A Review of the October 2019 Performance Assessment Event

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Contents

Original Publications

The paper A Review of the October 2019 Performance Assessment Event was originally released to the PJM Operating Committee in November 2019.

The appendix Performance Assessment Interval Settlements was originally released to the PJM Market Implementation Committee in March 2020.

Executive Summary

In early October, generators, transmission operators and load management resources successfully worked with PJM operators to maintain reliability during a short, abnormal October heat wave that led to emergency procedures, a Performance Assessment Interval and the first call on demand response resources in more than five years. This report details the conditions leading to these events, the actions PJM took, the decision-making behind those actions, conclusions and next steps.

PJM operators used the tools available to them to help ensure reliability and the delivery of bulk electricity to customers in the region without interruption. In general, these tools worked as designed, and prices largely reflected the tight system conditions resulting from extremely warm weather during a time when generation and transmission resources normally are out of service for maintenance. The most striking anomaly was load levels in the AEP and Mid-Atlantic zones that came in significantly below forecast. PJM has been and will continue to analyze this issue as well as pricing and operational issues that revealed themselves during this event.

PJM recognizes and appreciates the significant dedication of personnel throughout the PJM membership that ensured the reliable provision of service to wholesale customers during this period.

In Short: Events of Oct. 1 and Oct. 2

October is part of the fall shoulder season, when critical planned maintenance activities take generators out of service, significantly lowering the available generating capacity in the PJM footprint. Temperatures and load tend to be mild during this time. On Oct. 1, hot weather across much of PJM's footprint resulted in peak demand that exceeded the load forecast by about 5,500 MW, peaking at more than 125,500 MW. Peak demand at this time of year is typically closer to 100,000 MW.

As demand ramped up, PJM took several actions, including calling on spinning reserves for about 15 minutes, initiating a Shared Reserves event and importing an estimated 800 MW of power from a neighboring system. The rising demand also triggered three intervals of shortage pricing.

On the evening of Oct. 1, to meet the Day-Ahead Scheduling Reserve for Oct. 2, PJM called a Maximum Generation Emergency/Load Management Alert, an early alert that system conditions may require the use of the PJM emergency procedures. PJM also revised the load forecast for Oct. 2 to a peak of more than 132,000 MW as temperatures were forecast to be even higher in most of the PJM footprint.

Complicating the matter, on the morning of Oct. 2, a 765 kV transmission line was automatically taken out of service to isolate failed equipment, which heightened concerns about PJM's load/capacity position for the peak. And later in the morning, PJM was notified that as much as 2,000 MW of generation that was expected to be online would not be available for the peak of the day.

At noon on Oct. 2, PJM issued a two-hour lead time Pre-Emergency Load Management Reduction Action in the Dominion, PEPCO, Baltimore Gas & Electric (BGE) and AEP zones to address capacity concerns and to manage transmission constraints through the peak. This action triggered a Performance Assessment Interval (PAI), in which capacity resources in the affected zones are required to perform – PJM's first since the program was implemented that affected generation resources.

It was also the first time demand response was called on in more than five years, triggered by the Pre-Emergency Load Reduction Action. Early analysis shows an estimated 725 MW of demand response was initiated in response to the call. PJM will release final demand response numbers as soon as they are available.

Contrary to expectations, the Oct. 2 actual peak only reached 126,500 MW, significantly lower than the projected 132,000 MW forecast. PJM is working to understand the difference between the forecast and the actual peak. Those efforts are described later in this paper, as is a detailed account of the conditions, actions and decision-making behind the actions of Oct. 1 and 2.

What are Performance Assessment Intervals?

Purpose Behind Capacity Performance

The Polar Vortex of 2014 made it clear to PJM Interconnection that stronger incentives were needed to encourage investment to ensure better generation performance year-round. During that event, on the coldest day of the year, 22 percent of the generation in PJM was unexpectedly unavailable to serve customers. That event demonstrated that resources of all types could be vulnerable to extreme conditions and that years of relatively mild weather may have led to less focus on generator maintenance.

In response to changing grid conditions and generator performance, on June 1, 2016, PJM implemented Capacity Performance rules to ensure that capacity resources are available whenever they are needed and to transition unit performance risk from load to generation, especially in extreme weather conditions. These rules are intended specifically to encourage resources to make needed upgrades in plant equipment, weatherization measures, fuel procurement arrangements, fuel supply infrastructure and other factors.

How Capacity Performance Works

Under Capacity Performance, resources must meet their commitments to deliver electricity whenever PJM determines they are needed to meet power system emergencies. As a pay-for-performance requirement, resources may receive higher capacity payments and, in return, are expected to invest in modernizing equipment, firming up fuel supplies and adapting to use different fuels. Capacity Performance also incentivizes investment in new resources that are very reliable, available to meet demand during peak system conditions and therefore help to reduce costs in the energy markets. Resources with Capacity Performance commitments that fail to perform during power system emergencies are subject to significant non-performance charges.

PJM took a phased approach to implementing Capacity Performance. The number of megawatts cleared in the Reliability Pricing Model (RPM) capacity market as Capacity Performance increases each year until the delivery year 2020/2021, when all PJM resources are required to meet Capacity Performance requirements. For the 2019/2020 delivery year, approximately 84 percent of resources are required to meet Capacity Performance requirements.

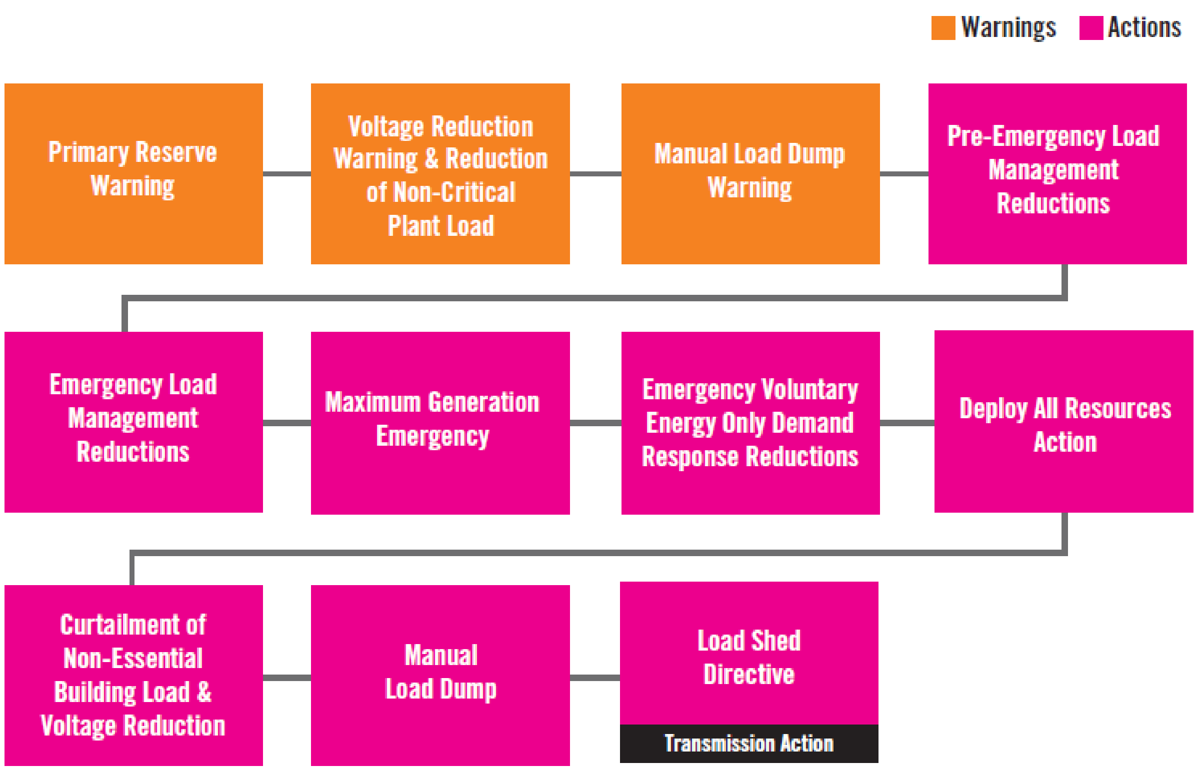
Performance Assessment Intervals

A PAI is an increment of time during which Capacity Performance resources are held to the Capacity Performance standard of deliverability. Resources subject to appraisal during PAIs are those that are located in the area where the PAI was triggered and cleared in the capacity auction with a Capacity Performance requirement. Resources that do not meet their Capacity Performance obligations during PAIs are subject to significant financial penalties.

PAIs occur for the duration of certain emergency actions declared by PJM. Emergency procedures are issued to mitigate capacity and transmission emergencies as detailed in Manual 13 and can include, but are not limited to, voltage reduction warnings, voltage reduction actions, manual load dump warnings or manual load dump actions.

PAIs are triggered for each interval in which PJM declares an Emergency Action (Figure 1). Emergency Warnings and Actions do not need to occur sequentially.

Figure 1. **PJM Emergency Warnings and Actions**



Non-performance is assessed based on the response of resources to fulfill their capacity commitments during a PAI. The shortfall/excess is calculated separately for each resource and each PAI. Resources with a shortfall are assessed a financial penalty, while resources demonstrating excess performance are eligible for bonus payments.

Portfolio netting – the use of multiple resources to satisfy the capacity commitment of a single resource – is not permitted.

Conditions on Oct. 2

Maintenance Season

The Oct. 2 PAI event took place during the peak of the fall maintenance season, which occurs between Sept. 16 and Dec. 31. Generally, lighter grid demand allows generators and transmission operators valuable time to temporarily disconnect and perform maintenance or make upgrades to their assets such as generators, transmission lines or substations. This necessary maintenance can significantly reduce the availability of the approximately 180,000 MW of total generating capacity in the PJM footprint.

The maintenance activity peaks in October and April, with about 2,400 separate planned transmission outages during each of those two months and more than 50,000 MW of generator outages.

Generation Outages

Because a variety of generators typically are out of service for maintenance during this time, significantly reducing the resources available to serve load, PJM issued an alert on the afternoon of Oct. 1 – called a Maximum Generation Emergency/Load Management Alert – to provide an early alert that system conditions may require the use of the PJM Emergency Procedures. It is implemented when Maximum Emergency generation is called into the operating capacity or if demand response is projected to be implemented.

Preliminary outage rates, calculated from eDART[1] installed capacity and outage reduction amounts, are shown in Figure 2. The pre-scheduled outage rates[2] (Planned and Maintenance Outages) in the PAI zones were significantly higher than in PJM overall. Forced outage rates in the PAI zones were slightly higher than in PJM overall, although the difference was less dramatic than with the pre-scheduled outage rates. In both the PAI zones and the overall PJM footprint, the aggregate forced outage rates of Capacity Performance units was approximately 10 percent lower than the forced outage rates of non-Capacity Performance units.

[1] The PJM eDART system is an online portal that is used in real-time operations to track generating unit capabilities on a minute-by-minute basis. PJM Generation Owners (GO) submit unit forced/unplanned outages and reductions through this portal during the current operating period so that, at any given time, PJM dispatch can assess unit availability and maintain adequate reserves to ensure system reliability. When a GO submits an unplanned reduction or outage, the actual cause of a reduction, trip or start failure may not be known until much later and indeed may be different from the cause reported on the eDART ticket. This is partly due to the plant needing to focus on real-time operations at the initial trip with the expectation of a more detailed trip analysis when time permits. This is reconciled at the earliest by the 20th of the month following the month in which the outage occurred, using the Generator Availability Data System (GADS). For these reasons, it is important to emphasize that the generation outage data provided and any associated analysis is subject to reconciliation with GADS data. These values are not final and should not be used for any decision making purposes.

[2] PJM uses many factors to evaluate and approve pre-scheduled outages, however, unseasonable weather, such as the heat experienced in early October, can create challenges with outages that have been scheduled in advance. PJM has the ability to recall active Maintenance Outages and cancel unstarted Planned and Maintenance Outages to mitigate these challenges.

Figure 2. **RTO and PAI Zone Outage Rates on Oct. 2, 2019**

Wednesday, Oct. 2, 2019			12:00	13:00	14:00	15:00	16:00	17:00	18:00
RTO	Overall	Planned Outage Rate	9.9%	9.9%	9.9%	9.9%	9.9%	9.9%	9.9%
		Maintenance Outage Rate	4.4%	4.4%	4.4%	4.4%	4.4%	4.4%	4.4%
		Forced Outage Rate	7.9%	8.1%	7.3%	7.0%	7.3%	7.2%	7.1%
	CP	Planned Outage Rate	10.3%	10.3%	10.3%	10.3%	10.3%	10.3%	10.3%
		Maintenance Outage Rate	4.8%	4.8%	4.7%	4.7%	4.7%	4.7%	4.7%
		Forced Outage Rate	6.4%	6.6%	5.7%	5.5%	5.7%	5.6%	5.5%
	Non-CP	Planned Outage Rate	7.9%	7.9%	7.9%	7.9%	7.9%	7.9%	7.9%
		Maintenance Outage Rate	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
		Forced Outage Rate	16.5%	16.7%	16.7%	16.2%	16.2%	16.2%	16.2%
PAI Zones (AEP, BGE, DOM, PEPCO)	Overall	Planned Outage Rate	16.3%	16.3%	16.3%	16.3%	16.3%	16.3%	16.3%
		Maintenance Outage Rate	3.6%	3.6%	3.5%	3.5%	3.5%	3.5%	3.5%
		Forced Outage Rate	8.9%	9.7%	9.5%	9.4%	9.5%	9.4%	9.3%
	CP	Planned Outage Rate	17.3%	17.3%	17.3%	17.3%	17.3%	17.3%	17.3%
		Maintenance Outage Rate	3.6%	3.6%	3.4%	3.4%	3.4%	3.4%	3.4%
		Forced Outage Rate	7.5%	8.3%	8.1%	7.9%	8.1%	7.9%	7.8%
	Non-CP	Planned Outage Rate	7.8%	7.8%	7.8%	7.8%	7.8%	7.8%	7.8%
		Maintenance Outage Rate	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%
		Forced Outage Rate	20.2%	21.1%	21.1%	21.1%	21.0%	21.3%	21.3%

Weather

On Oct. 1 and Oct. 2, 2019, the PJM footprint experienced extreme hot weather, especially for a day outside of the summer season. A significant portion of the PJM region was 10 to 20 degrees above normal (Figure 3). During this spell of hot weather, a large number of cities from the Ohio Valley to the East Coast tied or broke October temperature records (Figure 4).

Figure 3. **Temperature Deviation from Normal**

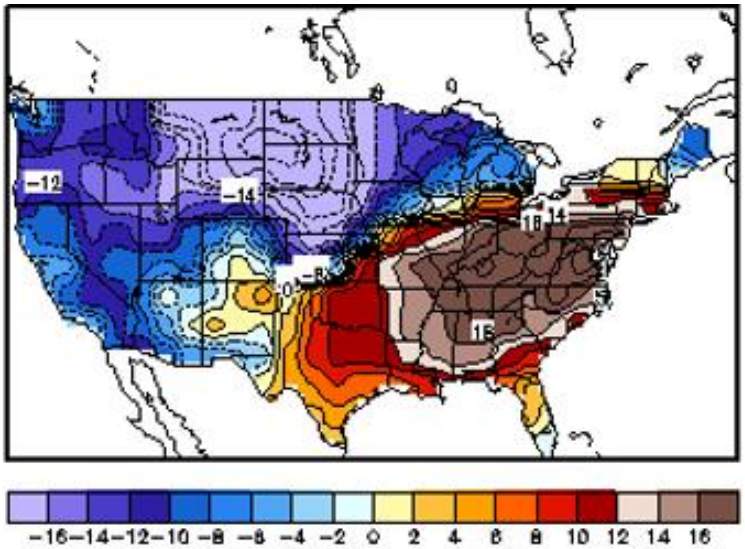


Figure 4. **Cities Experiencing Record-Setting Heat Oct. 1 to Oct. 4**

Locations that tied or set new all-time October record highs from Oct. 1-4, 2019.

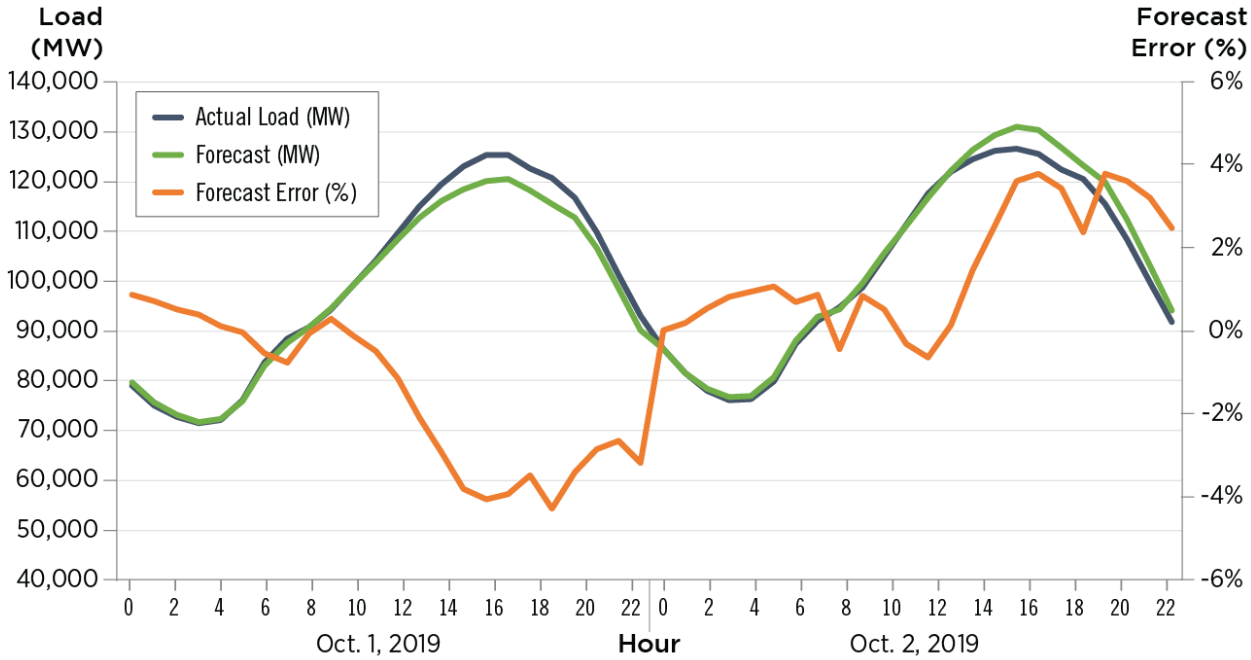
Additionally, on Oct. 2, a cold front was positioned just north of PJM, causing rain and clouds along PJM's northwestern border. As the front dropped south and east into the footprint, much cooler temperatures moved in behind it. This drop in temperature was expected, but progressed a few hours ahead of schedule, causing some temperature forecast error in northernmost cities in the ComEd and FE zones such as Chicago, IL, Cleveland, OH, and Toledo, OH.

Load Forecast

In order to create the final load forecast, PJM dispatchers use a suite of load forecast models that consist of pattern matching algorithms (models that forecast load by looking through historical data for similar weather patterns) and neural networks. One of the primary models is a temperature-based neural network, which uses temperature and the calendar – inputs like day of week and month of year – to forecast the load.

This model, and many of the others, rely on past days that look similar to the day that is being forecast. When the future day is out of the ordinary, such as a 90-degree day in October, the model has less historical data on which to base its forecast, or it may be considering incongruent data, such as 90-degree days in early September during which load may react very differently. It is common for load forecast models to underestimate load on extreme temperature days, especially in shoulder months when similar days are hard to find in the historical record. This was the case on Oct. 1 and was expected to be the case again on Oct. 2. However, while the load forecast was low for Oct. 1, it was high on Oct. 2 (Figure 5) for the reasons outlined below.

Figure 5. **Load Forecast versus Actual Load on Oct. 1 and Oct. 2**



In addition to the models not having a large selection of similar historical days to work with, the early arrival of the cold front also complicated conditions. Since temperatures are such a critical input to load forecasting, temperature forecast error is a typical cause of load forecast error and accounts for part of the load forecast error on Oct. 2.

Load forecast error refers to the difference between forecasted and actual load values – not a mistake or miscalculation.

Temperatures were well forecasted in the cities that were not impacted by the cold front; the average weather forecast error for 17:00 was 1.6 degrees once the cities in the ComEd and ATSI zones are excluded. The zones impacted by the early arrival of the cold front, experienced characteristic load forecast error, with the load coming in below the forecast due to cooler-than-expected temperatures. Of the 4,600 MW of load forecast error at the peak hour on Oct. 2, error in ComEd and ATSI made up about 50 percent.

Operations Timeline

The Week Before: Sept. 24–29

During the last week of September 2019, weather services were forecasting unusually hot temperatures for the first week in October. By Friday, Sept. 27, PJM's weather services were predicting temperatures in the upper 80s and low 90s in the western part of PJM for Tuesday, Oct. 1, with widespread 90 degree temperatures across most of PJM on Wednesday, Oct. 2.

The high system loads anticipated for Oct. 1 and Oct. 2, combined with scheduled generation and transmission outages, were expected to create challenging operating conditions. PJM staff began evaluating generation and transmission outages. On Friday, Sept. 27, PJM turned off the generation auto-approval feature in eDART, which approves generation outages, provided there are sufficient resources to reliably meet system needs for the future period.

PJM staff worked with transmission owners and generation owners to identify equipment on outage that could be returned to service. PJM staff also evaluated pending transmission outages and worked with the transmission owners to reschedule the work until after the high temperatures.

Approximately 1,200 MW of generation resources adjusted their maintenance schedules so that they would be available for the pending peak load days; however, no units already on maintenance outages were recalled 72 hours in advance[3] because projections did not indicate that this was necessary. PJM staff cancelled or deferred 134 transmission outages that were scheduled for the first week in October and two transmission facilities that were out of service for long-term maintenance activities were returned to service. Even with these efforts, there were 584 active transmission tickets and over 45,000 MW of generation was on outage.

Weather services continued to refine their forecasts for the week of Sept. 30 through Oct. 6. Temperatures were expected to be warmer on Tuesday, Oct. 1 and peak across most of the PJM on Wednesday, Oct. 2, followed by more seasonal temperatures later in the week.

Monday, Sept. 30

As temperatures for most of the PJM footprint were expected to be in the 90s, PJM issued a Hot Weather Alert for Wednesday, Oct. 2, for the entire RTO except the ComEd Zone. The ComEd zone was excluded because temperatures in ComEd were forecast to be below 90 degrees on Oct. 2, as a cold front was expected to move into the western part of PJM. The peak load for Monday, Sept. 30 was 109 GW and there were no significant operational issues.

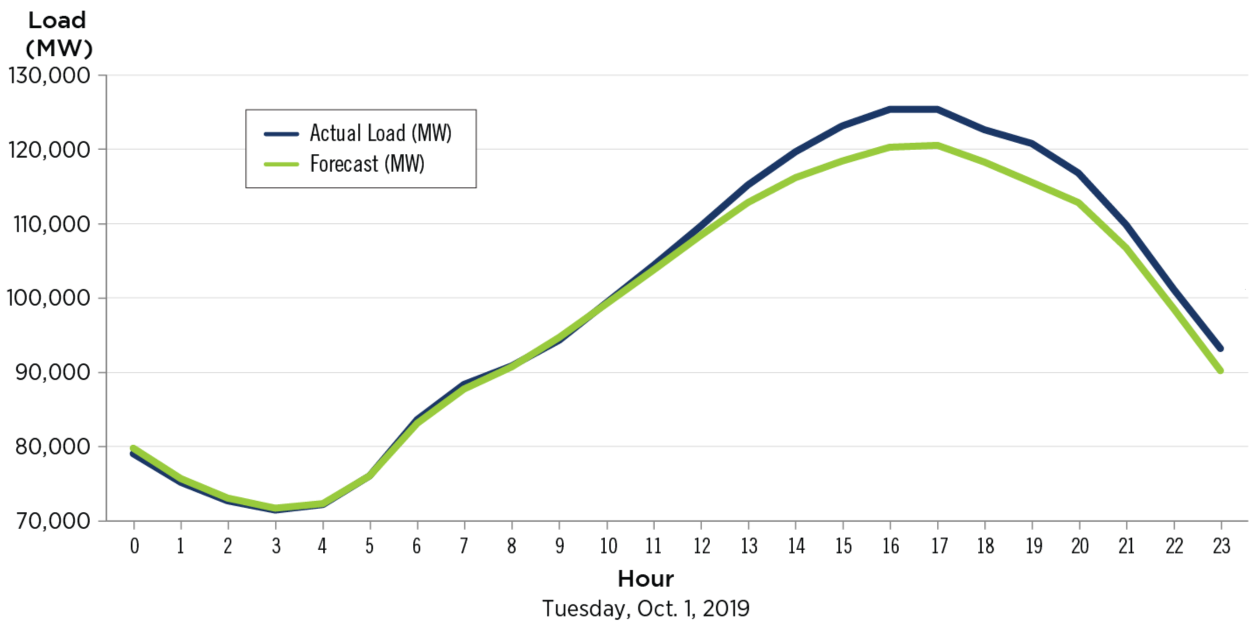
[3] For more information, please see Manual 10, Section 2.3.2

Tuesday Oct. 1

Heading into the Oct. 1 operating day, the PJM peak load was expected to be 120 GW at hour ending (HE) 18.[4] PJM had sufficient resources to serve the load and satisfy our reserve requirements; however, congestion was expected on the system as transmission constraints would limit resources that would otherwise be used to serve the load.

Approaching evening peak, it became clear that we would exceed the expected peak load. PJM continued to add generation as the load increased throughout the afternoon. At one point, as load was increasing, PJM called upon its synchronized reserve tools to ensure load/supply balance. PJM requested synchronized reserves be deployed and requested shared reserves from NPCC. Prices on the system were much higher as we headed into the evening peak, and shortage pricing was triggered for several intervals. Ultimately the peak load for Tuesday was 125.5 GW for HE 18, which was over 5,000 MW above the forecast heading into the operating day (Figure 6).

Figure 6. **Actual Load vs. Forecast Load for Oct. 1**



On Tuesday, Oct. 1, the load cleared in the Day-Ahead Market for Wednesday, Oct. 2, was approximately 121 GW. As temperatures across most of PJM were expected to be higher on Wednesday, Oct. 2, than they were on Tuesday, Oct. 1, the load forecast for Wednesday was increased to just over 132 GW. To serve that load and cover day-ahead scheduling reserves, Maximum Emergency Generation was called for the next day. As a result, on Oct. 1, PJM issued a Maximum Generation Emergency/Load Management Alert for Oct. 2.

System conditions for Oct. 2 were expected to be more challenging than PJM had experienced on Oct. 1. Load was expected to be higher, so additional resources would be required to serve the load and satisfy PJM's reserve obligations. Transmission congestion patterns were expected to be similar to Oct. 1.

[4] Hour ending (HE) is a term that denotes the time period of the preceding hour (e.g., 12:01 a.m. to 1:00 a.m. is hour ending 1).

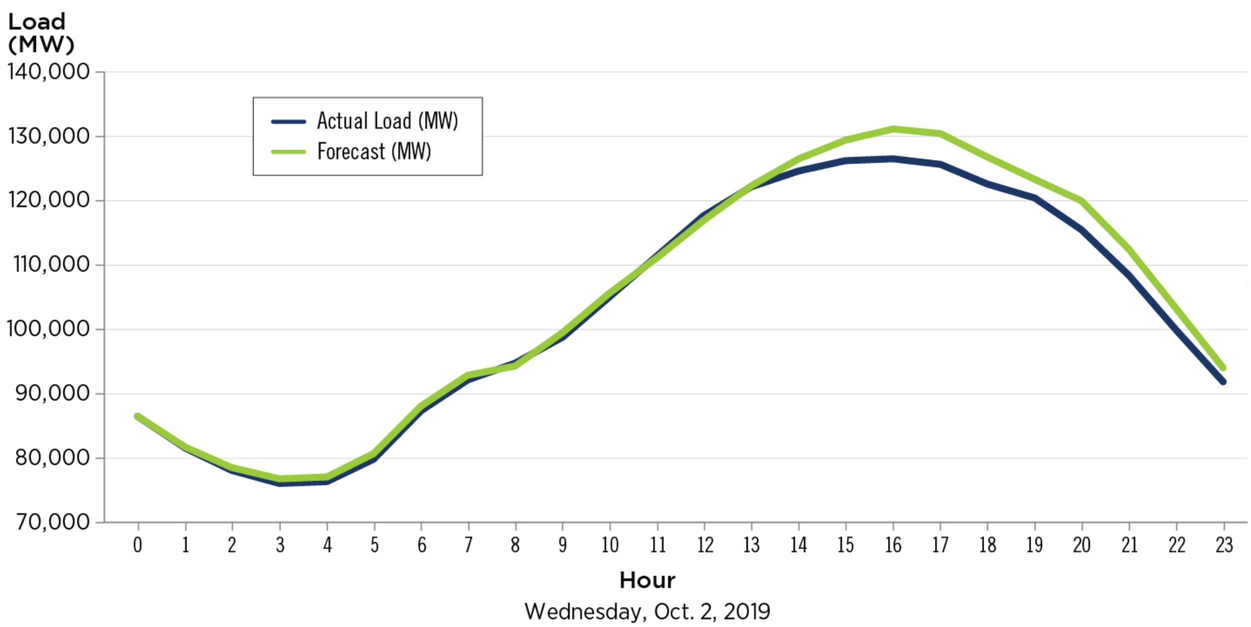
Transmission constraints on Tuesday were expected to limit the generation that would otherwise be available to serve load. Studies showed that a significant amount of the generation that was available would not be able to be utilized to full capability due to these transmission constraints.

Wednesday, Oct. 2

As we headed into the Oct. 2 operating day, PJM's overall capacity position deteriorated as some generation was lost after the evening peak on Tuesday. At 5:45,[5] the Maliszewski–Vassell 765 kV line in Ohio tripped due to failed substation equipment, which was expected to exacerbate congestion concerns and further limit available generation. In addition, several generators that were expected to be available for the peak notified PJM that they were either not going to be able to come online or would be delayed until after the peak for the day.

Throughout the morning, load continued to come in as forecast (see Figure 7).

Figure 7. **Actual Load vs. Forecast Load for Oct. 2**



[5] Times in this paper use the 24-hour clock.

Between 12:00 and 14:00, approximately 1,933 MW of non-firm exports were recalled (Figure 8). None of these exports were capacity-backed.

Figure 8. **Non-Firm Exports**

At noon, given the generation performance and the expectation that some of the available generation would not be able to be ramped to maximum output due to transmission constraints, PJM issued a Pre-Emergency Load Management Reduction Action for demand resources with a two-hour lead time[6] to be implemented by 14:00 in the AEP, Dominion, BGE and PEPCO transmission zones.

These zones were selected because the load reduction would not only help the overall load/capacity issue, but reduced load in these zones would also help to manage transmission constraints.

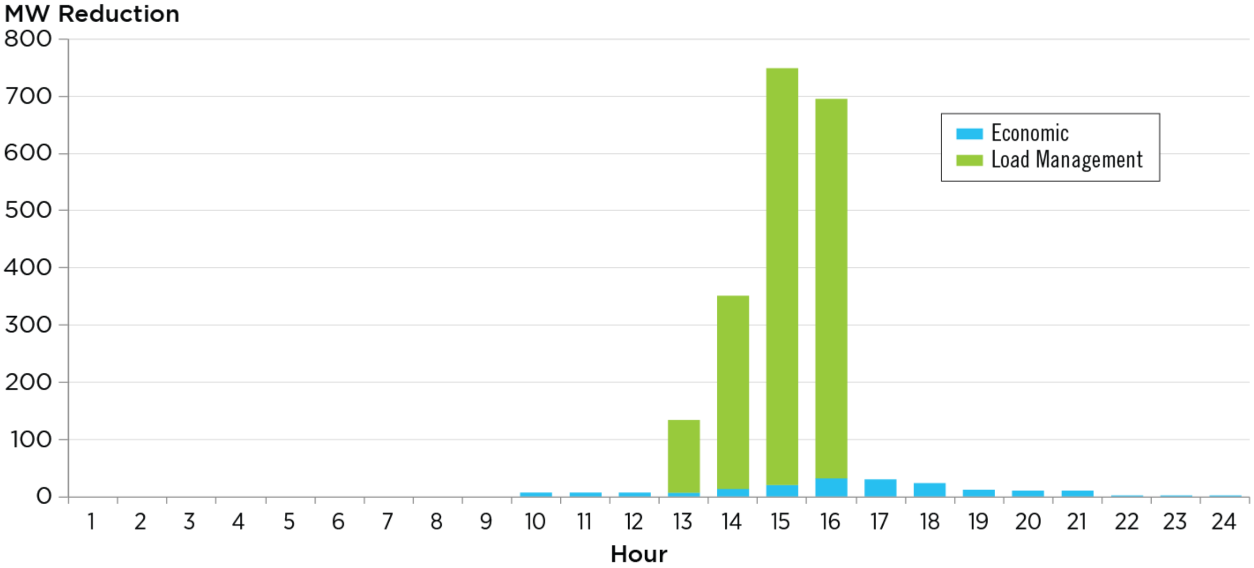
For the AEP, BGE, Dominion and PEPCO zones, there was 728 MW of 120-minute (Figure 9), 43 MW of 60-minute, and 888 MW of 30-minute load management reported as available by the Curtailment Service Providers. The Pre-Emergency Load Management Reduction Action was for both Capacity Performance and base demand response (DR). However, only Capacity Performance DR was obligated to respond since the event was outside the base DR compliance period of June to September. Even though it was outside the compliance period for base demand response, PJM anticipated some response from base DR.

[6] PJM normal protocol is to deploy the 120-minute lead time resources before the 60- or 30-minute lead time resources in case system conditions deteriorate and because they are less expensive. This allows PJM to reserve the shorter and more expensive lead time resources for later deployment. PJM will typically deploy the 30-minute DR resources first if there is an unforeseen problem such as a unit tripping offline and 120-minute lead time resources take too long to address the immediate issue. The energy price caps are higher for shorter lead time resources: 120-minute lead time resources = $1,100, 60-minute lead time resource = $1,425, 30-minute lead time resources = $1,849.

Figure 9. **Base and CP Demand Response Megawatts by Zone**

	AEP	BGE	DOMINION	PEPCO	Total
CP DR	23.3	0.2	0	1.9	**25.4**
Base DR (2 hour)	426.7	239.8	4	32.1	**702.6**
Total	**450**	**240**	**4**	**34**	**728**

Figure 10. **Estimated Demand Response in PJM**[7]



Load continued to increase as expected. At approximately 14:00, the rate of load increase declined considerably. Some reduction in the rate was expected due to the pre-emergency load management, however, the amount of load reduction significantly exceeded the load reduction that was expected in all zones in which it was called.

By 15:00, the load was several thousand megawatts below the load forecast curve. Pre-emergency load management was cancelled in the Dominion, BGE and PEPCO zones at 15:45 and in the AEP zone at 16:00. The peak load for the day ended up at approximately 126,500 MW at HE 17.

[7] Load Management Amounts are CSP-estimated expected reductions. Actual load reductions are not finalized until up to three months after event

Pricing Outcomes

Tuesday, Oct. 1, 2019

On Oct. 1, load materialized in higher quantity and more quickly than what had been forecast. The day was also met with high congestion causing higher than normal Locational Marginal Prices (LMPs) across the PJM region (Figure 11). The high congestion also caused several constraints to bind at the penalty factor[8] (Figure 12) which contributed to hourly LMPs exceeding $200/MWh between hour beginning (HB) 2–5 p.m. with a maximum PJM-RTO price of $691/MWh for HB 3 p.m.

Figure 11. **Real-Time Hourly LMPs – Oct. 1**

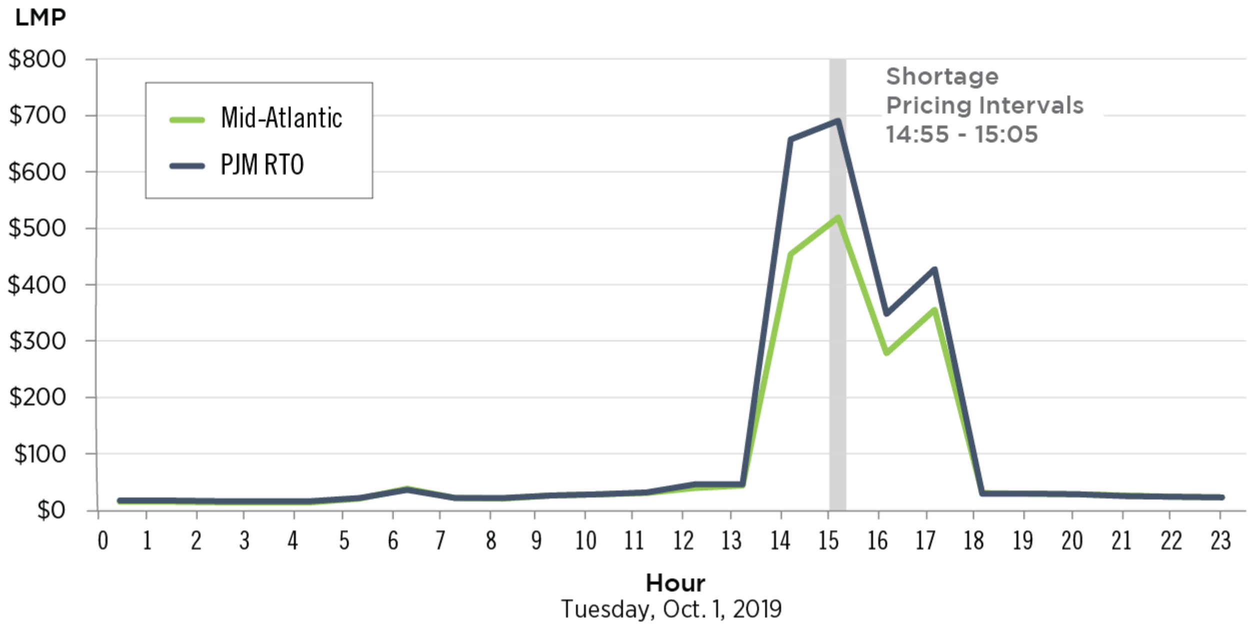


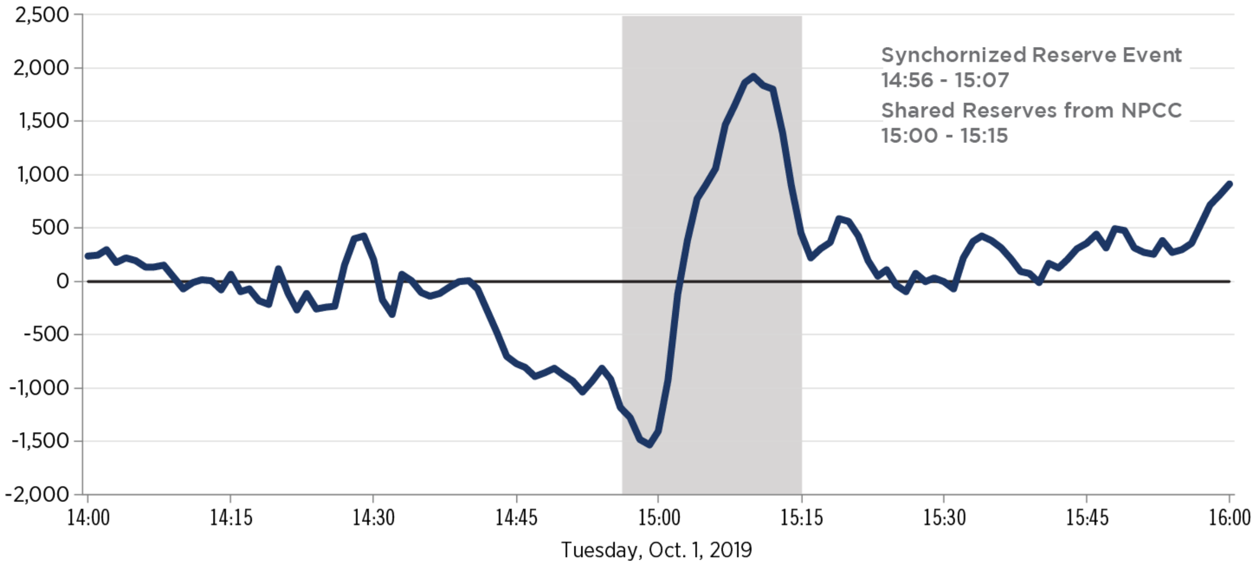
Figure 12. **Constraints Binding at the Penalty Factor in Interval 15:00**

Constraint Name	Contingency	Marginal Value ($/MWh)
CONASTON 5012/3-500B GCB C 500 KV	L500.Hunterstown-Conastone.5013	-$2,000.00
CONASTON 5012/3-500B GCB C 500 KV	BASE	-$2,000.00
CONASTON-PEACHBOT 5012 B 500 KV	BASE	-$2,000.00
HAVILAND J CB 138 KV	345/138.EastLima.T1	-$2,000.00
PRGEORGE TX1 XFORMER H 230 KV	L230.Chuckatuck-Surry.290	-$2,000.00
YUKON TRAN 4 XFORMER H 500 KV	500/138.Yukon.T1 & T3 (Sctnlz F)	-$2,000.00

[8] From Manual 11, Section 2.17 – Transmission constraint penalty factors are parameters used by the Market Clearing Engines (MCE) to specify the maximum cost willing to be incurred to control a transmission constraint. The ultimate effect of the transmission constraint penalty factor is that it limits the controlling actions the MCE can take to resolve a constraint by limiting the cost that is willing to be incurred to control it. All PJM internal constraints, regardless of voltage level, are defaulted to a $2,000/MWh transmission penalty factor in the Real-Time Energy Market. When a constraint binds at the penalty factor, it indicates that insufficient resources are available to control the constraint at a cost less than or equal to the penalty factor.

Around hour beginning 3 p.m., PJM also experienced low ACE[9] control (Figure 13), and, in order to keep up with demand, a Synchronized Reserve Event was triggered at 2:56:04 p.m. on Oct. 1, 2019. During this event, the available ramping capability on reserve resources was deployed to meet energy needs, leaving system reserves short of the synchronized reserve requirement which resulted in three intervals of reserve shortage (2:55, 3:00, 3:05 p.m.). Shortage pricing is triggered when reserves are being priced off of the demand curve for a given reserve product and reserve zone or sub-zone[10].

Figure 13. **Area Control Error (ACE)**



The energy component of LMP is set by the resource that can serve the next increment of load at the least cost. However, the cost of serving the next megawatt of load is not based solely on the resource's incremental energy offer. The congestion impact from the delivery of that additional megawatt is also considered when calculating the cost of that marginal megawatt. In addition, if the next increment of load requires converting a megawatt of reserves into a megawatt of energy, and this exacerbates reserve shortage conditions, the reserve penalty factors will be incorporated into energy prices. All of these factors contributed to an energy component of LMP of $3,644.16/MWh in the 3 p.m. interval (Figure 14).

9 Area Control Error is a measure of the imbalance between sources of power and uses of power within the PJM RTO. This imbalance is calculated indirectly as the difference between scheduled and actual net interchange, plus the frequency bias contribution to yield ACE in megawatts.

10 From Manual 11, Section 4.2.2.1 – The reserve demand curves are used to articulate the value of maintaining reserves at specified levels and ensure product substitution between energy and reserves up a specified penalty factor. The penalty factor represents the price at which reserves will be valued if the desired reserve MW cannot be met with the available reserves on the system, and also acts as a price cap beyond which reserves will not be procured through market clearing.

Figure 14. **Characteristics of the Oct. 1 Shortage Pricing Intervals**[11]

	Interval	Energy LMP ($/MWh)	RTO RMCP ($/MWh)	MAD SRMCP ($/MWh)	MAD NSRMCP ($/MWh)	RTO SRMCP ($/MWh)	RTO NSRMCP ($/MWh)	Shortage (Segment)
Oct. 1, 2019	**14:55**	2,550.21	3,756.92	616.44	16.44	316.44	16.44	MAD SR (2) RTO SR (2)
	15:00	3,644.16	5,064.39	1,150	300	1,150	300	MAD SR (2) RTO SR (2) RTO PR (1)
	15:05	912.83	1,104.42	693.23	93.23	393.23	93.23	MAD SR (2) RTO SR (2)

Wednesday, Oct. 2

With the continued hot weather, Oct. 2, 2019, was also met with high congestion throughout the day. PJM's RTO Regulating requirement is 525 effective MW during non-ramp hours and 800 effective MW during ramp hours[12] The Regulation requirement for non-ramp hours was increased to 800 effective MW given expected system conditions. There were ample synchronized reserves and primary reserves to meet the reserve requirements throughout the day; therefore, shortage pricing was not triggered on the Oct. 2.

Load Management did not set price throughout the PAI because it was not identified as the marginal resource. LMPs are set based on the offer price of the resource that can serve the next increment of load at the lowest cost. Given that load came in lower than forecasted throughout the duration of the load management deployment, there was ample unloaded generation available to serve load at a lower cost than the offer price of the pre-emergency load management. One of these resources was identified as marginal and therefore set energy prices.

With enough generation and reserves on the system, no transient shortage conditions were experienced. LMPs did not reach as high as the previous day, and there was still significant congestion throughout the day[13], which caused several zones to have very low to negative LMPs (Figure 15).

[11] LMP – Locational Marginal Price RMCP – Regulation Market Clearing Price SRMCP – Synchronized Reserve Market Clearing Price NSRMCP – Non-Synchronized Marker Clearing Price

[12] For more information, please see Manual 12, Section 4.4.3

[13] The list of active constraints for any given day can be found here: https://dataminer2.pjm.com/feed/rt_marginal_value

Figure 15. **Real-Time Hourly LMPs – Oct. 2**

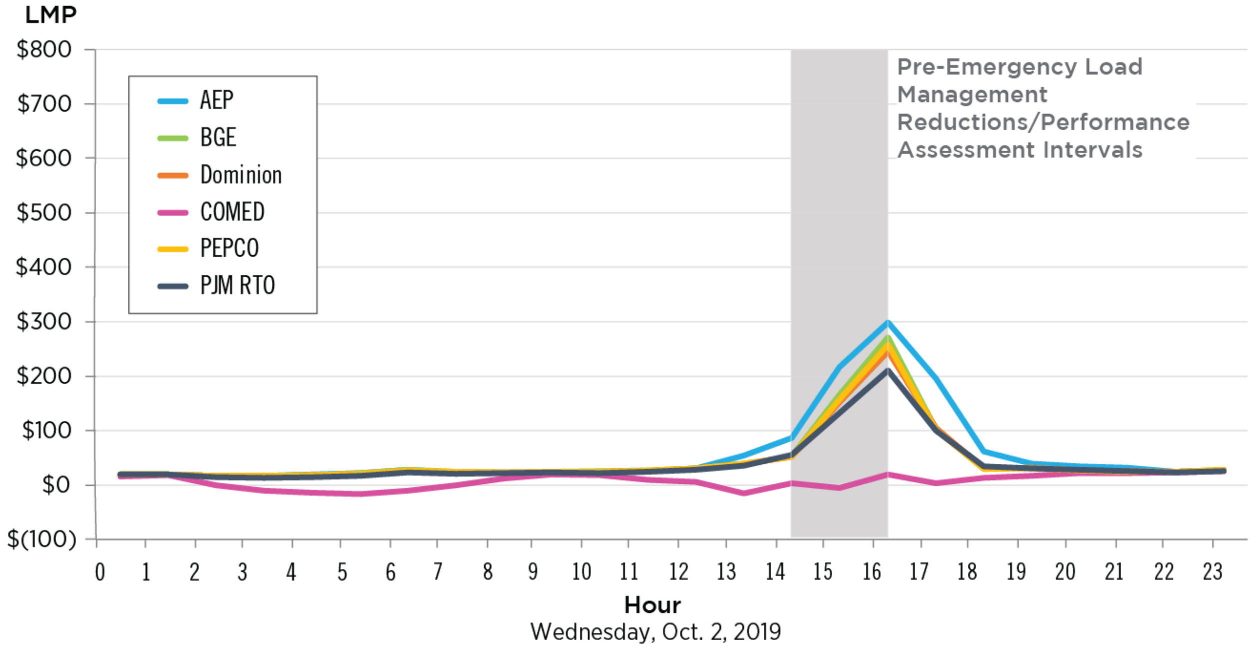


Figure 16 summarizes the energy, reserve and regulation prices during the PAI event.

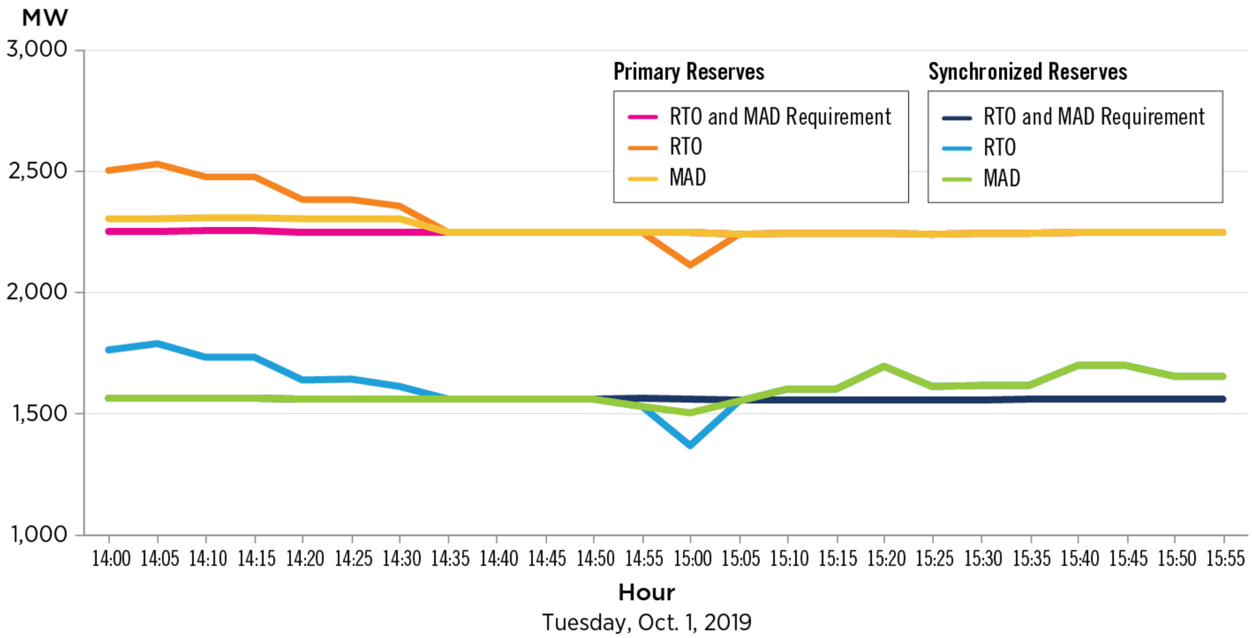
Figure 16. **Energy, Reserve and Regulation Prices During the PAI**

	Interval	Energy LMP ($/MWh)	Min Zonal LMP	Max Zonal LMP	RTO RMCP ($/MWh)	MAD SRMCP ($/MWh)	MAD NSRMCP ($/MWh)	RTO SRMCP ($/MWh)	RTO NSRMCP ($/MWh)
Oct. 2, 2019	14:00	$40.15	-$29.06	$116.81	$59.10	$0.00	$0.00	$0.00	$0.00
	14:05	$34.81	$3.55	$47.55	$22.70	$0.00	$0.00	$0.00	$0.00
	14:10	$41.57	$8.81	$54.47	$28.78	$5.00	$5.00	$5.00	$5.00
	14:15	$40.97	-$11.80	$58.03	$40.27	$5.00	$5.00	$5.00	$5.00
	14:20	$40.97	-$11.80	$58.03	$40.08	$5.00	$5.00	$5.00	$5.00
	14:25	$68.05	$10.89	$136.36	$44.50	$0.00	$0.00	$0.00	$0.00
	14:30	$66.25	$12.42	$133.17	$43.06	$2.09	$0.00	$2.09	$0.00
	14:35	$66.25	$12.42	$133.17	$43.06	$2.09	$0.00	$2.09	$0.00
	14:40	$51.22	$7.12	$106.34	$32.50	$0.00	$0.00	$0.00	$0.00
	14:45	$51.22	$7.12	$106.34	$32.50	$0.00	$0.00	$0.00	$0.00
	14:50	$79.99	$12.61	$158.52	$56.99	$0.00	$0.00	$0.00	$0.00
	14:55	$79.99	$12.61	$158.52	$56.99	$0.00	$0.00	$0.00	$0.00
	15:00	$79.99	$12.61	$158.60	$66.18	$0.00	$0.00	$0.00	$0.00
	15:05	$177.41	-$49.99	$521.30	$160.45	$7.50	$7.50	$7.50	$7.50
	15:10	$194.99	-$28.21	$547.61	$198.32	$5.00	$5.00	$5.00	$5.00
	15:15	$162.11	-$59.56	$474.90	$153.05	$3.50	$3.50	$3.50	$3.50
	15:20	$198.52	-$17.40	$545.53	$196.15	$5.00	$5.00	$5.00	$5.00
	15:25	$123.37	-$1.02	$293.47	$105.72	$3.50	$3.50	$3.50	$3.50
	15:30	$123.37	-$1.02	$293.47	$105.79	$3.50	$3.50	$3.50	$3.50
	15:35	$82.28	$19.25	$175.87	$62.41	$7.50	$7.50	$7.50	$7.50
	15:40	$82.46	$17.91	$176.31	$61.82	$0.00	$0.00	$0.00	$0.00
	15:45	$83.04	$20.38	$176.72	$62.84	$3.50	$3.50	$3.50	$3.50
	15:50	$84.54	$8.96	$188.76	$62.45	$0.00	$0.00	$0.00	$0.00
	15:55	$184.61	$12.49	$352.11	$189.20	$0.00	$0.00	$0.00	$0.00
	16:00	$106.25	$20.65	$193.48	$123.52	$0.00	$0.00	$0.00	$0.00

Reserves

The real-time reserve shortage that occurred on Oct. 1 is shown in Figure 17. On Oct. 2, shown in Figure 18, real-time reserves met or exceeded the reserve requirements for both the RTO and MAD areas. Following the Hot Weather Alert, the Day Ahead Scheduling Reserve for Oct. 2 was increased[14].

Figure 17. **Reserves on October 1[15]**



[14] M11 Section 11 details the procurement procedure and requirements for DASR; M13 Section 2 details the current reserve requirements. The DASR Requirement adheres to the requirements for Day-Ahead Scheduling [30-minute] Reserve defined by Reliability First Corporation and all applicable reliability councils for areas within the PJM RTO. Following the issuance of a Hot or Cold Weather Alert or escalating emergency procedures as defined in PJM Manual 13: Emergency Operations for the RTO, Mid-Atlantic Dominion, or Mid-Atlantic region, PJM increases the DASR requirement to reflect the additional reserves typically carried under such conditions and to ensure that adequate resources are procured to meet real-time load and reserve requirements. The increase in DASR is detailed in M11 Section 11.2.1. The DASR is cleared via a simultaneous optimization with the Day-Ahead Energy Market based on bid-in parameters and eligibility. For 2019 the annual reserve requirement was calculated to be 5.9%. Real-time reserve requirements on October 1st and 2nd adhered to the standards defined in M13.

[15] The Primary Reserves are composed of synchronized and non-synchronized resources. There is no requirement for non-synchronized reserves. Therefore, the primary reserves requirement can be satisfied by both synchronized and non-synchronized resources.

Figure 18. **Reserves on October 2**

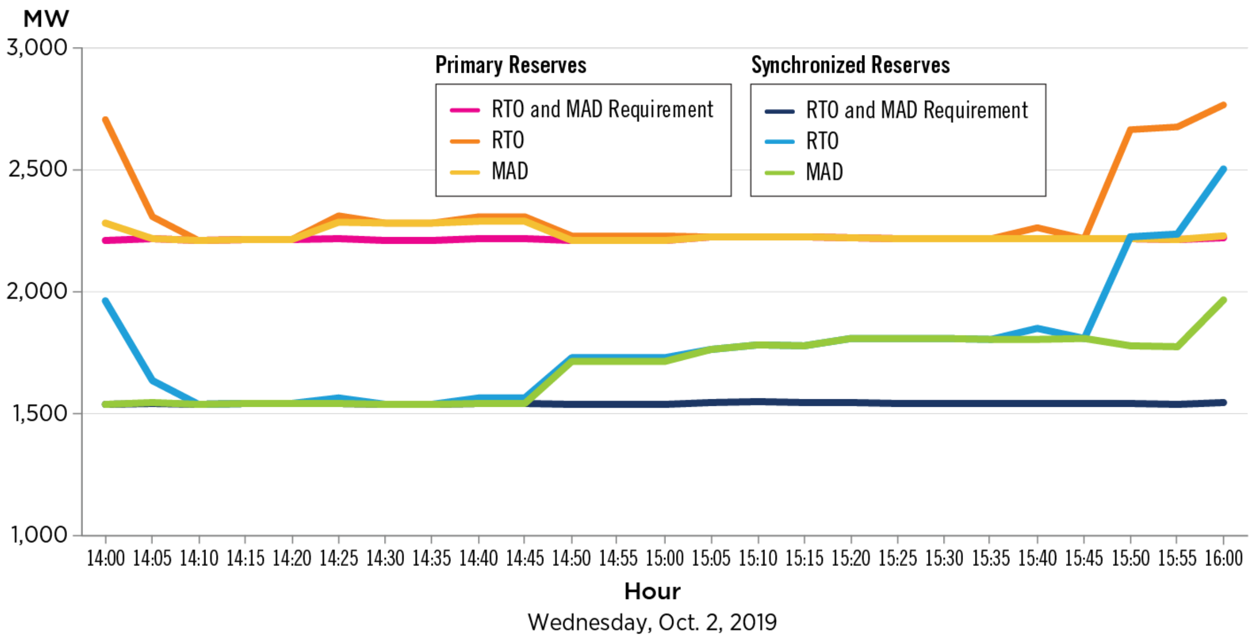
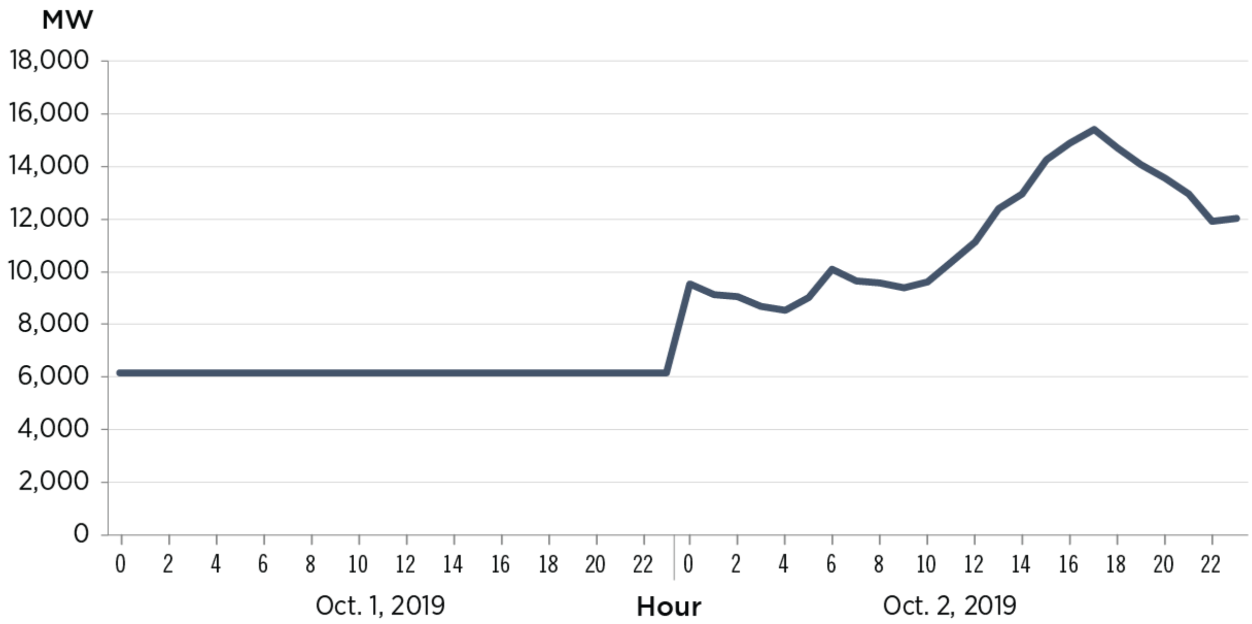


Figure 19. **Day-Ahead Scheduling Reserve**



Uplift

Preliminary uplift[16] charges for Oct. 1:[17]

- Total Uplift: $828,779
- Lost Opportunity Cost: $328,816
- Balancing Operating Reserve: $491,210

PJM classifies days where total uplift exceeds $800,000 as a high uplift day. The primary driver for Lost Opportunity Cost credits on Oct. 1 was a result of transient Real-Time LMP spikes during the shortage pricing intervals. Eligible units with a Day-Ahead award that were not run in real time due to system conditions may have accrued Lost Opportunity credits.[18] The primary driver for Balancing Operating Reserve credits on Oct. 1 was units that were run for constraint control.

Preliminary uplift charges for Oct. 2:[19]

- Total Uplift: $1,004,912
- Lost Opportunity Cost: $143,626
- Balancing Operating Reserve: $801,159

The primary driver for Lost Opportunity Cost credits on Oct. 2 was a result of Real-Time LMP spikes following the completion of the Load Management Event. These spikes can be attributed to the high number of constraints binding and several constraints binding at the penalty factor throughout the day, peaking from hour beginning 4 p.m. to 5 p.m. The primary driver for Balancing Operating Reserve credits on Oct. 2 was units that were run for constraint control resulting from bottled generation and high system loads.

[16] Uplift payments are made to market participants for operating a unit under specific conditions as directed by PJM to ensure that they recover their total offered costs when market revenues are insufficient or when their dispatch instructions diverge from their dispatch schedule.

[17] Uplift credits and charges are subject to change based on PJM Settlements rules

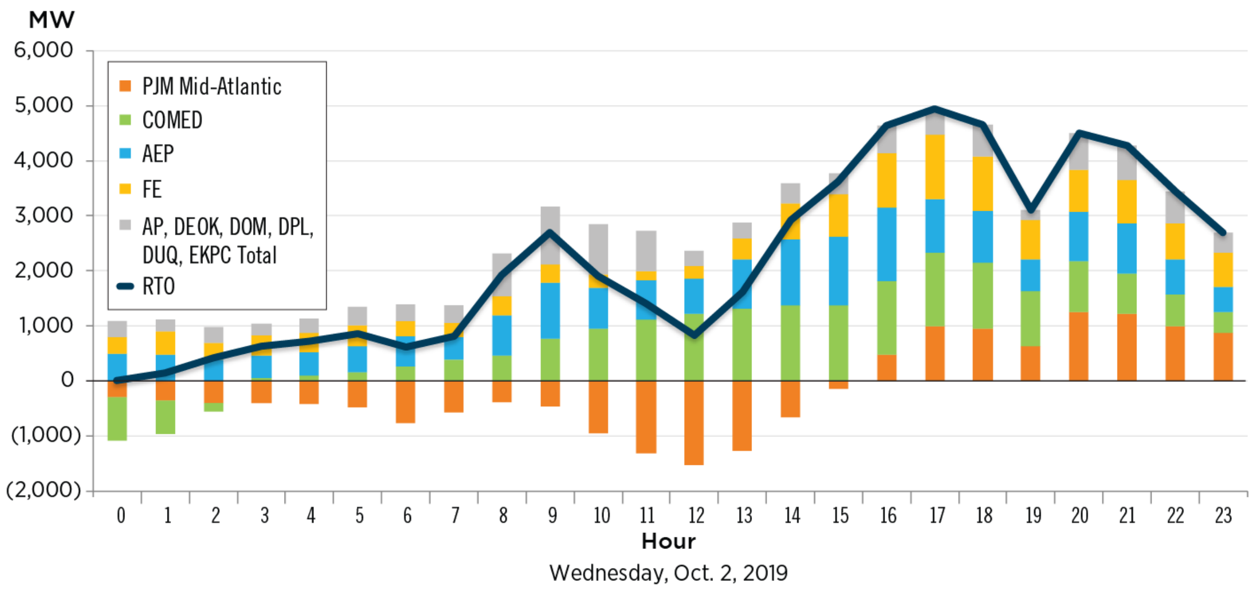
[18] Please see Manual 28, Section 5 for more information about Balancing Operating Reserve and Lost Opportunity Cost payments.

[19] Uplift credits and charges are subject to change based on PJM Settlements rules and do not include uplift credits associated with load management providers.

Where did the load go?

While PJM undertook emergency actions to assure reliable grid operations with cooperation by stakeholders, the Oct. 2 actual peak reached only 126,500 MW, significantly lower than the projected 132,000 MW forecast. 90 percent of the forecast error at peak can be attributed to four zones: ComEd (1,338 MW), AEP (1,333 MW), FE (989 MW), and PJM Mid-Atlantic (482 MW) (Figure 20).

Figure 20. **Oct. 2 Forecast Error by Zone**



The quick response of load-reducing resources, coupled with a cold front moving through Illinois and northern Ohio, only partially explains how demand drastically slowed its climb in the afternoon. PJM analyzed weather forecast error in the four zones with the highest contribution to overall load forecast error, as well as nodal load behavior, to determine why total load that day came in only 1,000 MW higher than the day before, despite temperatures being as much as 10 to 15 degrees higher in PJM's eastern zones.

Weather Analysis and Backcasting

Methodology

Temperature forecast error is one piece of the puzzle when deciphering load forecast error. Its contribution to load forecast error can be evaluated using a backcast. While load forecast models use temperature forecasts to produce a load forecast for a future day, a backcast utilizes the same model, but with actual temperature measurements from a historic day as the input, and outputs what the model's load forecast would have been that day if the temperature forecast was perfect. This process helps tease out the portion of the error that was caused by the temperature forecast compared to other potential sources of error, such as model error, human behavior and behind-the-meter generation.

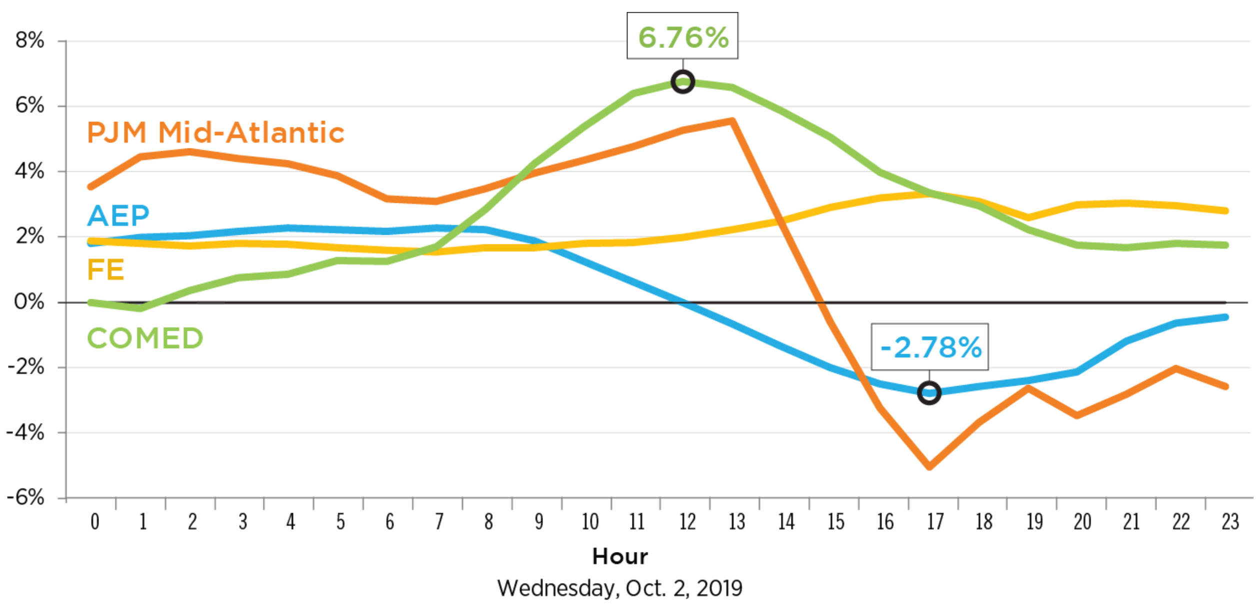
The backcast does not necessarily represent what PJM's published forecast would have been. This final forecast is published only after a human operator reviews output from multiple neural network and pattern recognition models, studies weather conditions, and uses experience and training to manually adjust the forecast. The backcast, to the contrary, is fully automated and uses only one temperature-based neural network model. In spite of these differences, the backcast can provide great insight into the extent of error due to temperature.

Results from the backcast for Oct. 2 showed that a perfect temperature forecast would have improved the neural network forecast in ComEd by almost 500 MW and in ATSI by about 300 MW. However, many cities ended up being a few degrees warmer than expected, leading to backcasts that were higher than the original neural network forecasts. In fact, if the models had perfect knowledge of temperatures, the load forecast for the RTO overall would have been 3,000 MW higher.

Backcast Results and Conclusions

The difference between the backcast error and base neural network model error is presented for the four zones that were identified to have contributed the most to the Oct. 2 forecast error. In Figure 21, positive values indicate the backcast had greater accuracy than the base forecast, while negative values indicate the opposite.

Figure 21. **Results of Backcast for Zones with the Greatest Contributions to Forecast Error**



Case Study: ComEd load forecast error attributed to temperature forecast error

The most positive value in Figure 21 – 6.76 percent at 1 p.m. – is from ComEd, and is calculated by subtracting the backcast error of 1.71 percent, from the base forecast error of 8.47 percent. Because the load forecast model performs with great accuracy when a perfect temperature forecast is used, we can conclude with high confidence that the early arrival of a cold front (which counts in PJM parlance as 'weather forecast error ') was the primary driver for load forecast error in ComEd.

This conclusion is further supported by 0, which plots the actual load, base neural net forecast, final forecast after adjustments from human operator, and the backcast. Beginning around Hour Ending 7 a.m., the orange line representing the backcast is far closer to the navy blue line, representing the actual load, than either of the lines that represent the load forecasts. This continues consistently throughout the remainder of the day.

The temperature forecast in ComEd was 3 to 5 degrees hotter than the actual temperatures during the PAI event. Additionally, temperature forecasts were as much as 10 degrees higher than actual temperatures earlier in the day (Figure 23). This supports the hypothesis that a cold front moving through the Midwest caused cooler than expected temperatures, which in turn reduced electricity demand in that area. FirstEnergy appears to exhibit some of this behavior as well, but the explanatory power of temperature is less than it is for ComEd.

Figure 22. **Results of COMED Backcast**

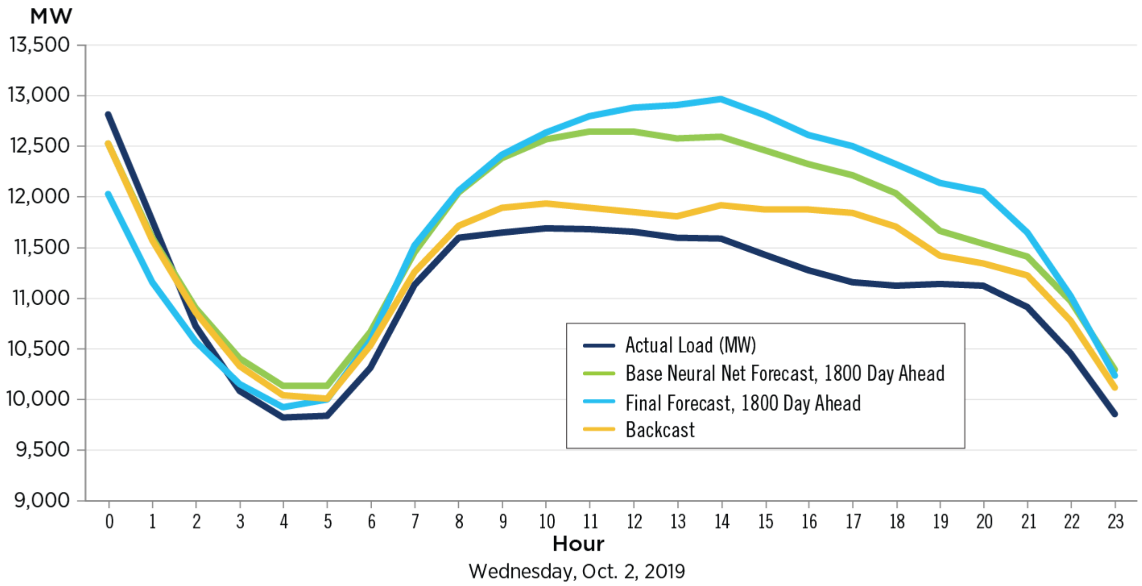
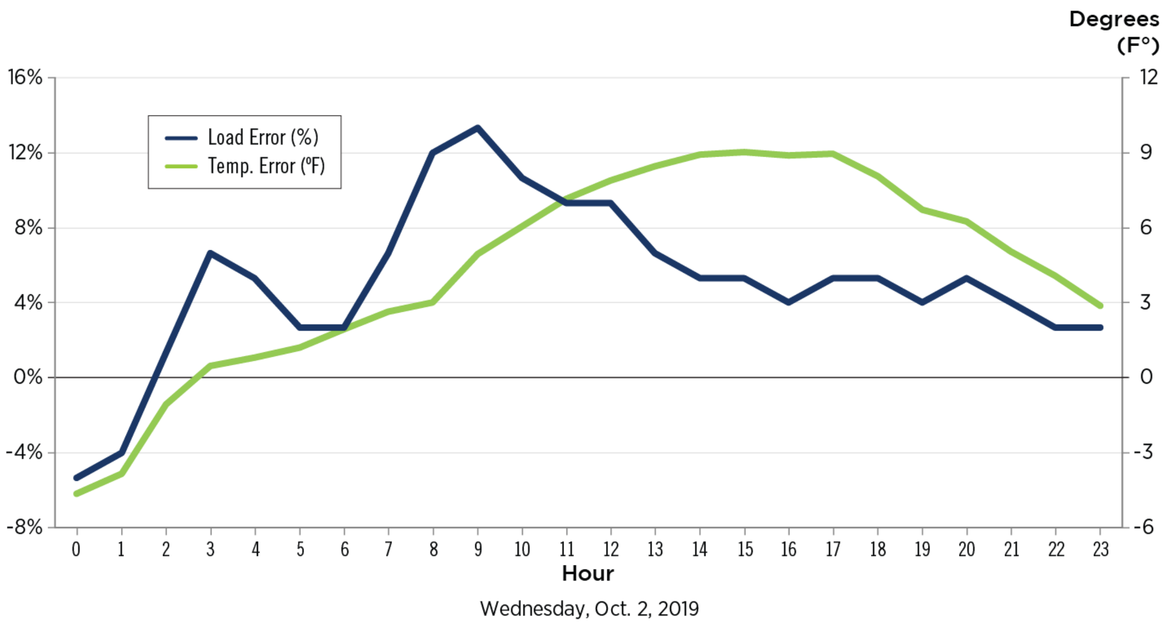


Figure 23. **Results of COMED Temperature Error Analysis**



Case Study: AEP – Temperature forecast error ruled out as cause of load forecast error

The behavior of AEP in Figure 24 is a case of perfect temperature data leading to less accurate load forecast. While the actual temperature was even hotter than expected, load came in lower than forecasted. Figure 24 shows the backcast (orange line) is even further from the actual load (navy blue line) than the forecasts during the peak of the day. Figure 25 demonstrates forecast error for load and temperature; the actual temperature was 2 to 4 degrees higher than what had been forecasted for the PAI event, yet AEP still experienced a far lower load than expected. To a similar degree, the same phenomenon is also observed in PJM Mid-Atlantic, requiring that we look for alternative sources of error in AEP and PJM Mid-Atlantic.

Figure 24. **Results of AEP Backcast**

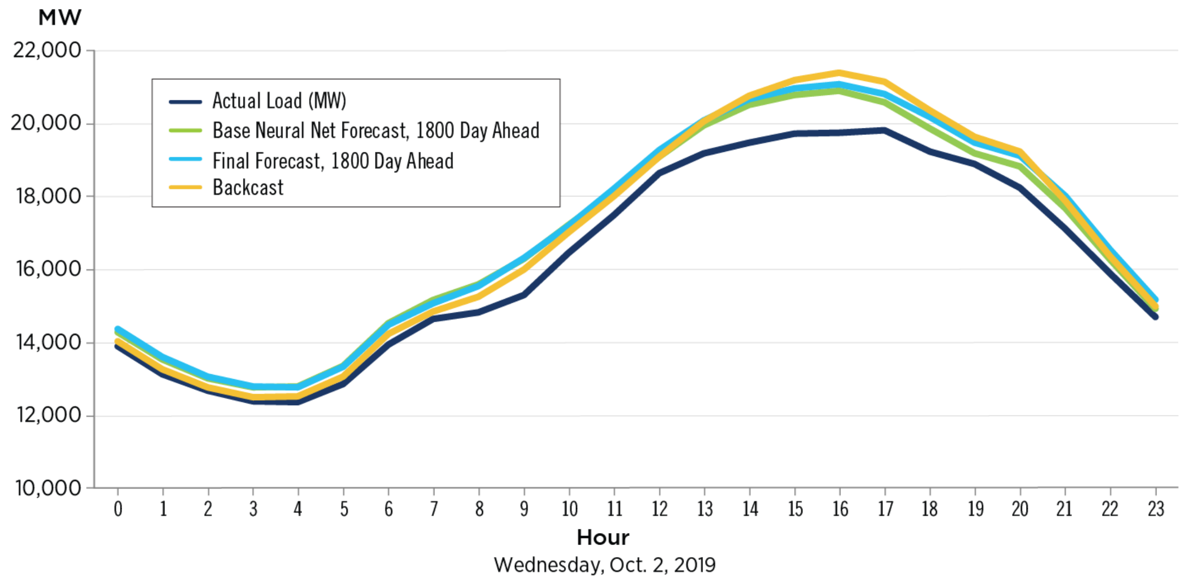
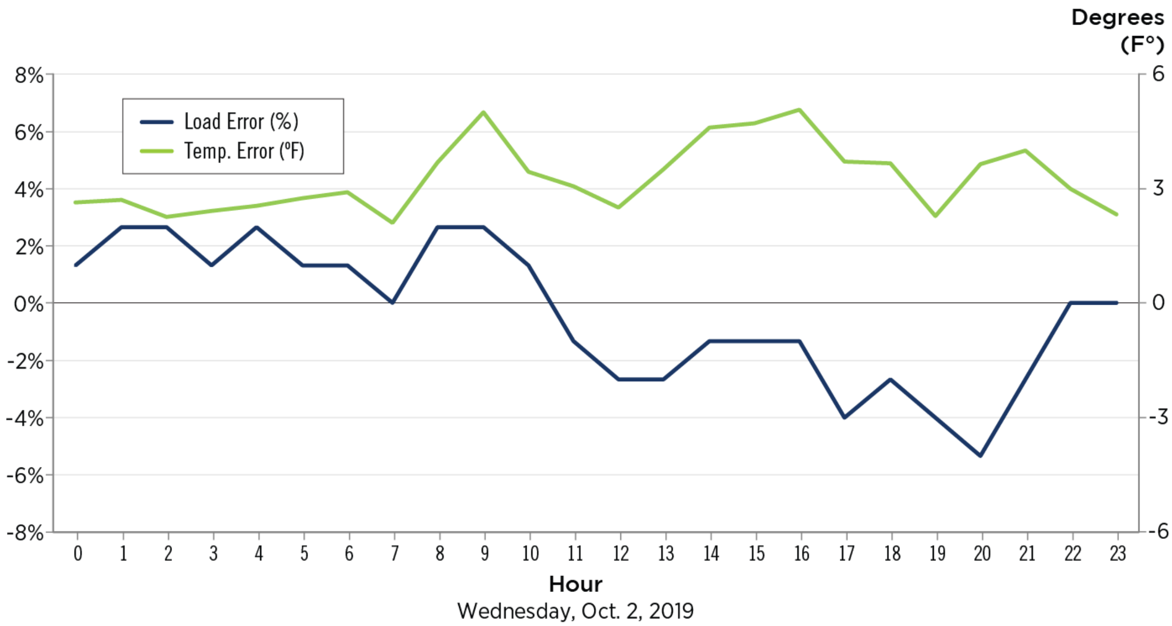


Figure 25. **Results of AEP Temperature Error Analysis**



Nodal Load Pattern Analysis

Methodology

While cold fronts that move across wide areas can impact load at a zonal level, some other drivers of load forecast error necessitate a more granular analysis. Demand response participants, behind-the-meter generation, and non-conforming load are not distributed evenly throughout each transmission zone, and each may contribute to unique load shapes at various nodes throughout the system. Load curves for telemetered nodal equipment were evaluated and classified into categories such as normal load behavior and intentional load reduction.

Results and Conclusions

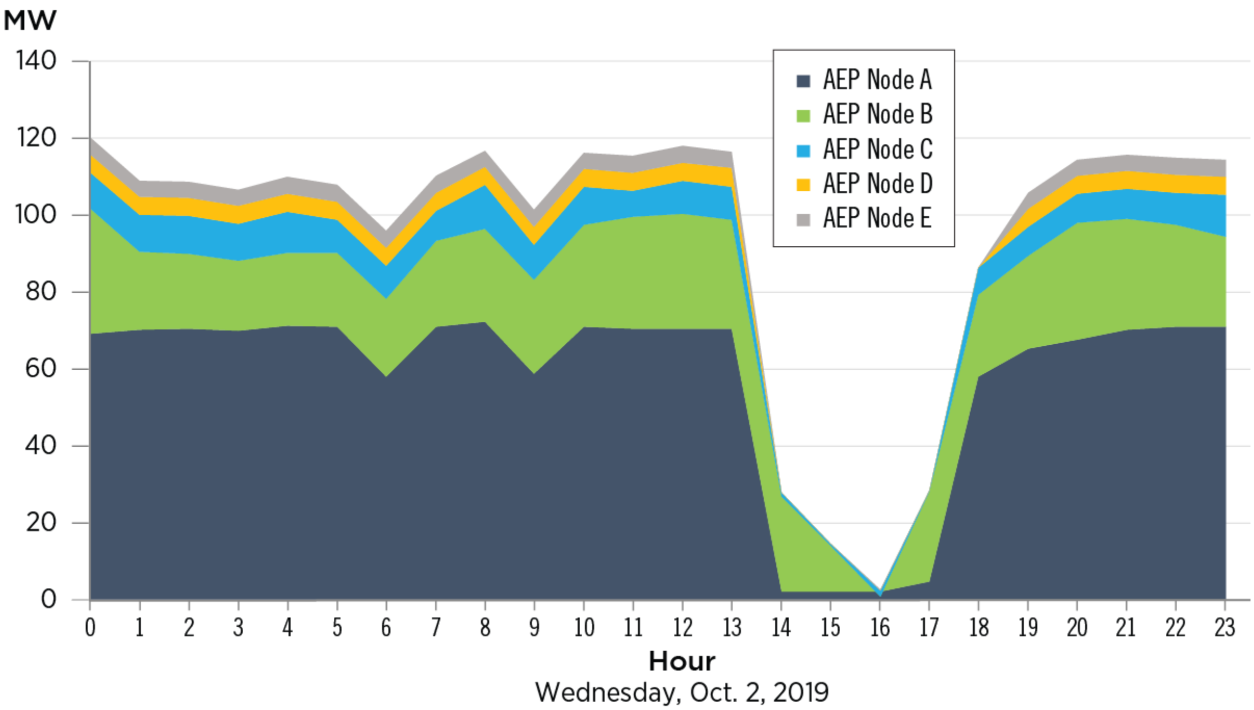
Load at many nodes throughout PJM was found to have decreased from 1–3 p.m., even though temperatures were rising. Many others increased but at a slower rate than the forecast would indicate. This behavior appears to be the primary cause of the error in AEP and PJM Mid-Atlantic, and a partial cause of the error in FE, in tandem with weather forecast error. The estimated 728 MW of PJM demand response will account for some of this reduction at some nodal equipment during the 2–4 p.m. timeframe. More work is needed to determine how much of the non-weather-driven load reduction during the PAI can be classified into the following categories: scheduled PJM DR; over-responsiveness of PJM DR; non-PJM, behind-the-meter load management programs; and industrial load response.

Case Study: AEP Nodal Load Reductions

While the load reduction in AEP cannot be explained by temperature, several instances of reduced load have been observed at nodal equipment. As shown in Figure 26, five nodal loads account for over 100 MW of load reduction. Many others decreased by smaller amounts.

The backcast estimated a 1,674 MW increase in load in AEP from hour ending 1–3 p.m.. An 831 MW increase was actually observed, leaving 843 MW of “missing load.” 450 MW of demand response was dispatched in AEP, leaving almost 400 MW unaccounted for and potentially attributable to load management programs that are not visible to PJM. A similar calculation for the PJM Mid-Atlantic zone, the other area whose error was not driven by weather, yields nearly 1,200 MW. A thorough analysis is needed to determine which nodal loads experienced decrease due to demand response compared to other reasons.

Figure 26. **Example of Nodal Load Behavior in AEP**



Conclusions and Recommendations

While PJM's review has resulted in some initial observations and recommendation areas, PJM will work with stakeholders to prioritize recommendations for further development. Some of these areas include the need to:

- Develop tools or approaches to increase observation of distributed energy resources and load during operational events. This will include working with states and members to gather additional data. These may also include developing additional tools to forecast this behavior in PJM operational tools.
- Review triggers for capacity performance and demand response triggers to ensure they are effectively triggering the reliability signals for which they were designed.
- Review load and weather forecasting tools to ensure they adequately include the data needed to provide accurate forecasts to operators and stakeholders.
- Review procedures for deployment of DR in entire zones as opposed to more granularly given the specific transmission constraints with which we were concerned.
- Work with stakeholders regarding any rule changes deemed appropriate based on the above analysis.
- Minimize or eliminate instances where emergency actions are taken triggering a PAI in locations where additional resource response is not needed as signified by low or negative prices. Clarify guidance to generators subject to performance assessments at locations where prices are low or negative during a PAI.

PJM will be presenting this paper to its Operating Committee and in other forums and looks forward to continuing to work with stakeholders to analyze t

PAI Settlements

Appendix: Performance Assessment Interval Settlements

Purpose

The purpose of this appendix is to provide more detail on the process and evaluation for penalties and bonuses associated with the Performance Assessment Intervals (PAIs) on Oct. 2, 2019, and provide data regarding the market settlement.

Background

The Pre-Emergency Load Management Reduction Action issued on Oct. 2, 2019, triggered Performance Assessment Intervals (PAIs) that require PJM to evaluate the performance of all resources located in the Emergency Action area for each applicable five-minute interval. The Emergency Action areas for the Oct. 2, 2019 performance assessment event spanned AEP, BGE, DOM and PEPCO for the intervals designated in Table 1. Throughout this paper, some data will be looked at on a five-minute interval basis, which will be described as a PAI, and some data will be looked at across the aggregate PAIs, from 1400–1600 EDT, which will be denoted as the performance assessment event.

Table 1. **Impacted Zones for Performance Assessment Event**

Zones	Performance Assessment Intervals
AEP, BGE, DOM, PEPCO	1400–1545
AEP	1545–1600

The resources located in the above areas that were evaluated for this performance assessment event include:

- **Generation:** All generation resources, inclusive of Capacity Performance (CP) and base capacity resources, energy-only resources and regulation-only resources.
- **Demand Response:** All pre-emergency CP and base demand response (DR) with two-hour lead time dispatched by PJM, economic DR and regulation-only DR.
- **Energy Efficiency:** All annual energy efficiency resources.

Current capacity market rules exclude some resources located in the impacted zones from PAI evaluations, which include pseudo-tie units modeled in the area and base energy efficiency resources.[20]

All resources are evaluated for the performance assessment event and are included in the calculations for total performance, balancing ratio and bonus eligibility; however, only the resources with a CP commitment are subject to performance assessment penalties.

Based on the resource's performance and capacity commitment, resources may be assessed non-performance charges or bonus performance credits. Non-performance is determined based on the response of resources to fulfill their capacity commitments during each five-minute PAI, and there is no netting permitted across intervals. The shortfall or excess is calculated separately for each resource and each interval. Resources with a shortfall, or delivered energy (or reduction) less than expected based on the capacity commitment, are assessed a financial penalty; while resources demonstrating excess performance, or delivery of energy (or reduction) greater than expected based on the capacity commitment, are eligible for bonus payments.

Resources that have been committed to a Fixed Resource Requirement (FRR) plan also have the option to elect the physical non-performance assessment option. Entities that elect the FRR physical option are not assessed non-performance charges and are not eligible for bonus performance credits for any performance associated with their FRR commitments. Instead, these entities must commit an additional megawatt quantity to their FRR capacity plan for the next delivery year in an amount equal to the sum of the net positive shortfalls for resources committed to their FRR plan, multiplied by the FRR physical penalty rate across all five-minute intervals in the performance assessment event.

Balancing Ratio

For each PAI, PJM calculates a balancing ratio which represents the percentage share of total generation capacity commitments needed to support the load and reserves on the system within the Emergency Action area during that interval. This balancing ratio is then used to set the expected performance level of generation CP resources within the Emergency Action area for each PAI.

Balancing ratio is calculated as:

Balancing Ratio (BR) = (Total Actual Generation and Storage Performance + Net Energy Imports + DR Bonus Performance) / All Generation and Storage Committed UCAP

Where:

[20] Prior to the 2020/2021 Delivery Year, pseudo-tie units are included in the assessment only if the Emergency Action area for PAI is PJM-wide. Base energy efficiency resources are not included in the assessment of PAIs that occur outside of the summer months of June through September.

- **Total actual generation and storage performance** is the actual metered output of the resources from PowerMeter adjusted for the real-time regulation or reserves assignment.
- **Net energy imports** are the net energy import quantity during the event reported in ExSchedule. Since the Oct. 2 performance assessment event was not RTO-wide, net energy imports are 0 MW.
- **DR bonus performance** is the net bonus megawatts for over-performing Curtailment Service Providers (CSP).
- All **generation and storage-committed UCAP** are the sum of the CP commitment UCAP value for all Reliability Pricing Model (RPM) generation resources included in the assessment.

The balancing ratio is expected to align with the system demands during the Emergency Action period. The peak demand on Oct. 2 was 126,000 MW; while this is a high load for the month of October, it is lower than the PJM peak load forecast which is used to establish the RPM reliability requirement (~165,000 MW). The RPM reliability requirement is established as the amount of capacity resources that are required to serve the forecast peak load and installed reserve margin to satisfy the PJM reliability criteria. As a result, it would be expected that the balancing ratio would be less than one, because the demand during the PAIs was significantly below the total committed capacity for those intervals. The average balancing ratio over the performance assessment event on Oct. 2 was 75 percent. The individual interval balancing ratios for each PAI are available in Table 2.

Table 2. **Balancing Ratio for Performance Assessment Intervals on Oct. 2**

PAI	Balancing Ratio
1400	72.62%
1405	73.05%
1410	73.55%
1415	74.13%
1420	74.28%
1425	74.19%
1430	74.42%
1435	74.45%
1440	74.66%
1445	74.78%
1450	74.54%
1455	74.55%
1500	74.14%
1505	73.91%
1510	74.16%
1515	73.89%

PAI	Balancing Ratio
1520	73.51%
1525	73.18%
1530	73.24%
1535	73.43%
1540	73.88%
1545	80.20%
1550	80.00%
1555	80.42%

Performance Shortfall

Non-performance is measured by comparing a resource's actual performance to their expected performance to calculate a performance shortfall. This performance shortfall represents the amount of the committed capacity from the resource that was needed during the event but was not delivered to the system. The performance shortfall is calculated as: expected performance minus actual performance.

The expected performance of a resource is its CP commitment, adjusted by the balancing ratio (for generation) to account for the megawatts needed during the PAI. The actual performance of a resource is defined as the output of the resource during the event, accounting for both energy and ancillary services. The energy output is accounted for by the metered output of the resource. Ancillary services are accounted for based on the real-time regulation or reserves on the resource. The calculation for the ancillary services is intended to ensure the actual performance captures the resource's performance up to their economic basepoint, even if they were moved off that dispatch point in order to provide the ancillary services in real-time.[21]

The expected and actual performance calculations for CP resources are based on resource type:

- Generation/Storage:
  - Expected Performance = Capacity Commitment (UCAP) x Balancing Ratio
  - Actual Performance = Metered Energy Output + Reserve/Regulation Assignment[21]
- Demand Response:
  - Expected Performance = CP Capacity Commitment (ICAP)
  - Actual Performance = Load Reduction + Reserve/Regulation Assignment[21]

[21] For calculations for reserve and regulation assignment megawatts factored into actual performance, see the Operating Committee presentation: https://www.pjm.com/-/media/committees-groups/committees/oc/20160913/20160903-item-12-pah-examples-with-reg-and-synch.ashx

- Energy Efficiency:
  - Expected Performance = CP Capacity Commitment (ICAP)
  - Actual Performance = PJM-Approved Post-Installation Load Reduction

If a resource's expected performance is greater than the actual performance, the resource will be assessed a non-performance penalty, unless the shortfall is excused from the performance shortfall. The excusal process and the megawatts that were excused for the Oct. 2 performance assessment event are discussed in the Excusal section of this paper.

The average initial shortfall across the performance assessment event, prior to excusals, was 10,457 MW. The PAI level data for the expected, actual and shortfall megawatts can be found in Table 3. Notably, actual performance across all resources in the Emergency Action area exceeds expected performance for each five-minute interval, somewhat contrary to the presence of an initial shortfall. This is the result of performance by resources that did not have a performance obligation at the time of the performance assessment event, and over-performance by some resources that did have a CP obligation.

Base capacity resources are only subject to non-performance charges for underperformance during PAIs occurring during the summer months of June through September. As a result, base capacity resources do not have an expected performance for the Oct. 2 PAIs. However, the actual performance of these resources, in addition to non-capacity resources (e.g., energy-only resources), are calculated and accounted for in the PAI settlements.

Due to the number of CP resources that exceeded the expected performance, and base capacity and energy-only resources that were online and generating during the Oct. 2 PAI, the aggregate actual performance in the PAI areas was greater than the expected performance, resulting in bonus megawatts for this event. Non-performance is assessed on an individual resource basis, and thus shortfall megawatts and associated non-performance charges are also calculated on an individual resource basis.

Table 3. **Aggregate Expected, Actual and Initial Shortfall Performance During Performance Assessment Intervals on Oct. 2**

Interval	Expected (MW)	Actual (MW)	Initial Shortfall (MW)
1400	40,947.07	45,258.37	11,035.68
1405	41,181.80	45,516.68	11,137.04
1410	41,464.30	45,827.56	11,227.73
1415	41,783.54	46,178.86	11,211.74
1420	41,866.22	46,269.84	11,246.60
1425	41,815.68	46,214.23	11,248.07
1430	41,944.89	46,356.41	11,317.67
1435	41,962.86	46,376.19	11,331.64
1440	42,080.33	46,505.46	11,316.54
1445	42,143.84	46,575.34	11,312.91

Interval	Expected (MW)	Actual (MW)	Initial Shortfall (MW)
1450	42,014.05	46,432.52	11,335.23
1455	42,021.04	46,440.21	11,325.13
1500	41,792.73	46,190.77	11,435.85
1505	41,661.26	46,046.09	11,357.26
1510	41,801.40	46,200.30	11,435.89
1515	41,651.93	46,035.82	11,492.00
1520	41,441.85	45,804.64	11,576.63
1525	41,256.69	45,600.89	11,508.37
1530	41,290.67	45,638.28	11,480.80
1535	41,393.43	45,751.36	11,325.09
1540	41,646.79	46,030.16	11,287.50
1545	19,947.56	22,148.92	4,367.16
1550	19,899.74	22,095.94	4,352.31
1555	20,002.65	22,209.95	4,302.55

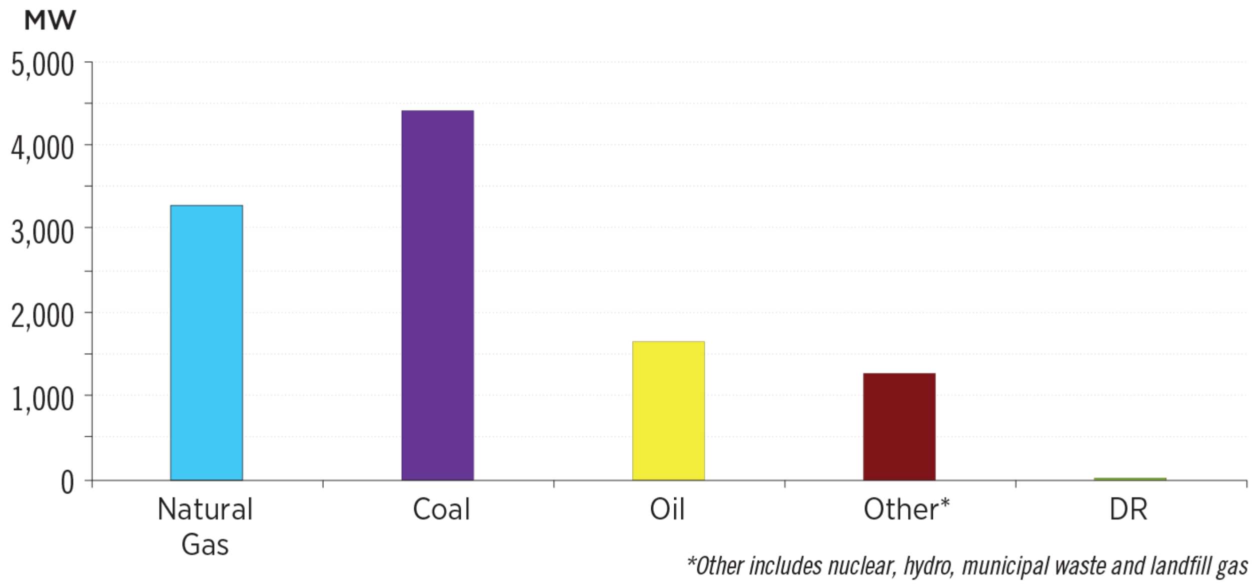
Breaking out the shortfall megawatts to a more granular level, the next few graphs and charts contain *only* the CP resources that had an initial shortfall. CP resources that have met or exceeded their expected performance, and base capacity and energy-only resources, are excluded from this data set.

Table 4. **Expected, Actual and Initial Shortfall Performance for Underperformance Resources During Performance Assessment Intervals on Oct. 2**

Interval	Expected (MW)	Actual (MW)	Initial Shortfall (MW)
1400	16,295.97	5,260.23	11,035.68
1405	16,113.26	4,976.15	11,137.04
1410	16,154.60	4,926.80	11,227.73
1415	16,350.90	5,139.09	11,211.74
1420	16,383.64	5,136.97	11,246.60
1425	16,662.45	5,414.31	11,248.07
1430	16,714.55	5,396.82	11,317.67
1435	16,702.37	5,370.66	11,331.64
1440	16,703.02	5,386.41	11,316.54
1445	16,567.61	5,254.63	11,312.91
1450	16,742.44	5,407.14	11,335.23
1455	16,716.86	5,391.66	11,325.13

Interval	Expected (MW)	Actual (MW)	Initial Shortfall (MW)
1500	16,098.74	4,663.08	11,435.85
1505	16,547.19	5,190.12	11,357.26
1510	16,112.88	4,677.17	11,435.89
1515	16,088.27	4,596.45	11,492.00
1520	16,315.42	4,738.98	11,576.63
1525	16,145.99	4,637.81	11,508.37
1530	17,011.18	5,530.57	11,480.80
1535	17,039.27	5,714.37	11,325.09
1540	16,120.46	4,833.15	11,287.50
1545	7,214.52	2,847.36	4,367.16
1550	7,708.20	3,355.88	4,352.31
1555	6,980.17	2,677.63	4,302.55

Figure 27. **Initial Shortfall Broken Down by Fuel Type**



Excusals

A resource's performance shortfall is evaluated for excusals and may be adjusted downward if the shortfall is deemed to be exempt. Megawatts are excused from performance for the following reasons:

- Megawatts were on a PJM-approved planned or maintenance outage.
- Megawatts were scheduled down by PJM, in alignment with the security-constrained economic dispatch (SCED).

- Megawatts were not scheduled to operate by PJM.[22]

For the Oct. 2 PAI events, the average excused megawatts for maintenance and planned outages were 7,293 MW. Being in October, the peak of maintenance season, the expected maintenance outages are higher than what can be expected in a typical winter or summer season. The shoulder period is when critical planned maintenance activities typically occur to ensure that these resources can continue to provide reliable generation throughout the year. These outages are scheduled and approved by PJM and recallable 72 hours in advance. This is the reason why these megawatts are deemed to be exempt from performance during their approved outage period. Prior to Oct. 2, PJM did not recall any generation maintenance outages, as load projections did not indicate that would be necessary. Forced outages, outages that are unscheduled or unplanned, are not exempt from performance; resources on a forced outage with a performance shortfall are assessed non-performance charges.

Megawatts that were not scheduled, or scheduled down by PJM, are exempt from performance penalties, because the resource followed PJM dispatch instructions and did not come online or generate past their dispatch point. This is important to system reliability during the performance assessment event that resources continue to follow PJM direction to help maintain power balance. If all resources were to come online and generate without PJM direction, this could result in reliability issues, such as transmission overloads, ACE imbalance, and stability. Therefore, resources that are not scheduled by PJM are exempt from performance penalties during that time. Resources may not be scheduled by PJM due to economic reasons, such as projected system conditions and locational marginal prices (LMPs) that did not support bringing the resource online; or controlling transmission constraints that supported lowering the unit's output; or the resource is held offline or down by PJM for reserves. Specifically, in the case of a flexible resource, PJM may hold a unit offline to have that resource available during the peak when they expect the generation will be needed. The average excused megawatts for resources not scheduled or scheduled down by PJM for the PAI events was 1054 MW.[3]

A more granular breakdown of the excused megawatts for the PAIs are detailed in Table 5.

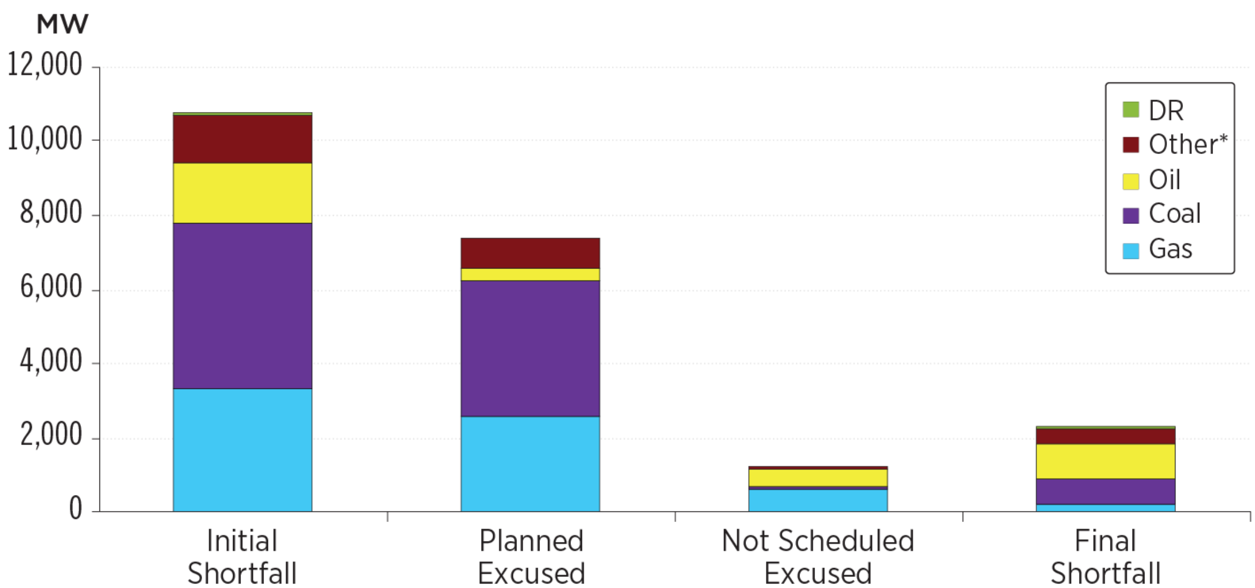
Table 5. **Excusal Megawatts for Planned Outages and Megawatts Not Scheduled by PJM by Performance Assessment Interval for Oct. 2**

Interval	Initial Shortfall	Planned Outage	Not Scheduled	Final Shortfall
1400	11,028.9	7,744.1	1,215.5	2,069.4
1405	11,130.3	7,800.3	1,235.8	2,094.2
1410	11,221.0	7,859.2	1,260.3	2,101.4
1415	11,205.0	7,933.6	1,117.8	2,153.6
1420	11,239.8	7,951.1	1,123.5	2,165.2

[22] If a resource was needed by PJM and would otherwise have been scheduled by PJM to perform, but was not scheduled to operate, or was scheduled down solely due to (1) any operating parameter limitations submitted in the resource's offer or (2) submission of market-based offer higher than cost-based offer, then these megawatts will not be considered exempted and will not result in downward adjustment of performance shortfall.

Interval	Initial Shortfall	Planned Outage	Not Scheduled	Final Shortfall
1425	11,241.3	7,940.3	1,099.9	2,201.0
1430	11,310.9	7,969.7	1,183.9	2,157.2
1435	11,324.9	7,972.6	1,176.0	2,176.3
1440	11,309.8	7,998.5	1,127.0	2,184.3
1445	11,306.1	8,012.9	1,134.4	2,158.9
1450	11,328.5	7,984.7	1,031.7	2,312.0
1455	11,318.4	7,987.3	1,060.1	2,271.0
1500	11,430.9	7,934.0	1,587.0	1,909.9
1505	11,352.3	7,905.7	1,195.6	2,250.9
1510	11,430.9	7,938.2	1,256.2	2,236.6
1515	11,487.0	7,904.2	1,370.1	2,212.8
1520	11,571.7	7,856.3	1,445.9	2,269.5
1525	11,503.4	7,819.2	978.5	2,705.7
1530	11,475.8	7,823.1	1,041.6	2,611.0
1535	11,320.1	7,848.3	1,175.3	2,296.5
1540	11,282.5	7,902.4	1,167.8	2,212.3
1545	4,362.2	2,984.9	90.6	1,286.6
1550	4,347.3	2,976.6	131.1	1,239.6
1555	4,297.6	2,994.9	90.9	1,211.8

Figure 28. **Fuel Type Breakdown of Excusals**



**Other includes nuclear, hydro, municipal waste and landfill gas*

As discussed in the Pricing Outcomes section of the paper, enough generation and reserves to support the load, in addition to heavy congestion in some areas, resulted in negative LMPs in some zones during the PAI events. Resources in these zones with negative LMPs are still evaluated in the performance assessment event. If the resource was offline and not called online to generate by PJM, that resource would be evaluated based on economics (comparing LMPs to the resource's offer curve). If LMP did not support the resource being online, the resource megawatt obligation would be excused under the not-scheduled excusal bucket. If the resource was online, generating at the negative LMP buses, these resources would be evaluated as being desired to run at their economic minimum on the cheaper of their offer curves. Any expected performance obligation above that point (economic minimum) would be excused under the not-scheduled excusal bucket for being uneconomic. If the resource was online, generating below the economic minimum point, the megawatts from the operating point up to economic minimum would be counted as shortfall megawatts and be subject to non-performance penalties.

Non-Performance Charges

Non-performance charge rates are calculated on a modeled RPM Locational Deliverability Area (LDA) basis for the relevant delivery year. The non-performance charge rate for a specific resource is based on the Net Cost of New Entry (Net CONE) ($/MW-day in installed capacity terms) for the LDA in which such resource resides and is calculated as:

Non-Performance Charge Rate ($/MW-5-Minute Interval) = Net CONE x Number of Days in Delivery Year / 30 Hours / 12 Intervals

The applicable charge rates for the Oct. 2 PAIs for those resources modeled in the RTO, BGE, PEPCO and SWMAAC LDAs for the 2019/2020 Delivery Year are detailed in Table 6.[23]

Table 6. **Non-Performance Charge Rates by LDA ($/MW-5-Minute Interval)**

Non-Performance Charge Rates by Locational Deliverability Area (LDA)	
BGE	$204.75
PEPCO	$231.91
RTO	$284.21
SWMAAC	$218.33

These charge rates are multiplied by the final performance shortfall in each PAI to determine the non-performance financial penalty for committed CP resources. The non-performance charge is calculated as:

Non-Performance Charge = Performance Shortfall MW * Non-Performance Charge Rate

The non-performance charge for the performance assessment event totals approximately $8.2 million, which was allocated across 53 resources with final performance shortfall megawatts.

[23] Modeled LDA Net CONE values for the 2019/2020 Delivery Year are available at https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2019-2020-bra-planning-parameters.ashx?la=en

Table 7. **Non-Performance Charges by Performance Assessment Interval for Oct. 2**

Interval	Non-Performance Charge
1400	$369,097.33
1405	$374,639.73
1410	$373,678.49
1415	$379,832.80
1420	$379,333.45
1425	$393,932.87
1430	$377,301.76
1435	$379,918.07
1440	$380,975.69
1445	$376,218.99
1450	$410,748.36
1455	$399,158.94
1500	$255,267.73
1505	$412,875.66
1510	$406,664.32
1515	$401,762.28
1520	$420,317.08
1525	$456,651.66
1530	$441,412.51
1535	$359,470.94
1540	$344,791.29
1545	$ 35,223.29
1550	$31,770.11
1555	$23,776.69

Stop-loss provisions are in place to limit the total non-performance charge that can be assessed on each capacity resource. For CP resources, the maximum yearly non-performance charge is 1.5 times the modeled LDA Net CONE ($/MW-day in installed capacity terms), times the number of days in the delivery year, times the maximum daily unforced capacity committed by the resource from June 1 of the delivery year through the end of the month for which the non-performance charge was assessed. For all CP resources involved in the Oct. 2 PAI event, the calculated non-performance charge for the event was below the maximum yearly non-performance charge. As a result, it was not necessary to apply the stop-loss provision to any CP resource for the Oct. 2 PAI.

Bonus Performance

A resource with actual performance above its expected performance is considered to have provided bonus performance, and will be assigned a share of the collected non-performance charge revenues in the form of a bonus performance credit. Bonus performance from a resource represents greater delivered energy (or reductions), in comparison to the amount of the committed capacity from the resource that was needed during the event. Bonus performance is calculated on all resources to determine over performance as: actual performance minus expected performance.

When calculating bonus megawatts, the actual performance for a dispatchable resource is capped at the megawatt level at which such resource was scheduled and dispatched by PJM during the performance assessment event. PJM caps the megawatt level that a resource is eligible to receive bonus credit for to incent resources to follow dispatch in real-time to support operations, and not chase potential bonus credits by over generating. Resources must also have at least one available schedule with economic minimum, economic maximum and emergency maximum, and at least one segment on the incremental energy curve.

The expected and actual performance calculations for bonus megawatt evaluations are based on resource type:

- Generation/Storage:
  - Expected Performance = (CP Commitment (UCAP) + Base Commitment (UCAP)) x Balancing Ratio
  - Actual Performance = Metered Energy Output + Reserve/Regulation Assignment
- Demand Response:
  - Expected Performance = CP Capacity Commitment (ICAP)
  - Actual Performance = Load Reduction + Reserve/Regulation Assignment
- Energy Efficiency:
  - Expected Performance = CP Capacity Commitment (ICAP)
  - Actual Performance = PJM Approved Post-Installation Load Reduction

The average bonus megawatts eligible for bonus credits for the performance assessment event on Oct. 2 was 9,706 MW. Approximately 81 percent of these megawatts came from CP resources while 19 percent came from base capacity or energy-only resources. The larger percent of bonus megawatts from the CP resources are driven by those resources being online generating, and the 75 percent balancing ratio. Resource output in excess of 75 percent of their capacity commitment, up to the megawatt level at which the resource was scheduled and dispatched, can be attributed to over performance.

Table 8. **Bonus Performance Megawatts for Performance Assessment Intervals for Oct. 2 Broken Down by CP Resources and Non-CP Resources**

Interval	Bonus MW – CP Resources	Bonus MW – Base/Energy Resources	Total Bonus MW
1400	8,999.9	1,854.8	10,854.7

Interval	Bonus MW − CP Resources	Bonus MW − Base/Energy Resources	Total Bonus MW
1405	8,783.0	1,924.5	10,707.5
1410	8,799.0	2,053.3	10,852.3
1415	8,657.6	2,106.9	10,764.5
1420	8,623.4	2,137.6	10,761.1
1425	8,803.6	2,150.6	10,954.1
1430	8,430.4	2,138.9	10,569.2
1435	8,410.2	2,150.3	10,560.5
1440	8,293.2	2,085.4	10,378.6
1445	8,298.7	2,045.4	10,344.1
1450	8,341.5	2,001.1	10,342.6
1455	8,361.3	2,006.8	10,368.0
1500	8,473.6	2,049.3	10,522.9
1505	8,554.4	1,866.5	10,420.9
1510	8,644.2	1,908.4	10,552.6
1515	8,647.7	1,876.6	10,524.3
1520	8,778.2	1,876.7	10,654.9
1525	8,626.2	1,914.1	10,540.3
1530	8,591.5	1,976.2	10,567.7
1535	8,584.5	2,123.2	10,707.7
1540	8,589.0	2,091.8	10,680.8
1545	2,705.4	818.4	3,523.8
1550	2,629.2	731.6	3,360.9
1555	2,690.6	733.1	3,423.7

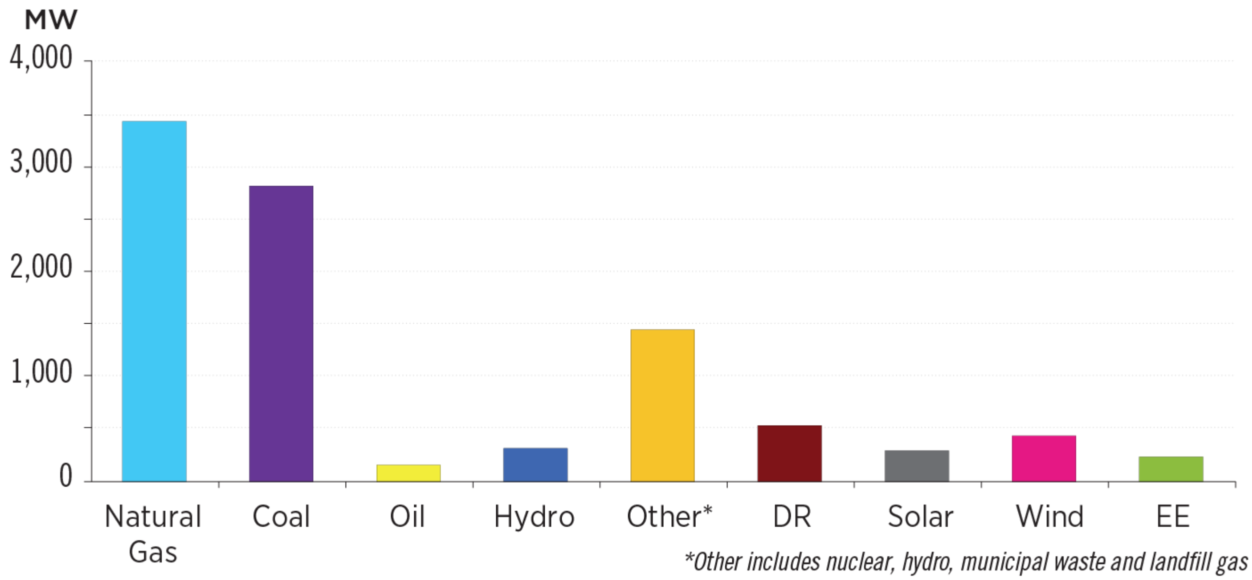
Total non-performance charges are allocated, at the account level, as bonus performance credit to resources that have bonus megawatts based on their pro-rata share of total bonus performance megawatts. The average $/MW-interval across the performance assessment event for bonus megawatts was $32.89.

Table 9. **Bonus Performance Credit by Performance Assessment Intervals for Oct. 2**

Interval	Total Bonus MW	Total Non-Performance Charge	Bonus $/MW-Interval
1400	10,854.7	$369,097.33	$34.00
1405	10,707.5	$374,639.73	$34.99
1410	10,852.3	$373,678.49	$34.43
1415	10,764.5	$379,832.80	$35.29
1420	10,761.1	$379,333.45	$35.25
1425	10,954.1	$393,932.87	$35.96
1430	10,569.2	$377,301.76	$35.70
1435	10,560.5	$379,918.07	$35.98

Interval	Total Bonus MW	Total Non-Performance Charge	Bonus $/MW-Interval
1440	10,378.6	$380,975.69	$36.71
1445	10,344.1	$376,218.99	$36.37
1450	10,342.6	$410,748.36	$39.71
1455	10,368.0	$399,158.94	$38.50
1500	10,522.9	$255,267.73	$24.26
1505	10,420.9	$412,875.66	$39.62
1510	10,552.6	$406,664.32	$38.54
1515	10,524.3	$401,762.28	$38.17
1520	10,654.9	$420,317.08	$39.45
1525	10,540.3	$456,651.66	$43.32
1530	10,567.7	$441,412.51	$41.77
1535	10,707.7	$359,470.94	$33.57
1540	10,680.8	$344,791.29	$32.28
1545	3,523.8	$ 34,140.12	$ 9.69
1550	3,360.9	$ 30,687.27	$ 9.13
1555	3,423.7	$ 22,693.52	$ 6.63

Figure 29. **Bonus MW by Fuel Type**



Resources that have been committed to an FRR plan and elected the physical non-performance assessment option did have bonus megawatts calculated for the Oct. 2 performance assessment events. The details on the FRR physical bonus megawatts are being withheld for data confidentiality reasons.[24]

Demand Response Performance

Detailed performance of DR for the Oct. 2 performance assessment event is reviewed in the Load Management Performance Review report.[25] An excerpt of these details on performance, shortfall, bonus and penalties are detailed below. The full report can be referenced for more detailed analysis.

Table 10 below summarizes CP and expected energy load reductions reported by CSPs prior to the event, compared to actual energy load reduction that was settled. PJM dispatched CP DR long-lead resources Oct. 2, 2019, during their mandatory compliance period and base DR resources during their voluntary period. Resources in Dominion, PEPCO and BGE zones were dispatched from 1400 through 1545 and resources in the AEP zone were dispatched from 1400 through 1600. Overall event performance during the mandatory compliance period was 78 percent. Capacity compliance is measured based on Firm Service Level and Guaranteed Load Drop approaches which can be significantly different from real-time energy load reductions. Further, CSPs reported an expected 728 MW of available reduction prior to the start of the event, compared to the 395 MW (54 percent) of load reduction which was actually provided. PJM uses the expected energy reductions reported by CSPs as part of the decision-making process when determining which DR resources should be dispatched to maintain system reliability.

Table 10. **Load Management Event Summary for Oct. 2**

Product	Capacity Committed (MW)**	Capacity Reduction (MW)	Capacity Performance	Expected Energy Reduction (MW)	Settled Energy Reduction (MW)***
Capacity Performance	25.4	19.9	78%	24.2	22
Base*	n/a	n/a	n/a	703.8	373
Total	**25.4**	**19.9**	**78%**	**728**	**395**

* Base DR was a voluntary event since resources were only required to reduce load through September. Base capacity load reductions are used to offset CP shortfall and any residual base reductions are eligible for bonus payments.

**Long lead time and pre-emergency resources only in the event zones.

***Megawatt reduction in HE 15 (highest reduction hour).

[24] PJM Manual 33 Section 3.1: https://www.pjm.com/~/media/documents/manuals/m33.ashx

[25] https://pjm.com/-/media/markets-ops/dsr/2019-2020-dsr-activity-report.ashx?la=en

The capacity reduction represents the megawatts reduced by CP resources based on their load levels during the event, compared to their Peak Load Contribution. The settled energy reductions include reductions from both CP and base resources, and are based on load levels during the event relative to recent days' load levels during the same hours. The shortfalls from capacity commitments receive non-performance charges. The settled energy reductions are made whole to their strike price.

Voluntary base DR, economic energy reductions and cleared ancillary services offers during the event intervals are eligible for bonus payments. Total bonus amount allocated to DR was $447,666. Average performance was a 6 MW shortfall which resulted in $40,049 in non-performance penalties. The bonus and non-performance penalty breakdown for DR is detailed in Table 11.

Table 11. **Penalty and Bonus Megawatts for the Performance Assessment Event on Oct. 2**

Product	Event Penalties	Avg. Shortfall (MW/Interval)	Avg. Penalty Rate ($/MW)	Event Bonus	Avg. Bonus (MW/Interval)	Weighted Avg. Bonus Rate ($/MW)
CP	$40,049	5.9	$284	$344	0.5	$36.5
Base	n/a	n/a	n/a	$441,283	558.5	$34.7
Economic Energy/Ancillary Services	n/a	n/a	n/a	$6,039	1.1	$36
Total	**$40,049**	**5.9**	**$284**	**$447,666**	**560**	**$34.73**

Settlement Billing Timelines

Non-performance assessments are billed starting three calendar months after the calendar month that included the performance assessment event and are spread across the remaining months in the delivery year. Monthly charges and credits are billed by dividing the total dollar amount due or owed by the number of months remaining in the delivery year.

For the Oct. 2 performance assessment event, charges and credits were first billed starting in the January 2020 monthly bill and will continue through the May 2020 monthly bill.