OAR-2008-0708

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Reply to: Civil Division

April 1, 2013

APR 01 2013

By Hand Delivery
Office of the Administrator
EPA Docket Center
EPA West Building, Room 3334
1301 Constitution Avenue, NW
Washington, DC 20004

Dear Administrator:

Enclosed for filing please find the Delaware Department of Natural Resources and Environmental Control's Petition for Reconsideration.

Please contact me if you require anything further.

Sincerely,

Valerie S. Edge
Deputy Attorney General

VSE/jrm/I/EPA/RICE

Enclosure

cc: Ali Mirzakhalili, Program Administrator

APR 01 2013

BEFORE THE ADMINISTRATOR
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

In the Matter of the Final Rule:

National Emissions Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; New Source Performance Standards for Stationary Internal Combustion Engines (Jan. 30, 2013)

Petition for Administrative Reconsideration

Pursuant to §307(d)(7)(B) of the Clean Air Act ("CAA"), 42 U.S.C. §7607(d)(7)(B), the State of Delaware Department of Natural Resources & Environmental Control ("Delaware") respectfully asks EPA to reconsider the final rule issued Wednesday, January 30, 2013, at 78 Fed. Reg. 6674, et seq., entitled National Emissions Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines ("RICE NESHAP"); New Sources Performance Standards for Stationary Internal Combustion Engines ("NSPS"); Final Rule. Delaware stands by and incorporates all of its prior comments on the rulemaking into this submission.

Modification of the NSPS Without Regard to §111

Specifically, Delaware requests reconsideration of EPA's decision to modify the NSPS without considering the impacts of criteria pollutants from rulemaking. The CAA authorizes EPA in §111 to adopt NSPS for new sources to control criteria pollutants. In 2006, EPA adopted the Combustion Engine New Source Performance Standard ("NSPS") for Compression-Ignition ("CI") engines. In that 2006 rulemaking, pursuant to §111 of the CAA, EPA expressly addressed the definition of "emergency" use with pointed discussion of the issue in both the Federal Register and in the Response to Comments Document. At that time, EPA had been urged to conform the definition of emergency in the NSPS to the existing NESHAP, and EPA's refusal to make that change was based on the record.

In 2008, EPA adopted the Spark-Ignited ("SI") NSPS and amended the RICE NESHAP in a joint rulemaking. EPA modified the NESHAP as authorized by the CAA §112, which is related to the regulation of hazardous air pollutants. EPA did the same for the NSPS as authorized by the CAA §111, which is related to the regulation of criteria pollutants. The record shows EPA was concerned with emissions of both criteria pollutants and HAPS. In this dual proceeding in 2008, EPA amended the definition of "emergency" in the RICE NESHAP to be more similar to that of the CI and SI NSPS, which made it more stringent. EPA, in its discussion concerning changes to the definition of "emergency," stated that it was "true that EPA was adopting a more stringent emergency engine definition and requirements as compared to the existing RICE MACT emergency definition. * * * However, EPA has learned a lot since the ICCR process from 10 years ago and knows now that there are health consequences for failing to regulate emergency engines and for having a broad definition that allows engines that are used for more than emergencies to emit at higher levels… ." 73 FR 3568 at 3583 (January 18, 2008).

The record shows, therefore, that EPA's decisions were based in part of its knowledge of health consequences related to emissions from emergency use.

EPA's rulemaking records in 2006 (for the NSPS) and 2008 (for NSPS and NESHAP) demonstrate EPA adopted the NSPS pursuant to the authority contained in § 111 of the CAA, which is designed to reduce emissions of criteria pollutants. EPA also considered public comment and criteria pollutant concerns related to the definition of "emergency" in both of those rulemakings. Further, both records demonstrate EPA was aware that there were differences between the definition in the NSPS and in the NESHAP of the term "emergency."

Throughout the process of EPA's most recent changes to the RICE NESHAP (the 2010 and 2013 Rules), EPA has been repeatedly urged to consider the potential increases in criteria pollutants due to the proposed changes. EPA refused to do so when it adopted the 2010 NESHAP modifications. Even after EPA proposed to also amend the NSPS (after the settlement was signed of the lawsuit over the 2010 NESHAP), EPA specifically and repeatedly declined in its Response to Comments Document and in the new Rule in 2013 to consider potential increases in criteria pollutants due to the Rule. Throughout the proceeding, EPA stated that the authority for the rulemaking was CAA § 112 and that it was only required to base its decision on hazardous air pollutants and MACT/GACT standards. Delaware disagrees and believes EPA should not refuse to consider impacts on criteria pollutant when setting the NESHAP, and should not approach air pollutants in an isolated fashion, disregarding the impacts of choices it makes in one venue on other regulatory programs.

While EPA has been unable to date to remedy the air pollution transport afflicting downwind states including Delaware, this decision will exacerbate the current situation in which more than 90% of Delaware's ozone deriving from upwind, out-of-state sources by increasing emissions from hazardous and criteria pollutants. Delaware recorded 39 exceedances of the old ozone standard in 2012 with the highest observation (25 percent above the standard) made at an urban monitoring location just 8 kilometers away from its western border. EPA's reliance on the historical data regarding the use of these emergency generators to refute our legitimate concerns regarding air quality impacts of these units under the revised rules have been proven to be wrong. According to a recent PJM report[1], use of such resources is projected to be 2.5 to 4.5 times higher in the next year and the years to follow. The resulting emissions increases in ozone precursor emissions are not considered by EPA in this rule and unmitigated will add to Delaware's challenge to meet the NAAQS.

Nonetheless, Delaware believes that EPA exceeded its statutory authority in modifying the NSPS definition of "emergency" in the context of statutory proceeding undertaken to modify a NESHAP, based solely on considerations of impacts on hazardous air pollution. Since EPA has specifically declined to consider criteria pollutants, cited a lack of data related to such an analysis, and did not even consider §111 of the CAA, Delaware believes EPA's action does not fulfill the requirement of the Clean Air Act for a NSPS to regulate criteria pollutants. Indeed, the lack of "conformity" was not an error or oversight and resulted from proceedings that considered the relevant statutory criteria. In order to amend an action properly taken previously pursuant to

[1] http://www.pjm.com/~/media/markets-ops/dsr/emergency-dr-load-management-performance-report-2012-2013.ashx (attached).

§111 of the CAA (modifying the NSPS definition of "emergency"), the CAA requires EPA to do so in a manner consistent with §111.

Delay of Fuel Requirements

Delaware also asks EPA to reconsider the delay and scope of its requirements for the use of ultra low sulfur diesel. Ultra low sulfur diesel is widely available and likely the only diesel fuel available in most areas. Thus, Delaware does not believe the delayed requirement for use of ultra low sulfur diesel fuel will add much value in reducing pollution impacts. EPA has further softened that requirement by allowing a sell-through provision to allow the continued use of other fuels until the supply on hand has been exhausted. Additionally, EPA delayed even that requirement until 2015. Given those factors, if there is to be any real value at all to this requirement, Delaware asks EPA to immediately adopt the requirement for its use. The sell-through provision should address any concerns about existing supply on hand, if, indeed, there are sources using the heavily polluting diesel fuels.

Delayed Recordkeeping

Finally, Delaware asks EPA to reconsider the delayed in recordkeeping, as the record lacks justification for delaying the implementation of those provisions. EPA has stated that it does not believe emergency use will increase based on its modifications. One concrete way EPA can acquire knowledge as to whether its prediction is correct is to adopt an immediate recordkeeping requirement which would provide a baseline as to current emergency use. In addition to the new study previously cited, attached is an email from EnerNOC, Inc., dated January 31, 2013, (the day after EPA's rule was published) offering an incentive of $2,000 per MW bonus payment for new demand response customers who enroll before February 15, 2013. As Delaware believed, this strongly suggests usage will increase since aggregators are offering bonuses to add additional users to their so called demand response programs. As Delaware has suggested previously, it believes emissions will increase because of the new rule modifications and that this type of so called emergency demand response generation is not necessary or helpful to the stability of the grid. Nonetheless, it is critical to have immediate recordkeeping and reporting, particularly with respect to the first date on which an entity signs an emergency use or aggregating contract with a provider to determine how the proposed changes increase the use of generators and increase emissions. Delaware asks EPA to reconsider its recordkeeping and reporting, and modify it to make the recordkeeping requirement to be immediate and to include the date on which any and all contracts are signed relating to demand response or emergency usage and to require the records and contracts be retained for at least 5 years. This data may be helpful in determining actual impacts from the rule changes.

Summary

As Delaware has stated numerous times in this proceeding, it is concerned about increases in emissions of hazardous air pollutants and criteria pollutants from the Rule changes. Delaware further believes that EPA must rectify its failure to address emissions of criteria pollutant before it can lawfully amend the NSPS. Thus, we urge EPA to expedite the requirement to use ultra low sulfur diesel to reduce the impacts and to require immediate recordkeeping to quantify the resulting emissions impacts of the rule. For these reasons, Delaware respectfully asks you to reconsider the above issues.

Respectfully submitted,

Dated: April 1, 2013

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Emergency Demand Response (Load Management) Performance Report 2012/2013

December 2012

APR 01 2013

pjm

For additional detailed information on any of the topics discussed, please refer to the appropriate PJM manual which can be found by accessing: http://www.pjm.com/documents/manuals.aspx

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Executive Summary

Emergency Demand Resources have the ability to participate as a capacity resource in the PJM capacity market (Reliability Pricing Model or RPM) or to support a Load Serving Entities Fixed Resource Requirement (FRR) plan. For the 2012/2013 Delivery Year the single Emergency DR (Load Management) product type available was available: Limited Demand Resources (LDR). The other type of resource, Interruptible Load for Reliability (ILR), was terminated after 2011/2012 Delivery Year and the two new products (Summer Extended DR and Annual DR) do not become available until the 2014/2015 Delivery Year. A Curtailment Service Provider (CSP) is the PJM member that nominates the end use customer location(s) as a capacity resource and is fully responsible for the performance of the resource. Emergency DR (Load Management) products are required to respond to PJM Emergency Load Management events which may occur from noon through 8pm on non-holiday weekdays from June through September during PJM system emergencies or receive a penalty. Emergency DR that is not dispatched during a system emergency must perform a mandatory test to demonstrate it can meet its capacity commitment or receive a penalty.

Figure 1 shows both the event and test performance values for the past 4 years. In the years where there was more than one event, the event performance is the event MW weighted average of all of the events.

Figure 1: Yearly Performance Summary

Performance Summary		
Year	Event Performance	Test Performance
2009	No Events	118%
2010	100%	111%
2011	91%	107%
2012	104%	116%

PJM dispatched Emergency DR two times during the 2012; July17th (Tuesday) and 18th (Wednesday). Figure 2 below shows a summary of the events where performance on July 17th was 103 percent and performance on July 18th was 104 percent. Summer 2012 performance was significantly higher than performance for the single event in July of 2011 (91 percent).

Figure 2: 2012 Emergency DR (Load Management) Events Summary

Event Date and Zones	Committed MW	Reduction MW	Performance
7/17, AEP, DOM	1,670	1,736	104%
7/18, AECO, BGE, DPL, JCPL, METED, PECO, PENELEC, PEPCO, PPL, PSEG	2,135	2,203	103%

The two summer 2012 events varied in size and length. The July 17th event was a long lead time event (resources have up to 2 hours to reduce) called in two zones (AEP and DOM), lasting for almost four hours, calling on 1,670 MW of DR resources. In comparison, the July 18th event was a combination of long and short lead times (short lead time resources respond in up to one hour) across 10 mid-Atlantic zones, lasting under two hours, calling on 2,135 MW of DR resources. The July 18th event had the potential to be a longer event, but storms developed and the associated drop in load shortened what would have otherwise been a longer event. The temperatures for both days, which were part of an extended heat wave, were in the mid to upper 90's°F across the PJM footprint. The load on the system was increasing beyond the forecasted amounts on both days. Not all CSPs responded with their committed amounts in all of the zones where they participate but performance improved over last year. In the 2012 events 51 percent of the CSP/zones did not respond with their committed amounts -- compared to 55 percent last summer. Conversely, 49 percent met or exceeded their commitments (vs. 45 percent last year). Underperformance penalties totaled $2 million ($5.6 million last year) or about 0.7 percent (1.3 percent last year) of the total DR of $267.5 million ($420 million last year). CSP credits for energy reduced during the events totaled $10 million.

DR resources that were not dispatched during the July emergency events were required to perform a mandatory one hour test. Each CSP must test all of these DR resources located in a zone at the same time. The test results for the 2012/2013 Delivery Year demonstrate that in aggregate, committed Emergency Demand Resources performed at 116 percent of their committed capacity values. Test results in excess of committed capacity values totaled 585 MW for the 3,635 MW of Emergency DR required to test this year. Similar to performance during the events, individually not all CSPs tested to their committed zonal amounts, but that number was small. Test failure charges totaled $1.7 million ($6.4 million last year), about 0.6 percent (1.5 percent last year) of total revenue.

New measurement and verification rules (M&V) went in to effect for this delivery year. These new rules came about as the result of the resolution of the so called "double counting" issue. The new rules cap the reduction amount that any registration can provide at its peak load contribution (PLC). Because of the transition to the new M&V rules and their potential impact on the ability to comply with their commitments, CSPs were provided the opportunity, through RPM incremental auctions to liquate unviable MW based on the new rules through the DR Capacity Transition Credits (CTC) and DR Alternative Transition Credits (ATC). Since the price of the Incremental Auction was less than the price of the Base Residual Auction, no CTC or ATC was paid to CSPs.

Emergency DR (Load Management) Overview

PJM Interconnection, L.L.C. procures capacity for its system reliability through the Reliability Pricing Model (RPM). The sources for meeting system reliability are divided into four groups:

1) Generation Capacity

2) Transmission Upgrades

3) Emergency Demand Resources (Load Management)

4) Energy Efficiency

For the 2012/2013 Delivery Year[1], there was only one Emergency DR product type available: Limited DR. In prior years another registration type, Interruptible Load for Reliability (ILR) was also available. With stakeholder and FERC approval the ILR product was eliminated at the end of the 2011/2012 Delivery Year. DR resources offer into the RPM's Base Residual Auction, one of the Incremental Auctions, or may take on a capacity obligation through the bilateral market.

DR agrees to be interrupted up to ten times per Delivery Year by PJM. The interruptions may be up to six consecutive hours in duration on non-holiday weekdays from noon until 8 PM EPT in the months from May through September. The interruptions must be implemented within two hours of notification by PJM. Those resources that can be fully implemented within one hour of notification are considered Short Lead Time Resources, while those that require more than one hour but not more than two hours of notification are considered Long Lead Time Resources. This agreement by Emergency DR (Load Management) Resources to allow PJM to provide notice of the interruptions enables PJM to procure less generation capacity while maintaining the same level of reliability according to the current reliability criteria and practices within the PJM market.

DR compliance can be more complex to measure than compliance for generation resources meeting their capacity obligations. In order to ensure the reliability service for which a Resource is paid has actually been provided, PJM utilizes three different types of measurement and verification methodologies. DR Resources can choose to be measured using:

- Direct Load Control (DLC) – Emergency DR (Load Management) for non-interval metered customers which is initiated directly by a Curtailment Service Provider's (CSP) market operations center, employing a communication signal to cycle HVAC or water heating equipment. This is traditionally done for residential consumers and requires the necessary statistical study as outlined in PJM Manual 19.
- Firm Service Level (FSL) – Emergency DR (Load Management) achieved by a customer reducing its load to a pre-determined level upon the notification from the CSP's market operations center. Industrial customers with a high load factor normally use this approach because they understand the electricity usage for their

[1] The Delivery Year for the capacity construct corresponds to PJM's Planning Year which runs each year from June 1 until May 31 of the following year

base electrical equipment that must operate even during an emergency situation. This is one of the easiest to verify since the firm service level amount is simply compared to the metered load during an event or test.

- Guaranteed Load Drop (GLD) – Emergency DR (Load Management) achieved by a customer reducing its load below the peak load contribution when compared to what the load would have been absent the PJM emergency or test event. This is normally utilized by customers that have a variable load profile to capture the impact of the system relative to what it would have been during the time periods under review.

New measurement and verification rules (M&V) went in to effect for this delivery year. These new rules came about as the result of the resolution of the so called "double counting" issue. The new rules ensure that all load reductions occur below the peak load contribution (PLC). This means each customer that participates should consume less power than their PLC (ie: reliability requirement) during an emergency or test event to comply. One of the effects of this change is evident in the large increase in registrations using the Firm Service Level methodology. Over 70 percent of the committed MWs where registered as FSL (see Figure 5). This is up from 32 percent last year.

Because of the transition to the new M&V rules and their potential impact on the ability to comply with their commitments, CSPs were provided the opportunity, through RPM, to liquate any load reductions which could no longer be delivered. First, a DR Capacity Transition Credit is available that protects the CSP from purchasing more expensive replacement capacity in Incremental Auctions in relation to the BRA price. Second, CSPs with unavoidable contractual obligations to pay their end-use customer(s), may recoup such losses through the Alternative Transition Credit. Both of transition mechanism are only available for the 2012/2013 and 2014/2015 DYs.

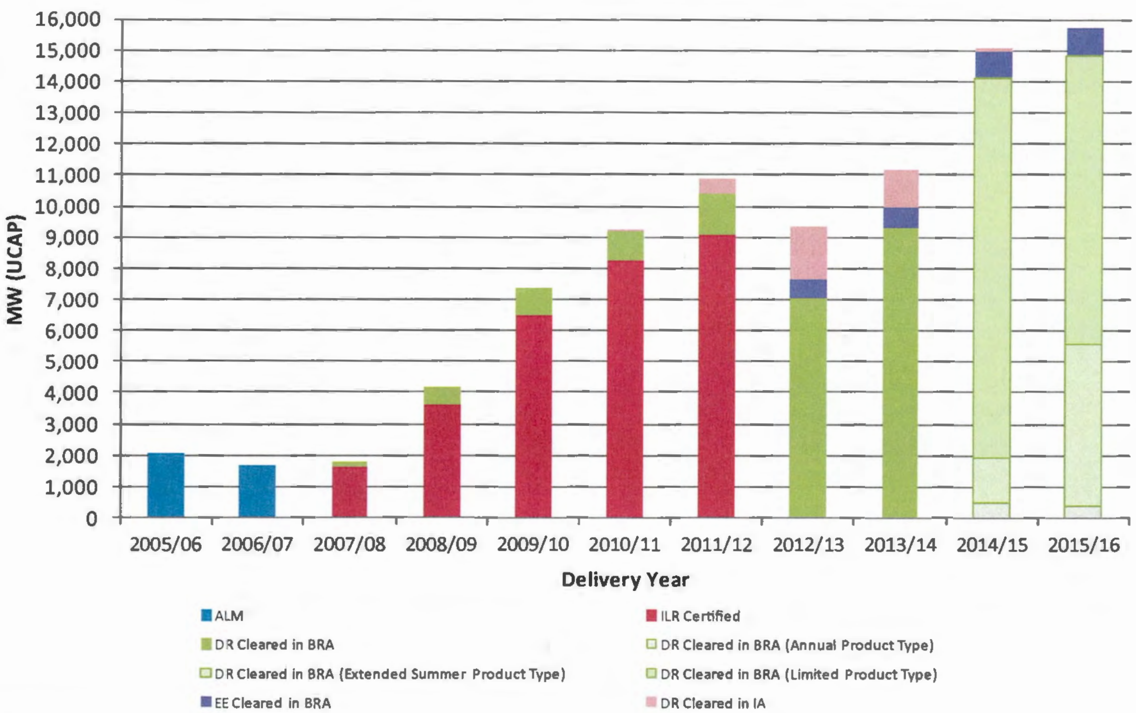
Emergency DR (Load Management) Participation Summary

The capacity numbers in this report are in terms of either Installed Capacity (ICAP) or Unforced Capacity (UCAP) depending upon which is most relevant. PJM calculates the Resource amounts required to meet the reliability standard in terms of UCAP which is also utilized to measure compliance with a RPM commitment. PJM determines the UCAP value of different types of Resources that are offered into the RPM auctions based on methods described in the PJM manuals.

For a conventional generation resource, ICAP value is the summer net dependable rating. The UCAP value is the ICAP value reduced by historical average forced outage and forced derating. Therefore, the UCAP value represents the average availability of capacity from a generating unit after forced outages and forced deratings. For a Emergency DR (Load Management) Resource, ICAP value is the nominated load reduction. The nominated load reduction for a Firm Service Level, Guaranteed Load Drop, or Direct Load Control resource is calculated in accordance with the PJM Capacity Market Manual, Manual 18. The UCAP value is calculated in two steps: First, the nominated load reduction is discounted to account for its reduced impact during higher load periods by multiplying by the Demand Resource Factor. Then, the value is increased to gross up the load reduction by the approved reserve margin.

Emergency DR (Load Management) participation in the PJM capacity construct has increased over time. ALM participation seven years ago in the 2006/2007 Delivery Year was under 1,700 Megawatts (MW). However, the Emergency DR (Load Management) commitments for the next three DYs average just under 13,000 MW each year and up to 14,800 MW by 2015/2016. This increase in participation by Emergency DR (Load Management) Resources reduces the need for generation capacity by providing reductions in demand at the system operator's request. Below is a graphical representation of the growth in Emergency DR (Load Management) participation at PJM in MWs of UCAP.

Figure 3: Emergency DR (Load Management) Participation History (UCAP)



In PJM, capacity is priced based on location to reflect the locational reliability requirements in various sub-regions of the market. The location of the capacity commitments are grouped by the Transmission Zones. Although capacity obligations are measured in UCAP, the most straightforward examination of Emergency DR (Load Management) participation by Zone is in MWs of ICAP. An ICAP value is converted to UCAP by applying a DR factor[2] and Forecast Pool Requirement (FPR) factor[3]. The DR factor accounts for load forecast uncertainty while the FPR is an adjustment for unforced reserve margin. For the 2012/2013 Delivery Year, Emergency DR (Load Management) Resources commitments represented 7,440 MW[4] of ICAP while total registered Emergency DR (Load Management) represented 8,548 MW. Registered Emergency DR (Load Management) may be in excess of the commitment if the CSP has indicated they have the potential to deliver an amount that is higher than their actual commitment[5].

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[2] See "Demand Resource (DR) Factor"; http://www.pjm.com/~/media/committees-groups/committees/cmec/20090805/20090805-item-07b-dr-factor.ashx

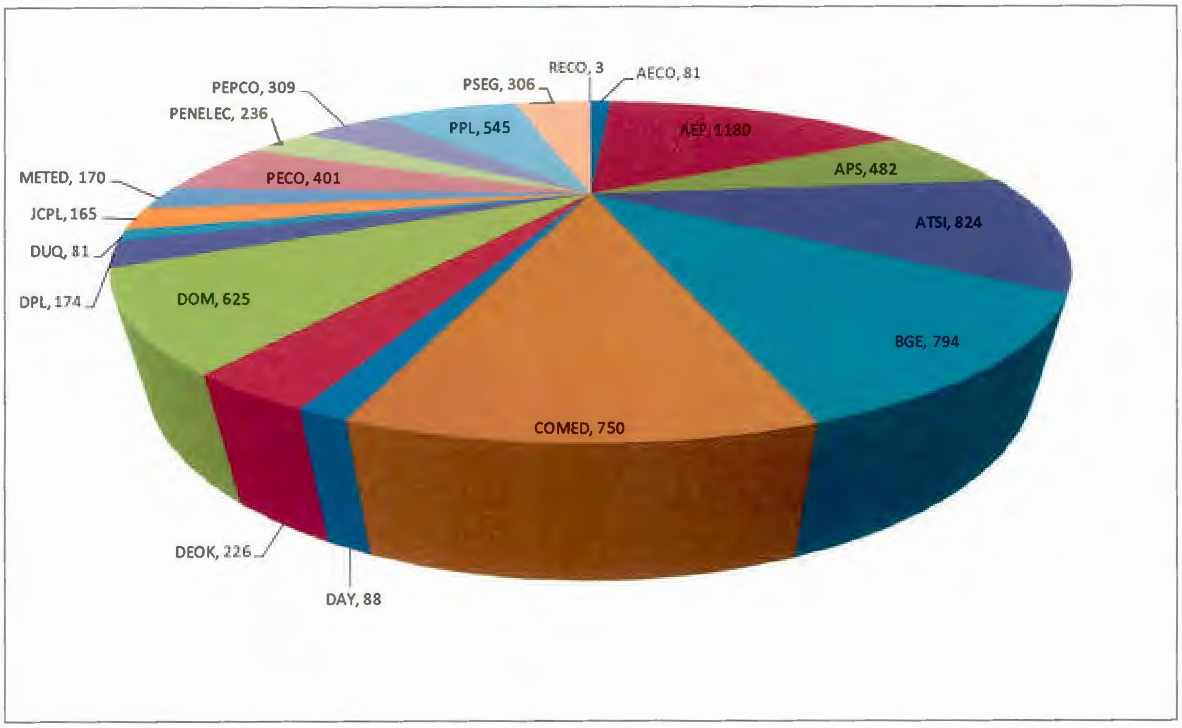
[3] The amount equal to one plus the unforced reserve margin (stated as a decimal number) for the PJM Region.

[4] Includes RPM auctions and FRR commitments

[5] For example, a CSP may clear 10 MW of resources in an RPM auction but register 11 MW load reduction capability by end use customers to fulfill such commitment.

Following is an illustration of how the registrations of Emergency DR Resources were spread across the 19 Zones for the 2012/2013 Delivery Year. Eighty-seven PJM members operate as a Curtailment Service Provider where over 1 million end use customers across almost every segment (residential, commercial, industrial, government, education, agricultural, etc.) participate as a Emergency DR (Load Management) resource

Figure 4: 2012/2013 Emergency DR Participation by Zone (MW ICAP)



Atlantic City Electric (AECO), American Electric Power (AEP), American Transmission Systems, Inc (ATSI), Allegheny Power (APS), Baltimore Gas and Electric (BGE), Commonwealth Edison (COMED), Dayton Power & Light (DAY), Dominion Virginia Power (DOM), Delmarva Power and Light (DPL), Duke Energy Ohio and Kentucky (DEOK), Duquesne Light (DUQ), Jersey Central Power & Light (JCPL), Metropolitan Edison (METED), PECO (PECO), Pennsylvania Electric Company (PENELEC), Potomac Electric Power Co. (PEPCO), PPL Electric Utilities Corp. (PPL), Public Service Electric and Gas Co. (PSEG), Rockland Electric Company (RECO).

Figure 5 below illustrates the percentage of ICAP registered by the major methods where 71 percent represents Firm Service Level, 14 percent represent residential direct load control type resources, 8 percent represents Guaranteed Load Drop that is exclusively provided through a back up generation resource as measured through the output of the backup generator and 6 percent represents Guaranteed Load Drop that is not exclusively provided by a back up generation.[6] Note that although MWs from resources registered as Guaranteed Load Drop via Generation

[6] Firm Service Level and Guaranteed Load Drop (other) may include load reductions achieved with back up generation done in conjunction with another type of control within the facility. Guaranteed Load Drop (back up gen only) represents an estimate of facilities that substantiate load reduction based on meter data from the back up generator, exclusively.

account for 8 percent of the total committed load, event and test data submissions show that generator output accounts for 9 percet of the nominated total, just slightly more than the committed amount.

Figure 5: Percent of Committed ICAP

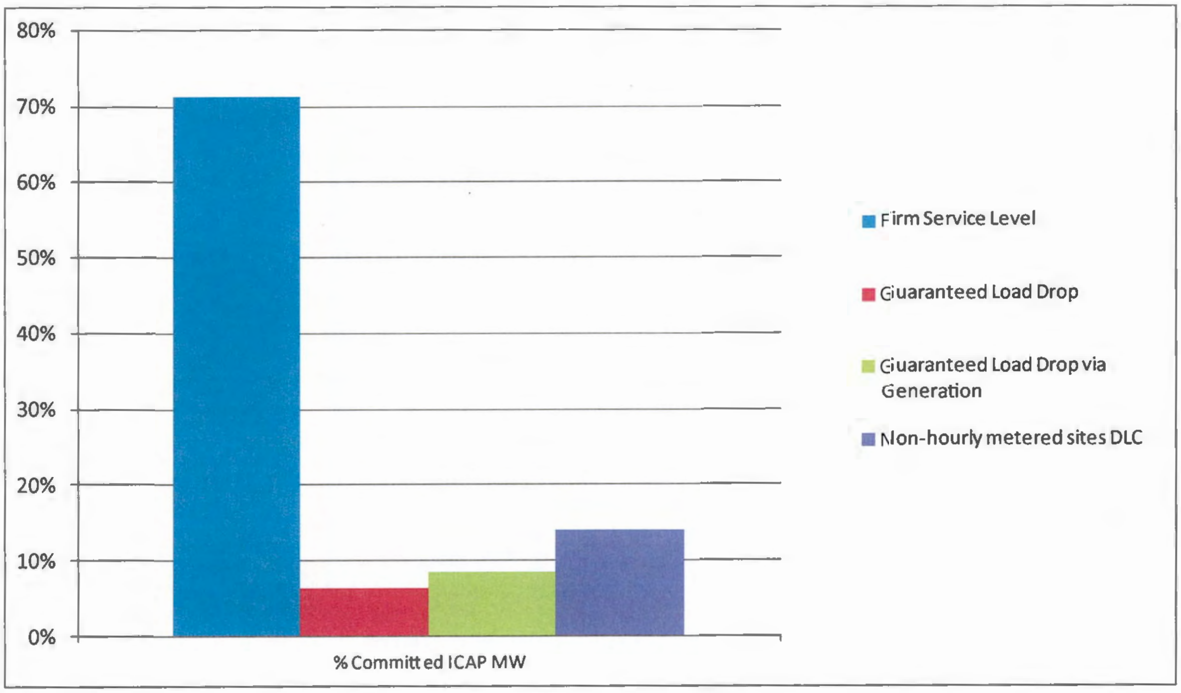
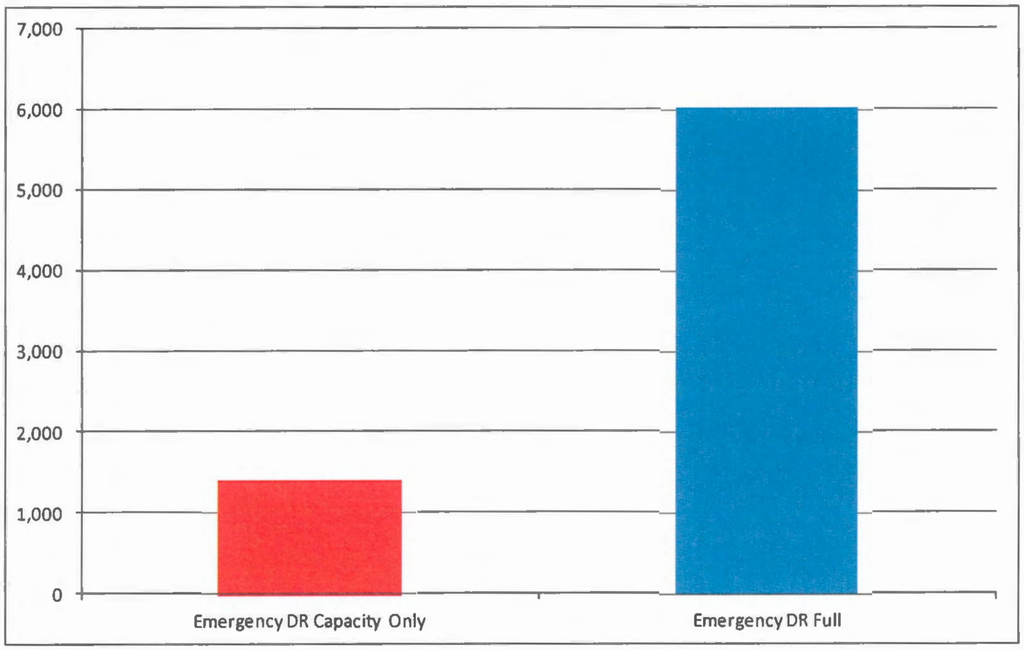


Figure 6 represents the current number of committed ICAP MWs for Emergency DR and is segmented to show the number of MWs registered as an Emergency Full resource (that receive both capacity revenue stream as well as an emergency energy revenue stream when there is an emergency DR (load management) event), compared to the number of MWs registered as Capacity Only (which indicates the CSP is not eligible for any emergency energy payments during an event). Approximately 19 percent of the total was registered as Capacity Only.

Figure 6: MW of Committed ICAP as Full or Capacity Only



2012 Emergency DR (Load Management) Events

Emergency DR is relied upon by PJM planning and PJM system operations to help maintain the safe and reliable operation of the PJM region. PJM had two Emergency DR (Load Management) events in 2012. Following is an overview of PJM Emergency DR (Load Management) events over the past 13 years.

Figure 7: Emergency DR (Load Management) Event History

Delivery Year	Event History
2012/2013	Tuesday, July 17, HE 1700[7] – 1900[8] Wednesday, July 18, HE 1700
2011/2012	Friday, July 22, HE 1300 – 1900
2010/2011	Tuesday, May 31, HE 1800 – 1900 Thursday, May 26, HE 1800 Friday, September 24, HE 1400 – 1800 Thursday, September 23, HE 1200 - 2000 Wednesday, August 11, HE 1500 – 1900 Wednesday, July 7, HE 1500 – 1900 Friday, June 11, HE 1700 – 2000
2009/2010	Wednesday, May 26, HE 1900 – 2000
2008/2009	No events

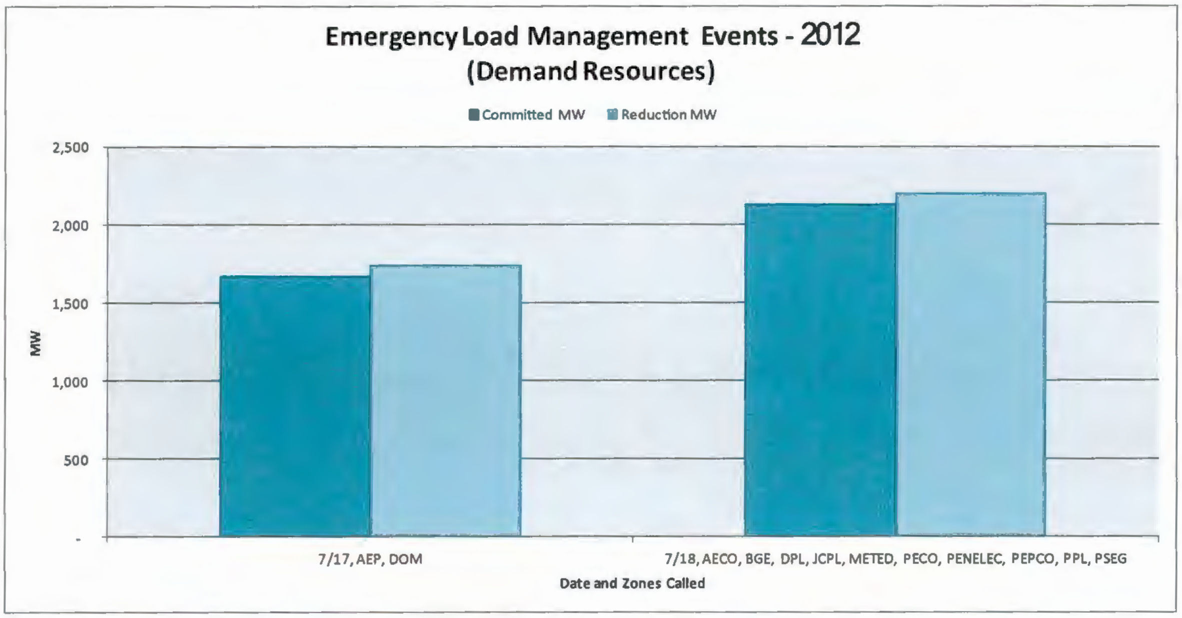
[7] HE in the table is an abbreviation for Hour Ending. For example, HE 1500 – 1800 is the same as the expression 2:00 PM until 6:00 PM.

[8] The times shown for each event are the beginning and end of compliance reporting times. Events are not called or released exactly on the hour and all Resources are expected to improve reliability by decreasing load or increasing generation as soon as practicable. The times shown are a summary of all Zones but the event may have been shorter or not even called in some Zones.

Delivery Year	Event History
2007/2008	Wednesday, August 8, HE 1500 - 1800
2006/2007	Thursday, August 3, HE 1500 – 1900 Wednesday, August 2, HE 1600 – 1900
2005/2006	Thursday, August 4, HE 1600 - 1700 Wednesday, July 27, HE 1400 - 1800
2004/2005	No events
2003/2004	No events
2002/2003	Tuesday, July 30, HE 1300 - 1800 Monday, July 29, HE 1500 - 1800 Wednesday, July 3, HE 1300 – 1800
2001/2002	Friday, August 10, HE 1300 - 1400 Thursday, August 9, HE 1300 - 1800 Wednesday, August 8, HE 1400 - 1800 Wednesday, July 25, HE 1600 - 1700
2000/2001	No events

PJM calls Emergency DR (Load Management) events by zone (or sub-zone) and by lead time. This allows PJM to address system conditions in a targeted, measured and phased manner. Figure 8 below depicts the overall performance for each of the 2012 Emergency DR (Load Management) events:

Figure 8: 2012 Emergency DR (Load Management) Events



Looking further into each event, the Figures 9 and 10 below show the hourly performance values for each event. As can be seen in both overall and hourly performance, the results are higher than anticipated. Review of the data shows that in all hours of the events the reductions provided by CSPs exceeded their committed values.

Figure 9: July 17, 2012 Hourly Performance

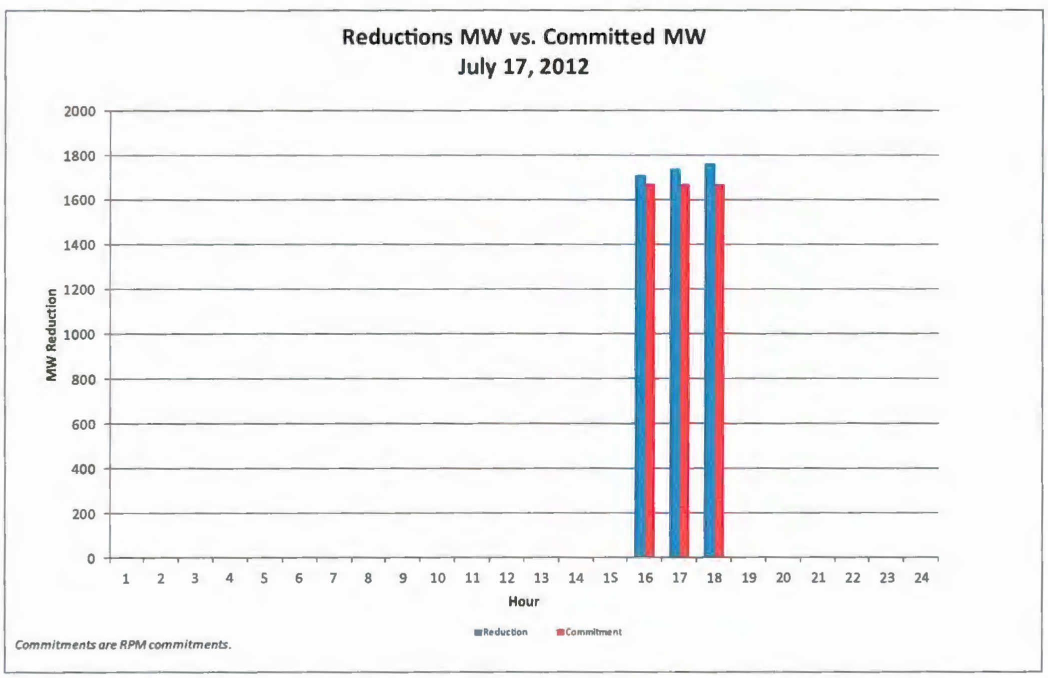
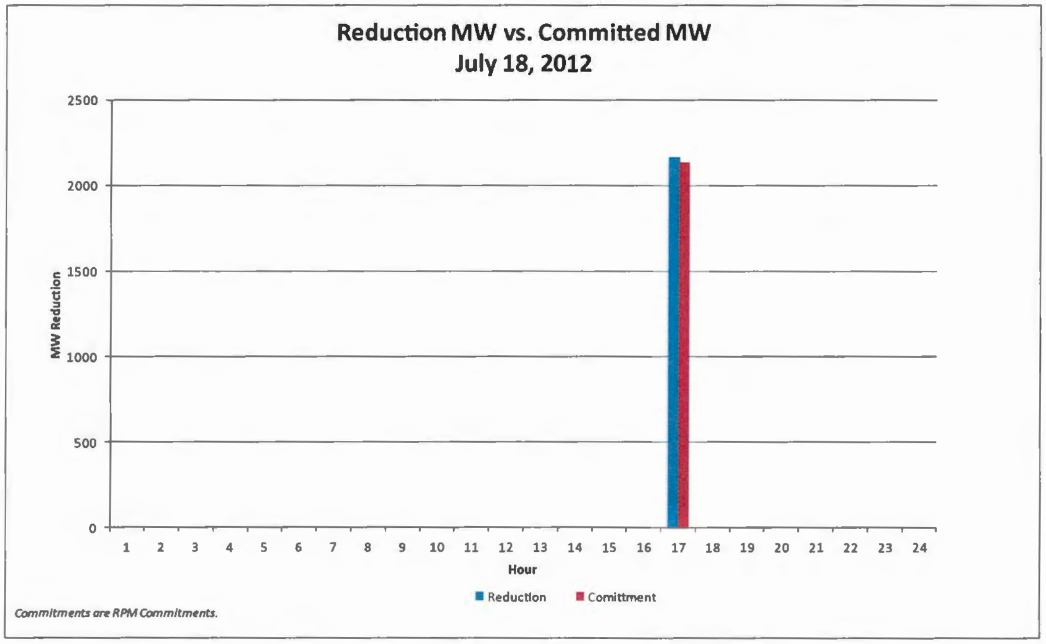


Figure 10: July 18, 2012 Hourly Performance



Event performance measurement can also be broken down by the specific zones called upon and the lead time of the resources. Only long lead time resources were called on for the July 17th event. The July 18th event was called in ten zones in a combination of long and short lead time resources. Performance for those Emergency DR (Load Management) events, by zone and lead time, is depicted in Figure 11 below. Zonal performance ranged from 11 percent to 141 percent.

Figure 11: 2012 Emergency DR (Load Management) Event Performance by Zone

EventDate	Committed MW	Reduction MW	Performance MW	Performance Percentage	Zone	Lead Time
7/17/2012	1046	1101	55	105%	AEP	Long
7/17/2012	624	635	11	102%	DOM	Long
7/18/2012	32	36	4	112%	AECO	Short
7/18/2012	705	727	22	103%	BGE	Long
7/18/2012	90	91	1	101%	BGE	Short
7/18/2012	127	113	-14	89%	DPL	Long
7/18/2012	47	48	2	103%	DPL	Short
7/18/2012	141	162	21	115%	JCPL	Long
7/18/2012	24	31	7	129%	JCPL	Short
7/18/2012	11	16	5	141%	METED	Short
7/18/2012	401	408	8	102%	PECO	Long
7/18/2012	0.7	0.4	-0.3	62%	PECO	Short
7/18/2012	236	238	2	101%	PENELEC	Long
7/18/2012	0.2	0.1	-0.1	26%	PENELEC	Short
7/18/2012	201	194	-7	96%	PEPCO	Long
7/18/2012	107	137	29	127%	PEPCO	Short
7/18/2012	1.9	1	-1	54%	PPL	Short
7/18/2012	10	1	-9	11%	PSEG	Short

CSP Event Performance

CSP performance is measured for each event by zone for all resources that were dispatched by PJM. The DR reductions made in a zone are compared to each CSP's reduction commitment. Under performance is penalized and over performance can be rewarded (within limits and to the extent that there were underperformance penalties paid, see Event Performance Penalties). Figures 12 and 13 below depict the performance of all CSP/zone combinations over each of the summer 2012/2013 DY Emergency DR (Load Management) events. It can be seen that performance is approximately normally distributed. In the July 17th event fifty-eight percent of CSPs zonal performance was within the 81 percent to 120 percent range while seventy-four percent feel into the wider range between 41 percent and 160 percent. For the July 18th event forty-seven percent of CSPs zonal performance was within the 81 percent to 120 percent range while eighty percent were between 41 percent and 160 percent. And, as expected, some performed better, others worse.

Figure 12: CSP Zonal Performance 7/17 Event

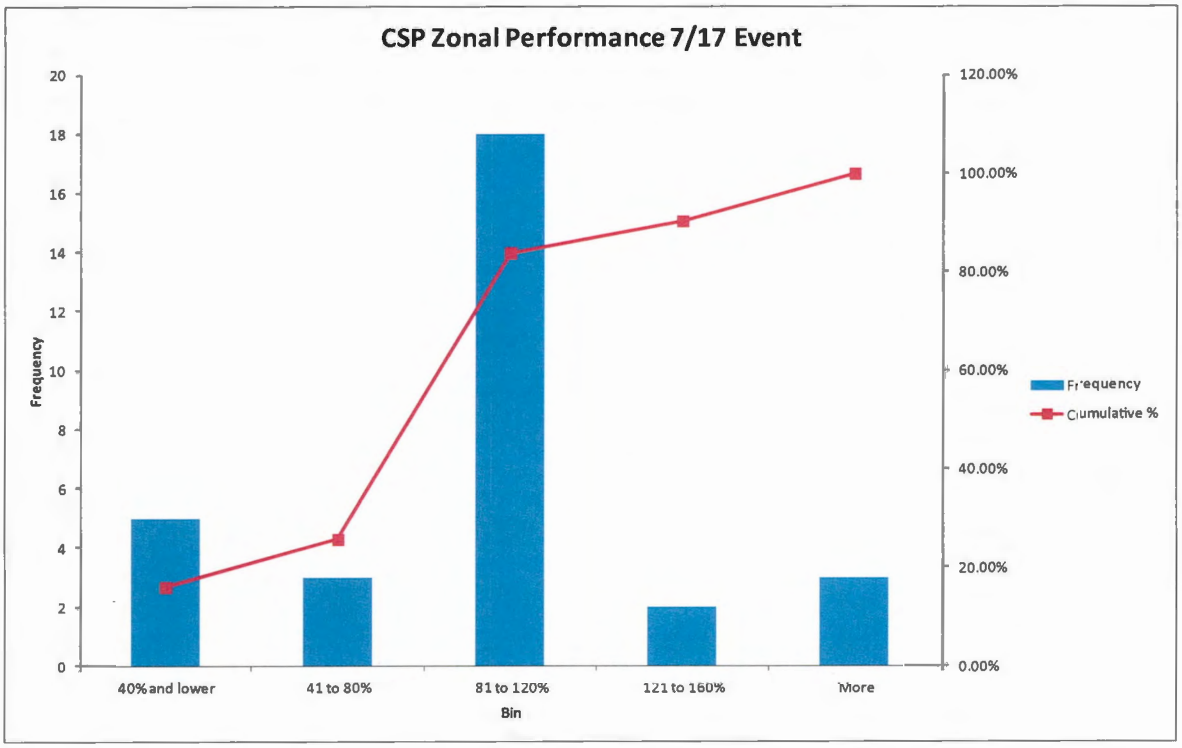
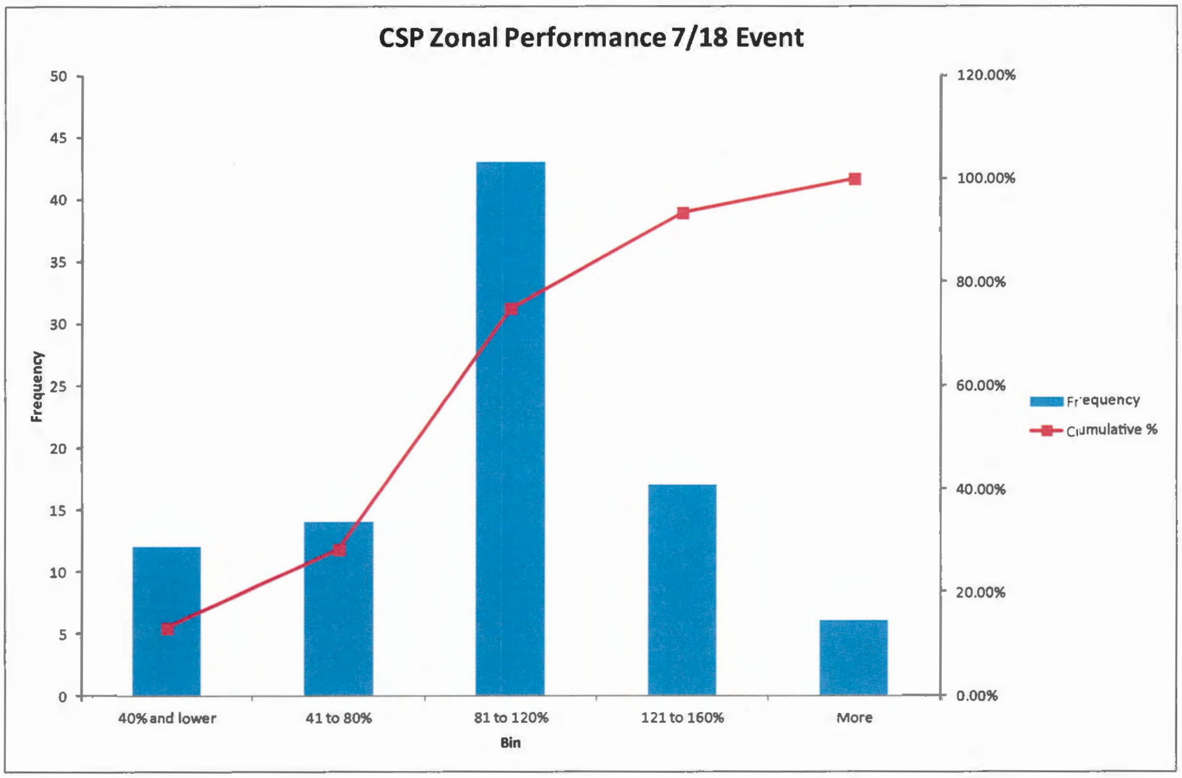


Figure 13: CSP Zonal Performance 7/18 Event



When comparing the event performance in 2012 with that of 2011 we see shifted results. In 2012 the CSP zonal performance shows a measurable shift out of the 41 percent to 80 percent category into the 0 to 40 percent and 121 to 160 percent ranges. The performance of the higher achieving group outweighed the under-performing group thus providing overall higher 2012 event performance results. The portion of CSP zonal performance at high tail of the distribution was similar year-over-year. Figure 14 below depicts the performance of all CSP/zone combinations over all of both the 2011 and 2012 Emergency DR (Load Management) events. It should be noted that there was only a single compliance event in 2011 as compared to two in 2012.

Figure 14: CSP Zonal Performance 2011 vs. 2012

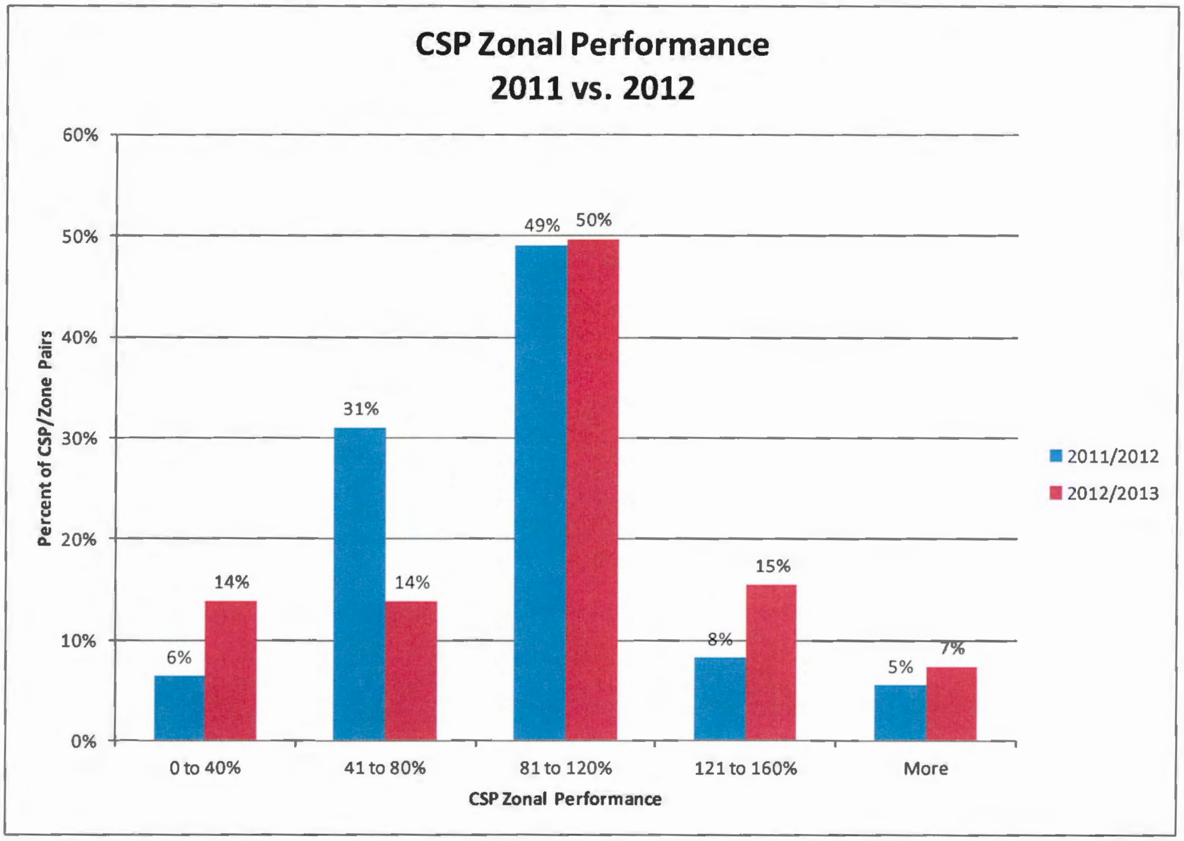
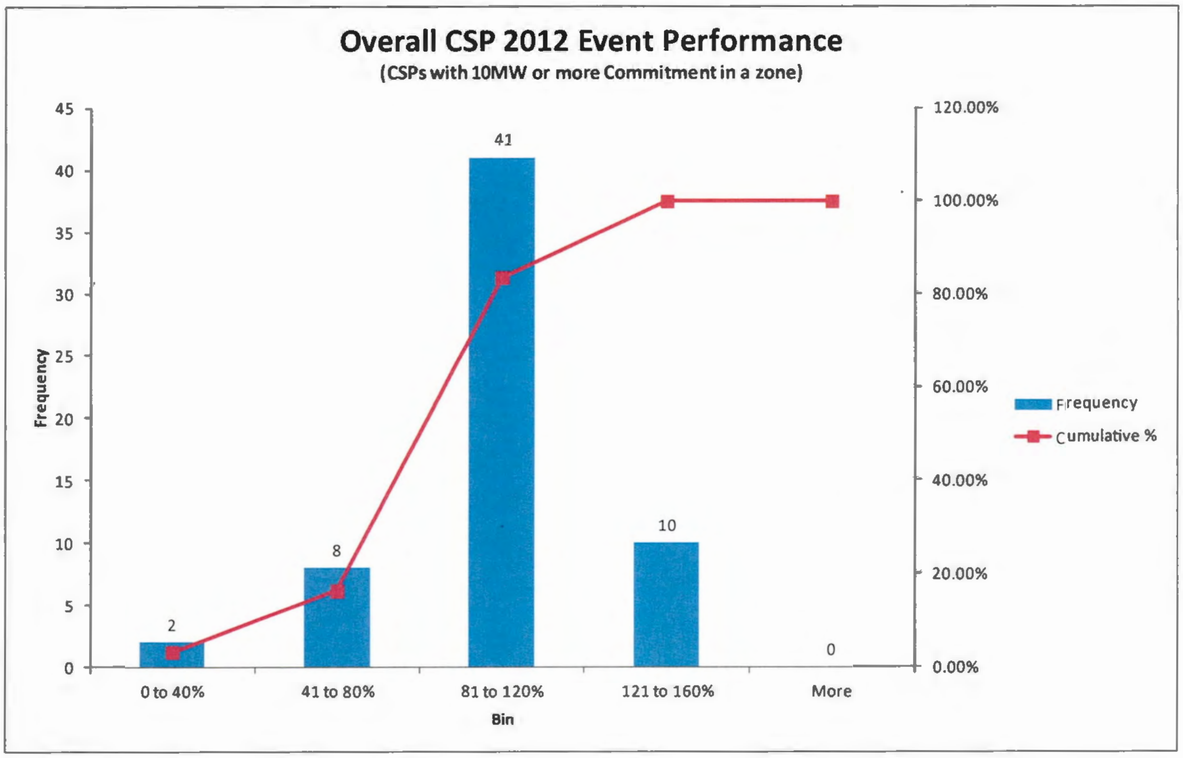


Figure 15 shows the combined – across zones and events -- performance of large CSPs for 2012. There were 26 CSPs with commitments of at least 10MWs in a zone. For purposes of the analysis these are considered large CSPs. The previous three charts included the performance of all CSPs, including the very small ones. Removing the small CSPs from the analysis provides a look at performance of members providing most of the load reductions. The frequency distribution of this group is almost normally distributed with no CSP performance in the high tail and only 2 in the low tail. This is a change from last year when there was a more scattered distribution.

Figure 15: Overall Large CSP Event Performance

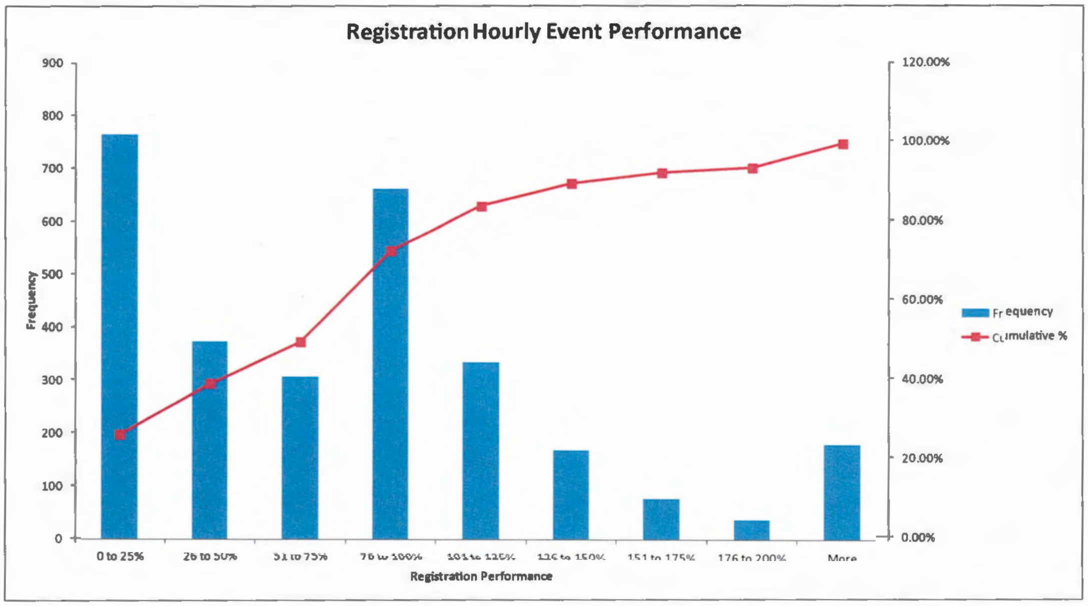


Registration Event Performance

Although CSP compliance is aggregated to a zonal level, PJM initially calculates performance by registration by end use customer by event by hour. Figure 16 below depicts the individual hourly performance of each registration called on for the 2012 Emergency DR (Load Management) events. Unlike the CSP performance above, the registration performance does not exhibit a normal distribution. Rather, the distribution has significant amount of activity in each "tail" which represents more extreme hourly resource event under and over performance. These tails represent significant numbers of registrations with low performance values (less than 25 percent) and another group with high performance values (greater than 200 percent) which offset through the aggregation of overall portfolio performance.

This effect is when, within a CSPs portfolio of registrations, some registrations over perform for the benefit of those that under perform yielding an aggregate performance that is satisfactory. The high performance can come from two possible situations. First, a site with a relatively high PLC may conservatively register with a reduction commitment that is much lower than the PLC and when called on to perform, would provide a reduction well in excess of its' registered commitment. The second situation is when a site with a relatively low PLC (i.e. a site that makes an effort to lower its load on days likely to be peak load days in order to avoid a high capacity cost) registers with a low reduction commitment because it is limited by its low PLC. However, when this site is called on to perform, it will provide a reduction well in excess of its registered commitment. This second situation does not occur this year due to the implementation of new M&V rules that limit the calculated reduction quantity to the PLC value[9].

Figure 16: Registration Hourly Event Performance



Event Performance Penalties

Emergency DR (Load Management) Event Penalties are assessed by CSP and zone and then disbursed to CSPs that over-perform and where necessary to LSEs. However, to preserve confidentiality, the results are reported on an aggregated basis. Emergency DR (Load Management) Event Penalties and Credits are currently billed as an annual lump sum. Figure 17 summarizes the annual charges and credits by Event. The total amount of Emergency DR (Load Management) Event Penalties assessed for the 2012 events is $2 million/year ($5.6 million last year). To put this value into context it is important to note that total CSP revenues for DR are approximately $267.5 million per year ($420 million last year). The penalty charges are about 0.7 percent of the total revenue (1.3 percent last year). The Emergency DR (Load Management) Event Charges collected from CSPs are first allocated on a pro-rata basis to those CSPs that provided load reductions in excess of the amount obligated. Any Emergency DR (Load Management) Event Charges not allocated to over-performing CSPs are further allocated to all LSEs in the RTO pro-rata based on Load Contribution.

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[9] This second situation had raised both a compliance and policy issue and was discussed at length in the Load Management Task Force, Markets Implementation Committee and reviewed at the Markets and Reliability Committee. Namely, should reductions achieved by registrations whose load was above its PLC at the time of the event be available to offset underperformance of other registrations. The FERC issued an order disallowing these reductions.

Figure 17: Emergency DR (Load Management) Event Penalties and Credits

	Annual Penalties	Annual Credits to Over-Performers	Annual Credits to LSEs
July 17, 2012 LM Event	$ 202,520.25	$ 189,657.65	$ 12,862.60
July 18, 2012 LM Event	$ 1,835,179.85	$ 1,018,612.80	$ 816,567.05
Total	**$ 2,037,700.10**	**$ 1,208,270.45**	**$ 829,429.65**

Emergency Energy Settlements

For Emergency DR events, Full Emergency type registrations are entitled to submit settlements for the energy reductions provided. The compensation is based on each registration's strike price and the LMPs during the event. Figure 18 shows the settlement values for each of the 2012 Emergency DR (Load Management) Events.

Figure 18: Emergency Energy Settlements for 2012 Events

Load Management Events	Emergency Energy Settlements
7/17/2012	$4,762,053
7/18/2012	$5,719,281
Total	$10,481,333

Reductions for Compliance and Emergency Energy Settlements

Load reductions during emergency events are calculated separately for purposes of compliance and emergency energy settlements. When calculating the reduction values used for compliance, the specific methodology depends on the type selected by the CSP during the registration: GLD, FSL or DLC. For GLD a CSP further determines the specific baseline calculation that results in the best estimate of what the facility's load would have been absent the reduction made for the Emergency DR (Load Management) event[10]. The CSP has five different calculation methods available to achieve the best estimate. For FSL the CSP simply reports the load level of the facility during the hours of the event and that value is subtracted from the PLC. Finally, for DLC the CSP reports exactly when the signal was sent to the end use customers to control the specific switches. Compliance reductions are calculated for all participants of an event.

When calculating reduction values for emergency energy settlements the procedure is different. For GLD and FSL the CSP calculates hourly reductions during events by subtracting the load at the facility during each hour from the load of the facility prior to the start of the event. For DLC, the CSP reports the load reduction from its approved estimation technique. Emergency energy settlements are only available to Full Emergency registrations. In order to receive a payment for an energy reduction the CSP must submit accurate data within the prescribed timeframe (60

[10] The CSP may also use meter data from a back up generation resource to determine the net metered load reduction at the site.

days from the event). Not all CSPs submit settlement data and if a facility had already fully reduced its load prior to the event, it cannot receive an emergency energy payment. Further, Emergency Capacity Only registrations by definition do not receive an emergency energy payment.

PJM analyzed compliance and emergency settlement data for the July 17th and 18th events for resources registered as Full Emergency to get an understanding of the difference in the measurement of load reduction based on capacity compliance rules compared to emergency energy rules. Average hourly load reductions based on capacity compliance rules were 1,077 MW and 2,120 MW for the 17th and 18th respectively. The average hourly load reductions based on emergency energy settlements for the same hours were 1,085 MW and 1,817 MW respectively. The three primary reasons for the difference are: 1) customers that may have reduced load earlier for the specific day, 2) the fundamental difference in how the load reductions are measured and 3) participants that did not submit the appropriate data for either capacity compliance or energy settlements.

2012 Emergency DR (Load Management) Tests

The implementation of the forward capacity market, RPM, has incented an increase in capacity-based demand response which has been beneficial to the region. Given the increasing dependence on demand response to maintain reliability, PJM has implemented annual Emergency DR (Load Management) Tests as a means to assess performance of Emergency DR (Load Management) resources that had not been called on to participate in an actual emergency event.

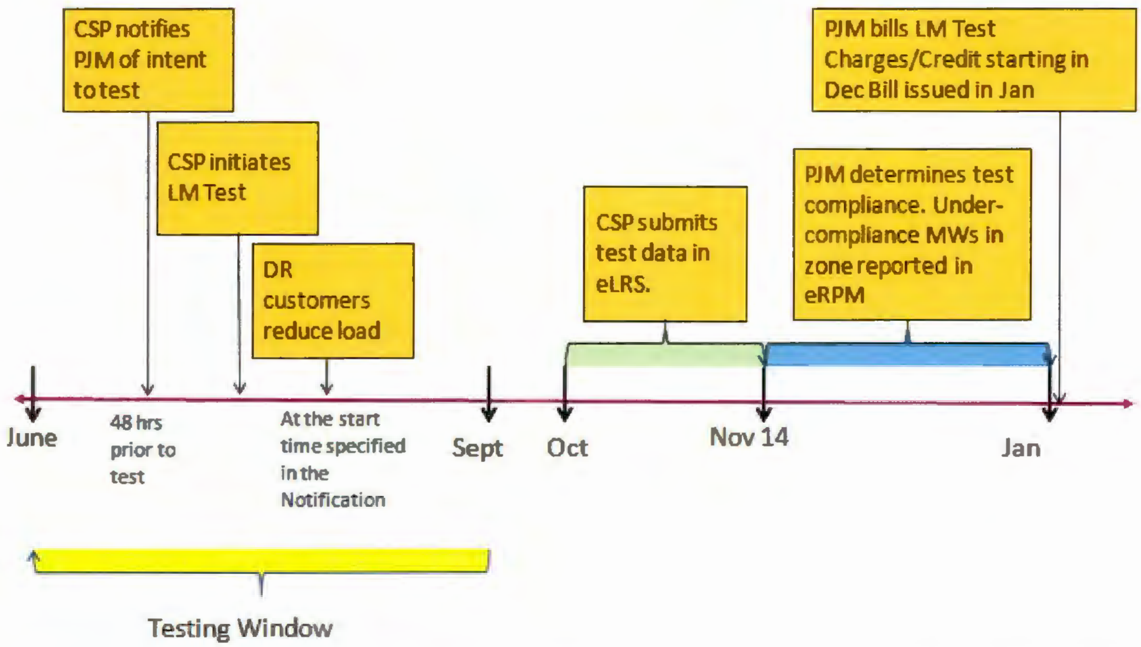
The Emergency DR (Load Management) Test is initiated by a Curtailment Service Provider (CSP) that has a capacity commitment. The CSP must simultaneously test all Resources in a Zone if PJM has not called an event in that Zone by August 15th of a given Delivery Year. If a PJM-initiated Emergency DR (Load Management) Event is called in a Zone between June 1st and September 30th there is no test requirement and no Test Failure Charges would be assessed to a CSP for that Zone.

The timing of a Emergency DR (Load Management) Test is intended to represent the conditions when a PJM-initiated Emergency DR (Load Management) event might occur in order to assess performance during a relative period. Therefore, a Emergency DR (Load Management) Test may occur from June 1st through September 30th on a non-holiday weekday during any hour from 12 noon until 8 PM EPT. All of a CSP's committed DR resources in the same Zone are required to test at the same time for a one hour period. The requirement to test all resources in a zone simultaneously is necessary to ensure that test conditions are as close to realistic as possible. It is requested that the CSP notify PJM of intent to test 48 hours in advance to allow coordination with PJM dispatch.

There is not a limit on the number of tests a CSP can perform. However, a CSP may only submit data for one test to be used by PJM to measure compliance. If the CSP's Zonal Resources collectively achieve a reduction greater than 75 percent of the CSP's committed MW volume during the test, the CSP may choose to retest the Resources in that Zone that failed to meet their individual nominated value.

CSPs must submit their test data using PJM's Load Response System (eLRS). For the 2012/2013 Delivery Year, the test data deadline was November 14, 2012. PJM reviews the information and contacts the CSP for additional supporting information where necessary. PJM determines test compliance and reports the information in PJM's RPM system (eRPM) during December. Any Emergency DR (Load Management) charges or credits are normally issued in January on the December bill.

Figure 19: Emergency DR (Load Management) Test Timeline



Emergency DR (Load Management) Resources are assessed a Test Failure Charge if their test data demonstrates that they did not meet their commitment level. The Test Failure Charge is calculated based on the CSP's Weighted Daily Revenue Rate which is the amount the CSP is paid for their RPM commitments in each Zone. The Weighted Daily Revenue Rate takes into consideration the different prices DR can be paid in the same Zone. For example, a CSP can clear DR in the Base Residual and/or Incremental Auctions in the same Zone, all of which are paid different rates. The penalty rate for under-compliance is the greater of 1.2 times the CSP's Weighted Daily Revenue Rate or $20 plus the Weighted Daily Revenue Rate. If a CSP didn't clear in a RPM auction in a Zone, the CSP-specific Revenue Rate will be replaced by the PJM Weighted Daily Revenue Rate for such Zone.

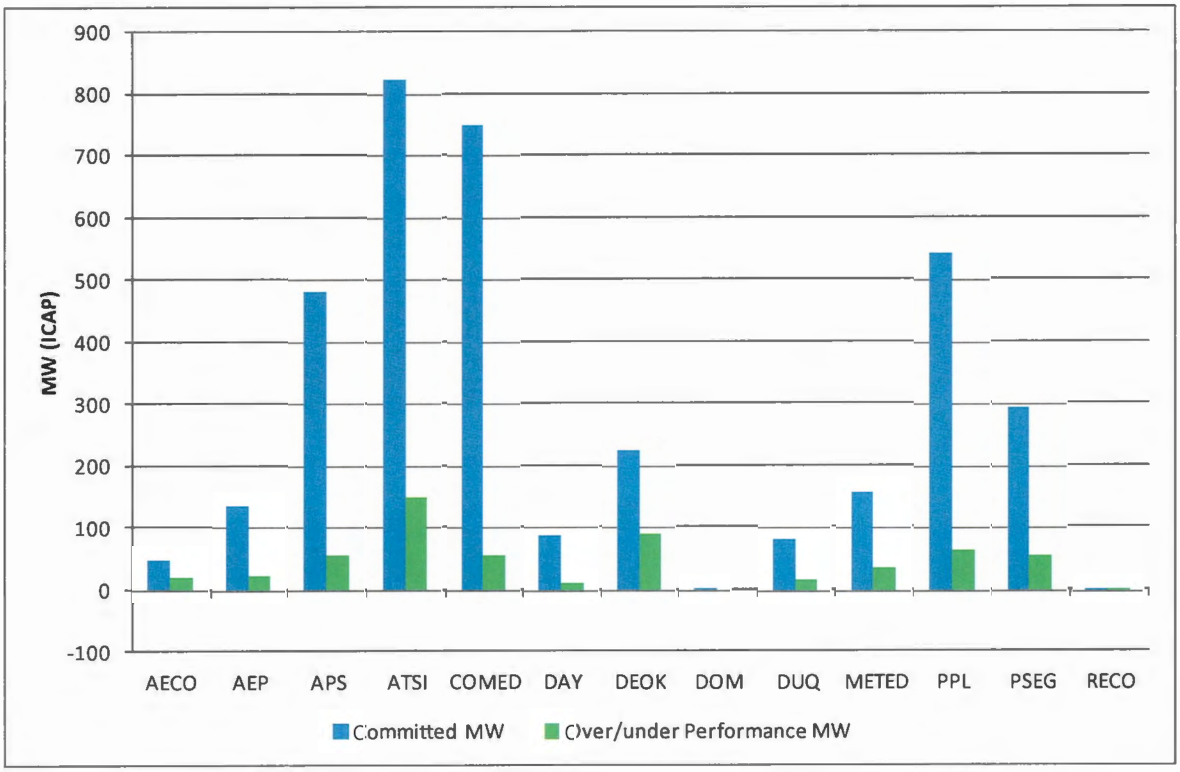
Emergency DR (Load Management) Test Results

There were 3,635 MW in ICAP of committed Emergency DR (Load Management) Resources that were not called upon to participate in any 2012/2013 Delivery Year emergency event. As a result, these resources were required to perform a test to assess their performance capability. Testing was performed by 51 CSPs in 12 Zones which resulted in a total of 133 CSP/Zone combinations. The over-compliance across all Zones and CSPs totaled 585 MW which equates to a performance level of 116 percent. Of the 3,635 MW of committed MWs, registrations with a combined commitment of 14 MW retested. The initial tests for these registrations showed a reduction value of 6 MW. After retesting, their reduction value was 16 MW, a 10 MW improvement. In tabular form, the Zonal results are as follows:

Figure 20: Emergency DR (Load Management) Commitments, Compliance, and Test Performance (ICAP)

Test Results				
Zone	Committed MW	Reduction MW	Over/under Performance MW	Performance Percentage
AECO	49	68	19	139%
AEP	134	158	24	118%
APS	482	538	56	112%
ATSI	824	973	149	118%
COMED	750	807	58	108%
DAY	88	99	11	112%
DEOK	226	316	90	140%
DOM	1.1	0.8	-0.3	70%
DUQ	81	98	18	122%
METED	159	196	37	123%
PPL	543	609	66	112%
PSEG	296	352	56	119%
RECO	3	5	2	164%
Total	3,635	4,220	585	116%

Figure 21: Emergency DR (Load Management) Test Obligations and Compliance (ICAP)



The performance on an individual CSP/Zone basis varied. Overall, 99 (74 percent) CSP/Zone combinations complied or over-complied in their Emergency DR (Load Management) Tests for the 2012/2013 Delivery Year. The over-compliance averaged 7 MW per CSP/Zone combination and totaled 660 MW of over-compliance. There were 34 (26 percent) CSP/Zone combinations that under-complied. The under-compliance averaged 2 MW per CSP/Zone combination for a total of 75 MW of under-compliance.

Test Failure Charges for the 2012/2013 Delivery Year are applied on an individual CSP/Zone basis for settlement purposes. However, the Test Failure Charges are reported on an aggregate basis here to preserve confidentiality. The average Penalty Rate for the 2012/2013 Delivery Year is $63.90/MW-day ($127.87 last year). This Penalty Rate is an average of $53.09/day when weighted by the under-compliance amounts ($130.37 last year). The annual penalties for under-compliance total just over $1.7 million which will be allocated to RPM LSEs pro-rata based on their Daily Load Obligation Ratio ($6.4 million last year). To better understand the order of magnitude, the under-compliance penalties compare to the total Emergency DR (Load Management) annual credits of just over $267.5 million ($420 million last year). Therefore, the under-compliance penalties are about 0.6 percent of the Emergency DR (Load Management) credits in the RPM (1.5 percent last year).

Edge, Valerie (DOJ)

To: Edge, Valerie (DOJ)
Subject: FW: DR bonus payment details

From: Nick Lake [mailto:nlake@enernoc.com]
Sent: [redacted] January 31, 2013 [redacted]
To: [redacted]
Subject: DR bonus payment details

[redacted]

ENERNOC

Problem viewing email? View in browser.

[redacted]

There has never been a better time to sign up for EnerNOC demand response. Payments for participating facilities in your geographical area are at their all-time high, meaning you will earn significantly more money for your participation than in past years.

Additionally, EnerNOC is offering a **$2,000 per MW bonus payment for new demand response customers who enroll before February 15th.** Early enrollment is beneficial to the electric grid, to demand response participants, and to EnerNOC, so we want to reward facilities who sign up early. This bonus payment is in addition to the ongoing revenues you would earn from EnerNOC.

Find out why thousands of Mid-Atlantic firms choose EnerNOC year after year. As always, EnerNOC demand response involves no risk for participants and no upfront or ongoing costs. You maintain control of your facility at all times, plus you get powerful tools to minimize your energy costs using our free, award-winning, energy management application, DemandSMART.

Would you be available for a meeting next week to discuss?

Best regards,
Nick

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