

Feedback Form

Intertie Offer Guarantee (IOG) - Adjustments to Payment Conditions

Feedback Provided by:

Name: Will Mercer

Title: Director, Physical Trading

Organization: Nexus Energy Inc.

Email: [REDACTED]

Date: 2026-09-30

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**
☒ **YES - Comfortable to publish to the IESO web page**

Following the September 16th 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 30, 2026.

Conditional IOG – Future Method

1. Do you have any questions/feedback on the proposed conditional IOG since the previous engagement session?

General Comments/Feedback

Do you have additional feedback to share with the IESO?

The IESO has proposed making the Import Offer Guarantee (IOG) conditional on system reliability margins. The main question is whether a standing guarantee provides additional value outside of declared Conservative Operating State, Emergency Operating State, or Energy Emergency Alert periods.

A positive supply margin does not make imports unnecessary

Ontario may have sufficient domestic supply to meet forecast demand while continuing to benefit from imports that reduce the cost of serving that demand and provide additional headroom if conditions change. Making the IOG conditional on expected system stress would reduce the incentive to offer imports, including hours when those imports could improve market efficiency without being required to avoid a supply shortage. Without a standing guarantee, importers will likely respond by withholding offers or submitting offers at higher prices to compensate for the additional risk. Either response could leave Ontario with fewer competitively priced imports.

The IESO's proposal focuses on providing the guarantee when the system is expected to be tight. However, a positive forecast margin does not establish that the available domestic supply is more economic than an import, or that the margin will remain positive as real time approaches. The assessment should consider the effect on import participation and customer costs, as well as the ability to meet forecast demand.

When an import is selected in pre-dispatch, it contributes to meeting the system's requirements at the offer prices and constraints represented in that schedule. If the import is no longer offered, the IESO will need to rely on more expensive domestic generation or commit additional units with associated start-up costs. A positive supply margin may show that replacement supply exists but does not illustrate that replacing it could result in increased costs.

Customer cost is part of the reliability tradeoff

Fewer competitively priced imports will increase pressure on real-time prices. Expectations of higher real-time prices influence day-ahead prices, extending the effect beyond the hours in which an import is withheld. Post MRP, monthly average day-ahead and real-time prices moved in tandem (Pearson correlation coefficient of 0.98). Customers settle roughly 147 TWh of consumption per year at the day-ahead price. A small day-ahead price increase will have a large impact on the wider market. If the IOG is not guaranteed during high pre-dispatch periods, fewer imports will remain available and real-time prices will move materially higher, with DA prices naturally following.

Item	Why it matters	Scale
Day-ahead price	Fewer imports can increase pressure on real-time prices, which can feed back into day-ahead pricing	\$1/MWh across about 147 TWh is about \$147M per year; \$5/MWh is about \$737M
LFDA	Customers are charged the Load Forecast Deviation Adjustment on consumption	\$0.10/MWh across about 147 TWh is about \$15M per year

Consumption = IESO settled Ontario demand, September 2025-August 2026 (147.4 TWh).

Without the guarantee, import offers must price in more risk

Timing is a key concern when relying on declarations, reopened windows, or out-of-market actions. Import offers must remain available prior to the resolution of the system's uncertainty. A guarantee activated after tighter conditions are forecast does not ensure that competitively priced energy will still be available to schedule. By then, suppliers may have committed energy elsewhere, leaving Ontario seeking higher-priced imports under more stressed conditions.

Without a guarantee, an importer that remains available after the day-ahead market must account for the risk that Ontario's real-time revenue will not cover the cost of the power it has committed. This reduces the incentive to import before a qualifying declaration and can raise the price needed to justify participation. Once conditions deteriorate, sourcing power may also become more expensive because the weather affecting Ontario can put pressure on neighbouring markets simultaneously. During the IESO's 2026 Conservative Operating State declarations, real-time prices in the neighbouring interfaces averaged 3.6 to 5 times their normal levels for the same month and hour.

Additionally, adverse events increase generation costs internally and externally. During Winter Storm Elliott (December 2022), spot natural gas prices across the eastern United States rose to many times their normal levels, and after Russia's invasion of Ukraine in 2022, natural gas and coal prices rose sharply worldwide. In those conditions, an importer's costs are substantially higher than in normal times. Offer prices are therefore inherently increased, reflecting both a higher cost of generation and added uncertainty of committing energy under stressed conditions.

Evening peak (HE16-21), all hours of the IESO's 2026 Conservative Operating State declarations during June 11, June 30-July 3, July 14, September 1-2. CAD/MWh.

Market (real-time price)	Average during Ontario COS	Normal average, same month and hour	Times normal	Hours at \$200+ during COS	Hours at \$200+ normally	Highest hour
PJM - Ontario interface (IMO)	\$602	\$120	5.0x	68%	7%	\$2,043
MISO - Detroit Edison zone (DECO)	\$618	\$143	4.3x	66%	9%	\$5,833
NYISO - Ontario proxy (O H)	\$266	\$74	3.6x	38%	3%	\$851

Declared hours = IESO Conservative Operating State windows from the IESO advisory archive (available from January 25, 2026; no Energy Emergency Alert or Emergency Operating State was declared in this period), EST hour-ending. Neighbouring market prices are hourly real-time prices at PJM's Ontario interface (IMO), MISO's Detroit Edison load zone (DECO) and NYISO's Ontario proxy zone (O H), shifted from Eastern Prevailing Time where needed and converted to CAD at the daily exchange rate. Normal = average price at the same node for the same month and hour of day on days without a declaration.

Already scheduled imports absorb short supply and demand shocks

April 7-September 24, 2026 (164 days)	Result
Short shocks (750 MW or more, over within 3 hours)	88 hours on 41 days
Average shock size	909 MW (demand 509 MW, wind 331 MW, forced outage 69 MW)
Post-DAM imports flowing	155 MW average; at least 100 MW in 35% of shock hours
Shock fit inside 10-minute reserve only because imports were already flowing	25 hours on 15 days; imports averaged 395 MW
Without those imports, shortfall exceeded all scheduled operating reserve	8 hours on 5 days

Reserve = the IESO's published real-time scheduled 10-minute reserve (10S + 10N) and 30-minute reserve for the hour, for hours with published reserve data.

Shock events are defined as events that developed after the import window had closed and could not have been reasonably forecast using the information available before close. By the time the change in demand, wind, or alternative generation became clear, no new import could be scheduled for the same hour. In 25 hours, the shock fit within the scheduled 10-minute reserve only because post-day-ahead imports were already flowing. In eight hours, removing those imports would have left the shortfall larger than all scheduled 10- and 30-minute operating reserves combined. This does not mean the imports were the only resource available to the IESO or that a reliability event would necessarily have occurred. It shows the additional system headroom provided by imports that had already been scheduled before the shock developed.

Examples from the shock hours

Six of the eight hours are shown below. The remaining two were July 4 HE8 and September 13 HE17. The figures were derived from the IESO's published generator output, intertie schedules, adequacy report, reserve totals, and prices.

Date, hour	What changed after imports committed	Shock (MW)	Post-DAM imports	10-min reserve	All reserve	DA price	RT price
Jul 27 HE19	Demand 700 MW above DA forecast; wind 309 MW below forecast	1,009	661	1,215	1,514	\$115	\$419

Date, hour	What changed after imports committed	Shock (MW)	Post-DAM imports	10-min reserve	All reserve	DA price	RT price
Jul 27 HE20	Demand +624 MW; wind 361 MW below; Greenfield G3 lost	1,065	725	1,412	1,572	\$102	\$394
Aug 10 HE17	Demand +564 MW; Greenfield G4 derated 156 MW	800	1,066	945	1,380	\$177	\$208
Aug 10 HE18	Demand +497 MW; wind 182 MW below; Greenfield G4 derate	833	681	945	1,403	\$179	\$167
Aug 16 HE20	Demand +576 MW; wind 245 MW below	821	1,196	945	1,380	\$93	\$163
Aug 16 HE21	Demand +569 MW; wind 360 MW below; 5-min price reached \$559	929	584	951	1,380	\$87	\$228

Shock = demand above the IESO day-ahead forecast + wind below the last forecast published before the import window closed + forced generation loss. The comparison is to scheduled operating reserve and is not a claim that a reliability event would otherwise have occurred.

August 10 HE17, after the import window had closed, demand was 564 MW above the IESO's day-ahead forecast and Greenfield G4 lost 156 MW, producing an 800 MW shock. The IESO had 945 MW of 10-minute reserve and 1,380 MW of total scheduled operating reserve. At the same time, 1,066 MW of post-day-ahead imports were already flowing. Without those imports, the shortfall against the earlier plan would have been approximately 1,866 MW, larger than the scheduled operating reserve carried for the hour.

Two additional unit trip examples

Two other events are worth noting even though they are outside the short-shock screen conducted above. The Darlington event lasted longer than three hours, and on June 10 lower-than-forecast demand partly offset the supply losses. In both cases, substantial post-day-ahead imports were already scheduled when supply conditions changed.

Date, hour	What happened	Post-DAM imports	DA price	RT price
Aug 1 HE16	Darlington 4 fell from 853 MW (HE14) to 637 MW (HE15) to zero (HE16); demand 517 MW above DA forecast	1,077 MW	\$85	\$142
Jun 10 HE18	Goreway 12 tripped (176 MW); Goreway 15 derated 126 MW; Lennox 1 unavailable from HE19; wind 297 MW below forecast; demand 879 MW below forecast	743 MW	\$109	\$446
Jun 10 HE19	Same outages; wind 283 MW below forecast	733 MW	\$108	\$353

Conclusion

The reliability review shows that post-day-ahead imports were already flowing when short supply and demand shocks developed after the scheduling window closed. In a subset of those hours, the imports provided enough additional headroom to change the comparison between the shock and the IESO's scheduled operating reserve. These examples support retaining an incentive to make imports available before tighter conditions can be identified with confidence.

The value of those imports also extends to the wider market and consumers. A positive supply margin may indicate that Ontario has enough supply to meet demand, but it does not show that replacing imports would likely result in higher RT prices. Fewer competitively priced imports requires more expensive replacement generation and results in upward pressure on market prices. The IESO should assess whether savings from reduced IOG payments would outweigh the additional costs borne by the wider market and consumers, alongside the loss of flexibility when conditions change unexpectedly.

These considerations become increasingly important as Ontario's domestic supply declines. Nexus recommends that the IESO defer making the IOG conditional until at least fall 2027, after Ontario has operated through a full winter and a full summer without the Pickering units scheduled to come offline for refurbishment. The removal of roughly 2,000 MW of baseload nuclear supply will leave the system tighter than the one on which the proposal's evidence is based. The renewed market has so far been observed for a little over one year. With less domestic supply, post-day-ahead imports are likely to play a greater role in absorbing short supply and demand shocks and limiting upward pressure on market prices. A decision to weaken the mechanism that keeps those imports available should rest on evidence from the system in which it will operate.