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Feedback Form

Intertie Offer Guarantee (IOG) - Adjustments to Payment Conditions

Feedback Provided by:

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Organization: Vitol Inc.

Email: [redacted]

Date: September 4, 2026

To promote transparency, feedback submitted will be posted on the IOG engagement page unless otherwise requested by the sender.

☐ **NO - There is confidential information, do not post**

☐X **YES - Comfortable to publish to the IESO web page**

Following the August 18th IOG – Adjustments to Payment Conditions engagement webinar, the Independent Electricity System Operator (IESO) is seeking feedback from stakeholders on the items discussed. The presentation and recording can be accessed from the engagement webpage.

Note: The IESO will accept additional materials where it may be required to support your rationale provided below. When sending additional materials, please indicate if they are confidential.

Please submit feedback to engagement@ieso.ca by September 4, 2026.

Conditional IOG – Future Method

1. Do you have any questions/feedback on the proposed conditional IOG?

Vitol does not support the proposed conditional IOG in its current form.

1. The IOG is a symptom, not the cause.
The IESO proposes to condition the real-time IOG on a declared adequacy need, noting that a significant share of IOG payments arose in hours when no such need existed. We agree with the observation, but not the diagnosis. The IOG is not the problem; it is a symptom of inaccurate pre-dispatch pricing. Pre-dispatch is the only public price signal to which an importer can react after the Day-Ahead Market closes. Over the sixteen month period from May 1, 2025 to August 18, 2026, pre-dispatch pricing averaged $90.04/MWh against a realized real-time price of $64.64/MWh (*i.e.,* a bias of +$25.41/MWh or +39.3%), it overstated the price that settled in 81.7% of all 11,385 hours examined, and the overstatement emerged each and every month without exception. One risks that imports will responsibly respond to the signals that the IESO publishes only to be exposed to the consequences of those signals being wrong. Eliminating the IOG does not improve the forecast. It will merely shift the cost of the IESO's forecast error onto importers. The predictable result is wider import offers, fewer imports, a higher pre-dispatch price and, ultimately, higher real-time prices paid by Ontario consumers.

Details supporting the need to fix the pre-dispatch:

Metric	May 1, 2025 → August 18, 2026 (11,385 hours)
Average pre-dispatch price (Avg PD)	$90.04/MWh
Average real-time price (Avg RT)	$64.64/MWh
Systematic bias (PD − RT)	+$25.41/MWh, i.e., pre-dispatch has run 39.3% above realized real-time
Median hourly error	+$13.89/MWh — more than half of all hours were overstated
Mean absolute error (MAE)	$40.72/MWh, equal to 63.0% of the average RT price
Root mean square error (RMSE)	$94.22/MWh
Hours where PD > RT	81.7% — the error is one-directional, not random
Months with a positive bias	16 of 16 — no month in the sample had pre-dispatch below real-time on average
Hours with |PD − RT| > $50/MWh	22.4% (≈ 1 hour in 4.5)
Hours with |PD − RT| > $100/MWh	8.8% (≈ 1 hour in 11)
Explanatory power	$R^2 = 0.37$ — pre-dispatch explains about 37% of real-time price variation
Calibration	RT = 25.9 + 0.43 × PD. A $100 increase in the pre-dispatch signal delivers only $43 of additional real-time price
Expected price risk transferred by the amendment	$33.06/MWh of scheduled import volume in every hour; $25.41/MWh net of offsetting upside

2. Fewer imports mean higher pre-dispatch and real-time prices– and, ultimately, higher costs for Ontario consumers
Before proceeding, the IESO should model the consequence to their constituents carefully. A conditional IOG does not eliminate market risk; it shifts that risk from load to importers. If importers can no longer expect to be made whole for losses arising from the IESO's own forecast error, they have three rational choices: embed a risk premium in their real time offers; redirect volume to the Day-Ahead Market, where the price is firm; or stop offering into Real-Time Market altogether. Each of these choices reduces the competitively priced import supply available after the Day-Ahead Market, weakens the supply stack, and creates further upward pressure on prices.

The effects of these choices readily compound. Fewer and more expensive import offers thin the pre-dispatch supply curve, raising the pre-dispatch price, and widening the very PD-to-RT gap. The result is the opposite of convergence. In the hours where import supply would genuinely have been dispatched, its absence also raises Real-Time prices. A more expensive resource sets the marginal unit and, on a steep supply curve, the loss of a few hundred megawatts of imports can increase the real-time price by tens of dollars per MWh. The IOG is paid to a small number of importers; whereas, any resulting increase in the real-time price is borne by all Ontario load. Eliminating a targeted payment while increasing system-wide energy costs is not cost saving. It merely replaces a limited payment with a broader—potentially larger—cost to Ontario consumers.

The arithmetic is stark. Shared across 16,000 MW of average Ontario load — roughly 140 TWh a year — the break-even is trivially small:

Annual IOG payments avoided	Break-even RT uplift ($/MWh)	As % of avg RT price	Hours/yr of +$100/MWh RT uplift that erase it
$5m	$0.036	0.06%	3.1 hours
$10m	$0.071	0.11%	6.3 hours
$20m	$0.143	0.22%	12.5 hours
$40m	$0.285	0.44%	25.0 hours
$60m	$0.428	0.66%	37.5 hours

If the amendment avoids $20m of IOG payments in a year, it becomes a net loss to Ontario consumers the moment the average real-time price rises by 14.3 cents per MWh — 0.22% of the current average price — or, equivalently, the moment the withdrawal of import supply raises the real-time price by $100/MWh for just 12.5 hours in the year. For context, the sample contains 634 hours with a real-time price above $200/MWh and 61 hours above $500/MWh. It would take a very small deterioration in import participation during those hours to erase the entire benefit of the proposal several times over.

3. Fixing the root cause of the pre-dispatch forecast issues would reduce IOG payments with no rule change. Because the IOG is payable when real-time settles below the import offer price, a pre-dispatch that converges to real-time mechanically reduces IOG exposure while improving export scheduling, intertie efficiency, and the quality of the market's price signal. Removing the IOG delivers none of those benefits and instead creates artificial risk that would increase costs for load and ratepayers because importers will widen their offers to self-insure against a forecast on which they cannot rely.

4. The Panel has published the same finding.
The concerns set forth herein are not novel. The Market Surveillance Panel has measured pre-dispatch to real-time price divergence at the interties in successive State of the Market reports: real-time below PD-1 approximately $30/MWh from 2018 to 2021 and ~$60/MWh in 2022; and ~$32/MWh in 2023 and ~$47/MWh in 2024 on the nodal basis, or ~$13/MWh and ~$20/MWh respectively measured PD-1 projected Intertie Zone Price (IZP) against real-time IZP. [1]

The Panel attributes the continuing inefficiency of Ontario's import trade to "the impact of systemic differences between the hour ahead pre-dispatch price, which facilitates intertie scheduling, and real-time prices," [2] and has already identified demand forecast deviation and wind generation forecast deviation as the two main contributing factors. [3] Our analysis extends the Panel's series into the renewed market and finds the bias undiminished. Market Renewal has not corrected the divergence; it remains a structural defect in pre-dispatch pricing that the IESO's proposal does not address. The differences between the Panel's intertie measurements and our Ontario-zone measurements reflect their measurement bases, as explained directly below.

The Panel's figures are measured at the interties during importing hours, and its intertie zonal price series is measured on the basis on which imports settle. Vitol's assessment is measured at the Ontario zone across all hours, for the reasons set out in Appendix A. The two data series are therefore not directly comparable in magnitude, and

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[1] OEB, MSP *State of the Market Report 2024* (March 2026), s.3.1, Figures 22 and 23.
[2] *Ibid.*, Executive Summary.
[3] *Ibid.*, s.3.1.

we do not present them as such: the Panel's IZP-basis figures are materially lower than its nodal-basis figures. We rely on the Panel's work to identify the bias, its direction, persistence and cause, but not its magnitude. We would welcome an opportunity to reconcile the difference and we invite the IESO to publish the intertie-zone convergence metrics so that the comparison can be made directly and on the correct settlement basis.

5. A deeper review of the pre-dispatch performance reveals longstanding structural flaws and vast room for improvement:

Performance is inferior to a trivial benchmark

Using the same 11,385 hour sample we measured the IESO pre-dispatch against two benchmarks that any participant could build in a spreadsheet.

Forecast	MAE ($/MWh)	RMSE ($/MWh)	Bias ($/MWh)
IESO pre-dispatch	40.72	94.22	+25.41
Simple — yesterday, same hour	41.32	86.11	−0.06
Simple— 7-day average, same hour	39.59	75.67	−0.54

Pre-dispatch outperformed on both measures (*i.e.,* root mean square error and mean absolute error) by a seven-day rolling average of the same hour. Both simple benchmarks are effectively unbiased; pre-dispatch is not. A signal produced by the system operator, with full visibility of outages, self-schedules, offers and the security-constrained model, should not be outperformed by a moving average.

Error exhibits a clear bias, not noise

A forecast can be noisy, in which case errors cancel out over time, or biased, in which case the errors remain. The pre-dispatch price is upwardly biased. The positive errors sum to approximately $376,430 across 9,298 hours, an average of $40.49/MWh in each overstated hour. Of that overstatement 46.5% arose in hours where real-time settled below $50/MWh — hours with no scarcity whatsoever. That is precisely the population the IESO has identified as generating IOG payments with no adequacy need. While the ISEO seeks to no longer provide IOG payment in these intervals, it is important to highlight that the root cause of the payments is the pre-dispatch forecast.

Underperforms when it matters most

The error rises from 8.0% of the real-time price in the $0–20 pre-dispatch band to 45.7% in the $100–200 band and 112.7% above $400. There were 580 hours (5.1% of the sample) in which pre-dispatch printed above $100/MWh and real-time settled below $50/MWh — a false scarcity signal that pulls imports in and then generates the very payments the IESO wishes to eliminate. Conversely, in 85 hours real-time settled above $200/MWh while pre-dispatch was below $100/MWh, so economic import offers were not scheduled. The proposal addresses neither of the failures.

Pre-dispatch band	**Hours**	**Avg PD $**	**Avg RT $**	**Bias $**	**Bias as % of Avg RT**
≤ $0	53	-0.1	1.8	-1.9	n/m
$0–20	639	10.9	10.1	0.8	8.0%
$20–50	4,249	38.0	32.2	5.8	18.0%
$50–100	3,420	72.0	59.0	13.0	22.0%
$100–200	2,131	134.7	92.5	42.2	45.7%
$200–400	699	273.3	187.7	85.6	45.6%
> $400	194	681.0	320.2	360.8	112.7%
TOTAL	11,385	90.0	64.6	25.4	39.3%

Divergence persists for whole days

The divergence is not a handful of five-minute intervals. Of the 473 complete days in the sample, 176 days (37.2%) had five or more hours in which pre-dispatch exceeded real-time by more than $50/MWh, 152 days (32.1%) had six or more, and 53 days (11.2%) had twelve or more. The worst days by average daily bias are shown below; in each case pre-dispatch held a scarcity price for most of the day while real-time never came close.

Date	Day-avg PD $	Day-avg RT $	Day-avg Bias $	Bias as % of Avg RT	Hours with Bias > $50
2026-01-26	643	255	387	151.7%	23
2026-01-25	699	326	373	114.5%	17
2026-01-24	569	343	226	66.0%	18
2025-07-14	266	41	225	555.4%	15
2026-07-02	336	123	213	172.8%	14
2025-06-04	236	30	206	692.4%	5
2025-06-25	259	83	175	209.9%	15
2026-02-06	373	210	162	77.2%	16
2025-06-24	466	315	152	48.2%	13
2026-02-08	308	157	151	96.3%	21

The measured bias is a lower bound on the error an importer faces at the point of commitment
Our figures compare the published pre-dispatch price for a delivery hour against the price that settled in that hour. As we understand current practice, revised pre-dispatch prices are published only for the hours inside the two-hour submittal window; for all later hours the importer must commit against a signal that has not been refreshed. The error embedded in the commitment decision is therefore larger than the error we can measure. On the measurable basis alone, the price risk the amendment transfers to importers is worth $33.06/MWh of scheduled import volume in every hour, or $25.41/MWh net of the offsetting upside (*i.e.*, hours where real-time settled above pre-dispatch).

The divergence continues to be an issue after the implementation of the Market Renewal
The forecast error was expected to diminish with the introduction of the Day-Ahead Market and locational pricing. However, based on the 16 months since May 1, 2025, it continues to persist. This indicates a persistent structural defect in the pre-dispatch process rather than an artifact of the previous market design. The IESO's proposed rule change falls short because it simply reallocates the consequence of the divergence, increasing costs to Ontario consumers in the process, rather than doing the more meaningful work of addressing the divergence itself.

6. Two anticipated objections.
We anticipate two possible critiques to our analysis and address them below:

- First, that pre-dispatch is not intended as a price forecast. We accept the distinction, but pre-dispatch is what importers are required to commit against, and the IOG exists precisely because participants must act on a signal they do not control.
- Second, that the gap arises because imports respond to the signal and depress the real-time price. That outcome is real but cannot explain the pattern in the data: In the 7,032 hours (61.8% of the sample) where real-time settled below $50/MWh and therefore no import response was called for, pre-dispatch still exceeded real-time in 90.6% of them, with a mean error across all 7,032 hours of +$24.41/MWh; the bias is present in all twenty-four hour-endings (74.5% to 92.0% of hours, +$9.80 to +$48.61/MWh) whereas imports response is concentrated over peak; and the bias widens rather than narrows as the price rises.

We would add that if the IESO's position is that the gap is caused by imports responding to the signal and thereby lowering the real-time price for load, then imports are performing precisely the function the IOG was designed to remunerate, and the case for withdrawing that remuneration is weaker, not stronger

Requests under this item. We ask the IESO to:

1. Retain the existing unconditional real-time IOG for import offers
2. Publish the assessment on which the proposal rests: the historical backcast of IOG payments split between hours that would and would not have qualified, the analytical methodology, and the counterfactual assumptions used, including what import behavior was assumed. Where confidentiality prevents publication, provide each affected participant with its own transaction-level results.

3. Add a pre-dispatch convergence workstream to this engagement, or commit to a parallel initiative with a published timetable: Efforts to address the pre-dispatch bias would reduce IOG exposure, while also improving export scheduling, intertie efficiency and the quality of the market's price signal — benefits the amendment does not deliver.
4. Publish monthly pre-dispatch-to-real-time convergence metrics as a public KPI: For example, set monthly bias target within a range of ±$5/MWh and fewer than 10% of hours with an absolute error above $50/MWh — and report performance against them. Publish bias in dollars and as a percentage of the average price, MAE, RMSE, and the share of hours with an absolute error above $25, $50 and $100 per MWh — reported in total, by pre-dispatch price band, by hour of day, and on an intertie-zone basis as well as for the Ontario zone.
5. Publish the contributing factors of the predispatch forecast error: demand forecast error, intermittent generation forecast error, outage and derate updates between pre-dispatch and real time, and scheduling-pass versus pricing-pass differences. The IESO indicated on August 18 that pass differences are out of scope; however, if the resulting divergence is why IOG payments are being made, the two issues cannot reasonably be separated.
6. Publish refreshed pre-dispatch prices for all forward hours of the pre-dispatch horizon, not only for hours inside the two-hour submittal window.
7. Model and publish the expected impact of the amendment on import participation, on the pre-dispatch price, and on the real-time price paid by load, including the break-even analysis above.
8. Sequence the change: do not implement a conditional IOG until published convergence metrics demonstrate sustained improvement or implement it with a defined review trigger that reinstates the guarantee if targets are not met.
9. Consider a transitional middle option: an IOG payable whenever the pre-dispatch price used to schedule the import exceeded the settled real-time price by more than a defined threshold. This limits IOG payments to hours in which the IESO's own forecast error was material, while keeping importers whole against that error.

2. Do you have any questions/feedback on the proposed IOG eligibility notification process?

Yes. In our view the notification process, as described, defeats the design intent of the amendment.

The conditional guarantee under the IESO proposal is unknowable when the offer must be made.
The economic value of a conditional guarantee is a function of how far in advance the importer knows whether it applies. Our understanding from the 18 August session is that the IESO acknowledged on August 18, 2026 that a qualifying declaration can be issued as late as the current hour — after the import offer has been committed. A guarantee that is unknowable at the moment of the scheduling decision cannot be relied upon, and rational participants will price as though it does not exist, including in the emergency hours the amendment is intended to protect. The result is that the Ontario consumers would bear the participation cost of removing the guarantee without obtaining the reliability benefit of retaining it in scarcity.

Requests under this item. We ask the IESO to:
1. Commit to a minimum advance notice period for qualifying declarations, expressed in hours relative to the mandatory offer window, and to state that period in the market rules or manuals rather than leaving it to operating practice.
2. Publish declarations in a machine-readable format suitable for automated ingestion into real-time desk systems. A website posting cannot be integrated into a real-time workflow and should not be treated as effective notice for a settlement-relevant condition.

3. Establish the treatment of an import that was scheduled before a declaration was issued in an hour that subsequently qualified, and confirm whether eligibility is determined at the time of scheduling or at the time of settlement.
4. Confirm the treatment of an import that helps the IESO avoid declaring a qualifying condition. On August 18 the IESO confirmed that no IOG would be paid in that case. That is a perverse outcome: the more effective the import response, the less likely the guarantee is to apply.
5. Publish the historical count and duration of Conservative Operating State and EEA Level 1, 2, and 3 declarations by month for at least the post-Market Renewal period, together with the operative criteria that will trigger them for IOG purposes. Without this, no participant can estimate what share of its current IOG entitlement would survive the amendment.
6. Model import participation on the assumption that advance certainty is zero and publish the result.

Real-Time Energy Lost Cost (ELC) MWP Eligibility for Imports

Do you have any questions/feedback on applying the ELC MWP Eligibility to Imports and the examples provided?

General Feedback:

We support the principle that imports should be treated consistently with other resources for lost costs arising from manual out-of-market actions, and we have no objection to the migration from charge type 1927 to 1900 in itself. We do not accept that this change offsets the removal of the IOG, and we do not have sufficient information to evaluate it fully on the material published to date.

The reason is that the ELC MWP is calibrated against a concept — the hours in which an adequacy need exists — for which the IESO has published neither the operative definition nor the historical data. Specifically, participants need the criteria, the historical frequency of qualifying declarations, and the split of historical IOG payments inside and outside those hours are available. to determine what proportion of its entitlement survives. We ask that our response on this item be treated as a reservation of position, to be completed once those inputs are provided; our silence on any element should not be read as acceptance.

We would also note a structural point. The ELC MWP compensates only the uneconomic portion of a schedule relative to the lost cost Economic Operating Point. By construction it leaves the price risk on the pre-dispatch-economic portion entirely uncompensated on non-declared days. It is therefore not a substitute for the IOG and, on the IESO's own examples, is not presented as one.

We are also unable to verify the adequacy of the calculation in practice, because the lost cost EOP is not currently published. We support the request that it be made available in the physical statement, or in a participant-specific file ahead of settlement statements.

- Example 1: Normal Conditions with ELC MWP & No IOG
  This example is the clearest statement of our concern, and we ask that the IOG be retained in the IESO's materials. It shows a residual loss of $750 borne by the importer with the price risk uncompensated, in what the IESO itself labels a normal day. On the evidence in Attachment A, normal days are not the exception: pre-dispatch exceeded real-time in 81.7% of all hours over sixteen months, and in 90.6% of the 7,032 hours in which real-time settled below $50/MWh. The example therefore describes the ordinary case, not an edge case, and the cumulative effect on import economics will be correspondingly large. We

ask the IESO to publish the expected annual value of this residual, in $/MWh of scheduled import volume and in total dollars, using its own historical data.

- Example 2: IOG vs ELC Payments
  We understand and accept the distinction drawn between the two payment types, and we agree that a lost cost arising from a manual out-of-market action is properly an ELC MWP rather than an IOG. Our concern is with what falls outside both categories. Under the proposed design, an import that was scheduled economically in pre-dispatch and then settled at a lower real-time price receives neither payment on a non-declared day. That residual — the pure consequence of the IESO's own forecast error — is the exposure documented in Attachment A, and it is estimated to be worth $33.06/MWh of scheduled import volume in every hour, or $25.41/MWh net of the offsetting upside in hours where real-time settled above pre-dispatch. We ask the IESO to confirm that this residual is understood and intended, and to quantify it in its assessment.
- Example 3: System Adequacy with ELC MWP & IOG in the same interval
  We have no objection to the mechanics shown, and we note the IESO's confirmation that an IOG and an ELC MWP can be paid in the same interval without overlap. We support the concern raised at the August 18 session that splitting a two-PQ-pair import between a reduced IOG and an ELC MWP under-compensates transactions whose pre-dispatch-economic offers reduced the severity of the manual action the operator would otherwise have needed. That outcome rewards the import that contributes least to resolving the constraint and penalizes the one that contributes most, which is the opposite of the incentive the market should provide. We ask the IESO to re-examine the allocation between the two payment types in the two-PQ-pair case and to confirm whether the whole-day claw back treatment applied to certain other resources is genuinely inapplicable to imports in all circumstances.

In addition, we request the IESO to confirm, in relation to the scenario raised at the August 18 session, whether an import can receive a negative effective price where pre-dispatch import congestion is deeply negative and real-time collapses, and whether any floor is contemplated.

Update Intertie Congestion Methodology

Do you have any questions/feedback on the rationale for updating the methodology?

We do not oppose the move to a single static methodology (RT IBP + PD ICP under all congestion conditions), and we accept that it is directionally favorable to imports and that it simplifies the settlement framework. We do not accept the rationale that it restores balanced risk and reward, for two reasons.

First, the exposures are asymmetric in frequency. The uncompensated price risk created by the conditional IOG is borne in every post-DAM hour in which an import is scheduled. The congestion benefit accrues only in the subset of hours in which import congestion is binding at the relevant intertie. Two exposures with materially different frequencies cannot be netted against one another without supporting evidence, which has not been shared to date.

Second, the required magnitude can be stated precisely. Over the 11,385 matched hours in our sample, the expected value of the price risk being transferred to importers is $33.06/MWh of scheduled import volume in every hour — the average across all hours of the amount by which pre-dispatch exceeded the settled real-time price, which is the amount an IOG would have covered. That is 51% of the average real-time price over the period. Netting the offsetting upside in hours where real-time settled above pre-dispatch ($7.66/MWh on the same basis) still leaves a net transfer of $25.41/MWh. For this change to be a true offset rather than a partial mitigant, the expected per-MWh value of the new congestion treatment would have to be of that order. We do not believe it is and request that the IESO to demonstrate otherwise.

Requests under this item. We ask the IESO to publish the following:

1. The expected annual value of this change to imports, expressed in $/MWh of scheduled import volume and in total dollars, alongside the expected annual value of the IOG being removed on the same basis, so that the claimed offset can be tested directly.
2. The historical frequency of binding import congestion by intertie zone over the post-Market Renewal period.
3. Whether the assessment measured the extent to which gains from the congestion methodology change offset IOG losses at the participant level, and if not, whether the IESO will assist participants in performing that analysis on their own data.

General Comments/Feedback

Do you have additional feedback to share with the IESO?

Yes, on four points.

1. The package cannot be assessed as a whole. The IESO has presented the conditional IOG, the ELC MWP extension and the congestion methodology as a single balanced package, but has not published the definition of an adequacy need, the historical frequency of qualifying declarations, or the expected value of the congestion change. Using available information, the two conforming changes mitigate a fraction of what the primary change removes, and no figure has been offered for the congestion benefit against which to test it. In our view the package should not proceed to a Vote to Post until the back cast, the declaration statistics and the congestion valuation are available to participants.

2. The evidentiary support for the proposal is thin and could be improved by making the assessment public. The proposal rests on a single year of post-Market Renewal experience. The analysis shows a positive bias in every month without exception, which suggests the IESO's own dataset is capable of supporting a longer and more granular assessment than the one relied upon. We also support the requests made by other participants for publication of the assessment, a historical back cast, the analytical methodology and the counterfactual assumptions, and for participant-specific results to be made available confidentially where publication is not possible.

3. January 2027 implementation is the wrong time of year. Implementing a change that reduces the incentive to import at the start of the winter peak period imposes reliability risk at the point in the year when it is least tolerable and does so while the Pickering refurbishment is underway and unit availability risk persists at Darlington. We ask the IESO to target a shoulder-season implementation and to allow at least one full winter of observation before any change takes effect. We would also welcome confirmation, on the record, that the change can be reversed if downstream effects on import participation prove adverse, and a statement of the metrics the IESO would use to make that determination.

4. The Day-Ahead Market is not a substitute for post-DAM liquidity. Directing importers to the DAM is only a partial answer. The DAM covers the position taken before DAM close; it does not address post-DAM incremental need, which is exactly the need pre-dispatch is meant to communicate. We support the request for statistics on day-ahead versus real-time import volumes, which we expect will show that DAM participation does not match how importers actually transact.

Closing. We appreciate the opportunity to comment, and we support the review the Market Surveillance Panel called for. Recommendation 24-1-1 asked the IESO to review the benefits and costs of the real-time IOG and to quantify the extent to which it enhances reliability or adequacy, contributes to inefficient import schedules, and dampens real-time prices. The Panel did not recommend conditionality, and stated that it "did not specifically recommend a threshold." In its December 19, 2025 update to the OEB the IESO stated that it was "collecting data to ensure that different seasons and system conditions are covered" and would "continue to monitor and evaluate." None of the three quantifications have been published, and the assessment underlying this proposal is not public. Our objection is therefore not to the review of the IOG, which we consider entirely legitimate, but to the sequence: a remedy is being advanced ahead of the analysis intended to justify it, and before the underlying cause of the payments — the inaccuracy of the pre-dispatch price signal — has been measured, published and addressed.

We would welcome a discussion with the IESO ahead of the September 16, 2026 engagement session. The full hourly dataset and all calculations discussed are available upon request, and we would be glad to reconcile our figures against the IESO's own pre-dispatch and real-time records. We are also willing to work with the IESO on the design of the convergence metrics and targets, and on the transitional threshold-based option described above.

Attachment A

Pre-dispatch vs Real-Time Price Performance in the IESO Market

Supporting details to the completed IOG Adjustments Feedback Form — IESO engagement on proposed amendments to the Intertie Offer Guarantee (IOG)

Attachment to	Completed IOG Adjustments Feedback Form, submitted to engagement@ieso.ca
Name	Seth Cochran
Title	Head of Strategic Market Policy
Organization	Vitol Inc.
Email	SCO@vitol.com
Date	September 4, 2026
Confidentiality	NOT CONFIDENTIAL. We consent to publication of this attachment in full on the IOG Adjustments engagement page.

Data, definitions and method

Source data. Two hourly series for the Ontario zone (ONZN) were extracted from Vitol's internal nodal market-data store, populated from IESO pre-dispatch locational marginal price (IESO_PRICE_PREDISPATCH_LMP, node ONZN) and the IESO real-time locational marginal price (IESO_PRICE_RT_LMP, node ONZN). Both series are sourced from IESO published market data. All prices are in Canadian dollars per MWh (CAD/MWh). All timestamps are in Eastern Standard Time, applied year-round with no daylight-saving adjustment, consistent with IESO market time; hours are labeled hour-ending. Sub-hourly observations are reduced to hourly values by using simple arithmetic average.

Pre-dispatch vintage. The pre-dispatch series used is the published ONZN pre-dispatch LMP for the delivery hour. We have used this vintage because it is the run against which the import schedule becomes binding and is therefore the most favorable to the pre-dispatch signal. Earlier vintages, on which importers must in practice commit for hours beyond the submittal window, contain larger errors. See Section A.5.1.

Choice of reference price. ONZN is used as the reference because it is the Ontario zonal price that anchors the pre-dispatch signal system-wide and is the price the IESO cites when explaining pre-dispatch-to-real-time divergence. We recognize that an import is settled at the intertie settlement price rather than the Ontario zonal LMP, and that the two differ when intertie congestion is binding. The convergence failure documented here is a property of the pre-dispatch optimization itself and is not an artifact of the zonal reference chosen; we would be pleased to replicate the analysis for individual intertie zones if the IESO considers that material, and we invite the IESO to publish the equivalent metrics on an intertie-zone basis.

Sample. The pre-dispatch series is populated from May 1, 2025, which defines the start of the sample. The sample runs to August 18, 2026, a period of 11,400 hours. Of these, 11,385 hours have both series populated and form the analysis sample; 15 hours were excluded because of missing data in one or both series. The sample spans 475 calendar days, of which 473 are complete days with all 24 hours matched. The Day-level statistics in Section A.7 are computed using the 473 complete days only, so that no day is understated by missing hours.

Definitions.

Bias is the mean error.

Error is defined throughout as pre-dispatch minus real-time, so a positive value means that pre-dispatch was above the price that settled.

MAE is the mean absolute error.

RMSE is the root mean square error. Percentage columns express each measure against the average real-time price for the same period, unless the column is explicitly labeled as a share of hours. Columns labeled "Bias as % of Avg RT" report the mean error divided by the mean real-time price for that grouping and may exceed 100% where pre-dispatch was more than double the settled price; columns labeled "% hrs PD > RT" report the share of hours in which the error was positive and are bounded at 100%. In the pre-dispatch band table, the percentage is not meaningful for the sub-zero band, where the average real-time price is itself negative, and is shown as "n/m".

Headline statistics. Average pre-dispatch $90.04/MWh; average real-time $64.64/MWh; mean bias +$25.41/MWh, equal to +39.3% of the average real-time price; median error +$13.89/MWh; MAE $40.72/MWh, equal to 63.0% of the average real-time price; RMSE $94.22/MWh. Pre-dispatch exceeded real-time in 81.7% of hours; the absolute error exceeded $50/MWh in 22.4% of hours and $100/MWh in 8.8% of hours. Ordinary least squares of real-time on pre-dispatch gives $RT = 25.9 + 0.430 \times PD$, with $R^2 = 0.366$.

Naive benchmarks. Two benchmarks were constructed using only real-time prices observed before the relevant pre-dispatch run: the "yesterday" benchmark uses the real-time price for the same hour-ending on the previous day; the "seven-day" benchmark uses the mean real-time price for the same hour-ending over the preceding seven days. Both benchmarks are evaluated using the same 11,385-hour sample as the pre-dispatch series, so the three sets of statistics in Section A.5 are directly comparable and reconcile exactly to the headline figures above.

Break-even calculations. The sensitivities in Section A.6.1 assume an average Ontario load of 16,000 MW, equivalent to 140.2 TWh per year, and are presented as illustrative sensitivities rather than as forecasts. They compare a stated level of avoided IOG payments against the uniform increase in the average real-time price that would offset it, and against the number of hours of a $100/MWh real-time price uplift that would offset it. No assumption is made about the probability of either outcome; the purpose is solely to establish the order of magnitude at which the proposal ceases to benefit load.

Reproducibility. The hourly dataset underlying every figure in this attachment, together with the associated calculations, is available upon request to the IESO.. We would welcome a reconciliation against the IESO's own pre-dispatch and real-time records before the September 16, 2026 engagement session.