2019 PJM Reserve Requirement Study

11-year Planning Horizon:

June 1st 2019 - May 31st 2030

Analysis Performed by PJM Staff

Reviewed by Resource Adequacy Analysis Subcommittee

October 8, 2019

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I. Results and Recommendations

PJM RRS Executive Summary

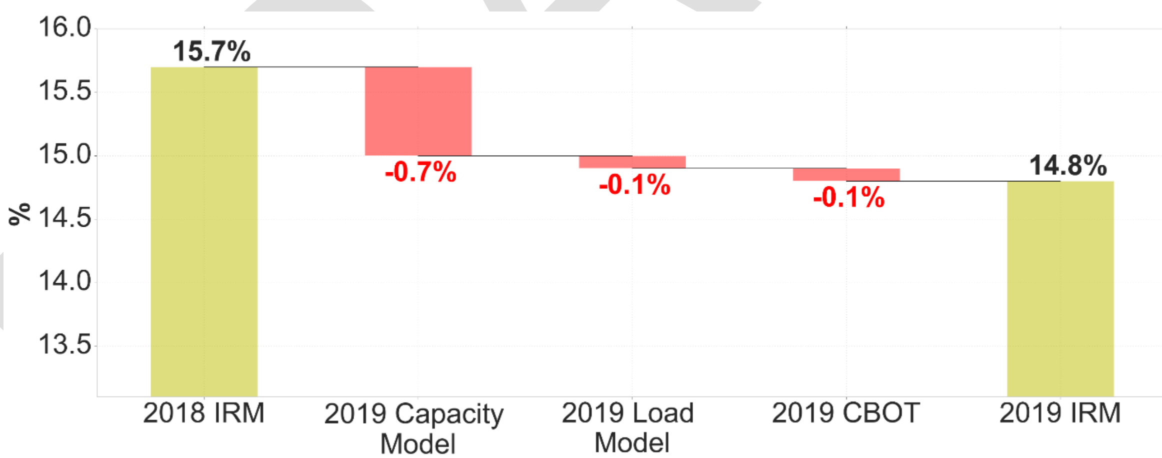
- The PJM Reserve Requirement Study's (RRS) purpose is to determine the Forecast Pool Requirement (FPR) for future Delivery Years, through calculating the Installed Reserve Margin (IRM). In accordance with the Reliability Pricing Model (RPM) auction schedule, results from this study will re-establish the FPR for the 2020/2021, 2021/2022, and 2022/2023 Delivery Years (DY) and establish the FPR for the 2023/24 Delivery Year.

- PJM uses this Study to satisfy the North America Electric Reliability Corporation (NERC) / ReliabilityFirst (RF) Adequacy Standard BAL-502-RFC-02, Planning Resource Adequacy Analysis, Assessment and Documentation. This Standard requires that the Planning Coordinator performs and documents a resource adequacy analysis that applies a Loss of Load Expectation (LOLE) of one occurrence in ten years. Per the final 2010 RF audit report, PJM was found to be fully compliant with Standard BAL-502-RFC-02.

- Based on results from this Study, PJM Staff recommends a **15.5% IRM (1.0882 FPR) for the 2020/2021 Delivery Year, a 15.1% IRM (1.0870 FPR) for the 2021/2022 Delivery Year, a 14.9% IRM (1.0867 FPR) for the 2022/2023 Delivery Year, and a 14.8% IRM (1.0860 FPR) for the 2023/2024 Delivery Year**.

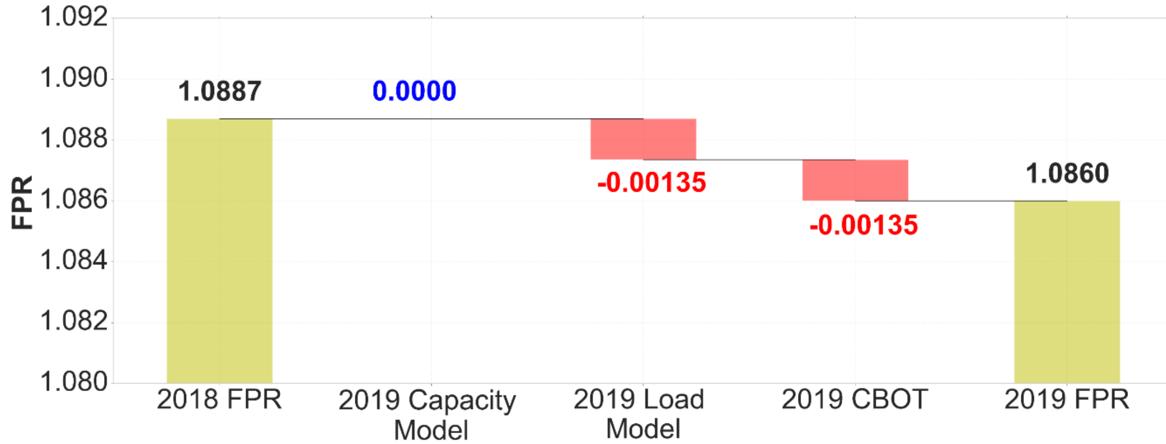
- The 14.8% IRM for 2023/2024 calculated in this year's study represents a decrease of 0.9 percentage points with respect to the IRM computed for 2022/2023 in last year's study. The decrease can be attributed to the factors and their estimated corresponding quantitative impacts depicted in Figure I-1.

Figure I-1: 2019 Installed Reserve Margin Waterfall Chart



- The 1.0860 (8.60%) FPR for 2023/2024 calculated in this year's study represents a decrease of 0.27 percentage points with respect to the FPR computed for 2022/2023 in last year's study (1.0887 or 8.87%). The decrease can be attributed to the factors and their estimated corresponding quantitative impacts depicted in Figure I-2 below.

Figure I-2: 2019 Forecast Pool Requirement Waterfall Chart



- The IRM decrease is driven by a lower average EEFORd in the 2019 PJM Capacity Model (6.1%) relative to the average EEFORd in the 2018 PJM Capacity Model (6.7%). To a lesser extent, the IRM decrease can also be attributed to: i) a lower August-to-July PJM peak ratio (96.5% in the 2019 Load Model compared to 97.0% in the 2018 Load Model) and ii) an increase in the emergency imports available from the World into PJM (i.e., an increase in the Capacity Benefit of Ties or CBOT).

- The FPR decrease is driven by the lower August-to-July PJM peak ratio and the increase in emergency imports available from the World into PJM, both discussed above. Changes to the capacity model largely have no impact on the FPR because the FPR corresponds to the IRM expressed in unforced capacity units (i.e., the FPR corresponds to the IRM decremented by the average forced outage rate).

- The results of the 2019 RRS are summarized below in Table I-1. PJM Staff recommends the values shown in bold in the following table.

Table I-1: 2019 Reserve Requirement Study Summary Table

RRS Year	Delivery Year Period	Calculated IRM	Recommended IRM	Average EFORd	Recommended FPR
2019	2020 / 2021	15.46%	**15.5%**	5.78%	**1.0882**
2019	2021 / 2022	15.14%	**15.1%**	5.56%	**1.0870**
2019	2022 / 2023	14.89%	**14.9%**	5.42%	**1.0867**
2019	2023 / 2024	14.84%	**14.8%**	5.40%	**1.0860**

- For comparison purposes, the results from the 2018 RRS Study are below in Table I-2:

Table I-2: 2018 Reserve Requirement Study Summary Table

RRS Year	Delivery Year Period	Calculated IRM	Recommended IRM	Average EFORd	Recommended FPR
2018	2019 / 2020	15.97%	**16.0%**	6.08%	**1.0895**
2018	2020 / 2021	15.89%	**15.9%**	6.04%	**1.0890**
2018	2021 / 2022	15.84%	**15.8%**	6.01%	**1.0884**
2018	2022 / 2023	15.66%	**15.7%**	5.90%	**1.0887**

- The Winter Weekly Reserve Target (WWRT) for the **2019/2020 winter period is recommended to be 22% for December 2019, 28% for January 2020, and 24% for February 2020**. The analysis supporting this recommendation is detailed in the "Operations Related Assessments" section of this report.

- The winter peak week capacity model changes approved by the Markets and Reliability Committee (MRC) in June 2018 and first implemented in the 2018 RRS were also used in the 2019 RRS. These changes had no practical impact on the recommended IRM and FPR values. The recommended WWRT value for January described in the bullet point above, however, is impacted by these changes due to the fact that the winter peak week is modeled to occur in January.

- The IRM and FPR recommended in Table I-1 are reviewed and considered for endorsement by the following succession of groups.

    - Resource Adequacy Analysis Subcommittee (RAAS)
    - Planning Committee (PC)
    - Markets and Reliability Committee (MRC)
    - PJM Members Committee (MC)
    - PJM Board of Managers (for final approval)

- PJM's Probabilistic Reliability Index Study Model (PRISM) program is the primary reliability modeling tool used in the RRS. PRISM utilizes a two-area Loss of Load Probability (LOLP) modeling approach consisting of: Area 1 - the PJM RTO and Area 2 - the neighboring World.

- The PJM RTO includes the PJM Mid-Atlantic Region, Allegheny Energy (APS), American Electric Power (AEP), Commonwealth Edison (ComEd), Dayton Power and Light (Dayton), Dominion Virginia Power (Dom), Duquesne Light Co. (DLCO), American Transmission System Inc. (ATSI), Duke Energy Ohio and Kentucky (DEOK), and East Kentucky Power Cooperative (EKPC). In addition, the PJM RTO includes for the first time the recently integrated Ohio Valley Electric Corporation (OVEC).

- The Outside World (or World) area consists of the North American Electric Reliability Corporation (NERC) regions adjacent to PJM. These regions include New York ISO (NYISO) from the Northeast Power Coordinating Council

(NPCC), TVA and VACAR from the South Eastern Reliability Corporation (SERC), and the Midcontinent Independent System Operator (MISO) (excluding MISO-South).

- Modeling of the World region assumes a Capacity Benefit Margin (CBM) of 3,500 MW into PJM, which serves as a maximum limit on the amount of external assistance. The CBM is set to 3,500 MW per Schedule 4 of the PJM Reliability Assurance Agreement. Figure I-7 shows the benefit of this interconnection at various values of CBM.
- There is a net addition of approximately 6,400 MW of generation within the PJM RTO in the period 2019-2023. This reflects approximately 15,000 MW of new generation and 8,600 MW of retired generation. The RRS study does not include Demand Resources.
- For the fifth year in a row, the load model time period 2003-2012 was used in the RRS study. This load model time period was endorsed at the July 11, 2019 Planning Committee meeting.
- Consistent with the requirements of ReliabilityFirst (RF) Standard BAL-502-RFC-02 - Resource Planning Reserve Requirements, the 2019 RRS provides an eleven-year resource adequacy projection for the planning horizon that begins June 1, 2019 and extends through May 31, 2030. (See Table I-4)

Results from the last ten RRS Reports are summarized below in Table I-3:

Table I-3: Historical RRS Parameters

RRS Year	Delivery Year	Calculated IRM	**Approved IRM**	Avg. EFORd	**FPR**
2009	2012/2013	15.4%	**15.4%**	6.28%	**1.0815**
2009	2013/2014	15.3%	**15.3%**	6.30%	**1.0804**
2010	2012/2013	15.5%	**15.5%**	6.26%	**1.0827**
2010	2013/2014	15.3%	**15.3%**	6.25%	**1.0809**
2010	2014/2015	15.3%	**15.3%**	6.25%	**1.0809**
2011	2012/2013	15.6%	**15.6%**	6.58%	**1.0869**
2011	2013/2014	15.4%	**15.4%**	6.52%	**1.0859**
2011	2014/2015	15.4%	**15.4%**	6.51%	**1.0860**
2011	2015/2016	15.4%	**15.4%**	6.52%	**1.0859**
2012	2013/2014	15.9%	**15.9%**	6.73%	**1.0889**
2012	2014/2015	15.9%	**15.9%**	6.72%	**1.0889**
2012	2015/2016	15.3%	**15.3%**	6.59%	**1.0849**
2012	2016/2017	15.6%	**15.6%**	6.38%	**1.0902**
2013	2014/2015	16.2%	**16.2%**	6.66%	**1.0926**
2013	2015/2016	15.7%	**15.7%**	6.26%	**1.0920**
2013	2016/2017	15.7%	**15.7%**	6.29%	**1.0917**
2013	2017/2018	15.7%	**15.7%**	6.29%	**1.0916**
2014	2015/2016	15.6%	**15.6%**	6.19%	**1.0913**
2014	2016/2017	15.5%	**15.5%**	6.30%	**1.0896**
2014	2017/2018	15.7%	**15.7%**	6.34%	**1.0911**
2014	2018/2019	15.7%	**15.7%**	6.35%	**1.0835**
2015	2016/2017	16.4%	**16.4%**	6.57%	**1.0952**
2015	2017/2018	16.5%	**16.5%**	6.59%	**1.0959**
2015	2018/2019	16.5%	**16.5%**	6.58%	**1.0883**
2015	2019/2020	16.5%	**16.5%**	6.60%	**1.0881**
2016	2017/2018	16.6%	**16.6%**	6.54%	**1.0967**
2016	2018/2019	16.7%	**16.7%**	6.59%	**1.0901**
2016	2019/2020	16.6%	**16.6%**	6.59%	**1.0892**
2016	2020/2021	16.6%	**16.6%**	6.59%	**1.0892**
2017	2018/2019	16.1%	**16.1%**	6.07%	**1.0905**
2017	2019/2020	15.9%	**15.9%**	5.99%	**1.0896**
2017	2020/2021	15.9%	**15.9%**	5.97%	**1.0898**
2017	2021/2022	15.8%	**15.8%**	5.89%	**1.0898**
2018	2019/2020	16.0%	**16.0%**	6.08%	**1.0895**
2018	2020/2021	15.9%	**15.9%**	6.04%	**1.0890**
2018	2021/2022	15.8%	**15.8%**	6.01%	**1.0884**
2018	2022/2023	15.7%	**15.7%**	5.90%	**1.0887**

Introduction

Purpose

The annual PJM Reserve Requirement Study (RRS) calculates the reserve margin that is required to comply with the Reliability Principles and Standards as defined in the PJM Reliability Assurance Agreement (RAA) and ReliabilityFirst (RF) Standard BAL-502-RFC-02. This study is conducted each year in accordance with PJM Manual 20 (M-20), PJM Resource Adequacy Analysis. M-20 focuses on the process and procedure for establishing the resource adequacy (capacity) required to reliably serve customer load in the PJM RTO.

The RRS results are key inputs to the PJM Reliability Pricing Model (RPM). These inputs include the Installed Reserve Margin (IRM) and Forecast Pool Requirement (FPR). More specifically, the FPR is used to calculate the Reliability Requirement for the PJM Regional Transmission Organization (RTO) in RPM Auctions.

The results of the RRS are also incorporated into PJM's Regional Transmission Expansion Plan (RTEP) process for the enhancement and expansion of the transmission system in order to meet the demands for firm transmission service in the PJM Region.

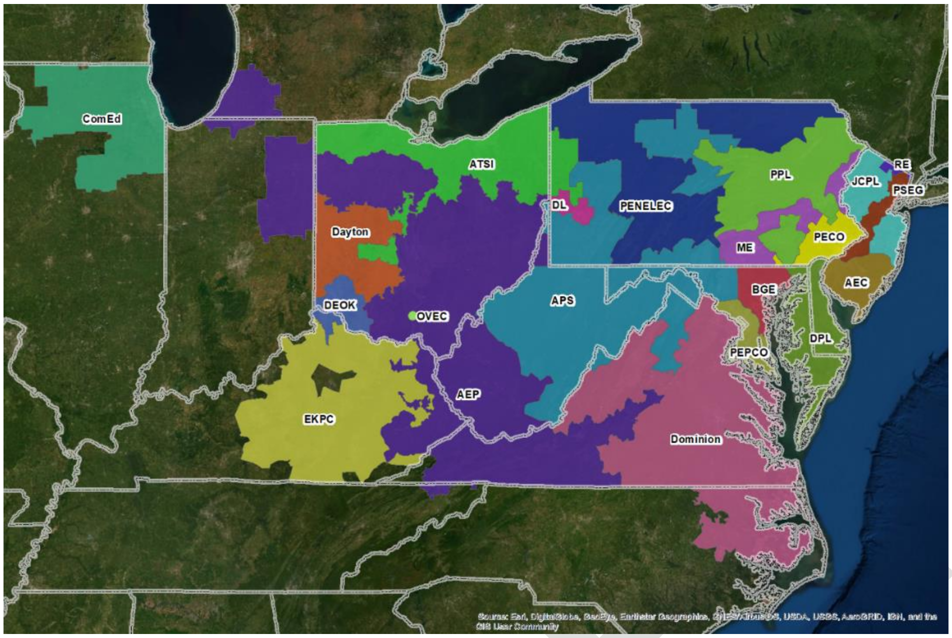
Installed Reserve Margin (IRM) and Forecast Pool Requirement (FPR)

In addition to serving as inputs for the RPM market, the IRM and FPR calculated in the RRS are critical values as they satisfy compliance requirements for ReliabilityFirst (RF). (See Section II. For further details on the process, contact regional_compliance@pjm.com.)

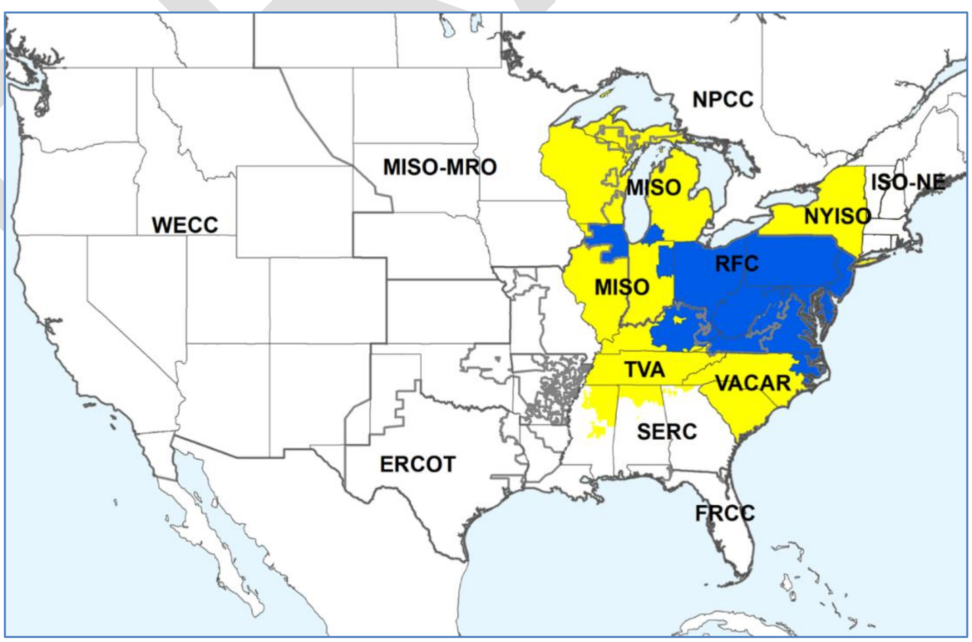
The timetable for calculating and approving these values is shown in the June 2019 study assumptions letter to the PC, reviewed as agenda item 5 at the June 13, 2019 PC meeting.

Regional Modeling

This study examines the combined PJM footprint area (
Figure I-3) that consists of the PJM Mid-Atlantic Region plus Allegheny Energy (APS), American Electric Power (AEP), Commonwealth Edison (ComEd), Dayton Power and Light (Dayton), Dominion Virginia Power (DOMVP), Duquesne Light Co. (DLCO), American Transmission System Inc. (ATSI), Duke Energy Ohio and Kentucky (DEOK), and East Kentucky Power Cooperative (EKPC). In addition, the PJM RTO includes for the first time the recently integrated Ohio Valley Electric Corporation (OVEC).



Areas adjacent to the PJM Region are referred to as the World (Figure I-4) and consist of MISO (excluding MISO-South), TVA and VACAR (both in SERC), and NYISO from the Northeast Power Coordinating Council (NPCC). Areas outside of PJM and the World are not modeled in this study.



Summary of RRS Results

Eleven-Year RRS Results

Table I-4 shows an eleven-year forward projection from the study for informational purposes. The Delivery Years for which the parameters must be reported are highlighted in yellow. These results do not reflect any previous modeling or approved values. Note that the projected reserves in column H exceed the IRM in column A for each of the next eleven Delivery Years. The study, therefore, indicates there are no gaps between the needed amount of planning reserves and the projected planning reserves over the eleven-year study period.

Table I-4: Eleven-Year Reserve Requirement Study

	Calculated IRM				Forecast Reserve					
	A	B	C	D	E	F	G	H	I	J
Delivery Year	IRM PJM RTO % (2 area)	IRM Outside World %	Average PJM EEFORd %	Average Weekly Maintenance %	Forecast Pool Require-ment (FPR)	Capacity MW	Restricted Load MW	Forecast Reserve PJMRTO %	Forecast Unrestricted Reserve PJM RTO %	PJM Reliability Index without World Assistance (years/day)
2019	15.6%	16.6%	6.7%	8.5%	1.0879	187,434	143,204	30.9%	23.8%	5.9
2020	15.5%	16.6%	6.6%	8.4%	1.0882	183,991	141,743	29.8%	22.0%	5.8
2021	15.1%	16.6%	6.3%	8.2%	1.0870	185,507	142,429	30.2%	22.4%	5.9
2022	14.9%	16.6%	6.2%	8.1%	1.0867	189,151	143,193	32.1%	24.4%	5.9
2023	14.8%	16.6%	6.1%	8.2%	1.0860	192,142	143,771	33.6%	25.9%	5.9
2024	14.8%	16.6%	6.1%	8.3%	1.0861	193,269	144,310	33.9%	26.1%	5.9
2025	14.8%	16.6%	6.1%	8.4%	1.0861	193,269	144,821	33.5%	25.7%	5.9
2026	14.8%	16.5%	6.1%	8.4%	1.0861	193,269	145,283	33.0%	25.3%	5.9
2027	14.8%	16.5%	6.1%	8.4%	1.0861	193,269	145,873	32.5%	24.8%	5.9
2028	14.8%	16.5%	6.1%	8.4%	1.0861	193,269	146,620	31.8%	24.2%	5.9
2029	14.8%	16.5%	6.1%	8.4%	1.0861	193,269	147,373	31.1%	23.5%	5.9

Calculated IRM Columns (PRISM Run # 57086)

- Calculated IRM, column A is at an LOLE criterion of 1 day in 10 years.
- Column A is based on the PRISM solved load, not the January 2019 load forecast values issued by PJM.
- Calculated IRM, column B is the World IRM at an LOLE criterion of 1 day in 10 years which is within the valid range shown in Table I-5 (15.24% to 20.14%). The exact World reserve value depends on World load management actions at the time of the PJM RTO's need for assistance. The World reserve levels in Column B that yield a PJM Reliability Index (RI) equal to an LOLE of 1 day in 10 years are within the valid range.
- Results reflect calculated (to the nearest decimal) reserve requirements for the PJM RTO (column A) and the Outside World (column B).
- Calculated IRM results are determined using a 3,500 MW Capacity Benefit Margin (CBM).
- The Average Effective Equivalent Demand Forced outage rate (EEFORd) (column C) is a pool-wide average effective equivalent demand forced outage rate for all units in the PJM RTO model (about 1,500 units). These are not the forced outage rates used in the RAA Obligation formula (as mentioned earlier in the document, EFORd

values are used in the FPR formula). The EEFORd of each unit is based on a five-year period (2014-2018, for this year's study).

- The average weekly maintenance (column D) is the percentage of the average annual total capacity in the model out on weekly planned maintenance.

Forecast Reserve Columns

- The capacity values in Column F include external firm capacity purchases and sales.
- 2,500 MW of unit deratings were modeled to reflect generator performance impacts during extreme hot and humid summer conditions. These 2,500 MW are included in the Column F value.
- The Restricted Load in Column G corresponds to Total Internal Demand (at peak time) minus load management as per the 2019 PJM Load Forecast.
- The PJM forecast reserves are above the calculated requirement (see Column H vs. Column A for years in yellow).
- Reserves in Column H (as well as the capacity value in Column F) include about 15,000 MW of new generation projects identified through the Regional Transmission Expansion Plan (RTEP). Generation projects in the PJM interconnection queue with a signed Interconnection Service Agreement (ISA) are included in the study at their capacity MW value.
- The RTEP is dynamic and actual PJM reserve levels may differ significantly from those forecasted in Column H. An additional factor contributing to future reserve margin uncertainty is the fact that PJM allows units to retire with as little as 90 days' notice as per PJM's Manual 14D.

PJM Reliability Index without World Assistance

- The values in Column J are for informational purposes only. PJM Reliability Index (RI) is expressed in years per day (the inverse of the days per year LOLE). This column indicates reliability when all external ties into PJM are cut ("zero import capability" scenario) for the corresponding PJM IRM in Column A.
- In other words, the values in Column J represent the frequency of loss of load occurrences if the PJM RTO were not part of the Eastern Interconnection. Compared to the 1 in 10 criteria (RI = 10), the values in Column J are much lower. This comparison provides a sense of the value of PJM being strongly interconnected. More specifically, if PJM were not interconnected, it could experience loss of load events roughly twice as often (at a reserve margin level equal to the IRM).

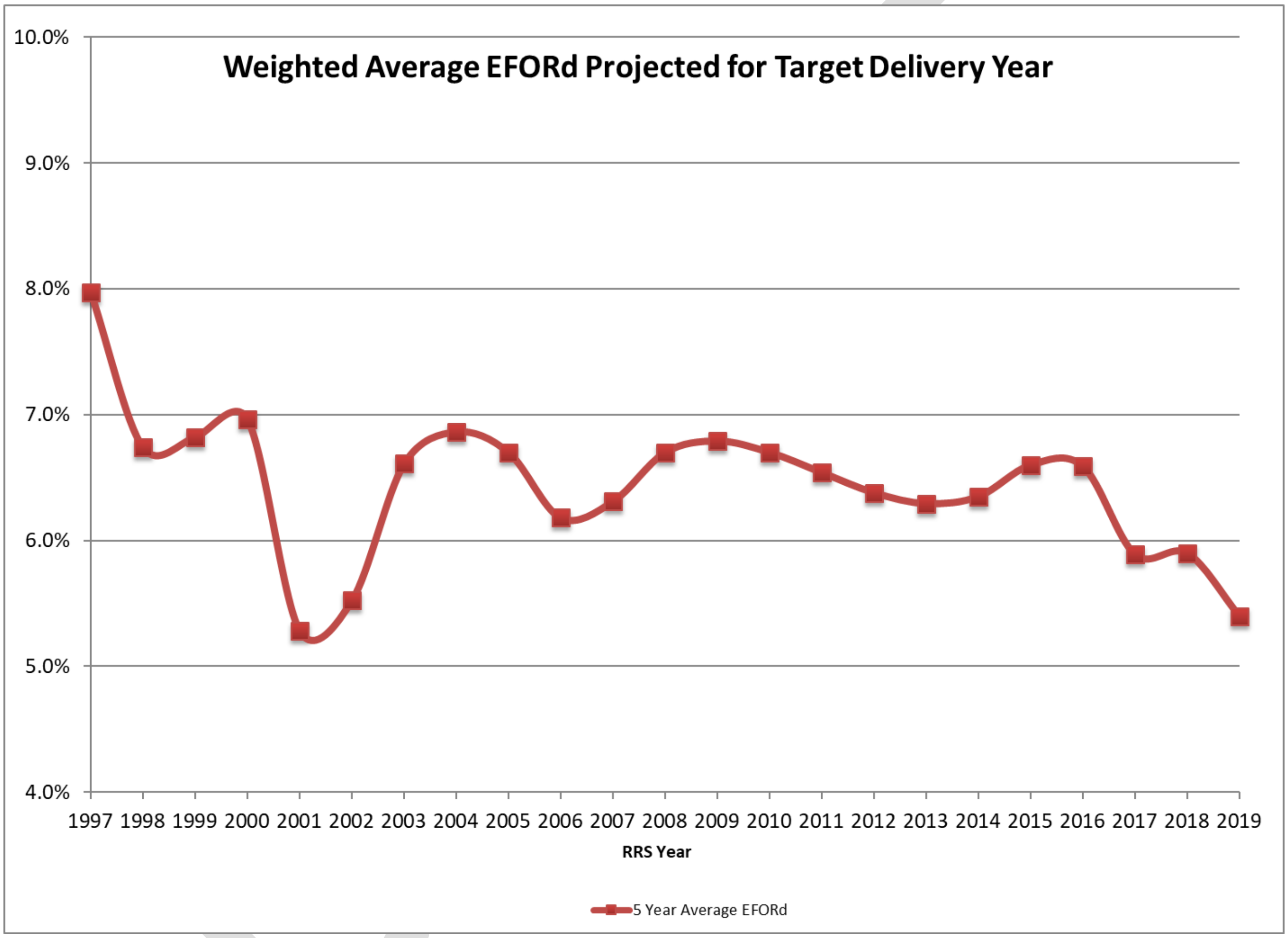
Key Observations

- General Trends and Observations
  - Pool wide average forced outage rate values (EFORd) for the target Delivery Year, in each of the annual RRS capacity models, are shown in Figure I-5. The forced outage rates of each unit are based on the historical five-year period used in a given study. It is important to note that the collection of generators included in each year's case varies greatly over time as new generators are brought in-service, some generators retire or mothball, and new generators are added due to PJM market expansion.

  - As shown in Figure I-5, average unit performance in the 2019 study model is significantly better than the unit performance in the 2018 study model (the weighted average EFORd in the 2019 RRS is 5.40% while in the 2018 RRS it was 5.90%). As a result, there is downward pressure on the IRM (estimated at 0.7 percentage points).

- This decrease in weighted average EFORd is due to the changes in the projected composition of the fleet for Delivery Year 2023/24: a large amount of deactivations (~8,600 MW) with high weighted average EFORd (10.8%) and a large amount of additions (~15,000 MW) with low weighted average EFORd (3.6%) are projected to occur prior to Delivery Year 2023/24.

Figure I-5: Historical Weighted-Average Forced Outage Rates (Five-Year Period)



- The World reserves were assessed and modeled in a similar manner as performed in previous RRS studies. Among the regions modeled as part of the World, the New York and MISO regions have firm reserve requirements, while the TVA and VACAR regions have soft targets. The soft targets chosen are consistent with general statements of the NERC targets for these regions. Table I-5 summarizes the values used to determine a valid range for a World reserve level of 15.24% to 20.14%. The reserve requirements considered for each region are shown in the IRM column. The diversity values shown are from an assessment of historic data, using the average of the values observed over the summer season. See Table II-3 for further details. Please reference Appendix F which presents a discussion of the modeling assumptions. It was agreed upon by the RAAS in previous years that the appropriate choice for World reserves is the one that satisfies the 1 in 10 reliability criterion for the World as long as it is within the valid range. This value in the 2019 study is 16.6% and it is within the valid range shown in Table I-5.

Table I-5: World Reserve Level, Valid Range to Consider

	NCP	IRM	Diversity	CP	LM	LM as % NCP	NCP- LM (NID)	CAP based on NID	CP- LM	Reserves as % of CP	Reserves as % of CP- LM
NY	32429	16.8%	0.9458	30670	925	2.85%	31504	36797	29745		
MISO	95216	16.8%	0.9902	94287	4552	4.78%	90664	105896	89735		
TVA	41526	15.0%	0.9536	39600	1795	4.32%	39731	45691	37805		
VACAR	42684	15.0%	0.9469	40419	1090	2.55%	41594	47833	39329		
Total Composite Region =	211855			204977	8362	3.95%	203493	236216	196615	15.24%	20.14%

LM: Load Management NCP: Non-Coincident Peak CP: Coincident Peak

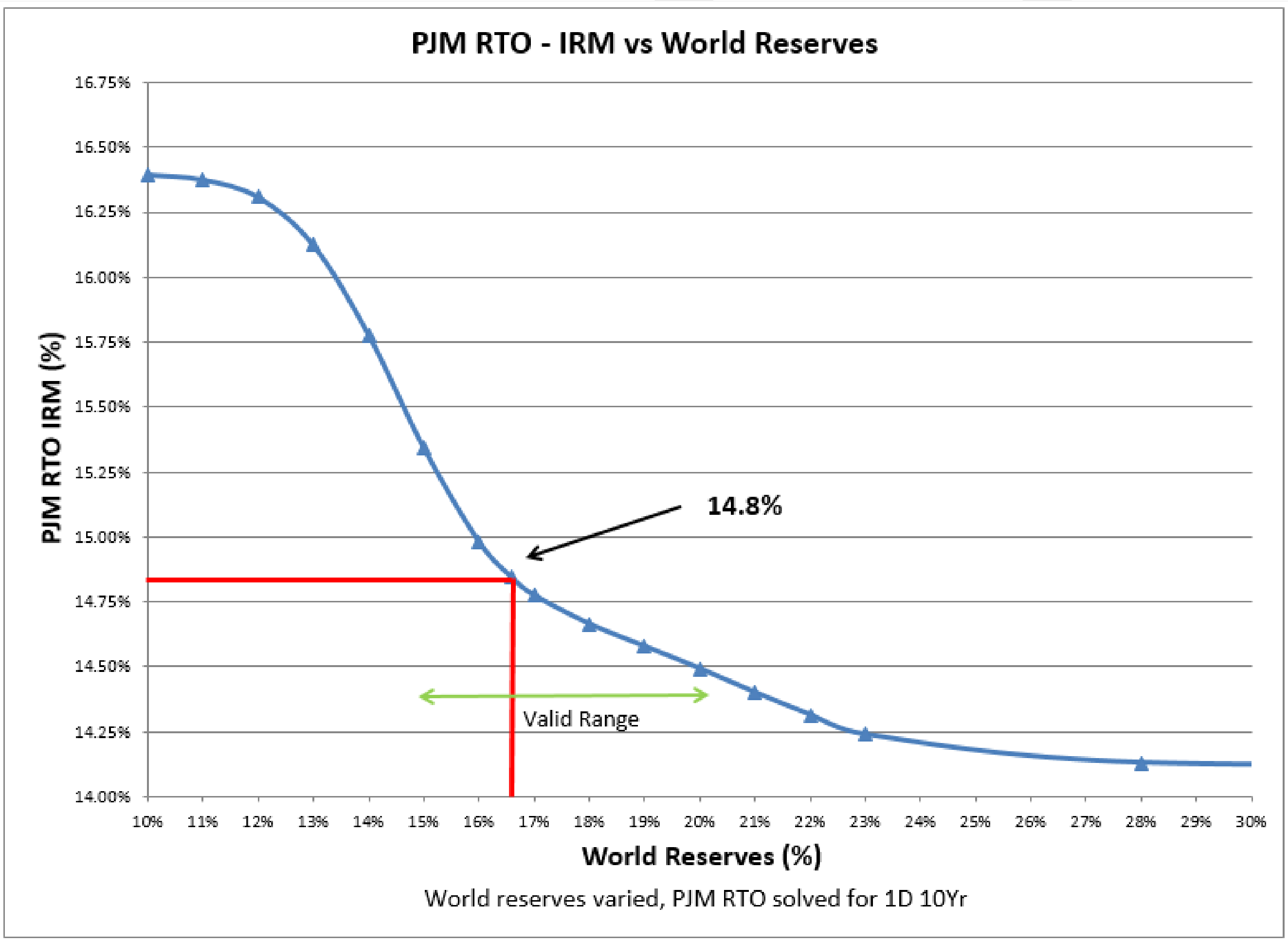
Data Sources

NY - NPCC Reliability Assessment for Summer 2019, Appendix VIII, Table 4 & Table 6, April 2019
Available at https://www.npcc.org/Library/Seasonal%20Assessment/NPCC_2019_Summer_Assessment.pdf
MISO - 2018 NERC ES&D Report - Peak Hour Demand Seasonal, 1st Year column
MISO excludes MISO-South
MISO LM Total from 2018 NERC ES&D Report- Controllable and Dispatchable Demand Response - Available (Year 1)
TVA and VACAR - 2018 NERC ES&D Report
Peak Hour Demand Seasonal, 1st Year column. TVA = SERC N (Summer), VACAR = SERC E (Winter)
Demand & Resources - Summer, Controllable and Dispatchable Demand Response - Available (Year 1). TVA = SERC N, VACAR = SERC E
NY and MISO are modeled at their approved IRMs as per the documents below:
http://www.nysrc.org/pdf/Reports/2019%20IRM%20Study%20Body-Final%20Report[6815].pdf
https://cdn.misoenergy.org/2019%20LOLE%20Study%20Report285051.pdf
TVA and VACAR are modeled at the soft target IRM of 15%.

- Load diversity between PJM and the World is addressed by two modeling assumptions. First, the historical period used to construct the hourly load model is the same for PJM and the World. Second, the world load model corresponds to coincident peaks from the four individual sub-regions.

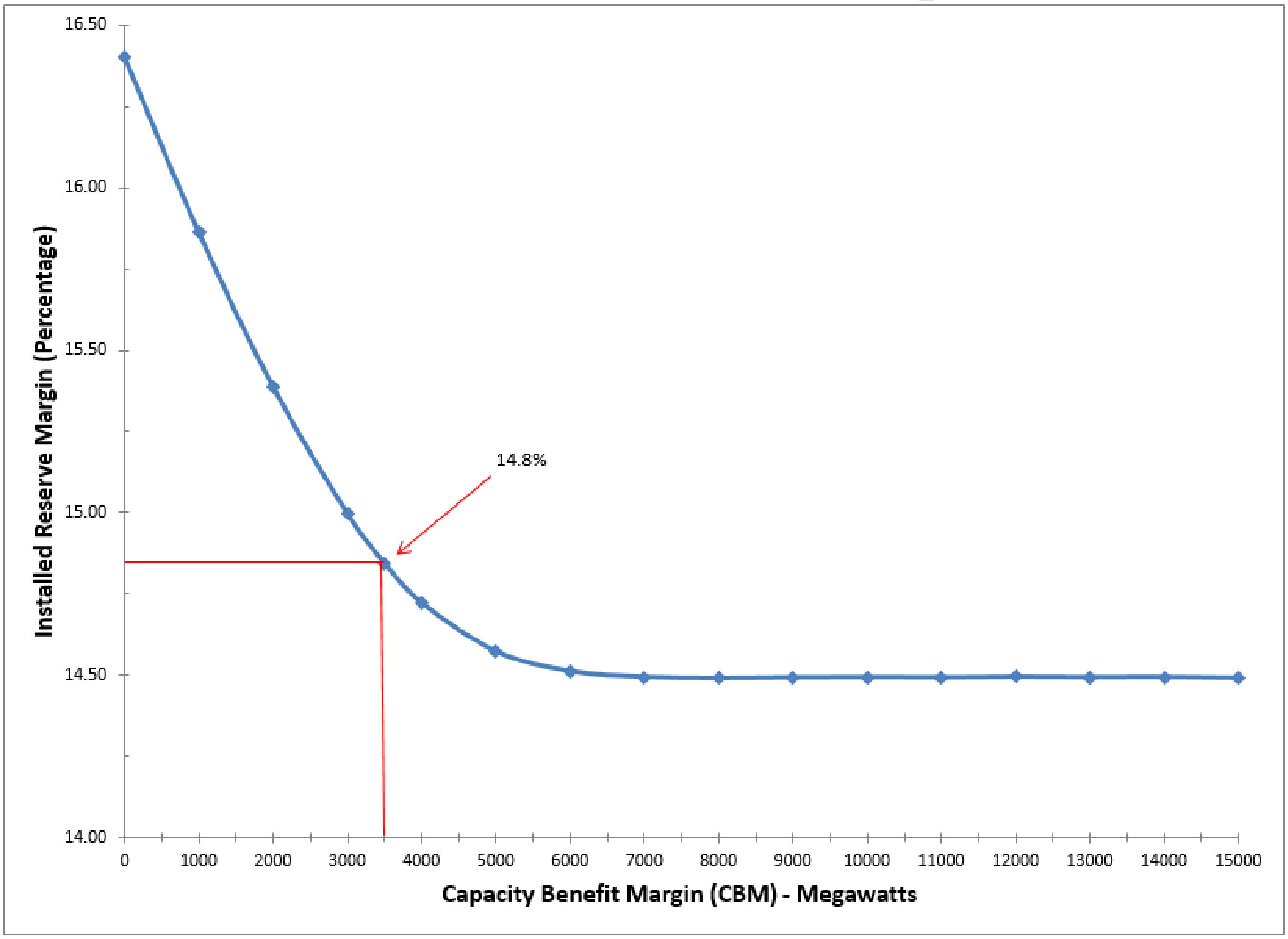
- Figure I-6 shows the impact of the World reserves on the PJM RTO IRM. This figure assumes a CBM value of 3,500 MW at all World reserve levels. The green horizontal line labeled "valid range" shows the range of World generation reserve levels depending on the amount of World load management assumed to be curtailed or to have voluntarily reduced consumption in response to economic incentives, at the time of a PJM capacity emergency. The lower end of the range (at 15.24%) represents the World reserve level if no World load management were implemented. The higher end (at 20.14%) is the reserve level assuming all World load management is implemented or customers have reduced their loads at the time of a PJM emergency. Figure I-6 indicates that the impact of additional World Reserves on PJM's IRM tends to decrease as World Reserves are outside of the valid range (above 19%).
- The PJM IRM at this "1 in 10" World reserve level is 14.84%. This is the basis for the recommended IRM, for Delivery Year 2023/2024, of 14.8%.

Figure I-6: Relation between the IRM and World Reserves



- Figure I-7 shows how the PJM IRM varies as the CBM is varied. As indicated by the red line, the official CBM value of 3,500 MW results in a PJM IRM of 14.8%. Thus, the PJM IRM is reduced by 1.6% due to the CBM (from 16.4%, the intercept with the y-axis, to 14.8 %). Based on the forecasted load for 2023/2024, this 1.6% IRM reduction eliminates the need for about 152,624 MW x 1.6% = 2,442 MW of installed capacity. Therefore, the Capacity Benefit of Ties (CBOT) in this year's study is 2,442 MW.

Figure I-7: Relation between the IRM and the CBM



- The underlying modeling characteristics of load, generation, and neighboring regions' reserves / tie size are the primary drivers for the results of the study. Although consideration of the amount in MW of either load or generation can be a factor, it is not as significant due to the method employed to adjust an area's load until its LOLE meets the 1 day in 10 years reliability criterion. Small changes to the parameters that capture uncertainties associated with load and generation can impact the assessment results.

Recommendations

- Installed Reserve Margin (IRM) — based on the study results and the additional considerations mentioned above, PJM recommends endorsement of an IRM value of 15.5% for the 2020/2021 Delivery Year, 15.1% for the 2021/2022 Delivery Year, 14.9% for the 2022/2023 Delivery Year, and 14.8% for the 2023/2024 Delivery Year. The IRM is applied to the official 50/50 PJM Summer Peak Forecast which corresponds to the Expected Weekly Maximum (EWM) of the peak summer week in PRISM.

- Forecast Pool Requirement (FPR) — the approved IRM is converted to the FPR for use in determining capacity obligations. The FPR expresses the reserve requirement in unforced capacity terms. The FPR is defined by the following equation:

    - FPR = (1 + IRM) * (1 – PJM Avg. EFORd)

- Based on the recommended IRM values, the resulting FPRs would therefore be:

    - 2020 / 2021 Delivery Year FPR = (1.155) * (1 – 0.0578) = 1.0882
    - 2021 / 2022 Delivery Year FPR = (1.151) * (1 – 0.0556) = 1.0870
    - 2022 / 2023 Delivery Year FPR = (1.149) * (1 – 0.0542) = 1.0867
    - 2023 / 2024 Delivery Year FPR = (1.148) * (1 – 0.0540) = 1.0860

- Winter Weekly Reserve Target — the recommended 2019 / 2020 Winter Weekly Reserve Target is 22% for December 2019, 28% for January 2020, and 24% for February 2020. This recommendation is discussed later in the report.

II. Modeling and Analysis

Load Forecasting

PJM Load Forecast – January 2019 Load Report

The January 2019 PJM Load Forecast is used in the 2019 RRS. The load report is available on the PJM web site at: https://www.pjm.com/-/media/library/reports-notices/load-forecast/2019-load-report.ashx?la=en. The methods and techniques used in the load forecasting process are documented in Manual 19 (Load Forecasting and Analysis).

Monthly Forecasted Unrestricted Peak Demand and Demand Resources

The monthly loads used in the RRS are based on forecasted monthly unrestricted peak loads. PJM monthly loads are from the 2019 PJM Load Forecast report. World monthly loads are derived through an examination of data from NERC's Electric Supply and Demand (ES&D) dataset. These values are in Table II-1 on a per-unit basis relative to the annual peak.

Table II-1: Load Forecast for 2023 / 2024 Delivery Years

Month	PJMRTO Unrestricted Loads	WORLD Unrestricted Loads
June	0.939852	0.954062
July	1.000000	1.000000
August	0.965418	0.994266
September	0.858779	0.903074
October	0.715088	0.731715
November	0.724906	0.760636
December	0.829480	0.834440
January	0.874708	0.859573
February	0.835339	0.820173
March	0.752269	0.763302
April	0.715241	0.688069
May	0.789726	0.805279

Forecast Error Factor (FEF)

The Forecast Error Factor (FEF) represents the increased uncertainty associated with forecasts covering a longer time horizon. The FEF is 1.0% for all future delivery years. See PJM Manual 20 and the "PJM Generation Adequacy Analysis – Technical methods" (at http://www.pjm.com/planning/resource-adequacy-planning/reserve-requirement-dev-process.aspx) and the Modeling and Analysis Section for discussion of how the FEF is used in the determination of the Expected Weekly Maximum (EWM).

With the implementation of the RPM capacity market in 2006, the FEF used in the RRS was changed to 1.0% for all future delivery years, based on a stakeholder consensus. This is due to the ability for PJM to acquire additional resources in incremental auctions close to the delivery year. This mitigates the uncertainty of the load forecast as RPM mimics a one-year-ahead forecast. Sensitivity number 8 in Appendix B shows the impact of different FEF values on the IRM.

21 point Standard Normal Distribution, for daily peaks

PRISM's load model is a daily peak load model aggregated by week (1-52). The uncertainty in the daily peak load model is modeled via a standard normal distribution. The standard normal distribution is represented using 21 points with a range of +/- 4.2 sigma away from the mean. The modeling used is based on work by C.J. Baldwin, as presented in the Westinghouse Engineer journal titled "Probability Calculation of Generation Reserves", dated March 1969. See PJM Manual 20 for further details.

Week Peak Frequency (WKPKFQ) Parameters

The load model used in PRISM is developed with an application called WKPKFQ. The application's primary input is hourly data, determining the daily peak's mean and standard deviation for each week. Each week within each season for a year of historical data is magnitude ordered (highest to lowest) and those weeks are averaged across years to replicate peak load experience. The annual peak and the adjusted WKPKFQ mean and standard deviation are used to develop daily peak standard normal distributions for each week of the study period. The definition of the load model, per the input parameters necessary to submit a WKPKFQ run, define the modeling region and basis for all adequacy studies. WKPKFQ required input parameters include:

- Historic time period of the model.
- Sub-zones or geographic regions that define the model.
- Vintage of Load forecast report (year of report).
- Start and end year of the forecast study period.
- 5 or 7 days to use in the load model. All RRS studies use a 5 day model, excluding weekends.
- Holidays to exclude from hourly data include: Labor Day, Independence Day, Memorial Day, Good Friday, New Year's Day, Thanksgiving, the Friday after Thanksgiving, and Christmas Day.

The Peak Load Ordered Time Series (PLOTS) load model is the result of performing the WKPKFQ calculations. The resulting output is 52 weekly means and standard deviations that represent parameters for the daily normal distribution. The beginning of Week 1 corresponds to May 15th. Table II-2 shows these results of PJM RTO WKPKFQ run 7324 used in this study, which uses 10 years of historical data from 2003 to 2012. This was reviewed and endorsed by both the Resource

Adequacy Analysis Subcommittee[1] and Planning Committee[2].

Table II-2: PJM RTO Load Model Parameters (PJM LM 7324)

ARC Week	Mean Seasonal	Standard Deviation	ARC Week	Mean Seasonal	Standard Deviation
1	0.65436	0.02944	27	0.70019	0.04620
2	0.68925	0.04663	28	0.71884	0.04083
3	0.76412	0.05557	29	0.74058	0.03928
4	0.81344	0.05707	30	0.78485	0.04761
5	0.80330	0.05538	31	0.80699	0.04942
6	0.90576	0.06357	32	0.77433	0.06537
7	0.87737	0.04230	33	0.74894	0.03925
8	0.90792	0.04359	34	0.80956	0.05960
9	0.91469	0.06762	35	0.75741	0.06388
10	1.00000	0.07922	36	0.81896	0.06926
11	0.93346	0.07587	37	0.82765	0.07006
12	0.97631	0.06377	38	0.76081	0.06198
13	0.94157	0.07390	39	0.79305	0.05889
14	0.88007	0.05793	40	0.77745	0.04844
15	0.83235	0.07556	41	0.76400	0.04366
16	0.81480	0.06856	42	0.75089	0.05112
17	0.76557	0.08462	43	0.72687	0.04386
18	0.73587	0.05861	44	0.69908	0.03665
19	0.71803	0.05010	45	0.68468	0.04300
20	0.66700	0.04289	46	0.67109	0.03821
21	0.68913	0.05606	47	0.65509	0.03981
22	0.67391	0.04061	48	0.64958	0.03292
23	0.65738	0.02339	49	0.64068	0.03125
24	0.65956	0.02998	50	0.63584	0.02441
25	0.66911	0.03178	51	0.66621	0.04262
26	0.69596	0.07585	52	0.67557	0.07709

PJM-World Diversity

PJM-World diversity reflects the timing of when the World area peaks compared to when the PJM RTO area peaks. The greater the diversity, the more capacity assistance the World can give at the time when PJM needs it and, therefore, the lower the PJM IRM. Diversity is a modeling characteristic assessed in the selection of the most appropriate load model time period for use in the RRS. A comprehensive method to evaluate and choose load models, with diversity as one of the considerations, was approved by the Planning Committee and used for the 2019 RRS.

Historic hourly data was examined to determine the annual monthly peak shape of the composite World region. Monthly World coincident peaks are magnitude ordered (highest to lowest) and averaged across years to replicate peak load experience. Magnitude-ordered months are assigned to calendar months according to average historical placement. These results are highlighted in yellow below in Table II-3.

[1] https://www.pjm.com/-/media/committees-groups/subcommittees/raas/20190702/20190702-pjm-load-model-selection.ashx

[2] https://www.pjm.com/-/media/committees-groups/committees/pc/20190711/20190711-item-06-pjm-load-model-selection-for-2019-rss.ashx

To examine seasonal diversity, an average of all historic years was used. The upper portion of Table II-3 summarizes the underlying historic data that led to a modeling choice of the values highlighted in yellow. Seasonal diversity is used in the determination of World sub-region coincident peaks in evaluating the range of permissible World reserve margins seen in Table I-5.

Table II-3: Intra-World Load Diversity

Annual Diversity

Area	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	18 year avg*
WORLD	2.39%	2.39%	3.62%	3.38%	2.82%	4.40%	6.22%	3.78%	2.23%	2.44%	2.78%	2.93%	2.22%	3.32%	3.50%	3.06%	2.82%	2.25%	2.60%	3.11%
MISO	0.00%	0.00%	1.74%	0.00%	0.74%	1.93%	7.81%	0.00%	1.44%	0.00%	0.21%	0.40%	0.00%	0.00%	2.23%	0.91%	0.86%	0.00%	0.26%	0.98%
NY	2.38%	3.40%	5.59%	4.50%	2.32%	7.42%	3.40%	5.22%	6.30%	5.58%	5.31%	6.44%	4.08%	4.20%	6.75%	7.01%	8.70%	8.04%	6.42%	5.42%
VACAR	4.96%	5.49%	5.50%	5.93%	5.21%	6.67%	6.53%	10.71%	1.14%	4.09%	5.62%	3.90%	5.23%	6.97%	3.49%	5.35%	3.65%	3.74%	6.65%	5.31%
TVA	5.09%	3.75%	4.58%	8.12%	5.56%	5.25%	4.53%	4.74%	2.26%	4.43%	4.28%	5.01%	2.94%	7.58%	3.88%	2.89%	3.61%	3.21%	2.68%	4.44%

Monthly Diversity

Month Number	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	Forecast Shape**
1	87.4%	85.5%	83.8%	88.7%	83.6%	90.6%	83.7%	84.9%	85.4%	83.5%	88.6%	92.1%	84.8%	89.3%	88.9%	83.1%	83.3%	89.0%	85.6%	86.0%
2	83.2%	81.3%	79.4%	84.8%	79.6%	85.1%	80.0%	81.2%	81.6%	79.2%	83.7%	86.4%	81.1%	84.7%	83.8%	78.6%	79.4%	84.6%	81.4%	82.0%
3	78.0%	76.3%	74.8%	79.3%	74.9%	78.7%	75.4%	76.4%	76.4%	74.8%	77.8%	80.0%	76.4%	79.0%	77.9%	73.5%	74.9%	79.2%	76.2%	76.3%
4	69.6%	68.4%	67.7%	70.6%	67.8%	69.5%	68.0%	68.9%	68.2%	68.1%	69.1%	70.8%	69.0%	70.5%	69.5%	66.3%	67.6%	70.9%	68.4%	68.8%
5	80.9%	80.2%	79.7%	82.1%	79.8%	80.8%	79.8%	81.0%	79.7%	80.4%	80.4%	82.1%	80.6%	82.3%	81.1%	77.9%	79.9%	82.2%	80.1%	80.5%
6	95.2%	95.3%	95.0%	96.2%	94.8%	95.5%	94.9%	95.8%	94.5%	95.2%	95.4%	96.1%	95.4%	96.5%	95.6%	92.6%	95.4%	96.2%	95.1%	95.4%
7	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	99.7%	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	98.7%	**100.0%**	**100.0%**	**100.0%**	**100.0%**
8	99.7%	99.6%	99.1%	99.0%	99.6%	99.5%	99.3%	99.1%	**100.0%**	99.2%	99.2%	98.6%	99.0%	98.5%	99.2%	**100.0%**	99.4%	98.3%	98.7%	99.4%
9	90.5%	90.5%	90.1%	89.8%	90.3%	90.6%	90.3%	90.0%	91.4%	89.7%	90.2%	88.8%	89.7%	88.7%	90.2%	92.3%	90.4%	88.0%	89.6%	90.3%
10	73.5%	73.6%	73.6%	73.3%	73.1%	74.0%	73.6%	73.3%	74.7%	72.9%	73.5%	71.7%	72.9%	71.7%	73.4%	76.0%	73.4%	71.1%	73.1%	73.2%
11	75.5%	76.6%	75.9%	76.1%	74.9%	77.1%	75.7%	76.6%	77.2%	74.8%	75.6%	74.4%	75.8%	73.2%	75.8%	79.2%	75.7%	73.5%	75.5%	76.1%
12	81.4%	83.5%	82.4%	82.9%	80.8%	84.4%	82.1%	84.1%	83.9%	80.8%	81.4%	81.4%	82.5%	78.8%	81.8%	87.0%	82.0%	79.8%	82.0%	83.4%

**Annual Diversity is used to convert reported Subarea forecasts to coincident values associated with the World peak*

***Forecast shape takes into account historical diversity, current World composition, and forecasted World Subarea growth*

Generation Forecasting

GADS, eGADS and PJM Fleet Class Average Values

The Generator Availability Data System (GADS) is a NERC-based program and database used for entering, storing, and reporting generating unit data concerning generator outages and unit performance. GADS data is used by PJM and other RTOs in characterizing and evaluating unit performance.

The PJM Generator Availability Data System (eGADS) is an Internet based application which supports the submission and processing of generator outage and performance data as required by PJM and the NERC reporting standards. The principal modeling parameters in the RRS are those that define the generator unit characteristics. All generation units' performance characteristics are derived from PJM's eGADS web based system. For detailed information on PJM Generation Availability Data System (GADS), see the eGADS' help selection available through the PJM site at: https://www.pjm.com/markets-and-operations/etools/egads.aspx.

The eGADS system is based on the IEEE Standard 762-2006. IEEE Standard 762-2006 is available by going to the IEEE web site: http://standards.ieee.org/findstds/standard/762-2006.html

The PJM Reliability Assurance Agreement (RAA), Schedule 4 and Schedule 5 are related to the concepts used in generation forecasting.

For units with missing or insufficient GADS data, PJM utilizes class average data developed from PJM's fleet-based historical unit performance statistics. This process is called blending. Blending is therefore used for future units, neighboring system units, and for those PJM units with less than five years of GADS events. The term blending is used when a given generating unit does not have actual reported outage events for the full five-year period being evaluated.

The actual generator unit outage events are blended with the class average values according to the generator class category for that unit. For example, a unit that has three years' worth of its own reported outage history will have two years' worth of class average values used in blending. The statistics, based on the actual reported outage history, will be weighted by a factor of 3/5 and the class average statistics will be weighted by a factor of 2/5. The values are added together to get a statistical value for each unit that represents the entire five-year time period.
The class average categories are from NERC's Brochure while the statistics' values are determined from PJM's fleet of units. A five-year period is used for the statistics, with 73 unique generator class keys. The five-year period is based on the data available in the NERC Brochure or in PJM's eGADS, using the latest time period (2014-2018 for 2019 RRS). A generator class category is given for each unit type, primary fuel and size of unit. Furthermore, this five-year period is used to calculate the various statistics, including (but not limited to):

- Equivalent Demand Forced Outage Rate (EFORd)
- Effective Equivalent Demand Forced Outage Rate (EEFORd)
- Equivalent Maintenance Outage Factor (EMOF)
- Planned Outage Factor (POF)

The class average statistical values used in the reserve requirement study for the blending process are shown in Table II-4.

In Appendix B, Sensitivity number 14 shows that a 1% increase in the pool-wide EEFORd causes a 1.39% increase in the IRM – indicating a direct, positive correlation between unit performance and the IRM.

Generating Unit Owner Review of Detailed Model

The generation owner representatives are solicited to provide review and submit changes to the preliminary generation unit model. This review provides valuable feedback and increases confidence that the model parameters are the best possible for use in the RRS. This review improves the data integrity of the most significant modeling parameters in the RRS.

Forced Outage Rates: EFORd and EEFORd

All forced outages are based on eGADS reported events.

- Effective Equivalent Demand Forced Outage Rate (EEFORd) – This forced outage rate, determined for demand periods, is used for reliability and reserve margin calculations. There are traditionally three categories for GADS reported events: forced outage (FO), maintenance outage (MO) and planned outage (PO). The PRISM program can only model the FO and PO categories. A portion of the MO outages is placed within the FO category, while the other portion is placed with the PO category. In this way, all reported GADS events are modeled.

  For a more complete discussion of these equations see Manual 22 at:

  https://www.pjm.com/-/media/documents/manuals/m22.ashx.
  The equation for the EEFORd is as follows:

  Equation II-1: Calculation of Effective Equivalent Demand Forced Outage Rate (EEFORd)

  $$\boxed{\textbf{EEFORd} = \textbf{EFORd} + (\textbf{1/4} * \textbf{EMOF})}$$

  The statistic used for MO is the equivalent maintenance outage factor (EMOF).

- Equivalent Demand Forced Outage Rate (EFORd) – This forced outage rate, determined for demand periods, is used in reliability and reserve margin calculations. See Manual M-22 and RAA Schedule 4 and Schedule 5 for more specific information about defining and using this statistic. The EFORd forms the basis for the EEFORd and is the statistic used to calculate the unforced capacity (UCAP) value of generators in the marketplace.

Table II-4: PJM RTO Fleet Class Average Generation Performance Statistics (2014-2018)

Start Date	End Date	Unit Type & Primary Fuel Category	Gen Class Key	EFORd	EEFORd	XEFORd	POF Weeks/Year	EMOF	Variance
1/1/2014	12/31/2018	FOSSIL All Fuel Types All Sizes	1	12.145%	12.330%	11.758%	4	2.234	20179
1/1/2014	12/31/2018	FOSSIL All Fuel Types 001-099	2	12.729%	12.710%	12.166%	3	1.799	4095
1/1/2014	12/31/2018	FOSSIL All Fuel Types 100-199	3	12.729%	12.710%	12.166%	3	1.799	4095
1/1/2014	12/31/2018	FOSSIL All Fuel Types 200-299	4	11.538%	11.791%	11.350%	5	2.776	27288
1/1/2014	12/31/2018	FOSSIL All Fuel Types 300-399	5	11.538%	11.791%	11.350%	5	2.776	27288
1/1/2014	12/31/2018	FOSSIL All Fuel Types 400-599	6	11.538%	11.791%	11.350%	5	2.776	27288
1/1/2014	12/31/2018	FOSSIL All Fuel Types 600-799	7	11.538%	11.791%	11.350%	5	2.776	27288
1/1/2014	12/31/2018	FOSSIL All Fuel Types 800-999	8	10.864%	11.791%	10.792%	5	2.776	27288
1/1/2014	12/31/2018	FOSSIL All Fuel Types 1000 Plus	9	10.864%	11.791%	10.792%	5	2.776	27288
1/1/2014	12/31/2018	FOSSIL Coal Primary All Sizes	10	12.145%	12.330%	11.758%	4	2.234	20179
1/1/2014	12/31/2018	FOSSIL Coal Primary 001-099	11	12.729%	12.710%	12.166%	3	1.799	4095
1/1/2014	12/31/2018	FOSSIL Coal Primary 100-199	12	12.729%	12.710%	12.166%	3	1.799	4095
1/1/2014	12/31/2018	FOSSIL Coal Primary 200-299	13	11.538%	11.791%	11.350%	5	2.776	27288
1/1/2014	12/31/2018	FOSSIL Coal Primary 300-399	14	11.538%	11.791%	11.350%	5	2.776	27288
1/1/2014	12/31/2018	FOSSIL Coal Primary 400-599	15	11.538%	11.791%	11.350%	5	2.776	27288
1/1/2014	12/31/2018	FOSSIL Coal Primary 600-799	16	11.538%	11.791%	11.350%	5	2.776	27288
1/1/2014	12/31/2018	FOSSIL Coal Primary 800-999	17	10.864%	11.791%	10.792%	5	2.776	27288
1/1/2014	12/31/2018	FOSSIL Coal Primary 1000 Plus	18	10.864%	11.791%	10.792%	5	2.776	27288
1/1/2014	12/31/2018	FOSSIL Oil Primary All Sizes	19	12.145%	12.330%	11.758%	4	2.234	20179
1/1/2014	12/31/2018	FOSSIL Oil Primary 001-099	20	12.729%	12.710%	12.166%	3	1.799	4095
1/1/2014	12/31/2018	FOSSIL Oil Primary 100-199	21	12.729%	12.710%	12.166%	3	1.799	4095
1/1/2014	12/31/2018	FOSSIL Oil Primary 200-299	22	11.538%	11.791%	11.350%	5	2.776	27288
1/1/2014	12/31/2018	FOSSIL Oil Primary 300-399	23	11.538%	11.791%	11.350%	5	2.776	27288
1/1/2014	12/31/2018	FOSSIL Oil Primary 400-599	24	11.538%	11.791%	11.350%	5	2.776	27288
1/1/2014	12/31/2018	FOSSIL Oil Primary 600-799	25	11.538%	11.791%	11.350%	5	2.776	27288
1/1/2014	12/31/2018	FOSSIL Oil Primary 800-999	26	10.864%	11.791%	10.792%	5	2.776	27288
1/1/2014	12/31/2018	FOSSIL Gas Primary All Sizes	28	12.145%	12.330%	11.758%	4	2.234	20179
1/1/2014	12/31/2018	FOSSIL Gas Primary 001-099	29	12.729%	12.710%	12.166%	3	1.799	4095
1/1/2014	12/31/2018	FOSSIL Gas Primary 100-199	30	12.729%	12.710%	12.166%	3	1.799	4095
1/1/2014	12/31/2018	FOSSIL Gas Primary 200-299	31	11.538%	11.791%	11.350%	5	2.776	27288
1/1/2014	12/31/2018	FOSSIL Gas Primary 300-399	32	11.538%	11.791%	11.350%	5	2.776	27288
1/1/2014	12/31/2018	FOSSIL Gas Primary 400-599	33	11.538%	11.791%	11.350%	5	2.776	27288
1/1/2014	12/31/2018	FOSSIL Gas Primary 600-799	34	11.538%	11.791%	11.350%	5	2.776	27288
1/1/2014	12/31/2018	FOSSIL Gas Primary 800-999	35	10.864%	11.791%	10.792%	5	2.776	27288
1/1/2014	12/31/2018	FOSSIL Lignite Primary All Sizes	37	12.145%	12.330%	11.758%	4	2.234	20179
1/1/2014	12/31/2018	NUCLEAR All Types All Sizes	38	1.301%	1.492%	1.267%	3	0.474	16447
1/1/2014	12/31/2018	NUCLEAR All Types 400-799	39	1.301%	1.492%	1.267%	3	0.474	16447
1/1/2014	12/31/2018	NUCLEAR All Types 800-999	40	1.301%	1.492%	1.267%	3	0.474	16447
1/1/2014	12/31/2018	NUCLEAR All Types 1000 Plus	41	1.301%	1.492%	1.267%	3	0.474	16447
1/1/2014	12/31/2018	NUCLEAR PWR All Sizes	42	1.301%	1.492%	1.267%	3	0.474	16447
1/1/2014	12/31/2018	NUCLEAR PWR 400-799	43	1.301%	1.492%	1.267%	3	0.474	16447
1/1/2014	12/31/2018	NUCLEAR PWR 800-999	44	1.301%	1.492%	1.267%	3	0.474	16447
1/1/2014	12/31/2018	NUCLEAR PWR 1000 Plus	45	1.301%	1.492%	1.267%	3	0.474	16447
1/1/2014	12/31/2018	NUCLEAR BWR All Sizes	46	1.301%	1.492%	1.267%	3	0.474	16447
1/1/2014	12/31/2018	NUCLEAR BWR 400-799	47	1.301%	1.492%	1.267%	3	0.474	16447
1/1/2014	12/31/2018	NUCLEAR BWR 800-999	48	1.301%	1.492%	1.267%	3	0.474	16447
1/1/2014	12/31/2018	NUCLEAR BWR 1000 Plus	49	1.301%	1.492%	1.267%	3	0.474	16447
1/1/2014	12/31/2018	NUCLEAR CANDU All Sizes	50	1.301%	1.492%	1.267%	3	0.474	16447
1/1/2014	12/31/2018	JET ENGINE All Sizes	51	12.437%	12.776%	11.061%	2	1.227	405
1/1/2014	12/31/2018	JET ENGINE 001-019	52	19.652%	19.948%	18.327%	1	1.349	28
1/1/2014	12/31/2018	JET ENGINE 20 Plus	53	12.335%	12.643%	10.679%	2	1.4	155
1/1/2014	12/31/2018	GAS TURBINE All Sizes	54	12.437%	12.776%	11.061%	2	1.227	405
1/1/2014	12/31/2018	GAS TURBINE 001-019	55	19.652%	19.948%	18.327%	1	1.349	28
1/1/2014	12/31/2018	GAS TURBINE 020-049	56	12.335%	12.643%	10.679%	2	1.4	155
1/1/2014	12/31/2018	GAS TURBINE 50 Plus	57	8.193%	8.576%	6.953%	3	1.05	781
1/1/2014	12/31/2018	COMBINED CYCLE All Sizes	58	4.391%	4.756%	3.598%	5	0.916	99999
1/1/2014	12/31/2018	HYDRO All Sizes	59	14.703%	13.922%	13.575%	1	2.463	46
1/1/2014	12/31/2018	HYDRO 001-029	60	14.703%	13.922%	13.575%	1	2.463	46
1/1/2014	12/31/2018	HYDRO 30 Plus	61	14.703%	13.922%	13.575%	1	2.463	46
1/1/2014	12/31/2018	PUMPED STORAGE All Sizes	62	2.066%	2.525%	1.728%	5	1.024	2812
1/1/2014	12/31/2018	MULTIBOILER/MULTI-TURBINE All Sizes	63	12.437%	12.776%	11.061%	2	1.227	405
1/1/2014	12/31/2018	DIESEL Landfill	64	19.183%	18.285%	18.767%	0	0.412	2
1/1/2014	12/31/2018	DIESEL All Sizes	65	8.431%	7.004%	7.645%	0	1.663	2
1/1/2014	12/31/2018	FOSSIL Oil/Gas Primary All Sizes	66	12.145%	12.330%	11.758%	4	2.234	20179
1/1/2014	12/31/2018	FOSSIL Oil/Gas Primary 001-099	67	12.729%	12.710%	12.166%	3	1.799	4095
1/1/2014	12/31/2018	FOSSIL Oil/Gas Primary 100-199	68	12.729%	12.710%	12.166%	3	1.799	4095
1/1/2014	12/31/2018	FOSSIL Oil/Gas Primary 200-299	69	11.538%	11.791%	11.350%	5	2.776	27288
1/1/2014	12/31/2018	FOSSIL Oil/Gas Primary 300-399	70	11.538%	11.791%	11.350%	5	2.776	27288
1/1/2014	12/31/2018	FOSSIL Oil/Gas Primary 400-599	71	11.538%	11.791%	11.350%	5	2.776	27288
1/1/2014	12/31/2018	FOSSIL Oil/Gas Primary 600-799	72	11.538%	11.791%	11.350%	5	2.776	27288
1/1/2014	12/31/2018	FOSSIL Oil/Gas Primary 800-999	73	10.864%	11.791%	10.792%	5	2.776	27288
1/1/2014	12/31/2018	Wind All Sizes	74	0.000%	0.000%	0.000%	0	0	0
1/1/2014	12/31/2018	Solar All Sizes	75	0.000%	0.000%	0.000%	0	0	0

Table II-5: Comparison of Class Average Values - 2018 RRS vs. 2019 RRS

Unit Type & Primary Fuel Category	Gen Class Key	EFORd Change	EEFORd Change	XEFORd Change	POF Change Weeks/Year	EMOF Change	Variance Change
FOSSIL All Fuel Types All Sizes	1	0.02%	-0.74%	0.27%	0.04	0.25	1765
FOSSIL All Fuel Types 001-099	2	0.15%	-0.60%	0.35%	0.04	0.26	1970
FOSSIL All Fuel Types 100-199	3	0.15%	-0.60%	0.35%	0.04	0.26	1970
FOSSIL All Fuel Types 200-299	4	-0.43%	-1.37%	-0.08%	0.11	0.29	309
FOSSIL All Fuel Types 300-399	5	-0.43%	-1.37%	-0.08%	0.11	0.29	309
FOSSIL All Fuel Types 400-599	6	-0.43%	-1.37%	-0.08%	0.11	0.29	309
FOSSIL All Fuel Types 600-799	7	-0.43%	-1.37%	-0.08%	0.11	0.29	309
FOSSIL All Fuel Types 800-999	8	1.26%	-1.37%	1.31%	0.11	0.29	309
FOSSIL All Fuel Types 1000 Plus	9	1.26%	-1.37%	1.31%	0.11	0.29	309
FOSSIL Coal Primary All Sizes	10	0.02%	-0.74%	0.27%	0.04	0.25	1765
FOSSIL Coal Primary 001-099	11	0.15%	-0.60%	0.35%	0.04	0.26	1970
FOSSIL Coal Primary 100-199	12	0.15%	-0.60%	0.35%	0.04	0.26	1970
FOSSIL Coal Primary 200-299	13	-0.43%	-1.37%	-0.08%	0.11	0.29	309
FOSSIL Coal Primary 300-399	14	-0.43%	-1.37%	-0.08%	0.11	0.29	309
FOSSIL Coal Primary 400-599	15	-0.43%	-1.37%	-0.08%	0.11	0.29	309
FOSSIL Coal Primary 600-799	16	-0.43%	-1.37%	-0.08%	0.11	0.29	309
FOSSIL Coal Primary 800-999	17	1.26%	-1.37%	1.31%	0.11	0.29	309
FOSSIL Coal Primary 1000 Plus	18	1.26%	-1.37%	1.31%	0.11	0.29	309
FOSSIL Oil Primary All Sizes	19	0.02%	-0.74%	0.27%	0.04	0.25	1765
FOSSIL Oil Primary 001-099	20	0.15%	-0.60%	0.35%	0.04	0.26	1970
FOSSIL Oil Primary 100-199	21	0.15%	-0.60%	0.35%	0.04	0.26	1970
FOSSIL Oil Primary 200-299	22	-0.43%	-1.37%	-0.08%	0.11	0.29	309
FOSSIL Oil Primary 300-399	23	-0.43%	-1.37%	-0.08%	0.11	0.29	309
FOSSIL Oil Primary 400-599	24	-0.43%	-1.37%	-0.08%	0.11	0.29	309
FOSSIL Oil Primary 600-799	25	-0.43%	-1.37%	-0.08%	0.11	0.29	309
FOSSIL Oil Primary 800-999	26	1.26%	-1.37%	1.31%	0.11	0.29	309
FOSSIL Gas Primary All Sizes	28	0.02%	-0.74%	0.27%	0.04	0.25	1765
FOSSIL Gas Primary 001-099	29	0.15%	-0.60%	0.35%	0.04	0.26	1970
FOSSIL Gas Primary 100-199	30	0.15%	-0.60%	0.35%	0.04	0.26	1970
FOSSIL Gas Primary 200-299	31	-0.43%	-1.37%	-0.08%	0.11	0.29	309
FOSSIL Gas Primary 300-399	32	-0.43%	-1.37%	-0.08%	0.11	0.29	309
FOSSIL Gas Primary 400-599	33	-0.43%	-1.37%	-0.08%	0.11	0.29	309
FOSSIL Gas Primary 600-799	34	-0.43%	-1.37%	-0.08%	0.11	0.29	309
FOSSIL Gas Primary 800-999	35	1.26%	-1.37%	1.31%	0.11	0.29	309
FOSSIL Lignite Primary All Sizes	37	0.02%	-0.74%	0.27%	0.04	0.25	1765
NUCLEAR All Types	38	-0.10%	-0.12%	-0.07%	-0.06	-0.01	-865
NUCLEAR All Types	39	-0.10%	-0.12%	-0.07%	-0.06	-0.01	-865
NUCLEAR All Types	40	-0.10%	-0.12%	-0.07%	-0.06	-0.01	-865
NUCLEAR All Types	41	-0.10%	-0.12%	-0.07%	-0.06	-0.01	-865
NUCLEAR PWR All Sizes	42	-0.10%	-0.12%	-0.07%	-0.06	-0.01	-865
NUCLEAR PWR 400-799	43	-0.10%	-0.12%	-0.07%	-0.06	-0.01	-865
NUCLEAR PWR 800-999	44	-0.10%	-0.12%	-0.07%	-0.06	-0.01	-865
NUCLEAR PWR 1000 Plus	45	-0.10%	-0.12%	-0.07%	-0.06	-0.01	-865
NUCLEAR BWR All Sizes	46	-0.10%	-0.12%	-0.07%	-0.06	-0.01	-865
NUCLEAR BWR 400-799	47	-0.10%	-0.12%	-0.07%	-0.06	-0.01	-865
NUCLEAR BWR 800-999	48	-0.10%	-0.12%	-0.07%	-0.06	-0.01	-865
NUCLEAR BWR 1000 Plus	49	-0.10%	-0.12%	-0.07%	-0.06	-0.01	-865
NUCLEAR CANDU All Sizes	50	-0.10%	-0.12%	-0.07%	-0.06	-0.01	-865
JET ENGINE All Sizes	51	-0.62%	-0.72%	0.05%	0.15	0.02	-41
JET ENGINE 001-019	52	1.50%	1.35%	1.43%	0.08	-0.01	2
JET ENGINE 20 Plus	53	-1.41%	-1.65%	-0.15%	0.21	0.07	-4
GAS TURBINE All Sizes	54	-0.62%	-0.72%	0.05%	0.15	0.02	-41
GAS TURBINE 001-019	55	1.50%	1.35%	1.43%	0.08	-0.01	2
GAS TURBINE 020-049	56	-1.41%	-1.65%	-0.15%	0.21	0.07	-4
GAS TURBINE 50 Plus	57	-1.40%	-1.38%	-0.67%	0.15	0.01	-97
COMBINED CYCLE All Sizes	58	-0.01%	-0.14%	0.05%	-0.09	-0.12	-134
HYDRO All Sizes	59	1.10%	-0.43%	1.34%	-0.06	0.33	5
HYDRO 001-029	60	1.10%	-0.43%	1.34%	-0.06	0.33	5
HYDRO 30 Plus	61	1.10%	-0.43%	1.34%	-0.06	0.33	5
PUMPED STORAGE All Sizes	62	-0.25%	-0.20%	0.03%	0.42	0.09	-268
MULTIBOILER/MULTI-TURBINE All Sizes	63	-0.62%	-0.72%	0.05%	0.15	0.02	-41
DIESEL Landfill	64	0.30%	-0.25%	0.31%	0.00	-0.04	0
DIESEL All Sizes	65	-0.06%	-2.16%	-0.28%	0.11	-0.08	0
FOSSIL Oil/Gas Primary All Sizes	66	0.02%	-0.74%	0.27%	0.04	0.25	1765
FOSSIL Oil/Gas Primary 001-099	67	0.15%	-0.60%	0.35%	0.04	0.26	1970
FOSSIL Oil/Gas Primary 100-199	68	0.15%	-0.60%	0.35%	0.04	0.26	1970
FOSSIL Oil/Gas Primary 200-299	69	-0.43%	-1.37%	-0.08%	0.11	0.29	309
FOSSIL Oil/Gas Primary 300-399	70	-0.43%	-1.37%	-0.08%	0.11	0.29	309
FOSSIL Oil/Gas Primary 400-599	71	-0.43%	-1.37%	-0.08%	0.11	0.29	309
FOSSIL Oil/Gas Primary 600-799	72	-0.43%	-1.37%	-0.08%	0.11	0.29	309
FOSSIL Oil/Gas Primary 800-999	73	1.26%	-1.37%	1.31%	0.11	0.29	309
Wind All sizes	74	0.00%	0.00%	0.00%	0.00	0.00	0
Solar All sizes	75	0.00%	0.00%	0.00%	0.00	0.00	0

Fleet-based Performance by Primary Fuel Category

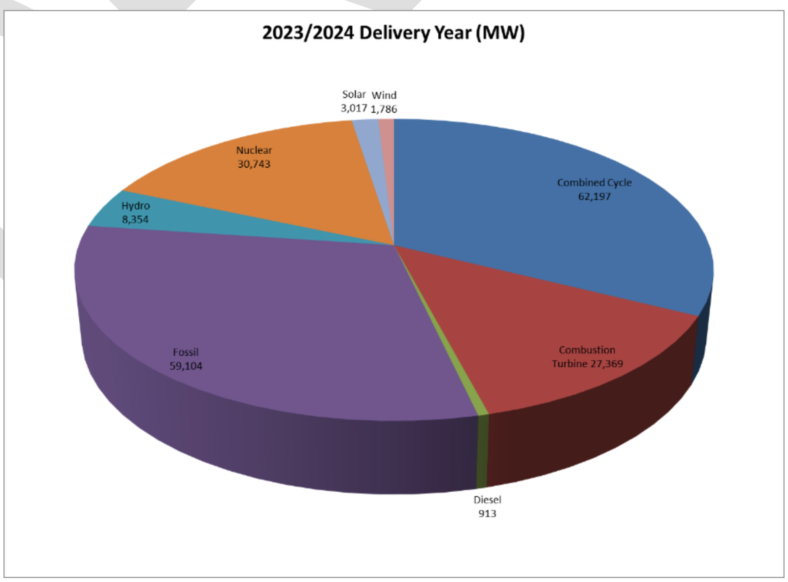
The PJM RTO fleet of units is summarized, by primary fuel, in Table II-6 for the 2023/2024 delivery year. This summary reflects the blending process discussed above. This summary also uses the summer net dependable rating (SND) of all units.

The outage rate and actual capacity for wind and solar units, however, reflects the PJM stakeholder process modeling, not actual outage event data. This modeling assigns a forced outage rate of 0% to solar and wind units and an ICAP value equal to the wind and solar unit's capacity credit. The capacity credit is calculated as per PJM Manual 21. Figure II-1 shows all PJM RTO capacity by fuel type for the 2023/2024 Delivery Year.

Table II-6: PJM RTO Fleet-based Unit Performance

2023/2024 Delivery Year	# of Units	Actual Capacity MW	% Total MW	Forced Outage Rates %	Ambient Temperature Derating (MW)
Combined Cycle	231	62,197	32.4%	3.79%	439
Combustion Turbine	393	26,028	13.5%	7.88%	551
Diesel	187	913	0.5%	11.84%	0
Fossil	192	59,104	30.8%	8.73%	1,370
Hydro	190	8,354	4.3%	4.01%	148
Nuclear	29	30,743	16.0%	1.26%	0
Solar	223	3,017	1.6%	0.00%	0
Wind	100	1,786	0.9%	0.00%	0
PJM RTO Total	**1545**	**192,142**	**100.00%**	**5.41%**	**2,508**

Figure II-1: PJM RTO Capacity



Modeling of Generating Units' Ambient Deratings

Per the approved rules in place for PJM Operations, Planning and Markets, a unit can operate at less than its SND rating and still not incur a GADS outage event. All modeled units' performance statistics are based on eGADS submitted data. The ambient derate modeling assumption, in addition to the eGADS data, allow all observed outages to be modeled in the RRS.

Derating certain generating units in the RRS is included to capture the limited output from certain generators caused by more extreme-than-expected ambient weather conditions (hot and humid summer conditions).

In the 2019 RRS, 2,500 MW of ambient derates in the peak summer period were modeled via planned outage maintenance. The impact of this assumption is an increase in the IRM of 1.38%.

Units on planned outage maintenance representing ambient derates were selected based on average characteristics of the types of units affected. PJM will continue to assess the impact of these ambient weather conditions on generator output.

Generation Interconnection Forecast

The criterion for planned generation units is to model only interconnection queue units with a signed Interconnection Service Agreement (ISA) without further adjustments to each unit's size (in other words, a commercial probability of 100% is assumed for these units).

The criterion for planned generation units matches the assumptions in the Capacity Emergency Transfer Objective (CETO) studies. Furthermore, a signed ISA is the final milestone in the PJM Interconnection Queue process; historically, a large proportion of the units achieving this milestone have ultimately ended up as in-service units.

For informational purposes only, Table II-7 shows the Average Commercial Probabilities for the projects in each of the Stages in the PJM interconnection queue. The commercial probabilities are calculated for each unit using a logistic regression model fitted to historical data (queues 'T' and after). The logistic regression models include predictors such as current stage in the queue (feasibility, impact, facilities, interconnection service agreement (ISA)), unit type (coal, gas, wind, etc.), location (US State), project type (new or uprate) and unit size (in MW).

Table II-7: Average Commercial Probabilities for Expected Interconnection Additions

Queue Stage	Average Commercial Probability
In the Queue, up to Feasibility Study Stage	5%
All of the above, plus Impact Study Completed	16%
All of the above, plus Facilities Study Completed	54%
All of the above and ISA executed	80%
Successful Completion	100%

Transmission System Considerations

PJM Transmission Planning (TP) Evaluation of Import Capability

PJM's Transmission Planning Staff performs the yearly Capacity Import Limit study to establish the amount of power that can be reliably transferred to PJM from outside regions (details of this study can be found in PJM's Manual 14b Attachment G). Although the PJM RTO has the physical capability of importing more than the 3,500 MW Capacity Benefit Margin (CBM, defined below), the additional import capability is reflected in Available Transfer Capability (ATC) through the OASIS postings and not reserved as CBM. This allows for the additional import capability to be used in the marketplace.

The use of CBM (on an annual basis) in this study is consistent with the time period of the RF criteria, and the Reliability Assurance Agreement, Schedule 4.

Capacity Benefit Margin (CBM)

The CBM value of 3,500 MW is specified in the PJM Reliability Assurance Agreement (RAA), Schedule 4. The CBM is the amount of import capability that is reserved for emergency imports into PJM. As a sensitivity case for this study, the CBM was varied between 0 MW and 15,000 MW. The relationship of IRM with CBM is graphically depicted in Figure I-7. A decrease in the CBM from 3,500 MW to 0 MW increases the pool's reserve requirement by about 1.6%. This value is influenced by the amount of PJM-World load diversity, and the World reserve level.

Per an effective date of April 1, 2011 concerning capacity benefit margin implementation documentation, compliant with NERC MOD Standard MOD-004-1, PJM staff has developed a CBM Implementation document (CBMID) that meets or exceed the NERC Standards, and NAESB Business Practices. This document is part of the PJM compliance efforts and is available via the PJM stakeholder process by contacting regional_compliance@pjm.com .

Capacity Benefit of Ties (CBOT)

The CBOT is a measure of the reliability value that World interface ties bring into the PJM RTO. The CBOT is the difference between an RRS run with a 3,500 MW CBM and an RRS run with a 0 MW CBM. The CBOT result was 1.6% of the PJM forecasted load or roughly 2,442 MW of installed capacity. The CBOT is directly affected by the PJM/World load diversity in the model (more diversity results in a higher CBOT) and the availability of assistance in the World area. Firm capacity imports, which are treated as internal capacity, are not part of the CBOT. The CBOT is a mathematical expectation related to the total 3,500 CBM value. The expected value is the weighted mean of the possible values, using their probability of occurrence as the weighting factor.

Coordination with Capacity Emergency Transfer Objective (CETO)

CETO studies assumptions are consistent with RRS assumptions due to marketplace requirements and to ensure the validity of the RRS assumption stating that the PJM aggregate of generation resources can reliably serve the aggregate of PJM load. By passing the load deliverability test, wherein CETO is one of the main components, this assumption is validated. See PJM Manual 14 B, attachment C for details on the Load Deliverability tests and refer to the RPM website cited in the RPM section for specific analysis details and results: http://pjm.com/markets-and-operations/rpm.aspx.

OASIS postings

The value of CBM is directly used in the various transmission path calculations for Available Transfer Capability (ATC). See the OASIS web site, specifically the ATC section for further specifics: http://www.pjm.com/markets-and-operations/etools/oasis/atc-information.aspx

Modeling and Analysis Considerations

Generating Unit Additions / Retirements

Planned generating units in the PJM interconnection queue with a signed Interconnection Service Agreement (ISA) are included in the study at their capacity MW value. Table II-8 gives a summary of the generator additions and retirements as modeled in the 11 year RRS model.

Table II-8: New and Retiring Generation within PJM RTO

Zone Name	Total Additions/Changes (MW)	Retirements (MW)	Total
AE	447	0	447
AEP	4,002	860	3,142
APS	3,515	1,278	2,237
ATSI	1,105	1,536	-431
BGE	0	403	-403
ComEd	1,265	304	961
Dayton	1,407	0	1,407
DLCO	4	1,811	-1,807
DomVP	2,681	889	1,792
DPL	550	102	448
DUKE	76	0	76
JCPL	93	7	87
METED	21	803	-782
PECO	26	66	-40
PEPCO	1	0	1
PN	55	198	-143
PPL	122	45	77
PSEG	10	0	10
Grand Total	**15,381**	**8,302**	**7,079**

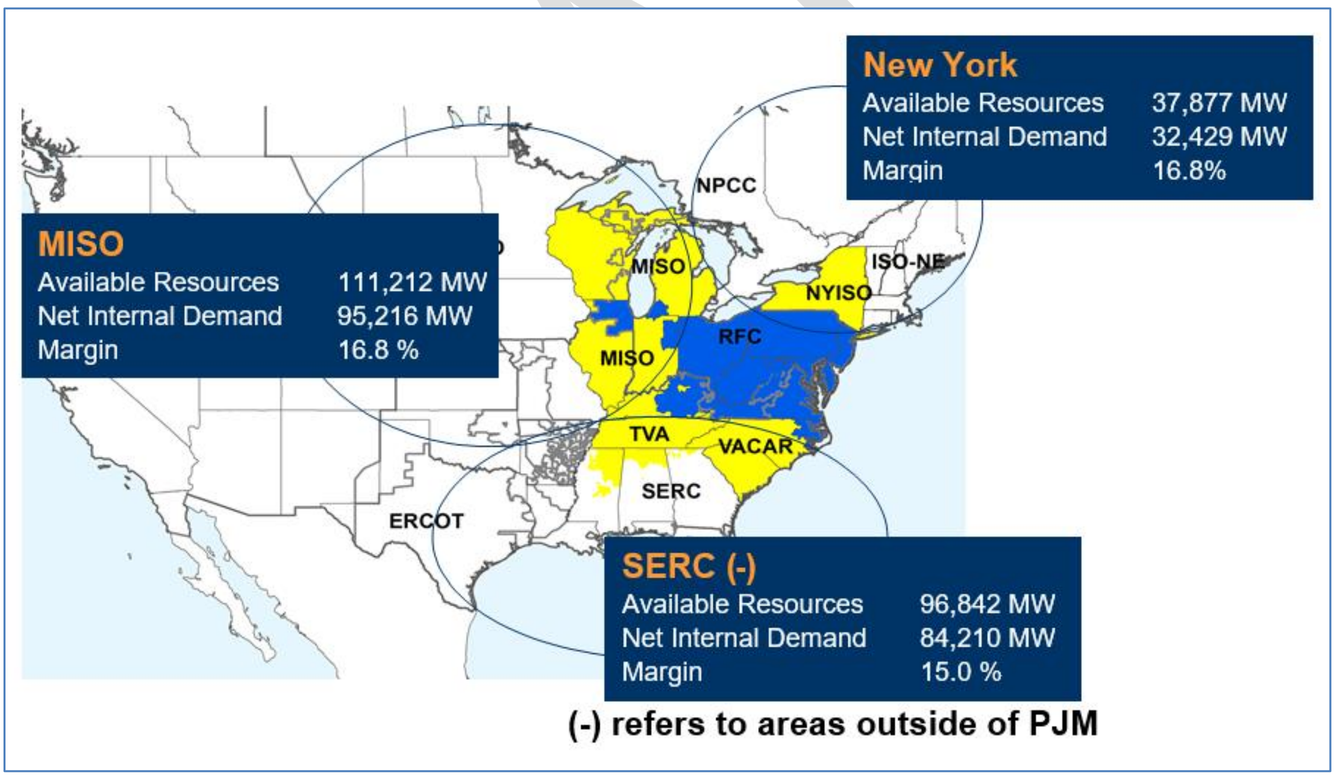
World Modeling

This data is publicly available through the NERC Electric and Supply Database – and is a compilation of all the EIA-411 data submissions. Per the June study assumptions, approved at the June 2019 PJM Planning Committee meeting, each of the individual regions was modeled at its required reserve requirement. The world region immediately adjacent to the PJM RTO was deemed to be the most appropriate region to use in the study, per previous RRS assessments. Modeling the immediately adjacent region helps to address concerns for deliverability of outside world resources to the PJM RTO border.

Among the regions included in the World, only New York and MISO have a firm reserve requirement target. For these regions, their latest published reserve requirements were used for the delivery years of this study. For the TVA and VACAR sub regions of SERC, a reserve target of 15% was used; this is consistent with NERC's modeling for assessment purposes.

Figure II-2 depicts the assumed capacity summer outlook within each of the Outside World regions that are adjacent to PJM for the delivery year 2019. The West region includes most of MISO (except MISO-South). The SERC (-) region includes the World zones: TVA and VACAR (excluding Dominion which is part of PJM).

Figure II-2: PJM and Outside World Regions - Summer Capacity Outlook



Expected Weekly Maximum (EWM), LOLE Weekly Values, Convolution Solution, IRM Audience

The Expected Weekly Maximum value (EWM) is the peak demand used by the PRISM program to calculate the loss of load expectation (LOLE). Both the EWM and LOLE are important values to track in assessing the study results. From observing these values over several historic studies, 99.9% of the risk is concentrated within a few weeks of the summer period. It is these summer weeks that have the highest EWM values (Refer to "PJM Generation Adequacy Technical Methods" and PJM Manual 20, for clarification and specifics of how the EWM is used and the resulting weekly LOLE). The EWM value is calculated per the following equation:

Equation II-2: Expected Weekly Maximum

$$EWM_X = \mu_X + 1.16295 * \sqrt{\sigma_X^2 + FEF^2}$$

Where:

μ_X = Weekly Mean,

1.16295 = A Constant, the Order Statistic when n=5

σ_X^2 = Weekly variance

FEF = Forecast Error Factor, for given delivery Year

x ranges from 1 to 52

In Figure II-3, the following EWM pattern can be seen for the PJM RTO and World regions. For all weeks not shown, the weekly LOLE approaches zero. The EWM pattern for PJM and the World in this year's study (blue line) are almost identical to the patterns observed in the 2018 RRS (dashed blue line).

Figure II-3: Expected Weekly Maximum Comparison – 2018 RRS vs. 2019 RRS

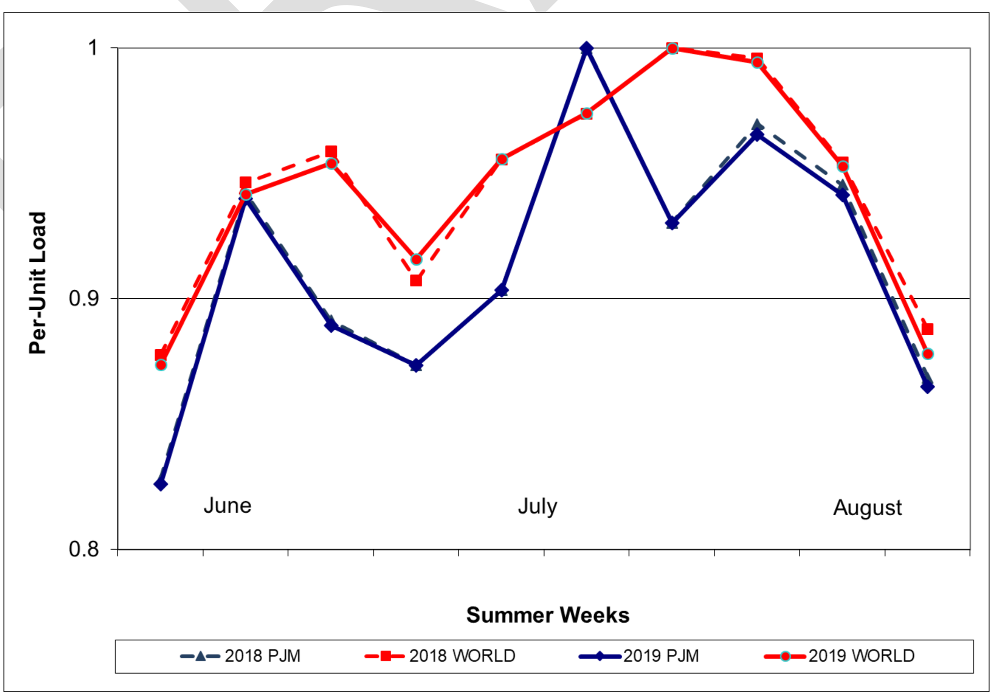


Figure II-4 shows the weekly share of Loss of Load for the PJMRTO in the 2018 RRS and 2019 RRS. No major differences in the weekly share of LOLE are observed between the two studies.

Figure II-4: PJMRTO LOLE Comparison 2018 RRS vs. 2019 RRS

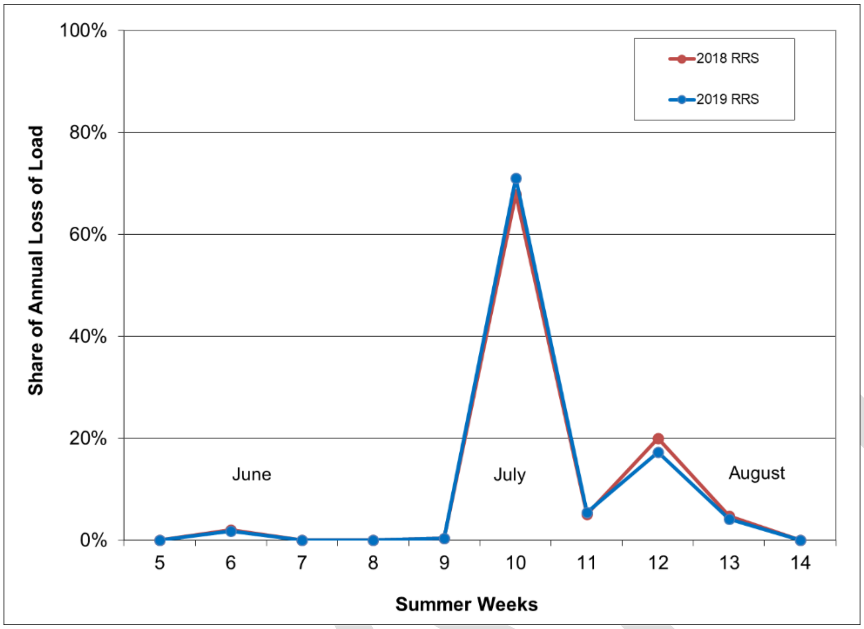
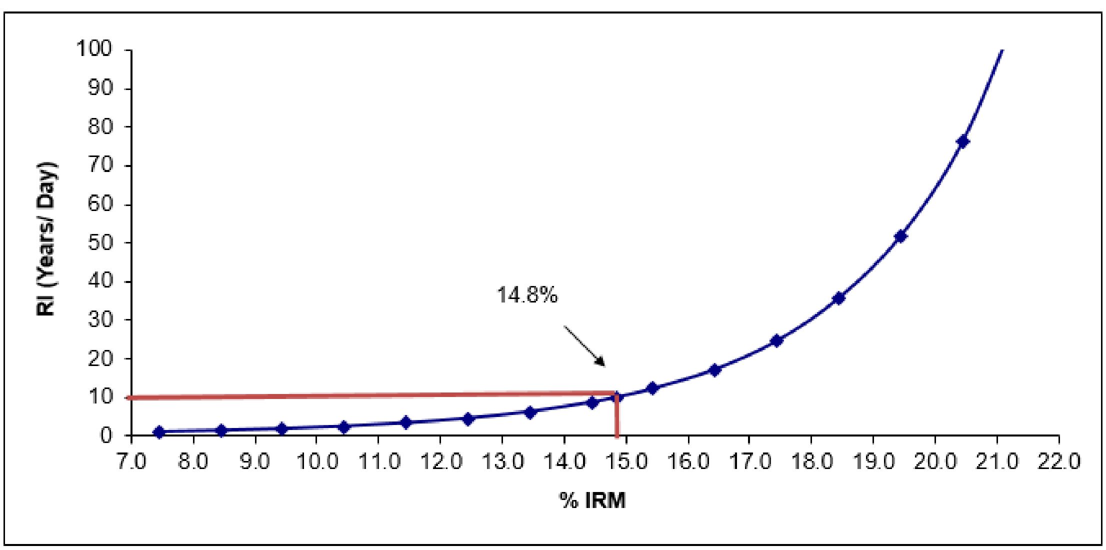


Figure II-5 shows how the PJM Reliability Index (RI) varies with the installed reserve margin. The plot is constructed by running a one area study, manually varying the PJM RTO reserve levels while assuming a constant CBOT at 1.6%. It can be observed that a reserve level of about 14.8% yields a loss of load event once every ten years.

Figure II-5: Installed Reserve Margin (IRM) vs. RI (Years/Day)



Standard BAL-502-RFC-02 clarification items

To provide clarity concerning several items in the Standard BAL-502-RFC-02 requirement section R1 titled "The planning Coordinator shall perform and document a Resource Adequacy analysis annually", the following is supplied:

R1.3.3.1 The criteria for including planned Transmission facilities: This is given in the RTEP assessments. The RTEP is overseen by the Transmission Expansion Advisory Committee (TEAC), a stakeholder group within the PJM committee structures. The Planning Committee also can establish and recommend appropriate criteria to be used for transmission facilities. See the Transmission System Considerations section for further details. The Criteria for inclusion of planned transmission facilities is given in the meeting minutes and presentations of the TEAC, PC, and the PJM manuals 14 A - E. The RRS is closely coordinated and integrated with these RTEP analyses, and with the decisions by the PC and TEAC as all are parts of the PJM Planning division efforts.

R1.4 Availability and Deliverability of fuel: An adhoc assessment was completed in July 2003, titled "Multi-Region Assessment of the Adequacy of the Northeast Natural Gas Infrastructure to Serve the Electric Power Generating Sector" addresses this topic. The Executive Summary of this report, pages v – xviii, provides the results of this assessment. This is a confidential report.

R1.4 Common Mode Outages that affect resource availability: The report, "Multi-Region Assessment of the Adequacy of the Northeast Natural Gas Infrastructure to Serve the Electric Power Generating Sector", address this issue in part. In general, these types of outages are considered by discrete modeling, with most outages assumed to be independent events. The assumption of independent outage events applies to both the resource and load models and avoids any need for a matrix of covariance states. The solution techniques for including a covariance matrix are considered not practically possible (long solution times). The Industry standard in the known solution methods is to make the assumption of independence for all outage events, treating any common mode outages by discrete modeling techniques. For example, for a "run of river" issue, more planned outages are modeled over the critical summer peak weeks due to several units using the same water source (same river). However, care should be used in drawing conclusions from the assumption for independence in the 21 point daily peak calculations. For example, there are steps involved in developing the load model parameters that do incorporate a correlation, particularly for the adjusted mean and standard deviations for each week. From a conceptual perspective this allows similar relationships, as those that exist in the development of the load forecast values, which allows the model to establish relationships between the weeks, such as magnitude ranking of weeks and the adjustment due to the load forecast monthly shape. The assumption of independence, understanding all the associated complexities, is implemented in the RRS modeling and calculation methods, which includes modeling of appropriate discrete common mode outage scenarios.

In addition, the methodology implemented to develop the winter peak week capacity model (approved by the MRC in 2018) partially addresses this issue as well by better accounting for the risk caused by the large volume of concurrent outages observed historically during the winter peak period. The methodology considers the development of a cumulative capacity outage probability table using historical actual RTO-aggregate outage data.

R1.4 Environmental or regulatory restrictions of resource availability: In the Generation Forecasting section, it is discussed that the resource performance characteristics are primarily modeled per the PJM manuals, 21, 22. In the eGADS reporting, there is consideration and methods to account for both environmental and regulatory restrictions. The RRS modeling of resources uses performance statistics, directly from these reported events. Both discrete modeling techniques and sensitivity analysis are performed to gain insights about impacts concerning environmental or regulatory restrictions. In the modeling of resources this can reduce the rating of a unit impacted by this type of restriction. The RRS model is coordinated with the Capacity Injection Rights (CIR) for each unit, which can be affected by these restrictions.

R1.4 <u>Any other demand response programs not included in the load forecast characteristics</u>: All load modeled and its characteristics are part of R1.3.1, per BAL-502-RFC-02. There are no other load response programs in the RRS model.

R1.4 <u>Market resources not committed to serving load</u>: In general, all resources modeled have capacity injection rights, are part of the EIA-411 filing and coordinated with the RTEP Load deliverability tests, documented in PJM Manual 14 B, attachment C. In addition, coordination with the RPM capacity market modeling is performed. An example of this is allowing the modeling of Behind-The-Meter (BTM) units, per the modeling assumptions. See Appendix A for further details regarding BTM modeling (See Manual M19, page 12; Manual 14D, Appendix A).

R1.5 <u>Transmission maintenance outage schedules</u>: Discussed in the Transmission System Considerations section is the coordination with the RTEP process and procedures. This issue is specifically addressed in the load deliverability tests, as discussed in this section. The CETO analysis is closely coordinated with the RRS modeling and report, and is fundamental to addressing and verifying the assumption that the PJM aggregate of generation resources can reliably serve the aggregate of PJM load.

Standard MOD - 004 - 01, requirement 6, clarification items

Capacity Benefit Margin (CBM) is established per the Reliability Assurance Agreement (RAA) section 4 and used in Planning Division studies and assessments. The Regional Transmission Expansion Planning Process (RTEP) provides a 15 year forecast period while the reserve requirement study provides an 11 year forecast period. Each individual year of these periods (15 and 11) are assessed. The RTEP and Reserve Requirement Study (RRS) are performed on an annual basis.

The RTEP and the RRS processes use full network analysis. Available Transmission Capability (ATC) and Flowgate analysis disaggregates the full network model in the short term (daily, weekly, monthly through month 18) as a proxy for full network analysis. The Available Flowgate Capability (AFC) calculator applies the impacts of transmission reservations (or schedules as appropriate) and calculates the AFC by determining the capacity remaining on individual flowgates for further transmission service activity. The disaggregated model used for the AFC calculation provides faster solution time than the full network model. The RTEP assessment is coordinated with the CBM, shown in the RAA, by its use of Capacity Emergency Transfer Objective (CETO) and load forecast modeling. CETO requirements are based on Loss of Load Expectation (LOLE) requiring appropriate aggregation of import paths for a valid statistical model.

Evidence:

- Annual RTEP baseline assessment report http://www.pjm.com/planning/rtep-development/baseline-reports.aspx
- Reliability Assurance Agreement (http://www.pjm.com/documents/~/media/documents/agreements/raa.ashx)
- Annual RRS report(s) http://www.pjm.com/planning/resource-adequacy-planning/reserve-requirement-dev-process.aspx
  - CETO load deliverability studies
  - Section 4, Manual 20 (http://www.pjm.com/~/media/documents/manuals/m20.ashx)
  - Section C.4, Manual 14B (http://www.pjm.com/~/media/documents/manuals/m14b.ashx)
- AFC/ATC calculations, Section 2 and 3 of PJM Manual 2 http://www.pjm.com/~/media/documents/manuals/m02.ashx

RPM Market

The Reliability Pricing Model (RPM) is the PJM's forward capacity market program that was implemented on June 1, 2007. The RPM requires the following input values derived from the RRS: IRM and FPR.

PJM's web based application, eRPM, is used to perform capacity transactions in the market place. The planning parameters derived from the RRS that are used in RPM are available at: http://www.pjm.com/markets-and-operations/rpm.aspx

IRM and FPR

The Installed Reserve Margin (IRM) is a percentage which represents the amount of installed capacity required above the forecast restricted 50/50 peak load demand. It is the buffer above expected peak load required to meet the reliability criterion. The IRM is a key input used to determine Load Serving Entity (LSE) capacity obligations. Calculation of the IRM is necessary to the determination of the Forecast Pool Requirement (FPR). The PRISM model adjusts the load level until it finds the solution load that meets the one day in ten years reliability standard. The IRM is calculated based on this solution load, for the peak day (which is also the peak week), using the installed capacity for that week in the numerator and the solution load in the denominator.

The FPR is a multiplier that converts load values into capacity obligation. The FPR has two necessary inputs to determine its value: the IRM and the PJM RTO pool-wide EFORd (equivalent demand forced outage rate). The FPR is defined by the following equation:

Equation II-3: Calculation of Forecast Pool Requirement (FPR)

$$\boxed{\text{FPR} = (1 + \text{Approved IRM}) * (1 - \text{PJM Avg. EFORd})}$$

The IRM and the FPR therefore represent identical levels of reserves expressed in different units. The IRM is expressed in units of installed capacity (or ICAP) whereas the FPR is expressed in units of unforced capacity (or UCAP). Unforced capacity is defined in the RAA to be the megawatt (MW) level of a generating unit's capability after removing the effect of forced outage events[3].

The capacity obligation associated with a particular PJM zone is an allocation of RTO resources procured in the RPM auction. The obligation is expressed in units of unforced capacity.

PJM's objectives are to establish an IRM that preserves reliability while not imposing an undue cost on load to pay for unnecessary generation reserves. PJM has used judgment in past recommendations for establishing an FPR due to some of the uncertainties associated with the current unforced capacity structure.

[3] This definition of Unforced Capacity largely applies to non-intermittent generators. For the purposes of this report, the UCAP value of an intermittent generator (such as wind or solar) is equal to its ICAP value, which in turn is equal to its capacity credit. The capacity credit is calculated as per PJM's Manual 21.

Operations Related Assessments

Winter Weekly Reserve Target Analysis

PJM calculates a Winter Weekly Reserve Target (WWRT) for each of the months in the 2019 / 2020 winter period (December 2019, January 2020 and February 2020). The WWRT is established to cover against uncertainties associated with load and forced outages during these winter months. It accomplishes this by ensuring that the total winter LOLE is practically zero. This year, PJM Staff recommends the values shown in Table II-9. The recommended values are required to be integers due to computer application requirements.

Table II-9: Winter Weekly Reserve Target

Month	WWRT
December 2019	22%
January 2020	28%
February 2020	24%

The procedure implemented to calculate the values in Table II-9 considers the following steps:

Step 1: Using GE-MARS, set up an RRS case with an annual LOLE equal to 0.1 days/year.

Step 2: In addition to the required planned maintenance schedule, simulate additional planned maintenance during each week of the three winter months until the annual LOLE is worse than 0.1 days/year.

Step 3: Calculate the available reserves in each of the winter weeks as a percentage of the corresponding monthly peak.

Step 4: The WWRT for each month is the highest weekly reserve percentage (rounded up to the next integer value).

Table II-10 shows the weekly available reserves that result from applying the above procedure.

Table II-10: Weekly Available Reserves in WWRT Analysis

Month	% Available Reserves	Max % Available Reserves (by Month)
December	17.38%	22%
	21.25%	
	21.60%	
	9.76%	
January	19.38%	28%
	13.15%	
	23.95%	
	27.19%	
February	19.43%	24%
	23.36%	
	17.53%	
	14.03%	

Monthly WWRT values were introduced for the first time in the 2016 RRS with the objective of addressing the larger load uncertainty in January compared to February and December. Prior to the 2016 RRS, the WWRT was a single value that applied to the entire winter season. Historically, January is the month where the PJM Winter peak is most likely to occur and also the winter month that historically has exhibited more peak load variability.

With this recommendation, the PJM Operations Department will coordinate generator maintenance scheduling over the winter period seeking to preserve a 22% margin in December 2019, 28% margin in January 2020 and 24% margin in February 2020 after units on planned and maintenance outages are removed**.** These margins are guides to be used by PJM Operations and are not an absolute requirement.

III. Glossary

Adequacy

The ability of a bulk electric system to supply the aggregate electric demand and energy requirements of the consumers at all times, taking into account scheduled and unscheduled outages of system components. One part of the Reliability term.

Available Transfer Capability (ATC)

Available Transfer Capability (ATC) is the amount of energy above base case conditions that can be transferred reliably from one area to another over all transmission facilities without violating any pre- or post-contingency criteria for the facilities in the PJM RTO under specified system conditions. ATC is the First Contingency Incremental Transfer Capability (FCITC) reduced by applicable margins.

BPS

The Bulk Power System (BPS) refers to all generating facilities, bulk power reactive facilities, and high voltage transmission, substation and switching facilities. The BPS also includes the underlying lower voltage facilities that affect the capability and reliability of the generating and high voltage facilities in the PJM Control Area. As defined by the Regional Reliability Organization, the BPS is the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition.

BRC

The PJM Board of Managers' Board Reliability Committee (BRC) is made up of PJM board members who conduct activities to review and assess reliability issues to bring to the full board of managers. The BRC is one of the groups that review the RRS report in the process to establish a FPR.

Capacity

The amount of electric power (measured in megawatts) that can be delivered to both firm energy to load located electrically within the PJM Interconnection and firm energy to the border of the PJM Control Area for receipt by others. Installed capacity and Unforced capacity are related measures of this quantity.

Capacity Benefit Margin (CBM)

Capacity Benefit Margin (CBM), expressed in megawatts, is the amount of import capability that is reserved for the emergency import of power to help meet LSE load demands during peak conditions and is excluded from all other firm uses.

Capacity Emergency Transfer Objective (CETO)

The import capability required by a sub area of PJM to satisfy the RF's resource adequacy requirement of loss of load expectation. This assessment is done in a coordinated and consistent manner with the annual RRS, but is an independent evaluation. The CETO value is compared to the Capacity Emergency Transfer Limit (CETL) which represents the sub area's actual import capability as determined from power flow studies. The sub area satisfies the criteria if its CETL is equal to or exceeds its CETO. PJM's CETO/CETL analysis is typically part of the PJM's deliverability demonstration. See Manual 20 section 4, and Manual 14B, attachment C for details.

Capacity Performance (CP)

Capacity product created within the RPM framework for 2018/2019 DY and subsequent DYs. CP is a more robust product than the capacity products available in auctions for DYs prior to 2018/2019 since it is required to provide enhanced performance during peak conditions. Additional information on CP can be found at http://www.pjm.com/directory/etariff/FercDockets/1368/20141212-er15-623-000.pdf

Control Area (CA)

An electric power system or combination of electric power systems bounded by interconnection metering and telemetry. A common generation control scheme is applied in order to:

- Match the power output of the generators within the electric power system(s) plus the energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);
- Maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;
- Maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice and the criteria of the applicable regional reliability council of NERC;
- Maintain power flows on Transmission Facilities within appropriate limits to preserve reliability; and
- Provide sufficient generating Capacity to maintain Operating Reserves in accordance with Good Utility Practice.

Delivery Year (DY)

The Delivery Year (DY) is the twelve-month period beginning on June 1 and extending through May 31 of the following year. As changing conditions may warrant, the Planning Committee may recommend other Delivery Year periods to the PJM Board of Managers. In prior studies, the DY was formerly referred to as the "Planning Period".

Deliverability

Deliverability is a test of the physical capability of the transmission network for transfer capability to deliver generation capacity from generation facilities to wherever it is needed to ensure, only, that the transmission system is adequate for delivery of energy to load under prescribed conditions. The testing procedure includes two components: (1) Generation Deliverability; and (2) Load Deliverability.

Demand Resource (DR)

A resource with the capability to provide a reduction in demand. DR is a component of PJM's Load Management (LM) program. The DR is bid into the RPM Base Residual Auction (BRA). See Load Management (LM).

Demand Resource (DR) Factor

Ratio of LM aggregate Load Carrying Capability (LCC) to total amount of LM in PJM. The LM LCC is determined by modeling LM in the PJM reliability program. The DR Factor is reviewed and changed, if necessary, each planning period by the PJM Board for use in determining the capacity credit for DR and Interruptible Load for Reliability (ILR). The use of the DR Factor was discontinued with the introduction of Capacity Performance in 2018/2019 DY.

Demand

The rate at which electrical energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time. Demand is equal to load when integrated over a given period of time. See Load.

Diversity

Diversity is the difference of the sum of the individual maximum demands of the various subdivisions of a system, or part of a system, to the total connected load on the system, or part of the system, under consideration. The two regions modeled in the RRS are the PJM RTO and the surrounding World region. If the model has peak demand periods occurring at the same time, for both regions (PJM RTO and World), there is little or no diversity (PJM-World Diversity). The peak demand period values are determined as the Expected Weekly Maximum (EWM). A measure of diversity can be the amount of MWs that account for the difference between a Transmission Owner zone's forecasted peak load at the time of its own peak and the coincident peak load of PJM at the time of PJM peak.

Eastern Interconnection

The Eastern Interconnection refers to the bulk power systems in the eastern portion of North America. The area of operation of these systems is bounded on the east by the Atlantic Ocean, on the west by the Rocky Mountains, on the south by the Gulf of Mexico and Texas, and includes the Canadian provinces of Quebec, Ontario, Manitoba and Saskatchewan. The Eastern Interconnection is one of the three major interconnections within the NERC and includes the Florida Reliability Coordinating Council (FRCC), Midwest Reliability Organization (MRO), Northeast Power Coordinating Council (NPCC), ReliabilityFirst (RF), Southeast Reliability Corporation (SERC) and the Southwest Power Pool, Inc. (SPP).

EEFORd

The Effective Equivalent Demand Forced Outage Rate (EEFORd) is used for reliability and reserve margin calculations. For each generating unit, this outage rate is the sum of the EFORd plus ¼ of the equivalent maintenance outage factor. See manual 22, pages 14-15 (http://www.pjm.com/~/media/documents/manuals/m22.ashx)

EFORd

The Equivalent Demand Forced Outage Rate (EFORd) is the portion of time that a generating unit is in demand, but is unavailable due to a forced outage.

eGADS

eGADS is PJM's Web-based Generator Availability Data System where generation data is collected to track and project unit unavailability – as required for PJM adequacy and capacity market calculations. eGADS is based on the NERC GADS data reporting requirements, which in turn are based on IEEE Standard 762-2006 (March 15, 2007).

EMOF

The Equivalent Maintenance Outage Factor (EMOF). For each generating unit modeled, the portion of time a unit is unavailable due to maintenance outages.

EWM

The Expected Weekly Maximum (EWM) is the weekly peak load corresponding to the 50/50 load forecast, typically based on a sample of 5 weekday peaks. The EWM parameter is used in the PJM PRISM program. Also see PJM Manual 20 pages 19-23.

FEF

The Forecast Error Factor (FEF) is a value that can be entered in the PRISM program per Delivery Year to indicate the percent increase of uncertainty within the forecasted peak loads. As the planning horizon is lengthened, the FEF generally increases 0.5% per year. FEF is held constant at 1.0% for all delivery years in the RRS, per stakeholder agreement of the approved assumptions.

FERC

The Federal Energy Regulatory Commission (FERC) is the federal agency responsible with overseeing and regulating the wholesale electric market within the US. (http://www.ferc.gov/)

Forced Outage

Forced outages occur when a generating unit is forcibly removed from service, due to either: 1) availability of a generating unit, transmission line, or other facility for emergency reasons; or 2) a condition in which the equipment is unavailable.

Forced Outage Rate (FOR)

The Forced Outage Rate (FOR) is a statistical measurement as a percentage of unavailability for generating units and recorded in the GADS. FOR indicates the likelihood a unit is unavailable due to forced outage events over the total time considered. It is important to note that there is no attempt to separate out forced outage events when there is no demand for the unit to operate.

Forecast Peak Load

Expected peak demand (Load) representing an hourly integrated total in megawatts, measured over a given time interval (typically a day, month, season, or delivery year). This expected demand is a median demand value indicating there is a 50 % probability actual demand will be above or below the expected peak.

Forecast Pool Requirement (FPR)

The amount, stated in percent, equal to one hundred plus the percent reserve margin for the PJM Control Area required pursuant to the Reliability Assurance Agreement (RAA), as approved by the Reliability Committee pursuant to Schedule 4 of the RAA. Expressed in units of “unforced capacity”.

GEBGE

GEBGE is a resource adequacy calculation program, used to calculate daily LOLE that was jointly developed in the 1960s/1970s by staff at General Electric (GE) and Baltimore Gas and Electric (BGE). The GEBGE program has since been largely superseded and replaced by PJM’s PRISM program in the conduct and evaluation of IRM studies at PJM. (See

PRISM.) GEBGE does prove useful to measure reliability calculations and to increase PJM staff efficiency in some sensitivity assessments.

Generating Availability Data System (GADS)

GADS is a NERC-based computer program and database used for entering, storing, and reporting generating unit data concerning outages and unit performance.

Generation Outage Rate Program (GORP)

GORP is a computer program maintained by the PJM Planning staff that uses GADS data to calculate outage rates and other statistics.

Generator Forced/Unplanned Outage

An immediate reduction in output, capacity, or complete removal from service of a generating unit by reason of an emergency or threatened emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the facility. A reduction in output or removal from service of a generating unit in response to changes in or to affect market conditions does not constitute a Generator Forced Outage.

Generator Maintenance Outage

The scheduled removal from service, in whole or in part, of a generating unit in order to perform necessary repairs on specific components of the facility approved by the PJM Office of Interconnection (OI).

Generator Planned Outage

A generator planned outage is the scheduled removal from service, in whole or in part, of a generating unit for inspection, maintenance or repair – with the approval of the PJM OI.

Good Utility Practice

Any of the practices, methods, and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision is made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather is intended to include practices, methods, or acts generally accepted in the region.

ICAP

For non-intermittent generators, installed capacity (ICAP) commonly refers to “iron in the ground” – or rated capacity of a generation unit prior to derating or other performance adjustments. For the purposes of this report, the ICAP of intermittent generators such as wind and solar refers to the capacity credit calculated for each such generator as per PJM’s Manual 21.

ILR

Interruptible Load for Reliability (IRL) is a component of PJM's Load Management (LM) program. In the RPM program, just prior to the final incremental auction, load with verifiable existing interruptible capability may declare themselves an Interruptible Load for Reliability (ILR). This component will end for the 2012 delivery year RPM market place. See Load Management and Demand Resources.

Import Capability

Import Capability, expressed in megawatts, is a single value that represents the simultaneous imports into PJM that can occur during peak PJM system conditions. The capabilities of all transmission facilities that interconnect the PJM Control Area to its neighboring regions are evaluated to determine this single value. (See SIL)

IRM

The Installed Reserve Margin (IRM) is the percent of aggregate generating unit capability above the forecasted peak load that is required for adherence to meet a given adequacy level. IRM is expressed in units of installed capacity (ICAP). The PJM IRM is the level of installed reserves needed to meet the ReliabilityFirst criteria for a loss of load expectation (LOLE) of one day, on average, every 10 years

ISO-NE

The Independent System Operator of New England (ISO-NE) is an independent system operator (ISO) and not-for-profit corporation responsible for reliably operating New England's bulk electric power generation, transmission system and wholesale electricity markets. Created in 1997 and with headquarters in Holyoke, MA, the ISO-NE control extends throughout New England including Maine, New Hampshire, Vermont, Rhode Island, Massachusetts and Connecticut. (http://www.iso-ne.com/)

LDA

Locational Deliverability Areas (LDAs) are zones that comprise the PJM RTO as defined in the RAA schedule 10.1 and can be an individual zone, a combination of two or more zones, or a portion of a zone. There are currently 25 LDAs within the PJM footprint.

Load

Integrated hourly electrical demand, measured as generation net of interchange. Loads generally can be reported and verified to the tenth of a megawatt (0.1 MW) for this report.

Load Analysis Subcommittee (LAS)

A PJM subcommittee, reporting to the Planning Committee that provides input to PJM on load related issues.

Load Management (LM)

Load Management, previously referred to as Active Load Management (ALM), applies to interruptible customers whose load can be interrupted at the request of PJM. Such a request is considered an emergency action and is implemented prior to a voltage reduction. This includes Demand Resources (DR), Energy Efficiency, and Interruptible Load for Reliability (ILR) –

ILR is only applicable in RPM markets prior to the 2012/13 delivery year, with ILR an inherent piece of all forecast load management values.

LCC

Load Carrying Capability (LCC), typically expressed in megawatts, is the amount of load that a given resource or resources can serve at a predetermined adequacy standard (typically one day in ten years).

LOLE

Generation system Adequacy is determined as Loss of Load Expectation (LOLE) and is expressed as days (occurrences) per year. This is a measure of how often, on average, the available capacity is expected to fall short of the restricted demand. LOLE is a statistical measure of the frequency of firm load loss and does not quantify the magnitude or duration of firm load loss. The use of LOLE to assess Generation Adequacy is an internationally accepted practice.
Let's consider the difference between probability and expectation. Mathematical expectation [E (x)] for a model is based on a given probability for each outcome. An equation for the calculation of expectation is:

$$E(x) = P_1X_1 + P_2X_2 + P_3X_3 + \ldots + P_nX_n$$

$$E(x) = \sum_{i=1}^{n} P_iX_i$$

Where

$P =$ probabilty of outcome

$X =$ definded outcome (Example: on or off)

The expected value is the weighted mean of the possible values, using their probability of occurrence as the weighting factor. There is no implication that it is the most frequently occurring value or the most highly probable, in fact it might not even be possible. The expected value is not something that is "expected" in the ordinary sense but is actually the long term average as the number of terms (trials) increase to infinity.[4]

For generation Adequacy the focus of these calculations, the LOLE, can be expressed in terms of probability as:

$$LOLE = \sum_{i=1}^{260} LOLE_i = \sum_{i=1}^{260}\sum_{j=1}^{21} LOLP_j$$

Where

$LOLE_i =$ Loss of Load Expectation for daily peak distribution

$LOLP_j =$ Loss of Load Probabilty for two state outcome, generation value is less than demand or not.

260 = Number of weekdays in a delivery year

Daily peak = The integrated hourly average peak, or Demand.

4 Power System Reliability Evaluation", Roy Billinton, 1970, Gordon and Breach, Science Publishers for further details on calculation methods.

The LOLEi for daily peak is calculated or convolved as:

$$LOLE_i = \sum_{j=1}^{21} LOLP_j = \sum_{j=1}^{21} PD_j(XD_j) * PG_j(XG_j)$$

$$\begin{aligned}
&\textit{Where} \\
&PG(XG) = \text{Probabilty of generation at 1st generation value(outcome) less than demand} \\
&PD(XD) = \text{Probabilty at given Demand value(outcome)} \\
&21 = \text{Discrete Distribution values to assess all likely values of Demand} \\
&\text{Demand} = \text{The integrated hourly average peak, or Daily peak.}
\end{aligned}$$

LOLP

The Loss of Load Probability (LOLP), which is the probability that the system cannot supply the load peak during a given interval of time, has been used interchangeably with LOLE within PJM. LOLE would be the more accurate term if expressed as days per year. LOLP is more properly reserved for the dimensionless probability values. LOLP must have a value between 0 and 1.0. See LOLE.

LSE

Load Serving Entity (LSE) is defined and discussed thoroughly at the following link. This is a PJM training class concerning requirements of an LSE, including: LSE Obligations, Who are LSEs?, PJM Membership, Capacity Obligations (RAA) for PJM, Agreements and Tariffs, Transmission Service, FTRs, Ways to supply Energy, Energy Load Pricing, Energy Market – Two Settlement, Ancillary Services, http://www.pjm.com/sitecore/content/Globals/Training/Courses/ol-req-lse.aspx .

MARS

The General Electric Multi-Area Reliability Simulation (MARS) model is a probabilistic analysis program using sequential Monte Carlo simulation to analyze the resource adequacy for multiple areas. MARS is used by ISOs, RTOs, and other organizations to conduct multi-area reliability simulations.

MC

The PJM Members Committee (MC) is reviews and decides upon all major changes and initiatives proposed by committees and user groups. The MC is the lead standing committee and reports to the PJM Board of Managers.

MIC

The PJM Market Implementation Committee (MIC) initiates and develops proposals to advance and promote competitive wholesale electricity markets in the PJM region for consideration by the Electricity Markets Committee. Along with the OC and the PC, the MIC reports to the MRC.

MISO

The Midcontinent Independent System Operator (MISO) is an independent, nonprofit regional transmission (RTO) organization that supports the constant availability of electricity in 15 U.S. states throughout the Midwestern U.S. and the Canadian province of Manitoba. The Midwest ISO was approved as the nation's first regional transmission organization

(RTO) in 2001. The organization is headquartered in Carmel, Indiana with operations centers in Carmel and St. Paul, Minnesota. (http://www.midwestiso.org/home)

MRC

The PJM Markets and Reliability Committee (MRC) are responsible for ensuring the continuing viability and fairness of the PJM markets. The MRC also is responsible for ensuring reliable operation and planning of the PJM system. The MRC reports to the MC.

MRO

The Midwest Reliability Organization (MRO) is one of eight Regional Reliability Councils that comprise the North American Electric Reliability Council (NERC). The MRO is a voluntary association committed to safeguarding reliability of the electric power system in the north central region of North America. The MRO region is operated in the states of Wisconsin, Minnesota, Iowa, North Dakota, South Dakota, Nebraska, Montana and Canadian provinces of Saskatchewan and Manitoba. (http://www.midwestreliability.org/)

NERC

The North American Electric Reliability Corporation (NERC) is a super-regional electric reliability organization whose mission is to ensure the reliability of the bulk power system in North America. Headquartered in Atlanta, GA, NERC is a self-regulatory organization, subject to oversight by the U.S. Federal Energy Regulatory Commission and governmental authorities in Canada. (http://www.nerc.com/)

NPCC

The Northeast Power Coordinating Council (NPCC) is a regional electric reliability organization within NERC that is responsible for ensuring the adequacy, reliability, and security of the bulk electric supply systems of the Northeast region comprising parts or all of: New York, Maine, Vermont, New Hampshire, Connecticut, Rhode Island, Massachusetts, and the Canadian provinces of Ontario, Quebec, Nova Scotia, New Brunswick, and Prince Edward Island. (http://www.npcc.org/)

NYISO

The New York Independent System Operator (NYISO) operates New York State's bulk electricity grid, administers the state's wholesale electricity markets, and provides comprehensive reliability planning for the state's bulk electricity system. A not-for-profit corporation, the NYISO began operating in 1999. The NYISO is headquartered in Rensselaer, NY with an operation center in Albany, NY. (http://www.nyiso.com/public/index.jsp)

NYSRC

The New York State Reliability Council (NYSRC) a nonprofit, sub-regional electric reliability organization (ERO) within the NPCC. Working in conjunction with the NYISO, the NYSRC's mission is to promote and preserve the reliability of electric service on the New York Control Area (NYCA) by developing, maintaining and updating reliability rules which shall be complied with by the New York Independent System Operator (NYISO). (http://www.nysrc.org/)

OC

The PJM Operating Committee (OC) reviews system operations from season to season, identifying emerging demand, supply and operating issues. Along with the MIC and the PC, the OC reports to the MRC.

OI

The Office of the Interconnection (OI), typically referring to the PJM Operations staff.

OMC

Outside Management Control (OMC) events are a category of data events recorded in the eGADS data. This data category was implemented per the IEEE Standard 762 titled, "IEEE Standard for Use in Reporting Electric Generating Unit Reliability, Availability, and Productivity", approved September 15, 2006, available in March 2007. PJM staff, consistent with NERC staff efforts, adopted this new reporting category, starting in January of 2006. Annex D of the IEEE Standard 762 gives examples for these event types including; substation failure, transmission operation error, acts of terrorism, acts of nature such as tornadoes and ice storms, special environmental limitations, and labor strikes or disputes. OMC events are eliminated with the introduction of Capacity Performance in 2018/2019 DY.

PC

The PJM Planning Committee (PC) reviews and recommends planning and engineering strategies for the transmission system. Along with the MIC and the OC, the PC reports to the MRC. Technical subcommittees and working groups reporting to the PC include: Relay Subcommittee (RS), Load Analysis Subcommittee (LAS), Transmission and Substation Subcommittee (TSS), Relay Testing Subcommittee (RTS), Regional Planning Process Task Force (RPPTF), and the Resource Adequacy Analysis Subcommittee (RAAS).

pcGAR

NERC's personal computer based Generator Availability Report (pcGAR) is a database of all NERC generator data and provides reporting statistics on generators operating in North America. This data and application is distributed by NERC annually, with interested parties paying a set fee for this service.

Peak Load

The Peak Load is the maximum hourly load over a given time interval, typically a day, month, season, or delivery year. See Forecast Peak Load.

Peak Load Ordered Time Series (PLOTS)

The Peak Load Ordered Time Series (PLOTS) load model is the result of the Week Peak Frequency application. This is one of the load model's input parameters. This is discussed in the load forecasting, Week Peak Frequency (WKPKFQ) parameters section of Part II – Modeling and analysis.

Peak Season

Peak Season is defined to be those weeks containing the 24th through 36th Wednesdays of the calendar year. Each such week begins on a Monday and ends on the following Sunday, except for the week containing the 36th Wednesday, which ends on the following Friday. Please note that the load forecast report used in this study define peak season as June, July and August.

PJM-MA

The PJM Mid-Atlantic region (PJM-MA) of the PJM RTO, established pursuant to the PJM Reliability Assurance Agreements dated August 1994 or any successor. A control area of the PJM RTO responsible for ensuring the adequacy, reliability, and security of the bulk electric supply systems of the PJM Mid-Atlantic Region through coordinated operations and planning of generation and transmission facilities. The PJM Mid-Atlantic Control Area is operated in the states of Pennsylvania, Maryland, Delaware, New Jersey, and Virginia. The PJM-MA control area is the Eastern edge of the PJM RTO region.

PRISM

The Probabilistic Reliability Index Study Model (PRISM) is PJM's planning reliability program. PRISM replaced GEBGE, using the SAS programming language. The models are based on statistical measures for both the load model and the generating unit model. This is a computer application developed by PJM that is a practical application of probability theory and is used in the planning process to evaluate the generation adequacy of the bulk electric power system.

RI

The Reliability Index (RI) is a value that is used to assess the bulk electric power system's future occurrence for a loss-of-load event. A RI value of 10 indicates that there will be, on average, a loss of load event every ten years. A given value of reliability index is the reciprocal of the LOLE.

Reliability

In a bulk power electric system, is the degree to which the performance of the elements of that system results in power being delivered to consumers within accepted standards and in the amount desired. The degree of reliability may be measured by the frequency, duration, and magnitude of adverse effects on consumer service. Bulk Power electric reliability cab be addressed be considering two basic and functional aspects of the bulk power system – adequacy and security.

ReliabilityFirst (RF)

ReliabilityFirst is a not-for-profit super-regional electric reliability organization whose goal is to preserve and enhance electric service reliability and security for the interconnected electric systems within its territory.   Beginning operations on January 1, 2006, RF is composed of the former Mid-Atlantic Areas Council (MAAC), East Central Area Reliability Coordination Agreement (ECAR) and parts of the Mid-America Interconnected Network (MAIN). RF is one of the eight Regional Reliability Organizations under NERC in North America.   RF is headquartered in Canton, OH with another office in Lombard, IL. The RF Control Area is operated in the states of Pennsylvania, Maryland, Delaware, New Jersey, Virginia, Illinois, Michigan, Wisconsin, Kentucky, West Virginia, Ohio, and Indiana. (http://www.rfirst.org/)

Reliability Assurance Agreement (RAA)

One of four agreements that define authorities, responsibilities and obligations of participants and the PJM OI. The agreement is amended from time to time, establishing obligation standards and procedures for maintaining reliable operation of the PJM Control Area. The other principal PJM agreements are the Operating Agreement, the PJM Transmission Tariff, and the Transmission Owners Agreement. (http://www.pjm.com/documents/agreements/~/media/documents/agreements/raa.ashx)

Reliability Pricing Model (RPM)

PJM's Reliability Pricing Model (RPM) is the forward capacity market in the PJM RTO Control Area. PJM Manual 18 outlines many aspects of this market place. (http://www.pjm.com/markets-and-operations/rpm.aspx)

Reserve Requirement Study (RRS)

PJM Reserve Requirement Study, which is performed annually. The primary result of the study is a single calculated percentage, the IRM and FPR, which represents the amount above peak load that must be maintained to meet the RF adequacy criteria. The RF adequacy criteria are based on a probabilistic requirement of experiencing a loss-of-load event, on average, once every ten years. Also referred to as the R-Study. (http://www.pjm.com/planning/resource-adequacy-planning/reserve-requirement-dev-process.aspx)

Resource Adequacy Analysis Subcommittee (RAAS)

Reporting to the PC, the RAAS assists PJM staff in performing the annual Reserve Requirement Study (RRS) and maintains the reliability analysis documentation (http://pjm.com/committees-and-groups/subcommittees/raas.aspx). See Resource Adequacy Analysis Subcommittee web site.

Restricted Peak Load

For the given forecast period, the restricted peak load equals the forecasted peak load minus anticipated load management.

RTEP

PJM's Regional Transmission Expansion Planning (RTEP) process identifies transmission enhancements to preserve regional transmission system reliability, the foundation for thriving competitive wholesale energy markets. PJM's FERC-approved, region-wide planning process provides an open, non-discriminatory framework to identify needed system enhancements. (http://www.pjm.com/planning/rtep-upgrades-status.aspx)

Security

The ability of the bulk electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system components or switching operations. One part of the Reliability term.

SERC

The Southeastern Electric Reliability Council (SERC) is a regional electric reliability organization (ERO) within NERC that is responsible for ensuring the adequacy, reliability, and security of the bulk electric supply systems in all or portions of 16 central and southeastern states, including Virginia, North Carolina, South Carolina, Tennessee, Georgia, Alabama, Mississippi, Arkansas, Kentucky, Louisiana, Missouri, Texas, and West Virginia. SERC is divided geographically into five diverse sub-regions that are identified as Central, Delta, Gateway, Southeastern and VACAR. SERC is headquartered in Charlotte, NC. (http://www.serc1.org/Application/HomePageView.aspx)

SIL

Simultaneous transmission Import Limit (SIL) study is a series of power flow studies that, per FERC order 697, assess the capabilities of all PJM transmission facilities connected to neighboring regions under peak load conditions to determine the simultaneous import capability. FERC Order, 124 FERC 61,147, issued August 6, 2008; found that PJM's studies, as amended, met the requirements for a SIL study. The purpose is to assist our members in responding to FERC regarding their two Market Power Indicative screens and their Delivered Price Test Analysis.

SND

The Summer Net Dependable (SND) rating for a given generation unit is used in the summer period. All processes use the SND rating as the basis for evaluating a unit.

SPP

The Southwest Power Pool (SPP) is a regional transmission organization (RTO) responsible for ensuring the adequacy, reliability, and security of the bulk electric supply systems of the Southwest U.S. region, including all or parts of: Kansas, Oklahoma, Texas, Arkansas, Louisiana, and New Mexico. (http://www.spp.org/)

THI

The Temperature-Humidity Index (THI) reflects the outdoor atmospheric conditions of temperature and humidity as a measure of comfort (or discomfort) during warm weather. The temperature-humidity index, THI, is defined as follows: THI = Td – (0.55 – 0.55RH) * (Td - 58) where Td is the dry-bulb temperature and RH is the percentage of relative humidity.

Unrestricted Peak Load

The unrestricted peak load is the metered load plus estimated impacts of Load Management.

Variance

A measure of the variability of a unit's partial forced outages which is used in reserve margin calculations. See PJM manual 22, page 12 and Section 3 Item C, (http://www.pjm.com/~/media/documents/manuals/m22.ashx).

XEFORd

XEFORd is a statistic that results from excluding OMC events from the EFORd calculation. The use of the XEFORd was discontinued with the introduction of Capacity Performance in 2018/2019 DY.

Zone / Control Zone

An area within the PJM Control Area, as set forth in PJM's Open Access Transmission Tariff (OATT) and the Reliability Assurance Agreement (RAA). Schedule 10 and 15 of the RAA provide information concerning the distinct zones that comprise the PJM Control Area.

IV. Appendices

Appendix A
Base Case Modeling Assumptions for 2019 PJM RRS

Parameter	2018 Study Modeling Assumptions	2019 Study Modeling Assumptions	Basis for Assumptions
Load Forecast			
Unrestricted Peak Load Forecast	152,887 MW (2022/2023 DY)	152,854 MW (2023/2024 DY)	Forecasted Load growth per 2019 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 16, 2019 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 2018 PJM Load Forecast Report and 2017 NERC ES&D report (World area).	Consistent with 2019 PJM Load Forecast Report and 2018 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	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.	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	2018 Study Modeling Assumptions	2019 Study Modeling Assumptions	Basis for Assumptions
Solar Resources	A solar 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.	A solar 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, 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 2019.
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: 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.	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	Consistency with other PJM reporting and systems.

Parameter	2018 Study Modeling Assumptions	2019 Study Modeling Assumptions	Basis for Assumptions
	•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.	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.	
Unit Operational Factors			
Forced and Partial Outage Rates	5-year (2013-17) GADS data. (Those units with less than five years data will use class average representative data.).	5-year (2014-18) 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 2014 to 2018 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	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	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 2018/19) 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.

Parameter	2018 Study Modeling Assumptions	2019 Study Modeling Assumptions	Basis for Assumptions
	2013/14 will be dropped and replaced with data from DY 2014/15).		
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.
Load Management and Energy Efficiency			
Load Management and Energy Efficiency	PJM RTO load management modeled per the January 2018 PJM Load Forecast Report (Table B7)	PJM RTO load management modeled per the January 2019 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.

Parameter	2018 Study Modeling Assumptions	2019 Study Modeling Assumptions	Basis for Assumptions
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.

Appendix B

Description and Explanation of 2019 Study Sensitivity Cases

Case No.	Description and Explanation	Change in 2018 Base Case IRM in percentage points (pp)
Individual and New Modeling Characteristic Sensitivity Case		
	The first six sensitivities use the previous 2018 reserve requirement study Base Case as the reference. For the sensitivity cases in red (Case No. 1-6), all differences are with respect to the 2018 Base Case result (2022 DY PJM RTO IRM = 15.66%).	
1	**Load model update – Weekly shape (#57128 2Area)**	**Decrease by 0.01** *
	Modeling characteristics from the Weekly Peak distributions, or 52 mean and standard deviation values, were impacted by updated historical data. The 2019 weekly load model for PJM and the World is based on the same historical time period as in the 2018 study (2003 to 2012).	
2	**Load model update – Monthly Forecast shape (#57131 2Area)**	**Decrease by 0.14** *
	Impact of using the monthly forecast from the 2019 PJM Load Forecast Report in place of the 2018 version. The monthly forecast for the World is also included in this sensitivity.	
3	**Load model update – Both weekly and monthly shape (#57134 2Area)**	**Decrease by 0.16** *
	Impact of using both the 2019 PJM Load Forecast Report and the updated weekly parameters simultaneously. This is a combination of Case No. 1 and Case No. 2.	
4	**PJM Capacity Model update**	**Decrease by 0.71** *
	Impact of using updated PJM RTO capacity model and associated unit characteristics.	
5	**World Capacity Model update**	**Increase by 0.01** *
	Impact of using updated World region capacity model.	
6	**PJM RTO and World Capacity Model update**	**Decrease by 0.70** *
	Impact of using both the updated PJM RTO Capacity Model and the updated World Capacity Model simultaneously. This is a combination of Case No. 4 and Case No. 5.	

Case No.	Description and Explanation	Change in 2019 Base Case IRM in percentage points (pp)
	Load Model Sensitivity Cases	
	Sensitivity numbers 7 and higher are based on the 2019 Base Case. All differences are with respect to the 2019 Base Case result (2023 DY).	
7	**No Load Forecast Uncertainty (LFU) (#57125)**	**Decrease by 4.85**
	This scenario represents "perfect vision" for forecast peak loads, i.e., forecast peak loads for PJM RTO and the Outside World areas have a 100% probability of occurring. The results of this evaluation help to quantify the effects of weather and economic uncertainties on IRM requirements. This sensitivity does not affect the forced outage rate portion in the FPR calculation, thus the FPR will change in the same amount.	
8	**Vary the Forecast Error Factor (#57126 and 57127)**	**See Below**
	This two-area sensitivity gauges the impact of the FEF on the IRM. When the FEF is decreased to 0% compared to the 1% used in the base case, the IRM falls by 0.16pp. When instead the FEF is increased to 2.5%, the IRM rises by 0.97pp. This sensitivity does not affect the forced outage rate portion in the FPR calculation, thus the FPR will change in the same amount.	
9	**Number of Years in Load Model (#57149 and 57151)**	**See below**
	These two-area sensitivity cases replace the time period used for the load model in the base case of 2003 to 2012 with other candidate load models considered in the selection process by RAAS.	

PRISM #	Time Period	PJM LM #	World LM #	2023 IRM %	Difference (PP)
57086	2003-2012 (10 Year LM)	51995	51997	14.84	-
57149	2004-2014 (11 Year LM)	52003	52004	14.86	0.02
57151	2002-2014 (13 Year LM)	52005	52006	14.78	-0.06

Case No.	Description and Explanation	Change in 2019 Base Case IRM in percentage points (pp)
10	**PJM Monthly Load Shape (#57154 and #57155)**	**See below**
	These two-area sensitivity cases test the impact of making adjustments to the PJM monthly load profile relative to the base case assumption in Table II-1. In the base case, the August peak is 96.5% of the annual peak. Increasing this August ratio by one percentage point (to 97.5%) increases the IRM to 15.23%, or 0.39 pp higher than the base case. Reducing this August ratio by one percentage point (to 95.5%) decreases the IRM to 14.56%, or 0.29 pp lower than the base case.	
11	**World Monthly Load Shape (#57156)**	**See below**
	This two-area sensitivity case tests the impact of making adjustments to the World monthly load profile relative to the base case assumption in Table II – 1. In the base case, the World peaks in July while its August peak is 99.4% of the annual (July)	

	peak. Switching the World's annual peak to August and making its July peak to be 99.4% of the annual peak reduces the IRM by 0.07 pp to 14.77%.	
	Generation Unit Model Sensitivity Cases	
12	**High Ambient Temperature Unit Derating (#57184 2Area)**	**Decrease by 1.38**
	Assessment of performance of PJM RTO units on high ambient temperature conditions indicated that some units cannot produce their summer net dependable rating on these days. This type of derating is per PJM's Operations rules and is not considered a GADS derated outage event. This assessment assumes that all units are not affected by high ambient temperature conditions and that they can produce their full summer net dependable rating. This sensitivity removes the 2500 MW on planned outage for the peak summer period (weeks 6-15)	
13	**Replace the EEFORd values with EFORd values for all units in the model. (#57185 2Area)**	**Decrease by 0.94**
	This case replaces the EEFORd statistic with the EFORd statistic, for all units. It assumes that EMOF is not included in the EEFORd computation.	
14	**Impact of change in EEFORd: F-Factor (#57186 1Area)**	**Increase by 1.39**
	There is a direct correlation to the forced outage rate of the PJM RTO units vs. the PJM IRM. This sensitivity increases the (EEFORd) by 1 percentage point.	
	Capacity Benefit Margin Sensitivity Cases	
15	**Various values of Capacity Benefit Margins**	**See Figure I-7**
	Figure I-7 shows the impact to IRM as the value of Capacity Benefit Margin (CBM) is increased. CBM is a measure of transfer assistance available from the outside neighboring region. This graph indicated what value PJM's interconnected ties have on the calculated IRM, and where the value of CBM saturates (becomes constant).	

<table>
<tr><th colspan="3">Reserve Modeling Sensitivity Cases</th></tr>
<tr><td>16</td><td>PJM RTO at cleared RPM auction (#57138)</td><td>RI = 82.9</td></tr>
<tr><td></td><td colspan="2">In this sensitivity, PJMRTO reserves are modeled as per the most recent RPM auction while the World is solved to meet the 1 in 10 criterion.

This sensitivity should have been run using results from the 2022/2023 RPM Base Residual Auction (BRA) but since that BRA has not been run yet, results from the 2021/2022 RPM BRA are used.

The 2021/2022 Reliability Pricing Model (RPM) Base Residual Auction (BRA) cleared 163,627.3 MW of unforced capacity in the RTO representing a 22.0% reserve margin. Accounting for load and resource commitments under the Fixed Resource Requirement (FRR), the reserve margin for the entire RTO for the 2021/2022 Delivery Year as procured in the BRA is 21.5%, or 5.7% higher than the target reserve margin of 15.8%. This reserve margin was achieved at clearing prices that are between approximately 44% to 82% of Net CONE, depending upon the Locational Deliverability Area (LDA). The auction also attracted a diverse set of resources, including a significant increase in Demand Response and Energy Efficiency resources, additional wind and solar resources, and one new combined cycle gas resource

The full report can be found at https://pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2021-2022/2021-2022-base-residual-auction-report.ashx?la=en</td></tr>
<tr><td>17</td><td>PJM RTO IRM Vs. World Reserves (#56628-56643)</td><td>See below</td></tr>
<tr><td></td><td colspan="2">For a two area study, World Reserves were varied from the calculated requirement (1 day in 10) to the forecasted reserves. The runs are made by solving the World for a fixed load (corresponding to an installed reserve level) and PJM RTO is solved to its criterion (1 day in 10). The results are in Figure I-6. The valid range of world reserves is determined through consideration of different load management assumptions. Within this valid range of world reserves, as the reserves of the world increase, the IRM requirement for PJM RTO declines at a decelerating rate.</td></tr>
<tr><td>18</td><td>PJM RTO RI Vs. PJM RTO Reserves (#56662-56676)</td><td>See below</td></tr>
<tr><td></td><td colspan="2">A two area study when PJM RTO reserves were varied from the calculated requirement (1 day in 10). The runs are made by solving the PJM RTO for a fixed load (corresponding to an installed reserve level) and World is at its 1D/10 YR level.

As the PJM RTO reserves increase, the reliability Index (measured by the LOLE value) increases exponentially. See Figure II-5.</td></tr>
</table>

<table>
<tr><th colspan="3">Topological Modeling Sensitivity Cases</th></tr>
<tr><td>19</td><td>Single Area PJM RTO Model (#57087)</td><td>Increase by 1.56</td></tr>
<tr><td></td><td colspan="2">This models only the PJM RTO in a single area case. The solution is for a Reliability Index (RI) of 10, or once every 10 years. When compared to the official case results, this represents the value of the interconnected ties, or Capacity Benefit Of Ties (CBOT). The difference between the base run and this sensitivity in the load carrying capability (LCC), multiplied by the reserve requirement, yields an approximate 2,442 MW of capacity that does not need to be inside the PJM RTO. This megawatt amount represents the value of the 3,500 MW CBM that is specified in Schedule 4 of the PJM Reliability Assurance Agreement (RAA).</td></tr>
<tr><td>20</td><td>Two Area Model with Ambient Derates for World Area -3,110 MW out on PO for World area</td><td>Increase by 0.01</td></tr>
<tr><td></td><td colspan="2">This sensitivity models the Base Case with ambient derates for the World region too. The same proportion of impact of ambient conditions on the World fleet of units is modeled as are modeled for the PJM generation fleet. The impact of ambient conditions on the generation fleet affects several generation categories as shown in Table II-6. Ambient conditions are modeled as Planned outages over the ten week Summer period, similar to the 2,500 MW derating used in the PJMRTO area.</td></tr>
<tr><td>21</td><td>Relationship between IRM and ambient impact on unit performance</td><td>See Below</td></tr>
<tr><td></td><td colspan="2">This sensitivity adjusts the total amount of ambient derates, for the appropriate generation categories affected by high ambient (THI) conditions (See Table II-6 for categories). Ambient derates are modeled as planned outages over the high LOLE summer period. The range of impact to the unit fleet due to high ambient conditions, for the entire PJM RTO fleet of units, was 2,500 – 8,500 megawatts. The increase in the IRM for every additional 1000 megawatts of ambient derates, on average, was 0.62 pp.</td></tr>
</table>

Appendix C

Resource Adequacy Analysis Subcommittee (RAAS)

RAAS Main Deliverables and Schedule

There are 3 primary deliverables of the RAAS.

1. The assumptions letter for the upcoming RRS

    Per the below time line, this activity is scheduled to start in June and be completed in July.

2. The IRM, FPR Analysis Report

    Per the below time line, this activity is scheduled to start in July and be completed in September.

3. The Winter Weekly Reserve Target in the Report

    Per the below time line, this activity is shown as item number thirteen, scheduled to be completed in September, for the upcoming winter period.

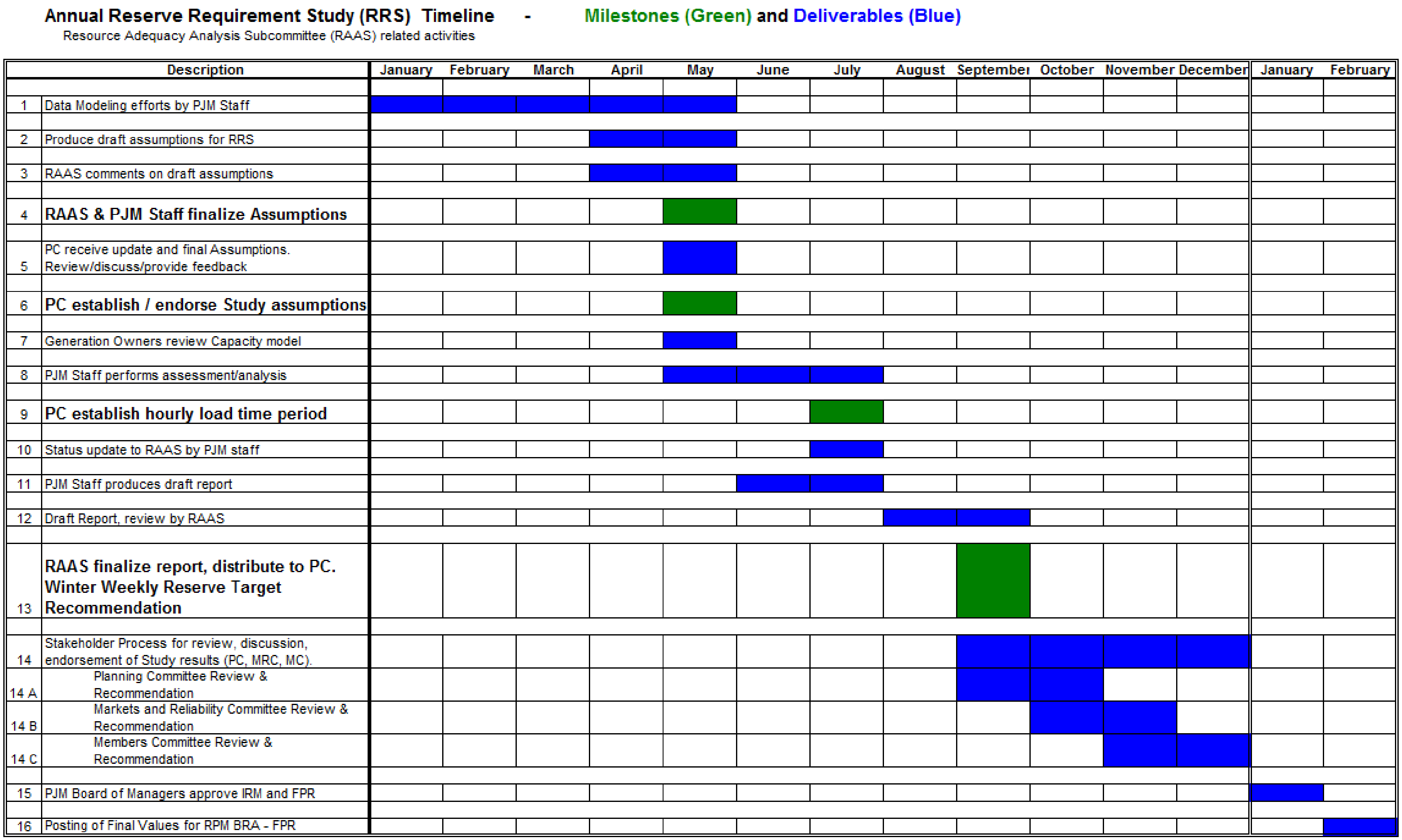
This technical working group was established by and reports to the PJM Planning Committee.

The activities of the PJM RAAS are shown at the following web link:

http://pjm.com/committees-and-groups/subcommittees/raas.aspx

Timeline for 2019 Reserve Requirement Study

Figure IV-1: Timeline for 2019 RRS



The 2019 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.

Appendix D has not yet been updated

Appendix D

ISO Reserve Requirement Comparison

The following compares the MISO, NYISO, ISO-NE and PJM RTO reserve requirements, on a 1) IRM, 2) IRM adjusted by load diversity, and 3) Unforced Margin adjusted by load diversity.

Observations from this comparison:

- The smaller NYISO and ISO-NE regions have lower load diversity which tends to inflate their *IRM adjusted by load diversity*.
    - NYISO's *Unforced Margin adjusted by load diversity* is higher than PJMs due to a starting IRM that is also higher (18.2% vs 16.2% for 2018) and the aforementioned lower load diversity.
- MISO's *Unforced Margin adjusted by load diversity* is lower than PJM's due to a larger amount of emergency assistance from neighboring regions into MISO. This understates MISO's IRM relative to PJM's.

Table IV-1: Comparison of reserve requirements on a coincident, unforced basis.

	MISO	ISO-NE	NYISO	PJM	PJM	PJM	PJM	PJM
Delivery Year	2018	2021	2018	2018	2019	2020	2021	2022
IRM	**17.10%**	**17.80%**	**18.20%**	**16.20%**	**16.00%**	**15.90%**	**15.80%**	**15.70%**
Load Diversity	3.55%	1.00%	1.91%	3.74%	3.74%	3.80%	3.78%	3.85%
IRM (adj. by div)	**13.09%**	**16.63%**	**15.99%**	**12.02%**	**11.82%**	**11.66%**	**11.59%**	**11.41%**
Average EFORd***	8.13%	8.01%	7.90%	6.20%	6.08%	6.04%	6.01%	5.90%
Unforced Margin	7.58%	8.36%	8.86%	9.00%	8.95%	8.90%	8.84%	8.87%
Unforced Margin (adj. by div)	**3.89%**	**7.28%**	**6.82%**	**5.07%**	**5.02%**	**4.91%**	**4.88%**	**4.84%**

*** Values from period 2012-2016 for MISO, ISO-NE, NYISO; 2013-2017 for PJM
Unforced Margin = ((1 + IRM) * (1- EFORd)) - 1
IRM w/div = ((1 + IRM) / (1 + Load Diversity)) - 1
Unforced Margin w/div = (IRM w/div * (1 - EFORd) / (1 + Load Diversity)) - 1
PJM RTO Load Diversity includes both Inter-regional and intra-regional diversity, per Table B1 of the January 2018 load forecast report (Diversity Interregional plus Diversity PJM Western plus Diversity Mid-Atlantic)
ISO-NE and NYISO columns use estimated values for load diversity. MISO and ISO-NE columns use estimated values for EFORd

Appendix E
RAAS Review of Study - Transmittal Letter to PC

October 17, 2019

Kenneth Seiler
Chairman Planning Committee
PJM Interconnection
2750 Monroe Blvd.
Audubon, PA 19403

Dear Mr. Seiler,

The Resource Adequacy Analysis Subcommittee (RAAS) has completed its review of the 2019 PJM Reserve Requirement Study (RRS) report.

The review efforts are in accordance with the RAAS Charter, as approved by the Planning Committee and posted at: http://pjm.com/committees-and-groups/subcommittees/~/media/committees-groups/subcommittees/raas/postings/charter.ashx

The review included the following efforts:

- Development and completion of the Study assumptions, including an activity timeline
- Participation in subcommittee meetings to discuss and review PJM staff progress in developing the Study model
- Identification of modeling improvements for incorporation into the analysis and report, as described in the June 2019 RRS Study Assumptions letter
- Participation in subcommittee meetings to discuss and review preliminary analysis results
- Verification that all base case study assumptions are fully and completely adhered to
- Review of a draft version of the study report

After review and discussion of the study results, the subcommittee unanimously endorsed the PJM recommendation shown in the table below.

RRS Year	Delivery Year Period	Calculated IRM	Recommended IRM	Average EFORd	Recommended FPR
2019	2020 / 2021	15.46%	**15.5%**	5.78%	**1.0882**
2019	2021 / 2022	15.14%	**15.1%**	5.56%	**1.0870**
2019	2022 / 2023	14.89%	**14.9%**	5.42%	**1.0867**
2019	2023 / 2024	14.84%	**14.8%**	5.40%	**1.0860**

PJM will be requesting Planning Committee endorsement of the recommendations detailed above at your October 17, 2019 meeting.

The review efforts of the RAAS will be concluded upon acceptance of this report by the Planning Committee.

Respectfully,

Thomas A Falin
RAAS Chair

Appendix F
Discussion of Assumptions

This appendix's intent is to document assumptions and modeling items that affect the calculated IRM for the base case run. The following considerations were included in the modeling and analysis

- Trends observed over several Study models are significant and are considered at the time of validating the recommendations resulting from this report.

- Historically significant drivers of the Study results include the overall unit forced outage rates, forecasted monthly load profile, load model diversity, forecast reserve for both Area1 (PJM RTO) and Area2 (World), size of the neighboring region modeled, and time period used in the hourly load model to create the weekly statistical parameters.

- The sensitivities presented in Appendix B provide an important tool for validating assumptions and results of the study.

- Mitigating uncertainty to the forward capacity market is an important consideration.

A discussion of the assumptions considered in the study is presented below,

Independence of Unit Outage Events (no recognition of common cause failures): Historically, this has been an assumption widely used throughout the industry. All production grade commercial applications used to perform probabilistic reliability indexes use this assumption. However, changes in the makeup of the industry, such as the current trend to build mostly units that rely on the shared gas transmission system, could invalidate this assumption for some units that do have a correlation for outages due to the shared gas transmission pipeline.

Forecast Error Factor (FEF): The RRS models a 1% Forecast Error Factor for all delivery years. This modeling, which began in the 2005 Study, represents a switch from the previous practice of increasing the FEF as the planning horizon lengthens.

Intra-World Load Diversity: The diversity values used are from an assessment of historic hourly data. See Table II-3 for further details. Using the average of the historic diversity values was considered to be a reasonable assumption (as opposed to using the minimum of the values which was deemed to be very conservative).

Assistance from World area: The value of the outside world's assistance is associated with two modeling characteristics: the timing of PJM's need for assistance and the ability of the World to supply assistance at this time of need. The assumption that the outside world adjacent to PJM will help PJM avoid Loss-of-Load events is based on historic operating experience.

Modeling all External NERC Regions in a Single Area: PRISM is limited to a 2-area model: PJM and the World Area. Thus, all external NERC regions are modeled in a single area, ignoring the transmission constraints between the areas. This approach assumes that all external NERC regions share loss-of-load events which are not the case in practice. Furthermore, PRISM solves the World to collectively be at a 1 in 10 reliability level whereas, in practice, each external NERC Region is at 1 in 10 and hence the World is collectively at a level worse than 1 in 10.

Units out on planned maintenance over summer peak period due to ambient conditions: The moving of planned outage events to the summer peak period is an assumption that has been used since 1992. This is consistent with what has been observed by Operations over the summer period and reflects PJM's experience with a control region that includes about 1,300 units. Currently, 2,500 MW are modeled out to reflect reduced unit output during high ambient conditions (hot and humid). Verification of this quantity was performed in early 2016 using Summer Verification Test data from 2013-2015.

Holding World at known reserve requirement level rather than forecast reserves: The World is modeled at the reserve requirement known for each of the surrounding individual sub-regions that make up the World region. This assumption ensures that PJM does not depend on World "excess" reserves that may be committed to other regions. Any excess reserves, however, may be uncommitted and actually available to serve PJM under a capacity emergency. Thus, this assumption may understate the amount of assistance available to PJM from the World area.

Normally-distributed load model: The uncertainty in the daily peak load model is assumed to be normally distributed. The normal distribution is approximated using a histogram with 21 points ranging from -4.2 to +4.2 standard deviations from the mean. This 21-point approximation is used in all weeks (and in each of the 5 days within a week) of the analysis. The means and standard deviations vary from week to week and are computed by a separate program. This program uses historic weekly load data, magnitude ordered within a season, to compute the mean and standard deviation for each of the 52 weeks in the model. The 21 point daily peak distribution is defined by each week's mean and standard deviation in the calculation of loss of load expectation.

PJM and World regions load diversity: The value of the Capacity Benefit Margin (CBM) is associated with the timing of PJM load model peaks relative to the timing of the World load model peaks. This difference in timing is assessed by the PJM-World Diversity. The PJM-World Diversity is a measure of the World's load value at the time of PJM's annual peak. This measure is expressed as a percentage of the World's annual peak (see Table II-3). Note that the greater the diversity, the more capacity assistance the World can provide at PJM's peak (or other PJM high load events). The value of PJM-World diversity might change depending on the dataset of historical hourly peaks considered.

Perfect correlation between two load models: As mentioned earlier in the report, PJM's load is assumed to be normally distributed (approximated via a 21-point histogram). The World's load model is modeled in the same way. When PJM is assumed to be facing a particular load level (for instance, load level 2, the second highest load level), the World is assumed to be facing the corresponding magnitude-ordered load level (i.e. the second highest out of the 21 load levels for the World). In other words, there is a perfect correlation between the two load models. In practice though, the World could be facing any other of the 20 remaining load levels.

World Load Management: The criteria to select the World reserve level stipulates that the World will be assumed to be at the higher of the following two reserve levels: 1) the reserve level that satisfies 1 in 10 (as found by PRISM) or 2) the composite reserve level as a percentage of the World peak (see Table I-5) excluding load management as an available resource. In the event that reserve level 1) is selected, then implicitly some load management is being assumed as an available resource in the World. On the other hand, when reserve level 2) is selected, no load management is assumed as available.