MITIGATING AFFORDABILITY RISKS TO ONTARIO'S ELECTRICITY SYSTEM REQUIRES ACCOUNTABILITY

Power Workers' Union, May 2024

This is the third in a series of four papers by the PWU that is intended to prompt discussion about better ways for Ontario to meet its growing electricity demand at a lower cost, with lower carbon emissions and in a more reliable, affordable and timely manner.

POWER WORKERS' UNION

The People Who Help Keep The Lights ON.

INTRODUCTION

The PWU's second paper described how systemic reliability risks require a radical rethink of Ontario's electricity system planning approach given its: conservative demand forecasts; low clarity on electricity system's needs; and unrealistic timelines for developing new supply. This paper focuses on how the lack of accountability for over-all affordability in Ontario's electricity system planning and procurement approach is driving up rate payer and taxpayer costs, neglects total system costs, ignores critical socio-economic impacts, and under values regional engagement.

Accountability for Affordability – a "top of mind priority for Ontarians" – is not reflected in Ontario's current electricity system planning approach.

The *Electrification and Energy Transition Panel (EETP)* Report devoted considerable attention to the subject of energy affordability, an important priority on the minds of consumers in this period of high inflation. The Panel's report noted that about half of Canadians (48 percent) are willing to pay more to fund the energy transition, but that number declines as the costs rise. The report also notes that "*Keeping costs low and any increases predictable will be crucial* ..." and that "*For large industrial consumers in particular, long-term certainty on electricity supply and pricing can be a key component in investment decision-making* ..." However, the EETP report did not address the critical issue of "accountability" for the "affordability" of addressing Ontario's energy needs. Furthermore, Ontario's Independent Electricity System Operator's (IESO) *2024 Annual Planning Outlook* is silent on the cost impacts of its demand forecast.[1] The PWU's 2021 government submission described the cost accountability gaps within the electricity sector.[2]

Prudent procurement of Ontario's needed electricity assets should transparently reflect the consequential impacts of cost, including total system cost, economic and social development, and regional needs.

1. The IESO's Markets-biased procurement approach and conservative demand forecasting are needlessly increasing Ontario's electricity costs.

Most of Ontario's supply mix continues to be procured in response to government directives as described in the PWU's first discussion paper. It could be argued that this is necessary given how inflexible and ill-suited IESO Resource Adequacy Framework (RAF) is for securing such assets. Effectively, the significant government role limits the IESO's accountabilities to a small, but critical share of new resource procurements.

[1] The 2024 APO, page 15, states: "This document does not speculate on future supply mixes ... the diversity of [which] will directly impact ... marginal costs and emissions of the electricity system. As such, these system outcomes are not forecasted in this APO."

[2] PWU submission to the MENDM on Ontario's Long Term Planning Framework, 2021.

The IESO relies exclusively on its administered market mechanisms for securing these supply resources.

Besides flexible thermal plants e.g., gas-fired generation, analyses show that market-based procurement mechanisms for "capacity" and "energy" become vague concepts ill-suited for procuring the fixed cost, clean electricity generation relevant today. [3] In fact, the IESO's market-biased procurements negatively impact affordability and emissions.

The following section discusses three related topics:

- Recent procurements have driven up costs and will result in higher emissions;
- Affordability risks are arising with the development of IESO's LT2 RFP; and,
- IESO's go-forward approach will further propagate these risks.

1.1. Recent IESO procurements have driven up costs and will result in higher emissions

a) Rate payer costs are higher due to the IESO administered capacity style procurements.

Capacity-style procurements to serve Ontario's baseload demand needs, unnecessarily increase costs and the use of gas-fired generation. While the IESO's 2024 APO did not comment on the future trajectory of the Hourly Ontario Electricity Price (HOEP), the 2022 APO provided a schedule reflecting the influences of a rising carbon tax while natural gas generation is increasing on the margin. The IESO's 2022 APO forecasts the HOEP of $23/MWh in 2023 to triple to $69/MWh in 2043. **For the approximate 25 TWh increase in natural gas baseload production,[4] the higher HOEP could add $1B to Ontario's electricity system costs**. Analyses show that under supply constraints, the HOEP could increase significantly more. [5] The impact on Ontario's industrial competitiveness would be severe given the value erosion in the Industrial Conservation Initiative (ICI) program. This could potentially triple the industrial cost of electricity.

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[3] Strategic Policy Economics, Electricity Markets in Ontario, 2019. Note market mechanisms could be relevant to the cost structures of biomass, hydrogen fueled generation and perhaps gas plants with CCS, but the vast difference in their costs and in other benefits that may arise due to new specified needs (e.g. emissions) undermine the efficacy and intent of the energy markets.

[4] Extrapolated from the emission projection provided by the IESO, Resource Adequacy Update, May 9, 2024.

[5] Dunsky, DER Potential Study, 2022; Strategic Policy Economics, Electricity Options Comparison, 2013.

b) IESO's inadequate demand forecasting resulted in much higher capacity costs.

The IESO initially estimated that the capacity cost for the LT1 RFP would be $622/MW-business day. The RFP realized instead $1680/MW-business day for gas-fired generators. This compares to $425/MW-business day implied by the IESO in its costing assumptions for its 2024 APO.[6]

The IESO attributes the high LT1 RFP results to the shorter assumed operating life which was limited to 2040 due to assumptions about the Environment and Climate Change Canada (ECCC) Clean Electricity Regulation (CER). This shorter life assumption of 12 years instead of 20 stems from the IESO's under-forecasting of Ontario's supply needs. In its CER response to the provincial and federal governments, the IESO suggested that most gas plants could be retried before 2040.[7] This 40% shorter life means that rate payers will pay over 60% more for that capacity than they otherwise should in that time frame. Expecting rate payers to pay in the near term for future long term stranded costs is a comparable circumstance to the provincial government's recent override of the OEB's ruling on Enbridge's rate application.

Properly informing Ontario policy makers regarding the future demand risk may have enabled them to take a firmer position on the CER to enable a more affordable transition – the policy direction currently adopted by Ontario.[8] Other analysis suggests that there are no jurisdictions in Canada that can comply with the draft CER 2035 target date for a net zero electricity system.[9]

c) The IESO's RFPs for storage capacity will lead to higher cost of energy and emissions.

Storage is an example of a technological change where the benefits are undermined by market structures. Despite the false assertions that storage facilities can be charged during off-peak hours to benefit from Ontario's clean electricity supply mix,[10] the 2022 APO forecast gas-fired generation to be on the margin virtually all the time, even in off-peak hours. With the higher 2024 APO demand forecast and the additional demand risks, the second paper in this series described how gas-fired generation will remain on the margin well beyond 2050.

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[6] IESO, 2024 APO Resource Costs and Trends Module, which uses US NREL 2023 ATB benchmarks.

[7] IESO submission to the ECCC, March 15, 2024, requested a 30-year operating life gas-fired generation to avoid a 2035 unmitigable resource shortfall as most of Ontario's gas assets were built in the late 2000s.

[8] Ontario's Powering Ontario's Growth report states: "*As a result, for the first time since 2005 Ontario's electricity demand is rising, and we know that to support this type of growth we need to ensure the continued availability of reliable, affordable, and clean energy. While we build the next phase of Ontario's electricity grid to reliably meet peak demand, in the near-term natural gas generation will continue to provide our province with an insurance policy to maintain system reliability and support electrification across our economy.*"

[9] PWU submission to the ECCC on the CER, November 2023.

[10] Ontario Newsroom, Ontario Completes Largest Battery Storage Procurement, Quick Facts, May 9, 2024.

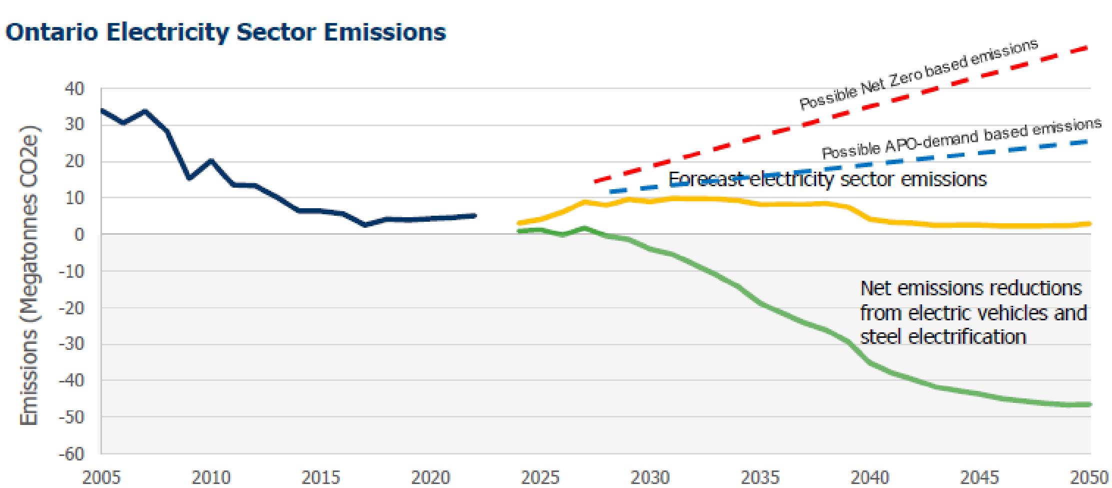
Given the minimum 15% losses involved in a battery/storage charge/discharge cycle, the cost of the energy output from a battery will be higher than the cost of the gas-fired generation used to charge it. This presents two consequences for dispatching battery output:

- Batteries will only be dispatched when any lower marginal cost generation is unavailable. This could relegate batteries to acting as reserve margin resources only, which does not materially help reduce the use of gas-fired generation.
- When dispatched, energy markets will award the 15% higher cost as an energy price premium to operating generation that is HOEP-reliant, directly providing an unearned financial benefit. For example, if batteries are operated 4 hours/day and 5 days a week, the 15% premium could add $75M/year of unplanned margins to gas-fired generators, a cost borne by rate payers. With energy markets subject to gaming over capacity availability, such a premium could provide a strong incentive to game.[11]

To the extent that storage is called upon frequently, the 15% premium increase in HOEP could further materially erode the benefits of the ICI and negatively impact Ontario's industrial electricity cost competitiveness with other jurisdictions.

d) These costs will be incurred while emissions rise.

Charging batteries with gas-fired generation will also result in 15% higher emissions compared to the direct use of that gas-fired generation. While the 2024 APO declined to discuss projected emissions implications, the IESO has since claimed that emissions from Ontario's future electricity system will decline to negligible levels by 2050 as shown below.[12]



[11] Alberta's big natural gas generators drive up electricity prices. The government is quietly changing that, The Narwhal, May 2, 2024.
[12] IESO, Resource Adequacy Update, May 9, 2024.

In developing this forecast, the IESO assumed that the CER would prohibit gas-fired generation post 2040 and, as a result, other new resources will be secured as needed to meet system demands between now and 2050.[13] The IESO has not identified what these resources may be. The PWU's last discussion paper showed that with the 2024 APO demand, even under the high nuclear scenario, gas fired generation will remain on the margin for many decades and cause electricity system emissions to potentially approach 27 Mt.[14] Under a higher demand Net Zero forecast Ontario's emissions could triple.[15]

1. 2. Recent IESO procurements have driven up costs and will result in higher emissions

While the LT2 RFP purports to address a 5 TWh energy shortfall, the IESO's criteria suggest it is simply a renewables procurement disguised by market mechanism terms that only serve to increase costs to rate payers. Unnecessary costs to rate payers are manifesting in three ways:

a) The constrained timelines that the IESO is specifying limit available options and increase costs.

The IESO is planning a series of long-term procurements for new facilities with a requirement for commercial operation within 5 years of an RFP release. Only limited supply options may be viable with these development windows, e.g., wind, solar and storage, assuming siting is approved. The IESO has not provided justification for these timelines. These timelines effectively eliminate large scale and long-lived bulk assets such as hydro and nuclear. Note that the IESO is now planning a separate longer lead time RFP for in service dates of 2034/35. [16]

b) IESO's newly developed Enhanced Power Purchase Agreement (E-PPA) revenue model is a higher cost solution without other benefits.

The IESO's E-PPA was not well received by many stakeholders as this new untried approach involved significant complexity, lack of clarity and unquantifiable risks.[17] Two examples of the risks are noteworthy: curtailments and settlements.

In response to stakeholder feedback, the IESO shifted the curtailment risk to rate payers by modifying the E-PPA design to guarantee that developers receive their revenue requirement. Rate payers will absorb the cost of any excess generation.

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[13] IESO submission to the ECCC regarding the CER updates, March 2024.
[14] At best, emissions would be no lower than 9 Mt assuming an extensive build out of renewables with a considerably higher overall electricity system cost.
[15] Strategic Policy Economics, Electrification Pathways for Ontario, 2021.
[16] IEO, Resource Adequacy Update, May 9, 2024; IESO LT2 RFP Webinar, May 23, 2024.
[17] Stakeholder feedback on the LT2 RFP design is available on the IESO's website.

The same guarantee has been offered to address the uncertainties about the market price settlements process. Further appeasing developers, the E-PPA provides an upside should the hourly market revenues exceed their quoted price. This upside premium will come at a cost to rate payers. **The E-PPA design is a high-cost patch because the IESO's energy market mechanism is simply not suited for these types of resources.**

Yet, even with these modifications, the IESO's E-PPA design did not resolve stakeholder concerns prior to submitting its recommendation to government.[18]

Subsequently, the IESO stated that the *"E-PPA revenue model has been designed to facilitate (and incentivize) hybridization."* [19] This appears incongruous with current objectives given that during the LT2 RFP process, the IESO indicated that it was not seeking hybrid facilities and advised proponents that co-located generation and storage capabilities should be separately bid. At the IESO's May 23 Webinar, the IESO introduced yet another revision to its revenue model, the Protected E-PPA, to address the settlement risk, adding another layer of complexity – a patch on a patch.

c) Cost selection criteria do not reflect what rate payers will pay.

The RFP cost selection criteria will be based on the proponents proposed Levelized Cost of Electricity (LCOE). This is important for developers given their lack of control over the output from intermittent solar and wind resources being procured and precludes hybrid solutions for low-cost bids.

However, LCOEs do not reflect curtailment costs or the rate premium and therefore is not an appropriate mechanism for comparing different bids. Both of these factors can vary depending on the technology (e.g., wind vs solar) as well as geographical location.

It is not clear how curtailments will impact on final costs. The second paper of this series showed that the forecast unserved energy in 2035 will be present for less than 43% of the time. This means that the output of any procured resources can only address that need for at most 43% of the time with much of that served with only at a small percentage of its capacity. The resulting cost to rate payers of supplying this unserved energy could potentially be more than 150% higher than the rated LCOE.

[18] The IESO was obligated by a December 7, 2023 letter to provide a report to the Minister in February, 2024. The IESO informed stakeholders on March 19, 2024, that it was submitting its approach to government for approval, albeit recognizing that concerns remained.

[19] IESO Enhanced PPA Revenue Model Update Memorandum – March 28, 2024.

Furthermore, the PWU's LT2 RFP submission to the IESO noted that the procurement design could not address the stated unserved energy need and that there will be a capacity shortfall.[20] The IESO indicated on May 9, 2024, that it will now be seeking 500 to 1000 MW of new capacity by 2031 as well.[21]

The assumed operational profile of new resources and their alignment with other system supply and demand profiles warrants disclosure. **The IESO must be clear about how it will be using the procured resources and the reasonableness of the costs that will be incurred for rate payers.**[22] As it stands, the PWU sees no evidence supporting the cost effectiveness of the anticipated outcomes of the IESO's procurement approach.

All of these cost risks arise because the IESO's administered market procurement mechanism is not suitable for meeting Ontario's emerging baseload-heavy, non-emitting, fixed cost resource needs. A straight-forward procurement with a PPA would be less costly, entail no additional curtailment risks and allow for dispatch based on local electricity system needs, much like how most of Ontario's generation is operated today. **Ontario requires a cost-effective procurement approach that considers how electricity system needs and available technologies evolved.**

1. 3. IESO's go-forward approach will further propagate these risks

Unfortunately, the IESO recently affirmed its intent to *"use this new model* [the E-PPA - NB] *as the foundation for other future energy procurements, alongside the capacity contract utilized in the LT1 RFP."*[23] The PWU reiterates shared-stakeholder concerns that this is an unproven model that attempts to shoehorn fixed cost assets into a capacity and energy markets framework.

Ontario needs a better planning and procurement approach to create a low-cost, low-carbon electricity system, including:

- **An accountability mechanism that requires the IESO to provide transparency and disclosure, in a manner that can be validated, on: how the system is expected to operate new resources; real system needs; and, the expected cost for meeting them**.
- **A procurement process for securing dispatchable power to provide either 24x7 baseload or intermediate flexible supply capable of supplying variable daily demand patterns**. This would make the costs of hybridization and other dispatchability needs explicit and transparent for RFP evaluation purposes.

[20] PWU submission to the IESO on the LT2 RFP design, Jan 2024.
[21] IESO, Resource Adequacy Update, May 9, 2024.
[22] PWU submission to the IESO on the LT2 RFP design, Jan 2024.
[23] IESO Enhanced PPA Revenue Model Update Memorandum – March 28, 2024.

2. The most affordable supply mix requires explicit consideration of total system cost

The challenges and cost risks identified emerge from inadequate specification of system needs. The PWU's previous paper argued that system needs should be specified in terms of baseload, intermediate and peak/reserve demand. This would provide a level playing field against which the total system cost of options can be compared.

The EETP report identified … "*a critical need for Ontario to develop a comprehensive energy transition policy vision*" and *"consider the generation, transmission, distribution, … that prioritizes affordability, reliability and economic development."*

Addressing affordability across this broad scope requires a procurement approach that considers two factors: (1) RFP rated criteria for all costs that will be borne by rate payers; and, (2) Planning for infrastructure to minimize the long-term costs.

2. 1. *Rated Criteria should Capture Full Costs to Rate Payers*

The full costs of generation options include four material factors:

a) Component costs and their effective LCOE under Ontario operating conditions;

b) The total cost of the integrated system solution to supply the system demand;

c) Transmission system implications for connecting the resources; and,

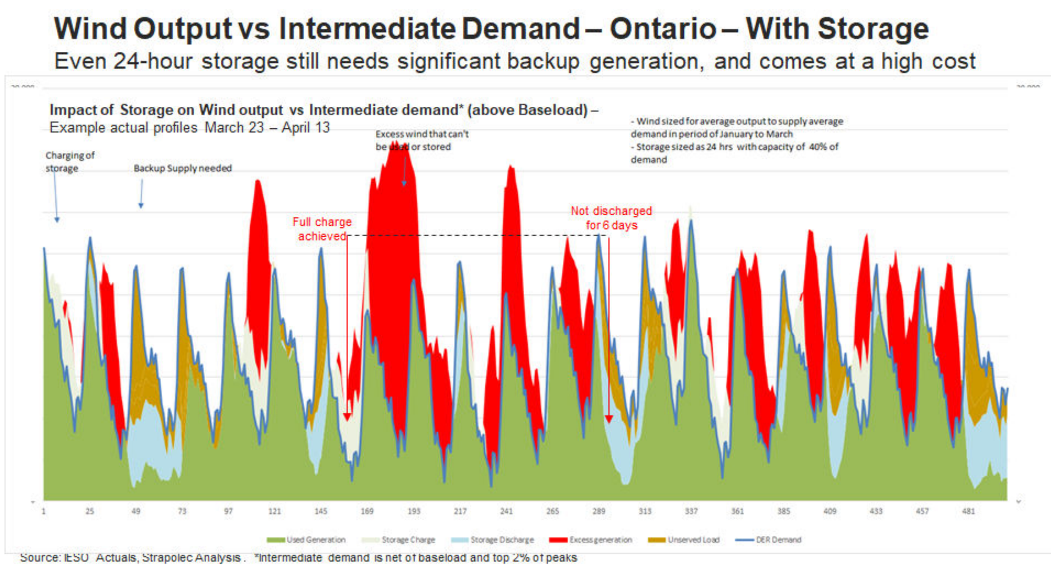
d) Liabilities associated with decommissioning and waste management.

a) Given system conditions, it is inappropriate to compare options on component costs alone

Assessing the fundamental costs of the technology options using LCOE alone as proposed in the LT2 RFP presumes an operating profile that does not impede or curtail other fixed cost assets, such as nuclear or hydro. For example, to incur no curtailment consequences from using the full output of wind resources, the output must only displace the potential use of less economic or otherwise desirable, variable generation e.g., gas-fired generation. For example, for this to be true in a baseload supply scenario: the installed wind capacity could not exceed the expected gas-fired generation used for baseload; the marginal wind cost would need to be less than the marginal gas costs; these economics would need to net out positive over the wind assets' entire economic life of 25-30 years; and the backup natural gas (or an equivalent) would need to be present until 2060. This is unrealistic, real system operations will have curtailments.

b) Solutions must be assessed on a total system cost basis, taking into consideration the lifetime operation profiles of the integrated energy resources required to meet demand.

The need to consider the total system costs is illustrated by the Figure below that compares the profile of actual wind generation in Ontario against a profile of intermediate demand.[24] Wind can be absent for several days, even at night. Wind can also generate significant output for substantial periods of time when generation is not needed, both during times of high and low demand. The effects can be moderated by storage, but even 24 hours of storage does not eliminate the need for gas-fired generation.[25]



When different technology options are assessed against the specified demand, e.g., baseload and/or intermediate, the full cost to rate payers becomes transparent. Ontario modeling results in the figure below show that integrated renewables solutions could be 60% more costly than nuclear based solutions even for meeting intermediate demand, not a traditional function for nuclear. Furthermore, intermittent renewables increase the need for flexible resources.

The IESO should use such modeling to inform decision makers and procurement plans.

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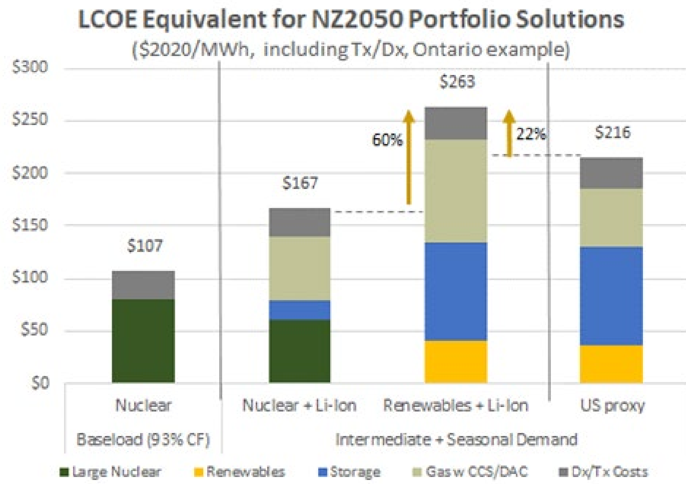
[24] Details provided in the PWU submission to the IESO on the LT2 RFP design, Jan 2024. Wind sized to match total output to total demand. Model includes substantial 24 hours of storage, capable of supplying 40% of the modeled peak demand. Even with this storage, substantial periods occur (indicated by the brown color), when unserved energy exists that must be supplied by flexible generation, presumable gas-fired.

[25] Note that the IESO has typically procured for 4 hours of storage capacity.



c) *Transmission costs are impacted by the location and number of resources*

Ontario's high voltage transmission network was initially developed to connect the province's population centers to its fossil, hydro, and nuclear generation. Similarly, the future expansion of this system is dependent upon the siting of new generation. Locating generation as close as possible to demand centers lowers transmission costs. With new supply connections, several factors materially impact on total costs.

- *Transmission is costly, approximating* $60/MWh for line lengths of 1500 km operated at full capacity.[26] While wind resources may have capacity factors of 40%,[27] much higher than today, for wind resources north of the Great Lakes that figured prominently in the IESO's Pathways to Decarbonization (P2D) report, the transmission costs to connect them could be $150/MWh – over three times the cost of the actual generation – significantly altering their economics.
- *Backup for renewables increases transmission circuit capability needs.* Renewable solutions require thermal/flexible backup and storage. If not co-located as hybrid solutions, three separate transmission circuits may be necessary, which increases costs. Furthermore, each of these resources and the transmission system will be operating at very low capacity factors as the resources take turns meeting demand. This drives up the cost of transmission assets.
- *Line losses.* Distances between the generation components may involve possible intervening Tx system constraints and line losses.

[26] DeSantis et al., iScience 24, 103495, December 17, 2021.
[27] IESO, 2024 APO, Resource Costs and Trends.

To optimize the affordability of Ontario's electricity system, the significant impacts of the cost of the transmission system must be reflected in the RFP rated criteria.

d) *Cost liabilities for end-of-life decommissioning and waste management should be considered*

The eventual cost of decommissioning should be considered. The liabilities associated with decommissioning and waste management are provided for nuclear generation, however, not for other resources. The unfunded decommissioning and waste management liabilities for wind, solar and batteries are becoming critical issues globally. Rate payers and taxpayers will ultimately be burdened with these currently unquantified and non-transparent costs.

2. 2. *Planning Infrastructure development to minimize long-term costs*

Ontario's procurement approach to optimize affordability should include two considerations: The pace of development to minimize stranded assets; and, maximizing alternative supply options.

a) *Optimizing the pace and scale of long-term infrastructure development*

The EETP report identified that: "*… the necessary build-out of the electricity system is a highly complex undertaking that will need to be paced and balanced …*" The PWU believes that the pace of infrastructure development should: be driven to optimize affordability in the long term; consider long-term demand; and identify the lowest cost long-term infrastructure options that will meet it, particularly for the new, needed baseload supplies.

Consistent with this view, Ontario's Minister of Energy requested that the IESO develop long-term hydro and nuclear options and the associated transmission infrastructure supporting it. Achieving this requires the IESO to consider the higher demand case of a full Net Zero economy given the long timelines for developing these assets.

The PWU recommends that the most practical accelerated timelines for asset development be identified first and then establish the transition requirements for other resources based on those timelines. **The IESO role within its RAF should be to: cost effectively fill in the resource and infrastructure gaps while minimizing reliability and stranded asset risks; and, maximize leveraging of the existing bulk transmission system infrastructure as it is expanded to support the long term baseload resources**.

b) Enabling Maximum Supply Mix Diversity

Clearer specification of system requirements would surface procurement options for many diverse generation solutions, including geothermal, biomass, DERs, hydrogen and new emerging innovations, e.g., space based solar.[28] All of these options are presently precluded by the IESO's procurement approach. For example, the government recently authorized the renewal of operations at Atikokan, a facility that, despite being a flexible thermal generating station, is sufficiently dissimilar in cost structure and benefits to the IESO's markets-based procurement approach. Analyses have shown that ongoing Atikokan operations are an economic solution for the north, particularly when considering transmission costs.[29]

3. Socio-economic impacts should be included in new resource decisions

The PWU maintains that given the significant infrastructure investments required to develop the future electricity system, the selection criteria should not exclusively focus on the lowest total cost of supply, but also include the socioeconomic impacts of investment decisions.[30] The EETP report echoes these priorities:

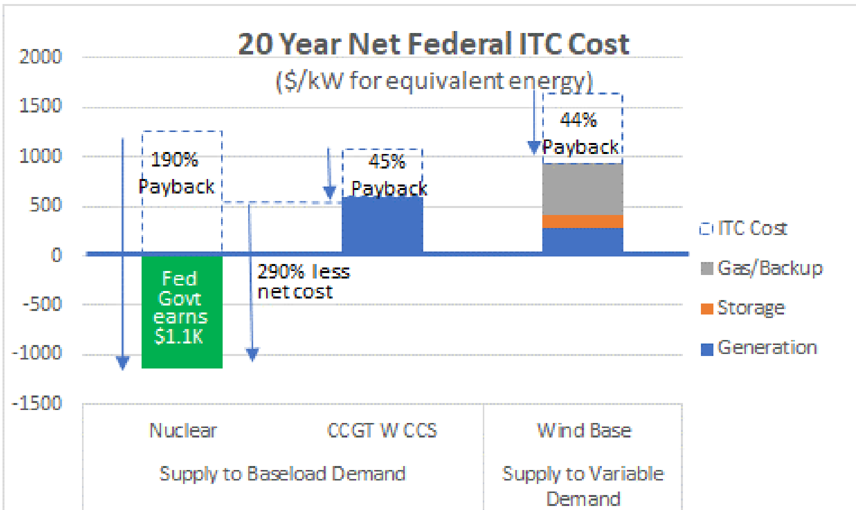
- Ratepayers cannot and should not be expected to be the sole funders of the transition;
- The province should consider shifting some of the cost to the tax base;
- Energy regulators are increasingly being asked to address a broader range of outcomes beyond price, cost, reliability, and quality of service;
- Focus on areas in which the province enjoys long-term competitive advantages relative to other jurisdictions, such as nuclear technology.

Besides enabling economic growth, electricity infrastructure investments generate increased tax revenues for government. These tax revenues could be considered as an opportunity to share costs between taxpayers and rate payer. For example, the PWU's submission to Finance Canada showed that nuclear generation, due to its high GDP impact, best optimizes the net lifetime economic benefits of government financial supports for clean energy.[31] The incremental tax revenues over the life cycle represent a "payback" for financial supports like investment tax credits (ITCs). The Figure below shows that federal tax revenues from new nuclear generation more than

[28] Strategic Policy Economics, Electrification Pathways for Ontario , 2021, explores hydrogen innovations and optimal use of behind the meter DERs; DERs will be discussed further in the final PWU discussion paper, https://cleantechnica.com/2024/04/25/space-solar-power-is-happening-sooner-rather-than-later/.
[29] Strategic Policy Economics, Extending Atikokan Operations, 2021.
[30] PWU submission to the MEDNDM in Ontario's long term energy planning, 2021.
[31] PWU submission to Finance Canada on the Fall Economic Statement Clean Tech Investment Tax Credit, January 2023; PWU Submission on 2023 Budget Investment Tax Credits to Finance Canada, Sept 8, 2023.

cover the cost of ITCs. This is in contrast to alternative integrated solutions that pay back less than half. Different technology options could have significantly different and material economic benefits that directly affect the net combined cost to rate payers and taxpayers.

Procurement criteria should include the economic benefits from government tax revenues.



4. Reform Regional Planning to minimize costs of community awareness and engagement.

The government's mandating of local and indigenous support on all projects has helped advance needed resource procurements. Developers have worked responsibly and cooperatively to help the IESO identify ~3000 MW of new capacity at over 30 sites during three procurements. However, not all municipalities have been supportive of the types of projects being proposed by some developers e.g., municipal objections to new gas-fired generation and storage facilities. The IESO's E-LT1 RFP missed its procurement targets by 323 MW (over 20%) of mostly gas-fired facilities. The LT1 RFP missed its 2500 MW target by 300 MW (12%), including a 55% or 500MW shortfall in procuring targeted gas-fired generation.

Experience in the last decade suggests that the siting in Ontario of any kind of electricity infrastructure — new wind, solar, nuclear, transmission and hydro –can expect to face robust public opposition. As Ontario's demand ramps up, so will the need to procure ever greater amounts of new capacity, possibly about 40,000 MW by 2050.[32] This will exacerbate the critical requirement for a better process that helps accelerate decision making. Equally important is the need to maximize positive cost-effective outcomes. Relying on developers to initiate and lead municipal approvals for new projects could face significant obstacles going forward.

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

The EETP report noted that: "*local governments want to play their role in addressing climate change, energy affordability and, by developing local energy sources, build community commitment. Establishing a strong link between local and municipal planning with regional and distribution sector energy planning has been a long-standing challenge.*" The EETP report went on to provide several related recommendations:

- *Recommendation 7:* To ensure municipalities, communities, and local businesses … participate in energy decision-making and take responsibility …, the Ministry of Energy should develop a strengthened framework for local energy planning and decision-making …
- *Recommendation 16:* The Ministry of Energy, working with the OEB, IESO, LDCs, municipalities and gas utilities, should develop a … framework … for enhanced planning co-ordination at the bulk, regional, and distribution levels in order to effectively pace and facilitate the fuel-switching, system optimization and enhanced levels of energy efficiency …
- *Recommendation 26:* The government, IESO, and OEB should … ensure transparent access to high-quality information and meaningful opportunities to participate in decision-making … The EETP report further elaborated on need for: Helping customers; Preparing the public; Strengthening community input; Education initiatives; and Fostering community-level engagement.

Currently, the IESO and LDCs have regional planning processes that could be better leveraged by adopting the EETP Panel's above noted recommendations. This would help optimize informed engagement and decision making by:

- Ensuring that regional and provincial demand forecasts are available, aligned and reflect the magnitude of the anticipated demand growth required to achieve Net Zero.
- Helping local communities understand their needs and the implications of their choices on their own reliability, as well as the rest of the province. Discussion can be facilitated by defining Ontario's demand in terms of baseload, intermediate or daily variations, as well as peak.
- Developing options that ensure local residents will have the electricity they need as demand grows and know the costs for them and the rest of Ontario. Options will typically involve localized solutions or bulk system transmission with generation elsewhere, each of which may have cost and risk advantages and disadvantages.
- Developing a cost accountability framework that allocates the development costs fairly across all customer classes in light of which levels of government drive the decisions, e.g., localize the cost of municipal actions for those residents.

- A Benefit-Cost Analysis (BCA) has been advanced by the OEB and provided direction for LDCs. The next phase of aligning the framework around total system costs and the IESO's approach remains.[33] The PWU has provide extensive inputs for an effective BCA framework.[34]
- Prioritizing developments in communities that help accelerate decisions. The inherent challenges of managing and aligning demand and infrastructure growth will be discussed in the PWU's next paper of this series.

CLOSING

Ontario's procurement practices must be reformed to include accountability for better affordability

This paper described the current absence of transparent mechanisms addressing cost accountability in Ontario's electricity system planning. This included: the consequential impacts of Ontario's procurement processes on Ontario's supply mix, total system cost, economic development, and engagement in regional planning activities. **Continuing to base Ontario's future supply mix procurements on capacity and energy markets unnecessarily exposes Ontario to significant affordability risks.**

The final discussion paper in this series of four will examine the deliverability risks in developing Ontario's transmission and distribution systems to meet the demand growth. This will include the integrated delivery of electricity, natural gas, and hydrogen. Mitigation options for building out distribution and transmission system capacity to meet the pace of electrification technology adoption will be outlined, e.g., moderating demand growth and leveraging the value of behind the meter distributed energy resources (DERs) and rate programs.

For over seventy years, the men and women of the PWU have played a critical role helping to keep the province's lights on. 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 has a successful track record working with other energy stakeholders to strengthen and modernize Ontario's electricity system. 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.

[33] OEB, Letter to Stakeholders, Final Phase One Benefit-Cost Analysis Framework for Addressing Electricity System Needs, (OEB File No. EB-2023-0125), May 16, 2024.
[34] PWU submission to the OEB on the Benefit Cost Analysis recommendations of the FEI WG, Jan 2023.