2018 NERC Probabilistic Assessment - PJM RTO Region

2020 and 2022 Delivery Years

December 12, 2018

Analysis conducted with assistance from the NPCC CP-8 WG
Report written by PJM Staff

Legal Notices

PJM Probabilistic Assessment: EUE and LOLH for 2020 and 2022

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Part I – Summary

PJM Probabilistic Assessment Background

- The purpose of this assessment is to provide adequacy metrics, namely Expected Unserved Energy (EUE) and Loss of Load Hours (LOLH), for the PJM RTO region in 2020 and 2022.

- The tool used to carry out this study is GE-MARS, a multiple-area hourly simulation model developed by General Electric.

- The study was conducted by the NPCC CP-8 WG, with full participation of PJM Staff. PJM staff has participated in the CP-8 WG efforts since 2005. PJM supplied the modeling data for most of the CP-8 WG external region which includes the full PJM RTO footprint. NPCC collaborates with PJM on interregional assessments to allow sharing of model data, analysis methods, and assessment techniques.

- Refer to the 2018 NPCC Probabilistic Assessment or the 2018 NPCC Long Range Adequacy Overview for further specific data modeling and techniques used.

- This report is to a great extent consistent with the 2018 NERC LTRA submission except for,

    - ❖ The NERC ProbA models around 2,500 MW of on-peak capacity derates as a result of above-average summer ambient conditions.

- The results for EUE and LOLH metrics in Table I – 1 and Table I – 2 are after implementing PJM's final emergency operating procedure (EOP). For the list of EOPs considered in this study, see Table I – 5 or Table I – 6. In addition, PJM supplies the metrics at the various EOP levels. The order of these EOPs is only representative; PJM dispatchers can, at their discretion and due to various system conditions, invoke any EOP step at any time regardless of the order indicated in this study.

- The PJM RTO consists of the following regions: 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 this study, the PJM-RTO region is broken into five sub-regions. The sub-regions are as follows,

Eastern Mid-Atlantic	AE, DPL, JCPL, PECO, PS, RECO
Central Mid-Atlantic	BGE, MetEd, PEPCO, PL, UGI
Western Mid-Atlantic	PN
PJM West	PJM Western (AEP, APS, ATSI, ComEd, Day, DEOK, EKPC, and DLCO)
PJM South	DOM

- In addition to the Base Case, a Sensitivity Case was run where PJM's 2022 forecasted planning reserve margin was reduced to one-third and two-thirds of the original value. The lower reserve margin values were achieved by scaling up the 2022 Base Case hourly loads.

Summary of Results

- **EUE and LOLH Probabilistic Metrics**

The Expected Unserved Energy (EUE) and Loss-of-Load Hours (LOLH) are reliability metrics directly supplied by the GE-MARS simulation. The requirements for this year's study establish 2020 and 2022 as the reporting years. Table I - 1 presents the EUE and LOLH for 2020 and 2022 under the Base Case, as well as the values of other parameters associated with system reliability. Table I – 2 presents the corresponding values under the Sensitivity Case.

Table I - 1: Base Case. Annual Peak Demand and Capacity Resources

Year	Net Energy for Load (GWh)	Net Internal Demand (MW)	Forecast Capacity Resources (MW)	Forecast Operable Capacity Resources (MW)	EUE (MWh)	LOLH (hrs/yr)	Forecast Planning Reserve Margin (%)	Forecast Operable Reserve Margin (%)
2020	808,638	144,287	192,952	176,993	0.000	0.000	33.7%	22.7%
2022	812,908	145,166	193,761	177,839	0.000	0.000	33.5%	22.5%

**Forecast Capacity Resources equals the total installed capacity, minus capacity derates, plus net firm transactions. The installed capacity value of intermittent resources (wind and solar) is equal to their capacity credit.*

***Forecast Operable Capacity Resources equals Forecast Capacity Resources minus generator forced outage rates*

****Net Internal Demand equals total internal demand minus demand response*

Table I - 2: 2022 Sensitivity Case. Annual Peak Demand and Capacity Resources

Case	Net Energy for Load (GWh)	Net Internal Demand (MW)	Forecast Capacity Resources (MW)	Forecast Operable Capacity Resources (MW)	EUE (MWh)	LOLH (hrs/yr)	Forecast Planning Reserve Margin (%)	Forecast Operable Reserve Margin (%)
1/3	965,355	174,310	193,761	177,839	338.4	0.146	11.2%	2.0%
2/3	881,213	158,409	193,761	177,839	0.000	0.000	22.3%	12.3%

**Forecast Capacity Resources equals the total installed capacity, minus capacity derates, plus net firm transactions. The installed capacity value of intermittent resources (wind and solar) is equal to their capacity credit.*

***Forecast Operable Capacity Resources equals Forecast Capacity Resources minus generator forced outage rates*

****Net Internal Demand equals total internal demand minus demand response*

Note that Demand Response (DR) resources (7,675 MW for 2020 and 7,721 MW for 2022) are subtracted from the Total Internal Demand yielding the Net Internal Demand value in the third column of Table I – 1 and Table I – 2.

The Base Case results in LOLH and EUE equal to zero for both 2020 and 2022 due to large Forecast Planning Reserve Margins. The reserve margins are significantly above the reference values of 15.9 percent and 15.8 percent, respectively.

The Sensitivity Case yields non-zero LOLH and EUE values for 2022 only when the forecast planning reserve margin is reduced to 11.2%, one-third of its original value. When the forecast planning reserve margin is reduced to two-thirds of its original value, 22.3% (well above the reference value of 15.8%), the LOLH and EUE values are still zero.

Table I - 3: Comparison with previous assessment for 2020

Year	Net Energy for Load (GWh)	Net Internal Demand (MW)	Forecast Capacity Resources (MW)	Forecast Operable Capacity Resources (MW)	EUE (MWh)	LOLH (hrs/yr)	Forecast Planning Reserve Margin (%)	Forecast Operable Reserve Margin (%)
2020*	841,989	153,471	194,678	178,212	0.001	0.000	26.8%	16.1%
2020	808,638	144,287	192,952	176,993	0.000	0.000	33.7%	22.7%

** Results from the 2016 Probabilistic Assessment*

Table I – 3 shows a comparison of the 2018 ProbA results with the 2016 ProbA results for year 2020. The LOLH and EUE in the 2018 ProbA are similar to the values reported in the 2016 ProbA.

The slight EUE decrease in the 2018 ProbA can be explained by the larger planning and operable reserves for 2020 in the 2018 ProbA compared to those in the 2016 ProbA (33.7% vs. 26.8%). The increase in 2020 reserves in the 2018 ProbA is mainly due to a reduction in forecasted Net Internal Demand which is caused by:

i) A much lower 50/50 forecast for 2020 in the 2018 ProbA than in the 2016 ProbA (151,962 MW vs 156,887 MW).

ii) A much higher Demand Response 2020 forecast in the 2018 ProbA relative to the 2016 ProbA (7,675 MW vs 3,416 MW).

- **EUE and LOLH by Month**

The monthly LOLH and EUE for 2022 are presented in Figure I – 1 and Figure I – 2, respectively, only for the Sensitivity Case that yields non-zero LOLH and EUE values. As expected for a summer peaking system, the risk is concentrated in the summer months.

Figure I - 1: Monthly LOLH in 2022, Sensitivity Case (1/3 of forecast planning reserve margin)

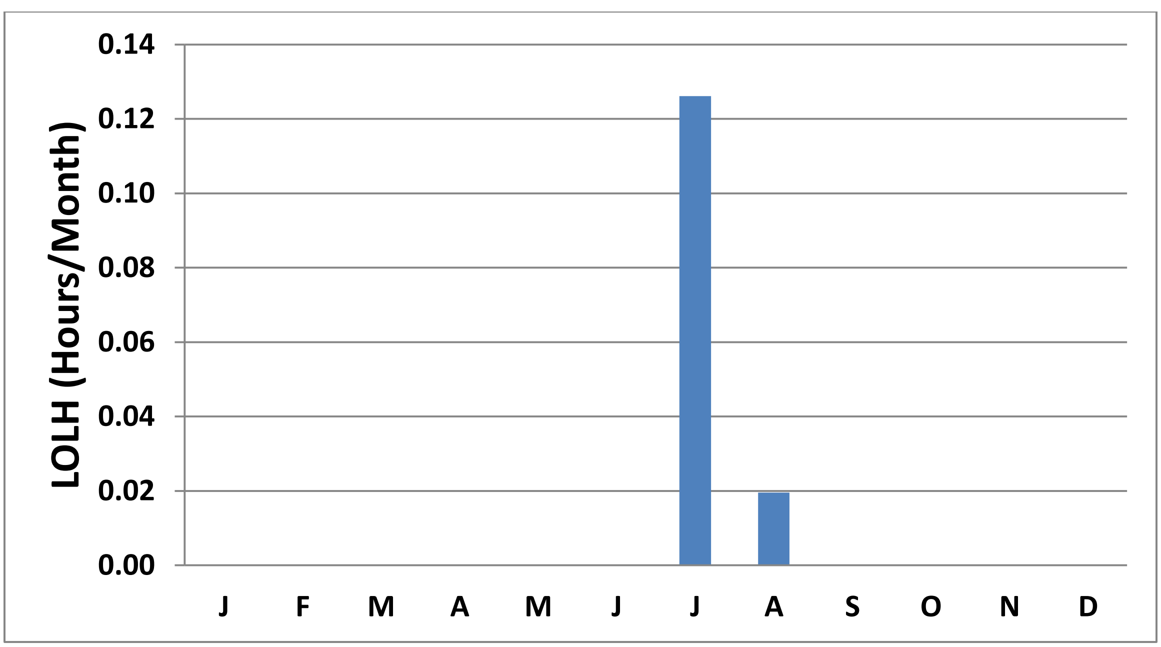


Figure I - 2: Monthly EUE in 2022, Sensitivity Case (1/3 of forecast planning reserve margin)

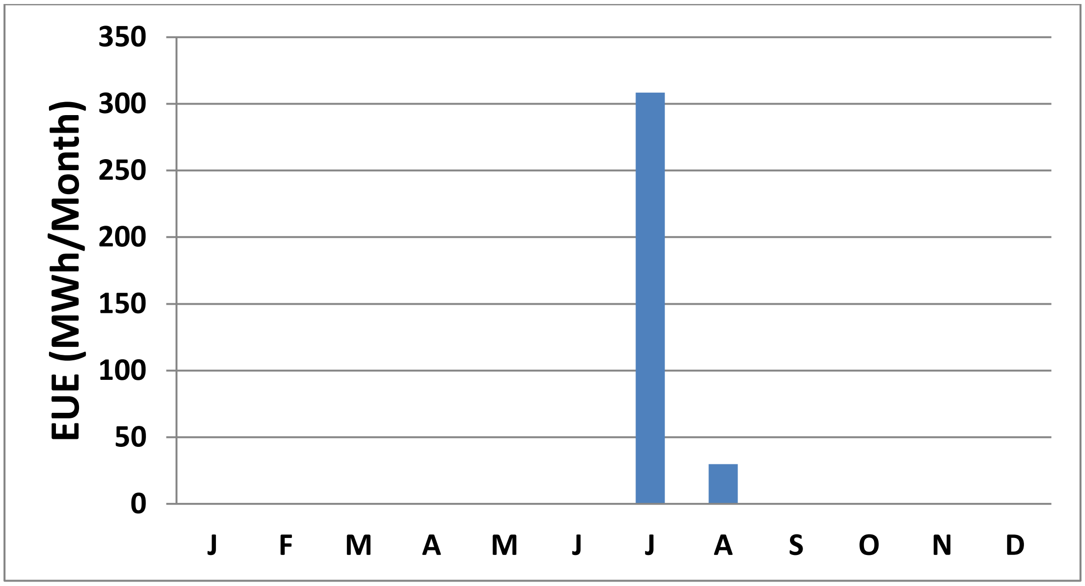


Table I - 4: Capacity and load at time of Region Peak – Base Case

	Summer	Winter
2020		
Capacity (MW)	193,724	185,850
Purchase/Sale (MW)	1,728	1,728
Load (MW) **	151,962	132,039
Max. Wind Capacity (MW) *	1,739	1,327
2022		
Capacity (MW)	196,261	196,343
Purchase/Sale (MW)	1,728	1,486
Load (MW) **	152,887	133,117
Max. Wind Capacity (MW) *	1,845	3,717

*** Wind capacity at capacity credit, not nameplate rating**

**** Demand response not subtracted.**

Detailed Results

- **Seasonal Capacities (Traditional, Wind), Purchases and Sales, 50/50 Peak Seasonal Loads**

  Table I – 4 presents the total seasonal capacities, 50/50 unrestricted peak seasonal loads, seasonal wind capacity, and the net of purchases and sales for the reporting years.

  Note that the imports and exports modeled for Summer 2022 are expected quantities (while those modeled for Winter 2020, Summer 2020, and Winter 2022 are firm quantities since capacity market auctions covering those periods have been run as of the time of running the 2018 Probabilistic Assessment).

- **EUE and LOLE values at each Emergency Operating Procedure in Base Case**

  Table I – 5 and Table I – 6 show the estimated annual PJM RTO region Loss of Load Hours (LOLH) and Expected Unserved Energy (EUE) for the years 2020 and 2022 at each one of 6 emergency operating procedures.

Table I - 5: Results for 2020 – LOLH (Hours/year) and EUE (MWh) – Base Case

	LOLH	EUE
Curtail Load / Utility Surplus	0	0
No 30 min Reserves	0	0
Volt. Red. Or Inter. Loads	0	0
No 10 min Reserves	0	0
General Public Appeals	0	0
Disconnect Load	0	0

Table I - 6: Results for 2022 – LOLH (Hours/year) and EUE (MWh) – Base Case

	LOLH	EUE
Curtail Load / Utility Surplus	0	0
No 30 min Reserves	0	0
Volt. Red. Or Inter. Loads	0	0
No 10 min Reserves	0	0
General Public Appeals	0	0
Disconnect Load	0	0

The values at each of the EOPs are derived from the respective reliability index values at each of the seven load levels (see Table II – 7), computing a weighted-average expected value based on the specified probabilities of occurrence (also in Table II – 7).

Demand Response resources are modeled as the first EOP (Curtail Load/Utility Surplus) in Table I – 5 and Table I – 6.

Part II – Modeling and Assumptions

Software Model Description

- **GE-MARS**

  The primary tool for performing reliability analyses at PJM is PRISM. However, due to the hourly nature of the outputs required in this study, GE-MARS, an hourly Monte Carlo simulation tool, was considered to be more adequate to carry out the study.

  GE-MARS uses a Monte Carlo simulation approach which requires an 8760 hour-long load shape as one of its inputs. The software compares available capacity with load during each of the 8760 hours. (GE-MARS has the capability to reduce the number of hours included in the metric calculations yet this option was not used to carry out this study).

Demand Load Forecast Modeling

- **Differences between reported data and similar data reported in the 2016 LTRA**

  There are minor discrepancies between the Total Internal Demand reported in the 2018 LTRA for 2020 and 2022 and the corresponding values in the 2018 Probabilistic Assessment. These discrepancies arise from the fact that in the 2018 Probabilistic Assessment PJM is modeled using 5 different regions with their respective Summer 2002/Winter 2004 hourly load shapes. This entails that PJM loads (the hourly sum of the loads in the 5 regions) in the 2018 Probabilistic Assessment are impacted by the load diversity among the 5 PJM regions observed in Summer 2002/Winter 2004. This load diversity is not the same load diversity considered in the 2018 PJM Load Forecast Report values, which is the source of the data reported in the 2018 LTRA.

  In order to match the PJM peak load reported in the LTRA, the non-coincident peaks (NCPs) of the 5 PJM regions published in the PJM Load Forecast were adjusted by suitable factors. These adjusted NCPs are then input into GE-MARS. The factors are computed so that after being applied to the NCPs and to each of the hourly load shapes, the difference between the PJM peaks in MARS and the peaks in the PJM Load Forecast is minimized. The downside of adopting this procedure is that the NCPs for the 5 regions input into GE-MARS do not necessarily coincide with the NCPs reported in the PJM Load Forecast (when the factor discussed above is different than 1). In past versions of the Probabilistic Assessment (prior to 2014), PJM opted to use the actual NCPs from the Load Forecast at the cost of not matching the PJM overall peak. Since the 2014 ProbA, PJM decided to match the overall PJM peak in the Probabilistic Assessment at the cost of not matching the NCPs for the 5 regions. A complete match between the data input into GE-MARS and the data published in the PJM Load Forecast is not possible due to the load diversity issue mentioned in the previous paragraph.

- **Chronological Load Model**

  The hourly load shape determined to be the most appropriate for the PJM RTO's LOLE assessments is Summer 2002 and Winter 2004. This choice has been confirmed by recent assessments of other candidate years.

  The hourly load shape of each of the 5 PJM sub-regions (Eastern Mid-Atlantic, Central Mid-Atlantic, Western Mid-Atlantic, PJM West, and PJM South) was considered for this study.

- **Load Forecast Uncertainty**

  The PJM RTO probabilistic load model in PRISM was translated into the load forecast uncertainties used in the LOD-UNCY table in GE-MARS. PRISM is the software used by PJM to run its Reserve Requirement Study whose main output is the Installed Reserve Margin. The load model in PRISM is a collection of 52 normal distributions, one for each week of the year. PRISM Load Models are available for each of the 5 PJM regions considered in this study.

Load forecast uncertainty in GE-MARS is input on a monthly basis. Since PRISM's load forecast uncertainty is modeled weekly, a procedure was developed to translate the weekly PRISM load forecast uncertainty into monthly GE-MARS load forecast uncertainty. The procedure starts by mapping the PRISM weeks into GE-MARS months. Then, Monte Carlo sampling is performed on the PRISM weekly normal distributions corresponding to each month. The objective of the sampling step is to generate a sizable collection of monthly peaks (2500 replications were run per month). Next, mean and standard deviation of monthly peaks are computed for each month, with standard deviations expressed as per unitized of the monthly mean. For instance, if the computed monthly peak mean is $x = 100{,}000\ MW$ and the computed monthly standard deviation is $s = 5{,}000\ MW$, the standard deviation is expressed as 0.05. In GE-MARS, the monthly load forecast uncertainty is modeled via discrete load levels. The load levels are determined by considering the following 7 discrete points: $x + 3s$, $x + 2s$, $x + 1s$, $x + 0s$, $x - 1s$, $x - 2s$, $x - 3s$.

The load forecast uncertainty is different for each sub region and varies from month to month. For illustrative purpose, Table II – 7 shows the load forecast uncertainty for July 2020. Table II – 7 also shows the probability of occurrence assumed for each of the seven load levels modeled (see last row of Table II – 7).

In computing the reliability indices, all of the areas were evaluated simultaneously at the corresponding load level, the assumption being that the factors giving rise to the uncertainty affect all of the areas at the same time.

For this study, reliability measures (EUE and LOLH) are reported for the expected load conditions. The values for the expected load condition are derived from computing the reliability indices at each of the seven load levels presented in Table II – 7, and computing a weighted-average expected value based on the specified probabilities of occurrence.

Table II - 7: Load Forecast Uncertainty for 5 PJM regions (July 2020)

	Per Unit Variation in Load						
Sub Region Name	**Level 1**	**Level 2**	**Level 3**	**Level 4**	**Level 5**	**Level 6**	**Level 7**
Eastern Mid-Atlantic	1.19334	1.12889	1.06445	1.0000	0.93555	0.87111	0.80666
Central Mid-Atlantic	1.14728	1.09819	1.04909	1.0000	0.95091	0.90181	0.85272
Western Mid-Atlantic	1.09282	1.06188	1.03094	1.0000	0.96906	0.93812	0.90718
PJM West	1.11599	1.07733	1.03866	1.0000	0.96134	0.92267	0.88401
PJM South	1.11132	1.07421	1.03711	1.0000	0.96289	0.92579	0.88868
Probability	0.0062	0.0606	0.2417	0.383	0.2417	0.0606	0.0062

- **Behind the Meter Generation (BTMG) Modeling:**

Behind the Meter Generation is not explicitly modeled in this study. The impact of Behind the Meter Generation is reflected in a lower load forecast (see Table B-8 in the 2018 PJM Load Forecast Report).

Demand Response Modeling

In GE-MARS, Demand Response Resources were modeled as an emergency operating procedure triggered whenever the reserves in each of the 5 regions fall below a certain threshold (the sum of the threshold in the 5 PJM regions is 3,400 MW). Once DR is called, it reduces the load on a 1-to-1 MW basis. Note that in 2020 there are two types of DR products: one available in the period June-September and another available all year long. This difference in availability is reflected in the GE-MARS runs. In 2022, all the DR is available all year long.

Capacity Modeling –Generation Forecasting

- **Generation Forecast Modeling consistent with 2018 NERC LTRA**

The generation units modeled in the 2018 Probabilistic Assessment are consistent with the data submitted to the 2018 NERC LTRA. This applies to both, existing and future units. Performance statistics considered for each of the generation units include: forced outage rates (EFORd and EEFORd), modeling of generating units' ambient deratings and planned maintenance requirements.

The GE-MARS model uses a forced outages (EEFORd) table (UNT-FORS) and a "number of transitions" table (NUM-TRNS) to develop the transition state matrices required by GE-MARS. All units' planned maintenance outages (PO) are directly inputted using the MNT-UNOP table. GE-MARS schedules the PO events to levelize reserves over the calendar year.

- **Fleet-based Performance by Primary Fuel Category**

The PJM RTO fleet of units for Summer and Winter 2020/22 is summarized by primary fuel in Table II – 8 and Figure II – 3. Seasonal ratings are as per information submitted by generation owners to PJM's Reliability Pricing Model (RPM). Outage rates and planned outages (for all units except wind and solar) are based on 5-year (2013-17) GADS data. (PJM class average data was used to cover data gaps for units installed in the last 5 years.) Wind and solar units are assigned a forced outage rate of 0 and a capacity credit factor computed based on generating output on peak hours (hours ending 3, 4, 5, and 6 PM Local Prevailing Time) during the past 3 summer periods (for more information see PJM Manual 21). The currently effective class average capacity credit factors are 13% for wind and 38% for solar of their nameplate capacity.

- **Generating Unit Additions / Retirements**

As mentioned earlier in the document, future units that fall under the Planned – Tier 1 in the 2018 NERC LTRA were added to the Probabilistic Assessment case at full output (in other words, their MW output was not adjusted by a commercial probability). Retirements modeled in the 2018 Probabilistic Assessment are consistent with the data reported in the 2018 NERC LTRA. Table II – 9 provides a summary of the generator additions and retirements modeled for this study.

Table II - 8: PJM RTO Fleet-based Unit Performance by Primary Fuel Category in 2020 and 2022

	Summer 2020		Winter 2020		Summer 2022		Winter 2022	
		Forced Outage		Forced Outage		Forced Outage		Forced Outage
	Total MW	Rates %	Total MW	Rates %	Total MW	Rates %	Total MW	Rates %
Coal	54,597	9.36%	54,976	9.42%	54,620	9.12%	54,460	9.11%
Petroleum	12,431	15.14%	12,443	15.15%	12,296	15.14%	12,328	15.14%
Gas	81,235	6.54%	76,829	6.62%	83,550	6.50%	83,541	6.50%
Nuclear	32,560	1.62%	32,560	1.62%	32,560	1.62%	32,560	1.62%
Other	20	12.07%	20	12.07%	20	12.07%	20	12.07%
Hydro	3,145	8.40%	3,123	8.35%	3,145	8.40%	3,145	8.40%
Pumped Storage	5,229	3.44%	5,229	3.44%	5,229	3.44%	5,229	3.44%
Geothermal	0	0.00%	0	0.00%	0	0.00%	0	0.00%
Biomass	1,336	13.41%	1,343	13.41%	1,336	13.41%	1,343	13.41%
Wind	1,739	0.00%	1,327	0.00%	1,845	0.00%	3,717	0.00%
Solar	1,431	0.00%	0	0.00%	1,659	0.00%	0	0.00%
TOTAL	**193,724**	**8.24%**	**187,850**	**7.08%**	**196,261**	**8.11%**	**196,343**	**6.83%**

Figure II - 3: PJM RTO Capacity by Fuel Type in Summer 2020 and Summer 2022

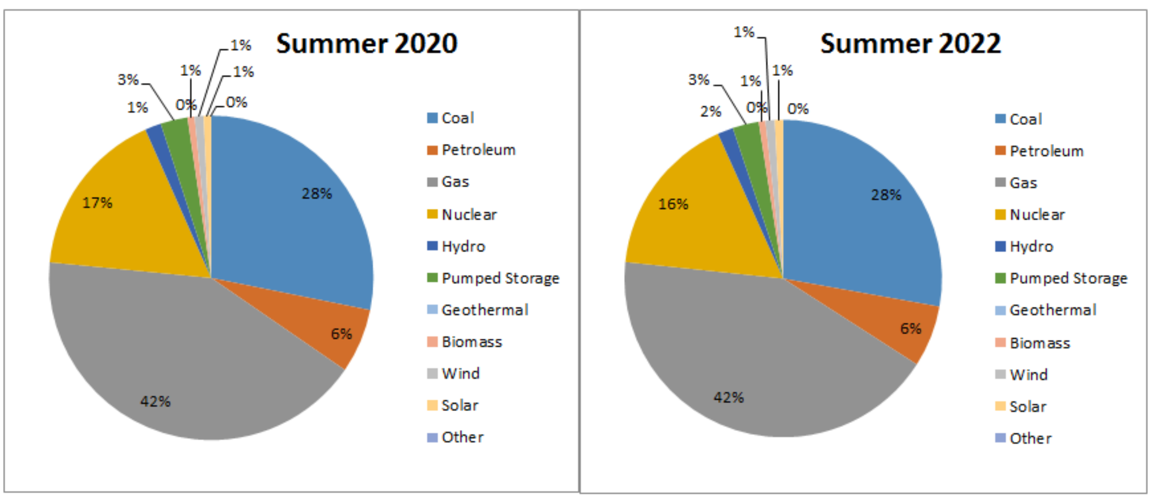


Table II - 9: New Expected and Retiring Generation within PJM RTO

	MW
Installed Capacity - July 2019	**181,013**
Expected Additions Before July 2020	14,785
Announced Retirements Before July 2020	-2,074
Expected Installed Capacity - July 2020	**193,724**
Expected Additions Between July 2020 - July 2022	3,370
Announced Retirements Before July 2022	-833
Expected Installed Capacity - July 2022	**196,261**

Transmission System Considerations

- **Transmission Additions and Retirements**

  The GE-MARS modeling and analysis is consistent with the 2017 RTEP Report which is the basis for the 2018 LTRA submission.

  GE-MARS uses a transportation model to simulate the flows between regions. The transfer limits between the 5 PJM sub-regions in the GE-MARS model are as in Figure II – 4. These limits represent simultaneous short-term emergency ratings and were calculated based on a First Contingency Total Transfer Capability (FCTTC) analysis. No transmission outages were considered in the analysis.

- **Simultaneous Import capabilities – Transfer Limits**

  The simultaneous import limit capabilities in the GE-MARS transportation model are determined between each external area and PJM. However, not all of this import capability is fully reserved for reliability purposes. In PJM's Installed Reserved Margin study, the portion of total import capability that is reserved for reliability purposes is only 3,500 MW. This restriction is not modeled in the Probabilistic Assessment study (in other words, in the Probabilistic Assessment, all of PJM's import capability can be used to reduce LOLH or EUE).

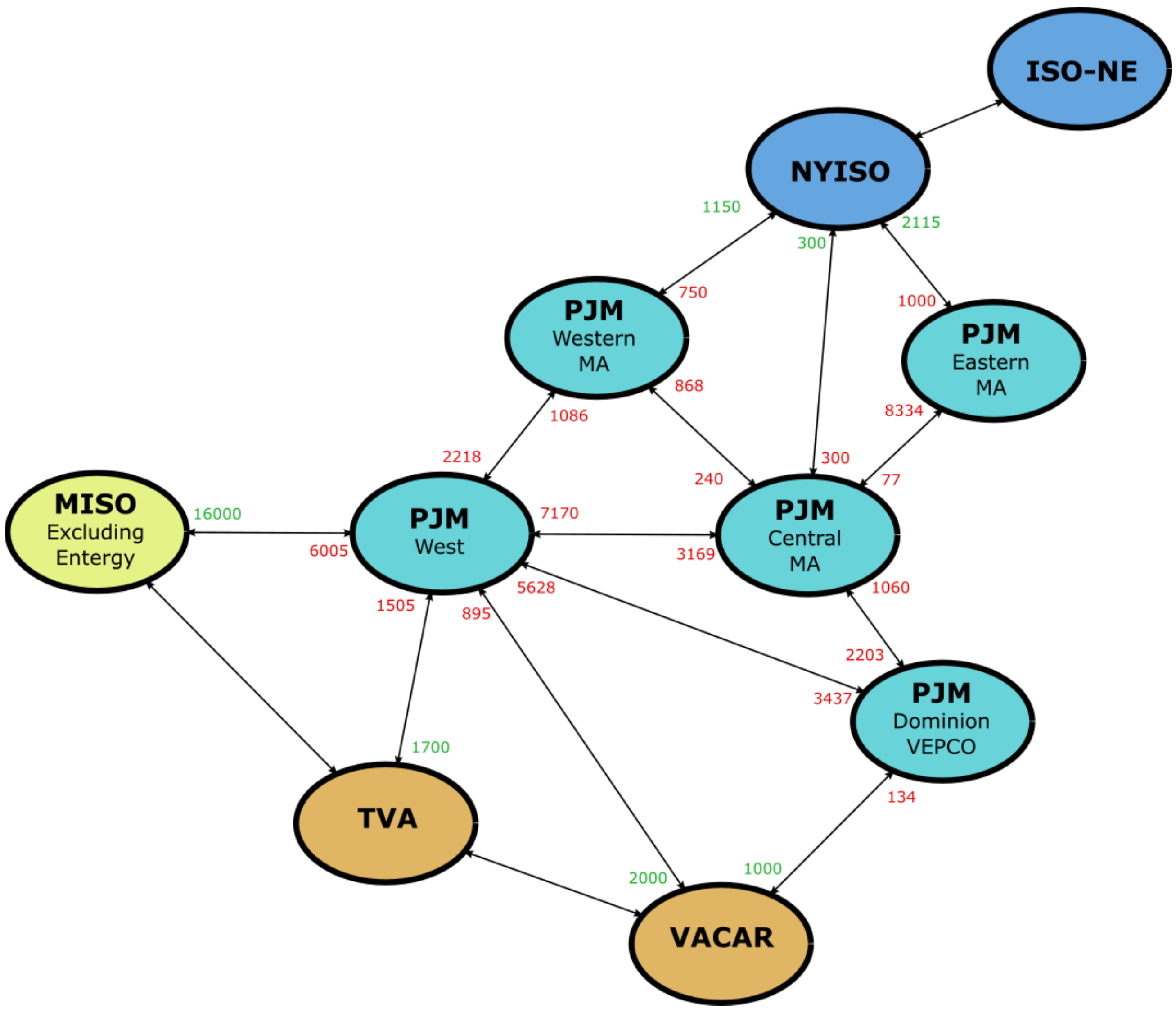
  As with the internal transfer limits, the external transfer limits were computed using a FCTTC analysis and represent simultaneous short-term emergency ratings. No transmission outages were considered.

  The reliability calculations (LOLH, EUE) are performed on an area basis, for each load level specified, at each EOP level on an hourly basis. If an area needs assistance to avoid an LOLE state before invoking the EOPs, assistance is considered from the other areas in the model.

- **Deliverability of internal and external resources**

  All internal generators modeled in this study have demonstrated to be deliverable. See PJM Manual 14b for details on deliverability tests. External capacity resources are modeled via contracts if they clear in the PJM capacity market (this assumption was relaxed for Summer 2022 because capacity market auctions have not yet been run for the 2022 delivery year; the amount of external resources assumed for delivery year 2022 was identical to the amount cleared in the 2021 delivery year). To clear in the PJM capacity market, external generators need to meet the following requirements:
    - Firm Transmission service to the PJM border
    - Firm ATC reservation into PJM
    - Letter of non-recallability from the native control zone

Figure II - 4: PJM RTO Transfer Limits



Assistance from and coordination with External Resources

- **PJM's Outside World – Reserve levels**

MISO, TVA and VACAR were modeled at the reserve target required to satisfy the 1 in 10 criterion. NYISO and ISO-NE, on the other hand, were modeled assuming the system "as-is" (as per the 2018 NPCC NERC Probabilistic Assessment case). PJM class average statistics were applied to the units created in the MISO, TVA and VACAR areas.

Load forecast information for the MISO area was obtained from MISO's 2018 LOLE Study Report while for TVA and VACAR load forecast information was gathered from the 2017 NERC ES&D Report.

- **Load Diversity**

The load diversity between PJM and the outside World is captured by using the Summer 2002/Winter 2004 Load Shape for all internal and external regions.

- **GE-MARS' Dispatch of Outside World Assistance**

The table INF-TRLM in GE-MARS is used to input interface transfer limits. Assistance from outside regions to PJM in an emergency situation depends upon the limits of the interface ties and the availability of generation in the outside world at the time of the emergency. Similarly, assistance from PJM to an outside region undergoing an emergency depends upon the tie limits and the availability of PJM resources at the time of the emergency.

- **Contracts Impacting World Assistance**

Contracts are scheduled over the interfaces. Firm contracts are scheduled regardless of whether or not the sending area has sufficient resources on an isolated basis (to avoid loss of load), but they can be curtailed because of interface transfer limits. Firm contracts are scheduled first, in the order in which they appear in the FCT-DATA table. When a contract is scheduled, the limits on these interfaces and related interface groups are adjusted accordingly. The contracts scheduled between PJM RTO and neighboring regions for this study are shown in Table II – 10.

Table II - 10: Contracts

From Pool	To Pool	Winter 2020 (MW)	Summer 2020 (MW)	Winter 2022 (MW)	Summer 2022 (MW)
PJM	NY	1,013	1,012	1,013	1,012
PJM	MISO	899	900	900	900
NY	PJM	197	197	197	197
PJM	TVA	109	109	109	109
MISO	PJM	2,152	2,399	2,399	2,399
TVA	PJM	580	593	593	593
VACAR	PJM	435	419	419	419

Definition of Loss-of-Load Event

For all PJM RTO Adequacy assessments, the emergency operations procedure that defines a loss of load event is the invocation of a voltage drop. As shown in Table II – 11, this is after invoking EOP step 2. Table II – 11 also shows the rest of the EOPs considered in this study as well as the MWs available when implementing each one of them.

For consistency in performing interregional study efforts, the reported metrics in Table I – 1 and Table I – 2 are after invoking EOP step 5.

Table II - 11: Emergency Operations Procedures during Summer 2020 and Summer 2022

	EOP	Unit	Amount (MW)
	Operating Reserves	MW	3,400
1	Curtail Load / Utility Surplus	MW	7,675 (2020); 7,721 (2022)
2	No 30-min Reserves	MW	2,765
3	Voltage Reduction	MW	2,201
4	No 10-min Reserves	MW	635
5	Appeals / Curtailments	MW	400

Part III – Appendices

Appendix A
Peak Demand and Capacity Resource Calculations

	2020	2022
ENERGY	**Annual**	**Annual**
Net Energy for Load - Annual (GWh)	808,638	812,908

	2020		2022	
DEMAND	**Winter**	**Summer**	**Winter**	**Summer**
Total Internal Demand				
Expected Demand (50/50)	132,039	151,962	133,117	152,887
Low Forecast Cummulative Probability	10%	10%	10%	10%
Low Forecast Demand	124305	139311	125591	139261
High Forecast Cummulative Probability	90%	90%	90%	90%
High Forecast Demand	138268	163546	139396	164662
Other Demand Factors	**0**	**1,825**	**0**	**2,450**
Energy Efficiency and Conservation				
Behind the Meter Generation				
Distributed Generation	0	1,825	0	2,450
Standby Load Under Contract				
Controllable and Dispatchable Demand Response	**1,582**	**15,350**	**13,754**	**15,442**
Total	791	7,675	6,877	7,721
Available	791	7,675	6,877	7,721
Net Internal Demand	**131,248**	**144,287**	**126,240**	**145,166**

	2020		2022	
CAPACITY	**Winter**	**Summer**	**Winter**	**Summer**
Capacity Installed (Nameplate)	**213,786**	**219,209**	**223,519**	**223,539**
Coal	59,542	58,886	60,351	60,351
Petroleum	14,085	14,105	13,965	13,965
Gas	85,778	90,639	92,126	92,126
Nuclear	33,139	33,139	33,139	33,139
Hydro	3,088	3,110	3,110	3,110
Pumped Storage	5,062	5,062	5,062	5,062
Geothermal				
Biomass	1,688	1,688	1,688	1,688
Wind	8,693	9,765	10,508	10,508
Solar	2,691	2,794	3,549	3,569
Other	20	20	20	20
Unknown				

Capacity Expected On-Peak (Existing Certain + Tier 1)	187,850	193,724	196,343	196,261
Coal	54,976	54,597	54,460	54,620
Petroleum	12,443	12,431	12,328	12,296
Gas	76,829	81,235	83,541	83,550
Nuclear	32,560	32,560	32,560	32,560
Hydro	3,123	3,145	3,145	3,145
Pumped Storage	5,229	5,229	5,229	5,229
Geothermal	0	0	0	0
Biomass	1,343	1,336	1,343	1,336
Wind	1,327	1,739	3,717	1,845
Solar	0	1,431	0	1,659
Other	20	20	20	20
Unknown	0	0	0	0

Capacity Adjustments On-Peak	0	2500	0	2500
Scheduled Outages	0	0	0	0
Transmission Limitations	0	0	0	0
Other	0	0	0	0
Weighted Average Forced Outage Rate On-Peak				
Coal	9.4%	9.4%	9.1%	9.1%
Petroleum	15.1%	15.1%	15.1%	15.1%
Gas	6.6%	6.5%	6.5%	6.5%
Nuclear	1.6%	1.6%	1.6%	1.6%
Hydro	8.4%	8.4%	8.4%	8.4%
Pumped Storage	3.4%	3.4%	3.4%	3.4%
Geothermal	0.0%	0.0%	0.0%	0.0%
Biomass	13.4%	13.4%	13.4%	13.4%
Wind	0.0%	0.0%	0.0%	0.0%
Solar	0.0%	0.0%	0.0%	0.0%
Other	12.1%	12.1%	12.1%	12.1%
Unknown	0.0%	0.0%	0.0%	0.0%
Operable Capacity Resources	174550	177765	182931	180339

	2020		2022	
CAPACITY TRANSFERS	Winter	Summer	Winter	Summer
Imports				
Firm	3411	3411	3167	0
Expected	0	0	0	3411
Exports				
Firm	1683	1683	1682	0
Expected	0		0	1683

	2020		2022	
CAPACITY OBLIGATIONS & OPERATING PROCEDURES	Winter	Summer	Winter	Summer
Other Obligations from Resources	3400	3400	3400	3400
Non-Spinning Reserves	2765	2765	2765	2765
Spinning Reserves	635	635	635	635
Other Obligations				
Operating Procedures (Before Loss-of-Load)	6001	6001	6001	6001
Additional Demand Response	0	0	0	0
Non-Spinning Reserves (Forgone)	2765	2765	2765	2765
Spinning Reserves (Forgone)	635	635	635	635
Other Obligations (Forgone)	0	0	0	0
Interruptible Load	0	0	0	0
Voltage Reductions	2201	2201	2201	2201
Public Appeals	400	400	400	400
Other	0	0	0	0

Base Case	2020	2022
PROBABILISTIC STATISTICS	Annual	Annual
Expected Unsupplied Energy (EUE) (MWh)	0.000000	0.000000
Loss of Load Hours (LOLH) (hours/year)	0.000000	0.000000

	2020	2022
SUMMARY TABLE	Annual	Annual
Net Energy for Load (GWh)	808638	812908
Total Internal Demand (MW)	151962	152887
90th Percentile (% above 50/50 forecast)	+ 8%	+ 8%
Net Internal Demand (MW)	144287	145166
Forecast Capacity Resources (MW)	192952	193761
Forecast Operable Capacity Resources (MW)	176993	177839
Expected Unsupplied Energy (EUE) (MWh)	0.000	0.000
Expected Unsupplied Energy (EUE) (ppm)	0.000	0.000
Loss of Load Hours (LOLH) (hours/year)	0.000	0.000
Forecast Planning Reserve Margin (%)	33.7%	33.5%
Forecast Operable Reserve Margin (%)	22.7%	22.5%

Sensitivity Case	2022 (1/3)	2022 (2/3)
PROBABILISTIC STATISTICS	Annual	Annual
Expected Unsupplied Energy (EUE) (MWh)	338.4	0.000000
Loss of Load Hours (LOLH) (hours/year)	0.1	0.000000

	2022 (1/3)	2022 (2/3)
SUMMARY TABLE	Annual	Annual
Net Energy for Load (GWh)	965355	881213
Total Internal Demand (MW)	182031	166130
90th Percentile (% above 50/50 forecast)	+ 8%	+ 8%
Net Internal Demand (MW)	174310	158409
Forecast Capacity Resources (MW)	193761	193761
Forecast Operable Capacity Resources (MW)	177839	177839
Expected Unsupplied Energy (EUE) (MWh)	338.397	0.000
Expected Unsupplied Energy (EUE) (ppm)	0.351	0.000
Loss of Load Hours (LOLH) (hours/year)	0.146	0.000
Forecast Planning Reserve Margin (%)	11.2%	22.3%
Forecast Operable Reserve Margin (%)	2.0%	12.3%