Capacity Performance Action Items

Updated as of September 12, 2014

Action Items numbers correspond with details in the Action Item spreadsheet posted on the Enhanced Liaison Committee - Capacity Performance page:

http://pjm.com/committees-and-groups/committees/elc.aspx.

Please send questions to CapacityPerformance@pjm.com

COMPLETED: Action Item #1

Were the coal units that were off on January 7 back on for the winter storm?

Here is the breakdown for the coal units that were on forced outage on 1/7/14 1900 that returned to service for at least 6 hours in January.

NOTE THAT THE PIE CHART FROM THE CAPACITY PRESENTATION (SLIDE 6) SHOWS 13,700 MW of coal due to rounding.

Coal on Forced Outage on 1/7/14 19:00	**13768**	**209**
Units Returned from FO on 1/7/14 1900	**Sum of MW**	**Count of Return to Service**
N	789	32
Y	12979	177

COMPLETED: Action Item #2

For the gas interruption outages, what percent were called outside of their DA awards?

Of the 9,848 lack of fuel outages (1/7/14 hour ending 19); 8,503 were not committed day ahead or 86%

3,490 or 41% of the 8,503 were offered into the DA based on the must offer rule.

COMPLETED: Action Item #3
Please add percentage on slide 6 for January 24 and 28

- 40200 MW/.22 (Forced Outage Rate on 1/7/14 @ 1900) = Approximately 183,000 MW of capacity
  - Jan 24 FO = 29,100/183,000 = 15.9%
  - Jan 28 FO = 23,800/183,000 = 13.0%

COMPLETED: Action Item # 4

- On January 7th, 2014 1900 HRs
  - 3,865 MW of forced outages were due to units with announced retirement dates

ADDITIONAL REQUEST IN PROGRESS #7: Action Item # 5 and 7

- On January 7th, 2014 1900 HRs
  - 40,170 MW of capacity was on forced outage
  - 30 MW of non-capacity was on forced outage

Note there was 2,060 MW attributed to ambient air - proportioned by Capacity and Non-Capacity forced outages on 1/7/14 @ 1900

On 1/7/14 @ 1900
38,111 Capacity on FO
29 MW Non-Capacity on FO
38,111 + 29 = 38,140 which doesn't equal 40,200.

The remaining 2,060 MW was attributed to "Ambient Air" tickets - proportioned
Capacity FO w/ Ambient Air Distribution = 38,111 + 2060 * (38,111/38,140) = 40,170 MW
Non-Capacity FO w/ Ambient Air Distribution = 29 + 2060 * (29/38,140) = 30 MW

COMPLETED: Action Item # 6

- On January 7th, 2014 1900 HRs
- For confidentiality purposes, TO zones were grouped into East, Central, South, West regions. The % Forced Outage by region was calculated as follows
  - % of TO Generation on Forced Outage = Total FO MW in TO Zone/Total MW in TO Zone
  - Each TO Zone was grouped into a region. The % of TO Generation on Forced Outage for each TO Zone in each region was averaged together to get the Average Percentage of Forced Outage Generation by Region.

COMPLETED: Action Item #6

Was generator location important to outage numbers? For instance, a particular LDA or behind a certain LDC?

Forced Outage Rate – January 7, 2014 HE 1900 by zone (some aggregation)

Geographic Region	Average Percentage of Generation on Forced Outage by Region
East: AE, DPL, JC, ME, PE, PL, PS	25%
Central: DUQU, FE-S, PN	24%
South: BC, DOM, PEP	16%
West: AEP, COMED, DAY, DEOK, EKPC, FE-W	22%

IN PROGRESS: Action Item #8

Slide 6 - are these chronically curtailed units that were on forced outage during January? Or, is it related to specific pipeline issues.

Data from Slide #6:

On January 7th, 2014 1900 HRs

- 3,865 MW of forced outages were due to units with announced retirement dates

COMPLETED FOR #9 and #10:

Action Item #9

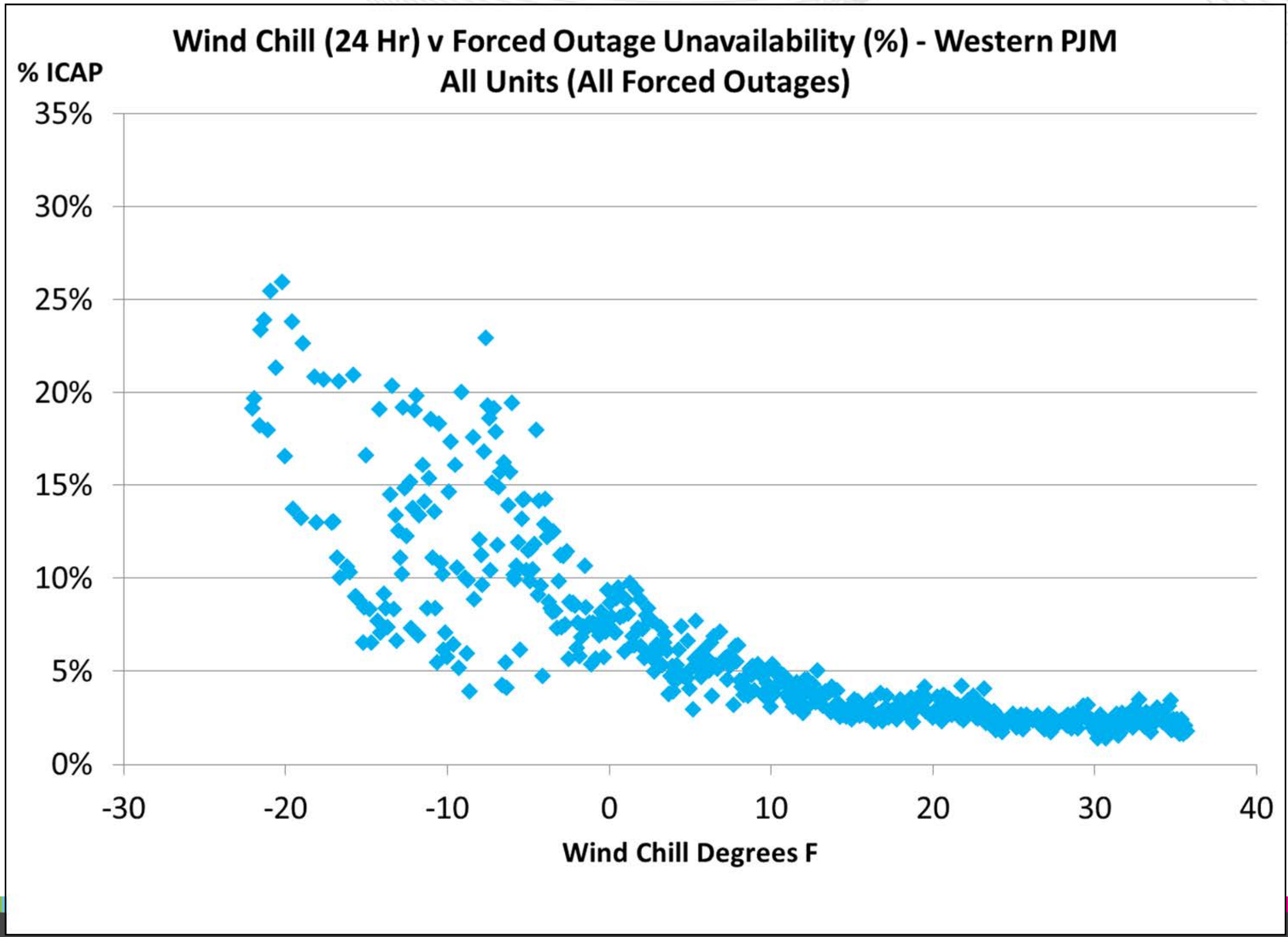
Please provide more data on outages compared to temperatures. With respect to extreme temperature (i.e. is this driven by fuel unavailability or mechanical issues, or other?) Question #4,5, 7

Action Item #10

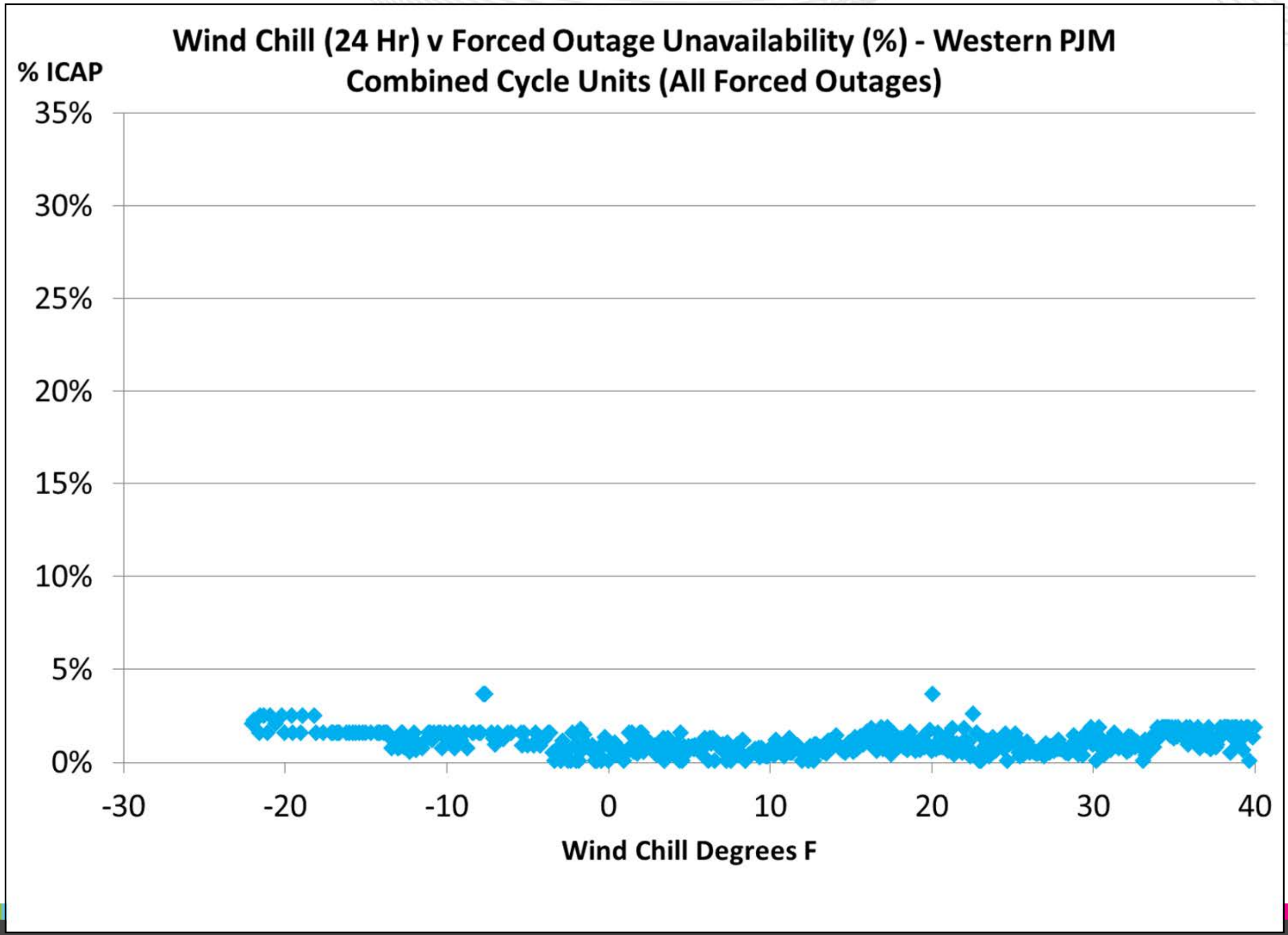
Can we see wind chill and outage by primary mover?

Please see the next few slides for graphs for Question #9 and 10

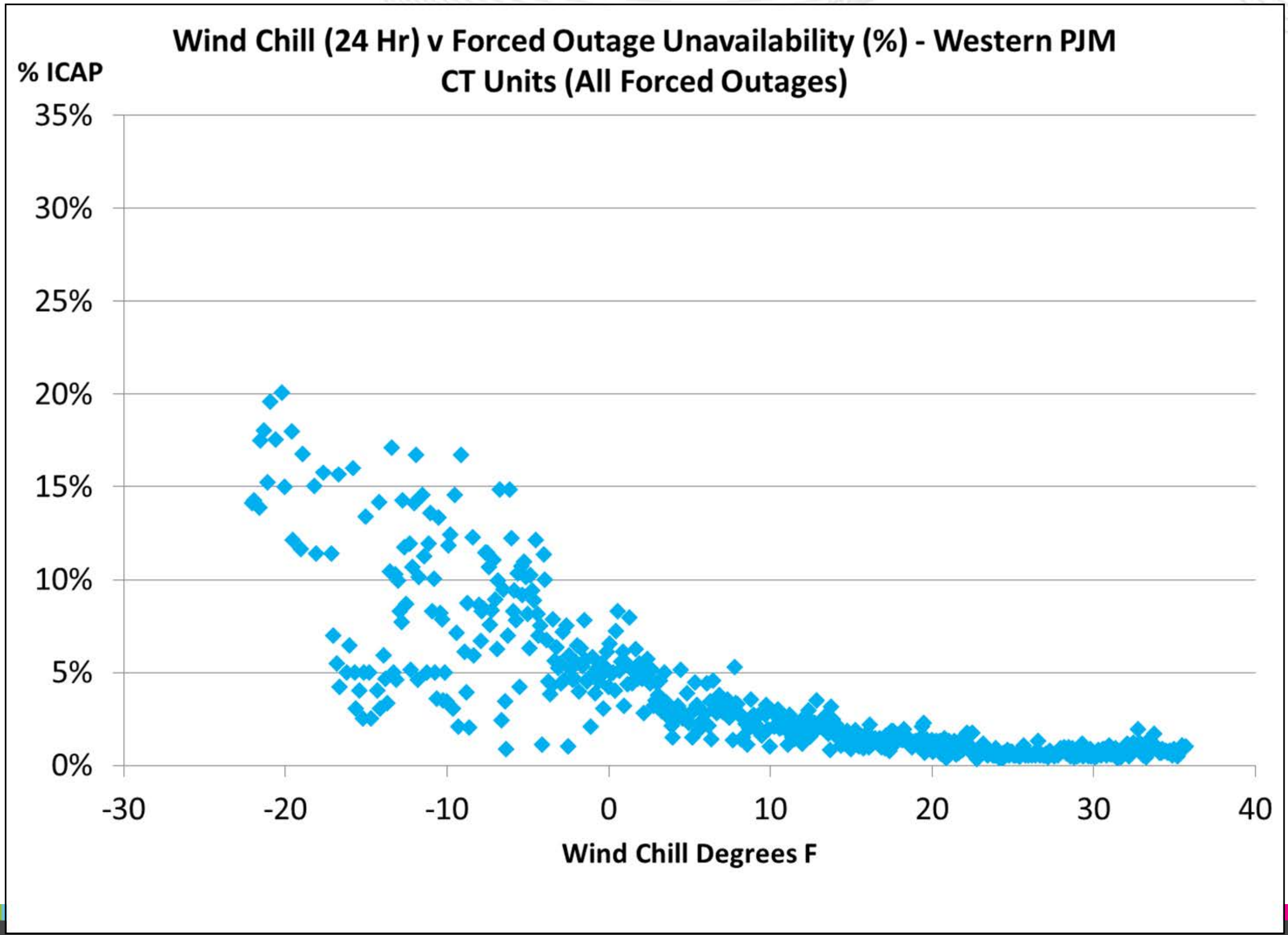
COMPLETED: Question #9 and #10



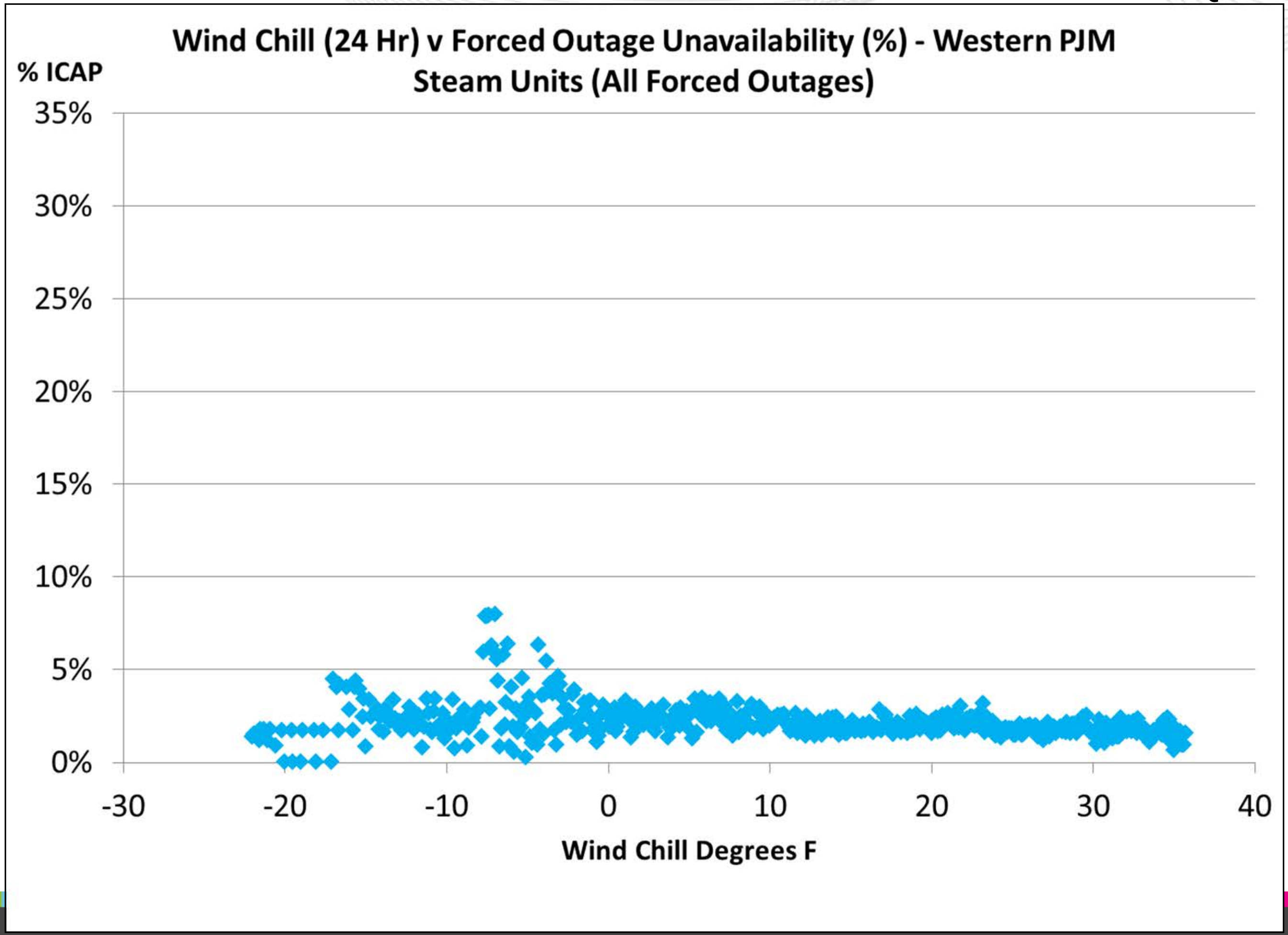
COMPLETED: Question #9 and #10



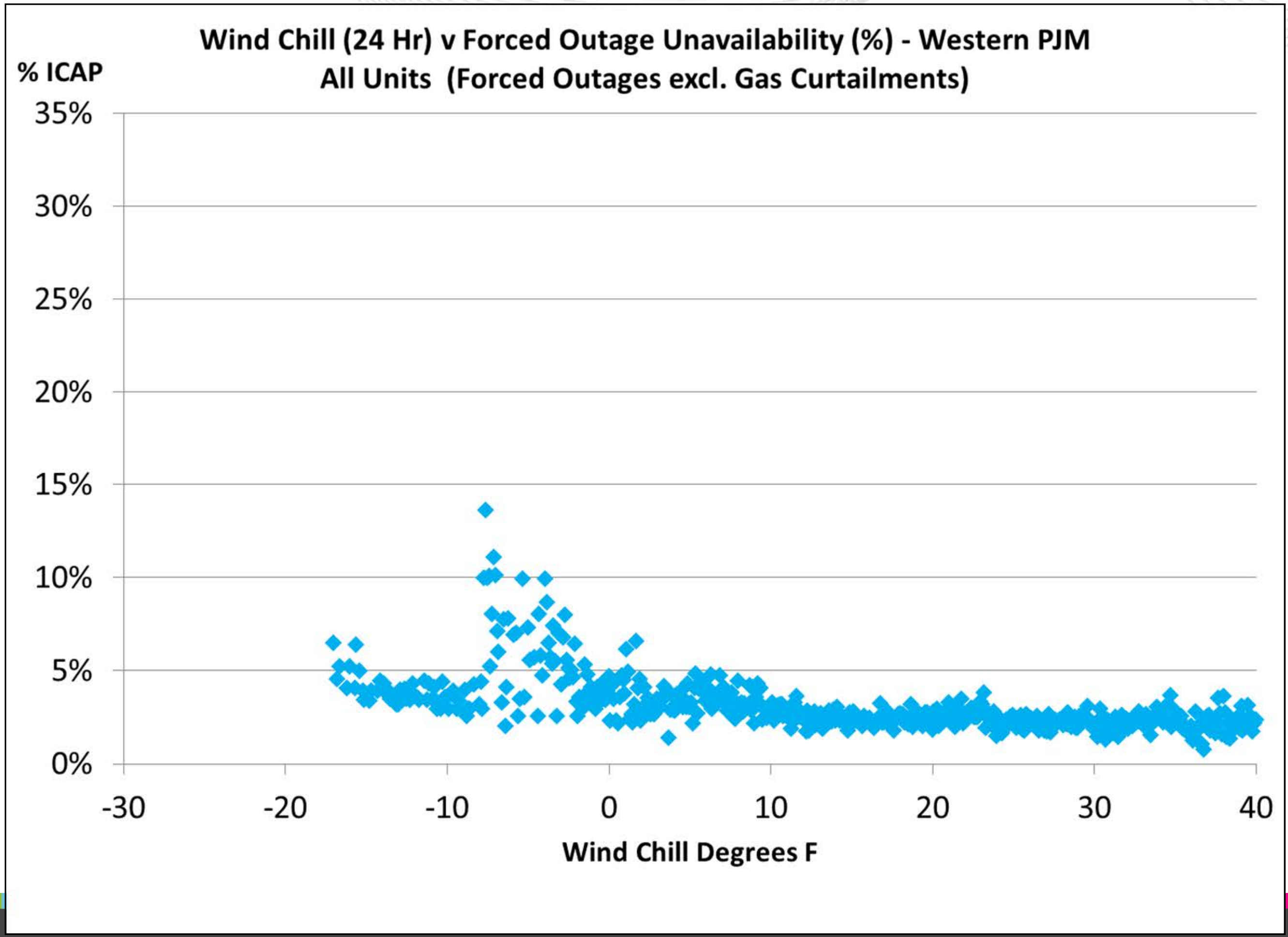
COMPLETED: Question #9 and #10



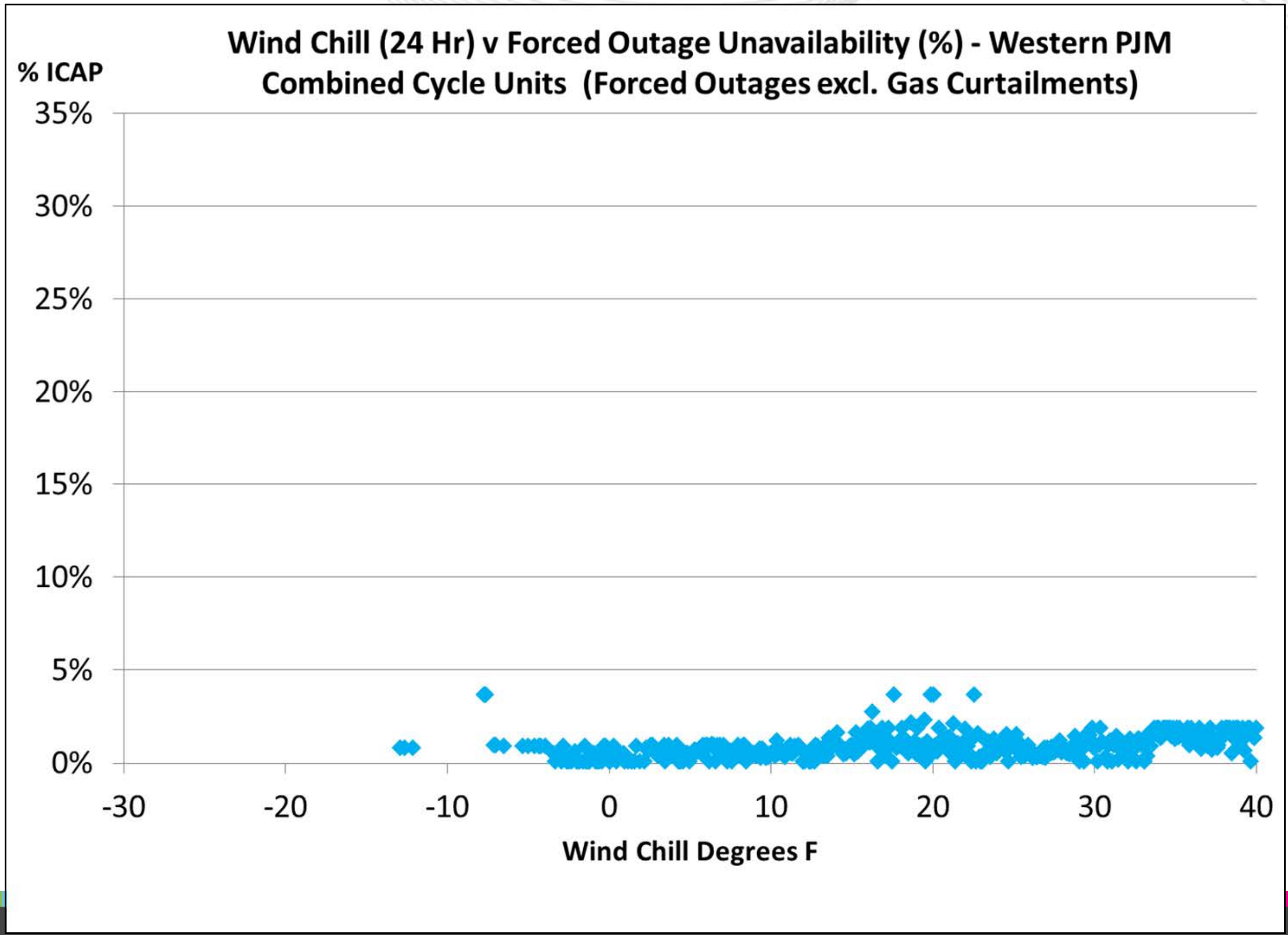
COMPLETED: Question #9 and #10



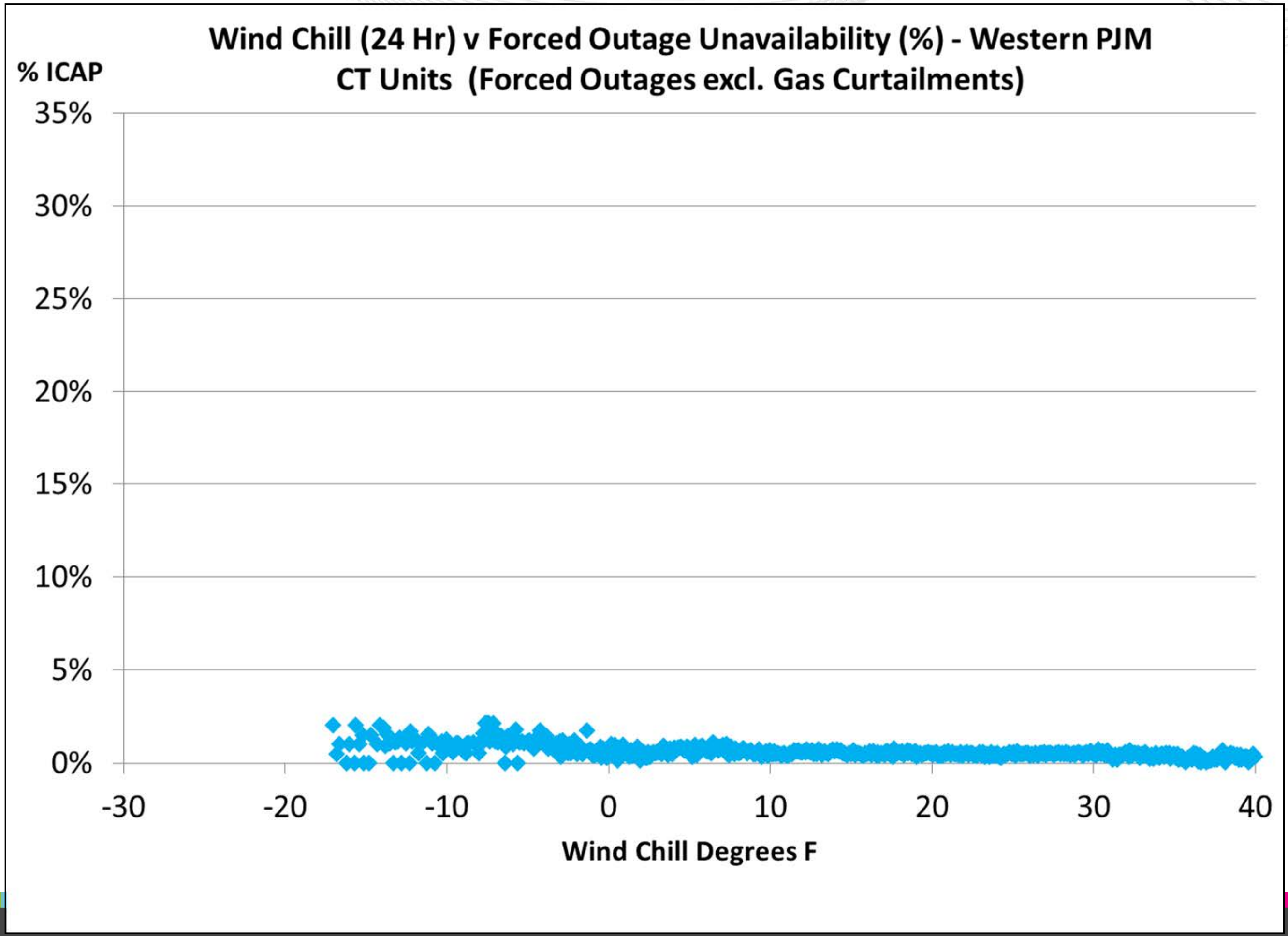
COMPLETED: Question #9 and #10



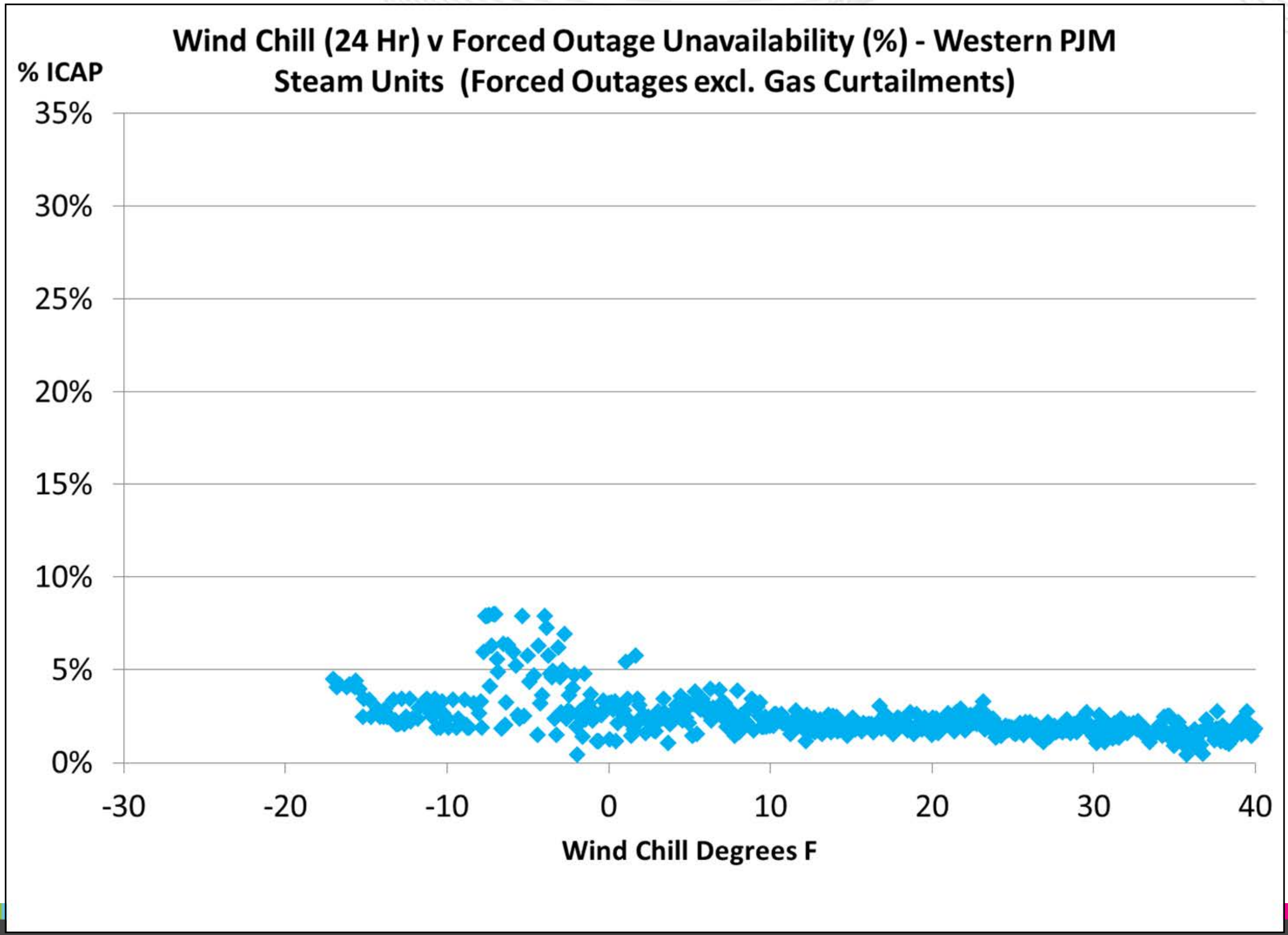
COMPLETED: Question #9 and #10



COMPLETED: Question #9 and #10



COMPLETED: Question #9 and #10



CONSIDERED FOR FURTHER DOCUMENTATION/DISCUSSION: Action Item #11
What does it take to improve physical performance at colder temps and what is the associated capital cost?

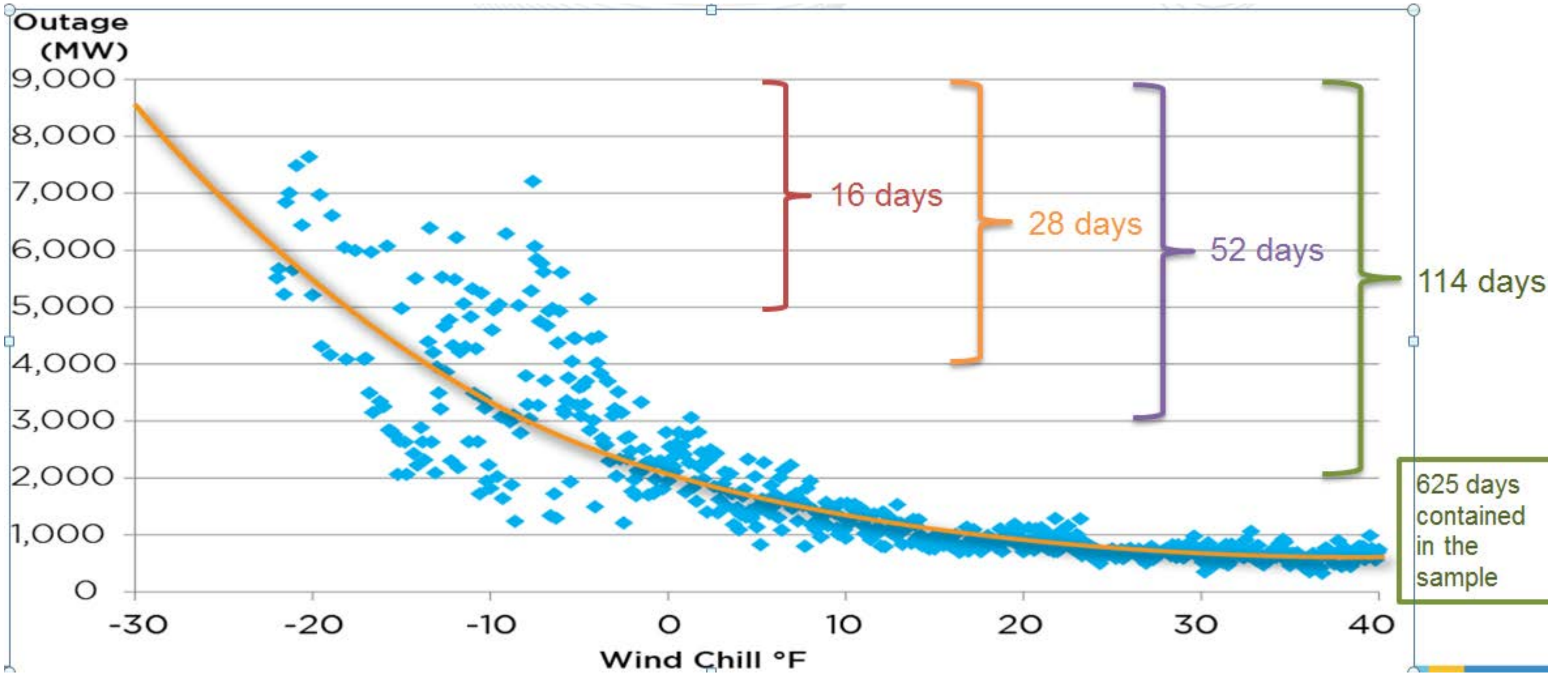
IN PROGRESS: Action Item #12

Is outage performance at cold temperatures better when the market incentives exist or was in demand during the time?

IN PROGRESS: Action Item #13

Is the generator performance also worse in hotter weather? (bathtub curve)

Is the wind chill and outage graph showing bad performance on just a few days? Can you show the cluster of days?

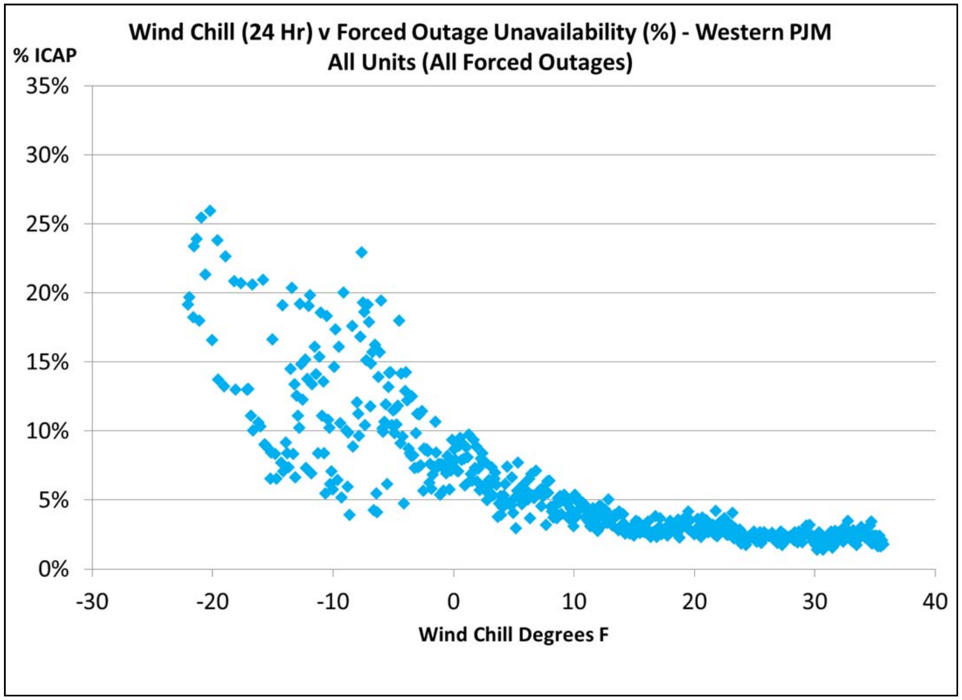


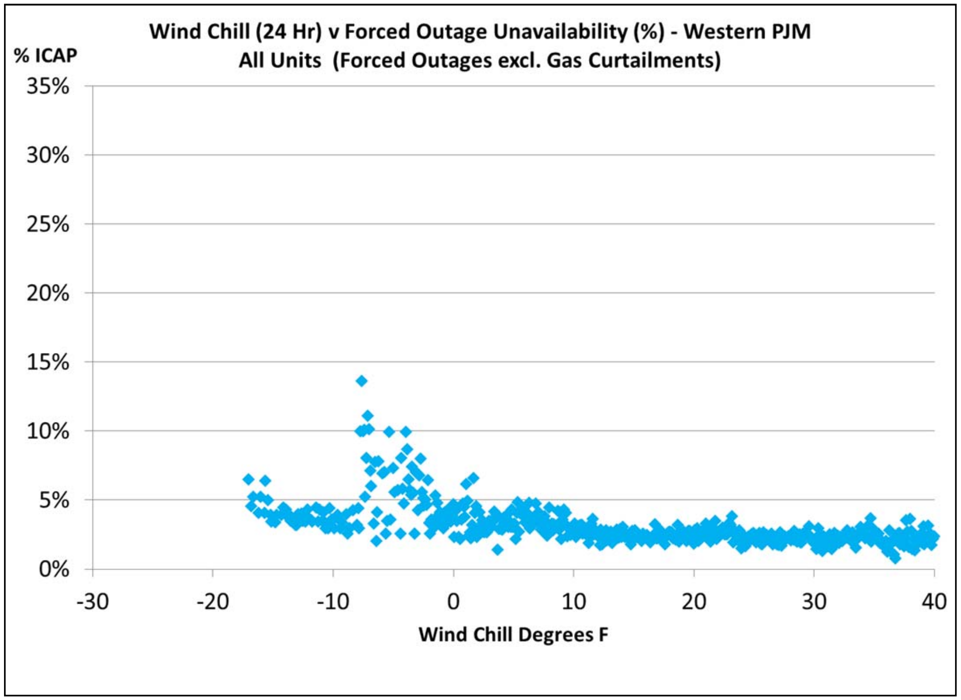
CONSIDERED FOR FURTHER DOCUMENTATION/DISCUSSION: Action Item #15 Part II report, please add more verbiage about the wind chill and forced outage chart?

COMPLETED: Action Item #16

Do we have similar information for other zones? Can we see the wind chill and forced outage charts?

Wind Chill v Forced Outage Unavailability (%) – Western PJM
Comparison of All Forced Outages and Forced Outages Excluding Gas Curtailments

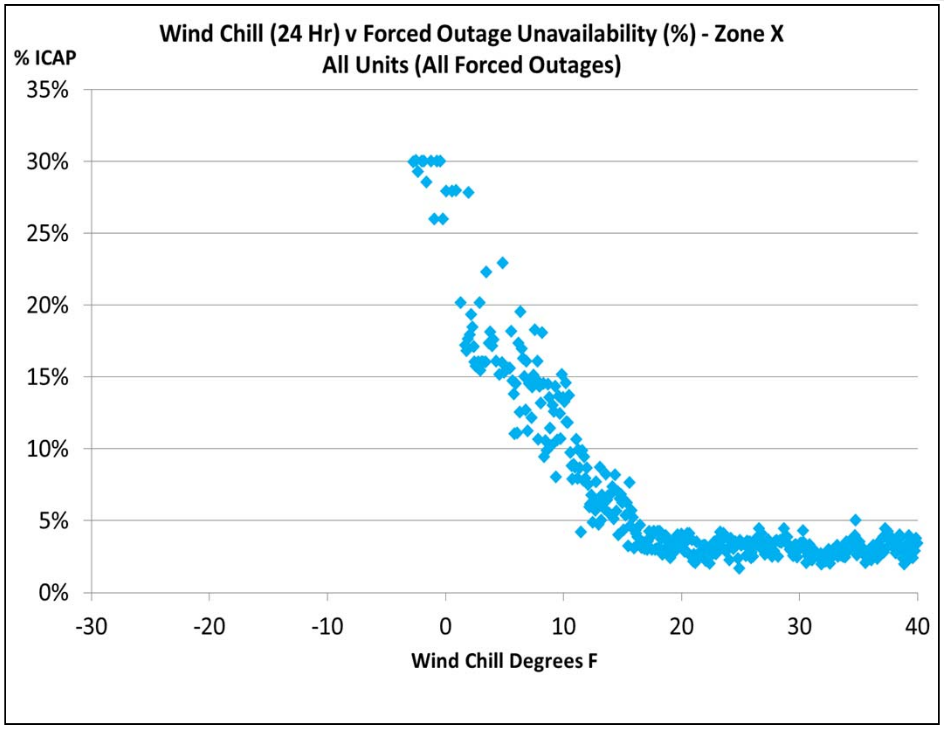


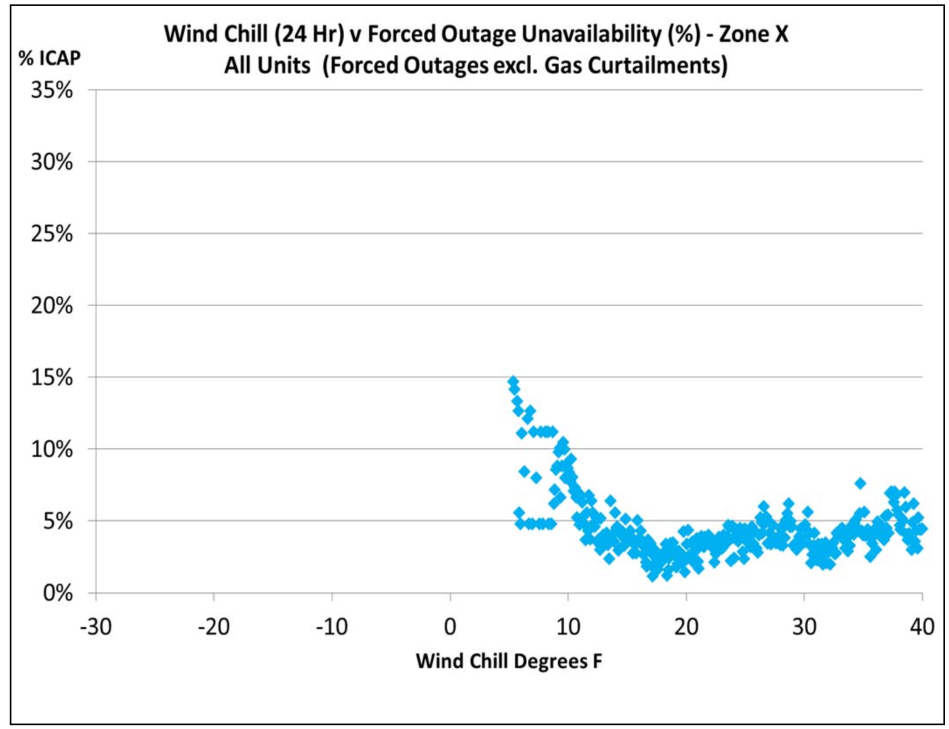


COMPLETED: Action Item #16

Do we have similar information for other zones? Can we see the wind chill and forced outage charts?

Wind Chill v Forced Outage Unavailability (%) – Zone X
Comparison of All Forced Outages and Forced Outages Excluding Gas Curtailments

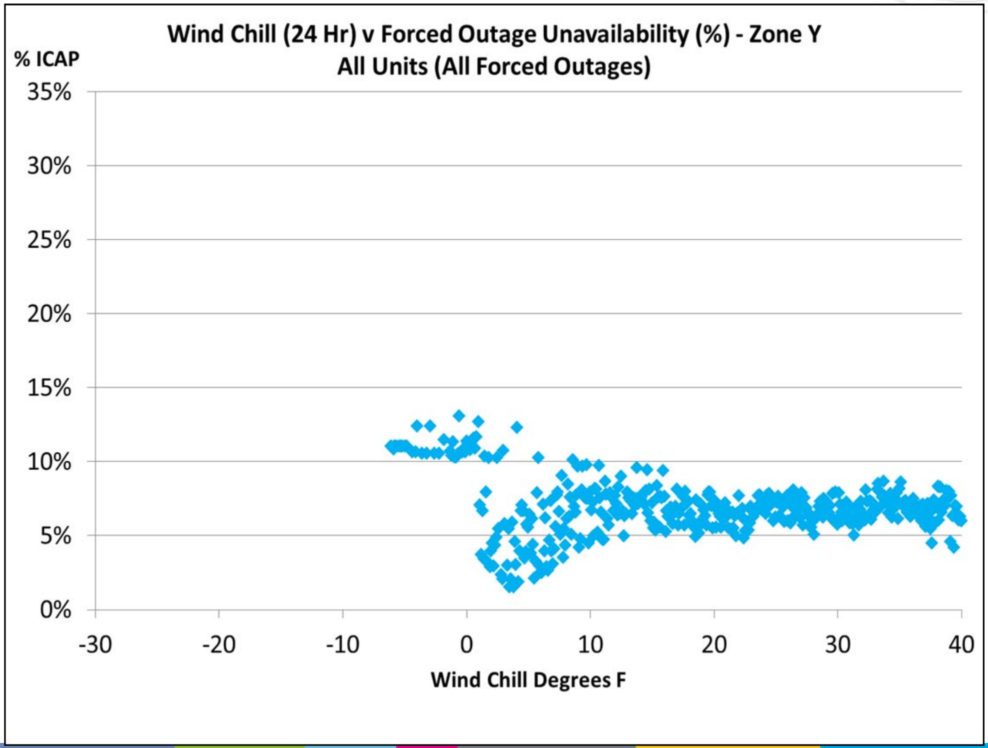


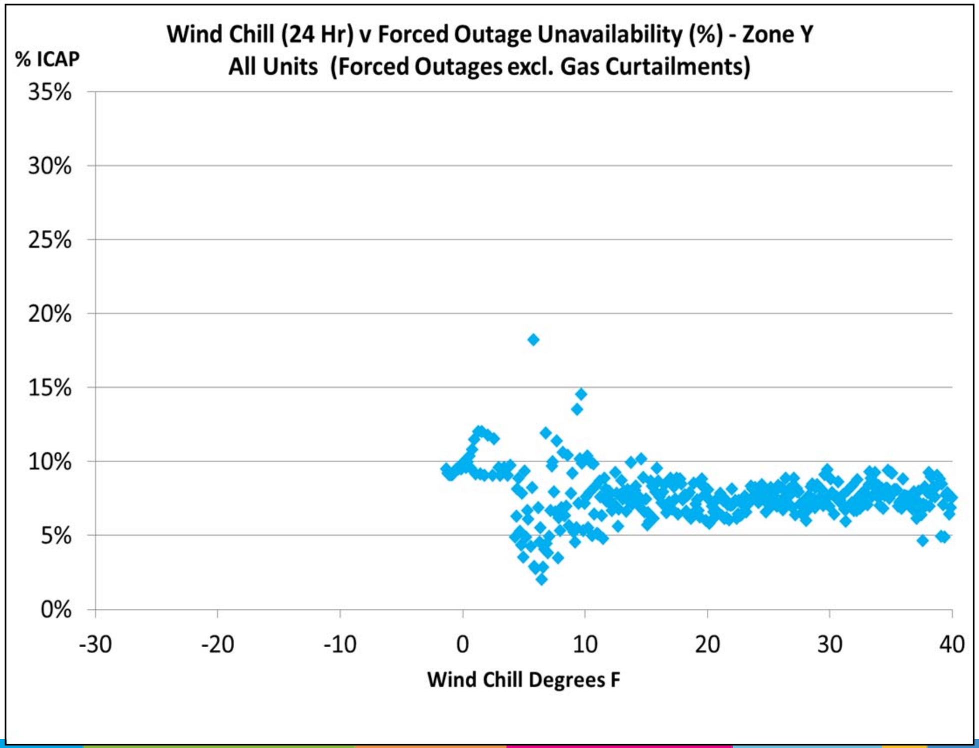


COMPLETED: Action Item #16

Do we have similar information for other zones? Can we see the wind chill and forced outage charts?

Wind Chill v Forced Outage Unavailability (%) – Zone Y
Comparison of All Forced Outages and Forced Outages Excluding Gas Curtailments

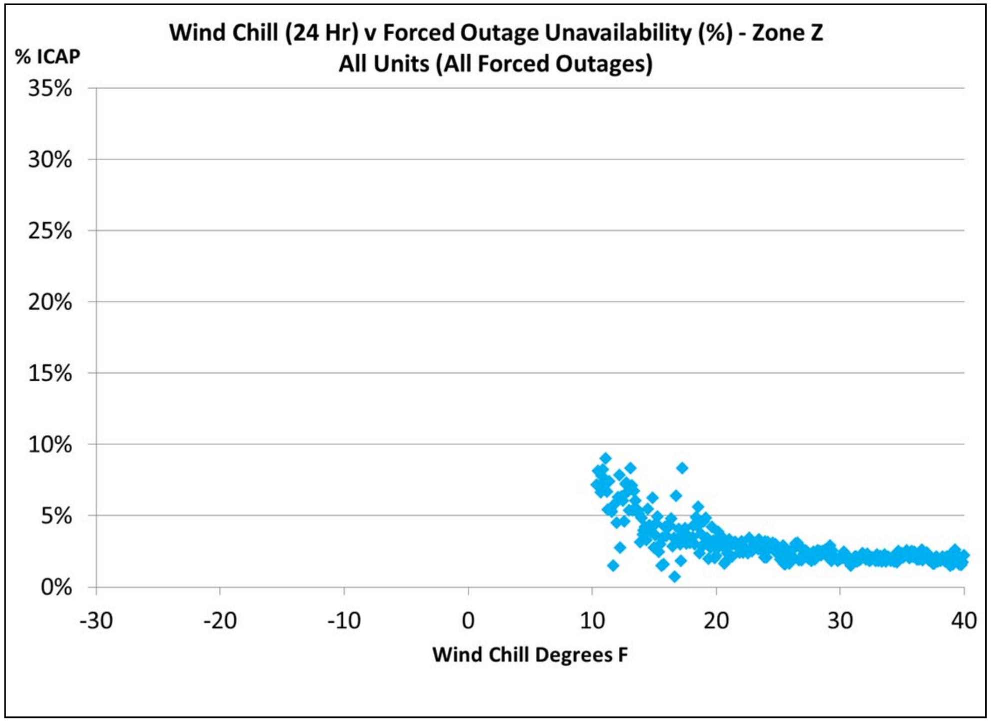


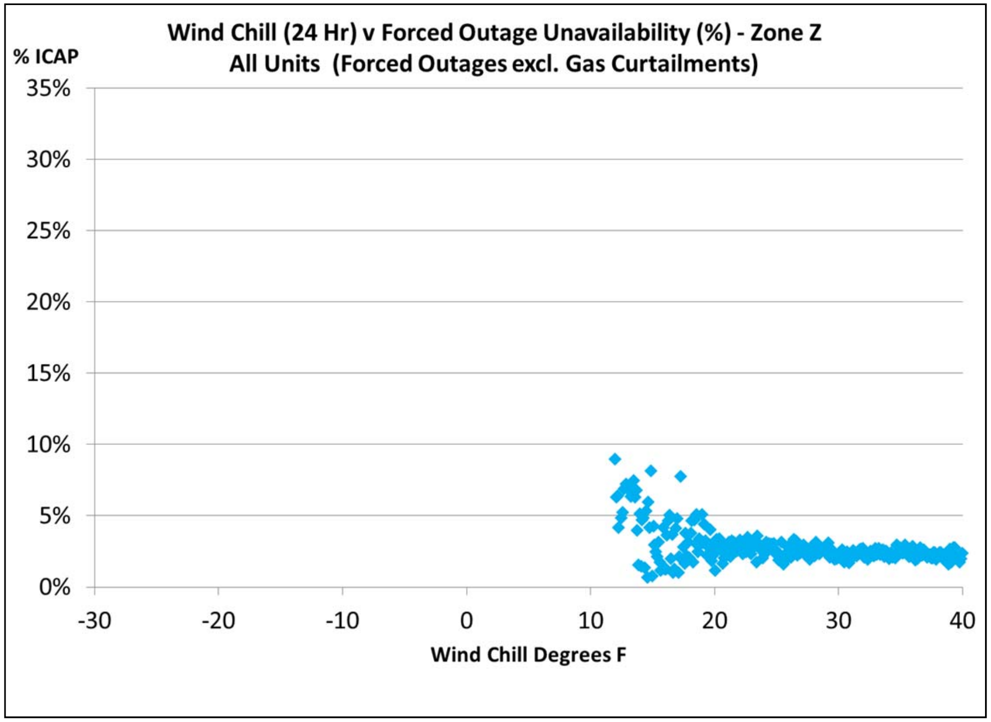


COMPLETED: Action Item #16

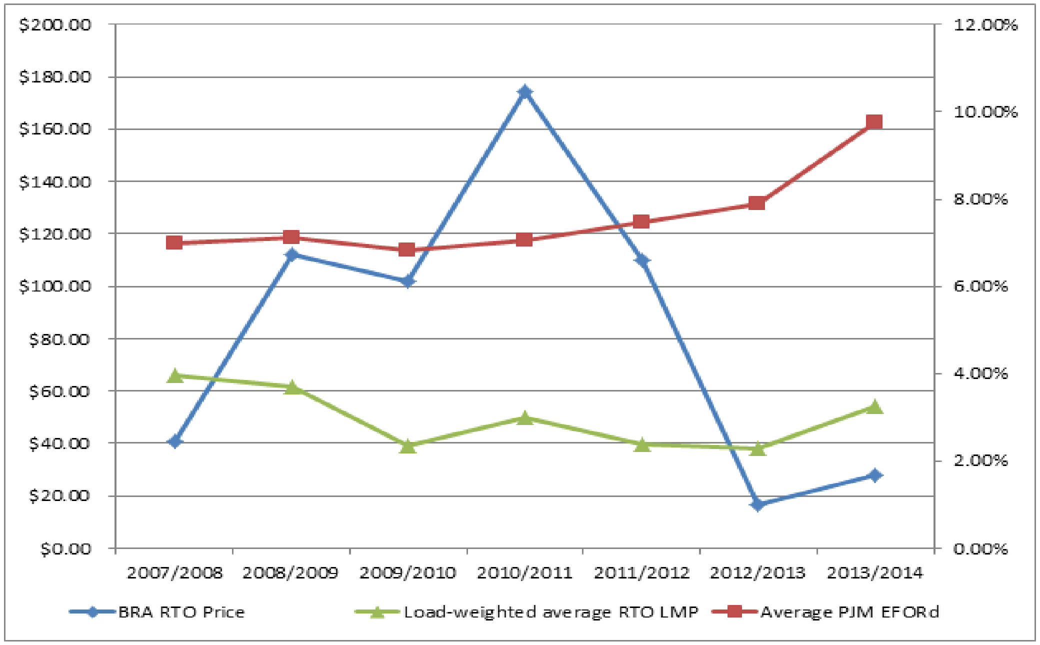
Do we have similar information for other zones? Can we see the wind chill and forced outage charts?

Wind Chill v Forced Outage Unavailability (%) – Zone Z
Comparison of All Forced Outages and Forced Outages Excluding Gas Curtailments





Are outages higher in years with lower capacity prices? Is there correlation between EFORd and the prices?



IN PROGRESS: Action Item #18

Please elaborate on the analysis demonstrating that January was a 1 in 10 event.

Weather conditions on January 7

PJM collected the lowest annual wind-adjusted temperature from each of the last 40 years and computed the population's mean and standard deviation. Assuming a normal distribution, the January 7 weather conditions were consistent with a "1 in 10" probability of occurrence.

Weather conditions in the month of January

PJM collected data on January heating degree days from each of the last 40 years and computed the population's mean and standard deviation. Assuming a normal distribution, the January 2014 weather conditions were consistent with a "1 in 10" probability of occurrence.

Action Item #18

Additional Data Files:

Capacity Performance - Winter Weather Parameter (PDF)

Capacity Performance - Heating Degree Days (PDF)

PJM RTO Winter Weather Parameter

Parameters for Normal Distribution		
Parameter	Symbol	Estimate
Mean	Mu	3.195424
Std Dev	Sigma	7.384563

Quantiles for Normal Distribution		
	Quantile	
Percent	Observed	Estimated
1.0	-14.02880	-13.98364
5.0	-11.86382	-8.95110
10.0	-10.49825	-6.26827
25.0	0.18790	-1.78539
50.0	4.50196	3.19542
75.0	7.85306	8.17624
90.0	11.77305	12.65912
95.0	14.60135	15.34195
99.0	15.00132	20.37449

Jan 7, 2014:
-4.1 WWP

PJM RTO January Heating Degree Days

Parameters for Normal Distribution		
Parameter	Symbol	Estimate
Mean	Mu	918.4244
Std Dev	Sigma	154.11

Quantiles for Normal Distribution		
	Quantile	
Percent	Observed	Estimated
1.0	626.113	559.911
5.0	683.482	664.936
10.0	727.871	720.924
25.0	795.856	814.479
50.0	914.079	918.424
75.0	1053.347	1022.370
90.0	1093.201	1115.924
95.0	1110.086	1171.913
99.0	1312.047	1276.938

January 2014:
1,084 HDD

IN PROGRESS: Action Item #19

slide 9 - Please make it more clear that this is excess outage above expected outages.

Data from original slide #9

January 7, 2014 7pm

Geographic Region	Average Percentage of Generation on Forced Outage by Region
East: AE, DPL, JC, ME, PE, PL, PS	25%
Central: DUQU, FE-S, PN	24%
South: BC, DOM, PEP	16%
West: AEP, COMED, DAY, DEOK, EKPC, FE-W	22%

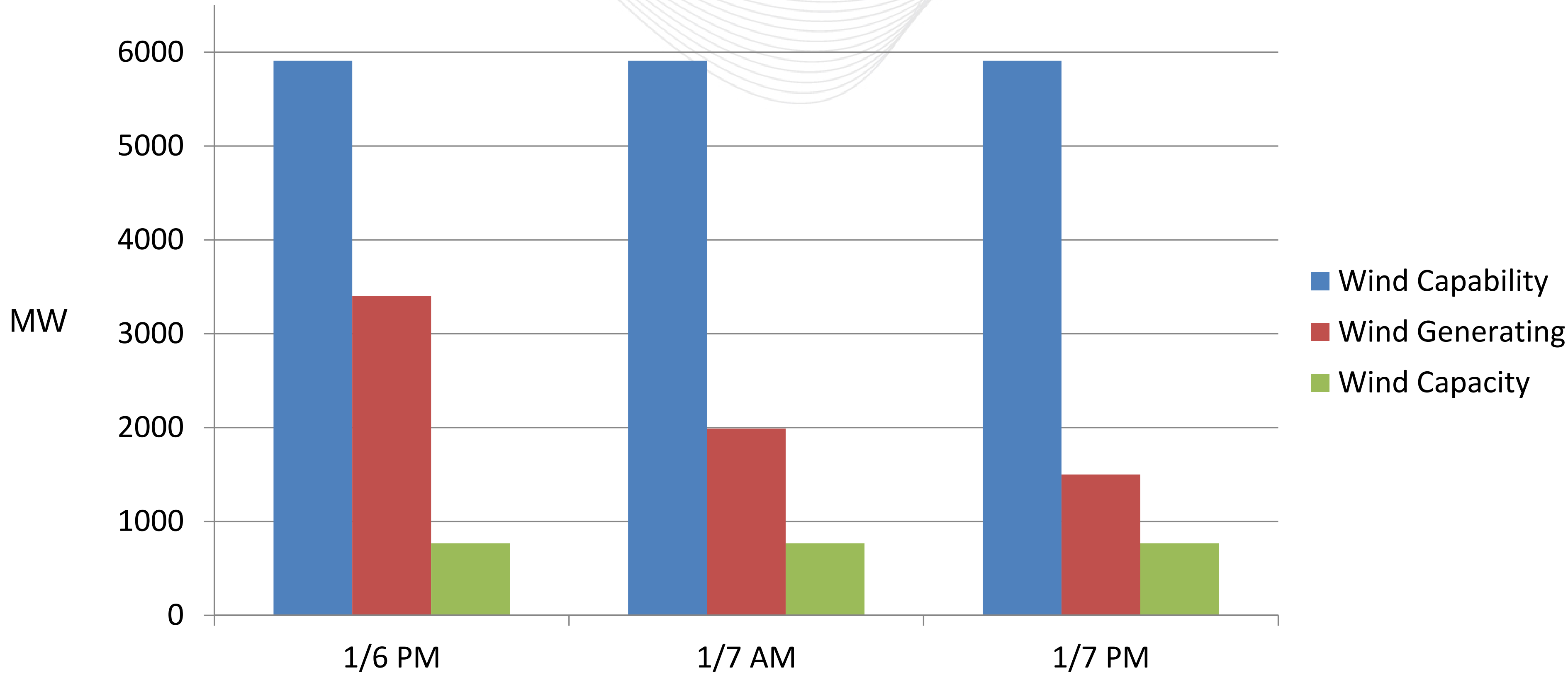
COMPLETED: Action Item #20

Remove the weather-outages units from the cumulative prob table so they are not double counted

The cumulative probability tables were built with GADS data from the period 2008 – 2012. It does not include performance data from this past January.

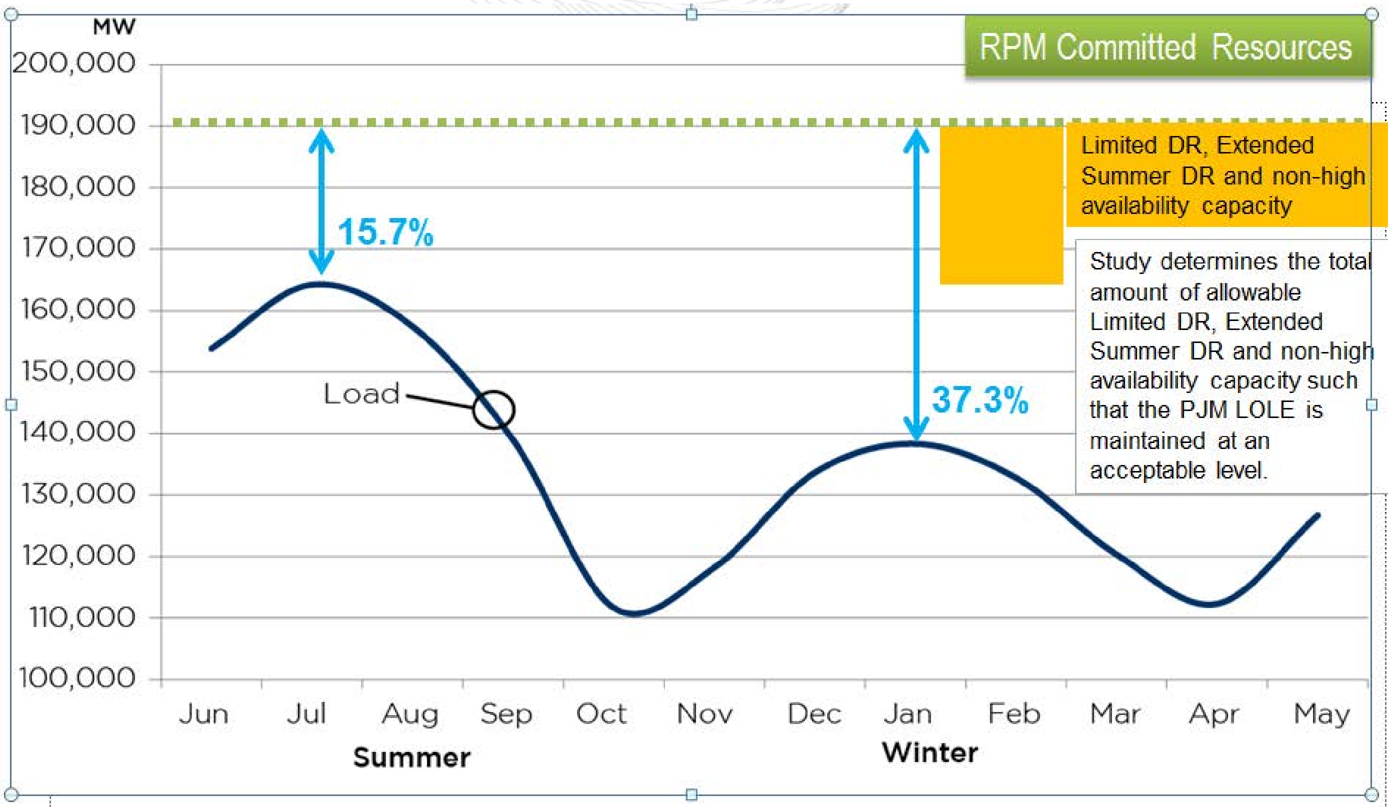
During the period 2008-2012, gas curtailments were not prevalent and events similar to January 7, 2014 were non-existent. Therefore, removing the weather-outages units from the cumulative prob table will not alter the mean and standard deviation in the unavailability distribution of the remaining fleet nor the results of the LOLP study.

COMPLETED: Action Item # 21:
How did wind perform in the winter?



CONSIDERED FOR FURTHER DOCUMENTATION/DISCUSSION: Action Item #22
Part II report, please add more verbiage about how a 15% outage over the expected outage in winter translates to a loss of load on a peak day.

Please further explain the 15.7% and the 37.3% reserve margin graph.



ADDITIONAL DATA REQUEST #24 and #25: Action Items #24 and #25

Please detail what resources were included for 2015 and 2016 comparison on slide 9.

Please share the differences in capacity between winter 2015 and 2016. What are your CIR assumptions.

Winter 2014/15

Total ICAP: 183,220 MW (174,250 Internal Committed + 4,228 External Committed + 4,472 Internal Uncommitted)

Winter 2015/16

Total ICAP: 174,760 MW (169,354 Internal Committed + 4,790 External Committed + 616 Internal Uncommitted)

COMPLETED: Action Item # 26

- Approximately 22,070 MW is dual fuel capable
- Information from GADS

CONSIDERED FOR FURTHER DOCUMENTATION/DISCUSSION: Action Items #27

Please increase summer capacity to push LOLE less than 0.1 as a sensitivity analysis and see how much that impacts the winter requirement.

CONSIDERED FOR FURTHER DOCUMENTATION/DISCUSSION: Action Items #28

In the final report, please be clear if the potential loss of load is about the model or the real world.

COMPLETED: Action Item #29

How much generation from the queue is ultimately built on a MW-basis and a generator-basis by primary mover (fuel-type)?

- Statistics are based on queues that have 90% of the proposed new generation projects either in-service or withdrawn (note: while PJM is currently in the AA1 queue, the latest queue that meets this criterion was the U1-queue which closed 4/30/08 and thus the data excludes the current gas boom)
- Only includes requests for new facilities (no uprates)
- Capacity MWs are based on what was studied and included in the final ISA

COMPLETED: Action Item #29

	Natural Gas	Wind	All Fuels
Number of Projects	302	168	613
Proposed MWs	121,678.4	2,904.1	147,135.2
MWs Completed	12,761.6	790.7	16,026.0
% of MWs Complete	10.5%	27.2%	10.9%
Number of Projects Complete	49	44	147
% of Projects Complete	16.2%	26.2%	24.0%

COMPLETED: Action Item #30

If a planned generator cleared in a BRA, how much of the queue is that?

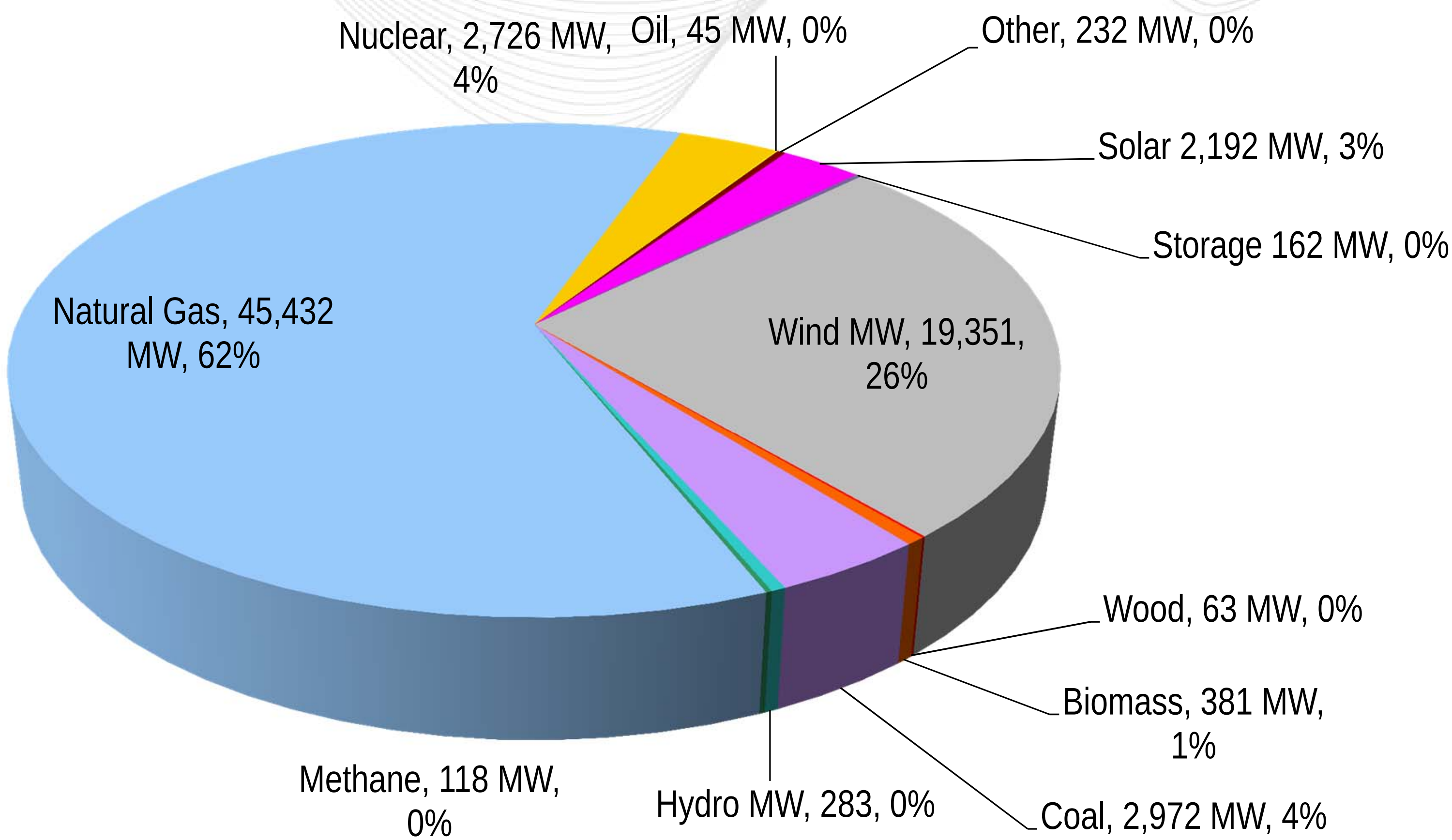
UCAP

DY	New Generation	Generation Uprates	Total
17/18	5927.4	339.3	6266.7
16/17	4281.6	1181.3	5462.9
15/16	4898.9	447.4	5346.3

ICAP

DY	New Generation	Generation Uprates	Total
17/18	6457.6	515.7	6973.3
16/17	4410.3	1238.0	5648.3
15/16	N/A	N/A	N/A

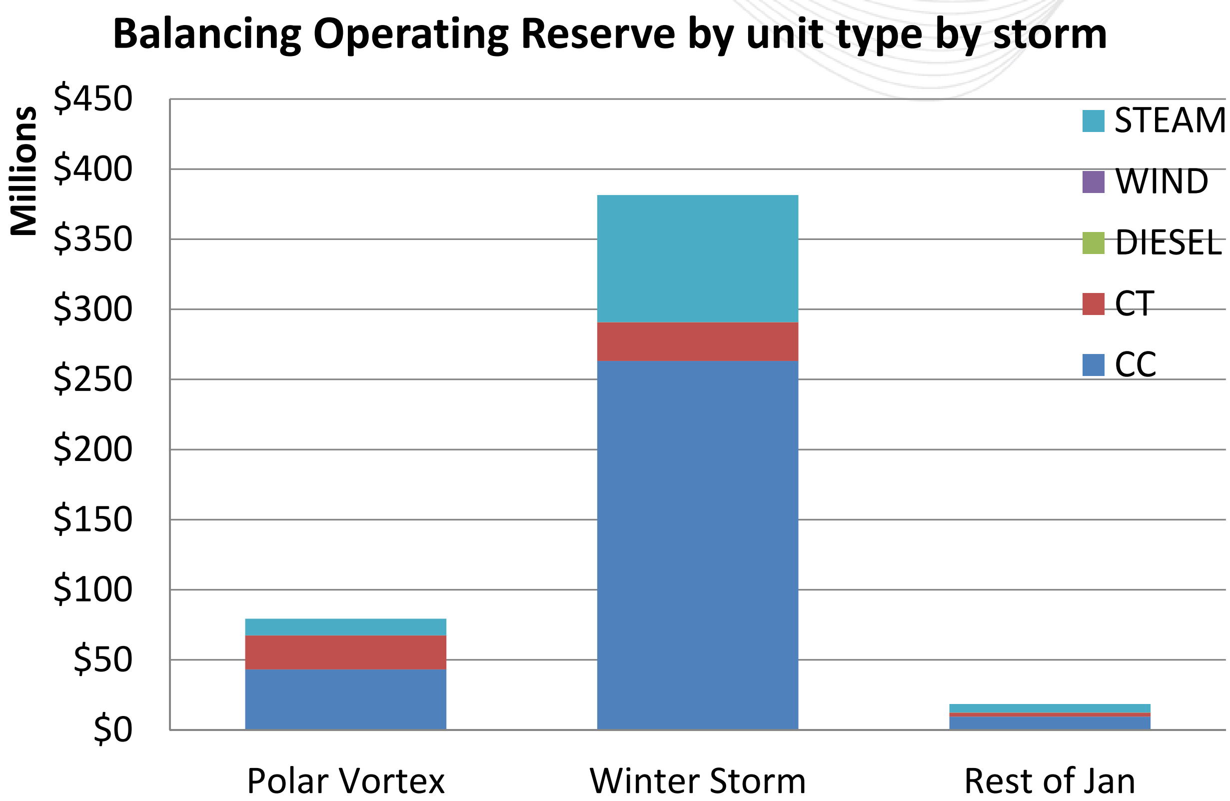
COMPLETED: Action Item #30



As of 03/2013

COMPLETED: Action Items #31

What percent or order of magnitude of the uplift from January was caused by gas/electric day coordination?



Uplift Drivers:

- Gas Prices
- Prudent (Conservative) Operations and Contractual Constraints.
- Interchange Volatility.

January Uplift Details:

- $597 million Total Uplift
- $357 million committed for Conservative Operations and Contractual Constraints.

CONSIDERED FOR FURTHER DOCUMENTATION/DISCUSSION: Action Items #32

Lack of compensation for resource flexibility.

Please be more clear in the report and add further detail.

CONSIDERED FOR FURTHER DOCUMENTATION/DISCUSSION: Action Items #33

Please provide further education regarding the current ability to recover staffing costs.

ADDITIONAL DATA REQUEST: Action Items #34

Please provide additional information about EFORp and how it is utilized

COMPLETED: Action Item #34: Peak Hour Period Availability (PHPA)

Capacity Performance Meeting

August 18, 2014

Peak Hour Period Availability Assessment

- Provides a means to assess whether committed generation resources are available at expected levels during critical peak periods
  - Credits or charges generation resource providers to the extent that they exceed or fall short of that expected availability.

Peak-Hour Periods

- PJM measures generation availability performance during peak load periods.
- The peak hour periods are defined based on summer and winter operating periods when high demand conditions are likely to occur.
- Defined Peak-Hour Periods:
  - Summer: June through August, hours ending 15:00 LPT through hour ending 19:00 LPT, on non-holiday weekdays
  - Winter: January and February, hours ending 8:00 LPT through 9:00 LPT and hours ending 19:00 LPT through 20:00 LPT, on non-holiday weekdays.
- Total number of hours is approximately 500 hours (can vary from year to year)

Calculate & Compare for each unit:

Target Unforced Capacity (TCAP)	vs.	Peak Period Capacity (PCAP)
Based on EFORd-5		***Based on EFORp***

Equivalent Demand Forced Outage Rate (EFORd-5)

- EFORd-5 determined based on 5 years of outage data through September 30 prior to the Delivery Year.
- Index similar to EFORd except that it is determined using 5 years instead of one year of outage data.
- Index calculated using GADs data.
- If unit does not have full 5 years of history, EFORd-5 will be calculated using class average EFORd and the available history.
- Class average EFORd will be used for a new generating unit.
- EFORd-5 is used to calculate Target Unforced Capacity.

Target Unforced Capacity (TCAP) is calculated for each unit committed to either RPM or FRR and is equal to:

Total Unit ICAP Commitment Amount	*	1 – EFORd-5

TCAP is the "target" used to measure the peak period availability of capacity from the generator in the Delivery Year. It may be different from the Delivery Year UCAP value.

Equivalent Peak Period Forced Outage Rate (EFORp)

- EFORp determined using following sets of hours from the defined peak periods:
  - Forced outage hours when needed (outage hours exclude Outside Management Control (OMC) events)
  - Forced partial outage hours when needed (outage hours exclude OMC events)
  - Service hours
- "Outage hours when needed" determined by PJM by identifying hours during which the real-time LMP would have exceeded the cost-based offer for the unit or PJM would have (absent the outage) called the unit for operating reserves, taking into account the unit's operating constraints.

Considerations for Single-Fueled, Natural Gas Units

- For a single-fueled, natural gas-fired unit, forced outages during the winter peak-hour period will not be used in determining the unit's EFORp if the resource provider can demonstrate that such failure was due to non-availability of gas to supply the unit as a results of events that were Outside Management Control (OMC).

- Lack of fuel in the cases where the operator of the unit is not in control of contracts, supply lines, or delivery of fuels is considered an OMC event.

Equivalent Peak Period Forced Outage Rate (EFORp)

EFORp =

$$\left(\boxed{\text{Forced Outage Hours When Needed}} + \boxed{\text{Equivalent Forced Partial Outage Hours When Needed}} \right) / \left(\boxed{\text{Service Hours}} + \boxed{\text{Forced Outage Hours When Needed}} \right)$$

If service hours < 50 hours during the peak period, the EFORp will be set to the lesser of the calculated EFORp or the calculated EFORd (based on outage data that covers the entire Delivery Year).

Peak Period Capacity Available (PCAP) =

Total Unit ICAP Commitment Amount	*	1 - EFORp

The Delivery Year PCAP of a unit is compared with the TCAP established prior to Delivery Year to determine a Peak Period Capacity Shortfall.

Peak-Hour Period Capacity Shortfall =

TCAP − PCAP

- A positive number indicates a shortfall
- A negative number indicates an excess

- Limited to 50% of Total Unit ICAP Commitment Amount * (1- Effective EFORd)
- If 50% limitation is triggered in a Delivery Year, the limit will increase to 75% the following Delivery Year.
- If 75% limitation is triggered in a Delivery Year, the limit will increase to 100% in the following Delivery Year.
- The 50% limit will be reinstated after 3 years of good performance.

Estimates of unit's EFORp and Peak Period Capacity Shortfall to be provided in December of Delivery Year.

- For each Resource Provider, the net of their Peak-Hour Period Capacity Shortfalls in an LDA are determined.
- The netting of Peak-Hour Period Capacity Shortfalls in an LDA is performed across committed units within a single account in eRPM.
- There is no netting of shortfalls across multiple accounts in eRPM.

Peak-Hour Period Availability is determined on a unit-specific basis; however shortfalls are netted across committed units in an eRPM account.

Adjusted Net Peak-Hour Period Capacity Shortfalls

- Excess available generation capacity in a party's account that satisfied the capacity resource obligations (satisfied DA Energy Market offer requirement and summer/winter testing requirement) may be used to reduce a Net Peak-Hour Period Capacity Shortfall in an LDA.
  - It may not be used to create a negative or more negative Net PHP Capacity Shortfall in an LDA (representing overperformance).
- This Adjusted Net Peak-Hour Period Capacity Shortfall in an LDA is separated into shortfall due to RPM commitments and shortfall due to FRR commitments.
- The Adjusted Net Peak-Hour Period Capacity Shortfall in an LDA is applied to each day in the DY.
- Resource Providers with a positive Adjusted Net Peak Period Capacity Shortfall in an LDA will be assessed a Peak-Hour Period Availability Charge retroactively for each day in the DY.
- Providers with a negative Adjusted Net Peak Period Capacity Shortfall in an LDA may share in the allocation of PHPA Charges.

Daily Peak-Hour Period Availability Charge =

Daily Peak-Hour Period Availability Charge Rate	*	Adjusted Net Peak Period Capacity Shortfall in LDA

•Different rate for shortfalls in LDA due to RPM commitments versus shortfalls in LDA due to FRR Commitments

•Charges are assessed daily and billed retroactively for the entire Delivery Year in the August bill (issued in September) after the conclusion of the Delivery Year.

Charge Rates for Shortfalls

- Rate Applied to Net Peak Period Capacity Shortfalls for RPM Commitments in an LDA is equal to the Provider's Weighted Average Resource Clearing Price in an LDA ($/MW-day).
  - Provider's Weighted Average Resource Clearing Price (WARCP) in an LDA is determined by calculating the weighted average of resource clearing prices in the LDA across all RPM Auctions, weighted by a party's cleared and makewhole MWs in the LDA.
    - Cleared MWs acquired or transferred through a Unit Specific Transaction for cleared capacity are accounted for in the calculation of Provider's WARCP.
    - Cleared MWs or Makewhole MWs in the LDA for wind, solar, DR or EE Resources are not considered in the calculation of Provider's WARCP.
  - If Provider's WARCP is $0/MW-day, a PJM WARCP in an LDA will be used.
    - PJM WARCP is determined by calculating the weighted average resource clearing prices in the LDA across all RPM Auctions, weighted by the total cleared and make-whole MWs in the LDA.

- Rate Applied to Net Peak Period Capacity Shortfalls for FRR Capacity Plan Commitments in an LDA is equal to the weighted average of resource clearing prices across all RPM Auctions for the LDA encompassing the zone of the FRR Entity, weighted by the quantities cleared in the RPM Auctions.

Allocation of Peak-Hour Period Availability Charges

- Charges for RPM Resource Commitments are allocated to over-performing Resource Providers that have a negative Adjusted Net Peak Period Capacity Shortfalls for RPM Commitments in LDA.
- Charges for FRR Capacity Plan Commitments are allocated to over-performing Resource Providers that have a negative Adjusted Net Peak Period Capacity Shortfalls for FRR Capacity Plan Commitments in LDA.
- Amount allocated to over-performing Resource Provider is capped at their Adjusted Net Peak Period Capacity Shortfall in the LDA times the Daily Peak-Hour Period Availability Charge Rate.

Allocation of Peak-Hour Period Availability Charges

- Any remaining balance of Charges is allocated to LSEs in LDA who were assessed a Locational Reliability Charge and FRR Alternative LSEs in LDA that over performed (i.e., FRR LSEs with negative Net Peak Period Capacity Shortfalls).
- Allocations to LSEs are performed on a pro-rata basis based on the LSE's daily unforced capacity obligations.
- Charges and Credits are assessed daily and billed retroactively for the entire Delivery Year by the August bill (issued in September) after the conclusion of the Delivery Year.

See the DY's RPM Peak Hour Period Availability Calculator posted on RPM Auction User Information web page to estimate charges and credits.

CONSIDERED FOR FURTHER DOCUMENTATION/DISCUSSION: Action Items #35

Please include implementation explanations for any potential proposed solutions.

CONSIDERED FOR FURTHER DOCUMENTATION/DISCUSSION: Action Items #36

Slide 13 - please provide a thorough discussion of the low probability and high reliability impact events which costs are not permitted recovery under current market rules.

CONSIDERED FOR FURTHER DOCUMENTATION/DISCUSSION: Action Items #37

Interested if performance results vary based on LDA versus rest of RTO.

CONSIDERED FOR FURTHER DOCUMENTATION/DISCUSSION: Action Items #38 What protections exist against the exercise of market power including portfolio effects?

TO BE CONSIDERED FOR FURTHER DOCUMENTATION/DISCUSSION: Action Items #39

Please bound the potential impacts on end-use customer costs - both incentives and penalties.

ADDITIONAL DATA REQUEST #45: Action Items #40 and #45

Slide 9 – What did PJM project with regard to wind resources and its performance for 2015 and 2016?

PJM assumed wind generators performed at their average capacity credit rating of 13% of nameplate.

Slide 10 – Please indicate how the GADS-filed unit ratings for the winter months posted by generators are reflected in the 190,000 MW IRM line.

On average, PJM unit winter ratings are about 1% higher than summer ratings. So the ICAP in the winter season would be about 192,000 MW.

TO BE CONSIDERED FOR FURTHER DOCUMENTATION/DISCUSSION Action Items #41

Please ensure that the discussion of incentives includes the impacts of portfolio effects.

TO BE CONSIDERED FOR FURTHER DOCUMENTATION/DISCUSSION: Action Items #42

Would like the generator survey to be updated with a follow-up based on the current thinking..

TO BE CONSIDERED FOR FURTHER DOCUMENTATION/DISCUSSION: Action Items #43 Slide 9 & 10 - Please provide more intraday information. (energy storage related)

COMPLETED: Action Item # 44

Slide 3 - What was the deviation between peak load and DA load?

Please Note: The day ahead load includes price sensitive load, decs, and incs (incs are subtracted out of DA demand).

- Load Comparisons for January 7, 2014:
  - Actual vs PJM Load Forecast

Peak	Actual Load	PJM Load Forecast	Delta
Morning	137,998	140,551	2,553
Evening	140,510	139,552	988

  - Actual vs DA Market Load (as bid by Market Participants)

Peak	Actual Load	DA Market Load	Delta
Morning	137,998	134,588	3,410
Evening	140,510	135,387	5,123

CONVERTED TO INTEREST: Action Items #46

What metrics will PJM develop in order to determine the cost effectiveness to customers of proposals to increase capacity performance?

CONVERTED TO INTEREST: Action Items #47

What is the justification for the continued treatment in the RPM of all capacity as homogenous resources when significant differences in the capability to respond to peak period requirements has been identified?

CONVERTED TO INTEREST: Action Items #48

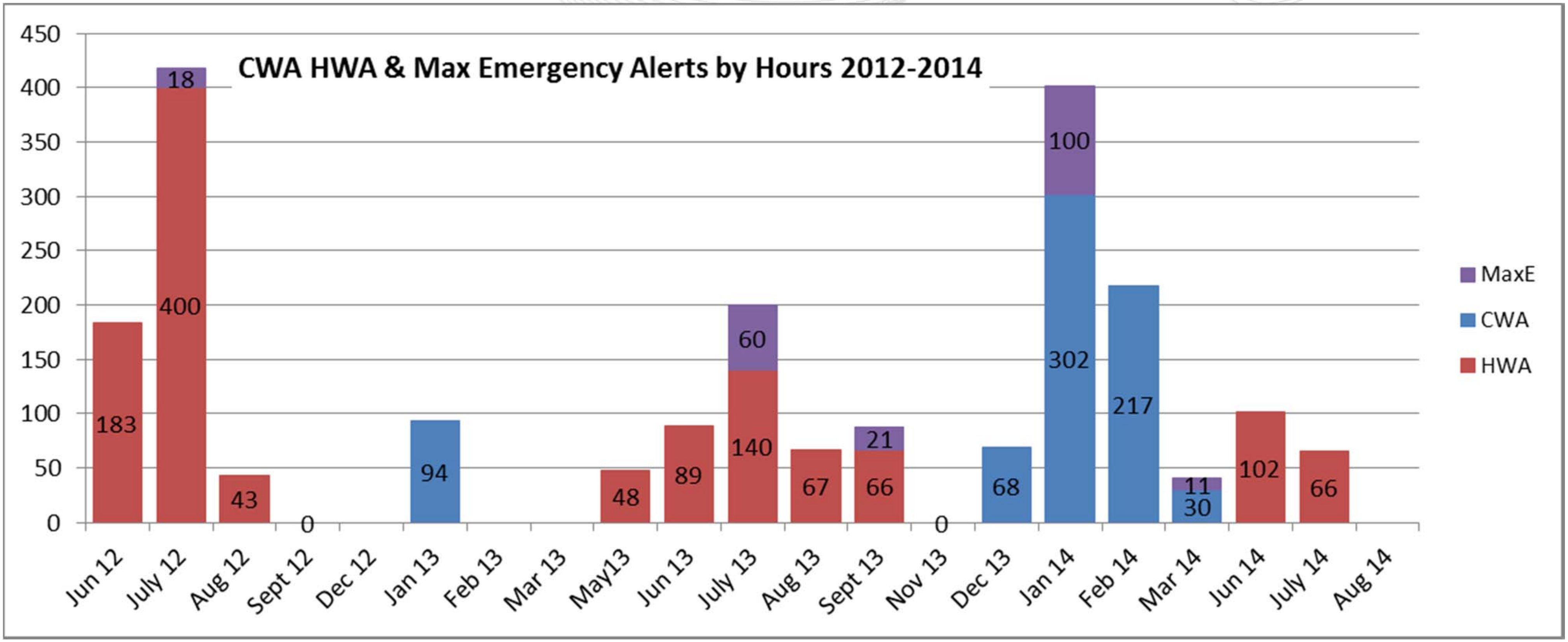
What non-generation options can PJM pursue to mitigate disruptions during peak periods? E.g., thermal storage capacity, development of demand response during winter peak periods, etc.

COMPLETED: Action Item #49 (revised)

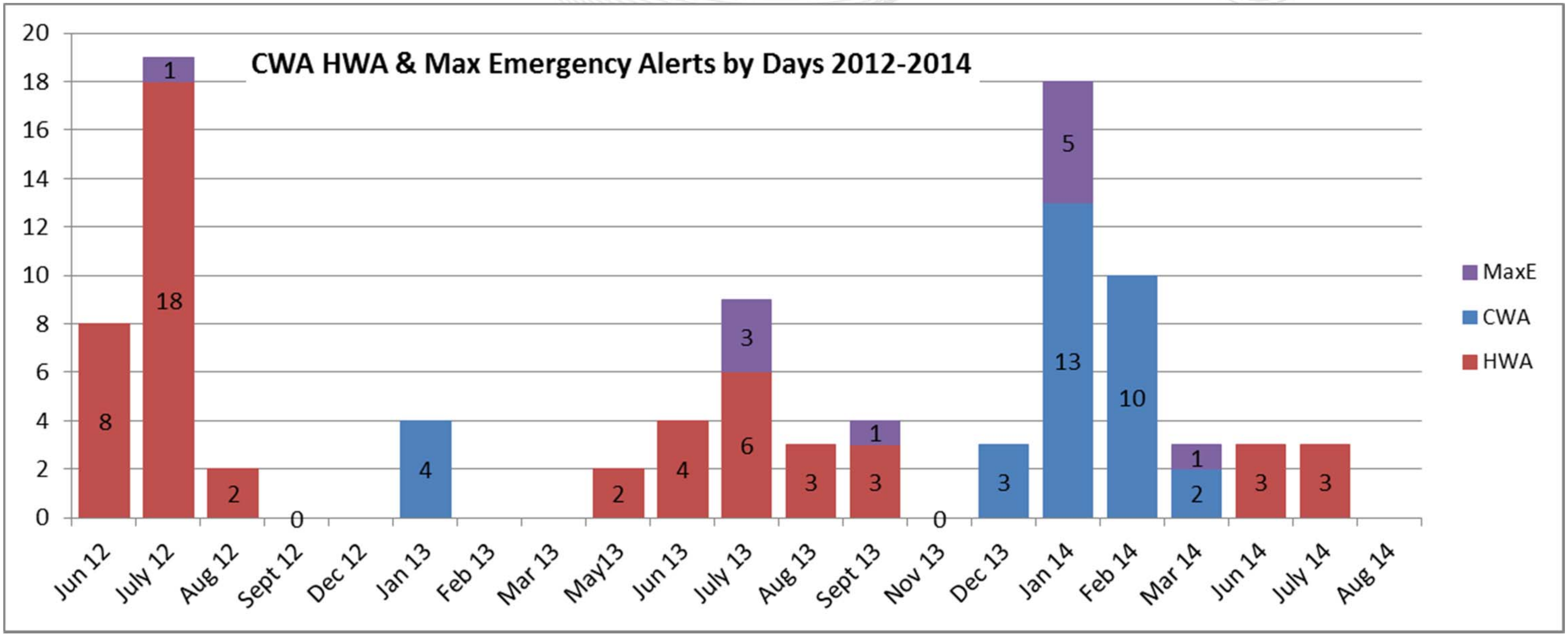
Please provide, for the past two years, the hours per month for Hot Weather Alerts, Cold Weather Alerts and Max Emergency Alerts

	Days			Hours		
	HWA	CWA	MaxE	HWA	CWA	MaxE
Jun 12	8			183		
July 12	18		1	400		18
Aug 12	2			43		
Sept 12						
Dec 12						
Jan 13		4			94	
Feb 13						
Mar 13						
May13	2			48		
Jun 13	4			89		
July 13	6		3	140		60
Aug 13	3			67		
Sept 13	3		1	66		21
Nov 13						
Dec 13		3			68	
Jan 14		13	5		302	100
Feb 14		10			217	
Mar 14		2	1		30	11
Jun 14	3			60		
July 14	3			66		
Aug 14						
TOTAL:	52	32	11	1162	711	210

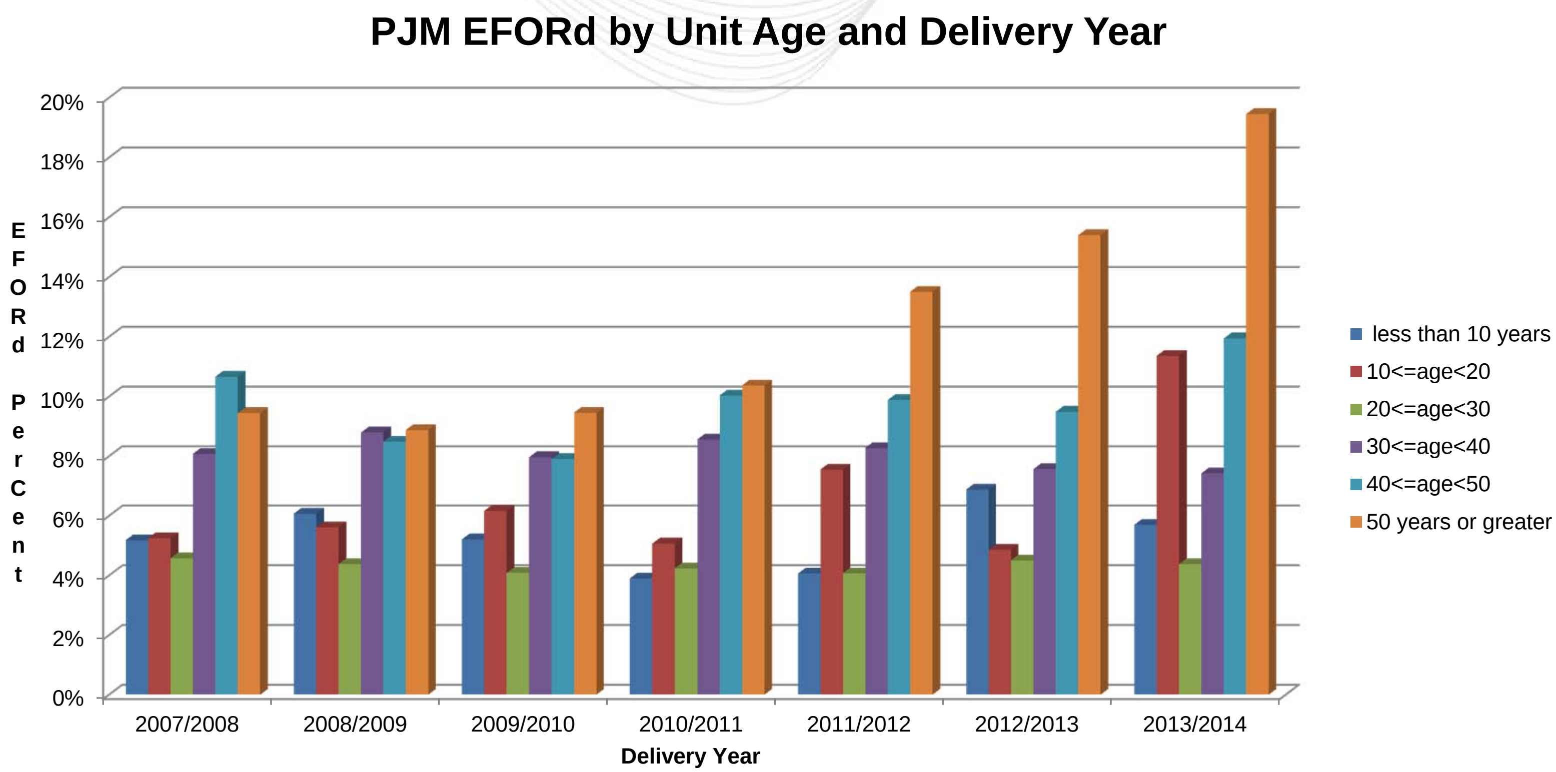
Action Item #49 (revised)



Action Item #49 (revised)



COMPLETED: Action Item # 50
Can we see EFORd based on plant age



IN PROGRESS: Action Item # 51
Can we see EFORd during periods of system stress (low Wind Chill periods)

IN PROGRESS: Action Item # 52

Is there an effort to investigate other performance causes (expected, non random)

IN PROGRESS: Action Item # 53
ID 16, can PJM look for other correlations - split out other causes

IN PROGRESS: Action Item # 54

Please provide discuss the tradeoffs of the quantity of: 1.) Limited DR, Extended Summer DR, and non-high availability capacity and 2.) the risks during the winter (see slide 16)

IN PROGRESS: Action Item # 55
Repost slide 17 with additional clarification related to CIRs

COMPLETED: Action Item # 56
Please provide historic EFORp credits and charges, by year

Historic Peak Hour Period Availability (PHPA) Charges & Credits

Delivery Year	PHPA Charges ($/year)	PHPA Credits to Overperforming Generation ($/year)	PHPA Credits to LSEs ($/year)
2007/2008	$42,866,630	$16,861,038	$26,005,592
2008/2009	$26,901,281	$26,901,281	$0
2009/2010	$14,397,060	$14,397,060	$0
2010/2011	$18,264,735	$18,264,735	$0
2011/2012	$4,698,917	$4,698,917	$0
2012/2103	$9,425,388	$9,412,693	$12,695

IN PROGRESS: Action Item # 57

Total capacity payments for any unit with a forced outage during Jan 2014 winter event and the amount of penalty for those units

COMPLETED: Action Item # 58

Provide examples of a hypothetical unit that had no performance issues on Jan 7 and compare that to a unit with a forced outage (look at peak day and how revenues flowed)

Example Resource ABCD

Installed Capacity (ICAP) 101 MW

Total Unit ICAP Commitment 101 MW

Actual EFOR data	
2013/2014 EFORd	0.37578
2013/2014 EFORd-5	0.17059
2013/2014 EFORp	0.20211

Peak Hour Period Availability Penalty Calculation =
Target UCAP (TCAP) - Peak Period Capacity Available (PCAP)

Where TCAP =
Total Unit ICAP Commitment Amount * (1-EFORd-5)
and PCAP =
Total Unit ICAP Commitment Amount * (1- EFORp)

Peak-Hour Period Capacity Shortfall **3.2***

* Positive represents under compliance therefore penalty assessed and assumes the organization did not have over compliance from other units in the same LDA.

Daily PHPA Penalty = **$88.74**
(= PHPA Shortfall * Org's Weighted Average Resource Clearing Price)

2013/2014 PHPA Penalty = **$32,388.64**

The Jan. 7, 2014 outage would impact the generator's 15/16 EFORd-1 and 15/16 - 20/21 EFORd-5 values

Assume Degraded 15/16 EFORd

2015/2016 EFORd	0.2

Original UCAP Commitment (from BRA) = **98 MW***
* (Assume participant offered a lower EFORd (0.03) expecting improved performance)

When the 15/16 Final EFORds are published in October of 2014, the participant will see theyare short.

RPM Commitment Compliance Shortfall = **17.2**
(UCAP Committed - UCAP Value of Resource)

The party would need to procure 17.2 MW (UCAP) of replacement capacity to avoid being assessed a RPM Commitment Compliance Penalty.

COMPLETED: Action Item # 58 CONTINUED

Provide examples of a hypothetical unit that had no performance issues on Jan 7 and compare that to a unit with a forced outage (look at peak day and how revenues flowed)

Emergency Cost Allocation

Assuming Emergency (Energy or Demand Response) was called, the unit would also be allocated a portion of the related charges for increasing RT purchases.

Assume	
Total Emergency Load Response Credits =	$5,000,000
Participant's Positive Bal Net Interchange =	100
Total PJM Bal Positive Interchange =	10,000.00

(Total Emergency Load Response Credits * (Participant's Positive Bal Net Interchange/ Total PJM Bal Positive Interchange)

Participant's Share of Emergency Load Response Charges = $50,000.00

BOR Deviation Charges

The unit would be subject to operating reserve for deviations charges

Assume	
Total RTO Bal OpRes for Deviations Credits =	$5,000,000.00
Total RTO Deviations =	20,000.00
Total East Bal OpRes for Deviations Credits =	$2,500,000.00
Total East Deviations =	7,500.00

RTO Bal OpRes for Deviations Charge = **$25,000.00**

(= Total RTO Bal OpRes for Deviations Credit *(Company Deviations/Total PJM Deviations))

East Bal OpRes for Deviations Charge = **$33,333.33**

(= Total East Bal OpRes for Deviations Credit *(Company Deviations/Total East Deviations))

Total BOR Deviation Charges = $58,333.33

IN PROGRESS: Action Item # 59

Provide information on Extreme Lead time units and correlation of load forecast uncertainties

COMPLETED: Action Item # 60

Provide the amount of MW, that are duel fuel units, with gas as the primary mover

19,940 MW

COMPLETED: Action Item # 61

With regard to the outage rates for the four regions, the South region [Pepco, BGE, Dominion] was lower than the other 3 regions. Were there any observable operational or firm supply factors that contributed to this lower forced outage rate? Could this aberration be related to slightly warmer temperatures in the South region?

61A: The Southern zone had a higher forced outage rate with regard to fuel/gas supply than other zones, indicating supply contracts were not firm or ‘better’ than other areas.

61B. The Southern zone had a lower forced outage rate with regard to electrical/boiler/other internal plant problems.

A possible explanation is a combination of the units being on-line before the polar vortex hit the area and even once it did, temperatures remained a bit warmer than the rest of the RTO.

- -Temps in the west were below 0-degrees by 1/6 @1300hrs.
- -Philadelphia, Washington DC and Richmond remained above freezing until 2000hrs on 1/6 and never went below zero. Richmond low temp was 10-degrees at 0700hrs on 1/7, compared to Chicago and Columbus at -11 and -5 respectively at that hour.

Hourly Temps From Noon Jan 6 to Noon Jan 7, 2014

	1/6/2014 12:00	1/6/2014 13:00	1/6/2014 14:00	1/6/2014 15:00	1/6/2014 16:00	1/6/2014 17:00	1/6/2014 18:00	1/6/2014 19:00	1/6/2014 20:00	1/6/2014 21:00	1/6/2014 22:00	1/6/2014 23:00	1/7/2014 0:00	1/7/2014 1:00	1/7/2014 2:00	1/7/2014 3:00	1/7/2014 4:00	1/7/2014 5:00	1/7/2014 6:00	1/7/2014 7:00	1/7/2014 8:00	1/7/2014 9:00	1/7/2014 10:00	1/7/2014 11:00	1/7/2014 12:00
Philadelphia (PHL)	45	41	38	40	40	37	36	34	32	31	26	21	16	14	11	9	7	6	5	5	4	4	5	6	7
Washington, DC (DCA)	40	40	40	39	39	37	34	32	26	22	18	15	12	12	10	9	8	8	7	7	7	7	9	11	13
Richmond (RIC)	47	45	47	45	44	42	42	37	34	31	28	23	20	18	16	14	13	12	11	10	10	10	12	13	15
Columbus (CMH)	1	0	0	-1	-2	-2	-3	-4	-5	-6	-7	-7	-7	-7	-6	-6	-6	-6	-5	-5	-5	-4	-4	-2	1
Chicago (ORD)	-15	-15	-14	-13	-12	-12	-12	-12	-12	-12	-11	-11	-11	-11	-11	-11	-11	-11	-11	-11	-10	-10	-10	-8	-6

IN PROGRESS: Action Item # 62

Describe the availability assumptions of Base Capacity resources during winter peak periods

IN PROGRESS: Action Item # 63
Need clear eligibility requirements for resources

IN PROGRESS: Action Item # 64
How is the 2.5x RPM revenue penalty limit derived

IN PROGRESS: Action Item # 65
Provide clarification:
RPM Revenue based on UCAP
Peak Penalty based on ICAP

IN PROGRESS: Action Item # 66
Risk premium calculation - how much history is used

IN PROGRESS: Action Item # 67

Revisit risk premium calculation and what is included

Are there any exclusions for Force Majeure

COMPLETED: Action Item # 68

Establish FAQs for each section, give members opportunity to submit via email subject matter of FAQs
Keep a list of types of issues people want to raise so that people know who to form coalitions with.
Like a clearing house board of sorts

FAQs with details will be posted with Action Items.
The FAQs will include the Requestor Company.

IN PROGRESS: Action Item # 69

PJM should revisit the requirements for the inter day cycling asset class (specifically - Economic minimum is less than or equal to 50 percent of the economic maximum)

IN PROGRESS: Action Item # 70

Please break out specific outage rates for the historical asset class forced outage rate, instead of lumping the data

COMPLETED: Action Item # 71

Would PJM please provide the number of hours by delivery year since RPM began during which PJM loaded Max Emergency Generation or was at a more severe emergency level.

Row Labels	2007/2008	2008/2009	2009/2010	2010/2011	2011/2012	2012/2013	2013/2014	2014/2015	Grand Total
Cold Weather Alert	406.7	609.2	117.6	948.9		160.4	2169.7		4412.5
Hot Weather Alert	1355.8	1589.6	1510.3	5410.8	1244.5	2101.8	794.8	919.1	14926.7
Manual Load Dump Warning	4.2	5.7	4.4	13.9	0.8		5.7	0.6	35.3
Max Emerg Gen	18.2	4.5		46.8		10.7	99.2		179.4
Max Emerg Gen Action Trans		2.2	6.3	14.4	39.6		37.9		100.4
Max Emerg Gen/Load Management Alert	77	79.1		126.1	103.1	25.1	338.2		748.6
Voltage Reduction	3.4	2.5					1.8		7.7
Voltage Reduction Alert							80.9		80.9
Voltage Reduction Warning	8.1	4.5	5.3	4.1		1.5	27.8		51.3
Grand Total	1873.4	2297.3	1643.9	6565	1388	2299.5	3556	919.7	20542.8

COMPLETED: Action Item # 72

Would you PJM please provide the number of hours by delivery year since RPM began during which PJM was at a hot weather alert, cold weather alert, max emergency alert or more severe emergency level.

Row Labels	2007/2008	2008/2009	2009/2010	2010/2011	2011/2012	2012/2013	2013/2014	2014/2015	Grand Total
Cold Weather Alert	406.7	609.2	117.6	948.9		160.4	2169.7		4412.5
Hot Weather Alert	1355.8	1589.6	1510.3	5410.8	1244.5	2101.8	794.8	919.1	14926.7
Manual Load Dump Warning	4.2	5.7	4.4	13.9	0.8		5.7	0.6	35.3
Max Emerg Gen	18.2	4.5		46.8		10.7	99.2		179.4
Max Emerg Gen Action Trans		2.2	6.3	14.4	39.6		37.9		100.4
Max Emerg Gen/Load Management Alert	77	79.1		126.1	103.1	25.1	338.2		748.6
Voltage Reduction	3.4	2.5					1.8		7.7
Voltage Reduction Alert							80.9		80.9
Voltage Reduction Warning	8.1	4.5	5.3	4.1		1.5	27.8		51.3
Grand Total	1873.4	2297.3	1643.9	6565	1388	2299.5	3556	919.7	20542.8

COMPLETED: Action Item # 73

Quick clarification from the data requests: is this saying that there were 402 hours of Cold Weather Alerts and Max Gen alerts for all of Jan? So looking at penalty exposure, base and Capacity performance resources would be subject to the new penalty factor during these hours? (Action #49)

The associated data table for Question #49 may have a better hour representation, so the answer is yes.

In addition, PJM staff would look at making HWA / CWA an hourly call versus the current daily call – for example, we issue HWA a day or days ahead and leave it for the whole day. We would modify procedures to cancel as soon as it was no longer needed rather than waiting for the end of the day.

IN PROGRESS: Action Item # 74

A summary by resource type of PJM capacity that likely can provide Capacity Performance, or can with minor additional investment, etc.; which results in an estimate of the mix of capacity that will provide the Base product; and leads to an estimate of the likely performance of the capacity that will provide the Base product.

IN PROGRESS: Action Item # 74

A summary by resource type of PJM capacity that likely can provide Capacity Performance, or can with minor additional investment, etc.; which results in an estimate of the mix of capacity that will provide the Base product; and leads to an estimate of the likely performance of the capacity that will provide the Base product.

IN PROGRESS: Action Item # 75

Could you explain and/or demonstrate how the MIN_WWP values for the RTO_EKPC zone are calculated, from underlying data. What exactly is the underlying data (temperature and wind, hourly or daily average, locations, etc.); what formula and weights are used to calculate the RTO aggregate value; etc. Better yet, provide the spreadsheet that calculates MIN_WWP for these dates from the underlying data.

IN PROGRESS: Action Item # 76

What is the temperature for the reference technology we expect performance at; is it different by LDA; (for example -10 °F)