Alternative Procedure for Determining Adjusted Offer Curves Used for Fast-Start Pricing

Under the proposal that was described in the NYISO's initial brief in Docket EL18-33 for extending the NYISO's current procedure for fast-start pricing to on-line units with dispatchable segments, the NYISO would:

- Determine the no-load cost for each such unit, which is the amount by which its minimum generation cost offer exceeds the product of its minimum generation level and the incremental energy offer for the unit's first incremental energy block.

- Divide that no-load cost by the unit's upper operating limit ("UOL"), to determine the no-load adjustment for that unit.

- Determine the start-up cost adjustment for that unit, which is the unit's start-up cost offer divided by the product of its UOL and its minimum run time. (This adjustment only applies until the unit completes its minimum run time. Afterward, the start-up cost adjustment will be set to zero.)

- Determine the adjusted offer curve for each unit by adding the no-load adjustment and the start-up cost adjustment (when applicable) to the incremental energy offer curve submitted for that unit.

The adjusted offer for the minimum generation block would be set equal to the adjusted offer for the first incremental energy block. The RTD pricing pass would then dispatch all on-line fast-start units at any point between zero and their respective UOLs, using these adjusted offer curves for each such unit.

Assumptions for Example

To illustrate how this would be applied, the NYISO's initial brief presented[1] an example of an on-line dispatchable fast-start unit with a minimum generation level of 90 MW, a UOL of 100 MW, a minimum generation cost offer of $4000/hour, a start-up cost offer of $400, and a minimum run time of 30 minutes, which submits the following incremental offer curve:

- $30/MWh to increase its output from 90 MW to 91 MW.

- $40/MWh to increase its output from 91 MW to 95 MW.

- $50/MWh to increase its output from 95 MW to 100 MW.

In that case, the NYISO would calculate the following for this unit:

- A no-load cost of $4000/hr. – (90 MW × $30/MWh) = $1300.

[1] NYISO initial brief at 7-8.

- A no-load adjustment of $1300 / 100 MWh = $13/MWh.
- A start-up adjustment of $400 / (100 MWh × 0.5 hr.) = $8/MWh.

Therefore, for the 30 minutes after this unit starts, its adjusted offer curve would be:[2]

- $30/MWh + $13/MWh + $8/MWh = $51/MWh to increase its output from 0 MW to 91 MW.
- $40/MWh + $13/MWh + $8/MWh = $61/MWh to increase its output from 91 MW to 95 MW.
- $50/MWh + $13/MWh + $8/MWh = $71/MWh to increase its output from 95 MW to 100 MW.

The red dotted line in Fig. 1 shows this adjusted offer curve, which the RTD pricing pass will use when determining real-time prices.

Fig. 1: Adjusted Offer Curve, Using the NYISO's Proposal

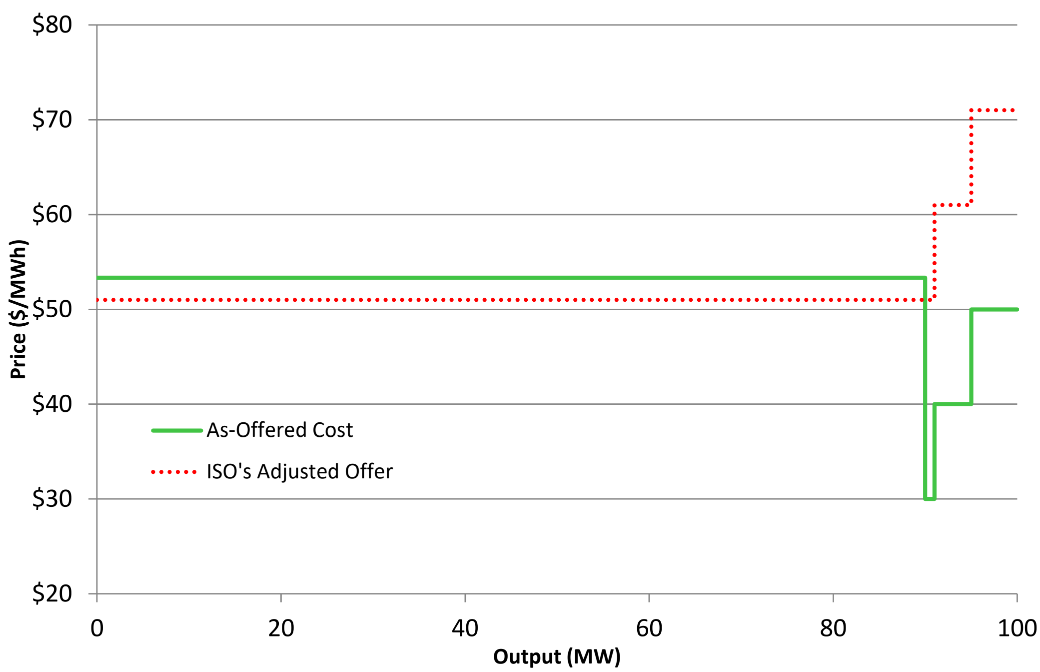


Fig. 1 also includes a solid green line showing the actual cost of operating this unit, which the RTD dispatch pass will use to issue basepoints to this unit. For the first 90 MW of this unit's capacity, which corresponds to its minimum generation level, the green line reflects the

[2] Each of these adjusted offer prices would be reduced by $8/MWh following the completion of its 30-minute minimum run time.

cost of operating this unit is calculated as the average cost of operating this unit at its minimum generation level for its 30-minute minimum run time, which is \$53.33/MWh.[3] For capacity above the minimum generation level, the green line reflects the incremental energy offers actually submitted for this unit. As this comparison makes clear, the NYISO's adjusted offer curve, which would be used by the RTD pricing pass but not the RTD dispatch pass, overstates the cost of increasing output above this unit's minimum generation level.

Proposed Procedure May Cause Real-Time Prices to Be Overstated

This difference can cause real-time prices to be overstated. Assume that the NYISO can meet all but 99 MW of load over the next half hour using on-line non-fast start resources. It has two options to meet the remaining 99 MW of load:

- It can start the fast-start unit in Example 1, and dispatch it to produce 99 MW.
- Or it can dispatch 99 MW of dispatchable generation from on-line non-fast-start resources, which has been offered at an incremental cost of \$60/MWh.

Given this choice, RTD's dispatch pass will start the fast-start unit, since its as-offered cost to operate at 99 MW for its 30-minute minimum run time is \$2595.[4] This is less than the cost of using available capacity from on-line non-fast-start resources, which is \$2970.[5] However, RTD's pricing pass will operate under the assumption that the fast-start unit is dispatchable from zero to 100 MW using the adjusted offer curve shown in red in Fig. 1. Therefore, in the pricing pass, the NYISO will schedule the fast-start generator to produce just 91 MW. It will schedule \$60/MWh dispatchable capacity from non-fast-start units to produce the remaining 8 MW, even though those units are not actually dispatched by RTD's dispatch pass because less expensive resources are available. As a result, the real-time locational-based marginal price ("LBMP") will be \$60/MWh, even though the capacity from those units is not actually used to meet load. This results from the fact that the adjusted offer curve used by RTD's pricing pass overstates the cost that is actually incurred when the fast-start unit operates above 90 MW.

Gaming May Exacerbate This Concern, Causing Real-Time Prices to be Greatly Overstated

Because the NYISO's no-load adjustment is tied to the offer submitted for the first incremental energy block of a dispatchable fast-start resource, generators can manipulate the no-

[3] Since it will cost \$400 to start this unit and another \$4000 × 0.5 hr. = \$2000 to run it at its 90 MW minimum generation level for 30 minutes, its average cost is \$2400 / (90 MW × 0.5 hr.) = \$53.33/MWh.

[4] The cost of starting this unit is \$400, and the cost of operating it at 99 MW for 30 minutes is (\$4000 + \$30/MWh × 1 MW + \$40/MWh × 4 MW + \$50/MWh × 4 MW) × 0.5 hr. = \$2195, for a total of \$2595.

[5] The cost of dispatching on-line non-fast-start resources to produce this energy is \$60/MWh × 99 MWh × 0.5 hr. = \$2970.

load adjustment by changing the offer for that first incremental energy block. Effectively, this permits generators to shift costs from their minimum generation segments to their dispatchable segments for the purposes of RTD's pricing pass, which will make the dispatchable segments appear be uneconomic when they are being evaluated by RTD's pricing pass, even though they are economic (and are being dispatched) by RTD's dispatch pass. Depending on the cost of the other resources that are available to RTD's pricing pass, this could permit the LBMP to be set by resources that are not even close to being economic.

To illustrate, suppose that the generator makes the following changes in its offer:

- It increases its minimum generation cost offer, which was \$4000/hr., to \$5030/hr., an increase of \$1030/hr.

- It decreases its offer to increase output from 90 MW to 91 MW, which was \$30/MWh, to –\$1000/MWh, a decrease of \$1030/MWh.

These two changes will offset and will not affect whether RTD's dispatch pass will operate this unit, because the cost of operating this unit at 99 MW for 30 minutes remains \$2595,[6] as before. However, these changes can have a significant impact on the dispatch by RTD's pricing pass. This unit's no-load cost would increase to \$5030/hr. – (90 MW × –\$1000/MWh) = \$95,030, so its no-load adjustment would skyrocket to \$95,030 / 100 MWh = \$950.30/MWh. Therefore, for the 30 minutes after this unit starts, its adjusted offer curve would be (as shown by the red dotted line in Fig. 2): [7]

- –\$1000/MWh + \$950.30/MWh + \$8/MWh = –\$41.70/MWh to increase its output from 0 MW to 91 MW.

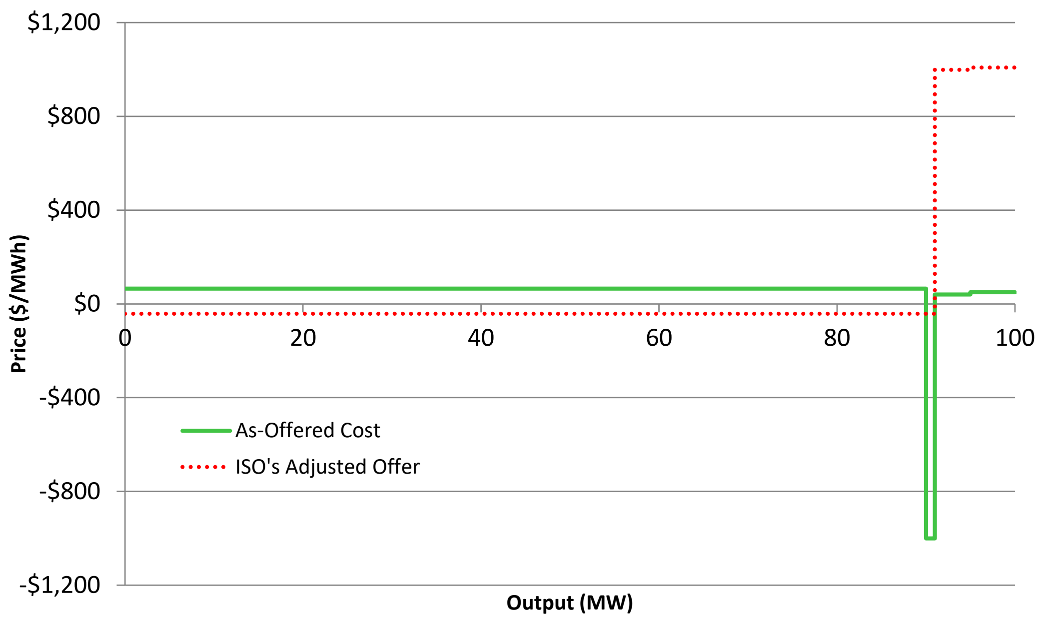
- \$40/MWh + \$950.30/MWh + \$8/MWh = \$998.30/MWh to increase its output from 91 MW to 95 MW.

- \$50/MWh + \$950.30/MWh + \$8/MWh = \$1008.30/MWh to increase its output from 95 MW to 100 MW.

[6] Under this revised offer, the cost of starting this unit is still \$400, and the cost of operating it at 99 MW for 30 minutes is (\$5030 + –\$1000/MWh × 1 MW + \$40/MWh × 4 MW + \$50/MWh × 4 MW) × 0.5 hr.. = \$2195, for a total of \$2595.

[7] Again, each of these adjusted offer prices would be reduced by \$8/MWh following the completion of its 30-minute minimum run time.

Fig. 2: Adjusted Offer Curve, Using the NYISO's Proposal, with Gaming



As in the previous example, RTD's pricing pass will schedule the fast-start generator to produce just 91 MW, while scheduling $60/MWh capacity from non-fast-start units to produce the remaining 8 MW. This would set the LBMP at $60/MWh.

However, suppose for the moment that dispatchable capacity from non-fast-start units had been offered at $900/MWh, rather than $60/MWh. Given the adjusted offer curve shown in Fig. 2, RTD's pricing pass would **still** schedule 8 MW from those units, even at a cost of $900/MWh. As expensive as they are, they are less expensive than the last 9 MW available from the fast-start unit, whose cost RTD's pricing pass believes to be almost $1000/MWh. Therefore, the LBMP would be $900/MWh, even though RTD's dispatch pass meets load using capacity from a fast-start unit whose average cost is less than $60/MWh.

An Alternative Procedure Would Better Address These Concerns

These problems occur because the NYISO's proposal for determining the adjusted offer curve applies the same no-load and start-up cost adjustments to the offers for the dispatchable and non-dispatchable portions of the unit. A better approach would allocate a larger share of no-load and start-up costs to the non-dispatchable portion of the unit, while minimizing the adjustment that is applied to the offers for the dispatchable portion of the unit. That way, the adjusted offer that the RTD pricing pass uses for the dispatchable portion of the unit will be as close as possible to the offer that the RTD dispatch pass uses to dispatch that portion of the unit.

The following approach meets this criterion. Under this approach, the NYISO would use the following procedure to determine an adjusted offer curve that the RTD pricing pass would use for on-line dispatchable fast-start-units:

- First, the NYISO would determine the output level that minimizes the average as-offered cost of operating that unit. This may be its minimum generation level, its UOL, or anywhere in between. For the purposes of this description, refer to this cost as the "minimum average cost," and let the unit's "AC-minimizing output level" refer to the output level at which the average cost is minimized.

- For all output levels that are less than the AC-minimizing output level, the NYISO would set the price on the adjusted offer curve equal to the minimum average cost.

- For all output levels above the AC-minimizing output level, the NYISO would set the price on the adjusted offer curve equal to the price on the offer curve that was actually submitted (which is actually used by the RTD dispatch pass to dispatch that unit).

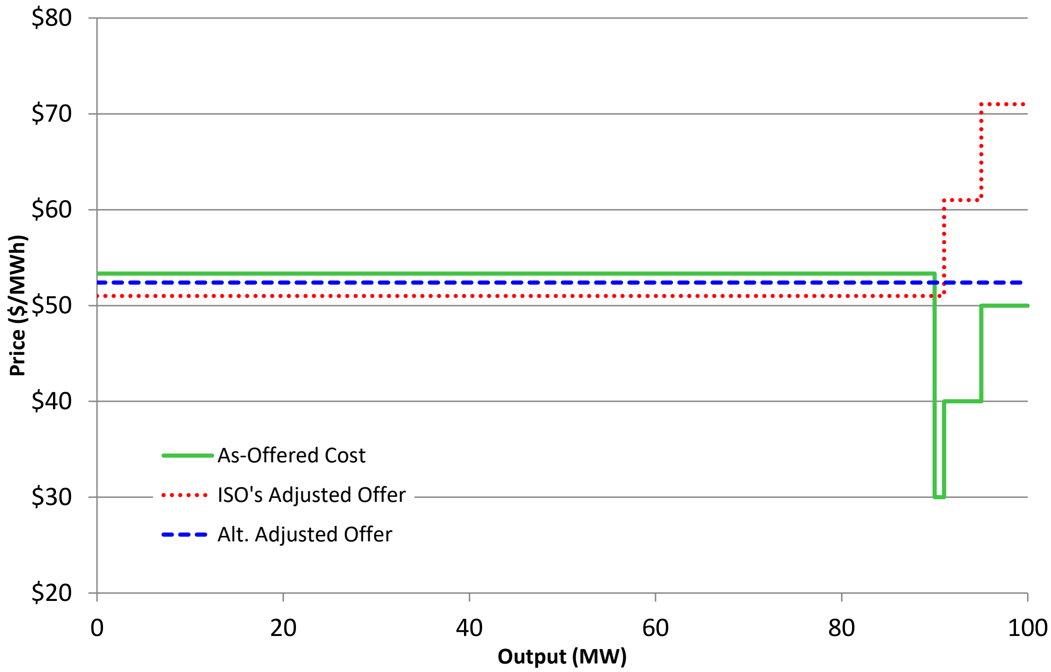
Applying This Approach to the Previous Example

If the unit in the example above were to operate at its 100 MW UOL for its minimum run time, its total cost would be $2620,[8] so its average cost is $2620 / (100 MW × 0.5 hr.) = $52.40/MWh. Since this exceeds the $50/MWh cost of its third (and most expensive) incremental energy block, that unit minimizes its average cost when it operates at its 100 MW UOL. Therefore, under this proposal, its adjusted offer curve would simply be set at $52.40/MWh for the full 100 MW capacity of this unit (as shown by the blue dashed line in Fig. 3). Therefore, in the example above, RTD's pricing pass would schedule this unit to produce 99 MW, and the real-time LBMP would be set by its adjusted offer, $52.40/MWh.

This adjusted offer curve still differs from the actual cost of operating this unit's dispatchable segment (which the RTD dispatch pass will still use). This is an unavoidable consequence of the need to implement offer curves that are convex (i.e., do not decrease) and that reflect the full cost of operating the resource, and it will occur in all cases when the average cost of operating the generator is minimized by operating it in its dispatchable range. However, in contrast to the NYISO's proposal, this approach minimizes this difference, thereby reducing the likelihood that LBMPs will be set by resources that are not actually economic to meet load, like the $60/MWh resources in the example above.

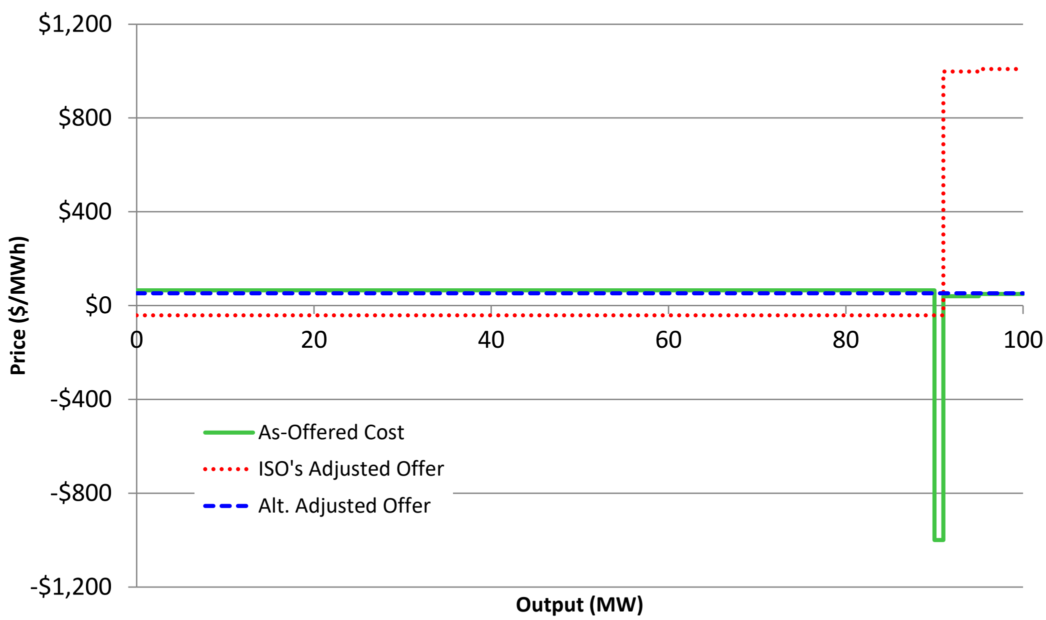
[8] The cost of starting this unit is $400, and the cost of operating it at 100 MW for 30 minutes is ($4000 + $30/MWh × 1 MW + $40/MWh × 4 MW + $50/MWh × 5 MW) × 0.5 hr. = $2220, for a total of $2620.

Fig. 3: Adjusted Offer Curves, Using Both Proposals



Additionally, as Fig. 4 shows, under this proposal, the gaming strategy described above would have no effect whatsoever. If it were employed, the adjusted offer curve would continue to be constant at $52.40/MWh for the full 100 MW capacity of the unit, because the gaming strategy does not change the "minimum average cost" or the "AC-minimizing output level." Therefore, the LBMP would also continue to be $52.40/MWh.

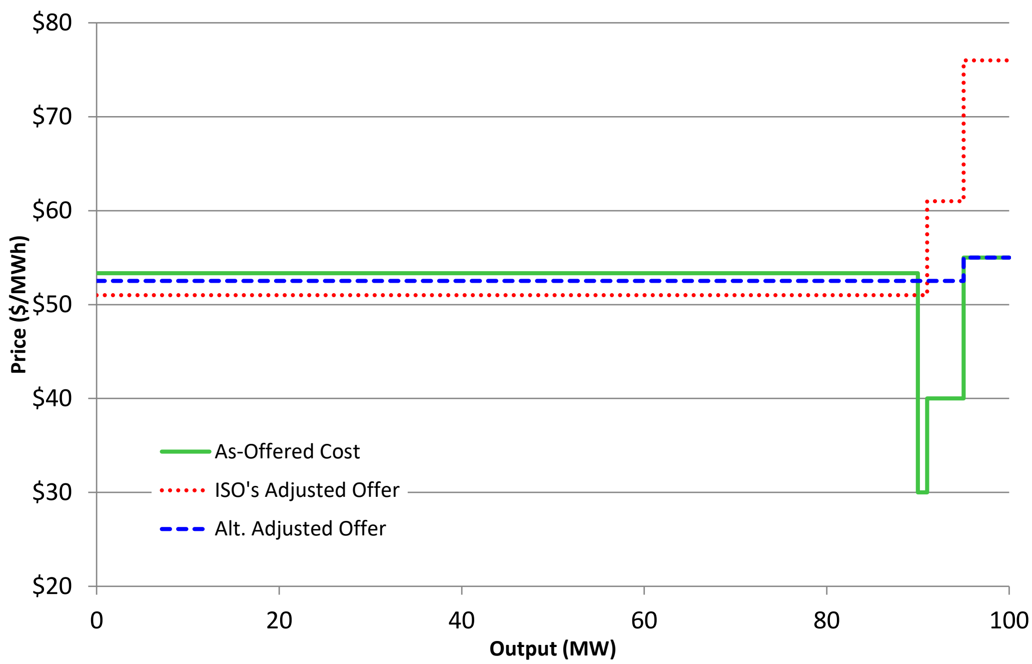
Fig. 4: Adjusted Offer Curves, Using Both Proposals, with Attempted Gaming



Applying This Approach to a Modified Example

Suppose that the unit's offer for its third and last incremental energy block had been \$55/MWh, rather than \$50/MWh. Fig. 5 shows how the adjusted offer curve would be drawn, both under the NYISO's proposal and the alternative approach described here. Under the NYISO's proposal, the no-load and start-up adjustments are the same as before, so the only change in the adjusted offer curve is a \$5/MWh increase in the adjusted offer for the last block, which rises from \$71/MWh to \$76/MWh to reflect the \$5/MWh increase in the incremental energy offer that was submitted for that block. Meanwhile, due to the increase in the offer to produce energy using that last incremental block, the average cost of operating the unit now would be minimized when its output is 95 MW, rather than 100 MW. The cost of operating at that level for 30 minutes is \$2495,[9] so its average cost at 95 MW is \$2495 / (95 MW × 0.5 hr.) = \$52.53/MWh. Therefore, under the alternative approach, this unit's adjusted offer curve would be set at \$52.53/MWh for output between 0 MW and 95 MW, and \$55/MW (i.e., the actual incremental energy offer that the RTD dispatch pass will use) for output between 95 MW and 100 MW.

Fig. 5: Adjusted Offer Curves, Using Both Proposals, with a Higher Offer for the Last Incremental Block



Given that offer, RTD's dispatch pass would schedule the fast-start unit to produce 99 MW. So would RTD's pricing pass, if the alternative proposal for determining adjusted offers were adopted. Therefore, the LBMP would be \$55/MWh, as it should be. In contrast, under the

[9] The cost of starting this unit is \$400, and the cost of operating it at 100 MW for 30 minutes is (\$4000 + \$30/MWh × 1 MW + \$40/MWh × 4 MW) × 0.5 hr. = \$2095, for a total of \$2495.

NYISO's proposal for determining adjusted offers, RTD's pricing pass would continue to produce an inefficiently high price of $60/MWh.