewable Natural Gas and hydrogen blending;
- Paced incentives for EV and heat pump adoption and other electrification options; and,
- ITCs for clean energy and technology options.

It is critically important to understand the capabilities and costs of the various available technologies, as discussed earlier, to ensure that federal programs are not incenting high-cost solutions that deliver minimal benefits to Canadians.

Closing

The government's priorities should be to: build a national energy vision that helps align provincial, territorial and indigenous peoples' aspirations for a Net Zero economy for Canada; create a common understanding of the viable electricity system options that can help achieve this target; rapidly develop long-lead time bulk system baseload supplies e.g., new nuclear generation; and, appropriately manage Canada's electricity system transition to mitigate the cost impacts of electrification to the economy.

The PWU has a successful track record of working with others in collaborative partnerships. We look forward to working with the federal government and other stakeholders to develop the non-emitting electricity system needed for Canada's future. The PWU is committed to the following principles: Create opportunities for sustainable, high-pay, high-skill jobs; ensure reliable, affordable, environmentally responsible electricity; build economic growth for communities; and promote intelligent reform of energy policy.

We believe these recommendations are consistent with and supportive of the government's objectives to transition to a Net-Zero economy and supply low-cost and reliable electricity for all Canadians. The PWU looks forward to discussing these comments in greater detail and participating in the ongoing stakeholder engagements.

Appendix A: PWU Submission to NRCan on Electricity Grid Modernization

March 23, 2023

Natural Resources Canada (NRCan) is seeking input regarding the regulatory, policy and market barriers and opportunities for accelerating the pace of electrification and electricity grid modernization to meet Canada's net zero goals. NRCan aims to enhance federal programming to address stakeholder needs in the complex regulatory environment related to grid modernization and electrification.

An NRCan report that suggests Canada's electricity grid must innovate to accommodate more variable renewable energy resources and a greater volume of flexible electricity loads across the entire electricity system is the premise for this consultation.[22] In fact, NRCan states that to meet Canada's targets, disruptive *changes via electrification and grid modernization are necessary*. NRCan suggests that there are barriers to the timely adoption of new emerging grid modernization technologies at the scale required. NRCan suggests that the existing regulatory and market framework may not be well suited to address and finance the needed transformation.[23] These factors raise additional concerns about the significant costs of the transformation and questions about the role of taxpayers, rate payers, and private investment. NRCan raises a particular concern about the burden that may be placed on vulnerable populations.

NRCan is seeking feedback on: the opportunities to accelerate the pace of electrification and modernization; regulatory constructs that may require changing; the barriers and opportunities for innovations in electric grid modernization, distributed energy resources, and behind-the-meter (BTM) resources; and, the impacts of cost allocation to different customer groups. This advice is intended to be used by NRCan to develop new federal programming in these areas.

The PWU believes that NRCan's underlying premise is flawed and is therefore focused on the "edges" of the challenge. The real barrier facing Canada is the timely creation of new low-carbon baseload generation. Additionally, the existing regulatory framework is workable for the foreseeable future, however, the market focused procurement framework existent in Ontario and Alberta is ill-suited to meet these needs.

The PWU makes the following recommendations:

1) Electrification planning should be based on established analyses and facts associated with Canada's Net Zero challenge, particularly with respect to the country's bulk electricity system;
2) Clearly identify the competing timelines between encouraging electrification and building the electricity system infrastructure required to meet it;
3) Focus federal programming on financing low-carbon bulk system infrastructure and encouraging consumer adoption of BTM demand side management technologies, such as bi-directional EV charging; and,
4) Minimize the cost of transitioning the electricity system and allow existing practices to protect vulnerable populations.

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[22] 2021 Smart Grid in Canada,

[23] 2022 report by Gattinger and Associates; 2020 report by Guidehouse.

Recommendation #1 - Electrification planning should be based on established analyses and facts associated with Canada's Net Zero challenge, particularly with respect to the country's bulk electricity system.

NRCan's current initiative was informed by the recommendations of the Smart Grid in Canada Report. The report correctly notes that the amount of electricity generated from renewable and non-emitting sources must expand to reach decarbonization and electrification goals. However, the report also indicates that new intermittent renewable energy sources and increasingly flexible loads must be integrated to uphold the integrity and stability of electricity grids. These conclusions are based only on a qualitative narrative that does not cite actual demand nor the requisite supply performance of technologies required to address it. Developing a reliable electricity system is an engineering problem and requires robust technical due diligence to ensure viable and cost-effective solutions are chosen to achieve this fundamental outcome and Canada's NZ goals.

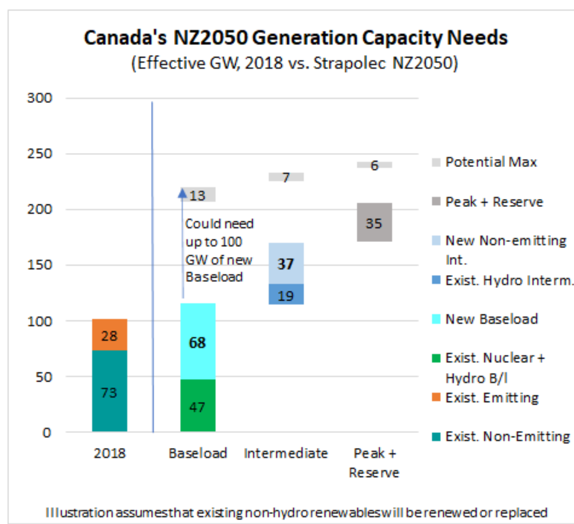
Two factors suggest that there is minimal need to dramatically reform the country's grid management practices:

- The nature of new demand growth has limited need for grid management innovation; and,
- Renewables must be integrated into dispatchable hybrid solutions to reliably supply emerging demand.

The nature of new demand growth and limited need for grid management innovation

To ensure reliability, electricity system operators require dependable supplies that can be dispatched to match supply to demand. More specifically there are three types of demand that the system must meet as illustrated by Figure 1. Growth is apparent in each category and Canada needs new non-emitting sources to meet it: [24]

- Approximately 70 GW of new baseload demand-- 24x7, 365 days per year;
- About 38 GW of variable demand that rises during the day and decreases at night and also seasonally. Most of this new variable demand will be in Ontario and Alberta (27 GW) to replace existing fossil assets; and,
- 35 GW of peaking demand (including reserve capacity) that occurs rarely, less than 2% of the time.



This doubling of the capacity of Canada's electricity system is a significant challenge. A closer examination of each demand type indicates that most of it can be achieved with no changes to grid

[24] Council for Clean and Reliable Energy, Commentary, Towards a National Energy Vision Case Study: Ontario and Quebec, 2022; Strapolec analysis

operations. Only about 7 GW being unlocked by adopting new grid management technologies. Optimizing these 7 GW is addressed in recommendation #3.

From a grid modernization perspective, there are no challenges inhibiting the development of new baseload supplies. Historically, large-scale, transmission connected baseload facilities have connected the electricity system to the load centers in Canada's cities and form the backbone of ensuring the entire grid is stable. Canada's publicly run system operators are experienced at managing these baseload needs. Each provincial operator can decide when and how to procure it.

Currently, peak demand in most provinces is driven by air-conditioning to cool buildings on extreme hot summer days and in future, like Quebec today, peak demand is forecast to shift to extremely cold winter days due to electrification of heating systems in buildings. Demand response for managing peak demand is an effective grid management practice. In addition to the Demand Response, competitive capacity market auctions and rate programs such as Ontario's Industrial Conservation Initiative (ICI) provide additional capabilities. When electrolytic hydrogen becomes available it could also offer Demand Response services at a substantially lower cost.[25] In fact, Ontario is already piloting an interruptible rate program for hydrogen producers that will facilitate their provision of demand response services.[26] Analysis has shown that hydrogen electrolysis demand response may enable the elimination of natural gas-fired generation in Ontario.[27]

Meeting variable demand is more complex. Studies show that consumer behaviors are the most significant drivers of variable daily and seasonal demand. However, analysis shows that the ability of these new grid technologies to influence those behaviors is modest. Studies show that demand side management capabilities may be able to mitigate 10% of the combined variable and peak supplies (excluding demand response), or about 7 GW nationally as mentioned above. That represents only 3 to 4% of the demand that the new electricity system is required to manage. The 80-20 rule suggests that this is not low-hanging fruit.

Renewables must be integrated into dispatchable hybrid solutions to reliably supply emerging demand.

Procurement of new supplies through RFPs should be straightforward if the requirements are specified by demand type. For example, an RFP for baseload that will be available 24x7, 365 days per year supply and that is dispatchable by the grid operator is easily defined. The challenge for decision makers is to remain focused on the procurement specifications not proponent hyperbole. The promise of renewables is a prime example even though wind and solar cannot deliver baseload supply without significant flexible back up generation.

With respect to solar, all major studies have concluded that only modest supplies of solar can be cost effectively integrated into the grid due to the general misalignment of solar output with demand, particularly in winter.[28]

[25] Strategic Policy Economics, Electrification Pathways for Ontario, 2021.
[26] https://www.ieso.ca/en/Sector-Participants/Engagement-Initiatives/Engagements/Interruptible-Rate-Pilot
[27] Strategic Policy Economics, Electrification Pathways for Ontario, 2021.
[28] EPRI 2021, CER 2021, Trottier 2021, Suzuki 2022, Strapolec 2021.

For wind, the most recent report by the Suzuki Foundation claims that it is possible to economically achieve a net zero electricity system in Ontario with significant amounts of wind energy and extensive interconnections between provinces, such as between Ontario and Quebec. However, the Ontario analysis is based on two egregiously flawed assumptions: 1) the lack of resolution and fidelity in the modelling simulations underrepresents the impacts of wind intermittency and the need for backup; and, 2) even with those optimistic simulation outcomes, the analysis unrealistically assumes that hydroelectricity from Quebec can compensate for the wind intermittency in Ontario. Quebec is already struggling to address its own need for almost 60% more generation and has limited options for new hydro to meet its own 10+ GW need for new baseload supply .[29] In fact, Quebec has signaled that it is not interested in developing electricity to manufacture hydrogen for export given that its first priority is domestic needs.[30] Therefore, it is extremely unlikely that Quebec will develop the additional 10 GW of new hydro identified in the Suzuki Report that will only be used to two months of the year to meet Ontario's sporadic winter peaking needs.

In spite of these aforenoted shortcomings, renewables can play a role. For example, given the extensive flexible generation that Quebec's hydro reservoirs provide, there is significant room for new integrated wind generation that will help extend the useable capacity of these vast reservoirs to help meet Quebec's growing demand. Quebec's reservoirs can provide the extensive flexible back up generation needed to support intermittent wind generation output without materially reforming its grid management practices.

Procurement and grid management becomes simple when decision makers recognize that renewables require backup flexible generation, even when supplemented by extensive amounts of storage.[31] If wind advocates wish to bid those technology options, efficient system operations require their integration into co-located dispatchable hybrid solutions that can reliably and cost-effectively meet the operational profile for baseload or variable demand. This approach obviates the need for advanced grid management innovations.

The federal government's role should ensure that independently verified and peer-reviewed facts regarding cost-effective options are transparently provided to all Canadians. The first priority should be to underscore the need to develop a non-emitting electricity system by 2035, including new, reliable, low-carbon baseload generation resources.

Recommendation #2 - Clearly identify the competing timelines between encouraging electrification and building the electricity system infrastructure required to meet it.

Huge amounts of new, cost-effective, low-carbon baseload supply must be developed rapidly. Public awareness about the urgency to address NZ is increasing electricity demand. The accelerating adoption of electric vehicles (EVs) provides an example. Analyses show that the demand for applications such as EVs and home heating will outpace the ability to develop the necessary infrastructure.[32] According to

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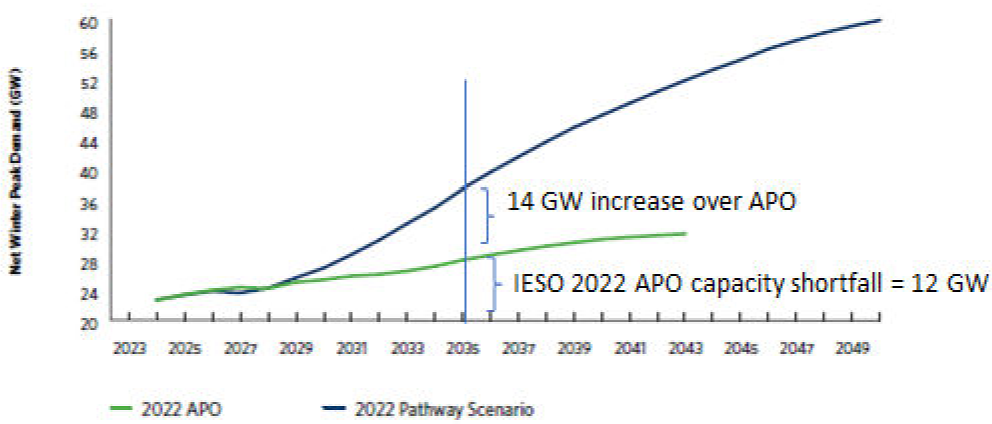
[29] Hydro Quebec 2022-2026 Strategic Plan, 2022; Globe and Mail, March 2023, Quebec needs Newfoundland and Labrador's power.
[30] Presentation at the Hydrogen Business Council Conference, Nov 2022.
[31] Strategic Policy Economics, Distributed Energy Resources in Ontario, 2018.
[32] Strategic Policy Economics, Electrification Pathways for Ontario

the IESO's 2022 Annual Planning Outlook (APO), Ontario needs 12 GW of new non-emitting supply by 2035 to comply with the pending federal Clean Electricity Regulation (CER) and avoid brownouts.[33] On the path to NZ, Ontario has the greatest need for rapid development of new infrastructure given its forecast need to develop 14 GW of new supply in the next 15 years over and above the 12 GW identified in the IESO's 2022 APO. This is illustrated in Figure 9, which was extracted from the IESO's Pathways to Decarbonization (P2D) study.

Figure 9 | Annual Winter Peak Demand



For most provinces, and Ontario and Alberta in particular, the optimum strategy will be to build new clean baseload as rapidly as possible and transition away from using fossil-fired generation to provide baseload power and use it instead for variable power and then ultimately for peak and reserve supply. The latter two phases of the transition will make emissions negligible and ultimately zero.

For baseload power, Canada has three options – nuclear, hydro and gas-fired generation with carbon capture. Additionally, the viability of these options is affected by regional factors. For example, the federal government is only supporting carbon capture in Alberta and Saskatchewan.[34] Ontario's IESO ruled out the viability of carbon capture in its P2D study. While there is available hydro development potential, studies in Ontario and Quebec show it to be insufficient to meet the full baseload demand.[35] The IESO's P2D study also suggests it will be very expensive at over $200/MWh. In light of these facts, new, large-scale nuclear generation is essential to meet the amounts of electricity required in the forecast timeframe and all viable infrastructure opportunities should be pursued as soon as possible given the long lead times required for their development.

Integrating renewables backstopped by fossil-fueled generation provides a near-term opportunity to reduce emissions during the energy transition until the non-emitting baseload resources are available. However, decision-makers need to recognize the risks of curtailment and ultimate stranding of any investments in the accelerated deployment of renewable generation, including decommissioning and waste management before non-emitting baseload options come online. Analysis indicates that the most

[33] IESO, Pathways to Decarbonization, 2022
[34] Federal Carbon Capture and Sequestration Tax Credit eligibility
[35] OPG, Hydropower options for Ontario, 2023.

cost-effective approach is to ensure that the baseload supplies are developed as rapidly as possible to mitigate these risks.

The federal government should work with the provinces to address these transition impacts and their respective contribution to achieving national Net Zero goals and incent the urgent, rapid development of low-carbon baseload resources. Delays expose Canadians to the unnecessary risks of brownouts associated with the accelerated electrification that is emerging across Canada.

Recommendation #3 - Focus federal programming on financing low-carbon, bulk system infrastructure and encourage consumer adoption of BTM demand side management technologies, such as bi-directional EV charging.

There are two key steps that the federal government could take to help accelerate the capacity of the electricity system to accommodate the ongoing electrification of the economy:

1) Provide financial support for investments in new low-carbon baseload supplies; and,
2) Incent the adoption of BTM demand management systems.

Supporting new low-carbon baseload supplies

The federal government's 2023 budget has considered the implications of the US Inflation Reduction Act (IRA) on Canada's climate policies. As a result, there has been significant discussion among energy sector stakeholders on the role of clean energy tax credits. The PWU believes it is critical that these credits should be applied to Canada's situation so as to create a level playing field for investment in non-emitting energy resources. This would facilitate investment in large-scale, non-emitting resources, help de-risk the projects for investors and support provinces that are investing in such projects.

The federal government acts should also consider:

1) Clearly, communicating the challenges Canada is facing and the roles that new nuclear, hydro and carbon capture can play to help achieve Net Zero;
2) Partnering with the provinces on low-carbon infrastructure projects, including leveraging Canada's Infrastructure Bank (CIB)—both financing and equity positions. In some instances, equity participation may be more favorable than tax credits; and,
3) Invest in a balanced manner in the development of the science and technology infrastructure in all three of these technologies: nuclear, hydro, and carbon capture.

Incent the adoption of BTM demand management systems

As mentioned earlier, studies have shown that BTM demand management systems can help mitigate system peaks. The most cost-effective mechanism for addressing peak demand is at the end user's location. This avoids the need for peak generation and increases the efficiency of the existing grid which can help avoid the need for upgrades. There are two key technology areas that NRCan could help promote more effectively: dual source heat pumps; and, bidirectional EV charging.

1) *Dual source heat pumps.* Studies have shown that this technology can help mitigate demand on the electricity system and reduce winter peaks by over 10% while still achieving a 90% emission

reduction.[36] Blending renewable natural gas and hydrogen increases the benefits. While heat pumps are expensive, their adoption could be accelerated with subsidies. NRCan currently provides heat pump subsidies which could be prioritized to dual fuel heat pumps that would use natural gas only on very cold days. Accelerating the adoption of dual fuel heat pumps versus other heat pump technologies could help manage the transition while a non-emitting electricity system is being developed.

2) *Bidirectional EV charging.* Studies have shown that on its own, bidirectional EV charging can provide much of the needed demand side management required to help smooth demand at the end user. In fact, for Ontario, given the recent push to develop 2500 MW of grid-based storage, if even 30% of EV owners become equipped with bidirectional chargers, Ontario's need for additional storage beyond the 2500 being procured may be obviated.[37] It is recommended that the bidirectional EV charger supported are vehicle-to-building (V2B) power supply, not vehicle to grid (V2G). Connecting to the grid is complex and of negligible, if not negative, value. However, using a homeowners EV to supplement electricity needs within the home and reduce its own demand from the grid provides the benefits required. [38] While NRCan currently supports the installation of EV chargers today, it should migrate its supports to bidirectional chargers and reduce support for other devices.

While these challenges have received significant attention, solutions can be effectively implemented without the need for developing sophisticated grid management capabilities. Time of Use (TOU) rate programs that incent consumers to shift their power consumption from times of daily peaks to times of lower demand have been shown to provide up to 70% of the benefits.[39] These solutions are more effective than hourly electricity market pricing as they are: deterministic, predictable, of known value, and simple to implement. Studies have shown that trying to use market-based mechanism along with grid management technologies to control non-emitting technology supplies is not viable due to the lack of a true variable cost signal.[40]

With TOU regimes, it is easy to program EV charging and heat pump operations to avoid using electricity at peak times. Furthermore, bidirectional EV chargers can supply power to the home at peak times. The result could achieve a 15% reduction in peak demand, or, more importantly, defer the need to construct 15% more new capacity.[41] Ontario has recently implemented an Ultra-Low TOU program, specifically aimed at encouraging EV owners to charge their vehicles at night. That same program offers significant value to EV owners that use their vehicles to offset their power consumption during peak hours. The gap is bi-directional EV chargers.

Recommendation #4 – Minimize the cost of transitioning the electricity system and allow existing practices to protect vulnerable populations.

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[36] Strategic Policy Economics, Electrification Pathways for Ontario, 2021; Guidehouse Report to Enbridge, Pathways to Net Zero Emissions for Ontario; 2022.
[37] Strategic Policy Economics, Electrification Pathways for Ontario, 2021.
[38] Strategic Policy Economics, EV Batteries Value Proposition for Ontario's Electricity Grid and EV owners, 2020.
[39] MIT, Electricity Retail Rate Design in a Decarbonizing Economy: An Analysis of Time-of-Use and Critical Peak Pricing 2022.
[40] Strategic Policy Economics, Electricity Markets in Ontario, 2020.
[41] Strategic Policy Economics, Electrification Pathways for Ontario, 2021.

NRCan has raised concerns about the cost of the transition to rate payers, taxpayers, and vulnerable populations. The federal government's strategy should focus on communicating the best options and provide financial support for infrastructure investments to help minimize the cost of the transition.

Studies have shown that optimizing the electricity system by using the most cost-effective options, specifically nuclear, hydrogen, demand-side management with dual fuel heat pumps and bidirectional EV charging will decrease the unit cost of electricity by as much as 25%.[42]

The federal government can help balance the costs between rate payers and taxpayers by backing up their climate policies with investment tax credits (ITCs) such as those being offered in the US as previously noted. Analysis provided to the government shows that tax credits could be designed that will not impact taxpayers in the long run while reducing the cost to rate payers by almost 30%.

If the development of the required infrastructure and the pace of electrification is properly managed (i.e., fact/analyses-driven, transparent, cost-effective) and employs a suite of existing tax and rate programs, costs to vulnerable populations can be reduced. As new challenges emerge, these tactics may be tweaked as required.

First and foremost, NRCan should focus on clarifying the needs, options and associated cost implications, and a going forward process. This in turn should be shared transparently with all Canadians. This should better inform the need for additional programming for vulnerable populations.

Closing

In summary, NRCan should not be investing resources in grid modernization. NRCan's priorities should be to: create a common understanding of what are the viable options to achieve Net Zero; rapidly develop baseload supplies, like new large-scale nuclear generation; and invest in behind the meter technologies, e.g., dual fuel heat pumps and bidirectional chargers that consumers can use to mitigate the cost impacts of electrification of Canada's economy.

The PWU has a successful track record of working with others in collaborative partnerships. We look forward to working with the federal government and other stakeholders to strengthen and modernize the electricity system of Canada and Ontario. The PWU is committed to the following principles: Create opportunities for sustainable, high-pay, high-skill jobs; ensure reliable, affordable, environmentally responsible electricity; build economic growth for Ontario's communities; and promote intelligent reform of Ontario's energy policy.

We believe these recommendations are consistent with and supportive of the government's objectives to transition to a Net-Zero economy and supply low-cost and reliable electricity for all Canadians. The PWU looks forward to discussing these comments in greater detail and participating in the ongoing stakeholder engagements.

[42] Strategic Policy Economics, Electrification Pathways for Ontario, 2021.

Appendix B – PWU 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:[43]

- 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:[44]

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.[45]

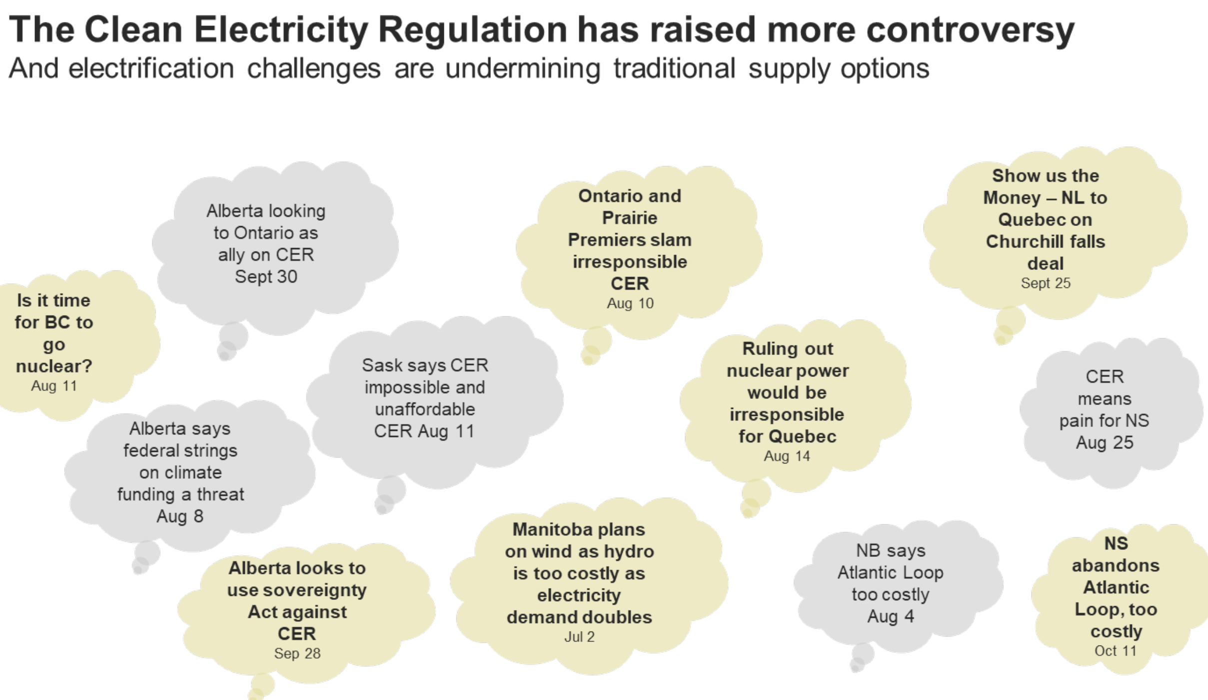
Many stakeholders share these concerns as respective provinces and territories continue to struggle to develop approaches that provide lower carbon energy for meeting future electricity demand.

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

[43] PWU submission to the ECCC regarding Canada's Proposed Frame for the Clean Electricity Regulations (CER), August 2022.
[44] Power Workers' Union Submission on Canada's Clean Electricity Standard Discussion Paper, April 2022.
[45] 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.

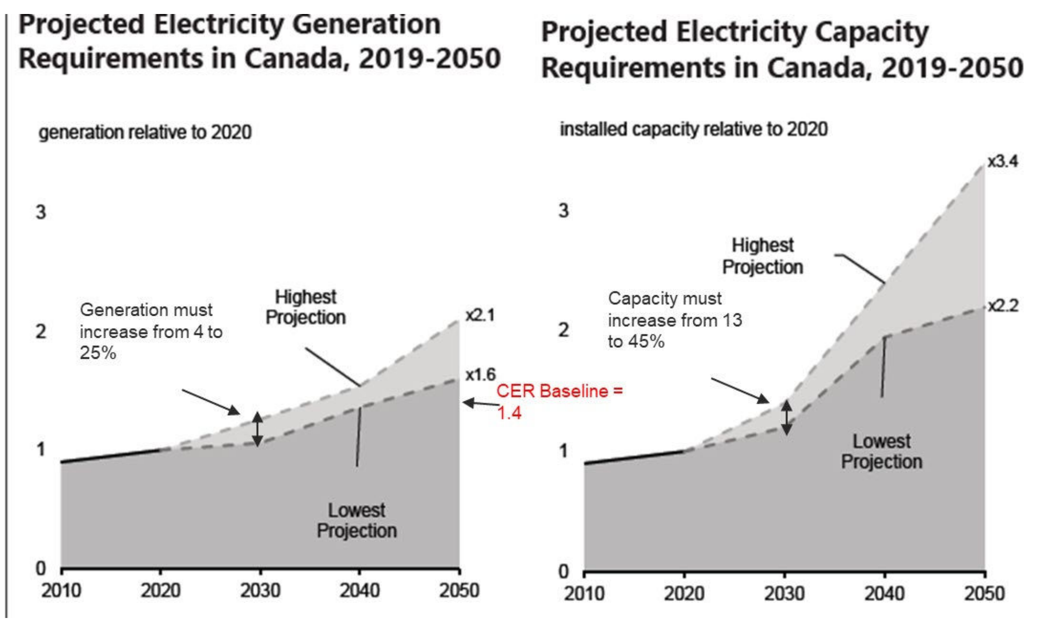
Three factors underscore the magnitude of the challenge facing the country in achieving the transition to a net zero economy:

- 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).[46] The Trottier Foundation

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

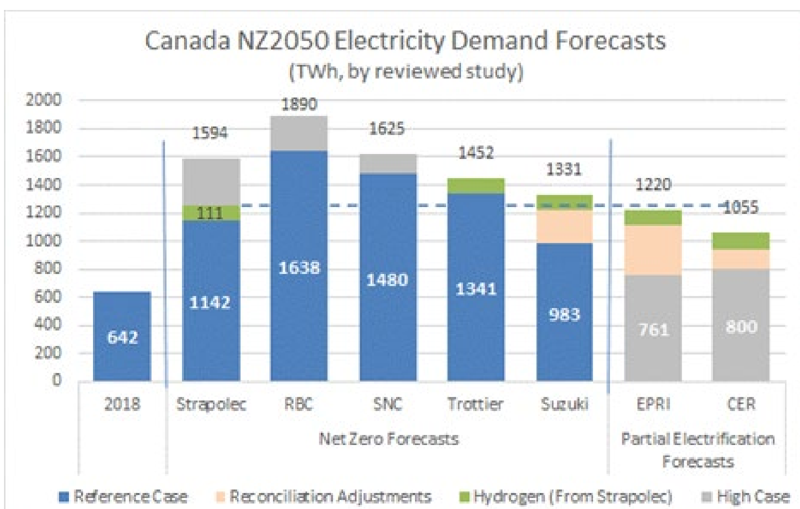
singularly projected the highest while the others, including from the Canada Energy Regulator in 2021, were on the low end.

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.[47] Differences in assumptions regarding carbon capture, electrolytic hydrogen, and biofuels net out to similar total demand forecasts.

Figure 3[48]



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.

47 SNC Lavalin, Engineering Net Zero, 2021; CCRE, A National Energy Vision, 2021.
48 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.[49] 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.[50] 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

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

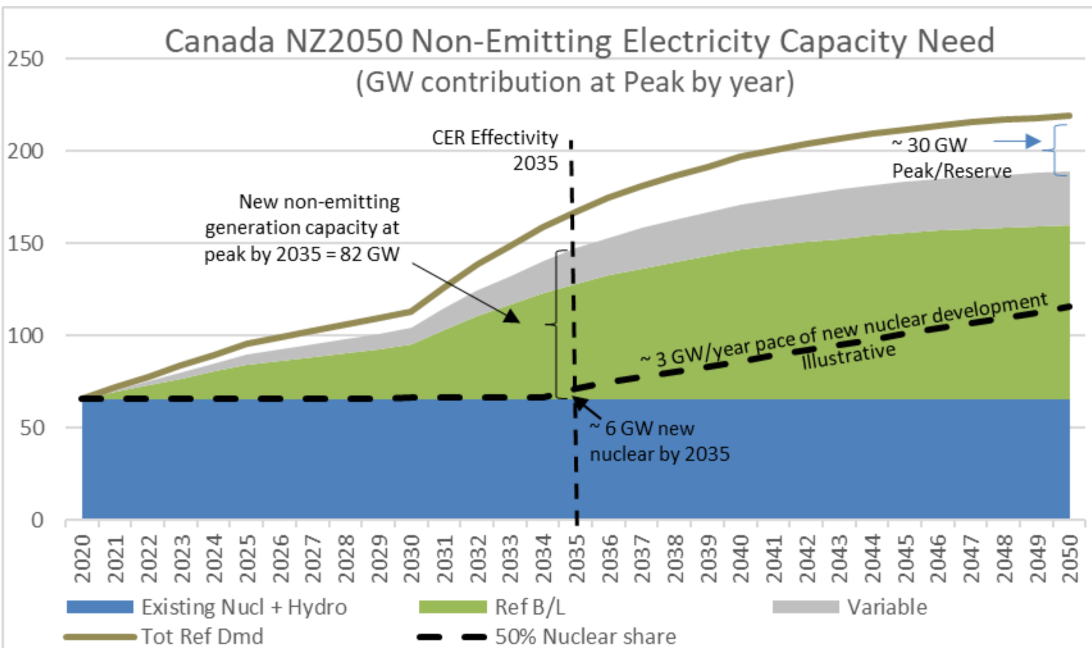
suggest the need to revisit the assumptions used to model the CER impacts to date. The challenges facing Canada's future supply options are further exacerbated by the higher demand noted and discussed above.

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.[51]

Figure 4 projects the minimum required pace of development by year of new non-emitting baseload, intermediate and peak supplies[52] to meet the demand forecast and displace emitting resources to achieve Net Zero by 2050.[53] Note that this chart reflects the de-rated capacity of the supplies to reflect their contribution potential at peak, when renewables contribution is minimal.[54]

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

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[51] Total 2050 demand shown reflects the Strapolec forecast which is the lowest of the Net Zero forecasts reviewed.

[52] 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.

[53] 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.

[54] 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.[55] 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.[56] 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.

[55] SNC Lavalin's 2021 Engineering for Net Zero report estimates that an aggressive development with minimal hurdles could achieve 55 MW by 2050.
[56] 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.

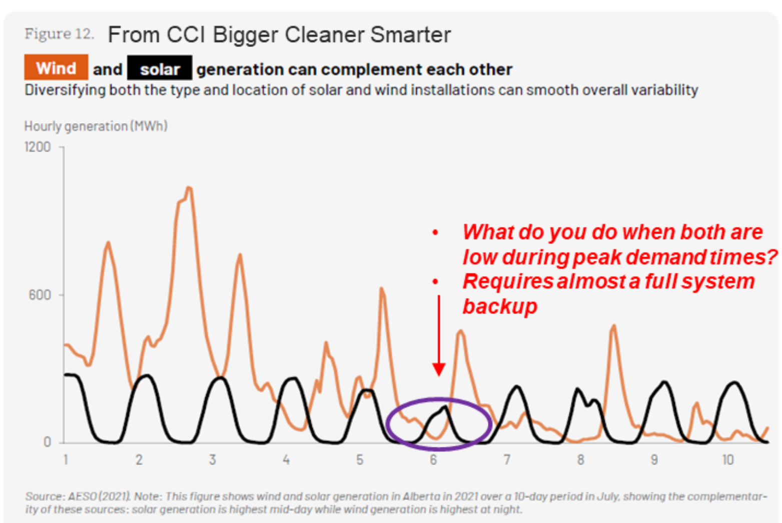
The PWU previously submitted extensive commentary and analysis to the ECCC on how to accurately model the contribution of renewables to the electricity system.[57] In that submission, the PWU recommended that the CES treatment of renewables should clearly recognize the challenges of relying on these 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)[58] and David Suzuki Foundation (DSF).[59]

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



[57] Power Workers' Union Submission on Canada's Clean Electricity Standard Discussion Paper, April 2022.
[58] Canadian Climate Institute, Bigger, Cleaner, Smarter - Pathways For Aligning Canadian Electricity Systems With Net Zero, May 2022.
[59] 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.

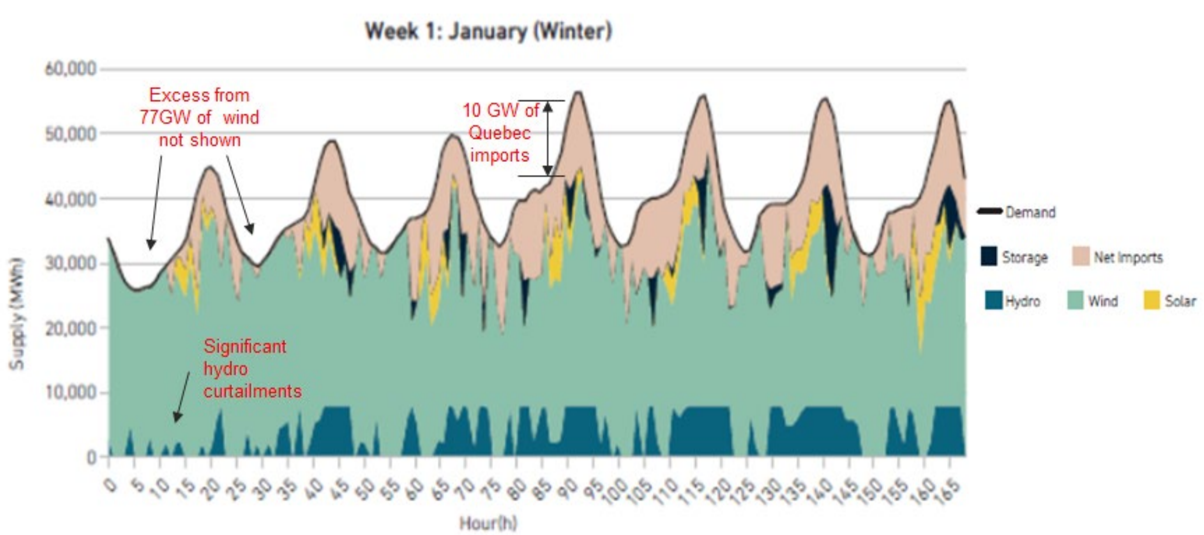
Figure 5 also illustrates how 5-6 days of storage would be required to store the required back up early in the week in anticipation of lower output later in the week. Such a low duty cycle significantly increases costs. It is also important to recognize that during winter, solar values are significantly 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.[60]

- 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

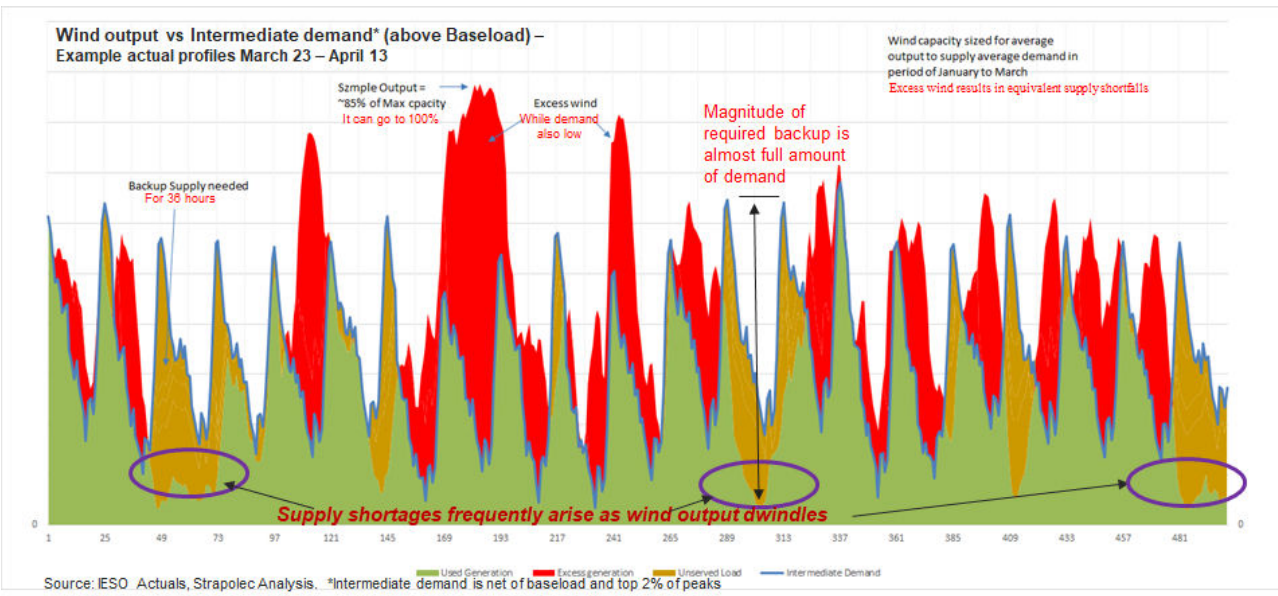


[60] The model has 77 GW of wind, 4 hours of storage at about 25% of demand (net of hydro supply), and some solar.

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



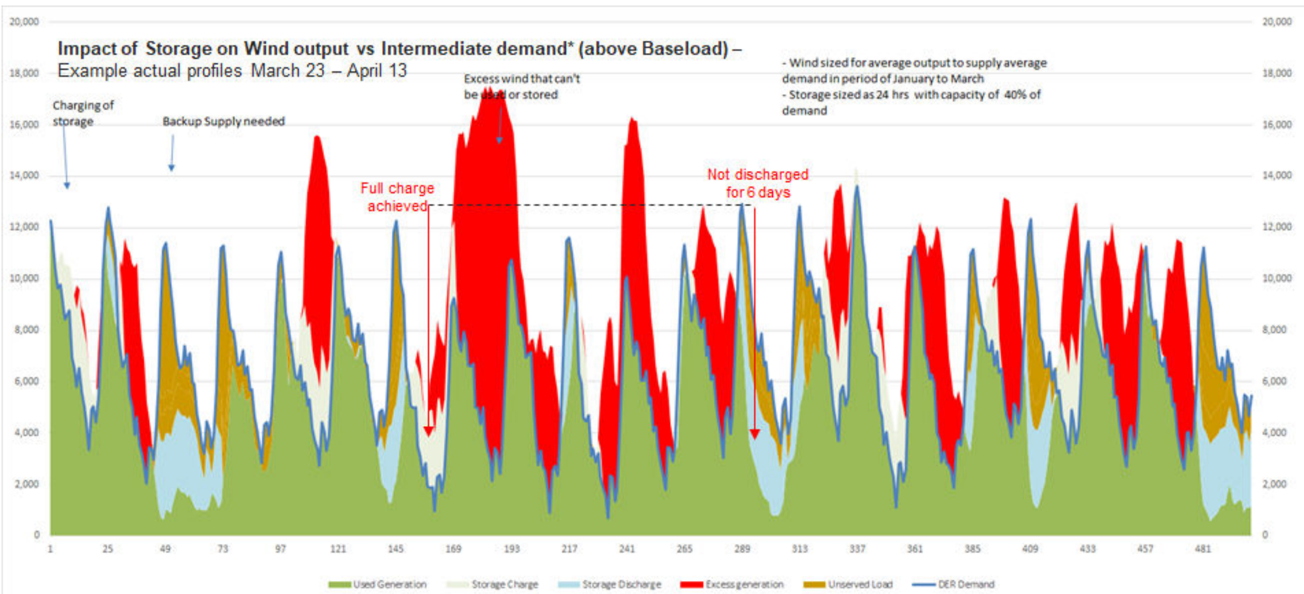
Many argue that storage can be used to smooth the intermittency of renewables. Figure 8 illustrates the behavior of storage against these actual demand and supply profiles by adding 24 hours of storage with a capacity to supply 40% of demand, a large amount. At 15% of wind capacity, this is double the 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.

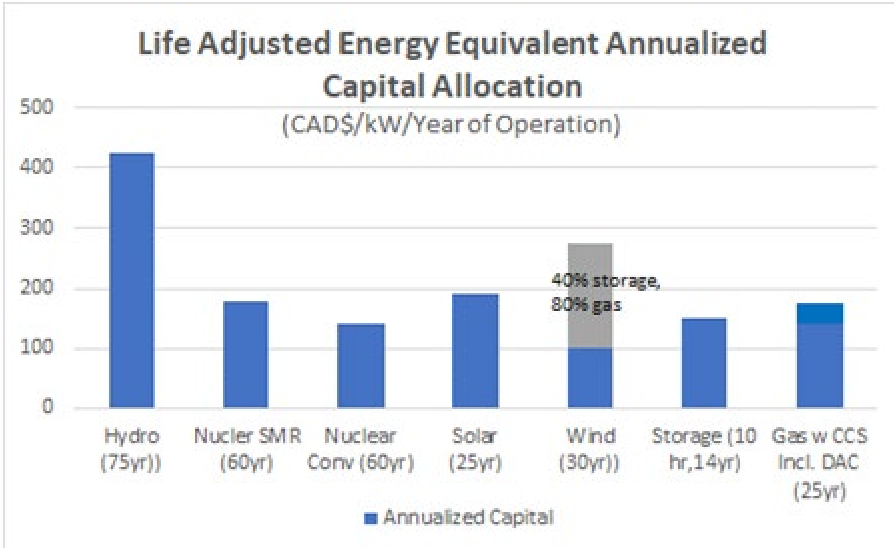
As a result, the conclusions arising from the analyses that support the CER should not be used by decision makers until this critical element of enabling a net zero electricity grid is adequately and properly validated.

Figure 8



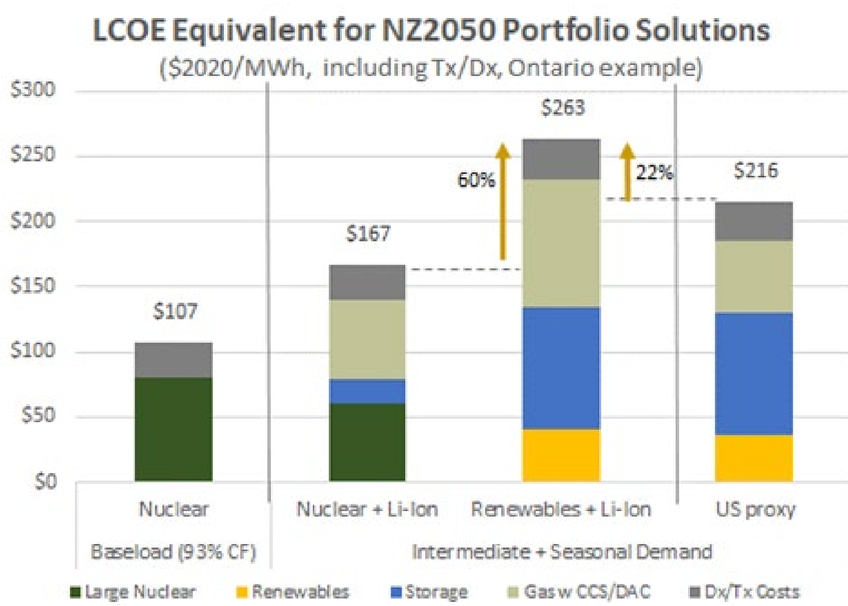
Many argue that renewables are low cost and that nuclear is high cost. Figure 9 illustrates the life adjusted energy equivalent capital costs of common generation options including storage. The figure reflects the capacity factor and the different economic life of the assets. These annualized equivalent 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.

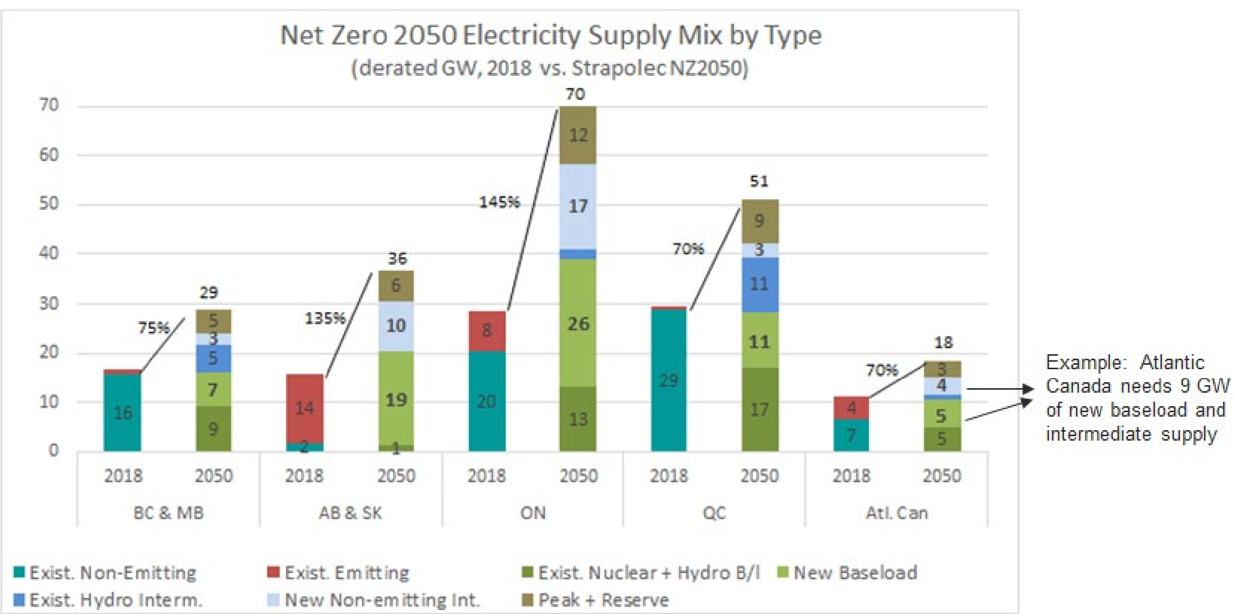
Ontario modeling shows that integrated renewables solutions could be 60% more costly than nuclear based solutions, even for meeting intermediate demand which is not a traditional function of nuclear. A renewables-based solution could make Ontario's electricity costs over 20% higher than those in the 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.[61] 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

[61] 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.[62] 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.[63]

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.[64] 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

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

modelling and wind costs that are 30% higher.[65] 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.[66]

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.[67] 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.

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

Appendix C - PWU Submission on Canada's Clean Electricity Standard Discussion Paper
April 2022

The Power Workers' Union (PWU) is pleased to submit comments and make recommendations to Environment and Climate Change Canada (ECCC) regarding the development of the Clean Electricity Standard (CES) and to help reach Canada's 2035 climate targets in a way that supports workers, communities, and the competitiveness of our 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 Plan, Clean Fuel Standard (CFS), Carbon Capture Utilization and Sequestration (CCUS) tax credit, and the 2030 Emission Reduction Plan.

The federal government has released a discussion paper on a proposed Clean Electricity Standard (CES) and is seeking comments from Canadians on its scope and design. The treatment of electricity within the Output Based Pricing System (OBPS) is also under review. The objective of the CES is to support the federal government's goal of establishing a net-zero emissions electricity system by 2035 and prevent the use of carbon-emitting electricity generating sources to meet demand growth created by decarbonizing the rest of the economy.

The proposed CES is intended to support the provinces and territories with their decisions regarding the:

1) Integration of wind and solar generation while de-risking the intermittency challenges;
2) Management of increased demand from electrification e.g., the transportation sector;
3) Deployment of emerging non-emitting options e.g., energy storage, geothermal and SMRs; and,
4) Promotion of energy efficiency and demand-side management to minimize demand and rate impacts.

The discussion paper requested feedback in several areas: Stranding of new emitting assets; CES as an incentive to deploy non-emitting sources, such as nuclear and storage; accelerating the development of the electricity system; resource availability and interconnections with neighboring jurisdictions; continued flexible use of natural gas; and, the CES's technology neutral objective.

The PWU provides the following recommendations in response to the discussion paper.

Context for and Viability of the CES's 2035 goals

5) The CES objectives should reflect that it is not possible to achieve net zero electricity emissions by 2035 and instead identify alternative pathways to achieve the desired outcomes as soon as possible.

Treatment of gas-fired generation and carbon pricing

6) The CES should allow for an ongoing role for gas-fired generation to provide peak and reserve capacity.
7) The OBPS should be modified to render the use of gas-fired generation for baseload and intermediate demand uneconomic.

Benefits and challenges of alternatives to continued gas-fired generation

8) The CES should support the use of biomass fueled generation.
9) The CES treatment of renewables should clearly recognize the challenges of relying on renewables to achieve its goals.

10) The CES should be technology agnostic, recognizing that the options for developing significant, new non-emitting generating assets are limited and affected by regional economics.
11) The CES should support the deployment of emerging technologies that mitigate the need for gas-fired generation during the transition and for the long-term.

Provincial and Territorial Considerations

12) The CES should be focused on policy drivers that can be used by the provinces and territories to develop the desired net zero emissions electricity system.
13) Regional interprovincial Tx Interconnections are dependent upon the type and location of new non-emitting supplies.
14) The CES should objectively communicate meaningful cost references regarding the available emission reduction options to support discussion and decision-making.

Relationships to other Federal Initiatives

15) Federal tax credits should be available to all low-carbon, baseload, and intermediate resource options to support the CES's technology agnostic objective.
16) The federal Green Bonds Framework (GBF) should be technology agnostic and include nuclear.

Context for PWU Recommendations

A stated objective of the CES is to reduce gas-fired generation emissions as soon as practically possible. Unfortunately, achieving this objective is complicated by the anticipated growth in demand for low-carbon electricity resulting from electrification of the economy.[68]

While the CES sets out a strategy for the transition towards 2035 and beyond, the viability of the pathways is influenced by the challenges existent in each provincial and territorial jurisdiction. Reducing Canada's dependence on natural gas will require new electricity infrastructure that depends on regional incremental demand and supply conditions, as shown in Figure 1. For example, significant low-carbon hydroelectric generation already exists in Quebec which has already addressed the building heat challenge and, as a result is forecasting modest demand growth by 2050. On the other hand, Alberta and Saskatchewan must convert their predominantly fossil fuel-fired generation and concurrently address the forecasted, second largest increase in electricity demand.

Ontario's electrification-driven electricity demand growth, the largest in Canada, will make its performance a critical factor for achieving the objectives of the CES.[69] The ECCC correctly acknowledges the pressing need for action given the significant amount of new, low-carbon energy infrastructure that is required by 2050.[70]

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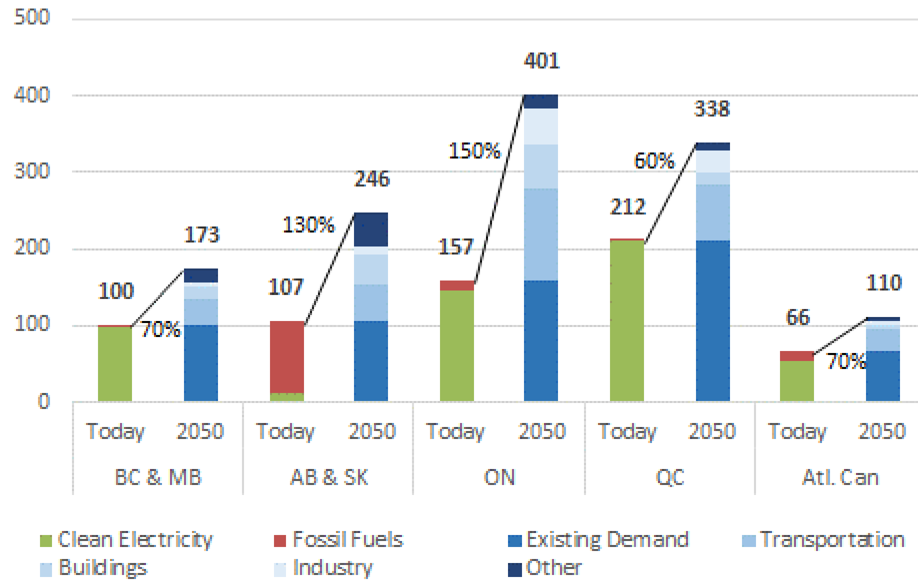
[68] Strategic Policy Economics, "Electrification Pathways for Ontario to Reduce Emissions", 2021; CCRE Commentary, "Toward a National Energy Vision: Canada's Low-Carbon Energy Infrastructure Opportunity in a Global Net Zero Future", 2021.
[69] PWU submission on the National Infrastructure consultation, regarding Government of Canada, "Building the Canada We Want in 2050", 2021.
[70] PWU submission to the 2030 emissions target consultation.

Figure 1 – Projected Growth in Needed Capacity to Achieve NZ2050 by Region in Canada



Source: Strapolec analysis

Context for and Viability of the CES's 2035 goals

Recommendation #1 – The CES objectives should reflect that it is not possible to achieve net zero electricity emissions by 2035 and instead identify alternative pathways to achieve the desired outcomes as soon as possible.

Ontario currently plans to meet its growing electricity demand by increasing its reliance on gas-fired generation. This will increase emissions from 4 Mt in 2017 to 17 Mt in 2042 [**Error! Reference source not found.**2], before considering the impacts of decarbonizing the economy.[71] Electrification of the economy will require even more capacity, potentially exposing Ontario to an unnecessary risk of brownouts in the late 2020s. Ontario is forecast to require 14 GW of new low-carbon supply by 2030.[72] This is equivalent to almost doubling Ontario's existing nuclear and hydro capacity in only 8 years. Ontario will need 20 GW by 2035. This is clearly not possible.

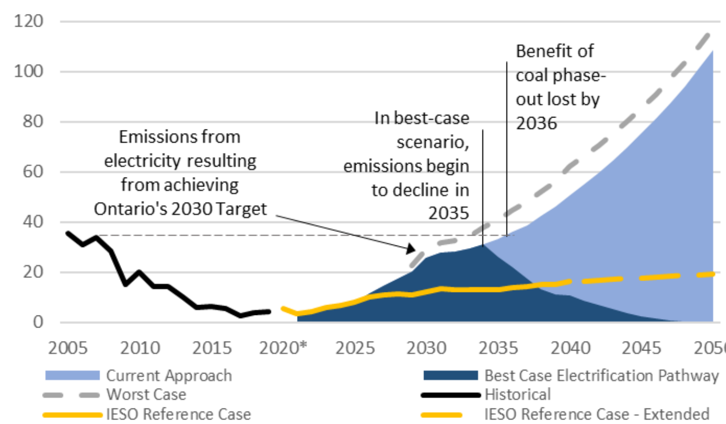
Analyses indicate that meeting the province's electrification demand will increase its' electricity sector emissions by an additional 35 Mt by 2042 as shown in Figure 2 – equivalent to a 25 percent increase in total overall provincial emissions. This will eradicate the emissions reductions achieved by Ontario's coal station closures over a decade ago. This will also set back Canada's overall 2030 national emission targets by 13 percent. In fact, without a change in strategy, Ontario's electricity sector emissions could increase to over 110 Mt by 2050. This equates to the total achievable forecast emission reductions from

[71] IESO, 2021 Annual Planning Outlook, Dec 2021
[72] Strategic Policy Economics, "Electrification Pathways for Ontario to Reduce Emissions", 2021; IESO, 2021 Annual Planning Outlook.

decarbonizing the electricity sector in all provinces that are still burning coal. This situation underscores the importance of the federal CES initiative.

Even under an aggressive build out of new low-carbon resources scenario, Ontario's emissions will not peak until 2035, well above the IESO's reference case, before dropping as shown in Figure 2. This will only be possible if Ontario starts immediately to build over 4000 MW of new baseload generation capability per year. However, even with such immediate and aggressive low-carbon capacity procurement, Ontario's electricity sector emissions will only be eliminated shortly before 2050. Such an aggressive procurement plan is not currently in play in Ontario. Over-reliance on natural gas-fired generation will persist for some time.

Figure 2: Emissions Implications Under Emitting and Clean Electricity Options
(Mt, 2005-2050)



Sources: IESO, APO, 2020; Source: IESO, 2021 APO, Chapter 7, Figure 42, 2021; Strapolec, Electrification Pathways for Ontario, 2021; Strapolec Analysis

Ontario's situation suggests that the ECCC should acknowledge achieving NZ by 2035 for the electricity sector is already impossible. The CES objectives should be refocused on the most effective policy options that can enable eliminating electricity sector emissions at the earliest date.

<u>Treatment of gas-fired generation and carbon pricing</u>

Recommendation #2 – The CES should allow for an ongoing role for gas-fired generation to provide peak and reserve capacity.

Natural gas-fired generation can cost-effectively provide peak and reserve capacity to the grid. Peak supplies are rarely used (<2% of the time) and produce negligible emissions over the year. Reserve capacity is almost never used, except under extreme emergency situations. The cost of mostly idle gas-fired capacity is much less than any other non-emitting option when its significant variable fuel cost is avoided. Considering the dispatch flexibility of natural gas-fired generation, it remains, at least for the short-term, an important asset for meeting peak and reserve needs. Forecasts suggest that Ontario will remain dependent upon gas-fired generation capacity for peak and reserve needs for a very long time. The most significant challenge for Ontario to 2035 is its need to meet baseload and intermediate demand with gas-fired generation.

Gas-fired generation is favoured by the electricity markets implemented in Ontario given its low capacity cost and how its low variable cost supply sets the energy market price. This inherent bias should be addressed by the CES to limit future participation in the energy market, as opposed to allowing payment of a carbon price as a permission to emit.

Recommendation #3 – The OBPS should be modified to render the use of gas-fired generation for baseload and intermediate demand uneconomic.

The need for new policy tools can be mitigated by modifying the OBPS to support the CES in the following ways:

1) Aggressively increase the application of the carbon price as a strong signal to investors;
2) The transition for consumers should be managed separately;
3) There should be no new provisions for credits or offsets;
4) Co-generation connected to the grid should be subject to the carbon price based on its efficiency; and,
5) Gas-fired generation based distributed energy resources (DERs) should be prohibited.

1) Aggressive carbon price

The Federal Output-Based Pricing System (OBPS) is inherently aggressive as the applicable carbon price for *new* generation transitions to fully expose all output by 2030. Unfortunately, the declining emission limits do not apply to existing generation. Furthermore, in Ontario, both existing and new generation will have negligible exposure to the carbon pricing under the province's Emissions Performance Standard (EPS) thereby eliminating any effective disincentives for natural gas-fired generation.

The treatment of natural gas-fired generation in both the OBPS and Ontario's EPS should be reviewed. The intent of these programs is to protect emission intensive trade exposed sectors from the competitive pressures associated with a carbon price on exported products. Gas-fired generation in Ontario, while it involves some electricity exports, is not trade exposed from a jobs perspective. Jobs in gas-fired plants are paid for by the province through fixed capacity payments. Applying the carbon price to natural gas-fired generation may limit the export of electricity to the U.S., but it will also save Ontario from the emissions associated with those exports. All gas-fired generation should be fully exposed to the carbon price and imports of electricity generated by gas-fired generation should be prohibited, as Ontario does with coal-fired generation.

The presence or absence of a carbon price will not affect the availability of natural gas-fired generation for peak or reserve purposes, but will dissuade its use for baseload and intermediate supply where the emissions do matter. Given the need for peaking and reserve capacity, the fact that fixed costs of the facilities are covered by capacity payments, and the significant growth in demand, there is no risk of stranding any existing gas-fired generation. By providing a strong price signal associated with emissions, investors will have the information they need to not expose ratepayers to the risk of stranding assets.

The CES should clearly signal the application of the full carbon price as soon as possible to incent new non-emitting supply.

2) Transition cost exposure to consumers

One clear drawback to a carbon price is that it increases the cost of electricity for consumers. This can be mitigated by rebating the carbon price to consumers via their electricity bills. These consumer rebates do not weaken the price signal for investors.

3) No need for additional credits or offsets

If the carbon price is fully applied to natural gas-fired generation, there is no need for any additional credits or offsets. Within the OBPS, the credit market allows for industry to find the cost-effective way to reduce emissions across the economy. This mechanism will be available if natural gas-fired generation remains within the OBPS. As mentioned above, there are no trade exposure risks requiring further action.

4) Output from Cogeneration facilities

The emissions from a Cogeneration facility are already addressed in the OBPS framework. However, any output from cogeneration facilities that is sold to the grid should be subject to the same carbon price formula that is applied to any other large, gas-fired generation facility. The OBPS already recognizes the efficiency benefit of Cogeneration facilities, which will continue to have an advantage over other gas-fired options when selling power to the grid. However, the limits should be decreased over time to fully expose generation sold to the grid by 2030, as recommended for all gas-fired generation.

5) Gas-fired DER should not be supported

Purpose built gas-fired DER generation should already be exposed to the carbon price under the Greenhouse Gas Pollution Pricing Act (GGPPA) as the emissions from these facilities would fall under the thresholds set for OBPS participation. Nevertheless, the final policy should ensure that these facilities are fully exposed to the carbon price and/or any future development is subject to an outright ban.

Benefits and challenges of alternatives to continued gas-fired generation

Recommendation #4 – The CES should support the use of biomass fueled generation

Canada's significant renewable, farm and forest-sourced, carbon-neutral biomass wastes represent another opportunity to reduce carbon emissions while providing electricity, heat and biofibre-based alternatives to fossil fuels.[73] As well, the distributed availability of the biomass feedstocks makes it a flexible source of low-carbon energy at both the regional and provincial level.[74] For example, biomass generation in Northwest Ontario is a cost-effective alternative to natural gas-fired generation in the region while reducing natural gas imports from the U.S. at the provincial level.[75]

Furthermore, forestry waste biomass generation can provide the same flexibility offered by natural gas-fired generation. This form of generation produces minimal net emissions due to its renewable feedstock and when coupled with CCUS (e.g. Bioenergy Carbon Capture and Storage (BECCS)) offers a net carbon sink option. This can help the CES achieve NZ for the electricity sector by compensating for any natural gas-fired generation required to provide peak/reserve/emergency supply.

The Atikokan Generating Station (AGS) in Northwestern Ontario represents an important opportunity to continue and expand the use of waste forestry biomass to produce low-carbon electricity and heat.

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[73] PWU submission on the National Infrastructure consultation, regarding Government of Canada. "Building the Canada We Want in 2050." 2021.
[74] PWU, Submission to MNRF on ERO 019-3514, Ontario's Draft Forest Biomass Action Plan, 2021.
[75] M. Brouillette, CCRE Commentary – Toward a National Energy Vision: Canada's Low-Carbon Energy Infrastructure Opportunity in a Global Net Zero Future, 2021; PWU submission to Ontario's Forestry Biomass Action Plan, 2021

Analysis shows this is an economic alternative to gas-fired generation.[76] OPG considers sustainably managed biomass generation to be one of its low-carbon generation sources along with hydro and nuclear. OPG classifies the AGS as a low carbon emissions source of supply based on the sustainable forestry practices that provide the wood pellets.[77]

Ontario's sustainable forest management planning processes and practices enable OPG's biomass program to satisfy the United Nations Framework Convention on Climate Change (UNFCCC) definition of renewable biomass. Additionally, the proven, available biomass supplies in the Northwest make the AGS a strategic location for producing low-carbon hydrogen that could help decarbonize heavy duty vehicles in the forestry sector.

Recommendation #5 – The CES treatment of renewables should clearly recognize the challenges of relying on renewables to achieve its goals.

The CES discussion paper favours the use of renewables for achieving its goals. However, there are evident risks associated with the underlying assumptions of the CES: availability of the technologies; modelling limitations; the amount of back-up natural gas-fired generation that is required, and the cost competitiveness.

1) Technology Availability Constraints

   The CES discussion paper asserts that renewables are widely available. However, there are several evident factors that will limit the availability of the renewable capacity required to meet the magnitude of Canada's emerging needs. As the CES paper notes, Canada's demand for electricity will be significant - over twice today's available capacity.

   Supplying 1000 TWh of new demand would require 40,000 five-MW wind turbines and 17 million acres of land on which to site them.[78] It is also worth noting that wind output is low in the summer. Grid solar installations would need 2.5 million acres and do not produce much electricity in the winter. Most of the prime locations for wind resources in Ontario have already been developed, yet to meet the 2050 target using renewables could require over 200 times more than what is already installed in Ontario. – and that is if the renewables output could be aligned with demand.

2) Modelling Limitations

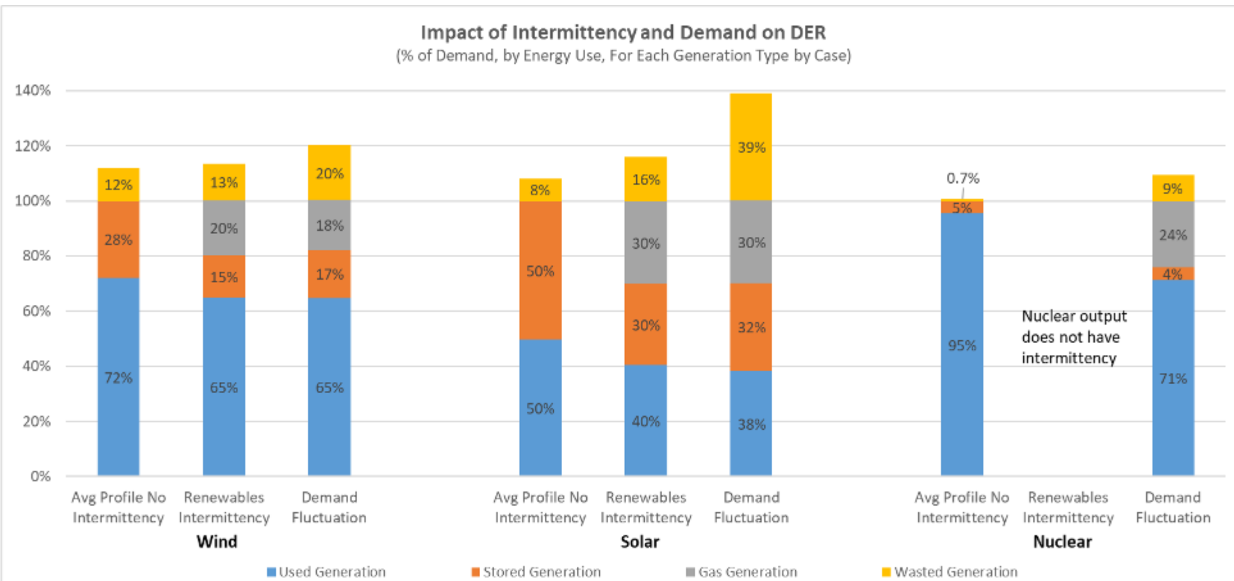
   Numerous modelling exercises have been undertaken around the world to assess the potential role for renewables in the future. However, studies of the reliability of these models suggests the

[76] Strategic Policy Economics, "Atikokan GS Extended Operations", 2022.
[77] https://www.opg.com/powering-ontario/our-generation/biomass/; OPG Annual Report, 2019; World Resources Institute, INSIDER: Why Burning Trees for Energy Harms the Climate, Dec 2017; OPG, Ontario Power Generation's Biomass Journey, Sept 2017; FutureMetrics LLC, Biomass Carbon Capture and Sequestration, Dec 2020.
[78] SNC Lavalin, "Engineering Net Zero, March 2021; Nuclear Innovation Institute, "Nuclear Intelligence Report", September, 2021; Strapolec analysis.

contributions of renewables is overestimated and the associated costs underestimated.[79] These conclusions reflect the manner in which intermittency is addressed i.e., hourly, daily, weekly and seasonal variability of both output and demand.

Understanding these limitations is critical. For jurisdictions like Ontario, for example, the amount of sunshine is half that of Arizona and the consistency of wind is two thirds of that of the mid west U.S. Improving the reliability of these models would demonstrate how the need for, and use of, storage increases as does the need for backup gas generation and the amount of excess generation that is wasted, as illustrated in Figure 3 for Ontario.[80] These shortcomings should be addressed within the toolset used by the ECCC to ensure the appropriate information is available to support cost-effective decisions regarding ECCC policies and plans.

Figure 3 – Implications for Storage and Backup Supply for Renewables Scenarios



Note: The simulations modelled, including the nuclear scenario shows how the technology options could meet daily intermediate demand in the IESO's reference forecast for 2030 that exceeds what Ontario's existing baseload could supply after the Pickering Nuclear Generating Station retires.

3) Need for Backup Generation

The need for backup firm supply is higher than many assume. Analyses have clearly demonstrated that the renewables-based scenarios require significant flexible backup generation, even with the use of storage. This occurs due to intermittency—the days, and even weeks, when the output from renewables is negligible and/or insufficient to charge storage assets. Gas-fired generation will be needed to supply 20% to 30% of the energy output planned from renewables as illustrated in Figure 3 above. Simulations show that replacing natural gas-fired generation for meeting baseload and

[79] Hans-Kristian Ringkjøb∗, et al., "A review of modelling tools for energy and electricity systems with large shares of variable renewables", 2018, Renewable and Sustainable Energy Reviews; Miguel Chang a,*, et al., "Trends in tools and approaches for modelling the energy transition", 2021, Applied Energy.
[80] Strategic Policy Economics, "Renewables-Based Distributed Energy Resources in Ontario", 2018.

intermediate demand with 100% renewables and storage would cost four times as much as other low carbon alternatives.[81]

If a net zero emission electricity sector is the objective, the use of unconstrained natural gas to backup renewables is not the solution. Improved modelling would enable the ECCC to deliver better results. In the short-term renewables can help transition a decrease in the use of natural gas-fired generation. In the longer-term, renewables and natural gas will not help Canada achieve NZ by 2050.

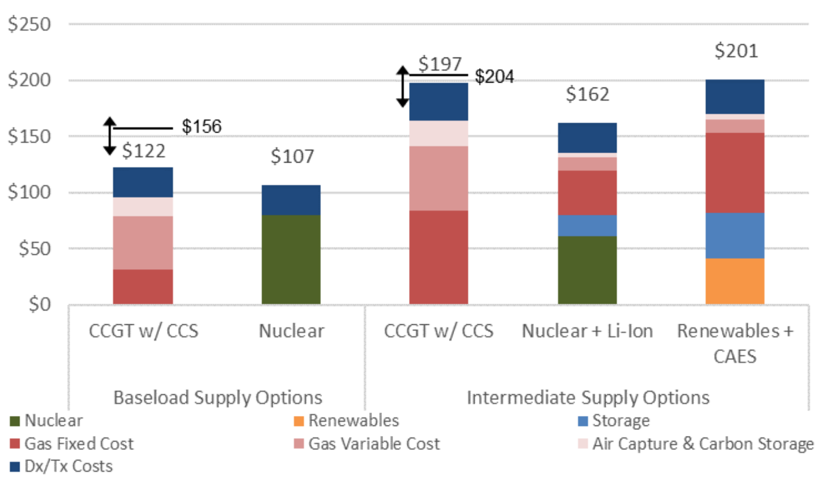
4) Cost Competitiveness

The CES discussion paper posits that renewables are becoming cost competitive as evidenced by their increased adoption across Canada. It is noteworthy to acknowledge that the vast majority of this adoption has been incented by substantial subsidies. For example, in Ontario these subsidies led to large cost increases and widespread consumer dissatisfaction.

The discussion paper correctly noted that the full cost of renewables is not clear as it includes expenditures for market and regulatory reforms, expansion and reinforcement of transmission and distribution infrastructure and for providing system flexibility. These costs all result from the intermittency and non-dispatchable nature of renewables.

As shown in Figure 4, detailed simulation models show that, even a decade from now, renewables solutions are expected to cost 25% more than other low-carbon generation options capable of meeting intermediate demand and almost twice as costly for baseload, reflecting the reliance on backup from gas-fired generation.

Figure 4: Integrated Low-emitting System Supply Cost Comparison
(LCOE $/MWh 2018CAD, NZ2050)



Note: Costs shown after conversion to Canadian context and include full life cycle costs, waste and decommissioning. Capital cost for CCGT w/o CC is based on IESO $140,000/MW/year, with CC adding $101,000/MW/year. Storage assumptions reflect lowest available cost, which is compressed air energy storage, co-located with wind farms. Source: Strapolec, 2021.

[81] CCRE Commentary, "Renewables-based Distributed Energy Resources in Ontario: A Three-Part Series of Unfortunate Truths, Part 2: Cost Implications", June 2019.

Recommendation #6 – The CES should be technology agnostic, recognizing that the options for developing significant, new non-emitting generating assets are limited and affected by regional economics.

Canada's significant low-carbon energy options – renewable biomass, hydroelectric, natural gas-fired generation with carbon capture and nuclear – can help Canada achieve its NZ targets. The latter three options are best suited for providing low-carbon baseload electricity, however, their potential availability is unequally distributed across the country.[82] Similarly, their respective roles in electrification of the economy and hydrogen deployment will vary by region.

Jurisdictions around the world are wrestling with the same challenges and are seeking low-carbon technological advantages in CCUS, new nuclear and small modular reactors (SMRs) and their roles in a hydrogen economy. Low-carbon nuclear and hydroelectric resources in Ontario and hydroelectric in Quebec could be key drivers for electrification and electrolytic hydrogen production while western Canada may be able to economically produce hydrogen from natural gas with carbon capture. All these potential solutions are not without challenges.

In Canada, recent major hydroelectric power developments outside of Ontario and Quebec have encountered significant issues – specifically Site C in BC, the Keeyask Dam in Manitoba, and Muskrat Falls in Labrador.[83] At the present time, Quebec is not planning for further investment in new hydroelectric plants.[84] While Ontario is exploring its remaining hydroelectric options, higher costs are anticipated.[85] Large-scale hydroelectric stations require extensive land. For example, meeting Canada's emerging electricity demand is expected to require 115 hydro reservoirs similar in capacity to BC's Site C project. Or alternatively, the required capacity is 15 times that of Quebec's James Bay complex and would require the flooding of up to 160,000 sq kms or 40 million acres of land.[86]

While significant economic and geological potential for CCUS exists in Alberta and Saskatchewan, its viability is less evident elsewhere in the country. Furthermore, natural gas-fired generation fitted with CCUS will not be a zero-emitter as it is only anticipated to be 90% efficient. However, the CCUS option could be integrated with renewables and/or direct air capture (DAC) to improve outcomes, but at some additional cost.[87]

Recently, the International Energy Association (IEA) noted the importance of nuclear energy for achieving Canada's Net Zero targets.[88] While the federal government and the western provinces are

[82] Strategic Policy Economics, "Towards a National Energy Vision", 2021.
[83] Strategic Policy Economics, "Towards a National Energy Vision", 2021.
[84] CBC News, "Quebec looks beyond hydroelectricity as last planned megaproject set to wrap", December 2021.
[85] Ontario Newsroom, "Province Asking Ontario Power Generation to Investigate New Hydroelectric Opportunities", January 2022; Strategic Policy Economics, "Towards a National Energy Vision", December 2021.
[86] SNC Lavalin, "Engineering Net Zero", March 2021; Strategic Policy Economics, "Emissions and the LTEP", 2016; Strategic Policy Economics, "Towards a National Energy Vision", 2021; The Canadian Encyclopedia, James Bay Project, January 31, 2011.
[87] Strategic Policy Economics, "Electrification Pathways for Ontario to Reduce Emissions", 2021.
[88] IEA, Canada Energy Policy Review, 2021.

supportive of Canada's SMR action plan, there is no material funding.[89,90] Concurrently, Ontario, with its low emission electricity sector profile dependent upon nuclear, is only pursuing small scale pilots with foreign-based technologies.[91] Given Canada's established need for low-carbon generation and the societal benefits of nuclear energy, the absence of nuclear in Canada's NZ strategy is jarring.

Analyses show that building new nuclear in Ontario is the best long-term solution for reducing emissions in the province. From a land use perspective, meeting Canada's emerging demand will only require 19 nuclear sites equivalent in size to the Bruce Power Complex. These facilities could be sited on 40,000 acres or 0.04 million acres of land – an area that is less than 0.1% of the land required to support wind or hydro.[92]

If the full price of carbon is incorporated in the CES and OBPS frameworks, the aforenoted three options will emerge as appropriate to their inherent regional advantages.

Recommendation #7 – The CES should support the deployment of emerging technologies that mitigate the need for gas-fired generation during the transition and for the long-term.

The CES discussion paper posed the question of the role that Distributed Energy Resources (DERs) could play in helping achieve the NZ 2035 goals for the electricity system. Three types of DER could be considered:

- Small gas-fired distributed generation, often Cogeneration;
- Renewables, typically solar; and,
- Storage.

Gas-fired generation based DERs should not be supported by the CES framework. Currently in Ontario, this type of installation is proliferating behind the meter due to generous provincial rate programs. However, as discussed previously, these kinds of applications could become less economic with a broad application of the carbon price in the GGPPA and/or OBPS and through rate reform.

Renewables-based DERs, typically defined as small, not grid scale installations e.g., rooftop solar, are high cost and largely non-dispatchable devices, even when coupled with storage. They add to the total system cost and require gas-fired back up as noted earlier. There are better alternatives. Programs such as Net Metering should be abandoned in jurisdictions with low fossil fuel supply mixes for these reasons. While these are provincial issues, the CES should provide clarity regarding the true costs, benefits and emission forecasts of DER.

Storage, although most often used to mitigate renewables intermittency, is the most attractive type of DER. The most valuable use of storage is for smoothing local demand. Locating storage as close as possible to the load provides flexible capacity that can reduce the need for gas-fired generation to meet

[89] NRCan, SMR Action Plan, 2021.
[90] NII, Nuclear Intelligence Report, "Why hydrogen needs nuclear", September 2021; Strategic Policy Economics, "Electrification Pathways for Ontario to Reduce Emissions:", 2021; Ontario Newsroom, "Small Nuclear Reactor Study Released, Alberta Signs SMR MOU", April 14, 2021.
[91] OPG, "OPG advances clean energy generation project", December 2, 2021.
[92] NII, Nuclear Intelligence Report, "Why hydrogen needs nuclear", September 2021.

peak, reserve and daily intermediate demands. Local community-scale storage may be the most cost-efficient as residential-scale storage costs are expected to remain high for some time.

Other emerging demand side management (DSM) technologies could potentially accelerate the transition to a NZ grid: electric vehicles (EVs); dual-fuel heat pumps; and, electrolytic hydrogen.

- EVs could effectively represent a subsidized form of small-scale storage directly available in homes and buildings.[93] Depending on the level of EV penetration, EV batteries could obviate the need for other forms of storage. Bidirectional EV chargers significantly enhances their utility.
- Dual-fuel heat pumps that operate off both electricity and natural gas could help mitigate the need for "peaking" gas-fired electricity generation in the winter. Producing heat from natural gas is far more energy efficient than generating electricity. Furthermore, blending renewable natural gas and hydrogen and then injecting it into the gas distribution system could reduce emissions during the transition to NZ.
- In the longer-term, as the hydrogen economy grows, electrolysers could meet most of the peak and reserve needs currently forecast for natural gas generation. [94]

A network of distributed hydrogen electrolysers integrated with the electricity system coupled with emerging DSM gas/electricity systems could achieve Canada's NZ objectives at a lower cost. These options reduce the use of natural gas and need for generation capacity while increasing the efficiency of the transmission and distribution system. When coupled with non-emitting baseload supplies, these technologies can effectively smooth local demand.[95]

Nuclear provides a well-suited foundation for an integrated low-carbon technology package that provides distributed storage capabilities and electrolytic hydrogen production. Accomplishing the CES NZ objectives can be accelerated by incenting new, low-carbon baseload generation. Storage and other DSM technologies will follow assuming the current biases favouring gas-fired generation are appropriately priced and regulated.

Provincial and Territorial Considerations

Recommendation #8 – The CES should be focused on policy drivers that can be used by the provinces and territories to develop the desired net zero emissions electricity system.

The CES discussion paper acknowledges that the provinces and territories have constitutional jurisdiction over electricity. However, the CES represents an opportunity to promote a national collaborative vision for electricity and other energy resources that benefit all of Canada. It can do so by establishing a common view on electricity system emissions, carbon pricing, the need for market reforms, and an end-point emissions standard to establish the conditions for regional investments in BECCS and DAC to support the CES NZ objective.

A Common View - The CES should define policy priorities to encourage provincial/territorial government accountability in providing a low-carbon electricity supply mix. The low carbon energy transition

[93] PlugNDrive, "EV Batteries Value Proposition for Ontario's Electricity Grid and EV Owners", 2020.
[94] PWU submission on the Natural Resources Canada (NRCan), "Hydrogen Strategy for Canada", 2020.
[95] Strategic Policy Economics, "Electrification Pathways for Ontario to Reduce Emissions", 2021.

exemplifies Canada's enduring policy dilemma – balancing the regional differences and disparities in resources and interests created by our vast geography. By focusing the CES on policy priorities, provincial/territorial governments are better able to optimize their own carbon footprint in support of achieving Canada's NZ goals.

Such an approach would provide government and private decision-makers with a framework to help balance and optimize the environmental, economic, and social benefits potentially achievable by building more low-carbon electricity, decarbonizing fossil fuels, and producing hydrogen. Maximizing the societal benefits from such investments would improve Canada's economic competitiveness while creating jobs and economic wealth. Governments could also work cooperatively to promote procurement criteria that further optimize these benefits.

Carbon Pricing - The OBPS and GGPPA rules for fossil fired-generation, consistent with the more aggressive approach recommended earlier, should be a sufficient federal tool to encourage the requisite decisions by regional governments and innovation by developers.

As previously noted, Ontario's emerging capacity gap and need for new gas-fired generation capacity in the near-term is a major challenge. The CES should encourage storage options that help avoid the need for new gas plants during the transition period and encourage investments in low-carbon baseload supply.

As well, these revenues should be invested to strategically optimize the cost effectiveness of carbon reductions and mitigate the impacts on Canada's trade exposed industries. Analysis shows that with a nuclear-based electricity system coupled with DSM and hydrogen and the smart re-investment of carbon price revenues, the requisite carbon price required to achieve Canada's 2050 targets could be as low as $106/tonne.[96] Keeping the carbon price low and implementing border adjustments could ensure low-carbon energy resources generate domestic economic growth and a competitive advantage in the global marketplace.

Market reform - In order to move effectively forward to a decarbonized electricity system, some deregulated provinces, like Ontario, will require electricity market reform, specifically with respect to resource procurement.[97] Analyses show that Ontario's electricity market design will not successfully secure the low carbon resources needed to achieve NZ.[98] Furthermore, such market mechanisms do not encourage achieving broader societal benefits from these system investments.

End-Point Emissions Standard - Establishing an aggressive carbon price and goal to eliminate gas-fired generation precludes the need for a specific end-point emissions intensity standard and the associated compliance confirmation mechanisms. This end point efficiency standard should be zero or negative, as all of these technologies are forecasting lower costs than single cycle natural gas-fired generation with a fully applied federal carbon price.

Recognizing the inherent challenges in eliminating gas-fired generation, the CES should include mechanisms to encourage CCUS, Direct Air Capture (DAC) of carbon and BECCS technologies.   It is worth noting that the BECCS has the advantage of producing negative emissions, a DAC requires significant

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[96] Strategic Policy Economics, "Emissions and the LTEP", 2016.
[97] Strategic Policy Economics, "Electrification Pathways for Ontario to Reduce Emissions", 2021.
[98] Strategic Policy Economics, "Electricity Markets in Ontario", 2020.

electricity to operate and CCUS technologies require a DAC to eliminate emissions that escape the CCUS systems. The end point zero emission standard may require an effectivity date beyond 2035 in order to provide a reasonable transition period as described earlier. It may only be achievable by 2050 and hence may not be relevant as part of a CES NZ 2035 objective.

Recommendation #9 – Regional interprovincial Tx Interconnections are dependent upon the type and location of new non-emitting supplies.

Investments in interprovincial interties come with very high costs. Canada's current interconnection infrastructure is focused on north-south electricity exchanges with the U.S. Currently, there are modest exchanges between provinces and territories given the large distances between Canada's urban centers and sources of supply. This may or may not change as demands for low-carbon electricity increase across the country.

For example, the Atlantic loop is currently being explored to facilitate the delivery of the region's low-carbon hydro resources to meet growing electricity demands in urban centers in eastern Canada. Other similar opportunities may exist—low-carbon electricity from BC to Alberta; from Manitoba to Saskatchewan; and, increased bilateral electricity trade between Quebec and Ontario.

However, forecasts indicate that all jurisdictions will experience significant demand growth that exceeds the capacity of their existing resources. The economics of new transmission investments will be driven by the type of new generation that is located in each jurisdiction and the emission reduction role it can play helping neighboring jurisdictions.

The uptake among the provinces of new hydro, CCU and nuclear technology may influence decisions on the need for long run transmission assets. While hydroelectric development has challenges as previously noted, if CCUS gains favourable economics, it could be a game changer. It is conceivable that successful CCUS implementation in Alberta and Saskatchewan may result in those provinces supplying BC and Manitoba instead. Alternatively, nuclear remains one of the most locationally flexible, low-carbon bulk generation options that any province could adopt.

Recommendation #10 – The CES should objectively communicate meaningful cost references regarding the available emission reduction options to support discussion and decision-making.

Annex A of the CES discussion paper provides a summary of the "cost and technological readiness of important technologies". The information is sourced from the Energy Information Agency (EIA) 2021 Annual Energy Outlook, which is a legitimate source for anchoring cost data. The U.S. National Renewables Energy Laboratory (NREL) also maintains an Advanced Technology Baseline that is drawn upon by the EIA. The NREL data provides more information. However, the cost information as presented in the Annex is misleading and incomplete and would lead to biased and ill-informed decision-making. Table 1 of the Annex, for example, provides overnight capital cost and variable O&M, but no fuel cost.

The information as presented incorrectly suggests the lowest cost option. For example, the overnight capital cost of a CCGT with 90% CCUS costs $3600/kw versus grid-scale solar at $1700/kw. However, if used for baseload, the CCGT may have a 90% capacity factor, i.e. it produces full output for 90% of the time in a year. By comparison, solar in Ontario has only a 19% capacity factor. This means that the relative cost for solar, based on per MWh of electricity produced, would be five times higher and the CCGT 10% higher, leaving the CCGT at only 45% of the cost of the solar (e.g. 5*1700 = 8500 vs 1.1* 3600 = 3960). The capacity factor is a significant determinant of what is commonly referred to as a levelized cost of electricity (LCOE), a better metric for comparing costs between generation types if assumptions are aligned.

Furthermore, the CCGT option would incur a variable cost of fuel that is not shown in Table 1 and hence there are no mechanisms to assess the relative merits of even gas vs solar options on a cost basis. Additionally, as the CCUS of the CCGT is assumed to be 90% efficient, there are additional carbon cost implications.

The CES should present more relevant cost comparators, specifically LCOEs and should do so for each province and territory. Relevant factors include:

1) Capacity factor that will be realized reflecting the useful energy produced. This must not only consider the weather determined factors (e.g., Ontario solar's 19% capacity factor which is much less than assumed by the EIA) – but also the operational capacity factor that considers wasted energy as a function of the supply mix of the jurisdiction in which it may be installed and the penetration of renewables in it.
2) Regional cost structures that consider local labour and other supply considerations that affect the capital cost. The EIA publishes these for various regions in the U.S. The ECCC should provide equivalent assumptions for Canada; and,
3) Exchange rates should not be universally applied when converting U.S. costs to Canadian costs as not all elements of the cost of generation should be scaled uniformly by the exchange rate, particularly when there are some domestic sources of the supply. In general, generation options like nuclear with significant domestic content will have lower net exchange rate implications than for imported technologies e.g., renewables.

The previously described system modelling is required to establish the capacity factors relevant to each Canadian jurisdiction. The total system cost associated with a supply mix option is most informative. For example, Figure 4 compares a renewables-based solution to a CCGT with the CCS option and a nuclear-based option. These are the comparators that would be most informative to decision-makers.

The ECCC should undertake to provide this guidance and create a comprehensive Canada wide, jurisdictionally representative guide on the cost implications of the various, available technologies for a low-carbon supply mix. This guide should convey the total system cost impacts including for backup, storage and wasted energy.

Relationships to other Federal Initiatives

The PWU recommends that the CES framework be adjusted to more assertively adopt a clear position in support of the role of low-carbon nuclear to meet Canada's future energy needs. Nuclear generation is an essential element of Canada's response to the climate change challenge and for achieving NZ by 2050. Strong, sustained advocacy and policy incentives by the federal government are imperative to ensure long-term, low-carbon energy security for Canada and achieve its economic and environmental targets. By providing a more balanced view of the available options and the cost and economic implications of each, the federal government, in concert with its carbon pricing policies, should not need additional programs.

Recommendation #11 – Federal tax credits should be available to all low-carbon, baseload and intermediate resource options to support the CES's technology agnostic objective.

The PWU supports the notion of a CCUS investment tax credit to help Canada's transition to a net-zero economy. However, the scope of such a program should be broadly structured to help reduce emission costs and to provide equitable tax support for the emission reduction strategies of all the provinces and territories. This means expanding tax credits to other non-emitting technologies that help displace emissions from natural gas consumed by the electricity system.[99]

The PWU has identified three examples of technologies that warrant tax credit support, particularly in regions where long-term carbon storage may be cost prohibitive or non-viable:

i. *Biomass-fired generation*

Biomass-fired generation is a source of flexible, dispatchable, low-carbon energy that can displace the contributions of natural gas-fired generation.

For example, Ontario Power Generation's biomass-fueled Atikokan Generating Station's strategic geographic location with transportation and grid connections, existing biomass infrastructure, and available heat outputs support its development as a low-carbon energy centre.[100]

Analyses show that Ontario has vast, renewable biomass resources available from forestry and agriculture wastes and purpose grown crops. Equipping the station with carbon capture and some level of storage/utilization capacity (e.g., increasing yields in nearby greenhouses) would make it a net carbon sink. Utilizing the wasted heat for pellet production would expand the existing supply chain providing additional economic, environmental and social benefits, including enhanced regional energy security.

ii. *Nuclear Production of Zero-carbon Hydrogen*

Nuclear generation—existing and future and any associated infrastructure for hydrogen production should be eligible for tax credits. Nuclear's 24/7 baseload output provides cost-effective low-carbon electricity for hydrogen electrolysers. In addition, the production from these electrolysers can complement nuclear's baseload role while providing system services that displace the need for natural gas-fired generation.[101]

iii. *Role of Hydrogen Electrolyser in the Electricity System*

During times of peak electricity demand, flexible, rapid response resources are required to ensure reliability — the role traditionally played by natural gas-fired generation. Reducing demand during peak times would help mitigate the need for gas-fired generation. Hydrogen electrolysers supplied

[99] PWU submission on the CCUS tax credit.
[100] PWU, Submission to MNRF on ERO 019-3514, Ontario's Draft Forest Biomass Action Plan, 2021.
[101] Strategic Policy Economics, "Electrification Pathways for Ontario to Reduce Emissions", 2021.

by baseload nuclear power can respond quickly to the needs of the electricity system by adjusting their production levels.[102] Ultimately, sufficient hydrogen production can be used to flatten the seasonal and daily load profile to better utilize all assets within the electricity system, enable the use of low-cost non-emitting baseload resources and displace natural gas fired generation.[103] The tax credits should be extended to the infrastructure required to enable hydrogen production to benefit the system and displace the emissions from gas-fired generation.

Recommendation #12 – The federal Green Bond Framework (GBF) should be technology agnostic and include nuclear.

Nuclear energy was specifically excluded from the list of eligible GBF investments. This exclusion was arbitrary, without consultation and was not based on evidence, logic, or science.

Nuclear energy is clean, safe and affordable. Last year the UN's Economic Commission for Europe (UNECE) determined that nuclear energy has one of the lowest carbon life-cycle footprints of any generation technology. Nuclear energy was central to the most successful carbon-emission reduction initiative in North America: the closure of Ontario's coal plants and the refurbishment of the province's low-carbon nuclear fleet.

The Government of Canada is aware that nuclear energy is proposed for inclusion in the European Union's sustainable taxonomy for electricity production technologies. This reflects years of consultation and collaboration, including the work of the EU's Joint Research Centre (JRC), which found no evidence that nuclear energy does more harm to human health or to the environment compared to other electricity production technologies that are already included in the taxonomy. In Canada, Bruce Power, issued its Green Financing Framework in mid-2021 followed by the issuance of its first $500 million Green Bond in November the same year.

Based on a 70-year legacy of nuclear excellence, Canada is a top-tier nuclear nation with demonstrated expertise in uranium mining, research and development, design, construction, operation and refurbishment, fuel recycling and waste management. Canada's nuclear industry contributes $17 billion in GDP and provides 33,000 direct and 43,000 indirect jobs. The current GBF discourages investment in nuclear energy and exposes the success and sustainability of the existing industry to unnecessary risk.

Closing

The PWU believes these comments and recommendations are supportive of Canada's CES NZ 2035 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.

The PWU would appreciate the opportunity to brief the Ministry directly as offered during the CES webinar on March 22, 2022.

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[102] PWU submission to Canada's Hydrogen Strategy, 2020.
[103] Strategic Policy Economics, "Electrification Pathways for Ontario to Reduce Emissions", 2021.

Appendix D - <u>Power Workers' Union (PWU) Submission on 2023 Budget Investment Tax Credits</u>

to the Department of Finance Canada, September 8, 2023

The Government of Canada launched a series of consultations with Canadians on measures to grow the clean economy. On June 6, the government requested feedback with no prescribed date on several ***budget provisions*** including the following Investment Tax Credits (ITCs) of interest to the PWU:

- Clean Electricity (CE) ITC and Clean Technology Manufacturing (CTM) ITC;
- Clean Hydrogen (CH) ITC, announced in the 2022 Fall Economic Statement;
- Clean Technology (CT) ITC, introduced in the 2022 Fall Economic Statement;
- Budget 2023 enhancements to ITC for Carbon Capture, Utilization, and Storage (CCUS); and
- Perspectives on labour and domestic content requirements.

On August 4 the Government requested feedback by September 8 on ***draft legislative proposals*** related to Measures to Grow Canada's Clean Economy including the following of interest to the PWU: CT ITC; CCUS ITC; and Labour Requirements Related to Certain ITCs.

However, all of these ITC and tax matters are intertwined with the *Powering Canada Forward Report* and the draft Clean Electricity Regulation and have varying implications on Canada's economy and emission reduction objectives. All of these initiatives are focused on securing affordable, clean energy to support Canada's energy transition to a Net Zero electricity grid in the short run (by 2035) and to a Net Zero economy by 2050.[104]

Previously, the PWU has made submissions to Finance Canada on the Clean Technology (CT) ITC introduced by the Fall Economic Statement.[105] The recommendations provided remain pertinent today and included:

- The nation's regional diversity and range of available clean energy options should be recognized including the important role for large and small nuclear reactors across the country;
- Clean energy policies should ensure a low-cost energy infrastructure that sustains Canada's economic competitiveness;
- Financial incentives should create a level playing field for all emission reducing technologies and should ensure cost-effective emission reductions;
- Clean energy investments should enable the maximum growth in jobs and GDP;
- The net lifetime economic benefits of clean energy financial supports should be optimized; and,
- Financial supports should incent the most sustainable and timely pathway to achieving NZ by 2050 and help achieve the objectives of the Clean Electricity Regulation (CER).

The PWU was pleased to see that the 2023 Budget included substantive provisions supportive of investment in nuclear technologies and the prioritization of economic growth and well-paying jobs. The PWU supports: the terms of the CTM ITC and the degree to which it mirrors similar provisions in the U.S. Inflation Reduction Act (IRA); and, the labour provisions in the draft legislative proposals. However, the

[104] Government of Canada, A Made in Canada Plan, Affordable Energy, Good Jobs, and a Growing Clean Economy, March 2023, pages 76 and 78.
[105] PWU submission to Department of Finance Canada on Fall Economic Statement Clean Tech Investment Tax Credit, January 2023.

ITCs still do not represent a level and balanced package of incentives necessary for achieving the objectives of the pending Clean Electricity Regulation.

The PWU provides the following recommendations:

1) The objectives of the electricity related ITCs should be aligned with "*achievable"* goals in the *Powering Canada Forward Report* and the development of the Clean Electricity Regulation (CER);
2) The implementation terms and eligibility dates for the CE ITC should reflect the same principles applied to the CCUS ITC;
3) The CE and CT ITCs should be harmonized with respect to eligible electricity generation technologies to ensure equivalent tax and rate payer benefits for the costs of reducing emissions and support achieving affordability;
4) The CE and CT ITCs should be harmonized to maximize the net economic benefits, including domestic content requirements similar to those provided by the U.S. IRA; and,
5) The "*competent authority*" required by the ITC to commit that the use of federal funding will lower electricity bills and achieve net-zero electricity in that jurisdiction should use validated total system cost and emission assessment methodologies approved for that purpose.

Recommendation #1 - The objectives of the electricity related ITCs should be aligned with "*achievable"* goals in the *Powering Canada Forward Report* and the development of the Clean Electricity Regulation (CER).

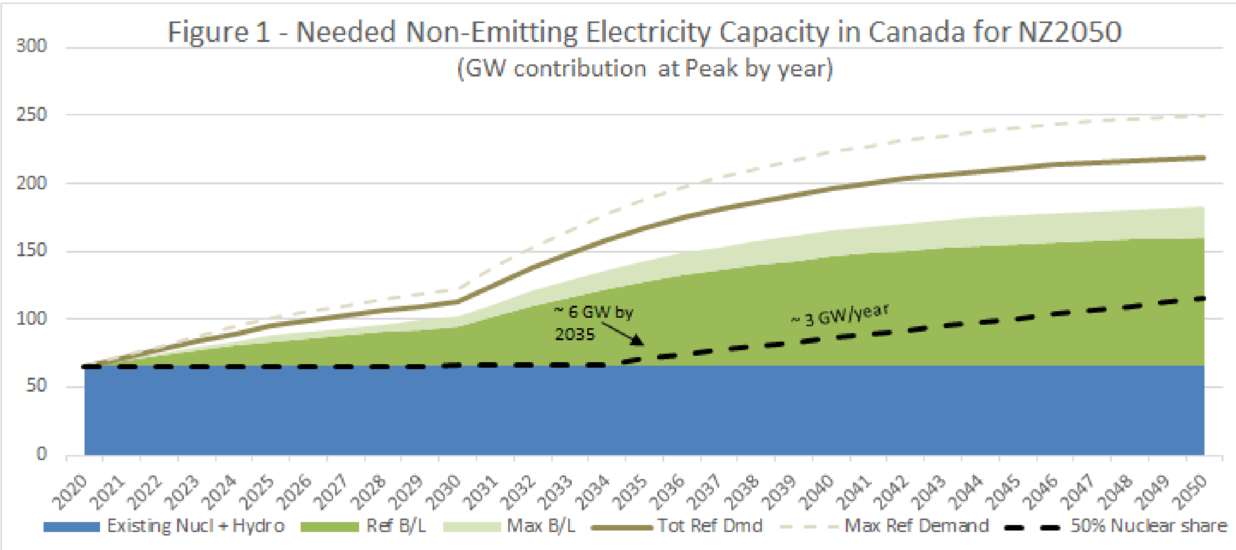
The Government's 2023 Budget provisions for ITCs: provide policies similar to those in the U.S. IRA; and, promote securing affordable clean energy supportive of Canada's energy transition to a Net Zero electricity grid by 2035. The latter is in conjunction with the draft CER currently out for stakeholder consultation. The 2023 Budget highlights the need to accelerate the development of clean electricity supplies to develop approximately 50% greater electricity system capacity by 2035.[106]

Under the proposed CE ITC, the incentives will not be available after 2034. While the CT ITC requires the assets to be operational by 2034, in the CE ITC it is not a specific requirement. Instead, the CE ITC states that a "competent authority" must provide a commitment that the federal ITC funding will help achieve a net zero electricity sector by 2035. With the CE ITC contingent on supporting NZ 2035 goals, there may be limited practical benefit of the ITC to any nuclear or hydro electric development. The current proposed CE ITC will not incent the accelerated investment in the large-scale electricity infrastructure that Canada needs. Furthermore, the challenges for the scale of new supply development are exacerbated by the concurrent replacement of existing fossil assets as is intended by the draft CER.

This substantial challenge for developing new non-emitting electricity capacity is illustrated in Figure 1.[107] The pace of development required to meet growing electricity demand and displace existing assets is significant. The magnitude of the required development is highlighted by the dotted line showing a

[106] Interpreted from 2023 budget, page 77, Chart 3.4
[107] Strategic Policy Economics analysis for the Canadian Nuclear Association April 2023 Workshop. Annual profile of demand for new non-emitting supply derived from emissions reduction profile contained in Navius Research, Achieving Net Zero Emissions by 2050 in Canada, 2021. Capacity needs for 2035 and 2050 are lowest among the reports assessed. Source :PWU submission to Department of Finance Canada on Fall Economic Statement Clean Tech Investment Tax Credit, January 2023.

nuclear development pathway capable of supplying half of Canada's needs by 2050. This would require operationalizing 3 GW/year of new capacity in every year from 2034 to 2050. This may be an aggressive ambition for the nuclear sector to meet. Under that scenario, other technologies would be required to address not only the remaining 50% of baseload demand but also the needs for intermittent supply as it emerges, including the lead up to 2035. The scale is daunting regardless of the type of generation being considered.



Several provinces have indicated that the CER goal of a net zero electricity grid by 2035 is not achievable for the above noted reasons. It is not achievable in an affordable way because the lower cost large-scale generation facilities such as nuclear and hydro take longer to site and develop.[108] Even in Ontario, where policy signals for 4800 MW of large scale nuclear for the Bruce Power site, 1200 MW of small modular capacity at Darlington and the refurbishment of the Pickering Nuclear Station, it is virtually impossible to complete these projects by 2034. It will also be challenging to operationalize the first units at the Bruce and the Pickering Station refurbishment by this date. As a result, achieving the 6 GW by 2035 as illustrated in Figure 1 may be optimistic, highlighting the urgency to accelerate the planning for the next forecast 3 GW requirement. This pace of development will only be undertaken if the "*clear and predictable foundation supports*" the government seeks with the ITCs are available for the full life of investments in clean electricity that the federal government is aiming to incent.

The timeline challenge for the significant investments required for new hydro and transmission is no less daunting. The notion that a net zero grid by 2035 can be achieved only through non-hydro renewables is a myth propagated by poor electricity system modelling (see recommendation #5).

The PWU's submission to NRCan on Electricity Gird modernization recommended that the Government clearly identify the competing timelines between electrification of the economy and building the electricity system infrastructure required to meet it.[109] As the *Powering Ontario Forward Report* states: *"As more and more Canadians plug in electric vehicles and ride electrified public transit, and as more and more homeowners switch to electric heat pumps, the clean power they need must be there for them—*

[108] Cost analyses were included in the PWU's earlier submission to Finance Canada on the FES ITCs.
[109] PWU Submission to NRCan on Electricity Grid Modernization, March 23, 2023.

when they need it, and where they need it. And we must be able to do the same for companies looking to grow and decarbonize their warehouses, offices, factories, and work sites….”

Since the CER consultation is ongoing until November 2023[110] and that more achievable dates for the CER's 2035 objectives may develop as a result, it may be more prudent for the ITCs' language to refer to the CER and not explicitly define 2034 as the final eligibility date. Additionally, to properly incent investment in accelerating the large-scale, long-development new nuclear, hydro and transmission bulk electricity system infrastructure Canada needs, CE ITC should establish that any projects whose development begins by 2034 are eligible, even if their operational dates are much later.

An unachievable arbitrarily selected 2035 date should not be the criteria. CE ITC eligibility should be applied to technologies supporting the achievement of net zero grid as soon as possible. The rationale is clear – a new nuclear or hydroelectric facility that becomes operational in 2038, would still be contributing to a net zero grid at that time and the project decision taken 10 years earlier would reflect that commitment.

Recommendation #2 - The implementation terms and eligibility dates for the CE ITC should reflect the same principles applied to the CCUS ITC;

The PWU's previous ITC submission recommended that Government financial supports should recognize nuclear, hydroelectric and transmission investments as large-scale, multi-year developments comparable to the challenges confronting CCUS technology projects. New nuclear generation should receive the same financial incentives.

Specifically, the CCUS ITC introduced in the 2022 Budget recognizes the capital intensity and long duration times for CCUS projects. Equivalent terms should be reflected in the CE ITC, specifically:

- Clear focus on Canada's longer-term NZ by 2050 objectives;
- Include eligibility for projects that have 2040 in service dates; and,
- Provide for annual tax credits for expenses incurred in a year versus when the project comes into service.

All of these terms materially impact the security investors need to finance these projects.

Recommendation #3 - The CE and CT ITCs should be harmonized with respect to eligible electricity generation technologies to ensure equivalent tax and rate payer benefits for the costs of reducing emissions and support achieving affordability.

Other low-carbon technologies such as wind, solar, small hydro and electricity storage are eligible under both the CE ITC and the CT ITC. However, there is an absence of clarity with respect to how these two incentives overlap. The CT ITC offers a 30% tax credit while the CE ITC only offers a 15% tax credit. While it is evident that these two incentives are not stackable, it is not clear as to why a taxable Canadian corporation would pursue the CE ITC when the CT ITC offers double the credit. As such, the 30% offered

[110] https://www.gazette.gc.ca/rp-pr/p1/2023/2023-08-19/html/reg1-eng.html

by the CT ITC provides an additional material subsidy to technology adoption by taxable corporations that is far greater than that available for large nuclear, hydro and transmission assets of Canada's public utilities.

As the PWU previously recommended, ITCs should create a level playing field for all clean technologies without bias that can result in uneconomic decisions. The disparity created by the differences in the ITCs can materially impact the costs to rate payers (who pay the net cost of electricity) and taxpayers (who fund the ITCs). Rate payers pay the net levelized cost of electricity (LCOE) after the subsidy. For example, as illustrated in Figure 2, the lower cost to taxpayers of the 15% CE ITC may only save ratepayers 10% of nuclear generation costs, while the 30% CT ITC will reduce the cost of renewables by 24%.[111]

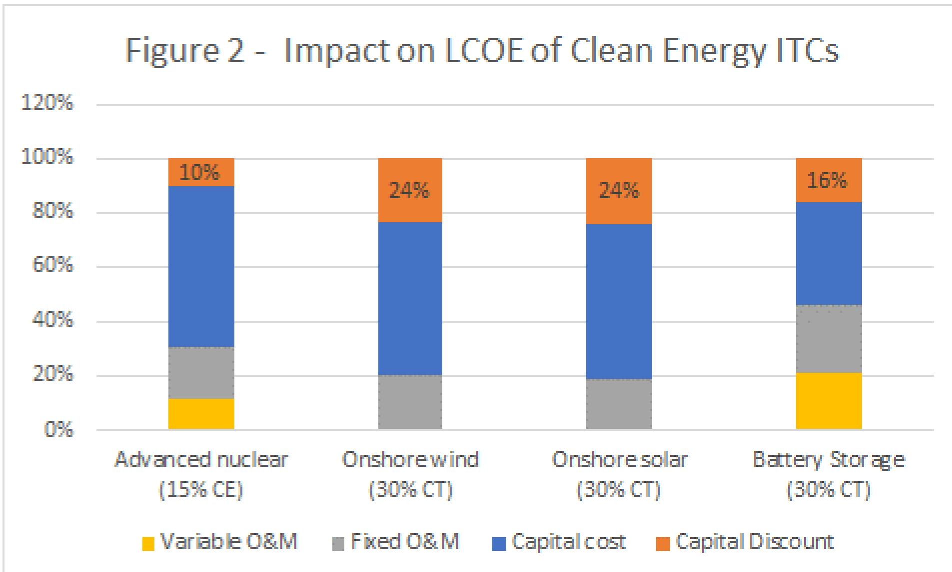


Figure 2 - Impact on LCOE of Clean Energy ITCs

The PWU's previous submission presented an analysis of the total system cost of various generation options which indicated that nuclear generation offered the best economic choice. The cost impact of the ITCs may encourage developers to choose uneconomic projects for ratepayers and taxpayers. Achieving a NZ grid requires a supply mix that is capable of meeting the forecast demand for electricity, both baseload and variable. Baseload demand exists 24x7, 365 days/year while variable demand fluctuates up and down depending upon the time of the day and/or season of the year. The impact of the ITCs on the LCOE of the *net total system cost* is illustrated in Figure 3. It shows that a renewables-based solution would benefit from a $31/MWh taxpayer subsidy, but the net

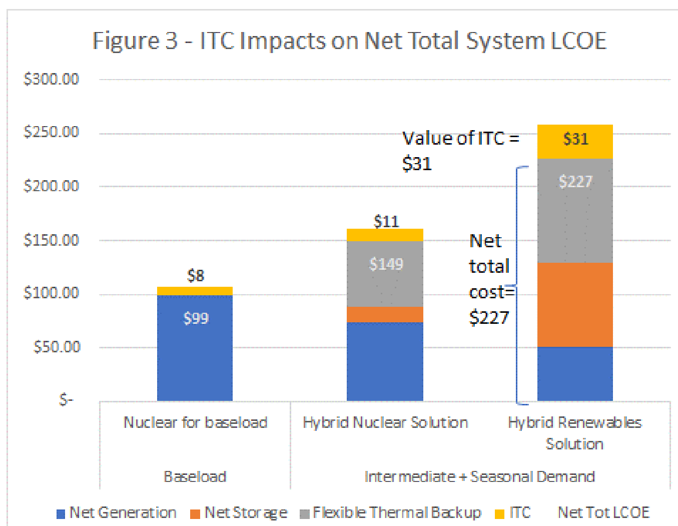


Figure 3 - ITC Impacts on Net Total System LCOE

[111] LCOE components obtained from the IEA 2022 Annual Energy Outlook.

cost to ratepayers would be 125% more costly than a nuclear baseload solution and 50% more costly than a nuclear based solution for intermediate demand.[112]

While large subsidies for renewables appear to lower the cost of generation when they are operating, it does not address the integrated costs of the system required to meet demand. In building a net zero grid, the impacts of variable demand fluctuations increase the complexity of the supply mix by requiring storage and flexible generation. To compensate for their intermittency, renewables need even more backup from storage, other available generation and grid integration. The cost of a renewables-based system, even with a substantial taxpayer funded ITC subsidy remains an uneconomic choice for achieving a NZ grid.

The ITCs should not incent the development of uneconomic resources but should instead create a level playing field and focus on reducing the LCOEs for all forms of non-emitting electricity generation by a similar percentage.

Recommendation #4 - The CE and CT ITCs should be harmonized to maximize the net economic benefits, including domestic content requirements similar to those provided by the U.S. IRA.

A transparent and robust cost benefit analysis of the investments being considered provides the best way to determine the net impact on taxpayers. The PWU's previous submission showed that for an equivalent ITC of 30%, the economic benefits from a nuclear baseload investment would generate sufficient tax revenue for government to effectively payback 95% of the cost of the ITC after 20 years. For a renewables-based system investment the payback would be only 50%.

For the nuclear scenario, an ITC of only 15%, as per the proposed CE ITC, would provide a payback to taxpayers exceeding the cost of the ITC by almost a factor of two. For taxpayers, the CT ITC pays back only half of the cost while the CE ITC for nuclear returns to taxpayers twice what it cost. This is not a level playing field in benefits for taxpayers.

One major factor impacting the significant difference in the comparison of the economic benefits is the domestic content associated with the investments. Nuclear generation in Canada has a very high domestic content ranging between 80% and 90%. This provides a significant payback for the ITC costs. Renewable technologies are primarily manufactured outside of Canada.

The U.S. IRA provides an additional ITC of 10% for future investments that by 2025 have at least 55% of the product components ***manufactured*** in the U.S.. Matching the domestic content requirements should be an important Canadian response to create and sustain a competitive manufacturing sector here. In response to the question posed by Finance Canada on this topic, the PWU recommends Canada should adopt the U.S. IRA provisions regarding the domestic content.

[112] Strategic Policy Economics analyses from Electrification Pathways for Ontario, 2021, adjusted to reflect nuclear and renewables cost assumptions used for the IESO Pathways to Decarbonization Study (P2D), 2022.

Recommendation #5 - The "*competent authority*" required by the ITC to commit that the use of federal funding will lower electricity bills and achieve net-zero electricity in that jurisdiction should use validated total system cost and emission assessment methodologies approved for that purpose.

As noted in Recommendation #3, the decision criteria of paramount importance should be the net impact on total system costs. The PWU's previous submission described the modelling challenges that can misinform policy makers about the viability and costs of some renewables-based options.[113] These modeling challenges have been discussed in many academic journals with the general conclusion that the benefits and viability of using renewables to supply a net zero grid are overstated.[114]

In a recent NRCan Hydrogen Progress Report, the modeling consultants provided a disclaimer stating that the fidelity of their models does not provide the fidelity required to measure and predict the impacts on daily variability of demand or intermittent renewables supply, impacting the estimates of the capacity needed from flexible generation backup.[115]

The emission impact of the required backup supply options for intermittent renewables is of paramount importance. In Quebec, that backup supply can be sourced from dispatchable large reservoir hydroelectric power. In Ontario however, the P2D Study by its Independent Electricity System Operator (IESO) assumed that the flexible generation would be hydrogen-fired thermal generation. The PWU agrees with the IESO's P2D study that replacing Ontario's existing gas-fired generation with hydrogen-fired generation by 2035 is not possible, and even if it was, it would be very costly. In Ontario, it is not at all clear that intermittent renewables solutions can contribute significantly to achieving a net zero grid without the needed large-scale, dispatchable, non-emitting backup supply that is unlikely to be available by 2035 or 2050.

While the 2023 Budget language describing the CE ITC requires that a "*competent authority*" commits to the affordable and net zero implications of investments made using federal funds. It should be made clear that such commitments in support of any specific investments must be based on an approved and validated analytical methodology for estimating the implications on total system costs and emissions. In such analyses, the technologies that will be deployed to provide the backup flexible generation and/or storage should be explicitly identified so that the costs and emissions implications can be transparently assessed and validated.

Closing

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[113] PWU Submission to Environment and Climate Change Canada on Canada's Clean Electricity Standard Discussion Paper, April 2022.

[114] Hans-Kristian Ringkjøb∗, et al., "A review of modelling tools for energy and electricity systems with large shares of variable renewables", 2018, Renewable and Sustainable Energy Reviews; Miguel Chang a,*, et al., "Trends in tools and approaches for modelling the energy transition", 2021, Applied Energy.

[115] NRCan, DRAFT-NRCan-Biennial Report-Consultations-2023-06-16, HYDROGEN STRATEGY FOR CANADA BIENNIAL REPORT, Page 21. "*The modeling results show that use of hydrogen for electricity generation is close to zero. However, it should be noted that the modeling only takes into account 16 representative time slices (i.e. data points for time-varying parameters) per year, and therefore, detailed fluctuations in electricity load profiles are not represented*."

The PWU supports the federal government's initiatives to provide tax credits to projects that reduce the emissions in Canada's electricity generation. The PWU recommends that the government's financial supports provide a level playing field for all non-emitting technologies and consider the timelines for the development for new nuclear generation, the achievability of the CER goals by 2035 and the net economic benefits that will accrue to Canada from a well-designed ITC.

The PWU has a successful track record of working with others in collaborative partnerships. We look forward to working with the federal government and other stakeholders to strengthen and modernize the electricity system of Canada and Ontario. The PWU is committed to the following principles: Create opportunities for sustainable, high-pay, high-skill jobs; ensure reliable, affordable, environmentally responsible electricity; build economic growth for Ontario's communities; and, promote intelligent reform of Ontario's energy policy.

We believe these recommendations are consistent with and supportive of the government's objectives to transition to a Net-Zero economy and supply low-cost and reliable electricity for all Canadians. The PWU looks forward to discussing these comments in greater detail with Finance Canada and participating in the ongoing stakeholder engagements.

Appendix E - PWU Submission to Infrastructure Canada on the National Infrastructure Assessment

The Power Workers' Union (PWU) is pleased to submit comments and make recommendations to Infrastructure Canada regarding the National Infrastructure Assessment. As part of a 12-year "Investing in Canada" plan, the federal government is conducting a National Infrastructure Assessment (NIA) to identify the needs and priorities for Canada's infrastructure and plan to help achieve Net-Zero emissions by 2050. The Assessment will focus on three main priorities:

- assessing infrastructure needs and establishing a long-term vision;
- improving coordination among infrastructure owners and funders; and
- determining the best way to fund and finance infrastructure.

The government's Engagement Paper seeks feedback from stakeholders on these three priorities and implementation options. Clean and renewable energy infrastructure, including "energy grids and storage, district and ground-source heating, clean and alternative fuels, [and] other ways of promoting electrification" are included in the Assessment. Also included is enabling clean energy technologies and solutions to help achieve decarbonization, such as hydrogen fuel cells, biofuels, long-life batteries, and carbon removal, capture and storage. The PWU is particularly interested in the government's support for public / private sector infrastructure funding and the Canada Infrastructure Bank (CIB).

The federal government's recognition of the infrastructure needs resulting from its Net Zero 2050 goal is welcomed by the PWU. Meeting these challenges will require informed planning guided by a long-term vision and innovative business models that get low-carbon energy projects built.

The PWU's submission focuses on the factors relevant for identifying the infrastructure needs of Ontario's energy system; its relationship to Canada's long-term vision and path to Net Zero; new policy tools and investment taxonomies; and innovative business models. The PWU makes the following recommendations:

1. An infrastructure decision-making framework must reflect the balance and potential synergies between low-carbon electricity, decarbonized fossil fuels and hydrogen.
2. Assessing Canada's future energy infrastructure needs must consider the need for electrification in Ontario.
3. Federal government support for Ontario's nuclear sector is required for the province to achieve decarbonization and advance the federal goal of Net Zero.
4. An effective national electricity vision must consider how new low-carbon energy assets will be provincially deployed and the needed infrastructure to connect them across Canada built to provide low-carbon energy security.
5. Canada's significant low-carbon energy assets in its vast, renewable agriculture and forestry biomass waste should be leveraged to provide electricity, heat and biofibre-based alternatives to fossil fuels.
6. The development of hydrogen economies in central and eastern Canada should be integrated with the deployment of low-carbon electricity system infrastructure.
7. Innovative public-private partnership business models should be supported by the CIB to enable investments in new, low-carbon nuclear, biomass, and hydrogen infrastructure.

Recommendation 1: An infrastructure decision-making framework must reflect the balance and potential synergies between low-carbon electricity, decarbonized fossil fuels and hydrogen.

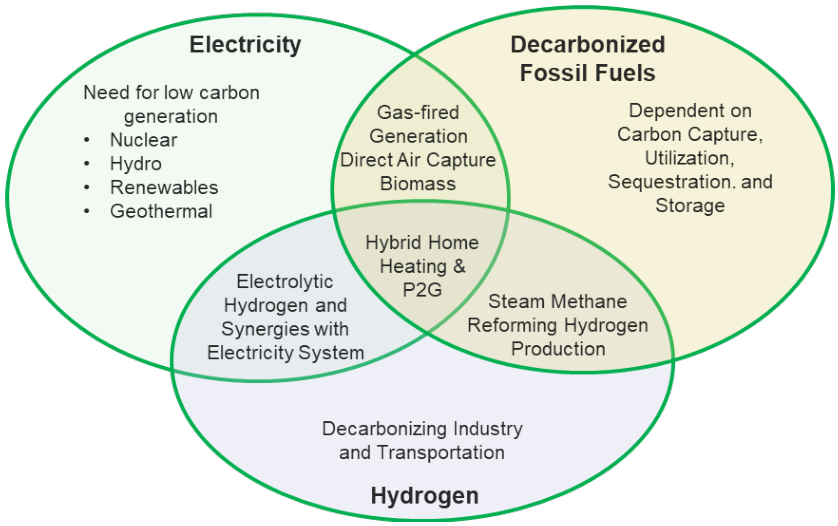
The energy landscape of the future will be shaped by the interplay of an emerging trifecta of energy infrastructure solutions:

- **Electricity**: Delivering low-carbon electricity to Canadians to displace fossil fuels will require sources of low-carbon generation, such as nuclear, hydro, renewables including biomass, and storage, as well as the transmission (Tx) systems necessary to deliver the energy to consumers.

- **Decarbonized Fossil Fuels:** Reducing carbon emissions from fossil-fueled generation can be achieved by installing carbon capture, employing storage, and using the carbon for other products and applications. In the electricity sector, gas-fired generation may remain a viable source of electricity if equipped with carbon capture, utilization, and storage (CCUS) technologies and backup direct air capture of carbon. These two technologies could also help make biomass-fired generation a carbon sink.

- **Hydrogen:** This non-emitting fuel can help displace fossil fuels in Canada's industrial and transportation sectors and can be blended into the natural gas delivery system. Hydrogen completes the trifecta, as it can be produced from a fossil fuel — natural gas — via steam methane reforming and/or via electrolysis using low-carbon electricity. Steam methane reforming produces emissions and requires CCUS for the resulting hydrogen to be low-carbon. With electrolysis, hydrogen production offers synergistic benefits that can reduce costs.

Figure 1: The Future Energy Trifecta



Each of these energy sources have unique infrastructure requirements, and the balance between the three will greatly influence the infrastructure demands of a decarbonized Canada. Regional differences may result in the balance of solutions varying across the country, impacting the need for national scale delivery infrastructure. Carbon capture is being actively explored in Western Canada, where geological formations create the ideal conditions for storing carbon. However, such potential for carbon storage has not been assessed for the rest of Canada.[116] In Central Canada and other regions with established low-carbon electricity infrastructure, electrification is the best understood solution and represents the most significant and most feasible contributor to the net zero pathway.

Recommendation 2: Assessing Canada's future energy infrastructure needs must consider the need for electrification in Ontario.

While regional approaches to emission reductions will differ across Canada, the three most viable options are electrification, energy efficiency and carbon capture. The resultant variability in responses will depend upon many considerations.[117]

Several studies point to electrification leading to the need to triple Canada's existing electricity infrastructure.[118] One accepted rule of thumb suggests that electrification increases electricity demand by 1.66 TWh for every Mt of emissions reduced. [119]

In Ontario, analysis suggests that energy efficiency gains could reduce future emissions by up to 28%, and a minimum level of electrification could contribute another 38%. Achieving the remaining 34% of emission reduction would rely on other measures such as carbon capture. Meeting that minimum degree of electrification would see Ontario's electricity capacity needs increase to over 70 GW in a 2050 net zero scenario.[120] That is 2.6 times the capacity of Ontario's existing system.[121] 55 GW of this would need to be met by new procurements or imports. [122] Doing so via imports from Quebec would require expanding Ontario's interties with Quebec by 40 times as well as new large-scale hydroelectric projects. Tx capacity throughout the province would also require similar increases to serve the flow from Quebec.

Alternatively, about 60% of this need could be supplied by baseload technologies such as nuclear. Given emerging technologies that smooth demand, electrification growth will be heavily weighted towards the need for baseload supply. The expected 33 GW of new baseload demand would be the equivalent of 40 new nuclear plants, with units similar in size to those at the Bruce Power Nuclear Station. Regional deployment of the new capacity could help reduce the need to expand Tx.

Developing this much electricity infrastructure in Ontario in less than 30 years represents a significant challenge. Since electrification is Ontario's most promising path to net zero, it is clear this challenge must be recognized and addressed in the province's and Canada's low-carbon energy plans. Achieving the Net Zero goal will require leveraging Canada's clean energy advantages: low-carbon electricity from nuclear, hydro, and biomass generation, and a solid Tx network to connect them.

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[116] Navius Research, Achieving net zero emissions by 2050 in Canada, 2021.
[117] Navius Research, Achieving net zero emissions by 2050 in Canada, 2021.
[118] SNC Lavalin, Engineering Net Zero, 2021; Environment and Climate Change Canada, Canada's Mid-Century Long-Term Low-Greenhouse Gas Development Strategy, 2016.
[119] Green Ribbon Panel, Clean Air, Climate Change and Practical, Innovative Solutions: Policy Enabled Competitive Advantages Tuned for Growth, 2020.
[120] This forecast electricity demand includes electricity required to produce hydrogen. Strapolec, Advancing Ontario's Energy Transition Part 1: Electrification Pathways, 2021.
[121] IESO, APO, 2020
[122] This forecast electricity demand includes electricity required to produce hydrogen. Strapolec, Advancing Ontario's Energy Transition Part 1: Electrification Pathways, 2021.

Recommendation 3: Federal government support for Ontario's nuclear sector is required for the province to achieve decarbonization and advance the federal goal of Net Zero.

Currently, about 60% of Ontario's electricity needs are met by nuclear and about 25% from its hydroelectric generation. This gives Ontario one of the "cleanest" electricity grids in the world. Besides producing low-carbon, baseload electricity, Canada's nuclear technology and expertise support a multi-billion-dollar a year industry, tens of thousands of jobs, and major advances in medicine, materials, and processes. Ontario's world-class nuclear supply chain is currently delivering the world's largest conventional nuclear program on cost and on schedule.[123]

It is becoming clear that net zero cannot be achieved without nuclear.[124] Ontario needs 33 GW of new baseload supply in less than 30 years, and nuclear is one of the few low-carbon energy sources that can deliver it. Canada's nuclear sector is well positioned to deliver this infrastructure. The following four factors support further investments in Canada's nuclear technology as a major part of its Net Zero goal:

a. Ontario's world-recognized expertise in conventional and advanced nuclear reactors, and Small Modular Reactors (SMRs). Canada has retained and expanded its reputation a world leader in CANDU nuclear technology. There are 30 active CANDU reactors in operation around the world reliably producing low-carbon electricity.[125] Canada has also developed a world-class Advanced CANDU nuclear reactor technology.[126] Today, Chalk River's CNL has become a North American centre for the development and advancement of SMRS with the support of Canada's SMR Action Plan.[127] SMRs are expected to become commercially viable later in the decade for distributed deployments to meet the growing needs in the late 2030s.[128]

b. Nuclear is the low-cost option. Nuclear power is already one of the least-cost sources of generation in Canada. Ontario continues to benefit from its low-cost hydro and nuclear baseload supply, which provides power at a cost of $80/MWh, while the remainder associated with renewables and gas-fired generation costs $180/MWh.[129] The future cost of the refurbished nuclear fleet is estimated at $80/MWh. Financing nuclear projects has been an investment challenge given the long timelines required for planning and construction. The current low interest rate environment, however, lowers the projected costs for a new nuclear facility in service by 2035 to be under $80/MWh as well.[130] SMRs include a range of different reactor technologies and sizes, whose costs have yet to be proven but may fall below $70/MWh.[131] The $80/MWh cost of new and existing nuclear power is 10% less than the forecast cost of gas-fired generation equipped carbon capture technologies.

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[123] Ontario Power Generation, Darlington Refurbishment, Website.
[124] World Nuclear Association, Net Zero Needs Nuclear, 2021.
[125] CNA, How a Nuclear Reactor Works, Website.
[126] Power Mag, Canada Completes Design Review for Advanced CANDU Reactor, 2011
[127] Canada's SMR Action Plan, Website.
[128] SaskPower, Énergy NB Power, Bruce Power, and Ontario Power Generation, Feasibility of Small Modular Reactor Development and Deployment in Canada, 2021.
[129] OEB, Regulated Price Plan Price Report, April 2021.
[130] NREL, 2020 Annual Technology Baseline, 2020, converted to Canadian context. Strapolec, Advancing Ontario's Energy Transition Part 1: Electrification Pathways, 2021.
[131] Economic and Finance Working Group, SMR Roadmap, 2018.

Analyses indicate that nuclear-baseload options that are coupled with new technologies, e.g. energy storage and demand response, can also provide flexible power to meet daily demand variations. Flexible renewables-based options in Ontario are estimated to cost 20% more. Non-emitting baseload solutions with renewables could be 75% more costly than nuclear baseload.[132]

c. **Investments in Canada's nuclear supply chain keep dollars in the country that yield substantial domestic economic benefits.** Ontario Power Generation's Darlington Refurbishment Program, and subsequent 30 years of operation, is estimated by the Conference Board of Canada to generate a total of $89.9 billion in economic benefits for Ontario. As well, the investment will create 14,200 jobs per year and boost personal income by an average of $1.6 billion on an annual basis. Ninety-six percent of the project costs will be spent in Ontario.[133] Bruce Power's 13-year Life Extension Program is estimated by the Ontario Chamber of Commerce to generate an economic impact of between $7.6 and $10.6 billion in Ontario and $8.1 to $11.6 billion in Canada. The federal government is expected to receive $144 million in excise tax and $1.2 billion in income tax.[134]

   Analyses indicate that investing in nuclear-based solutions for Ontario could generate upwards of $90 billion more direct GDP benefits compared to other alternatives, and provide double the government tax revenues. Building new nuclear generation in Ontario would avoid using more natural gas generation and sending dollars out of province to purchase U.S. gas, yielding a net trade impact of $270 billion CAD over a 20-year time frame.[135]

d. **SMRs offer industrial combined heat and power (CHP) and other benefits in support of Canada's transition to low-carbon energy.** Nuclear represents one of the few low-carbon resources capable of providing industrial CHP services to support many heavy industries, e.g., steel production. SMRs and conventional nuclear reactors can provide low-carbon heat to homes and businesses through district heating systems. SMR technologies can also supply heat, hydrogen, electricity and steam to decarbonize extraction and processing in Canada's oil sands and support mining operations.[136]

   The pace of electrification is increasing. For example, consumers and the transportation sector are moving more rapidly to EVs than was publicly considered less than a year ago. Efforts to electrify public transit are also accelerating.[137] Currently, Ontario plans to meet this demand with more carbon-emitting natural-gas generation. The resulting carbon emissions would increase the required reductions to meet Canada's 2030 targets by 24 Mt, or 15%.[138] This growth in electricity demand is putting Canada's 2030 emission targets at risk. Ontarians have recognized this risk, and municipalities and environmental groups are calling to phase-out natural gas-fired generation.[139]

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[132] Strapolec, Advancing Ontario's Energy Transition Part 1: Electrification Pathways, 2021; Strapolec Analysis.
[133] The Conference Board of Canada, Continued Operation of Darlington Nuclear Generating Station: An Impact Analysis on Ontario's Economy, 2016.
[134] OCC, Bruce Power Major Component Replacement Project: Economic Impact Analysis, 2019.
[135] Strapolec, Advancing Ontario's Energy Transition Part 1: Electrification Pathways, 2021; Strapolec Analysis.
[136] OPG, CNL, MIRARCO, Small Modular Reactor (SMR) Economic Feasibility and Cost-Benefit Study for Remote Mining in the Canadian North: A Case Study, 2021
[137] E.g., Global News, Ottawa plans to become 1st Canadian city with a fully electric bus fleet by 2036, 2021.
[138] Strapolec, Advancing Ontario's Energy Transition Part 1: Electrification Pathways, 2021.
[139] Mississauga, Mississauga Council Advocates Province to Phase out Gas-Fired Power Plants in an Effort to Fight Climate Change, 2021; The Energy Mix, Toronto City Council Calls for Ontario Gas Phaseout, 2021.

Canada's nuclear technologies are the best solution for helping Ontario achieve a net zero future. This requires immediate consideration and action. The federal government's continued support, specifically in the form of enabling policies, integration of nuclear in its climate change and economic planning, and in its public statements is an important prerequisite. In turn, this ongoing commitment will sustain a successful domestic industry and incent new business models that will capture the benefits of this option for Canadians.

Recommendation 4: An efficient national electricity grid will be required to connect new low-carbon energy assets and provide low-carbon energy security across Canada.

In the last few years, significant discussion has occurred across Canada on the importance of a "national grid" that is capable of transferring low-carbon energy to Canadian consumers.[140] The Council for Clean Reliable Energy has issued a paper calling for a National Energy Vision for Canada.[141] Several multi-stakeholder-sponsored collaborations have put forward post-pandemic low-carbon energy strategies for the country.[142] As well, Tx infrastructure discussions have been occurring between provinces. These include: The House of Commons report on the importance of strategic electricity interties;[143] electricity trade between BC and Alberta regarding the Site C dam; trade between Manitoba and Saskatchewan regarding the Keeyask dam; and the Atlantic loop involving the Muskrat Falls hydro project.[144] In the U.S., the Biden Administration is providing billions of dollars to develop a nation-wide grid.[145]

Several factors will influence what options are supported in Canada to develop abundant low-carbon supplies of electricity.

a. **Electricity demands required to achieve Net Zero will substantially exceed currently available supply.** For example, while BC, Manitoba and Quebec have substantial supplies of low-carbon hydro power, achieving net zero could double their respective electricity needs. Even a modest increase in demand would exceed available capacity. The question then becomes: "*What new capacity would these provinces elect to build*?". While there are significant remaining hydro resources,[146] many of the sites are remote from population centres, require extensive flooding of Indigenous and Metis lands, and will require significant investments in new Tx. The cost issues with recent hydro generation projects in Canada suggests financing could be a major challenge. Recently, Hydro-Quebec estimated that a new hydro development could cost roughly $130/MWh USD.[147]

b. **The need for Tx infrastructure depends on the location of the generation and the electricity demand to be served.** The availability of low carbon generation options and their economics will factor greatly into where generation is developed. One factor will be the costs of Tx investments. There is a cost-benefit analysis between building local generation, versus building generation farther

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140 Policy Options, A national energy grid would be a clean win for Canada, 2019
141 Karen Taylor, CCRE Commentary: A National Energy Vision for Canada: A Principled Approach, 2021
142 E.g., Task Force for a Resilient Recovery, Bridge to the Future, 2021
143 House of Commons, Strategic Electricity Interties: Standing Committee on Natural Resources, 2017.
144 The Globe and Mail, Alberta, B.C. discuss deal to swap pipeline for electricity, 2016; CBC, Province accused of withholding details on Manitoba Hydro contracts with Sask., 2021; Policy Options, The unintended consequences of the Atlantic Loop, 2020.
145 S&P Global, Biden's $2 trillion infrastructure plan aims to 'reenergize' US power grid, 2021.
146 Water Power Canada, Website.
147 Williams et al., Deep Decarbonization in Northeastern United States and Expanded Coordination with HQ, 2018.

from load and requiring investment in Tx. Developing access to large-scale hydroelectric facilities is an example of these considerations. Users of such generation must be willing to pay for the added economic and societal costs of long interconnections. However, most other non-emitting supplies can be flexibly located, minimizing the need for Tx lines to cross vast, unpopulated distances. Given the range of available technologies, nuclear generation offers solutions in either case: SMRs can be deployed at a local level, while larger reactors can provide centralized low-carbon baseload.

c. **Provinces decide the investments made in local generation or bulk system investments.** Meeting Canada's Net Zero goal will require the re-development of most of the country's existing energy infrastructure. Canada's constitution allocates accountability for energy to the provinces. Their decisions influence the distribution of jobs and economic benefits accruing from energy project investments. Canada's nuclear technologies offer flexibility and could be located in a region to provide local benefits. Small hydro and combined heat and biomass generation also offer local benefits. Investments in Tx that enables the movement of this low-carbon electricity to the grid is another attractive option. The federal government needs policies that maximize these benefits at the local and national level—a reliable Net Zero electricity system.

d. **Decisions in the U.S Will Impact Canada's options.** Canada's Tx infrastructure is heavily geared towards trade with the U.S., typically as export opportunities. B.C., Manitoba, Ontario, and Quebec all have substantial interties with the U.S., with expansion plans underway in most of them. Canada currently has relatively weak interties among the remaining provinces. This structure is important for future Canadian infrastructure decisions, as the U.S. is accelerating investments in low-carbon generation. For instance, the U.S. Department of Energy has set a target of 30 GW of offshore wind generation on the Atlantic coast by 2030, and is investing in several SMR designs.[148] Which country develops low-carbon electricity first may determine the direction that electricity flows across the interties. This could impact on low-carbon generation solution decisions in Canada, affect the need for interprovincial exchanges, and raise concerns about energy security.

Recommendation 5: Canada's significant low-carbon energy assets in its vast, renewable agriculture and forestry biomass waste should be leveraged to provide electricity, heat and biofibre-based alternatives to fossil fuels.

Biomass-fired electricity generation offers a low-carbon source of electricity and bioheat. It is considered carbon-neutral if harvested sustainably in accordance with existing international standards, and therefore has a place in Canada's net zero economy.[149] Furthermore, if combined with carbon capture, it can be a net carbon sink.[150] These benefits are particularly relevant to the use of renewable waste biofibre from Canada's forestry and agriculture sectors. Investing in infrastructure that advances the development of a bioeconomy in Canada can also make a positive contribution to achieving a net zero energy future in several ways:

a. **Biomass yields wide-ranging benefits for its host communities.** Renewable, low-carbon biomass from Canada's farms and forests present a significant opportunity to deliver clean energy and

[148] Clean Technica, Offshore Wind Power A Centerpiece Of US Department Of Energy's Power Plans, 2021; World Nuclear News, DOE selects advanced reactor concepts for funding, 2020.
[149] EIA, Biomass Explained, Website.
[150] American University, Fact Sheet: BECCS, Website.

economic benefits to communities in those sectors. Investments in biomass-fueled CHP plants can create jobs in the agriculture and forestry harvesting, trucking, and manufacturing sectors; kickstart new businesses in district heating; and bring social and environmental benefits to northern Indigenous communities.

Ontario is developing a Forest Biomass Action Plan to support economic development through the increased use of mill-by products and underutilized forest biofiber. This underutilized resource is expected to be significant, as Ontario's Forest Strategy indicates that there is "currently, 15 million cubic metres of wood available for harvest from Ontario's managed forests."[151] Similar initiatives are underway in other provinces and collectively these activities are developing a Canadian bioeconomy.

A Pembina Institute report indicated that Ontario has sufficient, readily available biomass wastes from the province's forestry sector to supply 3.4 TWh of electricity annually.[152] This would represent a locally-significant source of energy while providing jobs and supporting local industries. It would also provide power for mining, transportation, and northern development projects. Biomass-generated electricity is also a dispatchable energy resource that can respond to consumer demands, providing an alternative to natural gas for intermediate supply and reliability services.

b. The Atikokan Plant in Ontario is a low-carbon energy asset. The 210 MW Atikokan Generating Station (GS) in northwestern Ontario is fuelled by locally-sourced, renewable, low-carbon wood pellets and can produce baseload electricity and heat to help meet the region's energy needs. It employs approximately 65 people directly, but supports hundreds of jobs in biomass harvesting, pelletizing and transportation associated with wood pellet providers located in Atikokan and Thunder Bay. It also is linked to biomass research at Confederation College, Lakehead University and CRIBE. Currently, the plant operates at minimal capacity meeting peak demand or as back-up power.

The station's 741-acre site represents a unique opportunity to anchor a local, low-carbon energy hub. Its geographic location, transportation and grid connections, locally available biomass experience and infrastructure, large available supply and unexploited heat output could allow it to support a fully-fledged low-carbon energy centre. Unused bioheat could support additional low-carbon energy production, sustaining and expanding the region's bioeconomy and supporting new greenhouses for northern food production. Such an expansion would attract local commercial businesses and new users and create the potential for partnerships with Indigenous peoples.

c. Atikokan GS can provide low-carbon electricity and bioheat to Northwestern Ontario and support interties with Manitoba. The region's electricity needs are forecast to grow, driven by urban growth, new supply lines to remote communities, and new mining developments. With its location near the Watay Tx line and lines for new mining projects near Red Lake and Pickle Lake, Atikokan GS, located west of Thunder Bay, is well-placed to supply the region. The station can complement the supply Thunder Bay receives from Southern Ontario via the East-West tie line, freeing up capacity on the line to supply the ring of fire mining projects. It can also bolster the reliability benefits of the

[151] Ontario, Sustainable Growth: Ontario's Forest Sector Strategy, 2021.
[152] Pembina Institute and OPG, Biomass Sustainability Analysis, 2011.

Manitoba interchange and local hydro, making up for weather-related shortfalls in hydro production.

The Atikokan GS is critical to the City of Thunder Bay's recent Net Zero Strategy. Without an increase in production from Atikokan GS, the City will rely on carbon-emitting gas-fired generated electricity from southwestern Ontario.[153]

Infrastructure investments to harvest and produce new agriculture and forest biofibre-based low-carbon fuels should be a priority in the government's NIA to achieve net zero.

Recommendation 6: The development of hydrogen economies in central and eastern Canada should be integrated with the deployment of low-carbon electricity system infrastructure.

Hydrogen is a versatile fuel that can be used to decarbonize energy use in transportation, industry, building heating and electricity generation. It presents the opportunity to leverage new and existing technologies to serve as a backbone for a low-carbon energy ecosystem. In a net-zero future, Canada sees hydrogen delivering 30% of the country's end-use energy by 2050.[154] Hydrogen can be produced from either natural gas or electricity through electrolysis, as previously mentioned. In regions with clean electricity grids, such as Ontario, hydrogen economies will primarily revolve around electrolysis. This will require investment in new infrastructure e.g., electrolysers, Tx and distribution and additional low-carbon electricity generation.

Hydrogen produced by low-carbon electrolysers offers several benefits, particularly in Ontario.

a. **Nuclear complements hydrogen production**. Growth in hydrogen production would require a low-carbon electricity supply that can meet increased demand. Nuclear offers consistent baseload electricity supply that enables low-cost production and ensures a reliable supply. Research shows that nuclear is the only technology that can achieve low-cost hydrogen from electrolysis in the short to medium-term.[155] Besides nuclear, no other low-carbon supply option is able to provide the quantities of electricity required.

b. **Important synergies are possible between hydrogen and electricity system infrastructure.** Hydrogen electrolysis facilities offer significant operational flexibility to the electricity system as they can provide peak response to flatten variations in demand, shifting variable load to baseload and potentially reducing the need for peak supply.

c. **Ontario's extensive bulk electricity system has significant spare capacity** that can be leveraged to deliver electricity for local hydrogen production. This spare capacity could enable Ontario to begin rolling out hydrogen infrastructure without requiring new investments in its bulk delivery system.

d. **Ontario has hydrogen storage capacity.** Hydrogen could be stored in the existing natural gas storage caverns surrounding the Dawn Hub in southwestern Ontario. Hydrogen that is produced by low-carbon electricity can be "blended" with natural gas and injected into the existing delivery

[153] IESO, Annual Planning Outlook, 2020.
[154] Natural Resources Canada, Hydrogen Strategy for Canada, 2020.
[155] Lucid Catalyst, Missing Link to a Livable Climate, 2020.

network for uses such as home heating, an application known as power to gas (P2G). This “blending” reduces the emissions profile associated with the natural gas.

Investments in electrolytic hydrogen can contribute towards Canada’s Net Zero goal and, therefore, should be considered in the federal government’s Assessment.

Recommendation 7: Innovative public-private partnership business models should be supported by the CIB to enable investments in new, low-carbon nuclear, biomass, and hydrogen infrastructure.

One of the goals included in the NIA is to determine the best ways to fund and finance infrastructure. Based on experience, the PWU believes that public-private partnerships are one mechanism that can help deploy the low-carbon technologies required to meet Net Zero. Financing from the Canadian Infrastructure Bank (CIB) is another, while investment taxonomies that facilitate the required low-carbon energy investments represent a third. Canada’s NIA can benefit from the integration of these three mechanisms to share costs and benefits, minimize the risks, and accelerate the build-out of capital-intensive, low-carbon energy infrastructure: hydrogen, Tx, biomass, and nuclear.

Building new nuclear capacity involves capital-intensive projects with long lead times and a broad risk profile. Creative business models can help mitigate these risks through joint ownerships, regulatory provisions, financing supports, and aligned investor interests e.g., government equity. Such creative partnerships can unlock substantial benefits for all Canadians, including energy security, accelerated decarbonization, economic growth, low-carbon energy exports and scientific and technological innovation.[156] These outcomes are also relevant with respect to investments in hydrogen, Tx, and biomass partnerships.

The CIB’s criteria for “clean energy, including renewables” is ambiguous with respect to nuclear energy. Currently, nuclear power is also excluded from Ontario’s Green Bond program. Canada must clearly commit to nuclear power as a clean technology critical for achieving its Net Zero goal.

Closing

The PWU has a successful track record of working with others in collaborative partnerships. We look forward to working with the federal government and other stakeholders to strengthen and modernize the electricity system of Canada and Ontario. The PWU is committed to the following principles: Create opportunities for sustainable, high-pay, high-skill jobs; ensure reliable, affordable, environmentally responsible electricity; build economic growth for Ontario’s communities; and, promote intelligent reform of Ontario’s energy policy.

We believe these recommendations are consistent with and supportive of the government’s objectives to transition to a Net-Zero economy and supply low-cost and reliable electricity for all Canadians. The PWU looks forward to discussing these comments in greater detail with Infrastructure Canada and participating in the ongoing stakeholder engagements.

[156] Green Ribbon Panel, Clean Air, Climate Change and Practical, Innovative Solutions, 2020.