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Long-Term 2 RFP – December 13, 2023

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To promote transparency, feedback submitted will be posted on the Long-Term RFP engagement page unless otherwise requested by the sender.

Following the LT2 RFP engagement webinar, the Independent Electricity System Operator (IESO) is seeking feedback from stakeholders on specific items discussed during the webinar. The webinar presentation and recording can be accessed from the engagement web page.

Please submit feedback to mailto:engagement@ieso.ca by January 15, 2024. If you wish to provide confidential feedback, please mark "Confidential". Feedback that is not marked "Confidential" will be posted on the engagement webpage.

Resource Adequacy Framework and Cadenced Procurement Approach

Topic	Feedback
Do you have any comments or concerns regarding the cadenced nature between upcoming LT and MT RFPs?	Northland Power supports the IESO cadenced approach to upcoming LT and MT RFPs.
Do you have any comments or concerns regarding the proposed offering of both capacity style and new revenue model style of contracts, based on resource eligibility requirements and system needs?	If the IESO intends to procure both energy and capacity, it should do so in two separate procurements. The IESO has already procured capacity through E-LT and LT1 and may wish to run a separate streamlined version of those procurements to meet additional capacity needs.
Do you have any concerns regarding the proposed target setting approach for upcoming MT RFPs?	Northland Power appreciates that there must be competitive tension in procurements in order to drive affordable outcomes for ratepayers. That said, setting the procurement target as an arbitrary percentage of eligible capacity risks shuttering low-cost resources with preexisting community acceptance at a time when Ontario needs all the energy and capacity it can get. There are other ways of ensuring competitive outcomes, including reserve prices or caps, demand curves, among other options.

Topic	Feedback
Do you have any comments regarding how best to employ bridging and extensions to contracts to facilitate the success of the Resource Adequacy Framework?	Meaningfully extending the life of assets beyond their initial contract period requires significant capital investments. Capital plans are developed and approved years in advance of any work being undertaken at the facility. In order for suppliers to make those long lead time capital commitments, they require a clear picture of the future revenue opportunities available. While the cadenced nature of RFPs will provide some certainty of opportunity, the period between contract expiration and new contracted period under an RFP comes with no such certainty. The IESO should work to develop a simple and transparent means of bridging recently off-contract facilities to the next RFP opportunity. This could include a standard offer program in which facilities elect to participate as either an energy or capacity facility, receiving standardized contract terms based on the participation model elected. For instance, standard offer prices for capacity resources could be set in reference to the demand curve in the Capacity Auction. Such a program would provide much needed certainty of opportunity for suppliers making capital decisions for resources soon to be off contract. This program would only be available to resources coming off their first contract, and only until the start of the contract period for the first MT RFP the facility is eligible for (regardless of whether they are selected in that RFP).

LT2 RFP Resource Eligibility and Timelines

Topic	Feedback
Do you have any general feedback on resource eligibility and timelines?	Ontario is a centrally procured market, meaning internal government planning in collaboration with the IESO determines when and what type of generation will be procured by the province. This reality limits developers' ability to plan and advance projects well ahead of bid submission deadlines; therefore, we expect most of the bids in 2025 to consist of early-stage development sites (similar to LT1). Further to that, Ontario has not seen any meaningful renewable development activity since 2018, meaning the industry will have to work with local and provincial levels of government to modernize various renewable project approval processes. For example, the technical guidelines under the REA process will need to be updated and further research and collaboration will be necessary to better understand and mitigate risks to birds and bats. For these reasons we encourage the IESO to develop contract terms and timelines that align with this reality. For example, under New York's renewable energy procurement program project developers may extend their in-service dates by up to 3 years (provided they post additional security). This added flexibility, paired with clear contractual off-ramps with limited liability, will better align the LT2 procurement timeline with current state of province-wide development efforts.
If the potential of repowering an existing facility applies to you, would you be interested in exploring this option further?	Northland Power owns and operates a number of wind and solar facilities in Ontario and would be interested in exploring its repowering options.

Topic	Feedback
How should the optimal threshold for what constitutes a partial or fully repowered facility be determined and what considerations should be taken into account regarding the repowering of different resource types?	For the purpose of the LT2 eligibility, the IESO should not impose a minimum upsize threshold (e.g. 20%) for a project to be considered a repower. For many sites, it will be difficult, if not impossible, to increase the total output from its facility via repowering. For instance, wind turbines are more efficient than before, but they are also far larger and need to be separated from each other by a greater distance (relative to currently installed turbines). Given a fixed project footprint, interconnection, existing permitting requirements (noise, setbacks, etc.) among other constraints, a repowered facility may not be able to increase its historic output. However, the repower would ensure that the facility will continue to produce clean energy for the new term of the contract, when it would have otherwise run to fail and decommissioned. For this reason, the IESO should focus on procuring products (energy delivery on a 20-year term), not setting arbitrary investment or output thresholds, or setting a definition for repowering that fails to consider unique project-to-project circumstances.
What considerations should be taken into account for new-build DERs?	To realize the full benefit of DER resources, the IESO must ensure that it has the same visibility and access to data for DERs as it does for transmission-connected resources.
Please express any interest and opportunities for uprates and/or expansions at any of your existing facilities.	The IESO should explore uprates for existing solar facilities that are contractually limited to injecting 10 MW AC. In many instances, these facilities have the capability to generate more power, but are not permitted to do so under their contract. The IESO should work with impacted suppliers to procure this additional renewable energy, which is relatively inexpensive and available on an expedited basis.

Topic	Feedback
What early system congestion information do proponents need to guide them in choosing the location of their projects and when is this needed by within the procurement cycle?	Given the IESO's central role in planning supply and transmission buildout in the province, there is a significant informational asymmetry between the IESO and project proponents. It is in the IESO best interest, as well as the best interest of ratepayers, municipalities, and project proponents for the IESO to release as much data as possible. This information may be best communicated via a system map that clearly outlines interconnection availability, congestion risk, and any other relevant constraints related to connecting and delivering energy. This information should be based on the best available information regarding supply/demand dynamics and transmission buildout as of the LT2 in-service date in 2030. This may require seeking additional certainty from Hydro One and the government. Furthermore, this information should be released regularly (yearly for instance), not just when procurements are upcoming. This will allow proponents to continue long lead time development work for future procurements. In terms of the initial release of information, it should occur as soon as possible, and no later than 12 to 18 months prior to the RFP bid submission deadline. This information will help focus the efforts of developers, while providing communities with assurances that, regardless of the number of municipal support resolutions they provide, the number of projects built in a particular area is capped.

Topic	Feedback
Do you have any general suggestions for how to approach deliverability evaluation in the LT2 RFP?	If the IESO provides the information requested above to all market participants, the initial deliverability assessment of every resource will be largely duplicative. Furthermore, below Northland Power proposes changes to the Enhanced PPA structure that will reduce a project's exposure to curtailment and congestion risk. This too may alleviate the need to perform an initial informational deliverability assessment. In the event the IESO proceeds with the initial deliverability assessment, results need to be communicated no later than 6 months prior to the bid submission deadline. Any later and this information will be of little use in saving proponents time and money developing projects with significant curtailment risk.

Topic	Feedback
Do you have any comments regarding the impacts that agricultural land-use limitations may have on project development?	Northland Power supports CanREA's position on agricultural land-use limitations: "CanREA recommends that IESO procurements do not include additional restrictions on agricultural land use. The Provincial Policy Statement outlines land-use rules for energy development that municipalities must uphold. CanREA submits that energy development and land-use decisions are most appropriately addressed through local municipal planning decision-making processes."
Do you have any comments regarding what evaluation criteria can be utilized to evaluate project readiness, given tight timelines and reliability needs?	Northland Power supports forgoing an RFQ process, instead incorporating team experience and financial strength requirements into the RFP.
Do you have input on the proposed mechanism for valuing Indigenous participation?	Northland Power supports the current proposed mechanisms for valuing Indigenous participation. That said, E-LT included similar mechanisms, and yet approximately half of projects awarded through the RFP did not include Indigenous participation. In order to further incent Indigenous participation, the IESO should consider a price adder on top of the existing mechanisms.
Are there any other rated criteria that should be considered?	

Long Lead Time Resources

Topic	Feedback
Does the proposed approach to enabling long-lead time resources enable meaningful participation or sufficient certainty?	
What additional considerations should the IESO contemplate for enabling broader participation from long-lead time resources?	

Revenue Model

Topic	Feedback
As a potential proponent, are you generally supportive of the proposed Enhanced PPA revenue model? Are there any other considerations that the IESO should look into further with regards to the revenue model?	Northland Power cannot support the IESO's Enhanced PPA proposal as it misallocates risk and will lead to worse outcomes for project proponents, the IESO, and ratepayers. Please see the *General Comments/Feedback* section below for Northland Power's detailed feedback on the Enhanced PPA proposal, as well as recommendations for an alternative revenue model.

General Comments/Feedback

Enhanced PPA Feedback

The development, financing, construction, operation, and marketing of new renewable projects is rife with risks. Risk creates uncertainty, the presence of which has a direct impact on project costs, and ultimately the cost to ratepayers. To the extent these risks can be mitigated or all-together eliminated, costs come down. For this reason, it's critical that risks are allocated to the entities that are best suited to identify, forecast, and mitigate them; In doing so, incentivizing them to mitigate risk to the economically and socially appropriate extent.

Misallocating risk is costly. Allocating risk to a project proponent that's unable to accurately forecast and mitigate that risk will necessitate risk adders in RFP bid prices. Furthermore, when a project is allocated a risk, that risk is shared with the project's financiers, who are often less equipped to identify, forecast, and mitigate that risk. This necessitates higher lending rates to project proponents, or results in projects being wholly unfinanceable. These costs are real, these costs are borne by ratepayers, and these costs are a direct result of misallocating risk.

Many risks associated with new renewable projects are rightly allocated to project proponents. For instance, project proponents are best suited to manage the risks associated with the development, construction, and operation of projects. Many other risks are unsuitable to allocate to project proponents. These tend to be risks where the project proponent has limited information to help identify and forecast the risk, where they have little to no control over whether that risk materializes, and where there's no available hedges to that risk. In many cases, there's a more natural owner of that risk, one better suited to manage that risk and keep costs down (e.g. the IESO).

Below we identify different types of risk associated with the IESO's proposed Enhanced PPA, who is best positioned to manage those risks, and PPA designs that would allocate those risks accordingly.

1. Curtailment Risk

In the context of renewable variable generators, curtailment occurs when a facility is both available to generate and has sufficient fuel to do so, but is instructed to forgo that production due to conditions on the grid, including transmission outages, congestion, etc. Curtailment is the result of a complex interaction of supply, demand, and transmission factors, all of which are unrelated to the facility itself and its ability to produce energy. Furthermore, there are no actions that can be taken by the generator to alleviate the conditions causing that curtailment.

Curtailment is the result of electricity supply exceeding demand in a given area, with insufficient transmission capacity for that power to flow to other load centres. In this sense, curtailment is a result of the complex interaction between supply, demand, and transmission, none of which project proponents have any control over.

- Demand in Ontario, especially from large loads (i.e. those that are likely to shift supply/demand balances in a local area), is largely driven by government policy and incentives. The addition of large arc furnaces and future battery assembly plants being recent examples.

- In Ontario, supply is planned for and procured by the IESO, in consultation with the government. As such, the IESO determines the level of supply in the province, and largely controls where it's located through its connection process and locational incentives in RFPs.
- Similarly, the IESO is responsible for transmission planning in the province, in consultation with Hydro One and the government. As such, the IESO determines where on the system to build new infrastructure to alleviate congestion and curtailment.

These drivers of curtailment are entirely beyond the control of any project proponent. Furthermore, the unilateral decision-making power and often opaque processes of the IESO and the government prevent project proponents from making educated forecasts of future curtailment.

Unlike in other jurisdictions, there are no means of hedging against the risk of congestion and curtailment in Ontario. In New York for instance, there exists a market for financial transmissions rights (FTRs) for internal transmission paths. Purchasing FTRs for paths between the congested project area and uncongested load centre provides a strong hedge from economic curtailment. No such FTR market for internal transmission rights exists in Ontario, nor any other means for projects to hedge against uncertain curtailment risk for the 20+ years of the contract.

With no control over whether curtailment arises, no ability to forecast future curtailment accurately, and no means of hedging against the risk of curtailment, it's quite clear that curtailment risk should not be allocated to project proponents. If it is, that open-ended risk may cause projects to become wholly unfinanceable, or at a minimum, necessitate that all project proponents incorporate an extremely conservative view on curtailment when preparing their RFP bid prices (i.e. assume significant future curtailment, increasing their bid price accordingly).

Curtailment risk is more appropriately allocated to the IESO, as it has the ability to best forecast future curtailment, and the means to best mitigate that curtailment via transmission planning. Allocating curtailment risk to the IESO will ensure that curtailment is mitigated to the economically efficient level, saving ratepayers money in doing so.

Recommendation: To ensure the economically efficient level of mitigation and to lower ratepayer costs, Curtailment Risk should be allocated to the IESO, not project proponents.

As currently designed, the Enhanced PPA allocates all curtailment risk to individual project proponents. It does so by calculating contract payments using fixed contract volumes and exposing projects to curtailment risk in the energy market without any true-up via the contract.

A simple way to shift curtailment risk from project proponents to the IESO is by linking contract sales volumes to actual sales volumes, with some consideration for curtailed production. Under this structure, megawatts produced and megawatts curtailed would receive the contracted PPA price. This structure is similar to the current Renewable Energy Supply (RES), Feed-In Tariff (FIT), and Large Renewable Procurement (LRP) contract structures, none of which place uncapped curtailment risk on project proponents.[1] Furthermore, by linking contract sales volumes to actual sales volumes, this

[1] FIT contracts include a capped number of hours where curtailment goes uncompensated. The IESO could include such a feature in LT2 contracts, provided it meaningfully caps curtailment risk to proponents. That said, such a cap doesn't remedy the factors that made

structure protects the IESO and ratepayers from paying for megawatts they don't receive (for reasons outside of curtailment), unlike the Enhanced PPA.

With compensation linked to actual production, the IESO should extend compensation for energy produced in excess of volumes contracted through the RFP, up to a certain level. This approach is used in New York where NYSERDA buys RECs from TIER 1 contracted resources for production up to 20% in excess of annual contracted sale volumes. This additional revenue helps offset years with revenue shortfalls when output was lower than forecasted under the contract.

2. Day-Ahead to Real-Time Risk

Market Renewal will introduce a financially binding day-ahead (DA) market to Ontario. Resources scheduled in the DA market will be responsible for any deviations in their DA to real-time (RT) schedules; To the extent a resource produces less in RT than scheduled DA, it will be responsible for buying back the difference at the RT market price. In the context of this Enhanced PPA discussion, this is what's defined as DA to RT ("DA/RT") risk.

DA/RT risk is particularly pronounced for variable generators like wind and solar. Unlike gas-fired and storage resources that can reliably plan their operations day-ahead, variable generators must rely on forecasts of wind speed and solar irradiance to estimate future production. As recognized by the IESO, these forecasts are largely unreliable until the hours directly leading up to real-time, if at all.[2] As a result, variable generators can offer little to no certainty on their production volume for the following day. Nevertheless, under the DA market these resources will be asked to provide the same production certainty as other controllable resources. If resources over-forecast production DA, they will need to buy-back the shortfall at RT prices that are potentially far higher.[3]

The DA market is about providing operational certainty to the IESO and controllable resources. Variable generators are incapable of providing that certainty; In other words, they're incapable of mitigating DA/RT risk. Nevertheless, the Enhanced PPA misallocates DA/RT risk to project proponents by calculating Deemed Energy Revenue based on the DA market price, with no consideration for the RT price. This leaves proponents with two options:

1. Offer all forecasted production into the DA market, increasing the likelihood that DA market revenue will roughly match Deemed Energy Revenue under the contract. While this has the benefit of better aligning market operations with the hedge provided by the contract, it exposes the project to maximum DA/RT risk. To protect against this difficult to forecast DA/RT risk, the proponent would need to increase its RFP bid price.

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project proponents a poor owner of the risk in the first place, including an inability to forecast, mitigate, or hedge the risk. As such, project proponents are likely to assume all projects are curtailed to the cap in all 20 years, increasing their bid prices accordingly. If this curtailment fails to materialize, the IESO and ratepayers have nevertheless paid for this higher level of assumed curtailment. For this reason, the IESO should compensate for all curtailment.

[2] The IESO regularly turns off its centralized look-ahead forecasting system in favour of persistence forecasting.

[3] It's possible that RT prices could be lower than DA prices and the project could benefit from its DA/RT buy-back. That said, DA/RT risk is asymmetric in the sense that large discrepancies in DA to RT prices are far more likely to be price spikes than price craters – this is due to the hockey-stick shape supply curve.

2. Projects can hedge against DA/RT risk by offering an amount into the DA market that is very conservative, decreasing the likelihood the project will need to buy back unrealized production in RT. While this serves to reduce, albeit not eliminate DA/RT risk, it comes at the cost of structurally misaligning market operations from assumed contact operations, thus reducing the efficacy of the contract as a hedge. Furthermore, the intentionally conservative approach to DA offers provides the IESO with a distorted supply/demand picture DA, necessitating costlier resources to be scheduled.

Having project proponents accept DA/RT risk under Option 1 necessitates higher RFP bid prices, while leaving project proponents to hedge against this risk under Option 2 decreases the utility of the contract and leads to market inefficiencies. These outcomes strongly suggest that allocating DA/RT risk to project proponents would be a misallocation of risk.

The IESO, with its 10+ years experience centrally forecasting variable generation in Ontario, is better suited to forecast DA/RT production risk for variable generators. Furthermore, even if the IESO and project proponents were equally skilled at this type of forecasting, recall that the DA market is about providing operational certainty to the IESO, not variable generators. The IESO is naturally incented to mitigate DA/RT risk, variable generators are not. So, while the IESO could allocate DA/RT risk to project proponents, it comes at the cost of higher RFP bid prices and inefficient offer behaviour, whereas it comes at no additional cost to allocate this risk to the IESO.

Recommendation: To improve operational certainty in the Day-Ahead Market and lower ratepayer costs, Day-Ahead to Real-Time risk should be allocated to the IESO, not project proponents.

The Enhanced PPA misallocates DA/RT risk to project proponents by calculating Deemed Energy Revenue based on the DA market price, with no consideration for the RT price. In order to allocate this risk more appropriately, Deemed Energy Revenue under the contract should be calculated using the RT price. In order for the IESO to get the most accurate supply picture DA, it could require project proponents to offer their IESO centrally-forecasted production into the DA market, and to the extent DA revenue differs from RT revenues, reverse those revenues via the contract.[4] The resulting net revenue from the contract, DA market, and RT market would equal the contract bid price, and project proponents would no longer be subjected to DA/RT risk.

3. Shape Risk

The Enhanced PPA proposes to calculate Deemed Energy Revenue based on the simple average of the relevant average monthly price. Effectively, this contract structure assumes that the project is generating equally across all hours in a given month. Of course, actual output from variable generation can change significantly from hour to hour (even minute to minute), primarily as fuel availability changes. The corresponding difference between the flat production profile assumed under the contract, and the variable nature of actual production, is what’s referred to as shape risk.

[4] Note that this is the same contract mechanism the IESO has proposed to eliminate DA/RT risk for existing FIT-contracted resources when they’re transitioned to Market Renewal.

Shape risk manifests when the weighted average price realised through the market ("captured price") is less than the relevant monthly average price used to settle the contract. This tends to occur when a project produces more during low price hours than it does during high price hours. Under these circumstances, market revenues and contract revenues sum to something less than the project's contracted bid price. Conversely, a project may benefit from shape risk if it produces primarily during relatively high price hours, increasing its captured price above the relevant monthly average price calculated under the contract, allowing the project to earn more than its contracted bid price.

Given the forecasted diurnal load profile, and the average diurnal production profile of wind and solar resources, it's likely that solar resources will realise a captured price above the monthly DA average price, while wind resources will realise a lower captured price. As such, solar resources will be at a competitive advantage in an RFP, as the potentially higher captured price may allow them to bid a relatively lower contract price, whereas wind resources will need to bid a relatively higher contract price on account of its own shape risk. If it's not the IESO's intention to favour solar over wind resources, it should eliminate shape risk for project proponents.[5]

Of further concern, variable generators are no more able to control or mitigate shape risk than they are DA/RT or curtailment risk. Similar to curtailment risk, long-term shape risk is a function of supply, demand, and transmission dynamics, factors more squarely in the ambit of the IESO. Furthermore, project proponents are no better able to forecast shape risk than the IESO, with its lengthy experience centrally forecasting all the province's variable resources. Given this uncertainty and inability to mitigate, if project proponents are misallocated shape risk, they will need to take a conservative view and price this risk into their RFP bids.[6]

Recommendation: To preserve the competitive balance amongst eligible technologies and to lower ratepayer costs, Shape Risk should not be allocated to project proponents.

Under the Enhanced PPA, shape risk is misallocated to project proponents by calculating Deemed Energy Revenue based on the simple monthly average of the relevant market price. In order to allocate this risk more appropriately, Deemed Energy Revenue should be calculated based on the monthly weighted average market price, weighted by actual (and curtailed) production from the project. This will ensure alignment between the project's captured price, and its Deemed Energy Revenue under the contract.

4. An Alternative PPA Approach

Northland Power cannot support the IESO's Enhanced PPA proposal as it misallocates risk and leads to worse outcomes for project proponents, the IESO, and ratepayers.

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[5] If the IESO's intention is to prioritize the procurement of higher valued energy over lower valued energy, the proposed RFP bid price evaluation methodology fails to do so (given projects compete on bid price alone, not levelized net contract cost). Given the IESO has foregone this more direct means of prioritizing higher valued energy, it would be inconsistent to do so through the less effective means of allocating project proponents shape risk.

[6] In theory, projects can hedge against shape risk by actively managing their net position through a financial forward market. Unfortunately, Ontario's financial forward market lacks the liquidity to effectively implement a hedging strategy. Furthermore, hedging has a cost, which would need to be considered when bidding into the RFP.

Northland would like to propose an alternative revenue model that incorporates the findings and recommendations outlined above. The revenue model would have the following features:

- Contract payments would be tied to actual production (as opposed to a fixed contract quantity), with compensation for curtailed production.
- On a net basis, contract payments would be calculated based on real-time market prices.
- Contract payments would be calculated based on the weighted average monthly price, where that price is weighted by actual (and curtailed) production from the project.

In practice, this contract structure would most closely resemble the existing FIT contracts, as to be amended by the IESO's *FIT Contract Amendment Term Sheet*.[7] This structure has the benefit of appropriately allocating the aforementioned risks, while being familiar to project proponents, the IESO, and financiers – an important factor when considering the accelerated timeline required to complete these projects. With the appropriate contract structure in place, the table will be set for project proponents to compete to provide the lowest cost projects via the RFP.

Additional Miscellaneous Feedback

5. Who Owns Capacity and Environmental Attributes

The IESO needs to clarify who owns the capacity rights and environmental attributes associated with projects procured through LT2.

To the extent project proponents retain these rights, they will need to take a view on the future value of these potential revenue streams when determining an RFP bid price. Those that take an aggressive view on these revenue streams are the likeliest to win the RFP. This is problematic considering the uncertainty around the future of capacity and environmental attribute markets in the province.

Ontario lacks an open, stable, and competitive capacity market; At best it has a suite of byzantine procurement programs targeting specific technologies. Taking an informed long-term view on the future of these programs and project eligibility is not possible.

The IESO recently launched the Clean Energy Credit (CEC) market for environmental attributes. Not only is this market new with untested liquidity, but the supply of CECs is dominated by a single seller, which happens to be the same entity that designed and regulates the market. Similar to capacity, taking an informed long-term view on the future value of CECs is not possible.

For these reasons, Northland Power recommends that the IESO retain the rights to all capacity and environmental attributes associated with projects procured through LT2. By retaining these rights, project proponents need not forecast uncertain future capacity and environmental attributes revenue streams, leaving them to compete solely based on build cost (at least for the price portion of the RFP evaluation). This will ensure that the most cost-effective resources are selected through the RFP, not

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[7] Available here: https://www.ieso.ca/-/media/Files/IESO/Document-Library/market-renewal/MRP-FIT-Amending-Term-Sheet-20231108.ashx

just the ones that take the most hopeful views on future capacity and environmental attribute revenues.

In future RFPs, the IESO may reconsider who owns these products. For instance, if the CEC market evolves to have many sellers, credits can be traded outside of Ontario, and there's sufficient market liquidity, it may be more appropriate for project proponents to value that product and to retain its rights.

6. Municipal Support Resolution Requirement

Northland Power has significant concerns about proponents' abilities to secure a Municipal Support Resolution (MSR) on the timelines proposed by the IESO. Recent experience on the E-LT and LT1 procurements suggest a different approach is needed to informing and empowering communities to participate in the energy transition. This includes a greater role for the IESO and Government in partnering with communities to inform them on the province's energy needs, while setting realistic expectations on the scope of potential project development in their area. As part of E-LT and LT1, municipalities were inundated with MSR requests, yet received no guidance from the IESO on whether 100 MW or 1,000 MW of new capacity could be connected and built in their municipality, this surely chilled community acceptance.

More targeted discussions need to be held between project proponents, the IESO, the Government, and community leaders to arrive at a suitable framework for seeking and granting community support for LT2. In that spirit, stakeholders should consider whether the Government should mandate standard community funding amounts based on installed capacity or production. This would help set project proponent and community expectations in advance of seeking an MSR, and would ensure all projects compete on an even playing field in the RFP.