FAST-START PRICING

June 24, 2019

On April 18, FERC directed the ISO to implement changes to its current fast-start pricing procedures, in order to "allow the start-up costs of fast-start resources to be reflected in prices, and … relax the economic minimum operating limit of all fast-start resources … by up to 100 percent for the purpose of setting prices."[1] In order to comply with these directives, the ISO will need to develop procedures for setting the offer curves that will be used for on-line fast-start resources in RTD's pricing pass that may differ from the offer curves that are used for those resources in RTD's dispatch pass. The ISO must do this because a generator's minimum generation offer, when stated in $/MWh of energy generated at a resource's minimum generation level, may exceed its offer for its first incremental energy block. In such cases, if the minimum generation constraint is relaxed, it becomes necessary to allocate a portion of the generator's minimum generation offer to the resource's incremental generation capacity to ensure that the offer curves used in the pricing dispatch do not decrease as that resource's output increases. It will also be necessary to develop a procedure for allocating start-up costs over the period in which such a resource is expected to operate.

At the May 30 meeting of the Market Issues Working Group, the ISO asked stakeholders to submit proposals for allocating these costs. Consequently, the TOs offer the following proposal. While it is based on the proposal contained in comments previously submitted by the TOs in the proceeding that led to the FERC order,[2] the example used to illustrate the proposal has been modified to include multiple RTD intervals. Additionally, the proposal has been expanded to cover the allocation of start-up costs, because the TOs' previous example simply adopted the procedure for allocating start-up costs that the ISO had proposed in its initial brief,[3] in order to focus upon the allocation of minimum generation costs. While this proposal is offered for the ISO's consideration, the TOs will continue to consider this issue; therefore, it does not necessarily reflect a position being taken by the TOs.

[1] *N.Y. Indep. Sys. Operator, Inc.,* 167 FERC ¶ 61,057 (2019) at P 11.

[2] *N.Y. Indep. Sys. Operator, Inc.,* Reply Brief of the New York Transmission Owners, Docket No. EL18-33-000 (filed Mar. 14, 2018), Att. A.

[3] *N.Y. Indep. Sys. Operator, Inc.,* Initial Brief of the New York Independent System Operator, Inc., Docket No. EL18-33-000 (filed Feb. 12, 2018).

Step 1: Allocation of Start-Up Costs to RTD Intervals

Rationale

Initially, it is necessary to allocate the start-up costs for a fast-start generator over the time that the generator is expected to operate. The ISO's original proposal was simply to allocate start-up costs equally over each RTD interval in the generator's minimum run time. There are two problems with this approach.

First, the ISO may commit fast-start generators primarily to meet needs immediately after the time that the generator was started. If so, allocating those costs equally to each interval will allocate too small a share of those costs to the intervals immediately following the start of the generator, and too large a share to later intervals. This will tend to cause LBMPs immediately following the start of the generator to be lower than they should be, thereby providing insufficient incentive for generators to be able to start quickly. It will also tend to cause LBMPs in later intervals to be higher than they should be, thereby providing too much incentive for generators to begin producing energy after the need has passed.

Second, in some cases, fast-start generators may submit relatively high start-up costs but relatively low minimum generation and incremental energy offers. In such cases, it might not be economically efficient to commit that generator if it is only expected to operate for its minimum run time, but it might be economically efficient to commit it if it is expected to continue operating after the completion of its minimum run time. If so, a method that allocates start-up costs over the minimum run time, instead of the period of time that the generator is expected to operate at the time that RTC commits that generator (henceforth, the "anticipated operating period"), will allocate too large a share of those costs to the intervals within the minimum run time, causing LBMPs during that period to be higher than they should be, while allocating too small a share of those costs to the intervals following the completion of the minimum run time, causing those LBMPs to be lower than they should be.

Proposal

Taking both these considerations into account, start-up costs associated with a given fast-start generator should be allocated over the anticipated operating period, but the allocation procedure should also consider the relative value of energy produced in each interval within that anticipated operating period. More specifically: RTC produces advisory LBMPs (that are **not** used for real-time market settlement purposes) for each location for 15-minute periods. Therefore, for the purpose of developing adjusted offer curves that will be used by the RTD pricing pass, start-up costs for a fast-start generator that is started in a given RTC run should be allocated over the RTD intervals in the anticipated operating period in proportion to the amount by which the LBMP calculated in that RTC execution at that generator's bus exceeds the LBMP calculated in that RTC execution at that generator's bus immediately following the end of the anticipated operating period (or zero, if that difference is negative).

Illustrative Example

To illustrate how this procedure would work, consider an on-line dispatchable fast-start unit, with a minimum generation level of 72 MW, a UOL of 96 MW, a minimum generation cost offer of $3600/hour, a start-up cost offer of $400, and a minimum run time of 30 minutes. Also assume that this generator submits the following incremental offer curve:

- $30/MWh to increase its output from 72 MW to 84 MW.
- $50/MWh to increase its output from 84 MW to 90 MW.
- $55/MWh to increase its output from 90 MW to 96 MW.

Also assume that RTC commits the unit with the expectation that it will run in intervals 1 through 9, as shown in Table 1 below.[4]

Table 1: RTC Determination of Commitment and Expected Dispatch Levels for Illustrative Example

Interval	RTC LBMP ($/MWh)	Min Gen Cost ($/MWh)	1st Incre. Offer ($/MWh)	2nd Incre. Offer ($/MWh)	3rd Incre. Offer ($/MWh)	Min. Avg. Cost Excl. SU ($/MWh)	Dispatch (MW)
1	95	$ 50.00	$ 30.00	$ 50.00	$ 55.00	$ 47.14	96
2	95	$ 50.00	$ 30.00	$ 50.00	$ 55.00	$ 47.14	96
3	95	$ 50.00	$ 30.00	$ 50.00	$ 55.00	$ 47.14	96
4	75	$ 50.00	$ 30.00	$ 50.00	$ 55.00	$ 47.14	96
5	75	$ 50.00	$ 30.00	$ 50.00	$ 55.00	$ 47.14	96
6	75	$ 50.00	$ 30.00	$ 50.00	$ 55.00	$ 47.14	96
7	50	$ 50.00	$ 30.00	$ 50.00	$ 55.00	$ 47.14	90
8	50	$ 50.00	$ 30.00	$ 50.00	$ 55.00	$ 47.14	90
9	50	$ 50.00	$ 30.00	$ 50.00	$ 55.00	$ 47.14	90
10	40	$ 50.00	$ 30.00	$ 50.00	$ 55.00	$ 47.14	0
11	40	$ 50.00	$ 30.00	$ 50.00	$ 55.00	$ 47.14	0
12	40	$ 50.00	$ 30.00	$ 50.00	$ 55.00	$ 47.14	0

[4] The next-to-last column in this table is the minimum possible value for the average cost, including minimum generation and incremental energy costs but excluding start-up cost, incurred to run this generator in each interval. Since that value is less than the $50/MWh forecasted LBMP for intervals 7 through 9, the generator is committed in the expectation that it will run in these intervals. However, because this cost exceeds the $40/MWh forecasted LBMP for intervals 10 through 10, the generator is committed in the expectation that it will shut down at the end of interval 9.

In that case, start-up costs are allocated to intervals 1 through 9 as shown in Table 2. The start-up cost share for each interval in that table is proportional to the amount by which the RTC LBMP for that interval exceeds $40/MWh (which is the RTC LBMP for intervals 10 through 12, following the end of the anticipated operating period).

Table 2: Allocation of Start-Up Costs for Illustrative Example

RTD Interval	RTC LBMP ($/MWh)	Start-Up Cost Share	Start-Up Cost Allocation
1	95	18.3%	$ 73.33
2	95	18.3%	$ 73.33
3	95	18.3%	$ 73.33
4	75	11.7%	$ 46.67
5	75	11.7%	$ 46.67
6	75	11.7%	$ 46.67
7	50	3.3%	$ 13.33
8	50	3.3%	$ 13.33
9	50	3.3%	$ 13.33
10	40	0.0%	$ -
11	40	0.0%	$ -
12	40	0.0%	$ -
			$ 400.00

This differs slightly from a similar approach proposed by the MMU. The MMU proposed allocating these costs "in proportion to the value of its energy forecasted by RTC over the initial commitment period."[5] The logic underlying the difference is as follows. First, consider RTD intervals 10 through 12, in which the RTC LBMP is $40/MWh. This price is low enough that the generator is not expected to operate in those intervals. Therefore, since it was not started in the expectation that it could operate in those intervals, those intervals should not be allocated any portion of the start-up costs of this generator. Next, consider RTD intervals 10 through 12, in which the RTC LBMP is $50/MWh. The generator is expected to operate in these intervals, even though it does not need to do so to complete its minimum run time. But the savings that result from being able to operate that generator in those intervals are relatively small, as a slight decrease in the LBMP to $40/MWh in the following three RTD intervals was sufficient to render continued operation of the generator uneconomic. Consequently, those intervals should be allocated a very small share of start-up costs.

[5] *N.Y. Indep. Sys. Operator, Inc.*, Comments of the New York ISO's Market Monitoring Unit, Docket No. EL18-33-000 (filed Feb. 13, 2018) at 8.

STEP 2: ALLOCATION OF COSTS WITHIN EACH RTD INTERVAL

Objective

The next step is to allocate the sum of the minimum generation costs and incremental energy costs incurred within an interval and start-up costs allocated to that interval to the generator's capacity. The objective of this procedure should be to minimize the difference between the actual offer that was submitted for the generator's dispatchable segment, which is used by the dispatch pass to determine the schedule for the generator, and the adjusted offer that is used to determine the LBMP in the pricing pass. This will minimize inconsistencies between schedules and prices that result from the use of different offer curves in RTD's dispatch and pricing passes. It will also reduce the susceptibility of the approach to gaming, by manipulating bids in a manner that is intended to exacerbate the difference between the actual and adjusted offer curves.

Proposal

Under this approach, the adjusted offer curve for on-line dispatchable fast-start generators is determined as follows:

- First, the ISO determines the average as-offered cost of operating that generator, which includes that generator's minimum generation cost, its incremental energy offers if applicable, and the portion of its start-up costs that were allocated to that RTD interval, for each output level between that generator's minimum generation level and its UOL.
- Next, the ISO determines the AC-minimizing output, which is the output level at which the average as-offered cost of operating that generator during that RTD interval is minimized. This may be the generator's minimum generation level, its UOL, or anywhere in between. The average cost when operating at the AC-minimizing output level in a given RTD interval is the "minimum average cost" for that generator in that interval.
- Then the adjusted offer curve that is used for that generator in that RTD interval is as follows:
    - For all output levels that are less than the AC-minimizing output, the price on the adjusted offer curve is equal to the minimum average cost for that generator in that RTD interval.
    - For all output levels above the AC-minimizing output, the price on the adjusted offer curve is the same as the price on the offer curve that was actually submitted for that generator in that RTD interval.

Illustrative Example

Continuing with the preceding example, if the generator operates at its 96 MW UOL in intervals1 through 3, then in each of those intervals:

- It will incur $3600/hr. / 12 = $300 in minimum generation costs.
- It will incur ($30/MWh × 12 MW + $50/MWh × 6 MW + $55/MWh × 6 MW) /12 = $82.50 in incremental energy costs.
- Those intervals will each be allocated $73.33 in start-up costs.
- Therefore, the total cost allocated to each of those intervals is $455.83.
- The generator will produce 96 / 12 = 8 MWh of energy during each of those intervals.
- So its average cost when it operates at its UOL during those intervals is $455.83 / 8 MWh = $56.98/MWh.
- This exceeds the $55/MWh incremental energy bid for its most expensive incremental energy block. Therefore:
    - Its AC-minimizing output is its 96 MW UOL.
    - Its minimum average cost is $56.98/MWh.

Its adjusted offer curve for these RTD intervals is $56.98/MWh for its entire 96 MW UOL, as shown by the red dotted line in Fig. 1.

If the generator operates at 90 MW in intervals 4 through 6, then in each of those intervals:

- It will again incur $300 in minimum generation costs.
- It will incur ($30/MWh × 12 MW + $50/MWh × 6 MW) /12 = $55 in incremental energy costs.
- Those intervals will each be allocated $46.67 in start-up costs.
- Therefore, the total cost allocated to each of those intervals is $401.67.
- The generator will produce 90 / 12 = 7.5 MWh of energy during each of those intervals.
- So its average cost when it operates at 90 MW during those intervals is $401.67 / 7.5 MWh = $53.56/MWh.

- This is less than the \$55/MWh incremental energy bid to increase its output above 90 MW, but more than its \$50/MWh incremental energy bid to reduce its output below 90 MW, so:
    - Its AC-minimizing output is 90 MW, and
    - Its minimum average cost is \$53.56/MWh.

Its adjusted offer curve for these RTD intervals is \$53.56/MWh for the first 90 MW and \$55/MWh for the last 6 MW, as shown by the blue dashed line in Fig. 1.

If the generator operates at 84 MW in intervals 7 through 9, then in each of those intervals:

- It will incur \$300 in minimum generation costs.
- It will incur (\$30/MWh × 12 MW) /12 = \$30 in incremental energy costs.
- Those intervals will each be allocated \$13.33 in start-up costs.
- Therefore, the total cost allocated to each of those intervals is \$343.33.
- The generator will produce 84 / 12 = 7 MWh of energy during each of those intervals.
- So its average cost when it operates at 84 MW during those intervals is \$343.33 / 7 MWh = \$49.04/MWh.
- Once more, this is less than the \$50/MWh incremental energy bid to increase its output above 84 MW, but more than its \$30/MWh incremental energy bid to reduce its output below 84 MW, so:
    - Its AC-minimizing output is 84 MW, and
    - Its minimum average cost is \$49.04/MWh.

Its adjusted offer curve for these RTD intervals is \$49.04/MWh for the first 84 MW, \$50/MWh for the next 6 MW, and \$55/MWh for the last 6 MW, as shown by the magenta dotted-and-dashed line in Fig. 1.

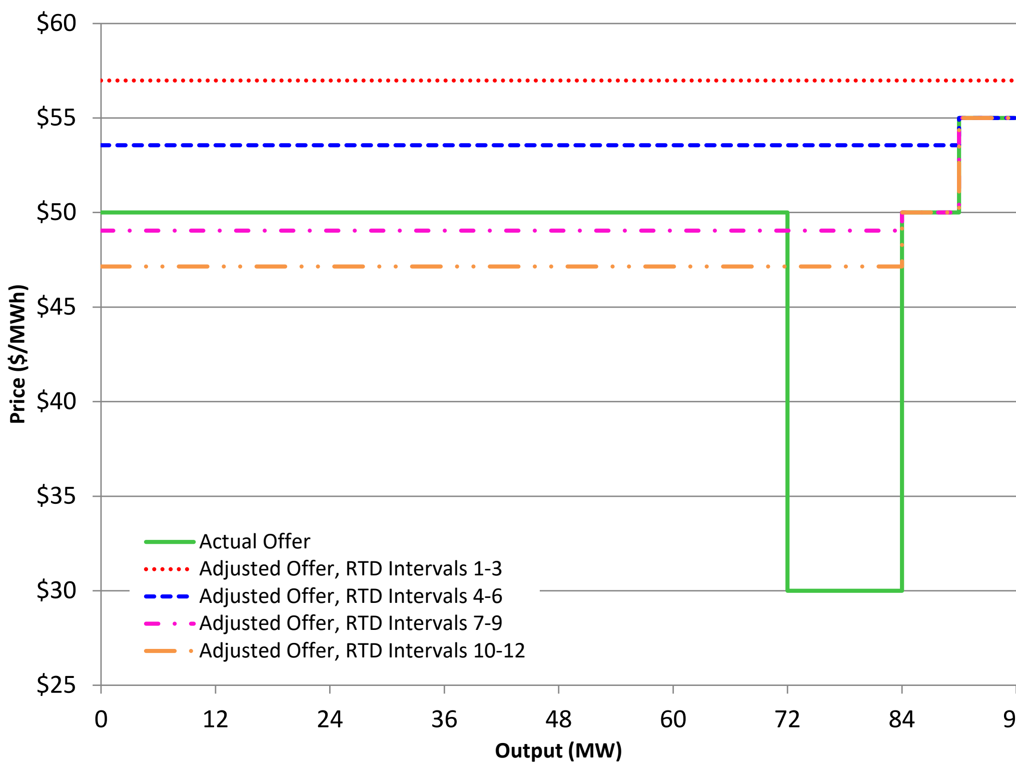
Finally, if the generator operates at 84 MW in intervals 10 through 12, then in each of those intervals:

- It will again incur \$300 in minimum generation costs and \$30 in incremental energy costs.
- Those intervals will not be allocated any start-up costs.

- Therefore, the total cost allocated to each of those intervals is $330.
- The generator will produce 7 MWh of energy during each of those intervals,
- So its average cost when it operates at 84 MW during those intervals is $330 / 7.5 MWh = $47.14/MWh.
- Once more, this is less than the $50/MWh incremental energy bid to increase its output above 84 MW, but more than its $30/MWh incremental energy bid to reduce its output below 84 MW, so:
    - o Its AC-minimizing output is 84 MW, and
    - o Its minimum average cost is $47.14/MWh.

Its adjusted offer curve for these RTD intervals is $47.14/MWh for the first 84 MW, $50/MWh for the next 6 MW, and $55/MWh for the last 6 MW, as shown by the orange dotted-and-dashed line in Fig. 1.

Fig. 1: Adjusted Offer Curves



While these adjusted offer curves differ from the actual cost of operating this generator's dispatchable segment, which is an unavoidable consequence of the need to implement offer curves that do not decrease and that reflect the full cost of operating the resource, this approach minimizes this difference. There is no difference between the price of the last incremental block in the dispatch and pricing passes in RTD intervals 4 through 12, nor is there any difference between the price of the second incremental block in RTD in in the dispatch and pricing passes in RTD intervals 7 through 12. Consequently, if those blocks are on the margin in the dispatch pass during those RTD intervals, they will set the price.

Additionally, under this proposal, attempts to manipulate the fast-start pricing rule by shifting costs between incremental energy offers and minimum generation offers would have no effect on the adjusted offer curves. However, shifting costs between start-up costs and minimum generation costs could affect the adjusted offer curve. For example, if the generator in the example above had submitted a minimum generation offer of $3100/hr. rather than $3600/hr., and had also increased its start-up offer from $400 to $775, the cost of its projected output level would have remained the same,[6] but the adjusted offer curve would have increased,[7] so it will be important to monitor attempts to manipulate the procedure used to derive these adjusted offer curves.

[6] For the 45-minute anticipated operating period in this example, the reduction in the minimum generation offer would reduce the as-offered cost of operating the generator by (3/4 hr.) × ($3600/hr. – $3100/hr.) = $375, offsetting the $375 increase in the start-up offer.

[7] The proposal described here allocates only start-up costs across intervals. One way to address this problem is to allocate the sum of the start-up cost and minimum generation cost incurred during the minimum run time across intervals, because in that case, shifting costs between minimum generation offers and start-up offers would have no effect. However, that can produce counterintuitive allocations for the period following the completion of the minimum run time. During such intervals (e.g., intervals 7 through 9 in the example), the generator can be shut down if it is no longer economic, in which case the minimum generation cost associated with that generator should no longer be incurred. Therefore the minimum generation cost incurred in those intervals should be allocated to those intervals. But a procedure that jointly allocates start-up costs and minimum generation costs over the anticipated operating period may allocate only a portion of those costs to those intervals.