Attachment F

Affidavit of Dr. Patricio Rocha Garrido
on Behalf of PJM Interconnection, L.L.C.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	)	**Docket No. EL19-___-000**
	)	
PJM Interconnection, L.L.C.	)	**Docket No. ER19-___-000**

AFFIDAVIT OF DR. PATRICIO ROCHA GARRIDO
ON BEHALF OF PJM INTERCONNECTION, L.L.C.

1. My name is Dr. Patricio Rocha Garrido. My business address is 2750 Monroe Blvd., Audubon, Pennsylvania, 19403. I am a Senior Engineer in Resource Adequacy Planning in the System Planning division of PJM Interconnection, L.L.C. ("PJM"). I am submitting this affidavit on behalf of PJM in support of its reserve market reforms in this proceeding.

2. Specifically, in this affidavit, I provide support for PJM's proposals to reform its Operating Reserve Demand Curves ("ORDCs").

<u>Qualifications</u>

3. I joined PJM in 2011. As a Senior Engineer with the Resource Adequacy Planning department, I am responsible for performing long-term resource adequacy studies involving loss-of-load probability calculations whose results serve as inputs into PJM's Reliability Pricing Model as well as PJM's Regional Expansion Transmission Plan. I have also collaborated with PJM's planning and operations groups in projects related to long-term load forecasting, short-term solar forecasting and net-interchange schedule forecasting models. Prior to joining PJM, as a graduate student/research assistant, I performed research and wrote articles on topics pertinent to restructured electricity markets, namely generation capacity expansion and financial transmission rights. I am a member of the IEEE Power and Energy Society and an active participant in interregional resource adequacy working groups.

4. I hold a Bachelor of Science degree in Industrial Engineering from University of La Frontera-Chile, and a Masters and Ph.D. degree in Industrial Engineering from the University of South Florida.

<u>Methodology to Calculate Proposed ORDC</u>

Overview

5. To operate the system securely and reliably, PJM must meet Minimum Reserve Requirements ("MRRs") for the Synchronized and Primary Reserve Requirements. These requirements are established by PJM in furtherance of North American Electric Reliability Corporation ("NERC") standards. The procurement of reserves occurs ex-

ante, based on real-time forecasts of load, wind output, solar output, net-interchange schedule, and projected availability of thermal units. However, such forecasts and projections have historically and inherently exhibited error. As Mr. Christopher Pilong, Director of Dispatch, PJM, explains in his affidavit in support of PJM's proposal, while PJM has automated tools and expert staff to ensure the accuracy of its forecasts, it is not possible for PJM to have perfect foresight into the future, and thus there is a degree of error inherent in the forecasts.[1] Meeting the MRRs is thus conditioned by the uncertainties in the above forecasts and projections. In the event that any or all of the uncertainties materialize, reserves in excess of the MRRs, to the extent they are available, can make up for a potential MRR deficiency. Therefore, quantifying the probability of such uncertainties provides a path to value reserves in excess of the MRRs. The quantification of the probabilities also includes accounting for factors that mitigate the uncertainties: in particular, PJM's Regulation Requirement procured in the Regulation market, which acts as the first line of defense against the real-time uncertainties due to the fast response provided by such resources.

6. In essence, the rationale for the approach taken by PJM to derive its proposed ORDC is to calculate the probability that the total error in real-time forecasts and projections (adjusted for uncertainty-mitigating factors) is greater than various reserve levels in excess of the MRR such that the MRR cannot be met, shortage pricing is triggered, and the Reserve Penalty Factor[2] is used in the calculation of Locational Marginal Prices ("LMPs") and reserve market clearing prices ("MCPs"). As a result, the proposed ORDC is composed of an MRR segment and a downward-sloping segment whose shape is determined by the declining probability of failing to meet the MRR as the magnitude of total forecast error (and available reserves) increases. Consequently, when available reserves are below the MRR, the price in the ORDC is the penalty factor to signal the need for more reserves in the system and escalate prices accordingly; as reserve quantities increase in excess of the MRR, the ORDC price gradually decreases signaling that the system has better capability to deal with the real-time uncertainties that may trigger an MRR shortage.

Minimum Reserve Requirement

7. PJM must meet MRRs for Synchronized and Primary Reserves for reliability. These requirements are established by PJM in furtherance of NERC standards to respond to the loss of the largest single contingency in the PJM system or other system events that require rapid recovery. A potential MRR deficiency exposes the system to being unable to respond in time to such contingencies and therefore represents a degradation in system reliability. An incremental per megawatt production cost, referred to as a penalty factor, is associated with each MRR. These penalty factors serve as a proxy for the incremental value of reserves when the available reserves in the system are less than or equal to the

---

[1] *See* Affidavit of Christopher Pilong on Behalf of PJM Interconnection, L.L.C. ¶ 6, included as Attachment E to this filing.

[2] The Reserve Penalty Factor represents the incremental value of reserves under shortage conditions. *See* Affidavit of Adam Keech on Behalf of PJM Interconnection, L.L.C. ¶ 11, included as Attachment D to this filing.

MRR. In PJM's proposed ORDCs, the penalty factors are the highest price points because they are aimed at signaling the need for more reserves in the system.

Impact of Uncertainty on Meeting the MRR

8. The procurement of reserves occurs ex-ante, based on real-time forecasts of load, wind output, solar output, net-interchange, and projected availability of thermal units. PJM runs several optimization engines leading in to real-time to ensure enough energy and reserves are on the system to meet real-time demand. These include the Ancillary Service Optimizer, Security Constrained Unit Commitment and Security Constrained Economic Dispatch ("SCED"). Specifically, when the optimization engines determine the procurement and/or pricing of reserves for target time T, those reserves are aimed at addressing the uncertainties between T and T+10 (in the case of the Synchronized and Primary Reserve Requirements which are expected to be met with resources responding in ten minutes) or between T and T+30 (in the case of 30-minute Reserve Requirement). Furthermore, in the case of the RT SCED, the run is performed 10 minutes prior to the target time T, that is at T-10. This entails that all inputs used in the RT SCED run are forecasts or projections of conditions for times T, T+10, T+30 as of T-10. As referenced above, forecasts or projections inherently have errors, because PJM does not have perfect vision into the future. Such errors impact the ability of the system to meet the MRRs. Consider the following scenario: at T-10, a quantity of reserves equal to the MRR is procured based on a load forecast equal to X; but if at T+10 the actual load is higher, X + A, then some of the reserves (a quantity equal to A) will need to be converted into energy creating a shortfall in the MRR (total reserves will be equal to MRR – A), triggering the penalty factor associated with that MRR. Consider an alternative version of the above scenario: if the procurement of reserves at T-10 is MRR + A, then even if A reserves are converted into energy to account for the actual load being X + A, there would be no MRR shortfall (the total reserves ex-post will be equal to the MRR). Because in the above scenarios the quantity A by which the load forecast is too low cannot be known ahead of time, reserves on the system above the MRR have value because they can account for the situation when the extra A quantity of load actually materializes.

9. Similar scenarios can be created for the other real-time forecast and projections: wind output, solar output, net-interchange, and projected availability of thermal units. Unfortunately, the magnitude of the errors in forecasts and projections is not a constant value. Historical data shows significant variation. Thus, to quantify the uncertainties associated with these errors, historical data for each forecast and projection can be leveraged to derive probabilistic distributions of the errors. Such probabilistic distributions can then be used to estimate the probability that, for instance, using the above illustrative scenario, the load error is greater than A. The probabilities can in turn be used to determine what percentage of the time procuring MRR+A reserves prevents an MRR shortfall and what percentage of the time it does not prevent an MRR shortfall, triggering the penalty factor associated with the MRR. These probabilities are the basis for the derivation of the value (i.e., the prices) of reserves in the ORDC, as discussed in the following subsections.

10. Hence, in PJM's proposal, the value of reserves is related to how likely it is the system will find itself in a reserve shortage even though at any given time the system may have more reserves than the applicable MRR. To determine how likely it is to go from being long to being short reserves, PJM will look at the probability of error in several key forecasting categories (load forecast error, wind output forecast error, solar output forecast error, net-interchange schedule forecast error, and forced outages of thermal units). In other words, establishing the value of reserves in excess of the MRR depends on the maximum value of reserves and the probability of not meeting the MRR given a specific level of reserves.

Uncertainties and Uncertainty-Mitigating Factors

11. The relevant real-time uncertainties that impact the ability of the system to meet the MRR are those associated with balancing supply and demand for energy and reserves in the dispatch case. On the demand side, the uncertainty is caused by the error in forecasting load. The load forecast model used in the RT SCED case is run every five minutes producing a forecast for the next six hours, in five-minute intervals (i.e., a total of 72 forecasted values, every five minutes). The forecast is run at the transmission-zone level.

On the supply side, the relevant uncertainties are the following:

a) Wind Output Forecast: the wind power forecast is run every five minutes producing a forecast for the next six hours, in five-minute intervals. The forecast uses static data (e.g., maximum capacity, location, turbine manufacturer) and real-time dynamic data (e.g., measured wind speed, measured output) of PJM's wind farms in order to create a forecast for each resource's output.

b) Solar Output Forecast: the solar power forecast is run every five minutes producing a forecast for the next six hours, in five-minute intervals. The forecast uses static data (e.g., maximum capacity, location, panel manufacturer) and real-time dynamic data (e.g., measured output) of PJM's solar sites in order to create a forecast for each resource's output.

c) Forced Outages of Thermal Units: the availability of thermal units is impacted by full or partial forced outages that occur without advance notification. Generating facilities in the PJM footprint are required to report such outages using the PJM eGADS system. This uncertainty is not necessarily produced by the error associated with a forecast model. However, its impact on balancing supply and demand for energy and reserves is equivalent to that arising from errors in forecasting models.

d) Net-Interchange Schedule Forecast: the net-interchange schedule forecast is run every fifteen minutes producing a forecast for the next four hours, in fifteen-minute intervals. Net-interchange is defined as the net of energy imports and exports. The model uses interchange schedules provided to PJM via the exSchedule tool.

12. Factors that mitigate uncertainty in real-time are also relevant to assess the ability of the system to meet the MRR. Such factors could be supply or demand-related but must be associated with reliably and rapidly responding to PJM's dispatch signals. Resources committed in PJM's Regulation Market meet these qualifications. PJM's Regulation Market runs every five minutes procuring resources to meet the Regulation Requirement which varies by season and time-of-day as shown in Table 1.

Table 1: Regulation Requirement

Season	Dates	Non-Ramp Hours	Ramp Hours	Effective MW Requirement
Winter	Dec 1 – Feb 29	HE1 – HE4, HE10 – HE16	HE5 – HE9, HE17 – HE24	Non-Ramp = 525MW Ramp = 800MW
Spring	Mar 1 – May 31	HE1 – HE5, HE9 – HE17	HE6 – HE8, HE18 – HE24	Non-Ramp = 525MW Ramp = 800MW
Summer	Jun 1 – Aug 31	HE1 – HE5, HE15 – HE18	HE6 – HE14, HE19 – HE24	Non-Ramp = 525MW Ramp = 800MW
Fall	Sep 1 – Nov 30	HE1 – HE5, HE9 – HE17	HE6 – HE8, HE18 – HE24	Non-Ramp = 525MW Ramp = 800MW

While there may be resources that under certain circumstances (e.g., high LMPs) become available and can mitigate the above real-time uncertainties, it is difficult to quantify the likelihood that such behavior will continue in the future (in contrast to the situation of the Regulation resources described above). Hence, PJM cannot reliably include this behavior as an uncertainty-mitigating factor in the procurement of reserves.

Look-Ahead Period for Uncertainty

13. The pricing of reserves via RT SCED occurs ex-ante based on multiple forecasts and projections. The uncertainties arising from these forecasts and projections can be quantified based on historical data. The duration of the look-ahead period to estimate the magnitude of these uncertainties (i.e., the forecasts' errors) varies depending on the reserve requirement. For the Synchronized and Primary Reserve Requirement, the length of the interval between the solution of the RT SCED case and the end of the period in which the procured reserves are expected to respond in case they are deployed is at least 20 minutes: (T+10) – (T-10). Similarly, for the 30-minute Reserves, the length of the applicable interval is at least 40 minutes. PJM is proposing to use 30 minutes and 60 minutes, respectively, as the corresponding look-ahead periods for estimation of the uncertainties. The additional duration of time in the look-ahead period in each case (10 minutes for the Synchronized and Primary Reserve Requirement and 20 minutes for 30-minute Reserves) is intended to capture deviations from when the RT SCED case is run (it may not be exactly run at T-10) and also to capture the value of reserves in subsequent intervals, which is not captured when solving the RT SCED case for a single interval.[3]

[3] Affidavit of Dr. William W. Hogan and Dr. Susan L. Pope on Behalf of PJM Interconnection, L.L.C., *PJM Reserve Markets: Operating Reserve Demand Curve Enhancements* at 18, included as Exhibit 1 to this filing.

Note that due to the rolling nature of the RT SCED cases, the look-ahead period for uncertainty also has a rolling nature (e.g., if the RT SCED case run at T-10 procures reserves to address uncertainty between T and T+10, then the next RT SCED case run at T-5 procures reserves to address the uncertainty between T+5 and T+15).

14. These timeframes, 30 minute uncertainty for 10 minute reserve products, and 60 minute uncertainty for the 30-minute Reserve product, also align with the operator actions available to address uncertainty within the prescribed timeframe. For example, if system uncertainty manifests in the 0-30 minute timeframe, the operator will respond to that uncertainty first (and automatically) by deploying Regulation. PJM's proposed curves address this by accounting for the supply of Regulation on the system. Second, the system operator will attempt to run the RT SCED to adjust the system based on errors in the forecast. This process deploys the reserves that the operator has assigned using the ORDC to respond to the uncertainty without violating the MRR. The final option would be to initiate a Synchronized Reserve event. All of the actions available within the 0-30 minute timeframe include the use of 10 minute reserves illustrating it as a reasonable time proxy over which to measure their value. For the 30-minute Reserve product which uses 60-minute uncertainty, the same general principles apply.

Development of Probabilistic Distributions to Quantify Uncertainty

15. The quantification of the uncertainties involves deriving probabilistic distributions of the forecast errors based on historical data adjusted to account for the uncertainty-mitigating factors, i.e., the Regulation Requirement. The assumption is that, in the future, similar levels of uncertainties can be expected. The key elements in the development of the probabilistic distributions are as follows:

a) <u>Using historical data from the most recent three full calendar years</u> – The choice of three years strikes a balance between reducing the impact that a single year may have on the probabilistic distribution and removing old error data that may not reflect the most up-to-date status of PJM forecasting models.

b) <u>Creating twenty-four probabilistic distributions based on uncertainty levels during combinations of time-of-day blocks and season</u> – The choice of twenty-four probabilistic distributions strikes a balance between: i) quantifying the uncertainty during specific periods that are expected to have larger uncertainties (such as the morning period in winter) relative to periods that are expected to have smaller uncertainties (such as the night-time in the fall); and ii) avoiding a large number of ORDCs which may result in market outcomes that change too frequently. Since the probabilistic distributions are the basis for estimating the value of reserves, i.e., the prices in the ORDCs, the choice of twenty-four probabilistic distributions results in twenty-four ORDCs.

The seasons and time-of-day blocks that are combined to derive the twenty-four ORDCs are shown in Table 2.

Table 2: Season and Time-of-Day Blocks

Season	Time-of-Day Block (in Hour Beginning)
Summer (June – August)	1 (2300 – 0200)
Fall (September – November)	2 (0300 – 0600)
Winter (December – February)	3 (0700 – 1000)
Spring (March – May)	4 (1100 – 1400)
	5 (1500 – 1800)
	6 (1900 – 2200)

c) Combining error data and Regulation Requirement data point-by-point to derive a net-load error probabilistic distribution – For each timestamp[4] in the three full calendar years, the forecast error data from the individual uncertainties:

- Load, Wind Output, Solar Output, availability of thermal units for the Synchronized, and Primary Reserve Requirement
- Load, Wind Output, Solar Output, availability of thermal units, and net interchange for the 30-minute Reserve Requirement

is combined with the Regulation Requirement data to calculate the time stamps' net-load forecast error according to the following formula:

Net Load Error at t = (Actual Load at t – Actual Wind Output at t – Actual Solar Output at t – Actual Net Interchange Schedule at t) – (Forecast Load for t at t-x – Forecast Wind Output for t at t-x – Forecast Solar Output for t at t-x – Forecast Net Interchange Schedule for t at t-x) + Forced Outages Thermal Units between t-x and t – Regulation Requirement at t.

All of the terms in the above formula are expressed in megawatts. The look-ahead period for uncertainty is represented by x (30 minutes for the Synchronized and Primary Reserve Requirements, 60 minutes for the 30-minute Reserve Requirement). Note that the Net Interchange Schedule uncertainty only applies to the 30-minute Reserve Requirement. The reason it is appropriate to exclude net interchange schedule in the Net Load Error for the Synchronized and Primary Reserve Requirements is that the Net-Interchange Schedule forecast error in the applicable look-ahead interval is negligible.[5]

[4] The net-load error calculation is made every five minutes for the Synchronized and Primary Reserve Requirement; every fifteen minutes for the 30-minute Reserve Requirement because the Net-Interchange Schedule Forecast is run every fifteen minutes.

[5] Interchange schedules cannot be changed in the last twenty minutes before an RT SCED case. Therefore, the thirty-minute forecasted net-interchange schedule value is very close to the actual net-interchange schedule value.

d) Using empirical distributions rather than imposing a distribution (e.g., normal)[6] to the net-load error data – Each of the twenty-four sets of net-load error values from the most recent three full calendar years is used as the net-load error empirical probabilistic distribution. This approach does not require imposing one of the theoretical distributions (e.g., normal) on the data.

16. Using each of the above empirical probabilistic distributions of net-load error to calculate, for instance, the probability of the net-load error being greater than a certain value *y*, can be performed simply by counting the number of observations in the distribution that are greater than *y*, divided by the total number of observations in the distribution.

Value of Reserves

17. As I discuss above, establishing the value of reserves in excess of the MRR depends on calculating the probability of not meeting the MRR when said reserve levels in excess of the MRR are available given all the uncertainties and uncertainty-mitigating factors (where all the uncertainties and uncertainty-mitigating factors are quantified via the net-load error distribution). To calculate the incremental value of reserves in excess of the MRR, PJM proposes to use the concept of expected value. Expected value refers to the weighted average outcome of a given decision when all possible outcomes are considered weighted by the probability of each outcome. In the context of the ORDC, the decision is procuring reserves in excess of the MRR while the outcomes are either meeting the MRR or failing to meet the MRR. Meeting the MRR entails no penalty whereas failing to meet the MRR triggers the penalty factor. Assume PBMRR is the probability of failing to meet MRR when X reserves in excess of the MRR are available given all the uncertainties and uncertainty-mitigating factors. The Expected Value of X reserves in excess of the MRR can be expressed as:

Expected Value of X = PBMRR (X) x Penalty Factor + (1 – PBMRR(X)) x 0

= PBMRR (X) x Penalty Factor

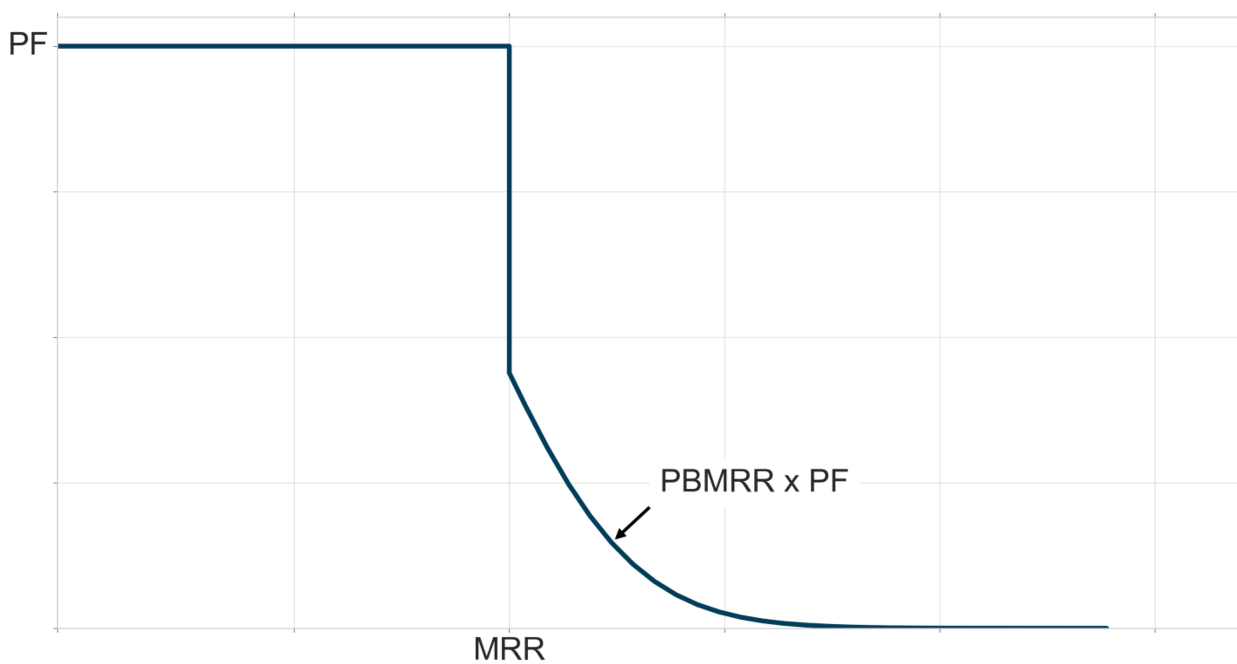
18. For example, if the MRR associated with the Synchronized Reserve (SR) Requirement is 1,400 MW, then the Expected Value of 300 MW in excess of the MRR (i.e., 1,700 MW) is equal to the PBMRR of 300 MW times the penalty factor corresponding to the SR MRR. The PBMRR of 300 MW represents how often in the last three years the 30-minute net-load error in the applicable season and time-of day block combination has been greater than 300 MW. Therefore, the PBMRR calculation is performed by counting the number of observations in the applicable net-load error empirical distribution that are greater than 300 MW, divided by the total number of observations in the distribution.

19. Therefore, for reserve quantities between zero and the MRR, the incremental value is the penalty factor whereas for reserve quantities in excess of the MRR, the incremental value

[6] As used here, "normal" refers to calculating the mean and standard deviation, and then the probabilities would be based on the theoretical normal distribution.

is calculated per the formula above. These incremental values constitute the prices in the ORDC as shown in Figure 1: if the system is short of reserves (i.e., the available reserve quantity is below the MRR) the price is the penalty factor to signal the need for more reserves in the system; as reserve quantities increase in excess of the MRR, the price gradually decreases signaling that the system has better capability to deal with the real-time uncertainties that may trigger an MRR shortage. Eventually, the prices in the ORDC drop to zero signaling that procuring additional reserves provides no incremental value due to the fact that the probability of experiencing real-time uncertainties of the same magnitude as the amount of additional reserves is zero.

Figure 1: Proposed ORDC Shape



Discussion of Selected Items in Proposed ORDC

20. The following items are discussed to provide further clarification on the underlying principles governing the shape of the proposed ORDC:

a) <u>Horizontal segment between 0 and MRR on the x-axis priced at the Penalty Factor on y-axis</u> – Applying the Expected Value of X formula above to reserve quantities below the MRR yields prices that are below the Penalty Factor. Such result is not consistent with the horizontal segment in the proposed ORDC. This occurs because the probability of failing to meet the MRR is less than one (or conversely, there is a non-zero probability that the MRR is met), even if there is an ex-ante MRR deficiency. Such a situation can be described as pricing reserves below the penalty factor when there is an MRR deficiency ex-ante because there is a non-zero chance that the net-load forecast error will turn out in PJM's favor, avoiding an MRR deficiency ex-post. Furthermore, an extreme version of the above situation where the quantity of reserves ex-ante is zero would yield an associated price that is less than the penalty factor, just because there is a slim chance that the net-load forecast error is so large *and* in PJM's favor that the MRR is met. This is inconsistent with operating the grid securely and reliably. Hence, if the system is short of the MRR ex-ante, the corresponding price in the ORDC should escalate to signal the need for more reserves. In the proposed ORDC, the penalty factor provides that signal.

b) Width of the curve – PJM's proposed ORDC is data-driven with the downward-sloping segment based on observed recent historical uncertainty. As such, the resulting width of the ORDC is a reflection of the following PJM-specific observations:

i. PJM is a large system. This entails that even a small load forecast percent error (e.g., one percent) is a sizable megawatt amount relative to the MRR associated with each reserve requirement. The same observation can be made regarding forced outages of thermal units.

ii. Renewable (wind and solar) penetration is low relative to the total generation in the PJM system, but impactful for reserve procurement. Wind and solar resources still represent a small share of the PJM resource fleet. However, the magnitude of the uncertainty associated with forecasting the current absolute penetration levels of wind resources especially (*see infra* Wind Output columns in Table 3 and Table 4), is high relative to the MRR associated with each reserve requirement. Expected increased penetration levels are likely to increase the magnitude of the forecasting uncertainties. However, if PJM forecasting models were to become more accurate in the future, such accuracy improvements will be reflected in the ORDCs by reducing the width of the downward-sloping segment.

iii. Table 3 and Table 4 show the 30-minute and 60-minute mean and standard deviation of the observed forecasts' errors and forced outages of thermal units for the summer peak period (summer afternoon) and a winter peak period (winter morning) in 2015–2017. Note that the PBMRR values used in the derivation of the ORDCs depend on the entire net-load error distribution and therefore, the standard deviation is a relevant statistic (in addition to the mean) to illustrate the magnitude of the uncertainties.

Table 3: 30-minute Forecasts' Error and Force Outages during selected periods

	Load		Wind Output		Solar Output		Forced Outages Thermal	
Period	Mean	St. Dev.	Mean	St. Dev.	Mean	St. Dev.	Mean	St. Dev.
Summer - Block 5	55.1	463.9	-73.2	201.3	-32.3	34.2	132.6	230.1
Winter - Block 3	69.3	482.8	-160.6	253.1	12.5	48.8	132.6	251.0

All values in MW. Errors are calculated as Actual minus Forecast. Hence, positive Mean values indicate underforecasting while negative Mean values indicate overforecasting. Forced Outages values can only be positive.

Table 4: 60-minute Forecasts' Error and Forced Outages during selected periods

	Load		Wind Output		Solar Output		Forced Outages Thermal		Net-Interchange Schedule	
Period	Mean	St. Dev.	Mean	St. Dev.	Mean	St. Dev.	Mean	St. Dev.	Mean	St. Dev.
Summer - Block 5	75.0	787.1	-65.3	242.0	-44.5	39.1	273.8	340.1	-73.6	392.2
Winter - Block 3	153.5	808.8	-158.2	303.2	6.2	54.4	269.0	379.2	-234.7	518.3

All values in MW. Errors are calculated as Actual minus Forecast. Hence, positive Mean values indicate underforecasting while negative Mean values indicate overforecasting. Forced Outages values can only be positive. Net-Interchange equals imports minus exports.

Mathematical Formulation

21. For ease of exposition, this subsection is focused on the mathematical formulation at the regional transmission organization ("RTO") level. Zonal considerations, which are also part of the PJM proposal, are described in the next subsection.

22. The PJM Proposal considers three reserve requirements: Synchronized (SR), Primary (PR) and 30-minute (R30). An ORDC is developed for each of these three requirements. Each of the ORDCs has a penalty factor (PF), a minimum reserve requirement (MRR) and a corresponding net-load error probabilistic distribution. The probabilistic distribution for SR and PR is based on 30-minutes uncertainty while the probabilistic distribution for the R30 ORDC is based on 60-minutes uncertainty.

23. In addition, three reserve products are defined: Synchronized (SR), Non-Synchronized (NSR), and Secondary (SecR). The relationship between the requirements and the products that can contribute to meet the requirement is shown in Table 5.

Table 5: Relationship between Requirement and Products in PJM Proposal

Requirement	Products Contributing to Requirement
Synchronized (SR)	Synchronized (SR)
Primary (PR)	Synchronized (SR) and Non-Synchronized (NSR)
30-minute (R30)	Synchronized (SR), Non-Synchronized (NSR), and Secondary (SecR)

Let,

MRR_{SR}: minimum reserve requirement in the SR ORDC

MRR_{PR}: minimum reserve requirement in the PR ORDC

MRR_{R30}: minimum reserve requirement in the 30-minute Reserves ORDC

PF_{SR}: penalty factor in the SR ORDC

PF_{PR}: penalty factor in the PR ORDC

PF_{R30}: penalty factor in the 30-minute Reserves ORDC

$PBMRR_{30}$: probability of failing to meet the MRR using 30 minutes uncertainty; this probability is applicable to the SR and PR ORDCs.

$PBMRR_{60}$: probability of failing to meet the MRR using 60 minutes uncertainty; this probability is applicable to the R30 ORDC.

r_{SR}: quantity of SR Product contributing to meet the SR, PR, and R30 requirements

r_{NSR}: quantity of NSR Product contributing to meet the PR and R30 requirements

r_{SecR}: quantity of SecR Product contributing to meet the R30 requirement

The shadow prices (SP) that result from using the ORDCs in the co-optimization of energy and reserves can be written as:

$$SP_{SR}(r_{SR}) = \begin{Bmatrix} PF_{SR}\ PBMRR_{30}(r_{SR} - MRR_{SR}), & r_{SR} - MRR_{SR} \geq 0 \\ PF_{SR,} & r_{SR} - MRR_{SR} < 0 \end{Bmatrix}$$

$$SP_{PR}(r_{SR}, r_{NSR}) = \begin{Bmatrix} PF_{PR}\ PBMRR_{30}(r_{SR} + r_{NSR} - MRR_{PR}), & r_{SR} + r_{NSR} - MRR_{PR} \geq 0 \\ PF_{PR,} & r_{SR} + r_{NSR} - MRR_{PR} < 0 \end{Bmatrix}$$

$$SP_{R30}(r_{SR}, r_{NSR}, r_{SecR}) \\ = \begin{Bmatrix} PF_{R30}\ PBMRR_{60}(r_{SR} + r_{NSR} + r_{SecR} - MRR_{R30}), & r_{SR} + r_{NSR} + r_{SecR} - MRR_{R30} \geq 0 \\ PF_{R30,} & r_{SR} + r_{NSR} + r_{SecR} - MRR_{R30} < 0 \end{Bmatrix}$$

The MCP at the RTO level for each of the reserve products are a function of the above shadow prices, recognizing the contribution of the product to each of the requirements:

$$SRMCP = SP_{SR}(r_{SR}) + SP_{PR}(r_{SR}, r_{NSR}) + SP_{R30}(r_{SR}, r_{NSR}, r_{SecR})$$

$$NSRMCP = SP_{PR}(r_{SR}, r_{NSR}) + SP_{R30}(r_{SR}, r_{NSR}, r_{SecR})$$

$$SecRMCP = SP_{R30}(r_{SR}, r_{NSR}, r_{SecR})$$

24. The above MCPs are representative of a cascading model for probabilities and prices: the Synchronized Reserve Market Clearing Price ("SRMCP") reflects the contribution that SR resources make to satisfy the SR, PR, and R30 requirements. Similarly, the Non-Synchronized Reserve Market Clearing Price ("NSRMCP") reflects the contribution that NSR resources make to satisfy the PR and R30 requirements. Finally, the Secondary Reserve Market Clearing Price ("SecRMCP") reflects the contribution that SecR resources make to satisfy the R30 requirement.

Zonal ORDC Considerations

25. The PJM proposal considers the development of zonal ORDCs. And while no tariff revisions are necessary to accommodate this proposal, PJM has included a discussion of it in this filing for completeness. The methodology to develop the zonal ORDCs includes the aspects so far described in this affidavit including the following clarifications:

a) If the zone is a transmission zone or a group of transmission zones, actual load, wind output, solar output, and availability of thermal unit uncertainties are used to develop the net-load error probabilistic distribution. A zonal estimate of the net interchange schedule uncertainty (which only applies to the development of the 30-minute Reserves ORDC) and of the Regulation Requirement are also used to develop the net-load error probabilistic distribution based on the zone's average load share contribution in the most recent three calendar years to the RTO average load in each of the twenty-four combinations of season and time-of-day blocks.

b) If the zone is a portion of a transmission zone or a portion of multiple transmission zones, zonal estimates of the load, wind output, solar output, availability of thermal units, and net-interchange schedule uncertainties as well as of the Regulation Requirement are used to develop the net-load error probabilistic distribution. The zonal estimates are based on the zone's average load share contribution in the most recent three calendar years to the encompassing transmission zone(s)' average load (for load, wind output, solar output, and availability of thermal units uncertainties) and RTO average load (for the net interchange schedule uncertainty and regulation requirement) in each of the twenty-four combinations of season and time-of-day blocks.

c) The MCPs at the zonal level for each of the reserve products are a function of the shadow prices resulting from using the zonal ORDCs in the co-optimization of energy and reserves, recognizing the contribution of the product to meet not only each of the zonal requirements but also the RTO requirements.

26. This concludes my affidavit.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	)	**Docket No. ER19-___-000**
	)	
PJM Interconnection, L.L.C.	)	**Docket No. EL19-___-000**

VERIFICATION OF DR. PATRICIO ROCHA GARRIDO

Dr. Patricio Rocha Garrido, being first duly sworn, deposes and states that he is the Dr. Patricio Rocha Garrido referred to in the foregoing document entitled "Affidavit of Dr. Patricio Rocha Garrido," that he has read the same and is familiar with the contents thereof, and that the testimony set forth therein is true and correct to the best of his knowledge, information, and belief.

DR. PATRICIO ROCHA GARRIDO

Subscribed and sworn to before me, the undersigned notary public, this 27th day of March, 2019.

Linda Spreeman
Notary Public

COMMONWEALTH OF PENNSYLVANIA
NOTARIAL SEAL
Linda Spreeman, Notary Public
Lower Providence Twp., Montgomery County
My Commission Expires Nov. 17, 2019
MEMBER, PENNSYLVANIA ASSOCIATION OF NOTARIES