PUBLIC VERSION – CONTAINS REDACTIONS

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England's Informational Filing for Qualification in the Forward Capacity Market for the 2023-2024 Capacity Commitment Period	)))	**Docket No. ER20-308-000**

MOTION TO INTERVENE AND COMMENTS OF THE ISO-NEW ENGLAND EXTERNAL MARKET MONITOR

Pursuant to Rules 212 and 214 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("FERC" or "Commission"), 18 C.F.R. §§ 385.212 and 214 (2007), Potomac Economics respectfully moves to intervene in the above-captioned proceeding concerning the ISO-New England's ("ISO-NE") informational filing for qualification of resources for the fourteenth Forward Capacity Auction ("FCA-14"). The ISO's filing included results of the Internal Market Monitor's ("IMM") review and mitigation of offers and bids from new and existing capacity resources.

Potomac Economics is the External Market Monitor ("EMM") for ISO-NE. The EMM is required to "review the quality and appropriateness of the mitigation conducted by the [IMM]. In the event that the [EMM] discovers problems with the quality or appropriateness of such mitigation, the [EMM] shall promptly inform the Commission, the Commission's Office of Energy Market Regulation staff, the ISO Board of Directors, the public utility commissions for each of the six New England states, and the Market Participants."[1] In addition, the EMM is

[1] See Section III.A.2.2 of the ISO-NE Tariff.

responsible for evaluating market performance and recommending design changes to the ISO-NE markets.

Our comments discuss the quality and appropriateness of key elements of the IMM's review and mitigation of New Resource Offer Floor Prices ("OFPs") for certain resources in FCA-14.[2] We also identify methodological concerns with certain elements of the IMM's determinations for large-scale energy storage resources ("ESRs").

I. NOTICE AND COMMUNICATIONS

All correspondence and communications in this matter should be addressed to:

Dr. David B. Patton
Potomac Economics, Ltd.
9990 Fairfax, Boulevard, Suite 560
Fairfax, VA 22030
(703) 383-0720

Dr. Pallas LeeVanSchaick
Potomac Economics, Ltd.
9990 Fairfax, Boulevard, Suite 560
Fairfax, VA 22030
(703) 383-0720

Raghu Palavadi Naga
Potomac Economics, Ltd.
9990 Fairfax, Boulevard, Suite 560
Fairfax, VA 22030
(703) 383-0783

II. MOTION TO INTERVENE AND REQUEST FOR CONFIDENTIAL TREATMENT

As the EMM for ISO-NE, Potomac Economics is responsible for evaluating the quality and appropriateness of the mitigation by the IMM. Therefore, Potomac Economics' interests cannot be adequately represented by any other party. Accordingly, Potomac Economics respectfully requests that it be permitted to intervene in this proceeding with full rights as a party.

This filing discusses the confidential details of some New Resource Offer Floor Price ("OFP") submissions of new resources and the IMM's determinations. Therefore, we request

2 We focus our comments on ESRs that whose capacity is larger than 50 MW.

confidential treatment of our comments pursuant to 18 C.F.R. § 388.112. We are filing a public, redacted version of our comments separately.

III. INTRODUCTION AND BACKGROUND

[redacted] of large-scale ESRs submitted OFP requests for FCA-14. The IMM reviewed the developers' submittals and issued a Qualification Determination Notice ("QDN") to each developer. The QDNs communicated the results of the IMM's review and the IMM-determined OFP (if the project was mitigated). The IMM filed all the QDNs and a summary of its mitigation as part of the confidential informational filing on November 5, 2019.

The ISO-NE tariff requires the IMM to reject developer-submitted information if it is "clearly inconsistent with the prevailing market conditions."[3] Therefore, if the IMM finds the any assumption underlying the requested OFPs to be outside the bounds of what could reasonably be expected by a developer, the IMM should substitute its own estimate in place of the developer-submitted value.

As the EMM for ISO-NE, we reviewed the mitigation performed by the IMM for resources that submitted OFP requests. The IMM provided us with detailed information regarding the developers' submittals and its rationale for mitigating individual resources. The IMM-determined OFPs of some of the ESR projects differed from the participant-submitted OFPs for several reasons, including:

- Insufficient documentation to support the submitted Weighted Average Cost of Capital ("WACC"); and
- The energy and ancillary services ("EAS") net revenues that were submitted by the developer were significantly higher than the EAS net revenues that were estimated by the IMM using its benchmark model.

[3] See Section III.A.21.2.(b).(i) of the ISO-NE Tariff.

We support the IMM's determinations relating to the WACC for ESR projects. Furthermore, we agree with the IMM's decision to reject submitted EAS net revenues that are unreasonably high. However, we find that the generic estimates that the IMM used instead of the submitted EAS net revenues are unreasonably low.

We are submitting the following comments as we believe they will be helpful to the Commission as it considers the mitigation results filed by the IMM. In this filing, we comment on the reasonableness of: (a) the IMM's determinations related to WACC, (b) the developer-submitted EAS net revenues, and (c) the IMM-determined EAS net revenues.

IV. IMM-DETERMINED WEIGHTED-AVERAGE COST OF CAPITAL

Some ESR developers submitted real after-tax WACC values that ranged from [redacted], compared to the 6.6 percent value that was used to develop the CONE and ORTP values, which were approved by FERC.[4] These developers provided either no documentation or insufficient documentation to support their submitted WACC values. The IMM deemed these submittals to be unsubstantiated and adjusted the WACC to the value from the CONE and ORTP study.

We support the IMM's decision to use the WACC value from the CONE and ORTP study rather than the submitted values. In the CONE and ORTP study, the WACC was developed for a hypothetical investment where the project would be exposed to normal market risk on the sale of energy, ancillary services, and capacity. For projects that submitted documentation to support a lower WACC (such as the term sheet for another ESR project), we found that key elements of the term sheet were not consistent with the assumptions used to derive the submitted WACC value. Therefore, we agree with the IMM's decision to reject the developer-submitted WACC values for some of the projects.

4 See 2016 report on *ISO-NE CONE and ORTP Analysis* by Concentric Energy Advisors.

V. DEVELOPER-SUBMITTED ENERGY AND RESERVE MARKET REVENUES

Estimating energy and ancillary services revenues for ESRs is complicated because it involves predicting the extent to which they can purchase electricity in lower-priced hours to charge in order to sell electricity (or reserves) in higher priced hours. This is complicated because the ESRs do not have perfect foresight and future energy and ancillary services prices can be volatile and uncertain. Therefore, differences in estimates largely reflect the expected quality of the forecasting and optimization of the ESRs charging and discharging cycles.

Some developers submitted EAS net revenues that were between [redacted] resources participating in the regulation market receiving an additional [redacted][5] The IMM deemed these developer-submitted EAS net revenues to be outside the bounds of what could be reasonably expected by a developer, and replaced them with its generic estimates. We agree with the IMM's decisions to reject the submitted EAS net revenues for these developers for the following reasons:

- First, in estimating EAS net revenues these developers assumed varying degrees of perfect foresight of real-time prices. Assuming perfect foresight leads to unreasonably high EAS revenue estimates.

- Second, the estimated EAS net revenues of some resources relied on being able to adjust their energy market offers for every five-minute interval in real-time. Such "price-chasing" behavior is not feasible under the current market rules, and all resources are required to submit offers 30 minutes in advance of each hour. Properly reflecting these time-constraints reduces the ability of ESRs (and other technologies) to profit from transient price volatility.

[5] While the methodology for estimating the EAS net revenues differed by developer, all the developers relied on historical prices to estimate EAS net revenues that consisted of net revenues from energy arbitrage, sale of real-time reserves and sale of frequency regulation for certain resources.

(Continued…)

To further evaluate the reasonableness of individual developers' submissions, we performed an analysis to estimate the EAS net revenues of a hypothetical two-hour ESR using several methodologies:[6]

- *Approach 1* - The ESR has perfect foresight of 5-minute real-time prices for the entire day and constructs its hourly offers to maximize the EAS net revenues. This approach would have yielded $56 per kW-year for a resource that participates only in energy and reserve markets, with resources participating in the regulation market receiving an additional $7 per kW-year. Given that this approach assumes a perfect forecast of 5-minute prices, it is an over-estimate of what a resource could actually earn.

- *Approach 2* - The ESR is scheduled optimally based on day-ahead energy prices, which is possible because all 24 hours of the day-ahead market are cleared simultaneously. The resource would receive additional net revenues from sale of spinning reserves in the real-time market. This approach would have yielded $30 per kW-year of EAS net revenues for a resource that participates only in energy and reserve markets, with resources participating in the regulation market receiving an additional $9 per kW-year. Given the limited sophistication of this approach, this represents the minimum that an ESR developer could reasonably expect to receive in EAS net revenues.

- *Approach 3* - The ESR continuously updates a forecast of the minimum and maximum prices over the remainder of the day based on: (a) price forecasts published for the Coordinated Transaction Scheduling ("CTS") process between ISO-NE and the NYISO, which look ahead 150 minutes, and (b) prices from the day-ahead market. Each month, the ESR determines real-time charging and discharging adjustment factors that would have maximized EAS net revenues in the previous month if the adjustment factors had been used to develop bids and offers relative to the continuously updated minimum and maximum price forecasts.[7]

Approach 3 would have yielded $34 per kW-year for a resource that does not participate in the regulation market, with resources participating in the regulation market receiving an additional $12 per kW-year. This approach shows that an ESR would likely perform better than

---

6 We assume that the ESR will charge and discharge once every day (i.e. 365 cycles a year). We estimate EAS net revenues for the period of March 2017 through February 2019. We further assume a round-trip efficiency of 86 percent, and that all efficiency losses will be incurred during charging.

7 For example, if the ESR would have maximized EAS net revenues in the previous month by offering to sell energy at 130 percent of the forecasted maximum price, the ESR will submit energy offers in the current month at 130 percent of the forecasted maximum price. We describe all the assumptions underlying this approach in the Appendix.

Approach 2 by considering more timely information closer to real-time. Further improvement is likely to be possible with additional forecast enhancements. Hence, although we believe this estimate is a good representation of the EAS revenues a reasonably competent ESR owner could achieve, we expect that ESR owners could exceed these levels of EAS revenues.

Overall, these analyses support the IMM's determination that some developer-submitted EAS net revenues were unreasonably optimistic. Hence, it was appropriate for the IMM to adjust the EAS net revenues and mitigate the OFPs of such ESRs.[8] As we explain in the following section, however, these analyses also indicate that the EAS revenue levels assumed by the IMM in mitigating the OFPs were unreasonably low.

VI. IMM-DETERMINED ENERGY AND RESERVE MARKET REVENUES

The IMM revised the developer-submitted EAS net revenues using a benchmark model that it developed for evaluating ESRs' OFP submissions for FCA-14. The IMM's benchmark model produced EAS net revenues that averaged [redacted] that receive only energy and reserve net revenues and an additional [redacted] on an average for ESRs that offer part of their capacity for regulation.

The IMM's benchmark model scheduled ESRs optimally each day based on day-ahead prices. The resulting charge/discharge schedule was settled using hourly real-time prices with an additional constraint that prevented discharge if real-time prices exceeded $300 per MWh (to avoid PFP-related penalties). The IMM described its benchmark model in detail as part of the QDNs it sent to the developers.

8 [redacted]

We are concerned that the IMM-determined EAS net revenues are unreasonably low, particularly for resources that receive only energy and reserve net revenues. The primary issue with the IMM method is that it ignores the ability of ESRs to use information that becomes available after the Day-Ahead market and the real-time prices that they are observing.

As discussed in Section V, relatively simple strategies that rely only on information that is available when submitting real-time offers can produce significantly higher EAS net revenues when compared to the IMM's estimates.[9] For instance, Approach 3 yielded $34 per kW-year in EAS net revenues as opposed to the IMM's estimate of [redacted] for resources that received only energy and reserve net revenues. The following issues with the IMM's methodology likely resulted in low estimates for EAS net revenues:

- First, the IMM's methodology does not consider all the information that a resource could utilize when constructing its offers in real-time. For instance, the IMM's model does not consider forecasted prices from the CTS process, which are publicly available and reflect more recent information on real-time conditions. As such, under the IMM methodology, the ESR would not be able to benefit from its abilities to react quickly to changes in real-time conditions.

- Second, the IMM utilized prices from the last three Capacity Commitment Periods. However, the ISO implemented fast-start pricing beginning March 2017 which resulted in higher spreads between on-peak and off-peak prices. Hence, using data from 2016 and the first two months of 2017 to estimate energy arbitrage profits is not appropriate, and likely led to lower estimates for EAS net revenues.

- Third, the IMM's model constrained the ESR discharge if the real-time prices rose above $300 per MWh to protect against PFP-related penalties. This is overly conservative, since considering price forecasts from CTS when developing real-time offers is likely to be sufficient to avoid PFP-related penalties. Hence, this assumption likely precluded the ESRs from profiting from price spikes.

---

9 The IMM's benchmark model determines the ESR schedule which in turn impacts the availability ("A") of the resource during PFP events. Based on its results, the IMM slightly decreased or increased each resource's A. Both Approach 2 and Approach 3 results suggested that the ESRs would be fully available (assuming no forced outage rate) during the reserve shortage events in 2017 and 2018. Hence, A values for ESRs could be two to seven percentage points higher than the IMM-determined values.

Overall, we believe that the IMM-determined EAS net revenues are well below what could reasonably be expected by an ESR developer, particularly for resources that receive only energy and reserve revenues. The IMM-determined EAS net revenues had a significant impact on the OFPs of some of the ESRs, and we are concerned that using these estimates has led to over-mitigation of some ESRs. Accordingly, we request the Commission direct the IMM to re-estimate the EAS net revenues using a more reasonable methodology for ESRs and revise its determinations accordingly.

We believe that the EAS net revenues produced using Approach 3 (see section V) are reasonable and that the underlying methodology represents a workable approach for determining the OFPs of ESRs for FCA-14 in the time available.

VII. CONCLUSION

WHEREFORE, for the foregoing reasons, Potomac Economics, Ltd. respectfully requests the Commission to grant its motion to intervene in this proceeding, accept these comments, and require the IMM to revise its determinations for OFPs of ESR for FCA-14.

Respectfully submitted,

/s/ David B. Patton

David Patton
President
Potomac Economics, Ltd.

CERTIFICATE OF SERVICE

I hereby certify that I have this day e-served a copy of this document upon all parties listed on the official service list compiled by the Secretary in the above-captioned proceeding, in accordance with the requirements of Rule 2010 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.2010).

Dated this 12th day of November, 2019 in Fairfax, VA.

/s/ David B. Patton

APPENDIX

A. Assumptions for Estimating Revenues from Regulation Market

In section V, we presented the results for additional net revenues that an ESR would receive by offering a portion of its capacity in the regulation market. We list below the key assumptions underlying our methodology:

- Based on FCA-14 submittals, we assumed that the ESR would set aside [redacted] of its capacity for participating in the regulation market.
- The average service or mileage movement of a ESR scheduled for regulation is [redacted]. We assumed a value higher than the average resource's mileage movement to reflect the higher regulation service provided by currently operating ESRs.
- The ESR's charging and discharging efficiency are 0.93. The amount of regulation capacity (and mileage movement) sold are discounted by this value.
- As an illustration, given a 100MW/ 200 MWh ESR with a certain number of cycles allocated to energy arbitrage, the allocation of hours for regulation in a year can be calculated in the following manner:

  Assume the number of cycles allocated to energy arbitrage = 300,

  Number of remaining cycles = 365 – 300 = 65.

  Available throughput for providing regulation = 65 x Duration (200 MWh) x 2 = 26000 MWh.

  If the effect of cycling is similar regardless of whether the battery is utilized for energy arbitrage or frequency regulation, number of available hours for regulation = 26000 MWh / (Throughput per hour of regulation) = 26000 / (10% x 0.5 x 100 MW x 18 ΔMW/MW/hr) = 144 hours per year. [10]

  However, the effect of cycling for frequency regulation and arbitrage are not similar. Assuming that the cycling from frequency regulation has a 10 times lower effect on ESR aging damage relative to a full energy arbitrage cycle, number of available hours for regulation = 144 x 20 = <u>2888 per year</u>. [11]

---

[10] In order to be able to follow the regulation signals in both directions, the maximum amount of regulation capacity this ESR can sell is 5 MW.

[11] ESRs providing regulation tend to operate in a shallow, optimal SOC range that minimizes battery aging. The relative effect on battery aging of cycling for frequency as opposed to

(Continued…)

- The developer would allocate the cycles/ hours across energy arbitrage and regulation in a manner that maximizes total net revenue over the year.

- The net revenues for the hours allocated to regulation would be determined using regulation capacity and service prices from the highest priced hours of the year.

B. Assumptions Underlying Approach 3

In section V, we discussed the results of three approaches for estimating the EAS net revenues of ESRs. We list below the key assumptions underlying Approach 3 for estimating the EAS net revenues:

- The ESR's hourly charge and discharge offers are each the product of two components: a) the minimum (for charging) or maximum (for discharging) of the forecasted hourly CTS and DA prices for the remainder of the day, and b) an empirically estimated adjustment factor.

- For all hours in a given month, we set the adjustment factors to equal the values that maximized profits in the prior month. We evaluated adjustment factors that ranged from 10 percent to 300 percent. Our model uses separate adjustment factors for charge and discharge offers.

- We estimated the hourly net revenues using the real-time energy and ten-minute spin prices, and the resource's output as determined by its charge and discharge offers.

- If the battery's SOC as determined by the charge offers is not 100 percent by hour 15 in winter months and hour 4 in summer months, we assume that the battery will charge fully in hours 15 and 16 (winter) or hours 4 and 5 (summer) regardless of the price forecast. Similarly, we assumed that the battery will be discharged completely by hours 19-20 on all days.

---

energy arbitrage is based on observations from the following studies: (a) *Optimal Battery Participation in Frequency Regulation Markets*, 2018, Xu B. et al, IEEE Transactions on Power Systems (Volume: 33 , Issue: 6 , Nov. 2018), and (b) *Calendar and cycle life study of Li(NiMnCo)O 2 -based 18650 lithium-ion batteries*, 2014, Ecker M. et al, Journal of Power Sources, Volume 248 – Feb 15, 2014. [redacted]