Minutes of the IESO Technical Panel Meeting

Meeting date: December 2, 2025
Meeting time: 9:00 a.m. – 10:06 a.m.
Meeting location: Virtual

Chair/Sponsor: Michael Lyle

Scribe: Trisha Hickson, IESO

Please report any suggested comments/edits by email to engagement@ieso.ca.

Invitees	Representing	Attendance Status Attended, Regrets
Jason Chee-Aloy	Renewable Generators	Attended
Rob Coulbeck	Importers/Exporters	Attended
Dave Forsyth	Market Participant Consumers	Attended
Jennifer Jayapalan	Energy Storage	Regrets
Forrest Pengra	Residential Consumers	Attended
Robert Reinmuller	Transmitters	Regrets
Vlad Urukov	Market Participant Generators	Attended
Michael Pohlod	Demand Response	Attended
Matthew China	Energy Related Businesses and Service	Regrets
David Short	IESO	Attended
Michael Lyle	Chair	Attended
Secretariat		
Trisha Hickson	IESO	Attended

IESO Presenters/Attendees	
Presenters:	**Attendees:**
Karen Backman	Jo Chung
Megan Cairns	Darren Byers

Agenda Item 1: Introduction and Administration

Trisha Hickson, IESO, welcomed everyone joining the meeting.

The meeting agenda was approved on a motion by Dave Forsyth.

The October 7 meeting minutes, (pending the action item, noted by Vlad Urukov, for the IESO to follow-up with the panel on the market manual process) were approved on a motion by Vlad Urukov.

Introductory Remarks from the Chair:

Michael Lyle, Chair welcomed everyone and noted one update for the panel stating that the IESO will be commencing interviews to fill Technical Panel vacancies early in the new year, in an effort to onboard new members by the March IESO Board cycle.

Agenda Item 2: Engagement Update

Ms. Hickson provided an update on the prospective schedule which is posted on the Technical Panel webpage and identified upcoming sessions as part of the IESO December Engagement Days and encouraged panel members and observers to attend.

Agenda Item 3: Adjustments to Real-Time Make-Whole Payments

Karen Backman, Supervisor of Market Development, provided an overview of the Adjustments to Real-Time Make-Whole Payments for Technical Panel education. Ms. Backman noted that the renewed market has been operating for over six months and is moving into steady-state operations. While extensive pre-launch testing was done, it did not cover all scenarios. Since launch, ongoing monitoring has revealed a few cases where real-time make-whole payments for operating reserves were incorrectly applied, adding unnecessary costs for ratepayers. Ms. Backman added that presentation will include a review of make-whole payments and economic operating points (EOPs), explain three identified issues causing incorrect payments, mainly during high-price or tight supply conditions, and summarize proposed changes, stakeholder feedback, and next steps.

The presentation can be found on the Technical Panel website.

- Mr. Urukov asked if the presentation included stakeholder comments submitted through the engagement to the IESO?

Ms. Backman replied that stakeholder comments are included, but as the deadline recently passed, some are still being processed by the IESO.

- Mr. Urukov, in relation to slide 3, asked how the IESO arrives at the determination that something is unwarranted and what is the test?

Ms. Backman noted that when the IESO undertook monitoring, specific cases were identified where market participants were receiving both lost cost and lost opportunity cost make whole payments when they were dispatched manually for reliability reasons. The IESO determined that these were duplicated payments. Therefore, unwarranted make whole payments refers to a Market Participant receiving duplicate payments.

- Mr. Urukov clarified his understanding that duplicate in this instance means a market participant should not be paid twice for the same MWs. Mr. Urukov asked what happens in the other two circumstances mentioned?

Ms. Backman indicated that one of the principles the IESO follows to establish if payments are warranted is based on whether make whole payments are reflecting an outcome that is physically feasible. Another principle is related to co-optimization of energy and operating reserve, where make whole payments should co-optimize in the same way as the DSO dispatch is co-optimized.

- Mr. Urukov acknowledged these points.

Ms. Backman indicated that the IESO will be making targeted corrections to market rules and manuals and that these will be identified during the presentation. She indicated that make whole payments are a mechanism to ensure resources can follow dispatch instructions without incurring financial losses.

- Mr. Urukov, referencing slide 4 (Make-Whole Payments), asked for clarification on the point stated in the slide that "schedules and corresponding locational marginal prices (LMPs) are more aligned than on the legacy market". He indicated this was difficult to follow given LMPs were only introduced in the new market. He questioned whether this implies that there is better alignment between LMP and schedules now compared to shadow prices and schedules in the legacy market.

Ms. Backman explained that the comparison is to the legacy market's unconstrained and constrained runs, where scheduling came from the constrained run, which then formed the uniform Ontario HOEP. Ms. Backman added that dispatch schedules may still differ from prices due to manual reliability actions or differences between scheduling and pricing passes. Make-whole payments are calculated using economic operating points, representing what a resource could have achieved under actual market conditions, and that these calculations must reflect physical capability and co-optimization of energy and operating reserve.

- Mr. Urukov acknowledged and asked whether on slide 5 (Make-Whole Payments in the Renewed Market), the bullet points outlining reasons for dispatch schedules to not be aligned with prices was an exhaustive list, as he recalled that MIO (multi-interval optimization), was possibly another reason.

Ms. Backman noted that these are largely the biggest categories of actions that may cause dispatch schedules to not to align to prices.

- Mr. Urukov asked, if MIO in joint optimization itself lead to differences?

Ms. Backman noted that yes, due to the way the optimization works.

- Mr. Urukov added, to clarify for the record these are two examples and possibly they are vast majority of cases, but there are other reasons why they could be divergent.

Megan Cairns, IESO, noted that most issues would likely fall under the second bullet *(scheduling pass/pricing pass differences)*, which is the scheduling to pricing pass differences because that is in every engine. If there are problems with joint optimization or issues with a schedule versus the LMP, that would fall under this point.

- Mr. Urukov clarified that there are several reasons why there could be differences between the scheduling pass and the pricing pass, one of which could be MIO, and ramp rates could be another, and that there are a number of idiosyncrasies within the dispatch engines that can cause this misalignment between prices and schedules.

Ms. Cairns noted that there are two buckets, the first being manual out of market actions that a control room operator may have taken to ensure reliability and the second one is scheduling/pricing pass differences within the engines.

Ms. Backman continued reviewing slide 6 on Economic Operating Points, which represent the output a resource could achieve based on offers, physical limits and prices. They serve as a reference point in calculating make whole payments.

- Mr. Urukov asked when you calculate EOP for energy and the three reserves, is that calculation itself subject to some type of joint optimization?

Ms. Backman noted that the EOP calculation engine is a separate engine from the DSO but that the intent is to co-optimize in the EOP calculation engine to arrive at that same co-optimized result had there not been any manual reliability dispatches. Ms. Backman clarified that the EOP is intended to reflect co-optimization, and that this is the third issue that is being addressed in the amendment.

- Mr. Urukov acknowledged these points.

Ms. Cairns clarified that the EOP engine does co-optimize, however the formulas for the MWPs which is the third change, do not co-optimize because they do not take out profit earned from the market and therefore there is double recovery. The actual value that you would receive from the EOP engine would consider co-optimization, it's the payment side that does not offset against the profit already made.

Ms. Backman proceeded to introduce the three specific items outlined on slide 9 that have been identified where make whole payments are being incorrectly calculated. The first item relates to the forbidden regions of hydro generators; dispatch schedules from the Dispatch Scheduling Optimizer account for these regions but the EOPs for make-whole payments do not, resulting in make whole payments based on physically impossible operating points.

- Mr. Urukov referencing slide 11 (Item 1 Overview: LOC and Forbidden Regions), noted that there was a detailed presentation on forbidden regions presented by the IESO on August 25th, 2022, and asked why this is being discussed now and why was it not brought up in those previous discussions.

Ms. Backman noted these are issues that the IESO would have had to have known about in advance to test for these issues.

- Mr. Urukov added that his understanding was that this was different because this is something that should have been applied to OR as it is applied to energy. Mr. Urukov asked why this was not discussed during the detailed design stage, or was it talked about and disregarded?

Ms. Backman noted that she is not aware of the specific conversations but noted that it was likely discussed. Ms. Backman added that she is unaware if this specific condition where energy falls within a forbidden region making the OR infeasible was carved out.

- Mr. Urukov asked whether when we talk about the feasibility of OR, we are contemplating the activation aspect of it as a market participant is not operating within that region but rather are standing by with the possibility of being asked to go to that region. He asked for clarity on whether when activated, the feasibility relates to the activation aspect. Ms. Backman noted that if it was activated, it would be infeasible and added that it also applies to the standby as a resource cannot be on standby if it is not feasible.

Ms. Cairns noted that for the EOP engine, when we say infeasible, especially regarding OR, when compared to the DSO, the DSO has rules where the energy schedule cannot be within the forbidden region. Therefore, the OR schedule would account for that limitation, and it would follow suit. The EOP engine does not have that rule so if it puts all those megawatts into OR and energy falls within the forbidden region. Ms. Cairns added the IESO is stating that portion is an infeasible schedule for OR as the DSO would not have the logic to activate that energy and a resource cannot operate in energy within its forbidden region. Ms. Cairns added this is where it is stemming from, the energy schedule, but then it shifts into the OR side when those megawatts move from the energy DSO schedule into the OR schedule in the EOP.

- Mr. Urukov acknowledged and noted the example would have been very helpful.
- Rob Coulbeck, Nexus Energy, asked for confirmation that if a resource is scheduled such as a hydroelectric resource, for zero megawatts, and it has a forbidden region of zero to 100, that it would not be schedule for OR within that zero to 100. Mr. Coulbeck added, so if the energy schedule is zero could that resource be scheduled for 50MW of operating reserve or is that infeasible and therefore not happening?

Ms. Backman noted that would be an infeasible outcome.

- Mr. Coulbeck noted, so in the current market, that resource, because it was infeasible, would result in a lost cost make whole payment, potentially.

Ms. Backman stated they should not receive a lost cost to make whole payment if it lands within their forbidden region.

- Mr. Coulbeck acknowledged this point.
- Mr. Urukov asked in the application of a forbidden region related to a make-whole payment adjustment, if the FROP is taken away from the initial MWP calculation for OR, as in the case for energy.

Ms. Cairns noted it would be the same FROP at the end of the equation on the OR side, subject to some caveats relating to the different classes of OR.

- Mr. Urukov noted on slide 19 (Item 3 Overview: RT-MWP Not Offsetting Amongst Energy and OR Products), if EOP is jointly optimized to come up with scheduling that respects joint constraints, can the IESO explain what is unwarranted? Is it for the same MW paid for energy and OR?

Ms. Backman noted that is it ignoring the revenue that was already made on the OR schedule and not subtracting what was already earned. It is looking at the EOP and assuming the full 100MW were eligible for MWPs.

- Mr. Urukov asked if EOP is being jointly optimized, why are revenues from the different products being removed?

Ms. Cairns clarified, the LOC EOP is co-optimized. Since it is going higher than the DSO, it requires a cap. The LOC EOP is co-optimized, but on the MWP side, the calculation is paying for the same megawatts twice, once for 10S OR and then again for energy. For example, if a resource has a capacity of 100 MW and the DSO schedule applies a reliability constraint that limits energy to 30 MW, with OR taking the remaining 70 MW, then at EOP, energy might be the most economic option for all 100 MW. Ms. Cairns added that since the resource already earned revenue for 70 MW through OR (even though it was not the most optimal allocation), that revenue must be subtracted when calculating the MWP. This ensures the resource is made whole to its most optimal schedule, which would have been 100 MW in energy.

- Mr. Urukov noted that examples would be helpful for the next discussion and added that he is following the explanation to some extent but finds it unclear whether actual OR revenues from the market or all OR revenues are being removed from the MWP calculation for OR.

Ms. Cairns noted that it applies only to the MWP calculation. All revenues earned in the market remain intact. The adjustment is made within the MWP to avoid double payment. For example, with energy alone, the calculation compares your market schedule and revenue against what you should earn based on your EOP, then subtracts the difference. This is done for each individual product. However, because the process is jointly optimized, it now also needs to compare across products. For instance, if energy and OR were jointly optimized, and the resource earned revenue in OR but should have been fully scheduled in energy, the MWP will only cover what you should have earned in energy, not energy plus OR.

- Mr. Coulbeck clarified that the sum of all settlements should never exceed the resource's total capacity. Using the 100 MW example, the combined total of energy settlement, OR settlement, and any make-whole payments should not surpass 100 MW. The principle is that a resource should never receive payment for more than its actual capacity, regardless of how the payments are structured. While the discussion focused on energy and operating reserve, does this also apply to other OR products? For instance, if a resource can provide 50 MW of operating reserve and is scheduled across 10-minute spin, 30-minute reserve, and lost opportunity cost, the sum of those should still equal 50 MW. Yet, make-whole payments may still occur in such cases. Mr. Coulbeck added that he has observed this scenario and wanted to confirm whether this change addresses that situation.

Ms. Cairns acknowledged and confirmed Mr. Coulbeck's understanding.

Ms. Backman added, energy and OR are co-optimized in scheduling, but the settlement of make-whole payments does not currently reflect that, which results in overpayment. In some cases, the same MW are paid once in the market for one product and again through a make-whole payment for another product. To address this, market rules and manuals will be updated to clarify offsetting logic and ensure settlement systems net payments correctly, preventing duplicate payments.

- Mr. Urukov asked for confirmation that the IESO would not change the EOP calculation itself but have a downstream process which matches to the feasible 100 MW in our example and offsets revenues. Which revenues will be subtracted first? For example, if a resource receives multiple MWPs for the same MW, perhaps one for energy and another for OR, how will you determine which revenue to offset, given that energy and OR may have different values?

Ms. Backman noted that the settlement system will review the revenue earned in the market for OR and energy and subtract those amounts from what the EOP calculation produces.

Ms. Cairns added that current real-time eligibility rules state that a resource is not eligible for a real-time make-whole payment if its DSO schedule is above its EOP. That rule will be updated to clarify that a resource is not eligible for a positive real-time make-whole payment in that scenario because it is not a true lost opportunity. This change allows the calculation to include negative adjustments where revenue was already earned in the market (e.g., OR). These amounts will be subtracted from the total MWP so that the resource is made whole to its most optimal schedule only for its 100 MW capacity. Without this subtraction, the resource could effectively be paid for 170 MW (100 in energy plus 70 in OR), which is not acceptable.

- Mr. Urukov asked whether most optimal refers to the highest paying amount?

Ms. Cairns confirmed, the calculation ensures the resource earns its most optimal 100 MW, with any OR or other product revenues subtracted so the total remains at 100 MW and not more.

- Mr. Urukov, referencing slide 24 (Summary of Stakeholder Feedback – Nov 21st), stated that given the complexity of EOP and these changes, which do not simplify the process, he believes that if participants have questions, they will likely arise only after reviewing the equations and examples. He asked, from a scheduling perspective, when the next stakeholder engagement session will occur in relation to the next technical panel meeting. He emphasized the importance of ensuring that the stakeholder community has the opportunity to provide input beforehand.

Ms. Backman responded that engagement with stakeholders will continue in December and will include examples and the redlined market rule and market manual changes.

Other Business

No other business was brought forward.

Adjournment

The meeting adjourned at 10:06 a.m.

The next regular TP meeting will be held on January 13, 2026.

Action Item Summary

Date	Action	Status	Comments
Oct. 7, 2025	The IESO to report back to the Technical Panel on possible changes to enhance the market manual	Open	

process once the assessment
is complete.