LT2 RFP: Revenue Model Update

The Enhanced Power Purchase Agreement

In December, 2023, the IESO announced that it was embarking on a series of resource procurements for new, non-emitting electricity supply to meet needs emerging at the end of this decade. Whereas recent IESO procurements, including the Long Term Request for Proposals (LT1 RFP), have focused on meeting demand during system peak hours, the coming procurements will be focused primarily on meeting energy needs. To that end, the IESO has evolved a new revenue model for energy producing resources with the aim of balancing revenue certainty for suppliers and alignment with the IESO's renewed market design: the **Enhanced Power Purchase Agreement** (E-PPA).

The IESO introduced the second Long Term RFP (LT2 RFP) and proposed E-PPA revenue model at a public webinar in December, 2023. At this meeting, the IESO communicated its projected energy needs and provided a conceptual overview of the E-PPA, including how it aims to meet a supplier's monthly revenue requirements via a combination of energy market revenues and a top-up in the form of a Grid Reliability Payment (GRP) from the IESO to the supplier. Following this meeting the IESO received written feedback focused on three key aspects of the E-PPA design, namely clarity on how the model takes into consideration: (i) curtailment risk, (ii) the variability in energy production in relation to market pricing (shape risk), and (iii) the uncertainties between Day-Ahead Market (DAM) and Real-Time Market (RTM) operations. At the second LT2 RFP webinar in February, the IESO presented detailed examples and also options on potential iterations to the E-PPA design, which would provide greater certainty for the supplier, while still enabling the benefits of active market participation.

This document provides more details on the E-PPA and the changes to its design the IESO has made to address stakeholder concerns.

Energy Contracts in the IESO's Renewed Markets

With the launch of the IESO's Market Renewal Program (MRP) occurring in 2025, ensuring that the contracts from the upcoming procurements align with the new market is a key goal for the IESO. With the LT2 RFP, the goal is to introduce a commercial model that provides revenue certainty for energy resources while enabling and encouraging more price responsive and market-focused behaviour from energy producing resources than the contracting model used in previous decades. As Ontario transitions out of a period of surplus electricity into one with growing needs, it will be important to encourage contracted resources to be more responsive to market prices and provide power when (and where) it is of most value to the system, which will help deliver cost-effective reliability.

The E-PPA revenue model has been designed to facilitate (and incentivize) hybridization, or other innovation that enables more control over the timing of delivered electricity, over the life of the contract.

The IESO will use this new model as the foundation for other future energy procurements, alongside the capacity contract utilized in the LT1 RFP. With cadenced procurements, the IESO will continue to evolve its procurement and contract design to ensure lessons learned and best practices are incorporated and system needs are addressed in an efficient manner.

Market Renewal Program Objectives

MRP is aimed at enhancing the efficiency, transparency, and competitiveness of Ontario's electricity markets. Its key objectives include improving the reliability of the grid, optimizing the supply mix, and enabling more cost-effective and efficient electricity market outcomes for ratepayers. By aligning the E-PPA revenue model with MRP, the goal is to create a contract structure that is reflective of actual market needs which show up in the form of day-ahead and real-time price signals. This alignment seeks to encourage day-ahead offers from suppliers based on their marginal costs and operational capabilities, leading to a more responsive, resilient and optimized energy marketplace. Underpinning the efficiency and effectiveness of MRP are several core components that drive its design, notably:

Locational Marginal Pricing (LMP): Central to MRP is the implementation of LMPs, which ensure that prices for electricity reflect the cost of production and delivery at specific nodal locations, enhancing economic efficiency and reliability of the grid.

Day-Ahead Market (DAM): The introduction of a DAM is a cornerstone of MRP, facilitating a more predictable and stable market by scheduling and settling resources on a day-ahead basis. This increased predictability enables suppliers to plan and optimize their operations according to expected market conditions and receive payment based on the DAM clearing prices, if the resource is scheduled in that timeframe.

Core E-PPA Design Principles

The E-PPA functions like a Contract for Differences with a market revenue deeming structure, similar to most of the IESO's gas generation contracts. The E-PPA attempts to separate market revenues and contract revenues, in order to drive greater exposure to market signals, thereby incentivizing more efficient operation (and fewer ratepayer-funded out-of-market payments).

Variables submitted by the supplier

Suppliers will need to offer in a proposal price ($/MWh) and an annual imputed production factor. The production factor should serve as an estimate of annual average capability (no curtailment assumptions would be built into this factor). The proposal price should be determined based on a project's annual revenue requirement ($) and estimated annual production (MWh), meaning its imputed production factor is inherently tied to its proposal price (i.e. the proposal price would be derived by assuming the amount of production reflected in the production factor).

Monthly payments under the contract (GRP), if any, would be the difference between monthly revenue requirements and the monthly deemed energy market revenues, calculated as follows:

$$\boldsymbol{Revenue\ Requirement_{monthly}} = Proposal\ Price * Imputed\ Production\ Factor * Contract\ Capacity * Hours\ in\ a\ month$$

$$\boldsymbol{Deemed\ Energy\ Revenue_{monthly}} = Day\ Ahead\ Locational\ Marginal\ Price_{monthly\ average} * Imputed\ Production\ Factor * Contract\ Capacity * Hours\ in\ a\ month$$

Revenue Requirement monthly: The total amount of revenue a supplier needs to receive in a month to cover capital, operational and maintenance costs, in addition to the rate of return required by the supplier.

Proposal Price: The price per megawatt-hour (MWh) that the supplier submits as part of their proposal. It reflects the unit cost that will generate the revenue requirement based on the amount of anticipated annual production over the life of the contract.

Imputed Production Factor: A value that represents the expected average production capability of the generator based on the energy resource, relative to the generator's maximum capacity. This factor does not assume any grid-based curtailment and is used to estimate the annual average energy production.

Capacity: The maximum instantaneous amount of power generating capability, in megawatts (MW).

Hours in a month: The total number of hours in the settlement month. This value varies by month, accounting for the exact days in each period (including for leap years).

Deemed Energy Revenue (monthly): The revenue that a supplier is deemed (ought) to have earned in the energy market in a month, based on the day-ahead average market prices and the supplier's production capability at their location.

Day Ahead Locational Marginal Price monthly average (DA LMP monthly average): The average price of electricity for a specific location in the DAM, calculated over all hours in a month. Negative prices are adjusted to zero to reflect operational realities, where generators should not produce when the market price is less than their marginal cost.

Negative Prices and Curtailment

This formula assumes that the average monthly Day Ahead Locational Marginal Price (DA LMP) is the simple average of all hourly DA LMPs in the month[1], with any negative prices set to zero.

- Negative prices are set to zero because resources are assumed to offer into the DAM at their marginal cost (≥ 0). Therefore, anytime the DA LMP is negative, the assumption is that the generator is not scheduled and earns no revenue in the DAM (note that they may still earn additional revenue in the Real-Time Market (RTM) even when they are not scheduled in the day-ahead timeframe if demand conditions change such that the real-time price shifts positive, and any such revenues would stay with the supplier).
- In hours where the DA LMP is negative and deemed revenues are zero, the GRP under the E-PPA acts as a counterbalance to ensure the supplier meets its revenue requirement. For instance, in an extreme scenario where a generator's locational price is constantly less than zero, the generator will be deemed to have earned no market revenues and the GRP will become equal to that generator's revenue requirement.
- When a generator that has been scheduled in the DAM is not called on to produce (curtailed) in real-time (signalled by negative prices) they will be kept whole to the revenue expectation from the DAM via the IESO's market settlement. This aspect of the market design leaves the incentive for generators to benefit from shifting production from lower priced hours to higher priced hours - earning additional revenue as well as increasing the efficiency of the scarce energy itself to the benefit of all Ontarian's.

[1] The proposed amendment to the design further down in the memorandum recommends using a capability weighted average DA LMP (monthly) for wind and solar resources. Hydroelectric resources will continue to use the simple average DA LMP (monthly).

Considerations and Changes Based on Stakeholder Feedback

Production Profile Considerations

Stakeholder feedback

Deeming a flat production factor against all hours of the day is mismatched with the actual production profile of variable generators (VGs), such as wind and solar, and introduces daily and seasonal "shape risk". Wind resources typically have more output during off-peak hours and in winter where prices today are lower. Similarly, solar resources (without integrated or co-located storage) will not be able to fully capture evening peak prices. It has been argued that this nuance will make it more challenging for VGs to meet or beat their deemed energy revenues if being deemed across all hours of the day, thus endangering their ability to meet their monthly revenue requirements.

IESO proposed approach for the LT2 RFP

VG resources will be deemed based on a Forecast Weighted Average Price (FWAP). The FWAP will take into consideration an individual resource's production capability from the IESO centralized forecast at their location and DA LMPs. For Hydroelectric resources, the IESO proposes to deem market revenues based on the simple average monthly DA LMP due to their different operational characteristics and the fact that daily centralized forecasts are not published by the IESO for resources other than wind and solar.

Forecast Weighted Average Price (monthly): Takes into consideration the IESO centralized forecast at the location of each individual resource and the associated hourly DA LMPs. For VGs, the FWAP approach should increase the ability for wind/solar resources to earn actual revenues that match their deemed market revenues while still creating the appropriate linkage between their production and the value to the system.

Example for a VG resource

Note that the FWAP calculation considers IESO forecasted production and DA LMPs in each hour (1-24) of each day over a calendar month, however, for illustrative purposes the example below has clustered delivery hours into three distinct hourly blocks for the month.

Hours over a month (clustered into three blocks for simplicity)	**IESO centralized forecasted production for a specific resource at their location**	**DA Locational Marginal Price** (Average across hours)	**Forecast Weighted Average Price**
HE 1-8	60 MW	$5	$300
HE 9-16	0 MW	$50	$0
HE 17-00	50 MW	$10	$500

$$\boldsymbol{Forecast\,Weighted\,Average\,Price\,(month)} = \frac{Sum\ of\ weighted\ prices}{Total\ forecasted\ production}$$

$$\boldsymbol{Forecast\,Weighted\,Average\,Price\,(month)} = \frac{\$800}{110\ MW} = \boldsymbol{\$7.27}$$

For comparison, the simple average monthly DA LMP would be **$21.67**

Increased Granularity in Production Factors to Address Seasonality Shape Risk

Stakeholder feedback

Enabling more granular production factors (e.g., monthly values), would further account for seasonality in the deemed calculation, allowing for better hedging and smoothing out supplier cash flows.

IESO proposed approach for the LT2 RFP

The IESO proposes enabling this change, such that suppliers can submit monthly imputed production factors (January through to December) that would apply for the life of the contract. These monthly imputed production factors will average to the annual imputed production factor that will be used to calculate monthly Revenue Requirements. The monthly imputed production factors will be utilised by the IESO in the deeming calculation to better reflect seasonality in a VG supplier's production and expected revenues for the DAM and RTM.

Example where annual (8760 hours) production factor submitted is 0.3.

Jan	Feb	March	April	May	June	July	Aug	Sept	Oct	Nov	Dec
0.3	0.4	0.4	0.3	0.3	0.2	0.2	0.2	0.2	0.4	0.4	0.3

Production Factors and Proposal Evaluation

An essential element of the E-PPA proposal evaluation process involves assessing the annual imputed production factors submitted by suppliers. Proposals will be evaluated on a proposal price in $/MWh which in tandem with the contract capacity and imputed production factor will determine the revenue requirement. A proposal with a higher imputed production factor will be able to submit a lower proposal price and obtain the same revenue requirement. Imputed production factors will be subject to a performance obligation.

Separately, monthly imputed production factors (that average of the annual value) can be utilized to address seasonality of cash flows in the monthly deeming calculation.

Day-ahead to Real-Time Considerations

Stakeholder feedback

The IESO acknowledges that it has heard from some VG resources concerns about the potential inability to manage the day-ahead to real-time differential. VG resources do not have full certainty that they can deliver their day-ahead schedule in real-time due to the actual wind/sun conditions at the time of production relative to their day-ahead forecast. The concern is that deeming revenues based on day-ahead prices would not reflect the risk of having to buy out of their day-ahead schedule in the RTM.

For example, if a resource is committed for 15MW day-ahead but is only able to deliver 5 MW in real-time, that resource will need to balance their position by paying a potentially higher RT price multiplied by the difference of 10 MW.

As outlined in the communication sent on March 19, the IESO is examining different options to address the concern outlined by stakeholders. The goal is to find a solution that adequately balances the incentives for resources to efficiently participate in the market with the suppliers' desire for greater certainty.