Minutes of the IESO Technical Panel Meeting

Meeting date: January 10, 2026
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	Regrets
Rob Coulbeck	Importers/Exporters	Attended
Dave Forsyth	Market Participant Consumers	Attended
Jennifer Jayapalan	Energy Storage	Attended
Forrest Pengra	Residential Consumers	Attended
Robert Reinmuller	Transmitters	Attended
Vlad Urukov	Market Participant Generators	Attended
Michael Pohlod	Demand Response	Attended
Matthew China	Energy Related Businesses and Service	Attended
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
Johnathan Paredes	

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.

It was noted that the December 2nd meeting minutes would be brought for approval at the next meeting, scheduled for February 10th, 2026.

Introductory Remarks from the Chair:

Michael Lyle, Chair welcomed everyone and noted one update for the panel stating that the IESO has commenced interviews with prospective new panel members. Mr. Lyle noted that he anticipates new appointments by mid-March.

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 January Engagement Days and encouraged panel members and observers to attend.

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

Karen Backman, IESO opened the presentation outlining that the discussion would be structured in two parts: a review of the December 16 stakeholder engagement materials, including examples of the proposed changes, followed by a walkthrough of a supplementary deck containing responses to questions submitted late last week from Technical Panel member, Vlad Urukov, OPG. The supplementary deck would be made available following the meeting. This deck also includes two minor updates to the posted rule language, one clarification based on Mr. Urukov's feedback and another arising from some further testing. These updates will be incorporated into the amendment package before posting for stakeholder review, and all submitted questions and responses will be posted in advance of the February Technical Panel meeting. Ms. Backman recapped that, since Market Renewal's launch in May, three specific issues involving energy and operating reserve interactions have led to incorrect make whole calculations; the proposed adjustments aim to align settlement formulas and Economic Operating Point (EOP) calculations with physical feasibility and co-optimization logic in some specific and limited cases. The pricing and scheduling from the Dispatch Scheduling and Optimization (DSO) algorithm remains correct. Ms. Backman introduced Johnathan Paredes and Megan Cairns who would walk through the detailed examples.

Mr. Parades began by explaining how some hydroelectric resources can submit a 'forbidden region' which are output levels that they cannot maintain on a steady basis. The make-whole payment structure reflects these forbidden regions in their calculations for energy, but does not do so for operating reserve, creating situations where the IESO is compensating hydroelectric generators for output levels that are physically not possible. Mr. Parades outlined this by pointing to the graphic on slide 7 of the presentation.

The presentation and associated materials is available on the [Technical Panel webpage](#).

- Mr. Urukov noted in reference to slide 8, that the scenario involving outputs of 5 and 35 MW is not valid, referring to an earlier point made that the DSO can only ramp through such values, not remain at them. Mr. Urukov sought clarification that the DSO could technically produce this outcome in a hypothetical situation where the ramp rate is extremely slow but noted that was probably not realistic and that the DSO would not stay at those output levels.

Mr. Paredes confirmed Mr. Urukov's statement and explained that the resource cannot remain at a constant output of 5MW, nor can the DSO schedule energy at exactly 5 MW on a continuous basis. The only way it could be at 5 MW is if it were temporarily passing through that level while ramping up or down. However, he stated that for the purposes of this example, the assumption is that the resource is already operating in a steady state. With that assumption, we can ignore any ramping requirements and continue the example based on a stable operating point.

- Dave Forsyth, AMPCO asked what the DSO initially considered or additionally considered in this scenario. Specifically, he questioned whether the DSO evaluated taking the energy down to 1MW and moving the 10-S unit up to 35 MW, given the lower cost on the 10-S side. He also asked whether the DSO would have selected that option or whether it automatically defaults to scheduling energy at 20 MW instead.

Mr. Paredes explained that while the DSO aims to make the most economic decision, it must do so within the constraints of the forbidden region. He emphasized that the 20 MW energy and 20 MW 10S outcome is not the only feasible solution, it is simply the one chosen for the purposes of illustrating this example.

- Mr. Forsyth acknowledged this point.

- Mr. Urukov asked whether, if the 10-S offer increased to 40 MW at $1.00, the Economic Operating Point (EOP) schedule would then shift to 0 and 40 MW.

Mr. Paredes confirmed that yes, if the 10-S offer increased and was not capped, and if it remained the most economic option, then the EOP would indeed produce that outcome.

- Mr. Urukov acknowledged the point and noted that it aligned with a physically plausible scenario he had considered previously.

Mr. Paredes, pointing to slide 14 of the supplementary deck, noted that the only change in terms of the inputs is, in this example the 10 S offer is now for 40 MW.

- Mr. Urukov stated that he was having difficulty understanding the explanation that the DSO selected the 20 energy/20 10S outcome as it was respecting the EOP. He discussed a comparison of two hypothetical resources: one with a forbidden region between 0 and 20 MW, and another without any forbidden region constraints. He noted that where the unit provides 4 MW of Operating Reserve (OR) but produces no energy appears to fall outside the forbidden region and therefore should remain a feasible option. Mr. Urukov commented that it seemed unusual that, in this example, one resource would receive a full make whole payment while another would not. Mr. Urukov asked for confirmation that if a resource has no forbidden region and has the same offer structure and maximum capability as the example resource, it would receive a make whole payment that brings it to the same operating profit level (approximately $30).

Mr. Paredes confirmed that if the resources were identical in all respects except that the forbidden region was removed, the DSO would calculate the make whole payment in the same way as illustrated in the example. He explained that, without a forbidden region, there would be no Forbidden Region Operating Profit (FROP) adjustment to subtract. In other words, the example reflects how a resource without a forbidden region would receive a full make whole payment, as there would be no forbidden region related deduction through the FROP calculation.

- Mr. Urukov acknowledged the explanation and asked how the forbidden region is influencing the outcome in this scenario, given that the DSO's selection of the 20 MW-energy and 20 MW 10S may be driven by factors unrelated to the forbidden region constraint. He noted that it was unclear why one resource appears to be penalized for having a forbidden region, while another similar resource in the same situation would receive its full make whole payment.

Mr. Paredes explained that the key factor in determining whether the FROP calculation applies is how the resource is scheduled relative to its forbidden region. He stated that FROP is triggered only when the energy schedule is either within the forbidden region, or exactly at the upper boundary of that region. He noted that if a resource is scheduled within the forbidden region, the constraint is binding, as the unit must be actively ramping through that area and the DSO is attempting to move it out of the region as quickly as possible. In such cases, applying the make whole payment for MW within the forbidden region is appropriate. Mr. Paredes acknowledged Mr. Urukov's concern regarding schedules that land exactly at the upper boundary (e.g., exactly 20 MW). He stated that, based on the DSO analysis, it is unlikely that a resource would be scheduled at the exact boundary due to unrelated factors such as pricing or scheduling discrepancies. Therefore, when a resource lands precisely at that upper boundary, the most plausible explanation is the presence of the forbidden region constraint, and this serves as the trigger for applying the FROP calculation.

- Mr. Urukov asked what analysis the IESO uses to assess the likelihood that a unit would be scheduled exactly at the upper boundary of a forbidden region for reasons unrelated to the forbidden region constraint.

Mr. Paredes responded that he did not have information prepared to address this question.

- Mr. Urukov acknowledged the response and commented that this is an area the IESO should examine further. He then sought clarification on another scenario: if the energy and OR schedule were instead 21 MW and 19 MW, respectively, placing the unit outside the forbidden region, then the FROP calculation would no longer apply.

Mr. Paredes confirmed that this interpretation is correct.

- Mr. Urukov added that his concern centres on this type of edge case. He agreed that such situations may be rare and represent a low likelihood of occurring but nonetheless believes that they warrant consideration. He stated that this edge case should be addressed explicitly and noted that he would leave this as a pending question for further review.

- Michael Pohlod, Voltus asked why a resource's forbidden region is not treated as a type of non-dispatchable designation within that region. He noted that if a generator cannot be dispatched through a certain operating range, it would seem reasonable for that range to be formally declared non dispatchable.

Mr. Paredes responded that the DSO already behaves this way: it attempts to avoid scheduling a unit within its forbidden region and does not place the unit at a steady state point inside that range. However, he explained that the issue arises with the EOP, which does not enforce forbidden region constraints. Because the EOP can produce a result that is within a forbidden region, the make whole payment mechanism must correct for this after the fact. He noted that this is a feature of the current market design.

- Mr. Pohlod followed up by returning to Mr. Urukov's earlier question, asking how the forbidden region is determined. He expressed concern that the previous explanation suggested the IESO "feels it out," and asked whether the forbidden region is formally declared by the resource.

Mr. Paredes clarified that forbidden regions are explicitly submitted by market participants. A resource may declare up to five discrete forbidden regions, specifying for each one an exact lower and upper MW boundary.

- Mr. Pohlod acknowledged the clarification.

- Rob Coulbeck, Nexus referred to the example on slide 8 and observed that the resource's energy schedule, as it is determined by the EOP, places it within the forbidden region. He noted that the resource effectively earns a $4/MW profit on 20 MW of energy when moved to the 20MW point. Mr. Coulbeck then noted that this profit is divided by 12 in the calculation, while the model simultaneously removes $9/MW of profit on the operating reserve side for the remaining 15 MW. He expressed concern that the resource appears to be penalized simply because it has declared a forbidden region. In his view, the mechanism seems to reduce the profit the unit would otherwise earn (e.g., at 35 MW OR) specifically because the resource has identified a constraint, even though the constraint itself may not be directly responsible for the lost opportunity.

Mr. Paredes responded that two factors are driving the outcome. One, the resource submitted forbidden region, which imposes a constraint that affects dispatchability and the second, the co-optimization of energy and operating reserve, which must operate within the resource's 40MW maximum capability. Mr. Paredes explained that the energy schedule must respect the forbidden region. If energy is forced to move from 5 MW to 20 MW to avoid the prohibited operating range, the forbidden region is the cause of this adjustment. At the same time, this energy movement forces the operating reserve schedule to shift from 30–25 MW down to 20 MW. Because both adjustments stem from the forbidden region, the resulting make whole payment is created by that constraint. Therefore, the payment is subject to reversal under the FROP calculation, which is intended to exclude make whole amounts arising from resource submitted forbidden region limitations.

- Mr. Coulbeck added that if the situation were reversed, where the energy price exceeded the OR price, the market rules already include mechanisms to reverse the energy side make whole payment. In his view, the proposed approach simply extends this logic to the case where OR prices exceed energy prices.

Mr. Paredes agreed, stating that the new aspect being introduced relates specifically to the operating reserve side. The current framework already reverses the energy side make whole payment; the proposed change adds a component to reverse the OR side lost opportunity payment as well, given that both outcomes share the same root cause: the forbidden region.

- Mr. Coulbeck acknowledged the explanation.

- Mr. Urukov returned to the comparison of one with a forbidden region and one without and reiterated his uncertainty regarding how the proposed approach treats them differently. He noted that, in the example, the optimal operating point is clearly 0 MW energy and 40 MW operating reserve. Mr. Urukov questioned whether the penalty being applied stems not from the resource having a forbidden region, but rather from the DSO's choice to schedule the resource within that region. He asked whether, if the unit were ramped incrementally from 0 MW to 19 MW (i.e., through the forbidden region), the proposed FROP mechanism would change the operating profit at each step. Specifically, he asked whether the resource would be penalized incrementally as it moves through each MW of the forbidden region, or whether its net outcome would consistently remain below the $30 optimal profit and converge to the same result.

Mr. Paredes responded that he had not worked through all incremental permutations from 0 MW to 19 MW and therefore did not have a numerical answer. However, he emphasized that the key consideration is not the resulting operating profit at each point. Instead, the principle behind the proposal is that make whole payments should not be paid when the unit is being scheduled within the forbidden region, because the only reason it is passing through that region is to respect its own submitted constraint. Mr. Paredes added, therefore make whole payments calculated while the unit is between 0 MW and 19 MW would be reversed through the FROP calculation.

- Mr. Urukov interpreted this to mean that the FROP mechanism would effectively claw back any make whole payments awarded while the unit is within the forbidden region, leaving the resource with a net make whole payment of zero throughout that entire range.

Mr. Paredes confirmed that this is correct in terms of the make whole payment outcome.

- Mr. Urukov then noted that once the unit reaches 20 MW, the upper boundary of the forbidden region, it would retain the make whole amounts awarded from that point onward.

Mr. Paredes clarified that this applies once the resource reaches above the upper boundary, 21 MW or higher.

- Mr. Urukov acknowledged this clarification, noting that this would still be subject to the check applied at the 20-MW boundary.

Ms. Cairns then presented on Item 2: Operating Reserve Ramping in Lost Opportunity Cost EOP Calculations. She provided an example as outlined in slides 11 through to 15 of the deck. There were no questions on this example.

Ms. Cairns then presented on Item 3: Real-Time Make-Whole Payments not Offsetting amongst energy and operating reserve products. She provided an example, in slides 18 through to 20, of how a resource might be compensated twice for the same MWs.

- Mr. Pohlod asked if a site is being constrained down on its energy schedule because of a transmission constraint, how is it also eligible to provide the OR, because would the constraint not be active in the event the resource was dispatched for operating reserves?

Ms. Cairns noted that differences between the scheduling pass and the pricing pass can affect outcomes in examples like the one discussed. She noted that if, in the scheduling pass, there were an OR shortfall, this would create a constraint violation price (CVP) for OR. That higher CVP would increase the OR price in the scheduling pass and would, in turn, drive a higher OR schedule. She added that when the process moves to the pricing pass, the system is no longer using the same CVP from the scheduling pass. If, for example, the pricing pass sees a $120/MWh energy price but no OR CVP, the EOP will consider the energy offer more economic. As a result, the EOP may schedule more energy because it is no longer seeing the higher OR price that originated from the earlier scheduling pass shortfall.

- Mr. Pohlod acknowledged this point.

- Mr. Urukov flagged that he noted that the example under discussion relates to LOC within a joint optimization framework. However, the proposed changes also extend to lost cost as shown in the four bracketed terms being modified. Mr. Urukov asked what the rationale is for including lost cost in these revisions.

Ms. Cairns responded that she could present an example illustrating how lost cost and lost opportunity cost interact, and the purpose of introducing the "max zero" term within the LOC calculation.

- Mr. Urukov clarified that his question was not about the "max zero" component, but specifically about why lost cost is included among the four terms being updated. He noted that the change appears to allow negative lost cost values to be retained in the calculation, and he asked for an explanation of the underlying rationale.

Ms. Cairns explained that lost cost is being included for two reasons. First, the revision avoids unintuitive outcomes that may arise if the EOP has a defect or produces an anomalous result. In the LOC context, the proposed change reverses any profits that may have been improperly assigned when a unit's EOP falls below its dispatch schedule, ensuring that the same MW are not compensated twice. Second, on the lost cost side, the only circumstance in which the revised formulation could produce a negative result is when a resource's EOP for lost cost is higher than its scheduled value, and the resource is uneconomic at that EOP. While this is an extremely rare edge case, it represents an unintuitive outcome, and therefore the design intentionally prevents make whole payments from being issued in such situations. Aligning lost cost with lost opportunity cost ensures consistent treatment of these rare but possible anomalies.

- Mr. Urukov restated his understanding, unlike the other three items where the IESO has observed instances of overpayments or unwarranted payments the lost cost issue has not yet been observed. Instead, the IESO is proactively closing a potential gap to guard against the possibility that an EOP defect could produce an unexpected or inappropriate outcome in the future. He noted that the change is therefore forward looking rather than corrective.

Ms. Cairns confirmed that this interpretation is correct.

- Mr. Urukov then asked whether the IESO had conducted stress testing to ensure that the proposed change would not penalize resources in legitimate cases or trigger negative outcomes unintentionally.

Ms. Cairns confirmed that stress testing had been done and that the change would not have unintended or harmful effects.

Mr. Urukov acknowledged the response.

Ms. Backman then presented the remaining slides in the presentation covering stakeholder feedback and next steps. Two engagement sessions have been held along with some additional one-on-one meetings with specific market participants. Most of the feedback has been requesting the examples that have been presented today. The next step following the posting will be to vote to recommend in February with a planned implementation in early April.

Following this, Mr. Paredes reviewed the supplementary presentation. He began outlining two updates that have been made to the market rule proposal document, the first was a result of Mr. Urukov's comments that it was ambiguous what assumptions would be made in the forbidden region lower limit variable in the new provision Ch.9 s.3.5.6.3. This would be corrected in the version posted for stakeholder comment. The second update was to Item 3 where through some further review, it was determined that there were some edge cases where there were some unintended outcomes, resulting in some changes to Ch.9 s.3.5.4.5 and 3.5.4.6.

- Mr. Urukov asked if this change was the result of a comment he had made and whether the IESO had come to its own determination that it was incorrect. Mr. Paredes confirmed this was so and provided an example to illustrate the point.

- Mr. Forsyth asked about a scenario in which a generator is injecting 85 MW and then, in the next five-minute interval, continues with the same real time schedule but increases its injection to 105 MW. He asked whether, in that situation, the resource would become eligible for an OR make whole payment, and whether the calculation considers where the generator was in the previous interval.

Mr. Paredes responded that the IESO does not look back to previous intervals when determining make whole payments. The calculation is performed independently for each five-minute interval. He explained that if, in the new interval, the generator's injection increases to 105 MW and its real time schedule is also 105 MW, there would be no need for a make whole payment. However, if the generator's injection rises to 105 MW while its EOP remains at 100 MW, this would be a typical lost cost scenario where a make whole payment is warranted. Mr. Paredes emphasized that issues arise only when the schedule and injection move in a direction opposite to the EOP. Once both the schedule and the injection are above the EOP, the situation aligns with normal make whole payment logic, and the standard calculation applies.

- Mr. Forsyth acknowledged the response.

Mr. Urukov noted a minor correction, indicating that the italicization for the phrase "30 minutes" is missing in subsection (e) of the FROP language. He then expressed appreciation to the IESO for preparing both the initial and follow up examples. Mr. Urukov emphasized that these examples are essential in helping stakeholders understand the complex calculations and thanked the IESO for the effort.

Other Business

No other business was brought forward.

Adjournment

The meeting adjourned at 10:10 a.m.

The next regular TP meeting will be held on February 10, 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 process once the assessment is complete.	Open	