2750 Monroe Blvd.
Audubon, PA 19403

May 3, 2018

**PLANNING COMMITTEE**

Dear Committee Members:

**2018 PJM RESERVE REQUIREMENT STUDY - DETERMINATION OF THE PJM INSTALLED RESERVE MARGIN AND FORECAST POOL REQUIREMENT FOR FUTURE DELIVERY YEARS**

Attached for your review and endorsement is the timetable, study assumptions, and modeling assumptions for the 2018 PJM Reserve Requirement Study (RRS). The study will examine the period beginning June 1, 2018 through May 31, 2029.

This study is consistent with the provisions of the Reliability Assurance Agreement among Load Serving Entities in the PJM Region. In accordance with Reliability Pricing Model (RPM) requirements, the results of this study will be used to determine the Forecast Pool Requirement (FPR) for the 2019/20, 2020/21, 2021/22and 2022/23 Delivery Years.

Specific items to note for the 2018 RRS include:

1. As specified in Schedule 4 of the Reliability Assurance Agreement, the Capacity Benefit Margin (CBM) modeled in this study will be 3500 MW. The CBM reflects the amount of transmission import capability reserved to capture the reliability benefit of emergency energy sales into PJM.

2. A Load Forecast Error Factor (FEF) of 1.0% will be modeled in all study years.

3. The load models for PJM and the World region will be based on assessment work performed by PJM staff and reviewed by the Resource Adequacy Analysis Subcommittee (RAAS). The assessment work will use the load model selection procedure endorsed by the Planning Committee at their June 7, 2018 meeting (see Attachment V). The Planning Committee will be asked to endorse the load model selection no later than July, 2018.

4. The World region will consist of the four external systems with direct ties to PJM (New York ISO, MISO, TVA and VACAR). Each of these four World sub-regions will be modeled at its required or target reserve margin.

5. For this study, the generator unit model data will be available for review, per Section 2 of Manual 20 and must be performed by PJM Member representatives that own generation. This effort is targeted for June of 2018.

6. A summary timeline of the RRS process is shown in Attachment IV.

7. Flexibility to allow for additional case development and analysis is requested for this study.

In communicating the study results, it is important to focus on the Forecast Pool Requirement which is used in the RPM Auction process.

PJM will request endorsement of these assumptions at the June 7th 2018 Planning Committee meeting.

Sincerely,

Thomas A. Falin
Manager, Resource Adequacy Planning Department

Attachments

cc: w/attachments:
Resource Adequacy Analysis Subcommittee
Resource Adequacy Planning Department

2018 PJM RESERVE REQUIREMENT STUDY (RRS)

**Summary of Annual Study Procedure**

The primary focus of the PJM Reserve Requirement Study (RRS) is an analysis to determine the installed reserves required by the PJM RTO to satisfy the criterion specified in the Reliability Principles and Standards as defined in the PJM Reliability Assurance Agreement (RAA). This Study, in conjunction with PJM's Load Deliverability Test, satisfies the requirements of ReliabilityFirst Standard BAL-502-ReliabilityFirst-02. The PJM Planning Committee (PC) has the primary responsibility to coordinate and complete activities to adhere to the requirements of the RAA. The Resource Adequacy Analysis Subcommittee (RAAS), established by the PC, has the responsibility to determine the proper assumptions used in this analysis and to review the final results.

The timetable shown in Attachment I list the sequence of activities in this process. To accomplish this task, subcommittees and working groups reporting to the PC have been assigned the responsibilities shown in Attachment I.

The member representatives that own generation calculate and maintain information on individual generating units and operating statistics. These individual unit statistics must be submitted via a secure PJM Internet application designed for this purpose.

The Load Analysis Subcommittee (LAS) reviews the PJM Staff's efforts to calculate and maintain load forecasting values and associated probability of occurrence statistics. The PJM staff uses the information supplied from the Generation Owners, LAS, EIA-411 Report, NERC Electric Supply and Demand (ES&D) database, and the historic hourly peak loads to produce a probabilistic PJM system model. This model is used to determine the reserve requirement necessary to meet the ReliabilityFirst criterion for resource adequacy of a Loss of Load Expectation (LOLE) of one occurrence in ten years.

The initial task of the RAAS in this process is to develop the study and modeling assumptions and to seek approval of these assumptions from the PC.

# ATTACHMENT I

## SCHEDULED TARGET DATES FOR THE 2018 PJM RRS

**Attachment IV**

| **Corresponding Timeline Number** | | **Target Date** | **Responsible Group** |
|---|---|---|---|
| **1** | **Capacity Data Model Development** | | |
| | a) Begin update of capacity model. | January 2018 | PJM Staff |
| | b) Submit updated outage rate data to PJM Staff. | January 2018 | Generator Owner Reps |
| **1** | **Load Data Model Development** | | |
| | a) Submit PJM Staff forecast to PC | January 2018 | PJM Staff |
| | b) Begin updating PJM load model. | January 2018 | PJM Staff |
| **7** | **Capacity Models Finalized** | | |
| | a) Submit final GORP outage rate data to PJM Staff. | May 2018 | Generator Owner Reps |
| | b) Load & capacity models not changed after this date. Confirm that capacity and PJM reserves correspond to latest available information. | June 2018 | PJM Staff |
| **8** | **FPR and IRM Analysis** | | |
| | PJM RTO region | July 2018 | PJM Staff |
| **9** | **Approval of Load Model Time Period** | | |
| | RAAS Recommendation. | July 2018 | PC |
| **8** | **Analysis of Winter Weekly Reserve Target for 2018-2019 Winter Period** | | |
| | PJM RTO region. | August 2018 | PJM Staff |
| **13** | **Report on Winter Weekly Reserve Target for 2018-2019 Winter Period** | | |
| | This is based on the approved 2018 PJM RTO Region Reserve Study results. | September 2018 | RAAS |
| | a) Forward letter to OC with recommended Winter Weekly Reserve Target. | Sept PC Mtg. | PC |
| **13** | **Distribute Final Report to PC** | | |
| | Final Draft | Sept PC Mtg. | RAAS |
| | Final Report | Oct PC Mtg. | RAAS |
| **14 A** | **Endorsement/Recommendation of applicable Factors (IRM and FPR)** | Oct PC Mtg. | PC |

# ATTACHMENT II

## STUDY ASSUMPTIONS FOR THE 2018 PJM RRS

**1.** The 2018 RRS will be conducted as outlined in the "PJM Generation Adequacy Analysis: Technical Methods," and PJM Manual M20 revision 8, "PJM Resource Adequacy Analysis".

**2.** The PJM Installed Reserve Margin (IRM) will be determined using PJM's two-area model, the Probabilistic Reliability Index Study Model (PRISM). The analyses will focus on results for Area 1, the PJM RTO representation. The Area 2 model represents the electrically significant regions adjacent to the PJM RTO as described in Item 7. The modeling details of performing a two-area study are described in Attachment IIIMARS will be used to supplement the PRISM study results, specifically concerning issues that require multi-area modeling techniques.

**3.** The PJM RTO footprint will be modeled as Area 1 in the study. Area 1 load will consist of the combined coincident loads of the following regions: PJM Mid-Atlantic, APS, AEP, ComEd, Dayton, DomVP, DLCO, ATSI, DEOK and EKPC.

**4.** All generators will be modeled as capacity units per the modeling assumptions in Attachment III. A wind or solar generator with three or more years of operating data is modeled at a capacity value based on its actual performance. For a wind or solar unit with fewer than three years of operating data, its capacity value is based on a blend of its actual performance and the class average capacity factor.

**5.** Ambient derates of generating units will be represented via planned outages over the summer period. This is done to reflect operating experience related to a reduction of generating capability due to extreme ambient temperatures that would not be captured otherwise.

**6.** The Capacity Benefit Margin (CBM) modeled in this study will be varied between zero and saturation. All reserve requirement values shown in the analysis results summary will assume a CBM of 3500 MW.

---

[1] PJM RTO includes: Atlantic City Electric; Baltimore Gas & Electric Co.; Delmarva Power; Jersey Central Power & Light Co. (JCP&L); Metropolitan Edison Co. (Met-Ed); PECO, an Exelon Company; Pepco; Pennsylvania Electric Co. (Penelec); PPL Electric Utilities; PSE&G; and UGI Utilities, Inc.; APS = Allegheny Power System; AEP = American Electric Power; ComEd = Commonwealth Edison; Dayton = Dayton Power & Light; DomVP = Dominion Virginia Power; DLCO = Duquesne Light Co. ATSI = American Transmission Systems, Inc; DEOK = Duke Energy Ohio/Kentucky; EKPC = Eastern Kentucky Power Cooperative.

**7.** World reserves will be modeled at the individual World sub-regions "one day in ten year" reserve levels. The World sub-regions shall be:

- New York Independent System Operator (NYISO)
- Tennessee Valley Authority (TVA)
- Virginia-Carolinas (VACAR)
- Midwest Independent System Operator (MISO)

**8.** Behind the meter generation (BTMG) is not included in the capacity model because such resources cannot be capacity resources. The impact of behind the meter generation (BTMG) is reflected on the load side.

**9.** The Forecast Error Factor (FEF) will be held at one percent for all planning periods being evaluated. This practice is consistent with consensus gained through the PJM stakeholder process.

# ATTACHMENT III

## MODELING ASSUMPTIONS FOR THE 2018 PJM RRS

### 1. Load Models

Both PJM and the World load models will be selected based on the methodology approved by the Planning Committee at their June 7, 2018 meeting (see Attachment V).

### 2. PJM RTO Capacity Model

The generating units within the PJM RTO Study region will use statistics as detailed in the PJM Manual M22 revision 17, "Generator Resource Performance Indices," dated April 1, 2017. The statistics used are: Equivalent Demand Forced Outage Rate (EFORd), Effective EFORd (EEFORd), Capacity Variance, and Planned Outage Factor (POF).

The data for these statistics is primarily provided through PJM's electronic Generation Availability Data System (eGADS) web interface, per the online help function within eGADS. A five year time period (2013-2017) is used for the calculation of these statistics. These statistics are compared, for consistency, to those calculated and shown in the NERC Brochure for units reporting events (2013-2017). The Generation Owners of the various individual units are required to review and provide changes.

For each week of the year, except the winter peak week, the PRISM model uses the above statistics of each generating unit to develop a cumulative capacity outage probability table. For the winter peak week, to better account for the risk caused by the large volume of concurrent outages observed historically during this week, the cumulative capacity outage probability table is created using historical actual RTO-aggregate outage data. Winter peak week data from time period Delivery Year 2007/2008 to Delivery Year 2017/2018 (11 winter peak weeks) is used to calculate the cumulative capacity outage probability table for the winter peak week. In addition, outage data from the winter peak week in Delivery Year 2013/2014 will be replaced with outage data from the winter peak week in Delivery Year 2014/2015.

### 3. World Capacity Model

The 2017 NERC Electricity Supply & Demand (ES&D) will be the basis for future World generating unit information. Future capacity plans for World areas will be obtained from neighboring NERC regions. All World unit EEFORd and maintenance cycles will be updated using the latest Class Average Outage Rates. These rates, obtained from the NERC's pc-based Generation Availability Report (pc-GAR) application or applicable PJM eGADS summaries, will be based on a five year period.

### 4. Planning and Operating Treatment of Generation

All generators that have been demonstrated to be deliverable will be modeled as PJM capacity resources in the PJM study area. External capacity resources will be modeled as internal to PJM if they meet the following requirements:

1. Firm Transmission service to the PJM border
2. Firm ATC reservation into PJM
3. Letter of non-recallability from the native control zone

**Assuming that these requirements are fully satisfied, the following comments apply:**

- Only PJM's "owned" share of generation will be modeled in PJM. Any generation located within PJM that serves World load with a firm commitment will be modeled in the World.

- Firm capacity purchases will be modeled as generation located within PJM. Firm capacity sales will be modeled by decreasing PJM generation by the full amount of the sale.

- Non-firm sales and purchases will not be modeled. The general rule is that any generation that is recallable by another control area does not qualify as PJM capacity and therefore will not be modeled in the PJM Area.

- Generation projects in the PJM interconnection queue with a signed Interconnection Service Agreement (ISA) will be modeled in the PJM RTO at their capacity MW value.

**5. Reserve levels in the World region**

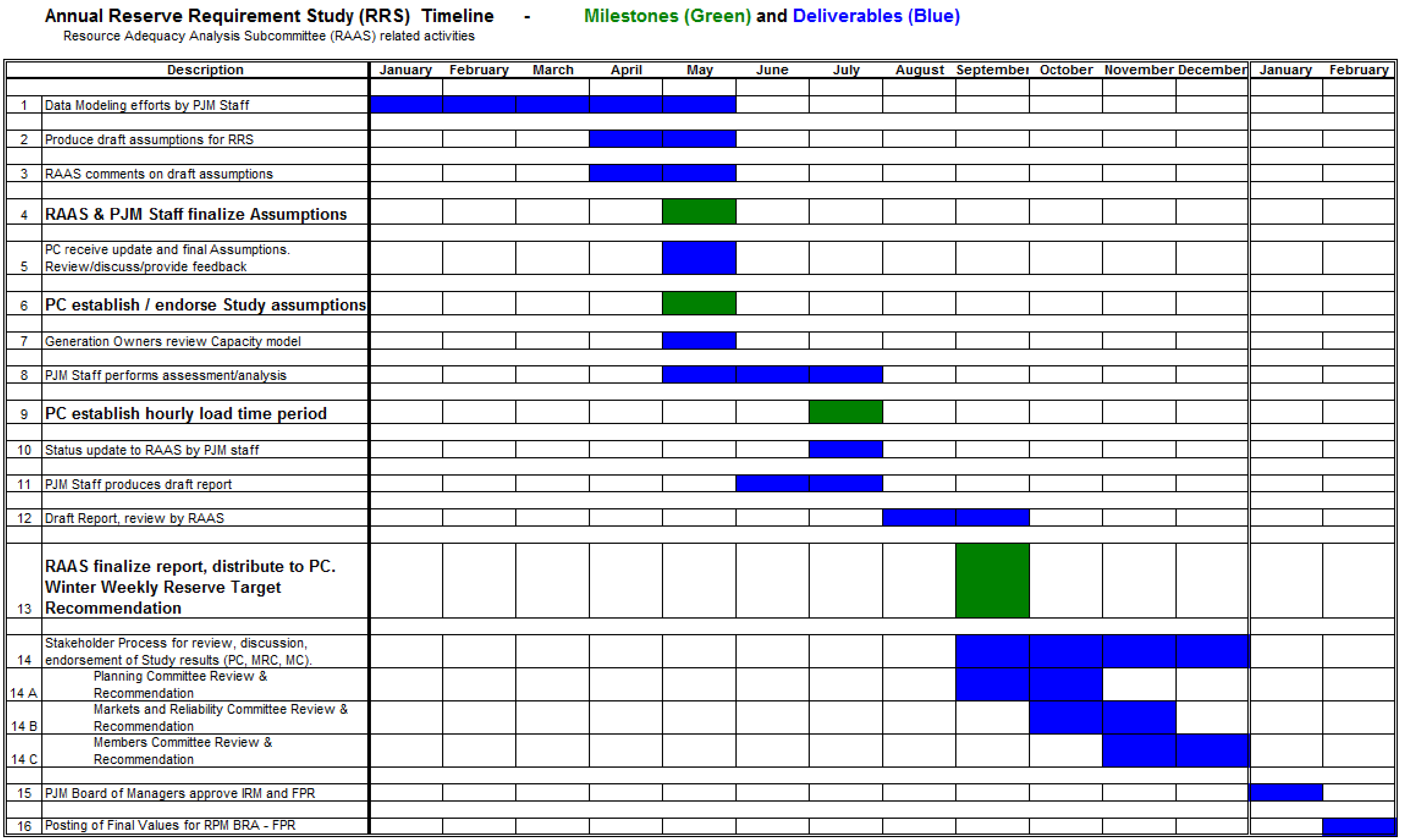
The World will be modeled at the higher installed reserve margin resulting from the following two approaches:

- The world combined reserve margin yielded by setting each area at its respective installed reserve margin adjusted to account for intra-world diversity.

- The world combined reserve margin yielded by collectively solving at the 1 in 10 criteria.

# ATTACHMENT IV

## Time Line for 2018 Reserve Requirement Study




The 2018 Study activities last for approximately 14 months. Some current Study activities, shown in items 1 and 2, overlap the previous Study timeframe. The posting of final values occurs on or about February 1st.

# ATTACHMENT V

## Load Model (LM) Selection Procedure for RRS

**Introduction**

The RRS uses PRISM to calculate the IRM/FPR. Load uncertainty in PRISM is modeled via 52 normal distributions, one for each week. The normal distributions (mean and standard deviation) can be estimated by using historical load data. The length of the time period used to estimate the normal distributions has to be 7 years or longer to ensure statistically significant estimates of the mean and the standard deviation. PJM has load data for its entire footprint and for its neighbors' from 1998 up until 3 years prior to the RRS year. Using this data, there are multiple time-periods (7 years or longer) that can be considered to estimate the mean and standard deviation. The comparative assessment of these time-period candidates (from here on in referred to as Load Model candidates) is based on two premises: 1) consistency with the RTO's CP1 distribution for 4 years in the future from the most recent PJM Load Forecast and 2) reasonable representation of historical PJM-World load diversity.

**Definitions**

To understand the premise of the comparative assessment at the core of the Load Model Selection Procedure, the following concepts are defined.

- CP1 Distribution (or Coincident Peak 1 Distribution): PJM develops a peak load forecast for each of the next 15 years at the RTO and zonal levels. The forecast accounts for weather uncertainty by considering historical weather scenarios. Each of these weather scenarios has the same probability of occurrence and produces a different peak load forecast. This collection of equally likely peak load forecast values corresponds to the CP1 Distribution. The value published in the PJM Load Forecast Report is the median (or 50/50 value) of the CP1 distribution.

- PJM-World Load Diversity: difference in the timing of annual peaks between PJM and the World. It is usually expressed as the World's load (in per-unitized terms) at the time of the PJM peak and vice-versa.

**Procedure**

- Assess the consistency of each of the Load Model (LM) Candidates with the RTO's CP1 distribution for 4 years in the future from the most recent PJM Load Forecast. This is accomplished by using two approaches:
    - Approach 1
        - For each LM Candidate,
            - Make the necessary adjustments to the 52 means and standard deviations so that the monthly peak relationship from the most recent PJM Load Forecast is captured by the LM.
            - Perform 5 random draws (one for each weekday daily peak) from the normal distribution that contains the expected annual peak
            - Calculate the highest of the 5 numbers previously drawn (this number represents the sampled annual peak)
            - Repeat the two step above N times, with N being the number of weather scenarios in the most recent PJM Load Forecast
            - Develop a Cumulative Distribution Function (CDF) by sorting the N sampled annual peaks (each of the N peaks is equally likely and therefore all have the same probability 1/N)
            - Calculate the point-to-point absolute MW error between the sampled CDF and the CDF produced with the CP1 distribution.
            - Add up the N absolute MW errors; this is the total MW error for a LM Candidate.

        - Select 3-5 LM Candidates with the smallest total MW error in the 70th percentile and above (where LOLE risk is concentrated).
    - Approach 2
        - For each LM Candidate,
            - Make the necessary adjustments to the 52 means and standard deviations so that the monthly peak relationship from the most recent PJM Load Forecast is captured by the LM.
            - Using the mean and standard deviation of the week that contains the expected annual peak, calculate the probability of the annual peak being less than or equal to each of the N peaks in the CP1 distribution (this results in N probability values)
            - Calculate the point-to-point absolute probability error between the above N probability values and the probability values of the CDF produced with the CP1 distribution.
            - Add up the N absolute probability errors; this is the total probability error for a LM Candidate.
        - Select 3-5 LM Candidates with the smallest total probability error in the 70th percentile and above (where LOLE risk is concentrated).

- Develop World Load Models using the time-periods of the PJM Load Models shortlisted in Approaches 1 and 2 (it is likely that both approaches produce the same set of PJM Load Models)
- Make the necessary adjustments to the 52 means and standard deviations of each World Load Model so that the relationship between the World's forecasted monthly peaks is captured by the LM.
- Compare the annual peaks of PJM and the World for each of the LM candidates and corresponding World LMs to ensure consistency with historical load diversity patterns. Also, consider the Capacity Benefit of Ties resulting from multi-year GE-MARS simulations.

**Additional Notes**

In the case of ties between LMs, take into consideration the following:

- A more recent LM is preferred
- A LM built with more data (longer time-period) is preferred
- Results from Approach 2 are favored over Approach 1 since Approach 2 does not rely on random sampling.

# Appendix A
# Base Case Modeling Assumptions for 2018 PJM RRS

| Parameter | 2017 Study Modeling Assumptions | 2018 Study Modeling Assumptions | Basis for Assumptions |
|---|---|---|---|
| **Load Forecast** | | | |
| Unrestricted Peak Load Forecast | 153,384 MW (2021/2022 DY) | 152,887 MW (2022/2023 DY) | Forecasted Load growth per 2018 PJM Load Forecast Report, using 50/50 normalized peak. |
| Historical Basis for Load Model | 2003-2012 | TBD | Load model selection method approved at the June 7, 2018 PC meeting (see Attachment V). |
| Forecast Error Factor (FEF) | Forecast Error held at 1 % for all delivery years. | Forecast Error held at 1 % for all delivery years. | Consistent with consensus gained through PJM stakeholder process. |
| Monthly Load Forecast Shape | Consistent with 2017 PJM Load Forecast Report and 2016 NERC ES&D report (World area). | Consistent with 2018 PJM Load Forecast Report and 2017 NERC ES&D report (World area). | Updated data. |
| Daily Load Forecast Shape | Standard Normal distribution and Expected Weekly Maximum (EWM) based on 5 daily peaks in week. | Standard Normal distribution and Expected Weekly Maximum (EWM) based on 5 daily peaks in week. | Consistent with consensus gained through PJM stakeholder process. |
| **Capacity Forecast** | | | |
| Generating Unit Capacities | Coordinated with eRPM databases, EIA-411 submission, and Generation Owner review. | Coordinated with eRPM databases, EIA-411 submission, and Generation Owner review. | New RPM Market structure required coordination to new database Schema. Consistency with other PJM reporting and systems. |
| New Units | Generation projects in the PJM interconnection queue with a signed Interconnection Service Agreement (ISA) will be modeled in the PJM RTO at their capacity MW value. . | Generation projects in the PJM interconnection queue with a signed Interconnection Service Agreement (ISA) will be modeled in the PJM RTO at their capacity MW value. | Consistent with CETO cases. |
| Wind Resources | Derived from hourly wind data over summer peak hours. Units can use a capacity factor of 13% or actual performance once historic data is available. | A wind generator with three or more years of operating data is modeled at a capacity value based on its actual performance. For a wind unit with fewer than three years of operating data, its capacity value is based on a blend of its actual performance and the class average capacity factor. | Based on Manual 21 Appendix B for Intermittent Capacity Resources. Capacity factors based on PJM stakeholder process, February July 13, 2017 Planning Committee, Agenda Item 10. |

| Parameter | 2017 Study Modeling Assumptions | 2018 Study Modeling Assumptions | Basis for Assumptions |
|---|---|---|---|
| Solar Resources | Derived from hourly solar data over summer peak hours. Units can use a capacity factor of 38% or actual performance once historic data is available. | A solar generator with three or more years of operating data is modeled at a capacity value based on its actual performance. For a solar unit with fewer than three years of operating data, its capacity value is based on a blend of its actual performance and the class average capacity factor. | Based on Manual 21 Appendix B for Intermittent Capacity Resources. Capacity factors based on PJM stakeholder process, July 13, 2017 Planning Committee, Agenda Item 10. |
| Firm Purchases and Sales | Firm purchase and sales from and to external regions are reflected in the capacity model. External purchases reduce the World capacity and increase the PJM RTO capacity. External Sales reduce the PJM RTO capacity and increase the World capacity. This is consistent with EIA-411 Schedule 4 and reflected in RPM auctions. | Firm purchase and sales from and to external regions are reflected in the capacity model. External purchases reduce the World capacity and increase the PJM RTO capacity. External Sales reduce the PJM RTO capacity and increase the World capacity. This is consistent with EIA-411 Schedule 4 and reflected in RPM auctions. | Match EIA-411 submission and RPM auctions. |
| Retirements | Coordinated with PJM Operations, Transmission Planning models and PJM web site: http://www.pjm.com/planning/generation-retirements.aspx . Consistent with forecast reserve margin graph. | Coordinated with PJM Operations, Transmission Planning models and PJM web site: http://www.pjm.com/planning/generation-retirements.aspx . Consistent with forecast reserve margin graph. | Updated data available on PJM's web site, but model data frozen in May 2018. |
| Planned and Operating Treatment of Generation | All generators that have been demonstrated to be deliverable will be modeled as PJM capacity resources in the PJM study area. External capacity resources will be modeled as internal to PJM if they meet the following requirements:<br>1.Firm Transmission service to the PJM border<br>2.Firm ATC reservation into PJM<br>3.Letter of non-recallability from the native control zone<br>Assuming that these requirements are fully satisfied, the following comments apply:<br>•Only PJM's "owned" share of generation will be modeled in PJM. Any generation located within PJM that serves World load with a firm commitment will be modeled in the World.<br>•Firm capacity purchases will be modeled as generation located within PJM. Firm capacity sales will be modeled by decreasing PJM generation by the full amount of the sale.<br>•Non-firm sales and purchases will not be modeled. The general rule is that any generation that is recallable by another control area does not qualify as PJM capacity and therefore will not be modeled in the PJM Area.<br>•Active generation projects in the PJM interconnection queues will be modeled in the PJM RTO after applying a suitable commercial probability. | All generators that have been demonstrated to be deliverable will be modeled as PJM capacity resources in the PJM study area. External capacity resources will be modeled as internal to PJM if they meet the following requirements:<br>1.Firm Transmission service to the PJM border<br>2.Firm ATC reservation into PJM<br>3.Letter of non-recallability from the native control zone<br>Assuming that these requirements are fully satisfied, the following comments apply:<br>•Only PJM's "owned" share of generation will be modeled in PJM. Any generation located within PJM that serves World load with a firm commitment will be modeled in the World.<br>•Firm capacity purchases will be modeled as generation located within PJM. Firm capacity sales will be modeled by decreasing PJM generation by the full amount of the sale.<br>•Non-firm sales and purchases will not be modeled. The general rule is that any generation that is recallable by another control area does not qualify as PJM capacity and therefore will not be modeled in the PJM Area.<br>•Generation projects in the PJM interconnection queue with a signed Interconnection Service Agreement (ISA) will be modeled in the PJM RTO at their capacity MW value. | Consistency with other PJM reporting and systems. |

| Parameter | 2017 Study Modeling Assumptions | 2018 Study Modeling Assumptions | Basis for Assumptions |
|---|---|---|---|
| **Unit Operational Factors** | | | |
| Forced and Partial Outage Rates | 5-year (2012-16) GADS data. (Those units with less than five years data will use class average representative data.). | 5-year (2013-17) GADS data. (Those units with less than five years data will use class average representative data.). | Most recent 5-year period. Use PJM RTO unit fleet to form class average values. |
| Planned Outages | Based on eGADS data, History of Planned Outage Factor for units. | Based on eGADS data, History of Planned Outage Factor for units. | Updated schedules. |
| Summer Planned Outage Maintenance | In review of recent Summer periods, no Planned outages have occurred. | In review of recent Summer periods, no Planned outages have occurred. | Review of historic 2013 to 2017 unit operational data for PJM RTO footprint. |
| Gas Turbines, Fossil, Nuclear Ambient Derate | Ambient Derate includes several categories of units. Based on analysis of the Summer Verification Test data from the last 3 summers, 2,500 MW out on planned outage over summer peak was confirmed to be the best value to use at this time. This analysis was performed early 2016 under the auspices of the RAAS. | Ambient Derate includes several categories of units. Based on analysis of the Summer Verification Test data from the last 3 summers, 2,500 MW out on planned outage over summer peak was confirmed to be the best value to use at this time. This analysis was performed early 2016 under the auspices of the RAAS. | Operational history and Operations Staff experience indicates unit derates during extreme ambient conditions. Summer Verification Test data confirms this hypothesis. |
| Generator Performance | Peak period generator performance is consistent with year-round generator performance | For each week of the year, except the winter peak week, the PRISM model uses each generating unit's capacity, forced outage rate, and planned maintenance outages to develop a cumulative capacity outage probability table. For the winter peak week, the cumulative capacity outage probability table is created using historical actual (DY 2007/08 – DY 2017/18) RTO-aggregate outage data (data from DY 2013/14 will be dropped and replaced with data from DY 2014/15). | New methodology to develop winter peak week capacity model to better account for the risk caused by the large volume of concurrent outages observed historically during the winter peak week. |
| Class Average Statistics | PJM RTO fleet Class Average values. 73 categories based on unit type, size and primary fuel. | PJM RTO fleet Class Average values. 73 categories based on unit type, size and primary fuel. | PJM RTO values have a sufficient population of data for most of the categories. The values are more consistent with planning experience. |
| Uncommitted Resources | Behind the meter generation (BTMG) is not included in the capacity model because such resources cannot be capacity resources. The impact of behind the meter generation (BTMG) is reflected on the load side. | Behind the meter generation (BTMG) is not included in the capacity model because such resources cannot be capacity resources. The impact of behind the meter generation (BTMG) is reflected on the load side. | Consistency with other PJM reporting and systems. |
| Generation Owner Review | Generation Owner review and sign-off of capacity model. | Generation Owner review and sign-off of capacity model. | Annual review to insure data integrity of principal modeling parameters. |

| Parameter | 2017 Study Modeling Assumptions | 2018 Study Modeling Assumptions | Basis for Assumptions |
|---|---|---|---|
| **Load Management and Energy Efficiency** | | | |
| Load Management and Energy Efficiency | **PJM RTO load management modeled per the January 2017 PJM Load Forecast Report (Table B7)** | PJM RTO load management modeled per the January 2018 PJM Load Forecast Report (Table B7) | Model latest load management and energy efficiency data. Based on Manual 19, Section 3 for PJM Load Forecast Model. |
| Emergency Operating Procedures | IRM reported for Emergency Operating Procedures that include invoking load management but before invoking Voltage reductions. | IRM reported for Emergency Operating Procedures that include invoking load management but before invoking Voltage reductions. | Consistent reporting across historic values. |
| **Transmission System** | | | |
| Interface Limits | The Capacity Benefit Margin (CBM) is an input value used to reflect the amount of transmission import capability reserved to reduce the IRM. This value is 3,500 MW. | The Capacity Benefit Margin (CBM) is an input value used to reflect the amount of transmission import capability reserved to reduce the IRM. This value is 3,500 MW. | Reliability Assurance Agreement, Schedule 4, Capacity Benefit Margin definition. |
| New Transmission Capability | Consistent with PJM's RTEP as overseen by TEAC. | Consistent with PJM's RTEP as overseen by TEAC. | Consistent with PJM's RTEP as overseen by TEAC. |
| | | | |
| **Modeling Systems** | | | |
| Modeling Tools | ARC Platform 2.0 | ARC Platform 2.0 | Per recommendation by PJM Staff. Latest available version. |
| Modeling Tools | Multi-Area Reliability Simulation (MARS) Version 3.16 | Multi-Area Reliability Simulation (MARS) Version 3.16 | Per recommendation by PJM Staff and General Electric Staff. Latest available version. |
| Outside World Area Models | Base Case world region include: NY, MISO, TVA and VACAR. | Base Case world region include: NY, MISO, TVA and VACAR. | Updated per publicly available data and by coordination with other region's planning staffs. |