



# RRS Education Session #2

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- Capacity Model refers to
  - Developing an Available Capacity probabilistic distribution (or conversely, an Outages probabilistic distribution)
  - Developing a deterministic schedule of Planned Outages
  - Modeling ambient derations
- Inputs to develop the Available Capacity distribution: Units' Forced Outage Rates (EEFORd), Units' Installed Capacity Values (in MW)
  - Installed Capacity Values are based on 50/50 weather
- Inputs to develop the Planned Outages schedule: Units' Equivalent Planned Outage Factors (EPOF, in weeks)

- Units included in the Capacity Model
  - Internal units eligible to bid in RPM (not necessarily committed for a future year)
  - External units that have long term contracts (for entirety of study period)
  - Future units that are currently in the interconnection queue. Their ICAP value gets adjusted as follows,  
$$\text{Adjusted ICAP} = \text{ICAP} \times \text{Commercial Probability}$$
  - No DR or EE are included.

- **EEFORd: Effective Equivalent Forced Outage Rate (Demand)**

$$\text{EEFORd} = \text{EFORd} + (0.25 \times \text{EMOF})$$

EFORd: portion of time that a generating unit is in demand, but is unavailable due to a forced outage. It also includes forced outage derations.

EMOF: Equivalent Maintenance Outage Factor. One-quarter of this factor is added to the EFORd to account for unplanned maintenance outages that occur in summer.

- **EPOF: Equivalent Planned Outage Factors.** It is measured in weeks/year and includes planned derations.

- Source of data to compute these indices for each unit
  - eGADS: PJM's web-based Generator Availability Data System based on NERC GADS data reporting requirements
  - Indices are reviewed by Generator Owner prior to every RRS
- Historical period used to compute these indices for each unit
  - Most recent 5 year period
  - This period is believed to provide enough hours of data and to be an acceptable representation of future performance of units.
  - For future units, PJM class averages are used
  - For units without 60 months of data, actual data and class average data are combined to derive the indices.



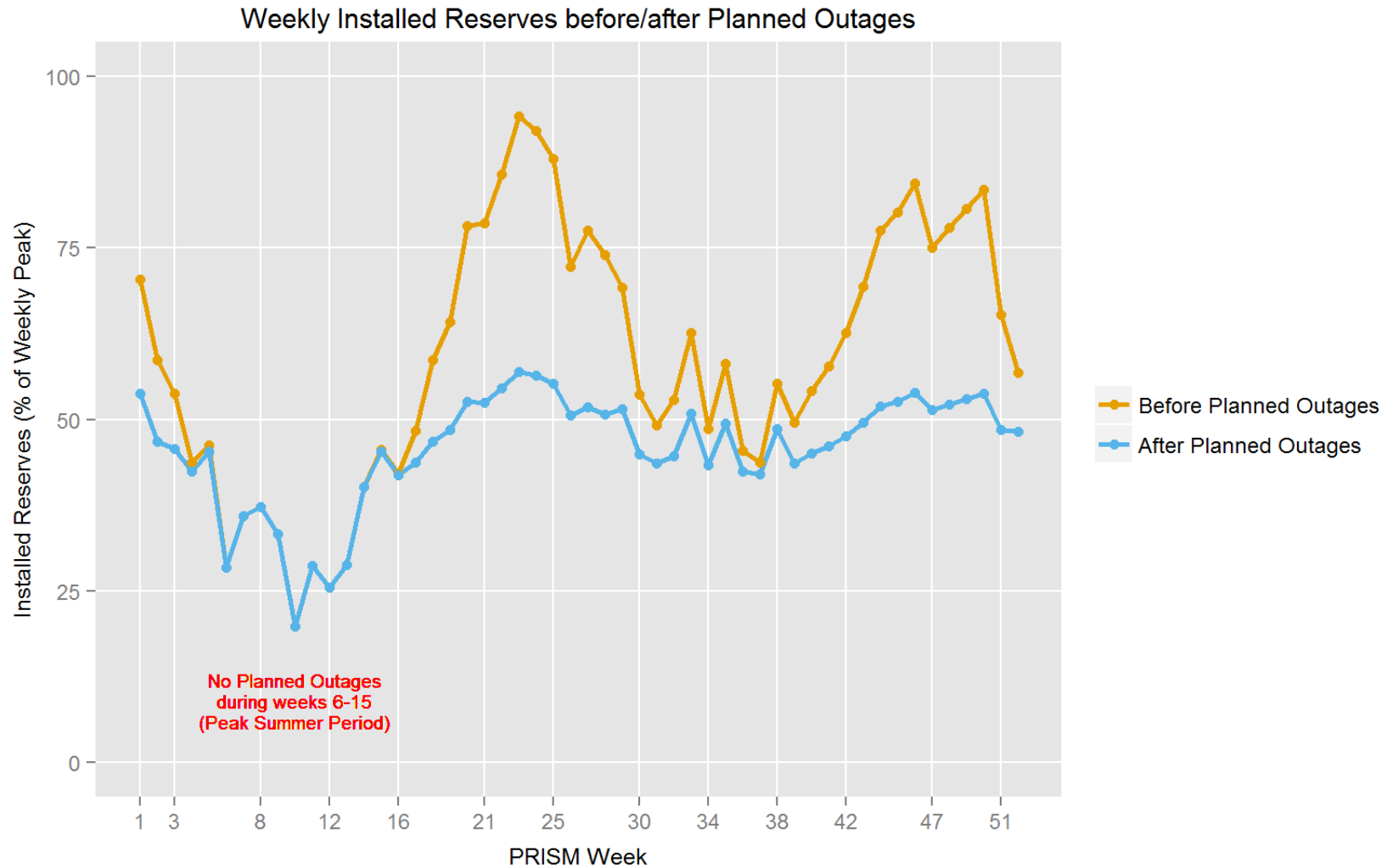
## • Class Averages

Unit Type & Primary Fuel Category	Gen Class Key	POF Weeks/Year	EFORd	EEFORd	XEFORd	EMOF
FOSSIL All Fuel Types All Sizes	1	4	11.99%	12.83%	11.25%	2
FOSSIL All Fuel Types 001-099	2	3	12.71%	13.36%	12.14%	2
FOSSIL All Fuel Types 100-199	3	3	12.71%	13.36%	12.14%	2
FOSSIL All Fuel Types 200-299	4	5	11.56%	12.65%	10.48%	2
FOSSIL All Fuel Types 300-399	5	5	11.56%	12.65%	10.48%	2
FOSSIL All Fuel Types 400-599	6	5	11.56%	12.65%	10.48%	2
FOSSIL All Fuel Types 600-799	7	5	11.56%	12.65%	10.48%	2
FOSSIL All Fuel Types 800-999	8	5	8.33%	9.25%	8.18%	2
FOSSIL All Fuel Types 1000 Plus	9	5	8.33%	9.25%	8.18%	2
FOSSIL Coal Primary All Sizes	10	4	11.99%	12.83%	11.25%	2
FOSSIL Coal Primary 001-099	11	3	12.71%	13.36%	12.14%	2
FOSSIL Coal Primary 100-199	12	3	12.71%	13.36%	12.14%	2
FOSSIL Coal Primary 200-299	13	5	11.56%	12.65%	10.48%	2
FOSSIL Coal Primary 300-399	14	5	11.56%	12.65%	10.48%	2
FOSSIL Coal Primary 400-599	15	5	11.56%	12.65%	10.48%	2
FOSSIL Coal Primary 600-799	16	5	11.56%	12.65%	10.48%	2
FOSSIL Coal Primary 800-999	17	5	8.33%	9.25%	8.18%	2
FOSSIL Coal Primary 1000 Plus	18	5	8.33%	9.25%	8.18%	2
FOSSIL Oil Primary All Sizes	19	4	11.99%	12.83%	11.25%	2
FOSSIL Oil Primary 001-099	20	3	12.71%	13.36%	12.14%	2
FOSSIL Oil Primary 100-199	21	3	12.71%	13.36%	12.14%	2
FOSSIL Oil Primary 200-299	22	5	11.56%	12.65%	10.48%	2
FOSSIL Oil Primary 300-399	23	5	11.56%	12.65%	10.48%	2
FOSSIL Oil Primary 400-599	24	5	11.56%	12.65%	10.48%	2
FOSSIL Oil Primary 600-799	25	5	11.56%	12.65%	10.48%	2
FOSSIL Oil Primary 800-999	26	5	8.33%	9.25%	8.18%	2
FOSSIL Gas Primary All Sizes	28	4	11.99%	12.83%	11.25%	2
FOSSIL Gas Primary 001-099	29	3	12.71%	13.36%	12.14%	2
FOSSIL Gas Primary 100-199	30	3	12.71%	13.36%	12.14%	2
FOSSIL Gas Primary 200-299	31	5	11.56%	12.65%	10.48%	2
FOSSIL Gas Primary 300-399	32	5	11.56%	12.65%	10.48%	2
FOSSIL Gas Primary 400-599	33	5	11.56%	12.65%	10.48%	2
FOSSIL Gas Primary 600-799	34	5	11.56%	12.65%	10.48%	2
FOSSIL Gas Primary 800-999	35	5	8.33%	9.25%	8.18%	2
FOSSIL Lignite Primary All Sizes	37	4	11.99%	12.83%	11.25%	2

Unit Type & Primary Fuel Category	Gen Class Key	POF Weeks/Year	EFORd	EEFORd	XEFORd	EMOF
NUCLEAR All Types	38	3	1.99%	2.18%	1.67%	0
NUCLEAR All Types	39	3	1.99%	2.18%	1.67%	0
NUCLEAR All Types	40	3	1.99%	2.18%	1.67%	0
NUCLEAR All Types	41	3	1.99%	2.18%	1.67%	0
NUCLEAR PWR All Sizes	42	3	1.99%	2.18%	1.67%	0
NUCLEAR PWR 400-799	43	3	1.99%	2.18%	1.67%	0
NUCLEAR PWR 800-999	44	3	1.99%	2.18%	1.67%	0
NUCLEAR PWR 1000 Plus	45	3	1.99%	2.18%	1.67%	0
NUCLEAR BWR All Sizes	46	3	1.99%	2.18%	1.67%	0
NUCLEAR BWR 400-799	47	3	1.99%	2.18%	1.67%	0
NUCLEAR BWR 800-999	48	3	1.99%	2.18%	1.67%	0
NUCLEAR BWR 1000 Plus	49	3	1.99%	2.18%	1.67%	0
NUCLEAR CANDU All Sizes	50	3	1.99%	2.18%	1.67%	0
JET ENGINE All Sizes	51	1	13.31%	13.70%	11.07%	1
JET ENGINE 001-019	52	1	16.07%	16.48%	14.88%	1
JET ENGINE 20 Plus	53	1	15.12%	15.55%	11.68%	1
GAS TURBINE All Sizes	54	1	13.31%	13.70%	11.07%	1
GAS TURBINE 001-019	55	1	16.07%	16.48%	14.88%	1
GAS TURBINE 020-049	56	1	15.12%	15.55%	11.68%	1
GAS TURBINE 50 Plus	57	2	10.22%	10.56%	8.16%	1
COMBINED CYCLE All Sizes	58	4	4.98%	5.52%	4.58%	1
HYDRO All Sizes	59	2	11.21%	10.93%	9.45%	2
HYDRO 001-029	60	2	11.21%	10.93%	9.45%	2
HYDRO 30 Plus	61	2	11.21%	10.93%	9.45%	2
PUMPED STORAGE All Sizes	62	5	2.33%	2.64%	1.75%	1
MULTIBOILER/MULTI-TURBINE All Sizes	63	4	11.99%	12.83%	11.25%	2
DIESEL Landfill	64	0	16.98%	16.42%	16.23%	1
DIESEL All Sizes	65	0	7.06%	7.63%	6.13%	2
FOSSIL Oil/Gas Primary All Sizes	66	4	11.99%	12.83%	11.25%	2
FOSSIL Oil/Gas Primary 001-099	67	3	12.71%	13.36%	12.14%	2
FOSSIL Oil/Gas Primary 100-199	68	3	12.71%	13.36%	12.14%	2
FOSSIL Oil/Gas Primary 200-299	69	5	11.56%	12.65%	10.48%	2
FOSSIL Oil/Gas Primary 300-399	70	5	11.56%	12.65%	10.48%	2
FOSSIL Oil/Gas Primary 400-599	71	5	11.56%	12.65%	10.48%	2
FOSSIL Oil/Gas Primary 600-799	72	5	11.56%	12.65%	10.48%	2
FOSSIL Oil/Gas Primary 800-999	73	5	8.33%	9.25%	8.18%	2
Wind All sizes	74	0	0.00%	0.00%	0.00%	0
Solar All sizes	75	0	0.00%	0.00%	0.00%	0

- Objective in the development of the schedule
  - Levelizing weekly reserves (in PRISM and MARS)
- Each unit has a EPOF in weeks/year
  - Current weighted average EPOF: ~4 weeks/year
- The “levelizing reserves” objective places more planned outages in weeks that have larger reserves (in PJM’s case, outside of summer period)

# Input #2: Capacity Model – Planned Outages Schedule





- The availability of each unit is assumed to have an independent Bernoulli distribution
  - Prob (Unit Online) =  $1 - \text{EEFORd}$
  - Prob (Unit Offline) =  $\text{EEFORd}$
- The Available Capacity Distribution is calculated for each week by summing the Bernoulli Distributions of the units not on planned outage during the week under consideration
- Sum of Bernoulli Distributions is performed via convolution

# Input #2: Capacity Model – Available Capacity Distribution

- If on a given week only a single 100 MW unit with EEFORd = 0.05 (Unit 1) is not on planned outage, the available capacity distribution is as follows,

Unit 1	Total Available Capacity	Prob
On	100	0.95
Off	0	0.05

- If in addition to Unit 1, there is a Unit 2 (ICAP = 80 MW, EEFORd = 0.07) also not on planned outage, then the available capacity distribution is as follows

Unit 1	Unit 2	Total Available Capacity	Prob
On	On	180	0.8835
Off	On	80	0.0465
On	Off	100	0.0665
Off	Off	0	0.0035

- If in addition to Units 1 and 2, there is a Unit 3 (ICAP = 200 MW, EEFORd = 0.1)

Unit 1	Unit 2	Unit 3	Total Available Capacity	Prob
On	On	On	380	0.79515
Off	On	On	280	0.04185
On	Off	On	300	0.05985
Off	Off	On	200	0.00315
On	On	Off	180	0.08835
Off	On	Off	80	0.00465
On	Off	Off	100	0.00665
Off	Off	Off	0	0.00035

**Key concept:**

**Prob (Event A and Event B) = Prob (Event A) \* Prob (Event B)**  
**If Event A and Event B are independent of each other**

- The tables in the previous slide correspond to PDFs of Available Capacity Distributions. From the PDFs, we can construct CDFs

PDF: probability density function;  $P(X = x)$

CDF: cumulative distribution function;  $P(X \leq x)$

Unit 1	Total Available Capacity	Prob
On	100	0.95
Off	0	0.05



Total Available Capacity	CDF
100	1.0000
0	0.0500

Unit 1	Unit 2	Total Available Capacity	Prob
On	On	180	0.8835
Off	On	80	0.0465
On	Off	100	0.0665
Off	Off	0	0.0035



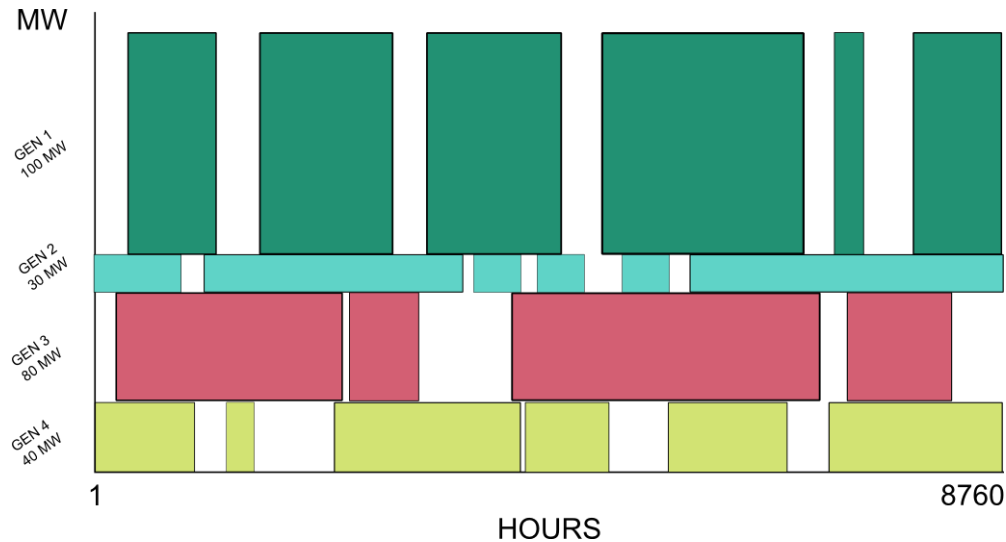
Total Available Capacity	CDF
180	1.0000
100	0.1165
80	0.0500
0	0.0035

Unit 1	Unit 2	Unit 3	Total Available Capacity	Prob
On	On	On	380	0.79515
Off	On	On	280	0.04185
On	Off	On	300	0.05985
Off	Off	On	200	0.00315
On	On	Off	180	0.08835
Off	On	Off	80	0.00465
On	Off	Off	100	0.00665
Off	Off	Off	0	0.00035

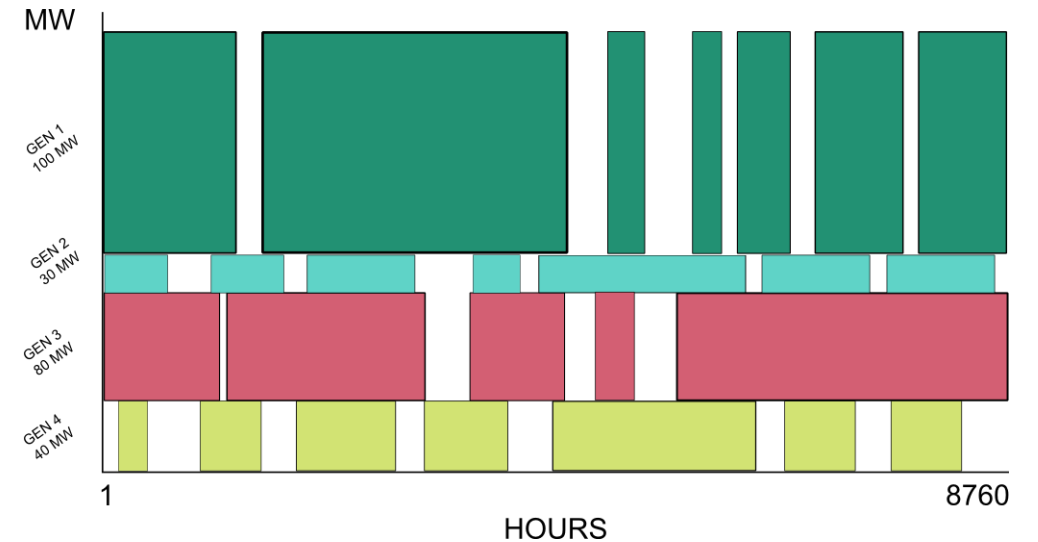


Total Available Capacity	CDF
380	1.0000
300	0.2049
280	0.1450
200	0.1032
180	0.1000
100	0.0117
80	0.0050
0	0.0004

- In MARS, via drawing random numbers (Monte Carlo)



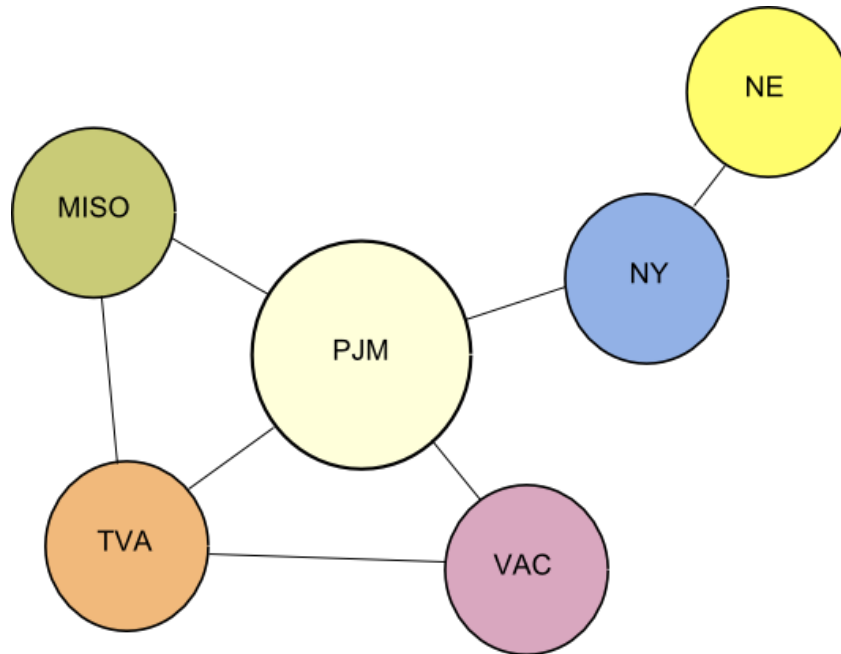
**Replication 1**



**Replication N**

- Rationale
  - Hot and humid summer conditions (above 50/50) limits MW output from certain types of generators
  - Units can operate at this reduced output without incurring a GADS outage event (event is not included in EFORd value)
- MW Impact
  - It has been assumed for several years that the amount of ambient derations throughout the PJM footprint is 2,500 MW
- Modeling in RRS
  - 2,500 MW are assumed to be on planned outage during the peak summer period (10 weeks)

- PJM and its neighbors



Though ISO-NE is not a direct neighbor, PJM includes ISO-NE in the World due to the emergency assistance they have provided in the past.

- PRISM allows for modeling only two regions.
- Due to this limitation, the neighboring regions are condensed into a single region: the World.
- As with PJM, the World requires a load model and a capacity model
- To develop the load model,
  - Historical daily peak loads of the 5 World regions are pooled together
  - World LMs are derived for the time-periods shortlisted in the Load Model Selection Procedure
  - PJM-World Load Diversity check is performed. A time-period is selected

- In GE-MARS,
  - An hourly load shape (8760 loads) needs to be input for each of the regions comprising the World.
    - Ideally, the load shape should be such that it represents a typical year
    - Other ISOs consider a set of “typical years” weighting them non-equally
  - In addition to the hourly load shape, 12 normal distributions (the monthly Load Forecast Uncertainty) must be input for each World member region



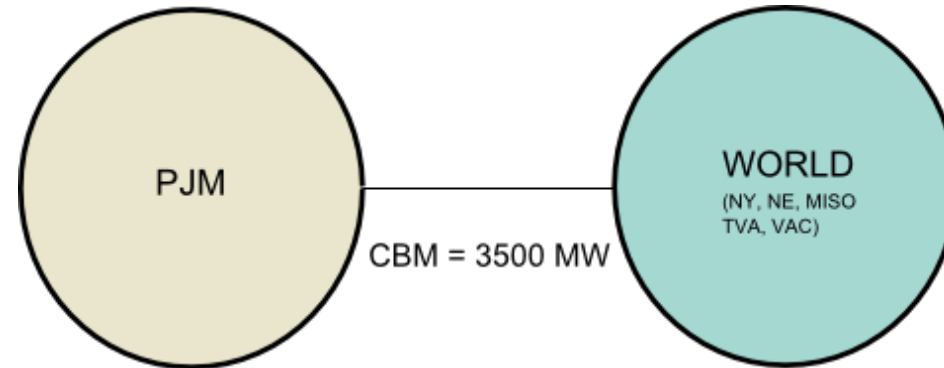
- To develop the capacity model,
  - We need to pool the generation resources of the 5 neighboring regions
  - But first, how many of these resources does each region include?
    - We look at each region's most recent IRM (if they have one) and forecasted annual peaks.
    - If a region does not have an IRM (TVA, VACAR), we use a soft target of 15%
    - We apply the IRM to the forecasted annual peaks and then subtract the amount of forecasted DR for each region
    - DR forecasted values are obtained from NERC's ES and D data submitted by the regions
    - The same IRM adjusted by the forecasted amount of DR of each region is used throughout the entire RRS study period
    - The idea here is to have a generation-only RRS case for the World. Similar to what we have for PJM

- After we have the amounts of generation to be modeled in each of the 5 regions for every year of the RRS study period
  - We develop a list of units based on form EIA-860 so that the generation target amount for each region is met
  - We determine a PJM class average for each of the units and assign PJM class average statistics to each unit.
- We then pool all the resources
  - Available capacity distribution and Planned Outage schedule are derived in an identical manner as PJM's
  - No ambient deration is considered for World units
- We are ready to run the RRS case

- Before we run the case, however, we perform a calculation to determine the valid range of possible IRM values for the World
  - This valid range will have in one extreme the IRM with DR excluded, while in the other extreme the IRM with DR included
- We do this, because when we solve the RRS case, both PJM and the World will be forced to meet the 1 in 10 criterion.
  - And we want to make sure that the resulting World IRM is within the valid range.
  - This also provides information regarding the amount of World DR that is impacting the “help” that PJM is receiving from the World.

- Valid Range Calculation
  - Using the NCPs of the regions and a diversity factor computed from historical data, we derive a CP value for the entire World.
  - Using the IRMs and NCPs of the respective regions, we compute a total amount of capacity resources available for the entire World.
  - Using the forecasted DR value for the regions, we compute a total amount of DR for the entire World.
    - Valid Range lower bound =  $(\text{Total Capacity World}) / (\text{CP World})$
    - Valid Range upper bound =  $(\text{Total Capacity World}) / (\text{CP World} - \text{DR World})$
  - In the 2015 RRS, Valid Range was [13.23%, 18.81%]

- Capacity Benefit Margin (CBM)



CBM is the limit on the amount of power that can be transferred between PJM and the World and vice-versa in a two-area RRS case.

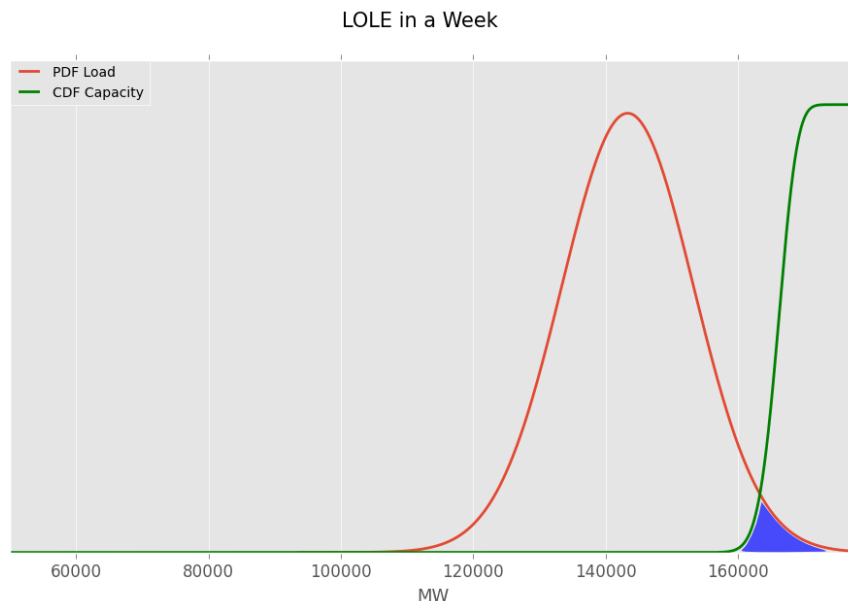
The CBM value of 3,500 MW is specified in the PJM Reliability Assurance Agreement (RAA), Schedule 4. PJM's additional importing capability is used in the marketplace.

- If  $X$  = Available Capacity Distribution at week  $t$
- and  $Y$  = Load Distribution at week  $t$
- Then a **Loss of Load Event** (LOLE) takes place when  $X < Y$ 
  - LOLE is defined when the margin is 0 MW or less (Margin =  $X - Y$ )
- The IRM is computed as
  - » IRM = Total Installed Capacity / Solved Annual Peak Load

when the Solved Annual Peak Load is such that

$$\text{Total LOLE} = \sum_{w=1}^{52} E(X < Y) = 0.1 \text{ days/year}$$

- Let's start with the Single Area RRS Case.



For each week, we need to compute the probability that load exceeds available capacity  $P(X < Y)$  (blue area in the figure).

The expected value of load exceeding available capacity in a week is then given by,

$$E(X < Y) = 5 \times 1 \times P(X < Y)$$

- 1 is because we are computing expected value
- 5 is because we have a daily peak load distribution aggregated by week (and there are 5 weekdays in a week)

- Mathematically,

Scenario	Load	Probability
4.2	185057	0.000033
3.78	180881	0.000145
3.36	176705	0.000638
2.94	172529	0.002351
2.52	168353	0.007273
2.1	164178	0.01894
1.68	160002	0.0414
1.26	155826	0.07608
0.84	151650	0.11749
0.42	147474	0.15248
0	143298	0.16634
-0.42	139122	0.15248
-0.84	134946	0.11749
-1.26	130770	0.07608
-1.68	126594	0.0414
-2.1	122418	0.01894
-2.52	118242	0.007273
-2.94	114066	0.002351
-3.36	109890	0.000638
-3.78	105714	0.000145
-4.2	101538	0.000033

PDF Load:  
 Mean = 143298  
 StDev = 9943

CDF Capacity  
 (in increments  
 of 10 MW)

Total Available Capacity	Cumulative Prob
178000	1.000
177000	1.000
176000	1.000
175000	1.000
174000	1.000
172520	1.000
173000	1.000
172000	0.999
171000	0.993
170000	0.971
168350	0.856
169000	0.916
168000	0.816
167000	0.670
166000	0.500
164170	0.222
165000	0.336
164000	0.202
163000	0.109
162000	0.053
161000	0.023
160000	0.009
159000	0.003
158000	0.001

$E(X < Y)$ :

$$\begin{aligned}
 185057 &\rightarrow 5 \times 1 \times 0.000033 \times 1.000 = 0.000165 \\
 180881 &\rightarrow 5 \times 1 \times 0.000145 \times 1.000 = 0.000725 \\
 176705 &\rightarrow 5 \times 1 \times 0.000638 \times 1.000 = 0.00319 \\
 172529 &\rightarrow 5 \times 1 \times 0.002351 \times 1.000 = 0.011755 \\
 168353 &\rightarrow 5 \times 1 \times 0.007273 \times 0.856 = 0.031128 \\
 164178 &\rightarrow 5 \times 1 \times 0.01894 \times 0.222 = 0.021023 \\
 160002 &\rightarrow 5 \times 1 \times 0.0414 \times 0.009 = 0.001863 \\
 155826 &\rightarrow 5 \times 1 \times 0.07608 \times \sim 0 = 0 \\
 \dots\dots\dots \\
 101538 &\rightarrow 5 \times 0 \times 0.000033 \times 0 = 0
 \end{aligned}$$

TOTAL = 0.069849 days/year



- We repeat the procedure shown in the previous slide for the remaining 51 weeks
- When we have that the Expected LOLE across the 52 weeks is equal to 0.1 days/year, we calculate
  - $\text{Single Area IRM} = \text{Total Installed Capacity} / \text{Solved Annual Peak Load}$
- The Single Area IRM is used to compute the CBOT
- The Two-Area IRM is the IRM that gets all the attention

- Two-Area IRM (or simply, IRM)
  - Theory is similar to LOLE computation in Single Area Case
  - However, we now need to include the help from the World
  - The Two-Area LOLE in a week is calculated as,

$$E(X < Y) = 5 \times 1 \times [ P(X < Y) - P(\text{Help from World}) ]$$

with  $P(\text{Help from World}) = P(\text{PJM needing } N \text{ MWs}) \times P(\text{World able to supply } N \text{ MWs within the CBM constraint})$

- Identical computations are performed to calculate the World LOLE

- Single Area RRS Case

	Year	ALM Sub Num	Run	Iteration	Area	Load Level	Week Num	Primary Load	Install Cap	Install Pct	Avail Pct	Tie Size	RI
First run	2019	.	1	1 1		0	10	150283	182530	21.457517	19.800643	3500	30.323166
Final run	2019	.	20	1 1		0	10	154464	182530	18.16993	16.557903	3500	9.9931317

Single Area IRM = 18.16993 ~ 18.2

- Two Area RRS Case

	Year	ALM Sub Num	Run	Iteration	Area	Load Level	Week Num	Primary Load	Install Cap	Install Pct	Avail Pct	Tie Size	RI
First run PJM	2019	.	1	1 1		0	10	150283	182530	21.457517	19.800643	3500	30.512648
First run World	2019	.	1	1 2		0	12	245919	279090	13.488588	13.488588	3500	2.299218
Final run PJM	2019	.	9	2 1		0	10	156731.61	182530	16.459985	14.871282	3500	9.996217
Final run World	2019	.	9	2 2		0	12	237704.46	279090	17.410696	17.410696	3500	9.9964503

Two Area IRM = 16.459985 ~ 16.5

RI: Reliability Index

$$RI = 1/LOLE$$

We always round the IRM to the first decimal point

$$\begin{aligned} \text{Capacity Benefit of Ties (CBOT)} &= \\ \text{Single Area IRM} - \text{Two Area IRM} &= \\ 18.2 - 16.5 &= 1.7 \end{aligned}$$

- From the IRM to the FPR
  - FPR is used to develop the Reliability Requirement in RPM
  - FPR is computed as
    - »  $FPR = IRM \times (1 - \text{Pool Avg XEFORd})$
  - To derive the Pool Avg XEFORd, we compute a capacity-weighted average XEFORd with the units in the RRS case for the year under study
  - $FPR = (1 + 16.5\%) \times (1 - 6.6\%) = 1.165 \times 0.934 = 1.0881$  (8.81%)

- Impacts of CP, if any, will be on the Capacity Model
  - Not on Load Model or World
- Capacity Model has 3 dimensions
  - Available Capacity probabilistic distribution
  - Planned Outages schedule
  - Ambient Derations

- Available Capacity probabilistic distribution
  - The implementation of CP could trigger a decrease in the forced outages (EFORd) of units
    - This decrease in EFORd could, in turn, result in a lower IRM
    - The impact on the FPR though will still be negligible
- Planned Outages schedule
  - The implementation of CP could trigger a decrease in planned outages of units
    - Since no planned outages are scheduled during summer, this decrease will have no impact on the IRM/FPR

- Ambient Derations
  - Currently (before CP), generators do not account for ambient derations in their MW bid (UCAP value), since their MW bid is based on GADS data, and ambient derations do not get recorded in GADS
  - The implementation of CP could prod generators to lower their MW bid to account for ambient derations during summer peak conditions (to avoid penalties)

- **Ambient Derations**

- However, we believe generators will not perform such an adjustment to their RPM bids since in most cases their UCAP value already “covers” their ambient deration MW risk.
  - For example, a 100 MW generator has an EFORd of 5%. Their MW bid value in RPM is likely to be  $100 \times (1 - 0.05) = 95$  MW
  - Its MW ambient deration is highly likely to be less than the MW reduction due to EFORd. In other words, Ambient Deration will be anywhere between 1MW and 5 MW.
  - Therefore, the generator will bid 95 MW in RPM which will be enough to cover the ambient deration risk
  - In the RRS, the unit will be assumed to be producing 100 MW 95% of the time and 0 MW 5 % of the time
  - Due to ambient derations though, instead of a 100 MW, the unit will be producing 97 MW or 98 MW. Thus, we still need to account for ambient derations in the RRS.