IESO MARKET RULE DESCRIPTION EVIDENCE IN RESPONSE TO PROCEDURAL ORDER NO.2

On November 8, 2024, Capital Power Corporation, Thorold CoGen L.P., Portlands Energy Centre L.P. doing business as Atura Power, St. Clair Power L.P. and TransAlta (SC) L.P. (**Applicants** or **NQS Generation Group**) applied to the Ontario Energy Board (**OEB** or **Board**) for a review of amendments (**Amendments**) to the Market Rules for the Ontario Electricity Market (**Market Rules**) made by the IESO to enable and operationalize the IESO's Market Renewal Program (**MRP**).

On December 2, 2024, the Board issued Decision and Procedural Order No. 2, which directed that the IESO prepare and file evidence that in clear language:

- describes the objectives of the Amendments;
- provides a detailed overview of the Amendments;
- describes how the Amendments achieve the objectives of the Amendments; and
- describes the key changes to the current market rules and the expected impacts on market participants.

The Amendments constitute the full set of market rule amendments necessary to enable and operationalize MRP. The core components of the Amendments are a new Single Schedule Market (**SSM**), a Day Ahead Market (**DAM**) and an Enhanced Real-Time Unit Commitment Process (**ERUC**). The IESO's evidence will focus on these core components of MRP, as well as the rule amendments that will create a revised Market Power Mitigation framework (**MPM Framework**).

The IESO has organized and presented this evidence in accordance with the Board's request to explain the Amendments in clear language. The IESO's evidence commences with a brief overview of MRP followed by sections that specifically address the SSM, DAM, ERUC and the MPM Framework. In each of these sections, the IESO describes the particular rule amendments, the purposes of the amendments, how the amendments will achieve their intended purposes, and how they are expected to impact market participants or classes of market participants.

1. Overview of the Market Renewal Program

The IESO initiated the MRP in 2016. The purpose of MRP is to modernize Ontario's electricity markets to improve efficiency and integrate an increasingly diverse and decentralized mix of resources into the Ontario market and electricity system. MRP will deliver significant ratepayer savings, ensure continued reliable operations of the system, and support the transformation underway within the electricity sector in Ontario and globally.

Ontario's wholesale electricity market was introduced in 2002 and was intended to be a competitive market that would ensure power system reliability at a lower cost than the vertically integrated system that preceded it. The current market design has met many of its objectives and enabled the IESO to manage the electricity grid reliably during an era of structural changes to Ontario's supply mix. However, the current wholesale market design remains largely unchanged since 2002 and has certain shortcomings that cause inefficiencies and other operational complexities and reliability challenges. In particular, Ontario's unique "two schedule system" results in a misalignment between price and dispatch that results in the uneconomic dispatch of resources, as well as additional costly congestion and cost guarantee payment programs.

Concerns with Ontario's market design have been reported on repeatedly by the OEB's Market Surveillance Panel (**MSP**), including in the December 2016 MSP report: Congestion Payments in Ontario's Wholesale Electricity Market[1] and the 2024 MSP Report: State of the Market Report 2023.[2] The Auditor General of Ontario has also been critical of the inefficiencies in Ontario's current market design, including in the Auditor General's 2017

[1] Congestion Payments in Ontario's Wholesale Electricity Market: An Argument for Market Reform
[2] State of the Market Report 2023

IESO Oversight Report[3],noting particularly that the market's additional payment programs have endured despite concerns expressed by the MSP.

The IESO has thoroughly evaluated the costs and benefits of implementing MRP changes and it has undertaken lengthy and involved stakeholder and market rule amendment processes to implement MRP.[4]

The primary objectives of MRP are to:

- address the current misalignment between price and dispatch in Ontario's electricity market, and eliminate the need for unnecessary congestion payments, by shifting to a SSM and introducing Locational Marginal Pricing (**LMP**);
- introduce a DAM that will provide greater operational certainty to the IESO and greater financial certainty to market participants, lowering the cost of producing electricity and ensuring the IESO commits the resources required to meet system needs; and
- improve efficiency and competitiveness and reduce the cost of scheduling and dispatching resources to meet demand, as it changes from the day-ahead to real-time, through the introduction of the ERUC.

In addition to these primary objectives, MRP establishes a new MPM Framework which is necessitated by the introduction of LMP and the opportunities that change creates for the exercise of market power. In order to facilitate these primary objectives, the MRP also introduces a range of additional related enhancements to the wholesale energy market, including:

- a more transparent zonal demand forecast;

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[3] Office of the Auditor General of Ontario, *2017 Annual Report: Volume 1 of 2*, 2017, section 3.06: Independent Electricity System Operator—Market Oversight and Cybersecurity ("2017 IESO Oversight Report").
[4] What is the Market Renewal Program?; October 22, 2019 Energy Stream Business Case: https://www.ieso.ca/-/media/Files/IESO/Document-Library/market-renewal/MRP-Energy-Stream-Business-Case-2019.pdf

- new options for managing price risk;
- a more efficient integration of emerging resource types (such as distributed energy resources, storage, and hybrid resources);
- additional dispatch parameters for hydro resources sharing a river system, enhancing their ability to reflect interrelated operational characteristics resulting in more efficient dispatch); and
- a more accurate price signals to facilitate better investment decisions.

The MSP stated in its State of the Market Report 2023 that "MRP will bring about key changes to the wholesale market with the objective of improving efficiency, competition and transparency" and that the concerns the MSP has repeatedly expressed regarding costly congestion and cost guarantee payment programs will be addressed by the implementation of Market Renewal.[5]

2. Single Schedule Market and Locational Marginal Pricing

2.1 Introduction to Single Schedule Market and Locational Marginal Pricing

MRP is replacing Ontario's current two-schedule market design with a SSM that will align market prices and system dispatch. The SSM achieves this alignment through the introduction of LMP, which account for transmission congestion and transmission losses that result from the "distance travelled" between the supply resource to the point of use on the system. Unlike the current market's uniform Hourly Ontario Energy Price (**HOEP**), LMPs will vary by location reflecting the actual cost of producing electricity at a given place and time.

[5] State of the Market Report 2023, p. 83.

2.2 Ontario's current 'Two-Schedule' Market and HOEP

The Ontario electricity market currently operates on the basis of a 'two-schedule' market design. This design consists of a pricing schedule, called an "Unconstrained Schedule", and a dispatch schedule, called a "Constrained Schedule".

The two-schedule design has been a feature of the Ontario electricity market since market opening in 2002 and was adopted as a recommendation of the Market Design Committee (**MDC**). The intent of the design was to assist in facilitating Ontario's transition from a vertically integrated electricity system to a wholesale market by imposing a uniform Ontario wide electricity price.

At the time of adoption of the two-schedule design, it was recommended by the MDC that Ontario should transition to a single-schedule within 18 months of market opening. This transitional design has endured from 2002 to the present day.

Ontario is the only market in North America with a two-schedule design. All other North American system operators and electricity markets have implemented, or transitioned to, a more effective design where prices and dispatch are aligned and set by a single schedule.

2.2.1 The Unconstrained Schedule

The Unconstrained Schedule sets a uniform market clearing price (**MCP**) for electricity every five minutes and it schedules supply on the basis of economic merit. The MCP is based on the energy offers of suppliers, which include both an offer price ($/MW) and an offer quantity (MW). The offers are stacked from lowest to highest and the MCP is determined by the lowest offered price in the stack that must be reached in order to satisfy the quantity of electricity required to meet the IESO's demand forecast. Suppliers offering at the MCP or lower clear the market in the Unconstrained Schedule.

The 12 MCPs in an hour are averaged to establish the province-wide HOEP, which is charged in the real-time market to market participant load customers, e.g., large consumers and local distribution companies which recover it from their customers.

This current market pricing schedule is called an “Unconstrained Schedule” because the determination of MCP and HOEP do not take into account actual system conditions or operational constraints. MCP and HOEP reflect only the costs for generating electricity as represented in offers submitted by suppliers. MCP and HOEP do not reflect the actual cost of supplying electricity, as the actual costs vary from location to location based on prevailing conditions and physical limitations on the system, e.g., line losses related to proximity to demand, transmission constraints, etc.

In addition, the IESO multiplies supply resources’ submitted ramp rates by 3 when determining MCP and HOEP. This “three-times ramp rate” contributes to price stability by making it more likely that slower, less expensive resources will set the price. However, it further separates MCP and HOEP from the true cost of generating electricity in Ontario, as MCP and HOEP do not reflect the actual generation ramp capabilities of price-setting resources.

2.2.2 The Constrained Schedule

The ’second schedule’, the dispatch or Constrained Schedule, determines the physical dispatch instructions for resources. Unlike the Unconstrained Schedule for pricing, the Constrained Schedule must take all system conditions and operational limitations into account in order to ensure that dispatch instructions are sufficient to maintain reliability. Dispatch cannot be ‘blind’ to system conditions or operational limitations in the way that price setting can be for MCP and HOEP in the Unconstrained Schedule, and so the Constrained Schedule will produce different dispatch instructions than would otherwise have been anticipated based on the Unconstrained Schedule.

By way of example, the Unconstrained Schedule may select and schedule several generators in close proximity because they have the lowest offer prices notwithstanding that there are transmission limits which prevent those generators being contemporaneously dispatched. The transmission system in the local area may, for instance, lack the capacity to transmit all of the scheduled generation from the local generators to supply demand. In that scenario, the Constrained Schedule would constrain-off one or more of the local generators that were economically scheduled in the Unconstrained Schedule and constrain-on other higher-priced generators that were not scheduled, but which are not subject to the same transmission limitations. While reliability is met in this scenario, the result is that the market price set by the pricing/Unconstrained Schedule no longer accurately reflects the actual cost of producing power.

The misalignment of the Unconstrained and Constrained Schedules results in Congestion Management Settlement Credits (**CMSC**) as (described below) to keep the constrained-off and constrained-on generators whole to their offer prices.

2.2.3 Inefficiencies with the Two-Schedule System

The two-schedule system causes reliability challenges and inefficiencies for Ontario.

When price and dispatch are mis-aligned, decisions that make financial sense to market participants may not be efficient or reliable for the market as a whole and, as such, may not be reflected in dispatch instructions. Dispatch instructions may override economic bids and offers and direct suppliers or consumers to supply or consume electricity when doing so would result in lost profits or operating losses. To account for losses in these cases, the current market design includes as an integral feature CMSC payments to address the differences between the two schedules and to compensate suppliers and consumers for losses incurred in following dispatch instructions necessary to maintain reliability.

For instance, when generators that are economically scheduled in the Unconstrained Schedule are constrained-off because of transmission limitations, they are entitled to CMSC payments to compensate them for their lost profit, i.e. the difference between their offer prices and the MCP. Likewise, when generators that are not scheduled in the Unconstrained Schedule because they are uneconomic are constrained-on, they are paid CMSC payments to compensate them for the operating losses they incur by being required to generate at a MCP that is below their offer prices. The larger the divergences between the two schedules, the more CMSC payments are required to reconcile the difference. Greater divergences increase the probability of inefficient outcomes, such as higher costs, complex settlements and opportunities for market participants to game the system.[6]

As reported on by the MSP in their December 2016 report, "no element of Ontario's wholesale electricity markets has attracted the attention and concern of the Market Surveillance Panel (Panel) more than Congestion Management Settlement Credit (CMSC) payments. These payments, a fundamental adjunct of Ontario's uniform price/two schedule market design, have resulted in inefficiencies and inappropriate wealth transfers, and have shown themselves to be susceptible to gaming."[7] In the same report, the MSP stated that "[a]nnual CMSC payments since market opening average $110 million per year with total CMSC payments over the life of the market exceeding $1.5 billion".[8]

CMSC payments are not part of the market price for electricity and are a less transparent means of compensating market participants. They result in inefficient price formation where locational differences are not reflected in the price signal. CMSC payments also cause inefficient production, consumption, and investment decisions, and inefficient allocation of costs to all consumers.

2.3 The Single Schedule Market and Locational Marginal Pricing Amendments

Changes reflecting the introduction of the SSM and LMP are reflected throughout MR *Ch.0.7 - System Operations and Physical Markets* and in MR *Chapter 0.9 – Settlements*.

The Amendments integrate SSM and LMP into the Market Rules through the use of a series of mathematical formulas called calculation engines. The Amendments obligate the IESO to administer the markets using these calculation engines pursuant to prescribed calculation engine formulas.[9] The calculation engine formulas provide the logic to

[6] For an example, see the Market Surveillance Panel's Report on an Investigation into Possible Gaming Behaviour Related to Congestion Management Settlement Credit Payments by Abitibi-Consolidated Company of Canada and Bowater Canadian Forest Products Inc. dated February 2015.
[7] Congestion Payments in Ontario's Wholesale Electricity Market: An Argument for Market Reform, p. 1.
[8] Congestion Payments in Ontario's Wholesale Electricity Market: An Argument for Market Reform, p. 2.
[9] MR Ch.0.7 ss. 4.4.1, 5.4.1, and 6.3.1 and MR Ch.0.7, Apps. 0.7.5, 0.7.5A, and 0.7.6.

determine LMPs for each location in Ontario as well as the market outcome for each market participant, based on a single, security constrained schedule.

The introduction of SSM and LMP will ensure that costs are transparently reflected in prices which in turn will:

- improve the incentives and price signals for dispatch, reducing costs and enabling better decision-making, including better investment decisions as a result of greater transparency into market costs;
- reflect a greater share of system costs (such as transmission congestion) in market prices, eliminating the need for CMSC payments;
- enable resources, including new technologies such as energy storage and demand response, to more actively participate in the market and make more informed decisions when supplying and withdrawing energy; and
- provide valuable information to system planners, potential developers and investors on system conditions and the cost of supplying or consuming power.

The introduction of SSM is also foundational to future market evolution and improvements. As discussed in greater detail below, it will enable and facilitate the implementation of important changes to the energy markets, such as DAM and ERUC, and will pave the way for further market enhancements in the future.

2.4 Impact on Market Participants

2.4.1 Market Participant Suppliers

All market participants supply resources will be settled on the basis of LMP. Paying supply resources a locational energy price that reflects system conditions where they are connected to the grid will provide an incentive for supply resources to submit offers that more accurately reflect their short-run marginal costs. They will be incented to do so in order to ensure their offers are competitive at their specific location on the grid. This, in turn, will result in efficient dispatch, reducing the risk of the system incurring unnecessary long-run operating cost.[10] Supply resources that are accustomed to offering materially above their short-run marginal cost will be incented to adjust their offer strategy.

2.4.2 Market Participant Loads

Locational pricing is also designed to link load customers' energy consumption decisions to actual system conditions. This will provide greater opportunities for load customers to control costs and will result in increased overall operational and economic efficiencies.

2.4.2.1 Dispatchable Loads

All dispatchable load customers will be subject to LMP. Accurate location-based price signals will encourage dispatchable loads to reduce consumption when local prices are high, thereby reducing demand and putting downward pressure on prices in relatively high-priced regions and, ultimately, enabling cost reductions for the responding dispatchable loads and other load customers in the region.

2.4.2.2 Non-Dispatchable Loads and the Ontario Zonal Price

Non-dispatchable load customers do not respond to market prices and thereby do not receive schedules or dispatch instructions in the IESO-administered markets. Locational prices therefore do not apply to non-dispatchable load customers, with the exception of those non-dispatchable load customers that elect to participate as a "price responsive loads" (see section 2.4.2.4 below).

In order to establish an energy price for the settlement of non-dispatchable loads, the Amendments create a single zonal price, called the Ontario Zonal Price, which is calculated as the weighted average of the day-ahead LMPs. Because the Ontario Zonal Price is based in part on the IESO's day-ahead load demand forecast, the IESO adjusts the Ontario Zonal Price to reflect differences between the day-ahead demand forecast and actual demand in real-time using a "Load Forecast Deviation Adjustment". Non-dispatchable load resources are therefore settled on the basis of the Ontario Zonal Price, adjusted by the LDFA.

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[10] Under MRP, operating reserves (standby capacity that allows the IESO to respond to short-term unexpected changes, such as downed transmission lines or generators), will also vary by region to reflect locational constraints.

2.4.2.3 Price Responsive Loads

The Amendments provide market participants currently participating as non-dispatchable loads with the option to more actively participate in the market by electing to be Price Responsive Loads (**PRL**). PRL is a new category of load customer created by the Amendments. PRLs will not be dispatchable but by participating in the DAM, they will be settled on the basis of LMP rather than Ontario Zonal Price. This new participation option provides non-dispatchable loads that elect to be PRLs with the opportunity to better plan their commercial operations and control their costs by knowing what costs they are committed to in advance. It affords them the opportunity to respond to price signals, without being subject to dispatch (and as such, maintaining control of the operation of their facility).

2.4.3 Distribution Connected Load Customers and the Retail Settlement Code

The Amendments will indirectly impact the financial settlement of distribution connected customers pursuant to the OEB's *Retail Settlement Code*, which provides for the settlement of distribution connected customers based on HOEP.[11] The *Retail Settlement Code* will need to be amended to replace references to HOEP with the Ontario Zonal Price. The OEB has initiated a process for making these MRP related changes to the *Retail Settlement Code*.

3. Day-Ahead Market

3.1 Introduction to the Day-Ahead Market

A DAM is a standard component of electricity market design, with almost all North American electricity markets including DAMs within their designs. DAMs provide financially binding schedules for participating resources a day in advance of operation. Typically, most of the supply is scheduled in the DAM and the real-time market is used to balance any deviations that occur between day-ahead and real-time.

As described below, Ontario currently utilizes a non-binding day-ahead commitment process with its two-schedule system instead of a DAM. With the introduction of an SSM in

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[11] The Code references the outdated "Hourly Ontario Energy Settlement Price" of the IESO's predecessor, the Independent Market Operator (IMO).

Ontario, the IESO will be able to implement a DAM, which will enable and encourage all resources to participate more fully and efficiently in the day-ahead timeframe by providing financially binding day-ahead prices and schedules. Improved day-ahead participation will provide the IESO with more operational certainty and market participants with more financial certainty as real-time approaches, enabling improved planning and risk management.

3.2 The IESO's Current Day-Ahead Commitment Process

In the late 1990s when Ontario's electricity markets were being designed, electricity markets were relatively new and DAMs were not yet a common feature as they are today. Although the potential for a DAM was considered prior to market opening, Ontario's electricity markets were launched in 2002 without a day-ahead scheduling process. The need to effectively schedule resources in advance of real-time soon emerged and the IESO began exploring the potential for a DAM in 2003. However, Ontario's unique two-schedule system proved to be a major barrier to implementing a DAM.

As a result, the IESO opted for an alternative solution and introduced the day-ahead commitment process in 2006. The day-ahead commitment process uses a day-ahead calculation engine to optimize energy and operating reserve for the 24 hours of the next day. The day-ahead calculation engine determines the least-cost security-constrained solution for a dispatch day based on the bids and offers submitted by all resources.

- Dispatchable generators submit offers day-ahead if they wish to participate in the next day's real-time market. The offer provides a declaration of the participant's capability and intent to submit offers in real-time. Dispatchable facilities eligible for cost guarantee may receive a commitment schedule day ahead; if they meet that schedule in real-time they will be kept financially whole to their day-ahead offer.

- Dispatchable loads submit bids a day-ahead if they wish to participate in the next day's real-time market as dispatchable resources. Loads that do not submit bids day-ahead may operate in real-time as non-dispatchable.

- Importers and exporters may choose to submit bids and offers day-ahead but are not obligated to do so.
- Self-scheduling and intermittent generation facilities must submit a schedule or forecast that represents their best estimate of what they plan to produce the next day.

While most resources do not receive any form of financial certainty from the day-ahead commitment process, it provides a cost guarantee for non-quick start (**NQS**) resources and an offer price guarantee for importers. Cost guarantees incent these resources to participate by eliminating the risk that they might not recover the costs they have incurred in advance of real-time and before prices are determined.

The introduction of the day-ahead commitment process represented an improvement, but it still has shortcomings, including that not all resources participate fully or efficiently because it is not financially binding. Failure of resources to participate fully or efficiently in the day-ahead commitment process results in an incomplete view of the next day's demand and supply, diminishing the IESO's ability to schedule and commit the lowest-cost set of resources to meet the next day's demand.

3.3 The Day-Ahead Market and its Objectives

The establishment of the DAM is embedded throughout the MRP Amendments, including the establishment of new definitions such as 'day-ahead market'. Appendix 7.5 outlines the mechanical operation of the DAM calculation engine which sets pricing and schedules for the DAM.

A key concept within the DAM is the two-settlement process. Resources that participate in the DAM will receive a financially binding schedule that will have them pay (in the case of consumers) or be paid (in the case of suppliers) for their day-ahead schedule based on their day-ahead LMP. When the quantity that resources produce or consume in real-time differs from their day-ahead schedule, these deviations will be settled (balanced) based on their real-time LMP.

The two-settlement system provides an incentive for resources to participate in the day-ahead timeframe. Resources that participate in the DAM can lock in a DAM price for their DAM schedules and use the real-time market to balance the difference. Greater certainty is realized because market participants will know what their revenues or costs will be if their DAM schedules materialize in the real-time market.

Conceptually, the two-settlement process is based on the following combined outcome of the following equations:

- Day-ahead settlement = Q_{DAM} X $\$_{DAM}$

- Real-time settlement = (Q_{RTM} – Q_{DAM}) X \$ real-time market

- Where,
  - Q_{DAM} = day-ahead market scheduled quantity
  - $\$_{DAM}$ = day-ahead market locational marginal price
  - Q_{RTM} = real-time market scheduled quantity
  - $\$_{RTM}$ = real-time market locational marginal price

Non-dispatchable load customers will not be eligible to participate in the DAM and will be represented in the day-ahead timeframe by the IESO's load forecast which is then "balanced" by the real-time operations of non-dispatchable loads through the load forecast deviation adjustment.

While the DAM incentivizes resources to participate, the efficiency of the DAM is directly tied to the level and accuracy of participation:

- The level of participation depends on the number of resources participating in the DAM as a greater number of resources participating will increase DAM liquidity and help drive a more stable DAM price signal.

- The accuracy of participation depends on how reflective DAM offers and bids are of a resources' expected energy delivery or consumption in the real-time market. For Ontario, the accuracy of IESO's forecast for non-dispatchable load will also be important.

It is expected that, as resources participate in DAM with their best estimates of available supply there will be a price convergence between DAM and the real-time market, resulting in a limited need for real time balancing.

3.4 The Impact of the Day-Ahead Market on Market Participants

3.4.1 Existing Resources

Existing resources that participate in the day-ahead commitment process will benefit from greater financial and operational certainty by locking in schedules and prices in DAM rather than waiting for less predictable schedules and prices in real-time. Financial certainty is created because resources know what their costs and revenues will be if their DAM schedules materialize in the real-time market. Operational certainty is created because a resource can better plan for real-time operations by securing fuel and staff in advance.

3.4.2 New Participation Opportunities

As part of the DAM, the IESO will be expanding the resources that are eligible to set prices by introducing two new participation opportunities – virtual transactions and PRLs – that will support the establishment of efficient price signals in Ontario. Expanding the range of resources that are be eligible to set prices will increase liquidity and enhance competition, which leads to greater discipline and improved day-ahead participation.

Virtual transactions are supply offers and load bids that participate in the DAM but will not deliver or consume physical power in the real-time market. Virtual transactions help to address inefficient scheduling outcomes by providing non-physical resources with an opportunity to compete with physical resources in the DAM. This increases liquidity and reduces the opportunities for market participants to manipulate DAM prices by physically withholding energy from the DAM. Virtual transactions also help align schedules and prices between the DAM and real-time markets by arbitraging predictable price differences between the two markets. Certain resources that are unable to set prices in real-time, such as imports and exports (because they are not dispatchable on a five-minute basis) will be eligible to set prices through the DAM (which schedules on an hourly basis).

To further expand the benefits of the DAM and widen participation, non-dispatchable loads will be given the option to become PRLs – a new category of market participant that will be created as part of the DAM. PRLs will be able to participate directly in the DAM by submitting energy bids but will continue to be non-dispatchable in real-time. The IESO will continue to forecast demand and bid on behalf of non-dispatchable loads that do not choose to become PRLs.

3.4.3 Hydroelectric Resources

Currently, hydroelectric resources that have interdependencies with other resources on the same river system are allowed to revise their offers after initial day-ahead commitment process results are released. This is provided to ensure that hydroelectric resources can deliver on the schedules they receive.

This approach will no longer be feasible under the two-settlement system utilized in the DAM. To enable fair competition and to increase the likelihood that hydroelectric resources receive feasible day-ahead schedules, the Amendments model additional hydroelectric operating characteristics in the day-ahead scheduling process. By better modelling hydroelectric resources' physical constraints, the IESO and market participants will benefit from a more accurate view of the next day's operations.

4. Enhanced Real Time Unit Commitment

4.1 Introduction to Unit Commitment

While a DAM can efficiently schedule resources to meet the following day's expected demand, conditions can and typically do change after the day-ahead scheduling process is complete (e.g., weather conditions or changes in supply from variable generators). Electricity markets require a mechanism to cost-effectively transition from day-ahead scheduling to real-time operations (known as the "pre-dispatch" timeframe). This evaluation addresses deviations between day-ahead and real-time in order to reliably meet real-time demand at the lowest possible cost.

Non-nuclear NQS resources (**NQS resources** or **NQS generators**) require a particular treatment in the pre-dispatch process due to their financial and operational characteristics. These resources incur three types of costs – the cost of providing energy (**energy costs**), the cost of starting up to be available to provide energy (**start-up costs**), and the cost of remaining connected to the IESO-controlled grid while generating net zero active power (**speed no-load costs**). In addition, once started, NQS resources must continue to generate a certain amount of power for a minimum period of time prior to shutting down so as to avoid damaging their equipment.

Without the appropriate market design, NQS resources may not make themselves available until they are certain they will be able to recover their costs in the real-time market. To address this issue, the IESO activates NQS generators using a process called unit commitment.[12] A unit commitment is an agreement between the IESO and an NQS generator, made in advance of real-time, that the NQS generator will run during specific hours in exchange for operational and financial guarantees.

The IESO's current pre-dispatch commitment decisions are based solely on NQS resources' energy costs and do not optimize NQS resources' costs across multiple hours. This means an NQS resource with lower energy costs, but higher overall costs, may be committed instead of a resource with lower total costs. As detailed below, the ERUC process will extend the use of three-part offers – consisting of offers for energy costs, start-up costs and speed no-load costs – into the pre-dispatch unit commitment process. The result will be pre-dispatch schedules and unit commitments that better reflect the total cost of NQS resource supply and that are based on a longer, more efficient optimization timeframe.

4.2 The IESO's Current Unit Commitment Process

A unit commitment process in pre-dispatch was not included in the province's electricity markets at opening because real-time energy prices were expected to offer sufficient

[12] Non-nuclear NQS generators are the only resources that receive commitments, including the cost recovery guarantee. Quick-start generators, nuclear generators, intertie traders, and dispatchable loads do not receive commitments from the IESO nor does the IESO guarantee that those resources will recover their costs.

incentive to ensure that resources would be online when needed. However, as Ontario's generation mix evolved to include more NQS resources, it became apparent that this approach would no longer suffice. To better integrate NQS resources, the IESO introduced a unit commitment process and accompanying financial guarantee in 2003. The program has evolved over time and is known today as the Real-Time Generation Cost Guarantee (**RT-GCG**) program.

As part of the RT-GCG commitment process, the IESO makes two guarantees to the NQS generator:

- *Operational guarantee* – The IESO guarantees that it will schedule the NQS generator to run in a way that respects its operational characteristics. This includes ensuring that the NQS generator will run for at least the minimum amount of time that it can run without damaging its equipment during shutdown and to at least the minimum level of electricity generation necessary for it to avoid damaging its equipment, among other operating requirements.

- *Financial guarantee* – The IESO guarantees that NQS generators recoup their costs for committed runs. Where the NQS generator's market revenue is insufficient to recover its costs, the IESO pays the NQS generator a top-up payment.

In return for these two guarantees, the IESO receives operational certainty in advance that committed NQS generators will be available to satisfy demand on the IESO-controlled grid.[13]

Currently, the IESO's commitment process differs depending on when the IESO commits the NQS resource. The IESO may commit NQS resources during two separate timeframes:

[13] Commitment must be distinguished from scheduling. Scheduling is the process by which the IESO determines the generation output or withdrawal consumption of all dispatchable resources on the IESO-controlled grid for every five-minute interval of the day. For NQS resources, the commitment represents a minimum potential schedule – the IESO must schedule a committed NQS resource for at least its minimum run time and to at least its minimum generation output. However, the IESO may schedule NQS resources for longer time periods and higher generation outputs, if the resources are economic for more than just their commitments.

- the day-ahead timeframe, which starts at 10:00 AM on the day before real-time and ends no later than 3:00 PM that same day; and
- the pre-dispatch timeframe, which is the period in between the day-ahead timeframe and real-time.

During the day-ahead timeframe, the IESO commits NQS resources using the day-ahead commitment process. NQS resources submit three-part offers – consisting of offers for energy costs, start-up costs and speed no-load costs – to the IESO for use in the day-ahead commitment process. The day-ahead commitment process uses three-part offers to optimize NQS resources' total costs when committing NQS resources in the day-ahead timeframe. Subject to commitments made for reliability, this is intended to ensure that the day-ahead commitment process commits the most economic NQS resources based on total costs.

However, the IESO is currently unable to achieve the most economic commitment of NQS resources during the pre-dispatch timeframe due to two key limitations in its current process. The first limitation is that the IESO is unable to account for NQS resources' total costs based on the three-part offers in the pre-dispatch process. As a result, the IESO commits NQS resources based on energy costs alone, while start-up and speed-no-load costs are not taken into account. This means that the IESO may commit an NQS resource with lower energy costs but higher overall costs instead of a resource with lower total costs.

The second limitation is that the IESO evaluates costs in the pre-dispatch process separately for each hour, without considering the minimum level of output that NQS resources must provide and the minimum amount of time they must generate electricity. This results in inefficient scheduling decisions as the IESO only considers the following hour, one hour at a time. For example, the IESO may dispatch a resource that has lower costs over a particular hour, even though it has a higher cost overall because it must continue to generate electricity for a longer period of time. These limitations are both inefficient and disadvantageous to lower cost NQS resources, which may be overlooked for commitment in favour of more expensive competitors.

These two limitations impact the way that the IESO compensates NQS resources under the cost guarantee. Currently, the IESO guarantees NQS resources' costs for commitments made during the pre-dispatch timeframe using the RT-GCG. Since the IESO commits NQS resources in the pre-dispatch timeframe based solely on energy offers without considering three-part offer start-up costs and speed no-load costs, payments under the RT-GCG program are not based on a competitive evaluation of offers. Instead, the RT-GCG program guarantees eligible costs based on values that the IESO has pre-approved for each NQS resource. Under the RT-GCG program, where an NQS resource's market revenue is insufficient to recover its eligible pre-approved costs, the IESO pays the NQS generator an amount equal to the unrecovered costs.

The MSP has repeatedly criticized the limitations of the IESO's process for committing NQS resources during the pre-dispatch timeframe and the RT-GCG program. The MSP has published numerous reports criticizing these and other aspects of the IESO's unit commitment process, including in 2010, 2014, 2016, and as recently as 2024.[14] Furthermore, the Auditor General of Ontario criticized the inefficiency of the IESO's commitment decisions, among other aspects of the unit commitment process, in its 2017 IESO Oversight Report.[15] The Auditor General stated in its 2017 Oversight Report that the GCG Program "allows gas generators to operate their equipment inefficiently costing ratepayers more than necessary" and that "the IESO continues to pay gas generators about $30 million more per year than necessary despite the OEB [Market Surveillance] Panel recommending that the IESO scale back its [GCG] Program".[16]

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[14] See Monitoring Report on the IESO-Administered Electricity Markets for the period from November 2009 – April 2010, Ontario Energy Board Market Surveillance Panel, dated August 2010; Monitoring Report on the IESO-Administered Electricity Markets for the period from May 2013 – October 2013, Ontario Energy Board Market Surveillance Panel, dated September 2014; Congestion Payments in Ontario's Wholesale Electricity Market: An Argument for Market Reform, Ontario Energy Board Market Surveillance Panel, dated December 2016; and State of the Market Report 2023, Ontario Energy Board Market Surveillance Panel, dated September 2024.

[15] 2017 IESO Oversight Report.

[16] 2017 IESO Oversight Report, p. 329.

4.3 The Enhanced Real Time Unit Commitment and its Objectives

With the introduction of ERUC, the IESO is seeking to improve the efficiency of commitments by addressing the two key limitations in the IESO's commitment process during the pre-dispatch timeframe discussed above.

To achieve this objective, ERUC extends the use of three-part offers and multi-hour optimization into the pre-dispatch timeframe when selecting NQS resources for commitment. As discussed above, the DAM will produce financially binding day-ahead schedules for all participants; for NQS resources, those schedules will be based on three-part-offers. If a NQS resource is scheduled in the DAM, the resulting day-ahead commitments will be transferred to ERUC. ERUC will then make additional scheduling and unit commitment decisions to address any deviations between DAM and real-time, ensuring reliability is maintained cost-effectively.

The introduction of ERUC will result in a more efficient dispatch, as commitments selected during the pre-dispatch timeframe will reflect NQS resources' total costs optimized over the pre-dispatch timeframe, instead of simply relying on the incremental costs found in energy offer prices for the next hour. ERUC will ensure that the most cost-effective set of resources will be available to meet demand in real-time when changes in system needs arise in the pre-dispatch time frame. Considering all these costs will increase transparency and competition within the commitment process and result in lower costs for consumers.

ERUC's integration of full three-part offer costs into the IESO's commitment decisions during the pre-dispatch timeframe will allow the IESO to compensate NQS resources based on these costs. Consequently, the Amendments eliminate the RT-GCG program and replace it with a new mechanism for guaranteeing NQS generator costs called the Real-Time Generator Offer Guarantee (**RT-GOG**). Under the new RT-GOG program, the IESO guarantees NQS resources their as-offered costs, as included in the start-up and speed no-load components of their three-part offers. Cost guarantee payments will typically be made if revenues earned are less than the costs incurred. Where market revenues exceed these costs, NQS generators are entitled to retain the net profit.

4.4 The Impact of the New Unit Commitment Process on Market Participants

With the introduction of ERUC, NQS resources will be committed economically based on their total costs. As no other types of resources receive commitments, the competition for commitments will be *among* NQS resources, not between NQS resources and other resources. This creates a competitive, market-based approach to committing NQS resources, allowing more efficient NQS generators to offer lower guaranteed costs and giving those resources a competitive position that reflects the efficiency of their operations compared to other NQS generators. Lower cost NQS resources will no longer be overlooked in favour of more expensive competitors due to limitations in the IESO's process.

All other market participants will benefit from reduced costs and improved efficiency as the ERUC will allow the IESO to more accurately select the most economic NQS resources for commitment.

5. Market Power Mitigation

5.1 Introduction to Market Power Mitigation

A market thrives when there is open and fair competition among many resources. Competition is unfair when market participants exercise "market power" by either economically or physically withholding energy from the market to increase the price. Economic withholding occurs when a portion of, or all, available supply is offered at prices significantly higher than short-run marginal costs and those higher offers raise prices as a result. Physical withholding occurs when a portion of, or all, available capacity is not offered into the market and prices are higher as a result.

The IESO has had a framework to address the potential exercise of market power since market opening. Under the current system, however, market power mitigation is carried out after the exercise of market power occurs. With the alignment of price and dispatch under the SSM, after-the-fact mitigation alone will no longer be viable. Instead, under the Amendments, the IESO will move to an approach that mitigates economic withholding before it occurs – a shift that prevents market participants from using market power to affect dispatch schedules and market prices. This approach is in keeping with that used by other North American system operators.

5.2 The Current Market Power Mitigation Rules

Currently, market power mitigation for economic withholding is performed after the withholding has occurred.

Circumstances can arise on the IESO-controlled grid in which a transmission constraint or security limit necessitates the constrained dispatch of a resource. The local nature of the transmission constraint, coupled with a lack of resources competing to provide the required physical service, can give rise to conditions of local market power. In such cases, market participants may receive excessive CMSC payments.

The Market Rules provide the IESO with the authority to mitigate the effects of excessive CMSC payments resulting from instances of local market power or related conditions by authorizing it to adjust CMSC payments. This adjustment of CMSC is intended to return the profit level to that which the market participant would have earned had their resource not been constrained. In determining whether local market power existed at a given time for a given resource, the IESO conducts three screens followed by a price investigation if market power is determined to exist.

The price investigation process determines whether the investigated price is consistent with the resource's underlying marginal cost or benefit, depending on the resource type. For energy limited resources, opportunity costs are also considered. During the price investigation process, market participants can make representations regarding CMSC recalculations or propose an alternate settlement price. If the IESO believes the investigated price or alternate price proposed by a market participant is inconsistent with the participant's underlying marginal cost or benefit, the IESO has the authority to recalculate CMSC.

In addition, constrained-off events that occur in a designated Constrained-off Watch Zone are subject to review under the Constrained-off Watch Zone framework. A zone is designated as a Constrained-off Watch Zone when resources in that area are regularly constrained off. Such conditions provide participants with the opportunity to receive excessive CMSC payments. To mitigate such payments, the IESO developed the Constrained-off Watch Zone framework, wherein resources found to receive persistent and significant constrained-off CMSC may be subject to a CMSC recalculation. Similar to the CMSC recalculation under local market power, the IESO will recalculate CMSC under the Constrained-off Watch Zone framework if it determines that the investigated offer/bid price is inconsistent with the resource's underlying cost or benefit. While similar in objective to the local market power process, the Constrained-off Watch Zone framework does not require the IESO to establish the existence of local market power in reference to the three screens.

5.3 The Market Power Mitigation Amendments

The objective of the MPM Framework in the future day-ahead and real-time markets is to help ensure efficient scheduling and pricing outcomes. Dispatchable resources that act as suppliers of a product will be tested for market power in the supply of that product.

MRP will replace the regime described above with (i) an ex-ante framework to assess economic withholding and withholding with respect to certain settlement amounts, and (ii) an ex-post framework to assess physical withholding.

Although their implementation differs, the ex-ante and ex-post frameworks share the same general approach to assessment of withholding:

- Check whether competition is or was restricted in an area and determine the resources in that area.
- If competition was restricted, check whether each identified resource's submitted dispatch data was outside of the applicable threshold (the "conduct test").
- If competition was restricted and a resource's dispatch was outside the applicable threshold (i.e., it failed the conduct test), check whether prices were higher than they would have been if there had been competitive conditions (the "impact test").

- If the prices were outside the specified threshold (i.e., the tested resource failed the impact test), the resource is mitigated.

The initiation of conduct and impact tests is based on the specific grid conditions corresponding to the area on the grid where a resource is located. When an area of the grid is unable to be supplied by additional resources, competition is reduced and this creates the potential for the exercise of market power by suppliers in that constrained area.

In general, the conduct and impact test thresholds are more relaxed in areas with significant competition and tighter in areas where competition is restricted. To determine whether submitted dispatch data was outside applicable thresholds, each resource must have estimates of the dispatch data parameters that the resource would have submitted if it were operating under competitive conditions. These estimates are called “reference levels” and “reference quantities” and are established in consultation with the market participant for a resource.

The ex-ante and ex-post mitigation frameworks are described in further detail below.

5.3.1 Ex-ante mitigation: Economic withholding

The IESO’s calculation engines mitigate economic withholding as part of the scheduling and dispatch processes in the day-ahead and pre-dispatch time frames to prevent offers that are unfairly high from affecting dispatch schedules and increasing market prices.

The conduct test will determine if select dispatch data values submitted by a market participant for a resource differ from that resource’s reference levels by more than the applicable threshold. If all tested dispatch data parameters for a resource pass the conduct test, no mitigation will be applied to that resource. If one or more dispatch data value for any resource fails the conduct test, the impact test will be conducted.

The calculation engines will compare “as-offered results” and “reference levels results” when applying impact tests. “As-offered results” are calculated using the prices and schedules that are determined using dispatch data values submitted by market participants. “Reference level results” are calculated using the prices and schedules that would have occurred had each dispatch data value that failed the conduct test been substituted with its respective reference level. The impact test compares the as-offered results to the reference level results. The impact test is failed if the prices in the as-offered results are greater than those in the reference level results by a specified impact threshold.

If the impact test is failed, each dispatch data value that failed the conduct test is substituted with the applicable reference level and schedules and prices are determined using the reference levels in place of the as-offered dispatch data.

5.3.2 Ex-ante mitigation: Mitigation of certain settlement amounts

The IESO will also perform ‘settlement mitigation’ for certain settlement amounts (i.e., day-ahead market make whole payment, day-ahead generator offer guarantee, real-time make whole payment, real-time generator offer guarantee, and the real-time ramp down settlement amount) as part of the settlement process.

For any resource that fails both ex-ante conduct and price impact tests, relevant dispatch data values will be substituted with values based on the resource’s corresponding reference levels.

The settlement impact test will compare the outcomes that were determined using the dispatch data used by the calculation engines and the settlement outcomes that would have occurred based on the reference levels. If the reference level settlement outcomes are less than the dispatch data settlements outcome by more than the relevant threshold, the reference level settlement outcomes will apply.

5.3.3 Ex-post mitigation: Physical withholding

Mitigation of physical withholding will also involve conduct and impact tests to assess withholding but differs from the ex-ante process for mitigating economic withholding in that: (i) the process uses reference quantities, instead of reference levels, in the conduct and impact tests; and (ii) because physical withholding is assessed ex-post, offer quantities will not be changed before market prices and schedules are determined. As a result, the IESO will run market simulations to determine simulated as-offered results and reference quantity results for use in the impact test.

As with the ex-ante framework, the ex-post conduct test will determine if offered quantities were significantly lower than what would have been offered under competitive conditions. The impact test will compare simulated as-offered results to simulated reference quantity results to determine if prices would have been significantly lower had the withheld quantities been offered into the market. If a market participant fails both the conduct and impact tests, then the market participant will be subject to a settlement charge.

5.4 Expected Impacts on Market Participants

5.4.1 Market Participant Load Customers

The IESO expects that the market power mitigation framework will result in more efficient scheduling and pricing outcomes by reducing the ability of market participants with market power to artificially increase prices.

5.4.2 Dispatchable Market Participant Suppliers

Market participants with dispatchable resources that are accustomed to offering significantly above their resources' short-run marginal costs may have to adjust their offer strategies accordingly or risk being mitigated.