Demand Response Strategy

PJM Interconnection

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Executive Summary

Consumer response to price is essential to efficient and competitive market outcomes, a principle that holds as true for wholesale electricity markets as any other markets. The more that demand actively participates in electricity markets,[1] the more competitive and robust the market results. Additionally, demand response (DR), if visible and dependable, has proven to be a valuable operational tool that assists in maintaining reliability both for real-time grid stability and long-term resource adequacy.

DR participation in the PJM Interconnection wholesale markets has matured significantly over the last 10 years. DR has transitioned from a legacy utility program to a resource, managed by curtailment service providers (CSPs), that is integrated into the wholesale markets and used to operate the grid. The CSP model[2] and capacity market revenue incented significant innovation and competition. In the capacity market, DR typically represents 5 percent of the annual committed capacity and is valued at more than $500 million. Under Capacity Performance (CP), DR resources must be capable of reducing load throughout the year (instead of participating as summer-only resources), which makes DR resources more comparable to generation but also impacts their participation compared to historic experience. The CP requirements incent DR resources to aggregate individual customer capabilities into a portfolio to meet the availability requirements and are a key factor that will affect the future DR strategy.

While DR resources are a significant part of the PJM wholesale markets, those markets have evolved, grid operational needs have changed, the focus on resilience is increasing and behind-the-meter technology has the potential to change the dynamics of markets and grid operations. Therefore, now is an appropriate time to review how demand resources integrate into PJM operations, markets and planning and to consider the future direction for DR. The purpose of this paper is to describe PJM's vision, roadmap and strategy for DR including short-term goals (one to two years), medium-term focus (three to five years) and longer-term direction (five-plus years).

PJM's strategic objectives for DR are to:

- Ensure that DR is a predictable, reliable and transparent resource with which to manage the grid
- Enable more efficient market outcomes through price-sensitive demand
- Increase alignment of wholesale and retail market incentives through coordination with state retail regulatory authorities

Retail Electricity Cost Savings (Demand Side) or Wholesale Market Revenue (Supply Side)

DR is driven by the end-use customer's desire to reduce electricity costs (or associated price and volume risks). This goal can be accomplished either through retail electricity cost savings via an appropriate retail electricity contract or tariff or through wholesale market revenue via payments as a participating supply-side resource. On the demand side, the customer may reduce electricity consumption when the retail price is high and increase consumption when the retail price is low to reduce overall electricity cost. On the supply side, the customer may receive a payment from a CSP to reduce load when the wholesale price is high (potentially resulting in an increase in consumption when the price is lower) and use

[1] DR may actively participate to reduce consumption in the retail market based the customer's retail contract and/or tariff to reduce its energy cost. This activity is integrated into the wholesale market either through the load-serving entity's demand bids or through a lower PJM forecast. Active participation in the markets does not require retail customers to directly participate in wholesale markets.

[2] The CSP model allows an aggregator (that is not required to be the load-serving entity, electric distribution company or end-use customer but is required to be a PJM member) to be responsible for DR activity in the wholesale market.

the payment (or "revenue") from the wholesale market to reduce electricity cost. Both approaches enable customers that are price sensitive to reduce electricity cost.

If DR is incented through the retail market, then PJM, as the wholesale market operator, will focus on the accuracy of the aggregate load forecast based on the customer's price elasticity of demand to determine which supply resources to commit to meet the forecasted load. This is especially true for the energy market although compensation through the capacity and ancillary service wholesale markets may be the more effective mechanism than through cost saving on the demand side through the retail market. The price elasticity of demand for electricity is driven by available retail contracts/tariff structures offered by the load-serving entity (LSE), which are based on the customer's needs and capabilities and associated retail regulatory policies. Retail contracts/tariffs that incent customers to manage their demand may take many forms, including block- and locational marginal pricing (LMP)-based index contracts, rebates or incentives, reduced fixed-price contracts, time-of-use rates or other innovative approaches used by the retail customer's LSE.

A customer's electricity supply costs[3] are primarily from energy, capacity and ancillary service costs. A customer's electricity cost as a percentage of operating cost varies widely and can be over 50 percent for electric-intensive industries. Electricity costs are based on a customer's actual consumption, so customers can realize electricity cost savings on the demand side with the appropriate retail contract or tariff in place. Further, each LSE can reflect its customers' price elasticity of demand in its own forecasts and procure the appropriate hedges against wholesale costs (e.g., forwards, options, contracts for differences) in the bilateral and/or day-ahead energy markets.

Table 1 breaks down electricity supply cost with the associated challenges of moving DR from wholesale market revenue on the supply side to retail cost savings on the demand side. The purpose of this table is to understand if there are significant obstacles to recognize the value of DR on the demand side of the retail electricity market instead of through the supply side of the wholesale market. The goal is to enable customers with flexibility to have an opportunity to reduce electricity cost (or risk) in one market or the other.

Table 1. Retail Electricity Cost Breakdown and Challenges to Manage on the Demand Side

Market	Percent of Customer's Generation Cost	Challenges to Move DR from Supply-Side Wholesale Market Revenue to Demand-Side Retail Cost Savings
Energy	80 percent	– Retail energy cost savings are less than retail energy cost savings combined with wholesale market revenue. – Interval metering may not be available due to the cost (primarily for residential and small commercial customers). – Retail contracts/tariffs are not available (primarily in regulated jurisdictions or for residential and small commercial customers).
Capacity	16 percent	– Customers will need to curtail more of their use in order to avoid missing one of the peak days that will help offset their peak load. This may result in unnecessary curtailment events as well as potentially adverse impacts to operations because of the unpredictability of these curtailments. – The grid may not need customers to reduce load on peak days if plenty of supply resources are available that can be dispatched more economically. – The total amount of capacity procured will not change significantly for several years. While

[3] The customer's retail electricity costs are primarily driven by distribution, generation (e.g., energy, capacity, ancillary services) and transmission costs. Generation is also referred to as the customer's "supply cost" and represents the cost to have resources available and for those resources to produce electricity.

Market	Percent of Customer's Generation Cost	Challenges to Move DR from Supply-Side Wholesale Market Revenue to Demand-Side Retail Cost Savings
		some customers' capacity requirements will go down, other customers' capacity requirements will go up, which will lead to cost shifting or a subsidy from one class of customers to another class of customers. – A forecast of demand reduction in the future based on past behavior is not as transparent and reliable as a future commitment to reduce load.
Ancillary Services	4 percent	– These are difficult to attribute to a specific customer, thus making it hard for customers to reduce ancillary services through direct actions. – Ancillary services are a small portion of total customer generation cost, so efforts to reduce them will not yield great savings. – There is a significant cost to meter and telemetry requirements – very few customers have 1 minute load data or real-time telemetry, which is required to participate. – A quick response is required, which typically requires investment in automation.

DR participation as an economic resource in the wholesale energy market has been low, even with the payment of full LMP. Many customers that typically might participate in the wholesale energy market can realize energy cost savings directly on their retail bills through more dynamic retail rate contracts. For those customers most willing to reduce load, there are few challenges to achieving energy cost savings on the demand side; many can find index-based contracts to realize electricity savings from load reductions. Small customers, especially those without interval metering, may have more significant challenges to realize energy cost savings from load reductions on the demand side.

On the other hand, the wholesale capacity market provides customers with good opportunities to reduce electricity cost (through payments) in exchange for a – typically small – number of DR events through participation in the wholesale capacity market as a supply resource rather than on the demand side through avoided retail cost. For example, if the capacity price is $150 MW-day and the customer must reduce load for 30 hours per year, the customer effectively will save $1,825 per MWh for each megawatt-hour reduced.[4] This financial benefit is the major reason why DR participation in the capacity market as a supply resource has been so robust compared with other markets.

The costs for ancillary services (such as synchronized reserves, day-ahead scheduling reserves and regulation) are difficult to mitigate on the demand side through a reduction in retail electricity costs. Ancillary service costs typically are charged to LSEs on a pro rata load-ratio-share basis. This allocation is an aggregate and not easy to attribute to an individual customer. Therefore, LSEs may pass these costs through to customers, but a customer cannot effectively reduce these costs on its retail electricity bill through targeted load reductions.

DR direct participation in the wholesale ancillary service markets as a supply resource is a much more effective way for a customer to manage these costs. Further, DR that can provide ancillary services can do so with little impact on the customer's operations, comfort or convenience due to the short duration of response if they make the appropriate investment in automation. For example, residential customers that participate in the synchronized reserve market would experience minimal impact on comfort since events last less than 30 minutes. (At 50 percent cycling, the internal temperature of a house will not increase significantly.)

[4] ($150 MW day * 365 days)/30 hours = $1,825 MWh

Paths to the Future

CSP Model

The CSP model of DR participation in PJM wholesale markets has been successful, and PJM believes this approach should be preserved for the foreseeable future.

Capacity and Ancillary Services Markets

DR should remain as a supply-side resource in the capacity and ancillary service markets. This approach is a more effective way for customers to manage these costs and for the wholesale market to incorporate these load-reduction actions.

Energy Market

The long term should be DR capability participation on the demand side of the energy market. PJM recognizes that the transition from customers receiving both supply-side payments and demand-side retail cost savings to receiving just demand-side retail cost savings will have obstacles to overcome. Nevertheless, this direction should be the long-term goal. PJM will look for opportunities to evolve in this direction through collaboration with load-serving entities and the state retail regulatory authorities.

If a customer desires to manage its energy cost, an appropriate retail rate/contract should be available to facilitate that capability. Retail customers should not necessarily receive compensation through the wholesale energy market. Such payments may result in a subsidy when customers already are on a dynamic retail rate. Subsidies for a single type of resource lead to inefficient market outcomes and distortion of energy price formation because that resource will be utilized when another type of resource may be more cost effective. The wholesale energy market should accurately forecast this price sensitively to effectively commit other resources.

Short-Term Goals: Transition to Capacity Performance and Annual Capability through Aggregation

The implementation of capacity performance is a major change in the DR capacity market availability requirements. Capacity performance requires DR resources to be available on an annual basis with the potential to dispatch for several hours during a day. PJM's short-term focus is on:

- Transitioning DR to CP requirements (PJM will continue to work with stakeholders on enhancements that add value)
- Developing a DR dispatch model to optimize dispatch and release of DR
- Reviewing DR and PRD rules and consider integrating into one approach
- Continuing to increase PJM operational visibility of DR
- Implementing broader energy market changes (e.g., five-minute settlements, hourly offers, price caps)
- Identifying any needed enhancement for Distributed Energy Resources that operate as DR
- Implementing mandatory training to ensure all CSPs are ready when DR is dispatched

Medium-Term Focus: Ensure DR Capabilities Align with Commitments

As we transition away from customer-specific capabilities to portfolio capabilities (based on the new annual CP requirements), PJM should review existing rules and procedures and make changes where necessary to ensure PJM fully understands the DR capability. In the medium term, PJM will:

- Ensure DR commitments reflect DR capabilities by developing and implementing:
  - More robust and comprehensive capacity testing requirements
  - Synchronized reserve testing with enhanced performance measurement using the Customer Baseline Load (approach
- Work with states and other stakeholders on other options to recognize the value of seasonal resource flexibility
- Refine PJM's ability to dispatch DR by quantity and location

Long-Term Direction: Explore Opportunities to Move DR in the Energy Market to the Demand Side

PJM will work with LSEs to determine how to enable more dynamic retail contracts to help align wholesale market prices with retail market prices or incentives and to help transition from wholesale energy market revenue on the supply side to retail energy cost savings on the demand side. In the long term, PJM plans to:

- Collaborate with LSEs to support contracts/pricing that foster demand elasticity
- Explore and develop opportunities to move DR in the energy market to demand side (cost savings) by modifying or eliminating energy compensation
- Expand participation in ancillary services markets where performance is comparable to generation
- Foster or support investment and implementation of DR automation
- Evaluate transitioning energy efficiency to the demand side (retail electricity cost savings) by eliminating capacity compensation

Demand Response Background

Demand response (DR) represents changes in electric usage end-use customers make from their normal consumption patterns in response to changes in the price of electricity or system conditions. DR helps customers manage their electricity costs and is a tool for grid operators to manage the power balance of the grid.

Large industrial customers with index price contracts will actively change their operations, including the use of on-site generation, to shift consumption to lower-price periods. For example, to lower its electricity bill, a university campus with thermal storage can determine the best time to melt ice to provide cooling during summer months. Residential customers can allow their utilities to turn off their air conditioners remotely on a periodic basis in exchange for a payment that may reduce their overall electricity costs. There are a wide variety of DR opportunities, and those opportunities continue to grow as DR capabilities are identified and enabling technology is deployed.

DR has been used at PJM and elsewhere to ensure reliability for more than 40 years. Vertically integrated utilities recognized DR as part of their integrated resource plans well before the Federal Energy Regulatory Commission (FERC) created regional transmission organizations or independent system operators. The use of DR to manage a retail customer's electricity costs as well as balance power on the grid has a long and successful history in the U.S. and in other countries around the world.

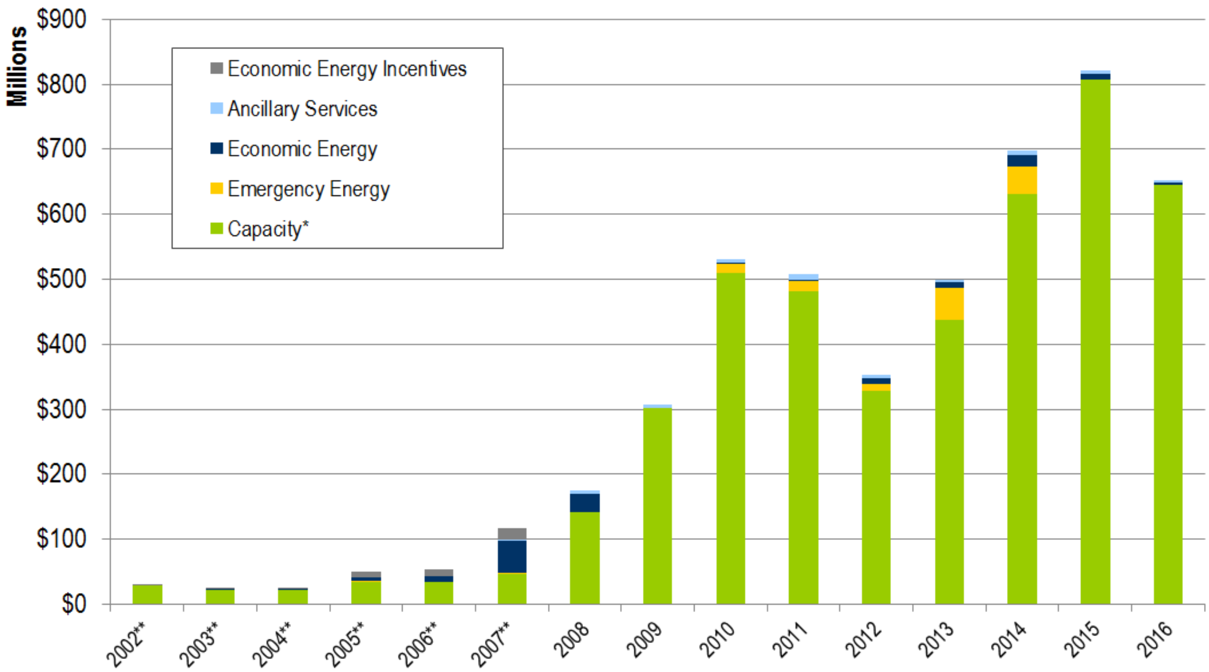
It is important to understand DR's long history in both the wholesale and retail electricity markets. Retail market activity has been fostered by a variety of entities, including federal agencies, retail regulators, electric distribution companies (EDCs), and load-serving entities (LSEs). Determining a path forward for DR in the wholesale market requires recognition that there are many different channels that help to identify and enable a customer's DR capability.

Wholesale Market Participation

DR participation in the wholesale market has evolved over many years from its initial use in integrated resource plans by vertically integrated utilities to the CSP model that exists in PJM today.

Under the CSP model, DR may be offered by any PJM member in the capacity, energy and ancillary service markets, such as synchronized reserve, day-ahead scheduling reserve and regulation. Revenues paid to CSPs in the wholesale market for DR have risen dramatically since the inception of the PJM Reliability Pricing Model (RPM) capacity market and CSP model, particularly revenues related to capacity payments and payments for reductions during system emergencies (Figure 1).

Figure 1. DR Revenue by Year, by Wholesale Service[5]



* Capacity net revenue inclusive of capacity credits and charges

**PJM assumes capacity value at $50 MW Day (PJM does not know the value of capacity credits in the forward market prior to RPM; only a portion of capacity was purchased through the daily capacity market at the time)

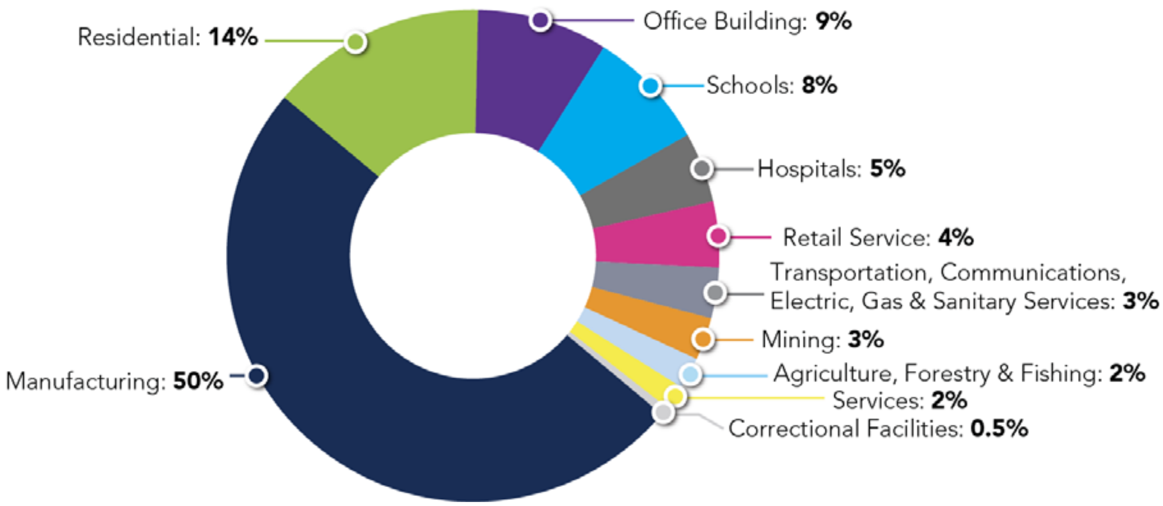
[5] DR has had many major changes that have impacted the participation of DR in the wholesale markets over time.

DR has the option to participate in PJM markets in three different ways: (1) DR may participate by reducing its reliability requirement during emergency/pre-emergency conditions (also known as load management) when there is a firm commitment to limit consumption to a specified level. Reductions through load management commitments also receive energy revenue when they are requested by PJM to reduce load. (2) DR may also participate by offering load reductions for economic reasons in the energy and ancillary service markets as an economic DR resource. (3) Since a customer may participate as both Economic DR and as Load management, Load management resources may also offer load reductions in the energy market for purely economic reasons and not wait to be requested to address a PJM emergency or pre-emergency condition.

For the 2015/16 delivery year, close to 11,000 MW of DR installed capacity was committed to PJM through RPM auctions, bilateral transactions or fixed resource requirement plans. Approximately 2,000 MW also were available to participate as an economic resource in the energy and ancillary service markets. Close to 1,300 MW were economic resources only, which means they had no capacity commitment and only participated in the energy and ancillary service markets. Of the close to 3,400 MW of economic DR, 560 MW were certified to participate in the synchronized reserve market and less than 20 MW were certified to participate in the regulation market.

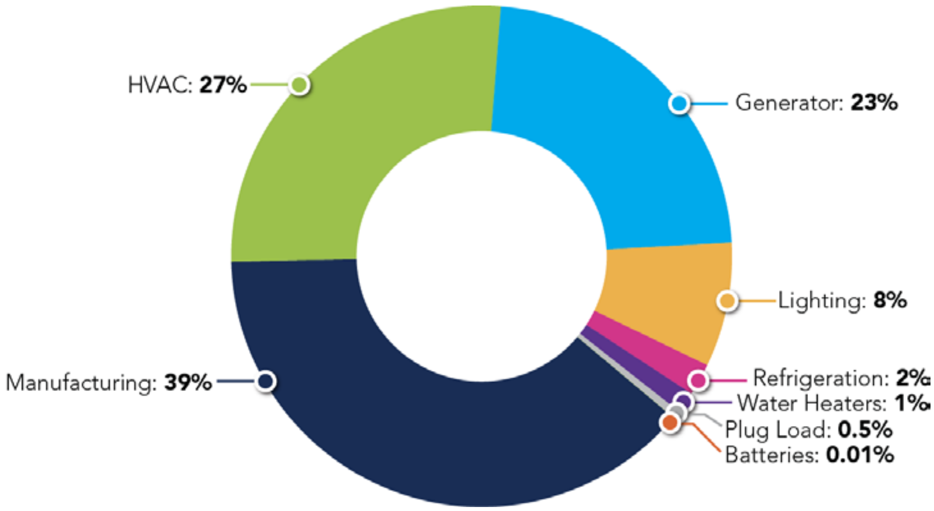
DR participation comes from a wide variety of customers that deploy several different measures to reduce load. For instance, 50 percent of the DR capability comes from the manufacturing sector, 8 percent comes from schools and 14 percent comes from the residential sector (Figure 2).

Figure 2. DR Capacity Capability for 2015/16 Delivery Year by Sector



As shown in Figure 3, DR load reductions are primarily implemented by running a behind-the-meter generator (23 percent), reducing HVAC (27 percent) or adjusting a manufacturing process (39 percent). How DR is implemented does not impact treatment of DR as a commitment to reduce load. For example, DER) are frequently used as a means to reduce load and offer into the wholesale markets. All DR resources that have behind-the-meter generation are, in effect, using DER.

Figure 3. Customer Load Reduction Methods for Delivery Year 2015/16 Confirmed Load Management Registrations



Retail Market Participation

Although there is significant participation of DR in the wholesale markets, DR has deep roots based on participation in the retail market. DR participates in the retail market to manage electricity cost in a variety of ways, in exchange for the retail LSE or EDC using the load reductions to manage peak loads for reliability reasons, economic reasons or both. DR may participate based on state initiatives that range from educating customers about DR to mandatory targets that require utilities to reduce peak load. LSEs also actively promote DR to their customers as it helps LSEs manage electricity costs and risks to their portfolios (and therefore for their customers). Finally, end-use customers have historically implemented DR to manage electricity costs directly through facility managers, contractors and consultants. The impact of DR in the wholesale market is represented in the load forecast and the way LSEs bid volume by prices in the energy markets.

State DR Initiatives

Several states in the PJM region have adopted strong policies that support DR:

Maryland enacted the EmPOWER Maryland Energy Efficiency Act (EmPOWER MD) in April 2008. EmPOWER MD set a statewide goal of reducing per capita electricity consumption by 15 percent and per capita peak demand by 15 percent by 2015 compared to 2007 levels. EmPOWER MD requirements translated to an annual statewide reduction of 5,475,409 MWh and of 2,117 MW by 2015. The act also required that the Maryland Public Service Commission implement a requirement for the state's electric utilities to reduce per capita electricity consumption by 5 percent by 2011 and 10 percent by 2015, compared to 2007 levels. Maryland Public Service Commission officials projected that more than $1 billion would be spent by the state's utilities on DR and energy efficiency plans between 2009 and 2015.

New Jersey's Board of Public Utilities adopted the Modified Demand Response Working Group Program to encourage the registration of new and incremental capacity from commercial and industrial customers into PJM's Interruptible Load for

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Reliability program for the period from June 1, 2009, through May 31, 2010.[6] This plan provided a financial incentive of $22.50 per MW-day for new and incremental DR. Effective June 1, 2009, CSPs registered 255 MW of new or incremental DR from commercial and industrial end-use sites in New Jersey. The 255 MW increase represented a 75 percent increase over the 337 MW of DR previously registered from New Jersey commercial and industrial customers. Approximately 90 percent of the new or incremental DR also registered as load management for the following year.

Pennsylvania enacted Act 129 in 2008. This act included a provision requiring electric utilities to reduce total annual weather-normalized energy consumption by 3 percent and peak demand by 4.5 percent over the 100 hours of the highest demand by May 31, 2013. Failure to achieve these reductions in consumption and peak demand exposed utilities to significant financial penalties. Through a series of orders, the Pennsylvania Public Utilities Commission has implemented the provisions of Act 129. The most recent of these orders establishes a budget and peak reduction target for each electric utility, to be accomplished through four-hour reductions during summer afternoons, triggered by a day-ahead load forecast equal to 97-plus percent of the utility's peak load forecast.

Load-Serving Entity Initiatives

LSEs have actively pursued DR primarily through different contracts and tariffs. Vertically integrated utilities have curtailment rates or riders that allow customers to receive lower prices in exchange for an option to call on them to reduce load when needed by the LSE. The LSE uses this call option to manage its risk and the electricity cost for the customer. These types of tariffs typically come with a significant penalty for non-performance if the customer does not reduce load according to the tariff's terms.

Deregulated retail markets have much more flexibility for contracts than the traditional regulated retail rate structure and associated rate-case approach. Deregulated LSEs will often have individual contracts for customers in order to align the customers' electricity cost/risk profile with the existing LSE products and services.

A customer's flexibility to reduce load may be optimized through a variety of contract structures, including:

- Discounted rate with penalty for non-performance: The customer may have a discounted fixed price rate but be required to shift load when called a certain number of times. This structure has been in place in regulated markets for many years. If the customer does not curtail when called, it will receive a penalty.
- Real-time/day-ahead index with block hedges: This is the most common approach for larger industrial and commercial customers that want to actively manage their electricity costs. The customer buys or sells power at LMP and uses block purchases to hedge its risk. A block purchase is exactly what it sounds like – a wholesale market product traded in on-peak, off-peak or round-the-clock blocks. A block purchase gives the customer flexibility in how much to hedge and the chance to change load patterns to reduce electricity costs (e.g., reducing consumption when LMP is high, selling back blocks and receiving the proceeds, avoiding paying high LMP prices if unhedged).
- Time-of-use prices: Different prices in different time periods allow customers to shift typical usage patterns to lower-price periods.

[6] Board Staff Report on New Jersey Capacity, Transmission Planning and Interconnection Issues, Docket Nos. EO11050309 and EO09110920, December 2011, pg. 41.

- **Peak-time rebate:** Customers are paid a rebate if they shift usage when needed by the LSE. The rebate is based on the LSE's ability to reduce its cost/risk to supply the customer during high-energy-price periods.

- **Critical-peak pricing:** Customers will pay very high prices when wholesale prices are high. This is typically a more dynamic form of time-of-use prices and reflects times when the system is close to shortage conditions.

LSEs are also implementing advanced technologies that allow customers to better manage their electricity consumption and costs based on the terms of their contracts. In some areas, LSEs provide hourly meter data and associated load data information and analytics software. There are also situations where LSEs provide advanced thermostats.

Customer-Specific DR Initiatives

A retail end-use customer can implement DR initiatives on its own or through energy service companies. Many of these efforts have been focused on managing regulated tariff demand charges, shifting usage to off-peak periods or energy efficiency measures, which are another form of passive DR.

Customers, or their contractors/consultants, have a variety of actions available help them manage electricity costs without any LSE involvement. For example, some customers will have discretionary load on an automated maximum demand limiter to ensure monthly EDC demand charges are minimized. Customers may actively look to reduce consumption during the PJM peak period (called "peak shaving") to lower their capacity obligation in the next delivery year, which would reduce their electricity costs.

Assumptions and Guiding Principles

DR is not a traditional generation resource, nor is it like any other supply resource. Rather, it is a commitment to reduce consumption for either reliability purposes (such as a grid emergency) or for economic purposes. This distinction should be acknowledged when considering the future path for DR in the wholesale markets.

Guiding Principles

- There should be no difference in the incentives for DR to participate on the supply side or demand side of the energy and capacity markets. That is, the total expected net energy and capacity expenditures should be the same in either case.
- Markets are non-discriminatory in that they are resource-, technology-, age-, size- and fuel-neutral, subject to reliability considerations.
- Efficient markets consider all resources, regardless of characteristics, to achieve cost-effective supply-demand balance and reliability outcomes. In effect, the objective of markets is to minimize the cost (and maximize the surplus) of serving load and maintaining reliability.
- Resources in wholesale markets should have comparable requirements. This will help foster competition, leading to better service and lower costs. Comparable does not necessarily mean identical, since different resources have different characteristics.

Understanding some of the basic differences between generation and DR is helpful to determine the future DR strategy. DR has very different characteristics than Generation but has been a very useful resource to manage the grid. Table 2 provides a comparison of key attributes of generation and DR to consider.

Table 2. Comparison of Central Station Generation and DR Attributes

	Central Station Generation	DR[7]
Motivation	In business to produce power – the more it is dispatched, the more revenue it earns	Uses electricity for comfort or to run a business – does not want to reduce load unless it will help reduce electricity cost
Capital Intensive	Large, irreversible capital investment – entry and exit have a long time frame. Resource typically in market for 40 years	Small capital investment – entry and exit into market very flexible and typically based on opportunity cost
Source of Flexibility	Start-up and shut-down parameters as well as ramp rates determine flexibility. Flexibility is provided at the cost of wear and tear and less-efficient performance	Well-managed portfolios with appropriate technology able to provide some flexibility
Administrative Scale	Approximately 2,000 generation units. Very small percentage of retirements vs. new units. Once modeled, they typically remain unchanged for many years	Two million retail customers today (out of approximately 65 million in footprint). Mix of customers that participate can change on frequent basis (every year)
Predictability	Once iron is in the ground, there is fairly predictable availability and performance (long history as a benchmark)	Varies based on underlying retail customer mix and associated capability. Sites and their capability can change frequently based on their preferences and changing value of energy

DR Service Models[8]

DR is based on an end-use customer's ability to reduce load in response to a signal, whether it is a price signal from the retail or wholesale market or a directive to reduce in response to system conditions.

"End-use customer" is synonymous with a retail customer, i.e. the entity that purchases electricity in order to consume the electricity. This is different from a wholesale customer that purchases electricity but does not consume it, rather reselling it to another wholesale or retail customer. Retail customers range from the households of the approximately 65 million people in the PJM footprint to consumers such as commercial and industrial businesses, which make up a significant part of the U.S. economy.

PJM does not interact with retail end-use consumers, primarily interacting with the end-use customer's LSE, EDC or CSP:

- The LSE or its designee is responsible for the wholesale power requirements for its retail customers.
- The EDC is responsible for the distribution infrastructure used to move the power to the retail customer.
- The CSP is the PJM member responsible for all DR activity where any PJM member (be it an LSE, EDC or company specialized in DR) can serve as a CSP for retail customers.

[7] Many PJM resources have significantly different characteristics, including: wind, batteries, environmentally limited generation, hydro, pumped storage and energy efficiency. A high-level comparison was done against a typical central station power plant to acknowledge there are key differences that should be considered when thinking about comparability of resources in the wholesale market.

[8] The following article outlines similar choices for DR in the European electricity markets: https://www.entsoe.eu/Documents/Publications/Position%20papers%20and%20reports/entsoe_pp_dsr_web.pdf.

Current State

DR was originally only provided by the EDC/LSE to the wholesale market. This was because retail electricity markets were regulated, and the EDC was a vertically integrated entity that was also the retail customer's LSE.

Once retail electricity markets were restructured and retail competition began, PJM allowed LSEs to provide DR not only for their own customers but also for customers of other LSEs. Eventually, PJM created the role of the CSP, which allows a completely different entity to provide the end-use customer DR to the wholesale market.

However, a company that specializes in demand reductions with the ability to aggregate those reductions to offer into the wholesale market has different incentives than LSEs and EDCs. EDCs, given traditional rate designs and regulatory structures, have little incentive to increase DR penetration, as it erodes the revenues needed to cover the costs of fixed infrastructure or excess revenues over those forecast.

In contrast, CSPs engaged only in DR have incentive to bring as much as possible into the market, since more DR should mean more profit for the CSP. The CSP model fosters competition and innovation and has contributed to the large increase of DR in the PJM markets over the last 10 years. LSEs, on the other hand, earn profits by providing electricity for retail customers, and DR is just a small part of their overall strategy to buy power from the wholesale market and sell to the retail market.

There are many alternative ways to model DR in the wholesale market. The merits of each alternative vary based on the specific wholesale market service. When retail customers do not have the opportunity to effectively manage their electricity costs through the retail market, they should be able to manage those costs through the wholesale market. This is discussed in more detail in each wholesale product's section.

Looking into the future, the question becomes whether PJM should continue with a CSP-based DR model or migrate toward an LSE-, EDC- or retail customer-based model. This question is considered as part of the holistic review of current DR practices and the development of a future DR strategy. The following are some pros and cons of the different approaches:

LSE Model

In this model only the LSE can offer DR into the wholesale market for their specific customers. This is the approach envisioned with price-responsive demand and wholesale load response (discussed in more detail under the capacity market section). The benefits and challenges of the LSE model for DR activity include:

Benefits

- Consolidates all load reduction activity for both retail cost savings and wholesale revenue to one entity that works with the customer
- LSEs can leverage existing wholesale market tools to manage load obligations (i.e., flexible demand bids for energy market, minimum capacity amount for wholesale markets, self-supply ancillary services)

Challenges

- LSEs have historically enabled less DR than through the CSP model. This approach may also limit competition compared to CSPs that focus only on DR business

- LSEs' may not have the ability to make longer-term commitments (three years in the future) for load reductions in the capacity market for some customers, as the customers are not under contract, and it is difficult to predict if they will be under contract that far in the future

EDC Model

In the EDC model, only the DR activity is consolidated and offered into the wholesale market by the EDC. A similar model is in place at the Midcontinent Independent System Operator (MISO) and is being considered in some cases as a distribution service organization-type model. The benefits and challenges of the EDC model for DR activity include:

Benefits

- Has one defined entity that does not change (no customer switching issues)
- May help with customer education and acquisition (especially for small retail customers)

Challenges

- May limit competition and innovation. Proper incentives must be in place to have an EDC take on this role. Proper anti-competitive governance is needed to ensure all entities can compete to provide DR
- Will require significant coordination and support from a retail regulatory authority, and each state may have different rules, which will increase complexity for customers with locations in multiple states
- Will have additional administrative costs for providers to work through EDCs to connect retail customer capability to the wholesale market

Retail Customer Model

In this model, retail customers can participate directly in the wholesale market as a DR resource. Retail customers do not need to participate through another entity (CSP, EDC or LSE). The benefits and challenges of the retail customer model for DR activity include:

Benefits

- May eliminate costs associated with margin for an LSE, EDC or CSP to provide this service

Challenges

- Have high costs of education, implementation and administration due to volume and level of expertise required
- Are potential legal and regulatory issues with obligations from retail customers directly into the wholesale market
- May be low level of customer level of interest

CSP Model

This is the model currently in place in PJM. Any PJM member can act as a CSP and bring DR resources to the wholesale market. EDCs, LSEs and even retail customers that are PJM members may take on the role of a CSP. Benefits and challenges of the CSP model for DR activity include:

Benefits

- Highly competitive, with ability to identify and enable DR capabilities through innovation
- Flexible and works well in all retail market structures. Can be supported with or without the direct involvement of the retail regulator

Challenges

- Must ensure that CSP load reductions do not negatively impact LSE wholesale activity; for example, if customer reduces load after LSE has already procured electricity to supply the load

Future Recommendation

PJM believes DR should leverage a competitive CSP-based model. This model has a proven track record demonstrating the ability to harness DR capability in a variety of retail markets to help manage the grid. PJM has realized significant growth in DR capability across all customer types. In part, this can be attributed to the use of a CSP-based model. In many cases, the underlying retail customers did not understand their DR capability until the CSP helped them unleash it. In addition, the CSP model is very flexible and can accommodate different underlying retail regulatory structures, such as the EDC model or LSE model, based on retail regulators' policy objectives.

Since DR participation in the wholesale market has matured, it is a good time to consider mandatory training and certification requirements for CSPs, similar to training requirements for generation dispatchers. Load management resources are dispatched on an infrequent basis, and it is important that CSPs understand exactly what needs to be done when they are dispatched to avoid any issues when the resources need to reduce load. PJM should explore if CSPs should be certified before they may offer customer load reduction services to the market. This will help ensure a minimum level of expertise and may improve performance and reliability.

Ideally, the right market structure will provide incentives to invest electricity cost savings into the automation of DR. This will move the industry from "sneaker" DR[9] to automated DR, which will increase its flexibility and performance while also minimizing the opportunity cost of not consuming electricity.

Markets and Operations

This section,reviews the current state of DR in PJM markets and operations processes and the proposed future state in order to give a detailed review of how DR participates in the wholesale market today and what changes to consider in the future. The current and proposed future state are broken down by market (capacity, energy and ancillary services) and by key DR process (dispatch, measurement and verification).

Capacity Market

Each PJM member that provides electricity to consumers must acquire enough power supply resources to meet demand not only for today and tomorrow, but also for the future. Members secure these resources through the PJM capacity market. PJM's capacity market, called the reliability pricing model, ensures long-term grid reliability by procuring the power supply resources needed to meet predicted energy demand three years in the future.

Current State

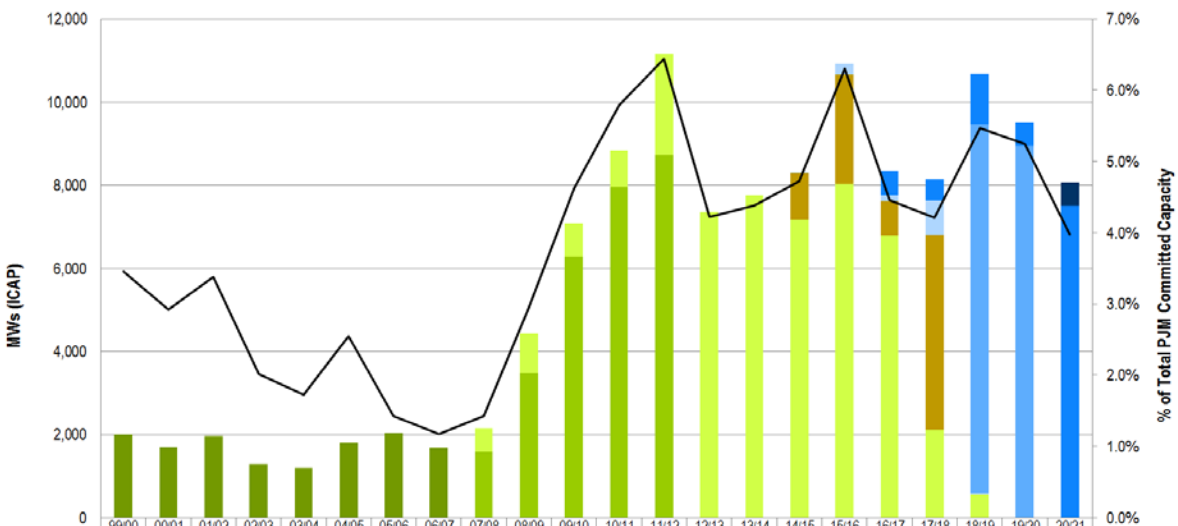
DR participation in the capacity markets has grown significantly over time and has gone through major changes every year for the last 10 years. These changes have focused on making DR a more operational, available and reliable tool to manage the grid.

[9] Sneaker DR is when a person at the site will "run around" and take actions to reduce load instead of using the automated execution of DR strategy to reduce load based on a signal.

Because of PJM's new Capacity Performance (CP) standard for market participants, which requires year-round availability with an unlimited number of interruptions throughout the delivery year, it is anticipated that the amount of DR in the capacity market will decline. The Capacity Performance standard was implemented to increase the availability and performance of capacity resources and ensure all capacity resources have similar obligations. A significant amount of DR resources can only reduce load in the summer and are, therefore, considered seasonal. PJM stakeholders established the Seasonal Capacity Resource Senior Task Force to examine potential solutions that will allow seasonal resources to continue to participate under the CP requirements.

Figure 4 illustrates the amount of capacity from DR resources from past delivery years and the amount expected in the future based on RPM auctions and fixed resource requirement (FRR) plan commitments. Since the 2009/2010 delivery year, DR has made up 4–6 percent of the overall amount of capacity procured. DR grew rapidly following the implementation of RPM, a CSP-based DR participation model and the expansion of the PJM footprint. Growth has slowed with the many changes made to the market since. These include more robust measurement and verification requirements, the elimination of interruptible load for reliability, the implementation of a limited DR cap, increased operational flexibility requirements and the new CP requirements.

Figure 4. DR Capacity Commitment (RPM & FRR) Over Time



	99/00	00/01	01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
PRD																						558
Annual - CP																		574	508	1,225	564	7,508
Base - CP																				8,854	8,946	
Annual - DR																22	266	144	822	44		
Extended Summer - DR																1,126	2,635	836	4,697	1		
Limited - DR									555	940	815	869	2,425	7,361	7,753	7,166	8,027	6,783	2,118	555		
Limited - ILR									1,585	3,489	6,274	7,961	8,731									
Limited - ALM	2,005	1,693	1,962	1,292	1,207	1,806	2,042	1,677														
DR as % of Total PJM Committed Capacity	3.5%	2.9%	3.4%	2.0%	1.7%	2.5%	1.4%	1.2%	1.4%	2.9%	4.6%	5.8%	6.4%	4.2%	4.4%	4.7%	6.3%	4.5%	4.2%	5.5%	5.3%	4.0%

Note: Limited = 10 events; June–September, Extended Summer = unlimited events; May–October or June–September, Base = unlimited events; June–September and Annual = unlimited events year round. This is a high-level description of availability requirements for different products across the years. The amount of DR committed for the delivery year is not known until June 1, since a significant portion of DR has been replaced with other capacity resources prior to the start of the delivery year. It is highly likely that the DR commitment for 2016/17 through 2018/19 will significantly decrease due to replacement capacity transactions.

CSPs may make capacity commitments in PJM RPM auctions similar to generation owners. CSPs submit a DR plan to PJM in advance of the auction. The DR plan specifies the maximum amount of DR that the entity would like to offer into the auction. DR resources in the plan are classified as existing or planned. Existing resources include resources that have been registered in a prior delivery year. Planned resources represent new resources that have not previously been registered. Planned resources must post credit with PJM to be allowed to participate in the auctions, whereas existing resources are not required to post credit with PJM.

PJM reviews DR plans and identifies any zones where multiple CSPs may be targeting the same customers. PJM uses a specific saturation threshold for each zone based on history and staff reports from the FERC to determine if duplicate customers could be an issue. If the zone is identified, then the CSP must provide site-specific information to support its plan so that PJM can identify if two different CSPs are targeting the same customers. PJM does this to ensure resources are not offered into the market when they are not able to deliver. The CSP must also provide an officer certification stating that the officer believes the megawatts offered and cleared in the RPM auction will be physically delivered by the CSP in the delivery year. This was implemented to reduce speculative behavior, in which a CSP sells megawatts in base residual auction and replaces them with megawatts purchased in the incremental auctions for financial gain.

There is a similar process for price responsive demand (PRD). Providers submit a plan that allows them to participate in an RPM auction. PRD participated for the first time in the 2020/21 Base Residual Auction. PRD represents load that will be offline when energy prices reach a certain threshold. Therefore, capacity is not required to ensure the reliability of the load that will definitely be offline due to high energy prices.

Once PJM approves the PRD and/or DR plan, the CSP may offer into the RPM auction up to the amount approved for the plan. The DR offers are then considered with offers from all other capacity resources through the auction clearing mechanism. While DR is considered a supply resource in the auction clearing process, PRD is considered a change to the demand curve. The effect of both DR and PRD on the capacity market outcome is the same, assuming they have the same capacity market offer price/quantity.

Table 3. PRD vs. DR Resource Characteristics

Process	DR	PRD
RPM Auction	• Submit DR plan (existing/new) • Clear as supply resource on supply curve	• Submit PRD plan • Clear as demand resource on demand curve
Registration	• Customer address • No LSE	• Customer address and specific electrical location (pNode) • LSE required
Dispatch	• Primarily administrative actions • PJM has ability to deploy by zone/subzone, lead time, and resource type • PJM can ramp into and out of event to manage grid based on specific locations. • Subzonal by ZIP code	• PJM does not dispatch • CSP must ensure load does not exceed CSP committed maximum value based on LMP • Subzonal by pNode
Other		• Supervisory control required (CSP must be able to dispatch remotely) • Must manage LSE by registration where customers change LSEs and EDC auction off aggregate load in tranches to LSE
Energy Market	• Paid full LMP and made whole to offer price • If marginal, will set energy prices	• No energy market compensation • Can set prices if marginal based on demand bid prices
Measurement and Verification	• FSL approach in summer and CBL approach in winter	• Adjusted FSL approach year round
Shortfall Remedies	• Replacement resources	• No replacement resources – may only cover with more customers
Compensation	• CSP receives compensation based on auction	• PRD provider will receive bill credit if they are the LSE

Process	DR	PRD
	price multiplied by committed capacity	to reflect the reduced capacity need based on final capacity price multiplied by the committed capacity • Non-LSE PRD provider must work out arrangements to be paid by LSE

Once DR/PRD clears in an auction, it has a capacity commitment for the delivery year, similar to any other capacity resource. The DR resource must register enough end-use customer DR capability prior to the start of the delivery year. The registration includes the specific end-use customers that are under contract to reduce load for the CSP for the delivery year. A registration may include one or more end-use customer locations where each location includes the EDC account number, address and a variety of other customer information. Each registration nominates the amount of capacity that will be provided from the customer(s) on the registration. Registration-nominated capacity may not exceed the peak load contribution determined by the EDC for the delivery year. The peak load contribution represents the amount of capacity allocated to the retail customer by the EDC. The CSP must register enough end-use customers whereby the aggregate nominated capacity is equal to or greater than the RPM or FRR capacity commitment. If the CSP does not have enough registered capacity to meet its commitment prior to the start of the delivery year, they must procure replacement capacity or receive a daily deficiency charge. The daily deficiency charge is the greater of $20 MW day or 1.2 multiplied by the CSP's daily revenue rate.

The nominated value is adjusted up for losses to make comparable to generation on the transmission system. DR unforced capacity (UCAP)[10] is grossed up by the forecast pool requirement factor, assuming that DR will reduce based on its commitment and will not, therefore, require reserves for load that is not there.

DR with a capacity commitment may purchase replacement capacity from another capacity resource to fulfill its capacity commitment. Historically, CSPs have replaced base residual auction capacity commitments more (on a proportional basis) than generation resources.[11] This has led to concerns by PJM regarding the physical delivery of DR capacity, which resulted in a filing[12] currently outstanding at the FERC. PRD is not permitted to use replacement capacity to remedy a short capacity position.

PRD registrations are very similar to DR registrations, except that the nominated capacity must be aligned with the LSE responsible for the capacity at all times. In open retail electricity markets, this means that each time the customer switches LSEs, the registration must reflect the new LSE. This can be administratively intensive since the EDC, not PJM, maintains these records for retail customers. Further, PRD may currently register customers throughout the delivery year, whereas DR registration must be confirmed prior to the start of the delivery year.

10 Unforced capacity means installed capacity rated at summer conditions that is not on average experiencing a forced outage or forced derating, calculated for each capacity resource on the 12-month period from October to September without regard to the ownership of or the contractual rights to the capacity of the unit.

11 See 2015 Market Monitoring Report, Capacity Market, Table 5-12. As shown in Table 5-10 and Table 5-12, capacity in the RPM load management programs was 12,149.5 MW for June 1, 2015, as a result of cleared capacity for DR and energy efficiency resources in RPM auctions for the 2015/2016 delivery year (16,643.3 MW), less replacement capacity (4,493.8 MW).

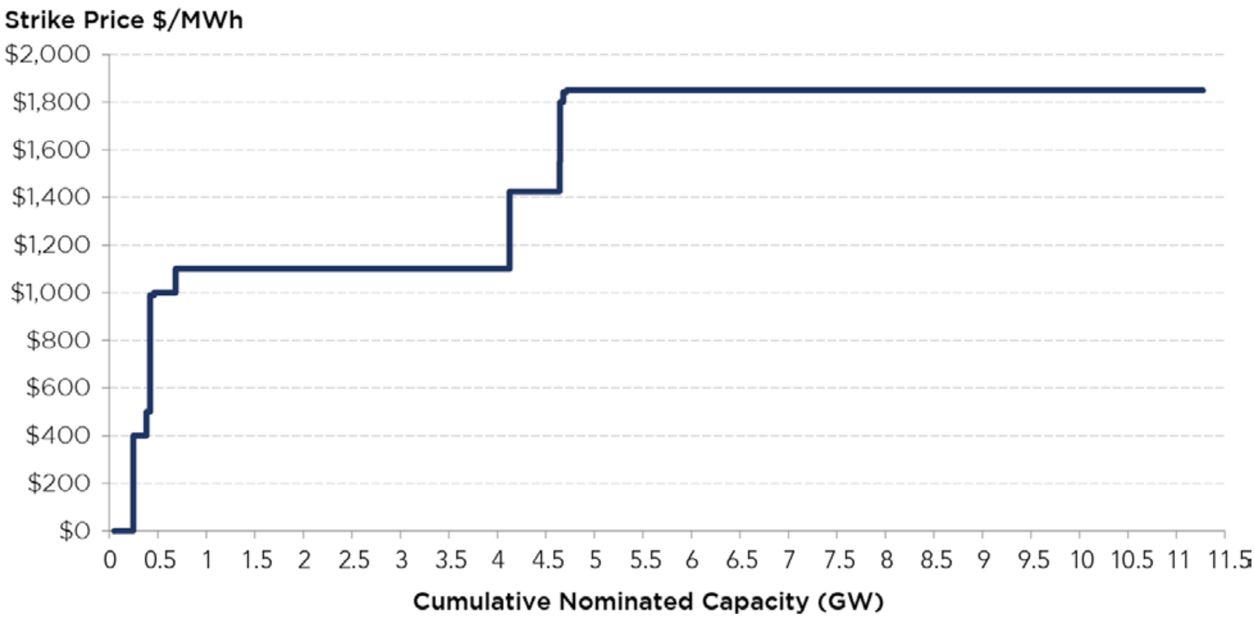
12 FERC rejected PJM's filing (known as the Replacement Capacity Filing). In rejecting the PJM filing, FERC initiated an FPA 206 investigation into the tariff, saying that there may be some aspects of the tariff that may no longer be just and reasonable but that PJM's filing did not necessarily prove it or offer reasonable solutions. The FERC was going to establish a technical conference, but PJM filed a letter asking the commission to hold off until after FERC action on the CP market reforms. PJM later filed another letter asking the FERC to further defer additional proceedings until at least one incremental auction under the CP rules is held. PJM filed an informational report in November 2016 requesting that the FERC continue to defer action on the FPA Section 206 investigation to allow PJM to gather additional data and for PJM's stakeholders to examine potential reforms to the Incremental Auction structure.

PRD plans were submitted by PRD providers for the first time in January 2017, since PRD was adopted in 2012. CSP have not participated in PRD in the past because of: (1) the requirement for supervisory control and an automated response; (2) the cost savings that go directly to the LSE (not the PRD provider); (3) the limited options to remedy shortfalls; (4) the requirements to identify and dispatch on a nodal basis; (5) the requirement for dynamic retail energy prices triggered by a nodal LMP; (6) lack of payment from the energy market; and (6) administrative complexity to manage the contractual relationship between the LSE and each retail customer, as customers may switch LSEs on ongoing basis in deregulated retail electricity markets.

Dispatch/Deployment of Load Management (DR with Capacity Commitment)

Load management that also participates as economic DR may be dispatched on an economic basis through security-constrained economic dispatch (SCED)[13] similar to other capacity resources based on their availability. A small amount of load management is actually dispatched on an economic basis; only roughly 20 percent of load management resources also have an economic registration. Further, while each load management resource also has an energy offer price that can be used for dispatch, the vast majority are all offered near or at the energy offer price caps. Approximately 10,500 MW of the 11,000 MW registered as load management has an offer price at or above $1,000 MWh[14]. This means virtually all the load management is dispatched by PJM through administrative actions.

Figure 5. 2015/16 Load Management Energy Offer Prices



PJM will dispatch load management when expected to be short on reserves. Typically, this means most of the economic generation available has been dispatched and load management is expected to be needed to meet the system load and reserves in order to avoid loading maximum emergency generation or taking other emergency actions. PJM has significant flexibility to determine how to dispatch load management to manage the grid. Without considering sub-zonal dispatch

[13] SCED is an area-wide optimization process designed to meet electricity demand at the lowest cost, given the operational and reliability limitations of the area's generation fleet, demand response resources and transmission system.

[14] The energy offer price cap for load management resources varied based on the associated lead time as follows: 120 minute = $1,100/MWh; 60 minute = $1,450/MWh; and $30 minute = $1,849/MWh.

flexibility, there are effectively 78 different options (two types by 13 zones by three lead times) for an RTO-wide capacity shortage. The following are the key parameters used to dispatch load management:[15]

1. Resource type

    - Pre-emergency resources: All load management resources fall into this category unless they are granted an exception to be an emergency resource.
    - Emergency resources: Load management resources that use generation are only allowed to operate during PJM emergency conditions that require the declaration of an Energy Emergency Alert from the North American Electric Reliability Corporation.

2. Geographic location

    - Transmission zone: Typically, DR is dispatched by zone unless there is a more localized issue.
    - Subzone: PJM may dispatch based on a registration located in a PJM-defined set of ZIP codes. If the subzone is set up prior to the operating day, the load management resources must respond or they will receive a significant penalty. If PJM creates the subzone during the operating day, then the load management resources will respond on a voluntary basis and be paid energy revenue for their load reductions.

3. Lead time

    - 30 minutes (63 percent – 7,293 DR MW for the 2015/16 delivery year): All load management resources fall into this category unless they have a physical limitation that does not allow them to respond in 30 minutes. PJM will only grant an exception based on tariff-defined reasons, and the CSP must submit customer-specific information for consideration.
    - 60 minutes (5 percent – 583 DR MW for the 2015/16 delivery year): Load management resources fall into this category, if they are qualified for an exception based on a verified physical inability to respond in 30 minutes or fewer.
    - 120 minutes (32 percent – 3,759 DR MW for the 2015/16 delivery year): Load management resources fall into this category if qualified for an exception based on a verified physical inability to respond in 30 minutes or fewer.

4. Frequency of dispatch: If there are no locational considerations, PJM looks to rotate the load management that is dispatched to ensure that one set of resources is not dispatched more frequently than other resources.

For a typical capacity shortage, PJM will deploy the 120-minute lead time resources first and stagger the amount dispatched so that the load reductions are ramped in as system conditions materialize. The 30-minute lead time resources are expected to be used for unexpected system issues, when capacity is needed immediately. Dispatchers will also look to ramp out of an event to keep the overall load flat and mitigate any snap-back effect from loads – such as air conditioner units in the summer – that are turned back on when the DR dispatch is ended.

[15] Product-specific dispatch and consideration for how to use only 10 dispatch limit will disappear with full implementation of CP.

How to Determine the Amount of DR Available to Dispatch

PJM requires CSPs to provide an hourly estimate of their expected real-time energy load reductions. CSPs provide this estimate to help guide PJM decisions, since the CSPs have the most accurate and latest information on the status of their DR resources. For example, if an industrial customer's load is already down due to a holiday or plant outage, the expected load reduction will already reflect the fact that this customer will not reduce any load. This assists in estimating what the expected impact will be, compared to the aggregate PJM forecast. The CSPs are required to review and update this information on a more frequent basis depending on the severity of system conditions. PJM will also take into consideration and reduce the expected load reductions based on load management that was already dispatched for economic purposes.

Figure 6 is an example of a real-time report that dispatchers can access so they understand the DR capability available by zone and lead time. As mentioned above, this can be viewed on a much more geographical basis through the use of ZIP codes and dynamic processes to create subzones.

Figure 6. PJM Real-Time DR Dispatch Report

	Pre-Emergency and Emergency Combined															
	Estimated Available Combined Pre-Emergency and Emergency Load Management MW (12:00 thru 20:00)															
Refresh Data	(Estimate of available zonal reductions based on CSP reported energy reduction estimates, hourly values of DA cleared economic reductions and SCED RT dispatchs at the time of report issuance. Values will change as SCED dispatches and/or CSPs provide updated estimates.)															
	Detailed hourly reports are available. Call Jack O'Neill x4525 or 610-585-5252 (cell) or DSR_Ops (dsr_ops@pjm.com).															
		Long Lead time MW and Price (2 Hrs.)					Short Lead Time MW and Price (1 Hr.)					Quick Lead Time MW and Price (30 min.)				
	[A] = [B]+[C]+[D]	[B]			Notice Time	End Time	[C]			Notice Time	End Time	[D]			Notice Time	End Time
Zone	Total Available to Reduce (MW)	Emergency Remaining	Price ($/MWh)	Already Dispatched by PJM for Economics	Shift Supervisor Entry	Shift Supervisor Entry	Emergency Remaining	Price ($/MWh)	Already Dispatched by PJM for Economics	Shift Supervisor Entry	Shift Supervisor Entry	Emergency Remaining	Price ($/MWh)	Already Dispatched by PJM for Economics	Shift Supervisor Entry	Shift Supervisor Entry
BGE	143	41	1,100	0.0			8	1,425	0.0			94	1,849	0.0		
PEPCO	98	12	1,100	0.0			2	1,425	0.0			84	1,849	0.0		
AECO	53	5	1,100	0.0			0.5	1,425	0.0			48	1,849	0.0		
DPL	105	14	1,100	0.0			1	1,425	0.0			90	1,849	0.0		
JCPL	58	8	1,100	0.0			2	1,425	0.0			48	1,849	0.0		
METED	136	42	1,100	0.0			12	1,425	0.0			83	1,849	0.0		
PECO	249	43	1,100	0.0			51.5	1,425	0.0			154	1,849	0.0		
PENELEC	161	94	1,100	0.0			5	1,425	0.0			62	1,849	0.0		
PPL	482	146	1,100	0.0			20.9	1,425	0.0			315	1,849	0.0		
PSEG	160	24	1,100	0.0			10	1,425	0.0			126	1,849	4.9		
RECO	4	0	1,100	0.0			0	0	0.0			4	1,849	0.0		
DOM	318	126	1,100	0.0			15	1,425	0.0			176	1,849	0.0		
AEP	1,381	492	1,100	0.0			20	1,425	0.0			868	1,849	0.0		
APS	392	199	1,100	0.0			10	1,425	0.0			182.3	1,849	0.0		
ATSI	526	128	1,100	0.0			18	1,425	0.0			380	1,849	1.2		
DUQ	51	22	1,100	0.0			0	1,425	0.0			29	1,849	0.0		
DAY	68	30	1,100	0.0			0	1,425	0.0			38	1,849	0.0		
DEOK	161	115	1,100	0.0			2	1,425	0.0			44	1,849	0.0		
EKPC	0	0	0	0.0			0	0	0.0			0	0	0.0		
COMED	768	175	1,100	0.0			19	1,425	0.0			574	1,849	0.1		
Total available	**5,315**	**1,717**		0.0			**199**		0.0			**3,399**		6.2		
BGE &PEPCO	242	53		0.0			11		0.0			178		0.0		
Mid-Atlantic	1,650	429		0.0			113		0.0			1,108		4.9		

PJM will use the CSP-reported expected load reductions in real time to determine if the load management dispatched is marginal for price formation through the locational pricing calculator engine (used for all PJM resources). If the load management dispatched is marginal then it will set price based on the highest offered price of all registrations dispatched (typically the price cap). Load management that is dispatched uses the zonal distribution factors ("Dfax") as part of the process and can only set prices if there is a closed-loop interface[16] for the geographic area. The creation and maintenance of closed-loop interfaces requires significant internal coordination and administration, especially for load-management resources dispatched on a subzonal basis.

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[16] A closed-loop interface is a circular interface defined by a set of transmission lines that form a "pocket" with load and generation. These types of interfaces are used to translate voltage conditions into thermal constraints that can be used by the dispatch and pricing algorithms. This allows PJM's pricing algorithms to use generation and/or load management within the closed loop to set the LMP, allowing the price to reflect generation and/or load management needed for reliability purposes.

Measurement and Verification

Load management resource capacity performance is predominately determined by whether or not the customer's load was below its firm service level.[17] If the customer's peak load contribution was 10 MW and it committed to only use 5 MW (its firm service level) if dispatched by PJM, then compliance is measured based on whether or not the load is at or below 5 MW. If the load is below 5 MW, the customer has over-performed; if the load is above 5 MW, it has under-performed.[18]

The new CP rules for DR have changed the way DR performance is determined in the non-summer months. Instead of simply looking at the customer's firm service level during the non-summer months, the rules were changed to ensure DR must actually reduce load during the non-summer month. This was done to ensure that air conditioner load that does not exist in non-summer cannot be used as a CP resource. Furthermore, lower load in the winter is already captured in the loss of load expectation study and cannot be represented as non-summer capacity contribution.

This has raised equity issues, since a customer that received a high peak load contribution but otherwise does not need that capacity must now reduce load during the non-summer months when the non-summer load is already lower, for example, if a customer's summer load is typically 2 MW but its non-summer load is only 1 MW. If the customer can ensure its load will never be above 1 MW during the entire delivery year, it still cannot qualify as a CP DR resource. Many of the state residential air conditioner direct load control programs fall into this category.

Performance for DR registrations dispatched by PJM is aggregated across zones as long as there are no system constraints. This allows DR registrations that over-perform to offset any penalties for those registrations that underperform. This provides the CSPs with flexibility to meet their targets based on registrations in their portfolios.

Future State of DR in the Capacity Market

Customers should have the opportunity to purchase less capacity if they will ensure their load will not exceed the amount of capacity procured for them when required by PJM to manage the grid. This ability would provide economic benefit to the market, operations, planning and the customers themselves. It may not make sense to make a large capital investment to upgrade an existing generator or build a new generator when it only operates for a handful of hours during the year if PJM can rely on load reductions to manage those system conditions. Further, a customer predicting when it should reduce load (peak shave) during the five CP hours in order to receive a lower peak load contribution (and therefore lower capacity cost) is not as effective as having the grid operator direct when and where the load should be reduced in order to manage the grid and ensure reliability. Therefore, PJM believes DR (and/or PRD) should remain as an active resource in the wholesale market as a supply resource instead of only as a demand resource used to reduce the capacity cost on a customer's retail electricity bill through peak shaving.[19]

CP requirements are expected to have a significant impact on the ability of DR to participate directly in the wholesale markets. The biggest impact will be on state investments in residential air conditioner cycling programs. This type of activity can no longer participate without finding winter capacity capability resources with which they can aggregate to perform year-round.

[17] Firm service level determines the maximum energy that will be consumed when DR has been dispatched. DR will need to reduce consumption (or not increase consumption if already at lower level) to comply for the event and avoid a financial penalty.

[18] PJM will cap underperformance at the peak load contribution since any customer in the system may consume more than their peak load contribution and not receive a penalty. If PJM was to penalize participants for this additional consumption it may be considered discrimination against participants.

[19] This does not mean that customers cannot continue to peak shave on the demand side if they believe this is their best opportunity to manage cost. PJM believes the opportunity for DR and/or PRD to participate in the wholesale capacity market should be retained into the future.

PJM has already made the following enhancements to CP market rules in order to foster participation for seasonal resources: (1) implemented an auction clearing process to match summer capability and winter capability to provide another option when commercial aggregation does not materialize; (2) allowed summer and winter resources to aggregate across LDAs, which permits excess wind winter capability in the West to aggregate with DR summer capability in the East; and (3) updated DR winter measurement and verification to make it more consistent with the summer firm service level approach. PJM should continue to identify opportunities to help accommodate aggregation to meet the CP requirements.

Retail customer peak shaving has a very limited impact on the amount of capacity that will be procured through RPM and is not the most effective option. Under the existing PJM forecast process, a customer would need to predict and reduce load on the PJM 10 coincident peak days for 18 years for one-half the load reduction in order to be recognized in the PJM forecast, and therefore the RPM demand curve (also known as variable resource requirement or "VRR") and associated amount of capacity procured.[20] Peak shaving impacts the retail customer's peak load contribution and their share of the capacity cost on a much timelier basis. Since most EDCs use the five coincident peak day method to calculate the peak load contribution, a customer that reduces load on the five coincident peak hours during the summer will reduce the capacity cost for their LSE for the next delivery year. If the customer's retail contract passes through their actual capacity cost then the customer will receive the lower capacity cost. In effect, customer peak shaving results in capacity cost shifting from customers that peak shave to customers that do not peak shave, since the overall amount of capacity procured will not be significantly reduced based on the current forecast process and retail capacity cost allocation tends to be done with the five coincident peak day/hour methodology.

In the future, DR, PRD and the rationale for the PJM wholesale load responsibility (WLR)[21] proposal should be reviewed and potentially rationalized into one flexible and consistent structure. The WLR structure was developed based on preferred DR and PRD attributes under the assumption that the wholesale market would not be permitted to make payments for DR. While there are benefits to having options in the tariff, currently DR and PRD have some fundamental inconsistencies that should be reviewed. Table 3 provides a high level summary of the differences between the two structures. For example, a retail customer's load reductions are measured and determined differently for PRD versus DR though they have the same impact on the reliability of the system.

Ideally, DR/PRD capacity commitments (RPM auction/FRR plan) should be more transparent. PJM should explore when DR is considered as existing and if any enhancements should be made to the DR plan process used for RPM auctions since existing megawatt may be significantly different than future customers used to meet the commitment. The distinction between existing and planned DR in the DR plan is made to manage credit risk, and PJM should revisit whether or not the design in place is appropriately managing PJM members' credit risk.

DR performance has been very good in the past,[22] but the frequency of dispatch has been very low. For example, PJM has not dispatched DR since April 22, 2015[23] and has not had a mandatory compliance event (where CSPs would receive a penalty for non-compliance) since Sept. 11, 2013. Further, the DR testing requirement, which was modeled after the generation testing requirement, is limited and does not adequately represent a real load-management event situation. DR that is not dispatched during a mandatory compliance period is only required to perform a one-hour test.

[20] See May Seasonal Capacity Senior Task Force meeting material for a comprehensive explanation of this conclusion.

[21] See Appendix A for description of proposed WLR resource.

[22] See Annual Load Management Performance Report for additional details. For an example, see the 2015/2016 report at http://www.pjm.com/~/media/markets-ops/dsr/2015-2016-dsr-activity-report-20151221.ashx.

[23] A complete history of DR dispatch can be found at http://www.pjm.com/~/media/planning/res-adeq/load-forecast/alm-history.ashx.

Table 4. Load Management (DR with Capacity Commitment) Performance

Delivery year	Event performance	Test performance
2009/10	No Events	118 percent
2010/11	100 percent	111 percent
2011/12	91 percent	107 percent
2012/13	104 percent	116 percent
2013/14	94 percent	129 percent
2014/15	No Events	144 percent
2015/16	No Events	133 percent

While customers commit to providing DR primarily to reduce electricity cost, it is not the primary business purpose of the customer. The true DR capability on the PJM system is not really known since it is dispatched on such an infrequent basis, and the current test requirements are for only one hour a year as coordinated by the CSP. Customers only want to reduce load to avoid a penalty, and it is inefficient to have customers reduce load when it is not needed by the grid. As DR resources are required to do more under the CP framework, it is important for PJM to gain a better understanding of expected performance under a variety of conditions. Ideally, PJM should be able to predict energy and capacity reductions based on season, location, hour of day and frequency of events. To provide better predictability of DR capability, it would be ideal for DR resources to be used on a more frequent basis – either to manage the grid or through more robust testing.

Today, the nominated amount of DR is grossed up by the forecast pool requirement (FPR) factor (~1.07). The FPR factor represents additional reserves for unforeseen outages and load forecast uncertainty. Since DR represents a load reduction, it was previously decided that the quantity of DR should be grossed up by FPR since the reserves are not needed. PJM should reconsider this assumption over the long term (since it assumes that DR will perform at or above 100 percent) or consider other mechanisms to incorporate past performance into future unforced capacity quantity.[24]

Dispatch (Future State)

DR operational changes, such as the ability to dispatch DR to avoid an emergency through the creation of pre-emergency DR resources and the reduction of lead time to produce load reductions from (typically) 2 hours to 30 minutes, has expanded PJM's flexibility to dispatch DR. To put in perspective, New York Independent System Operator (NYISO) must provide 24-hour notice to dispatch DR with a reminder three hours in advance and must pay for a minimum of three hours. In contrast, DR resources in PJM must respond in 30 minutes (unless they receive a lead time exception of one hour or two hours, based on their specific physical limitations) and PJM is only required to keep (and therefore pay) for a minimum of one hour. Further, the lead time of 30 minutes, 1 hour or 2 hours can be overridden in certain situations, and DR resources are then required to respond immediately or face a compliance penalty.

The optimal approach to dispatch DR resources would be based on their economic energy offer price, which reflects their underlying opportunity cost (or willingness to pay) for electricity. Since the majority of DR does not want to reduce load unless needed to manage the grid for an emergency, the majority of energy offers submitted are at the energy offer cap, as noted above. In most cases, DR opportunity cost is very difficult to quantify and varies greatly by hour, day, frequency of dispatch and duration of previous DR deployments. This means under the economic dispatch scenario, the decision of

[24] ISONE originally did same gross up but eliminated it a few years ago.

what and when to dispatch may be based on a tie-breaker since offer parameters (including price) would likely be the same or similar. Ideally, all DR is dispatched on a truly economic basis through SCED where offer prices have significant variation across customers. This would avoid the current situation, in which the DR aggregate capability appears as a large block loaded resources at one energy offer price point.

PJM has some flexibility regarding the dispatch of DR resources. PJM today (as mentioned above) can dispatch by resource type (pre-emergency versus emergency) by lead time (30, 60, 120 minutes) and by geographic location (zone or subzone, where subzone can be created one day in advance).[25] This is more flexibility than any other ISO/RTO for a comparable product. Since there is this flexibility, PJM should look to develop and implement a DR dispatch optimization tool. This tool would help provide recommendations to dispatchers for when, where and how much DR to dispatch and release. Ideally, DR dispatch flexibility may also be enhanced to allow the dispatch of specific volumes in zones and allow subzonal dispatch of registrations by electrical location (load bus) instead of by geographic location (ZIP code).

It would be helpful for PJM dispatchers to understand the impact of DR on real-time load, in order to be able to differentiate between normal real-time forecast error and load reductions from DR. Some key enhancements to consider for the future include:

- Forecast PJM real-time load by zone instead of at the aggregate level (e.g., Mid-Atlantic). This will help make DR impact more visible since it is a bigger percentage of zonal load then of aggregate (e.g., Mid-Atlantic) load.
- Calibrate CSP reported expected load reductions based on analysis of historic performance. Build a process to analyze results, feedback loop to CSPs and adjustment by PJM of CSP forecast.
- Require real-time or near real-time load data from CSPs and their end-use customers. This will help provide more visibility on when load is approaching firm service level and provide an indication of when DR load reductions have been fully implemented.

Measurement and Verification (Future State)

One of the key differences between generation and DR is the quantification of the amount of capacity delivered. For generation, we simply look at the metered output of the unit. For DR, the current approach is to look at the nominated firm service level load, which must be below the customer's capacity requirement. The customer's capacity requirement is based on an allocation/estimation process determined by the EDC, as described above.

In the future, it would be ideal for the EDCs to come up with a consistent and more robust approach to determine the customer's capacity requirement instead of the simple five coincident peak methodology. Further, some EDCs should consider ways to make it easier for customers and their CSPs to request and receive the customer's capacity requirement. The customer's capacity requirement (peak load contribution) is a critical component that determines the volume of DR capacity delivered in the market. Ideally, the EDCs should have a process that is more timely, accurate and transparent to determine each customer's capacity commitment that truly represents the amount of capacity needed to ensure there is adequate power for the customer.

[25] PJM may also dispatch by product type but since there will only be 1 CP product this is not considered in the future.

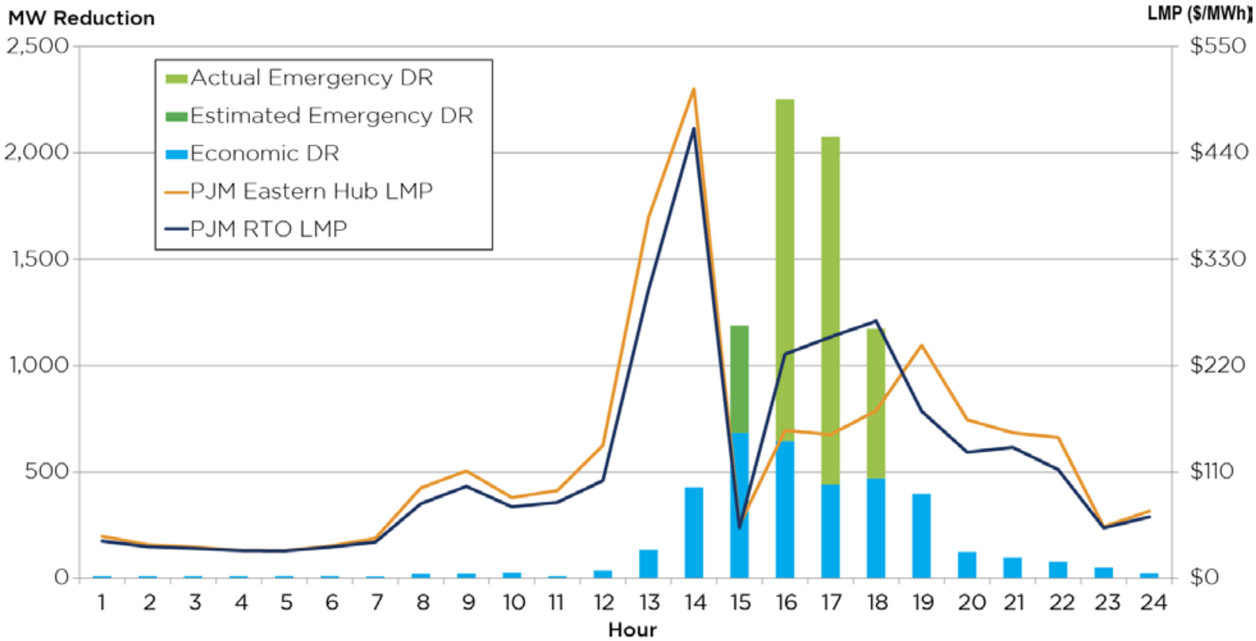
Energy Market

Current State

DR is available to participate in the energy market either as an economic DR resource or a load management (capacity commitment) DR resource. A retail customer can be both an economic resource and a load management resource. Currently, there are 3,495 MW registered to participate in the energy market as economic DR and 12,866 MW registered to participate as load management resources. On high-price energy market days, the maximum amount of economic DR that is available and dispatched is less than 1,000 MW.

As an example, Figure 7 illustrates the amount of DR deployed during a high-price period on July 18, 2013. On that day, more than 2,000 MW of load management (emergency DR) were dispatched in specific zones under emergency conditions while only approximately 600 MW were dispatched across the entire RTO based on normal economic dispatch.

Figure 7. Estimated DR in PJM: July 18, 2013



Registered Emergency DR amounts adjusted for RPM commitments (do not represent actual energy reductions).
LMPs included to represent energy market conditions on the operating day and not a relationship between dispatched DR and prices.
Actual load reductions are not finalized until up to three months after an event.

Many customers and CSPs have indicated they do not actively participate in the energy market as economic DR because of the limited cost savings (or revenue) opportunities. Low and relatively stable energy market prices are two of the reasons why retail customers with load flexibility do not actively participate in the energy market as economic DR. Since significantly high energy prices occur very rarely, it may not be worth the time and effort to actively participate. As CSPs typically receive a percentage of overall revenue, it may not be in a CSP's financial interest to pursue economic energy market DR participation because of the limited revenue opportunities compared to other priorities.

Load Management versus Economic DR Revenue

Assume a load management capability of 1 MW and a capacity price at $150 MW-day in a situation where a retail customer expects to be dispatched for only 10 hours a year. That means the customer would receive $54,750 per year for 10 expected hours of dispatch. The customer would also receive energy revenue, based on an offer price that is typically at the price cap. To simplify: If the offer price is $1,000 MWh, this means the customer would get paid $5,475 MWh from the capacity market to reduce load for 10 hours ($54,750 from capacity market divided by 10 hours of load reductions) plus an additional $1,000 MWh from the energy market, for a total of $6,475 MWh for each hour when it reduces load. In other words, that customer would receive more than five times the amount from the capacity market than from the energy market, even with the energy price near the top.

On the other hand, if a CSP has an economic DR offer price of $200 MWh and gets dispatched four times the number of hours in the energy market – or 40 hours a year – it would only make $8,000 for the year, compared to the $54,750 it would receive in the capacity market, not including any additional emergency energy payment. As energy prices have moderated with the shale gas revolution, this has led to even less interest in participating as an economic DR resource.

Economic DR

Economic and load management DR are available to set energy market prices and receive make whole payments. There is no must-offer[26] requirement because, in most cases, DR costs (or a customer's willingness to pay) are unknown or highly variable. Load Management resources provide an energy offer price and shutdown cost for the delivery year. This is submitted when the specific retail customers are registered. The energy offer price is not based on cost and is typically established at the energy offer price cap, since the load management resource does not want to be dispatched until all other resources are exhausted, and because the resource will receive more revenue when dispatched with a higher offer price. Most resources do not submit shutdown costs, but all shutdown costs should reflect any fixed costs that are incurred when PJM dispatches the resource; the costs are also subject to review by the Independent Market Monitor.

Quantifying the shutdown cost for a DR resource is very complicated unless the underlying customer uses behind-the-meter generation to facilitate the load reduction. An industrial company's willingness to pay and associated shutdown cost may change dramatically from day to day or from hour to hour, based on each specific order and where the order is during the fulfillment process. A plastic injection molding operation, for example, cannot easily stop production without significant waste and risk of damage to a machine. Further, the flexibility of when to deliver an order and the associated impact from any delay can vary widely and impact the customer's willingness to pay.

Load reductions are determined on the difference between the customer baseline load (CBL) and the actual load. The CBL is really a forecast of the customer's usage calculated so PJM can determine the load reduction. A load reduction in the energy market is determined differently from a load reduction in the capacity market. A load reduction in the capacity market is based on the amount of capacity reserved for the customer, (peak load contribution) compared to load when asked to reduce. PJM has a robust CBL process in place that also tests each registration to ensure that the CBL is reasonably accurate before the customers can participate in the market. PJM has published a comprehensive study on CBL accuracy used by PJM stakeholders and throughout the world.[27]

Future State for DR in the Energy Market

Ideally, DR participation in the energy market would be in the retail market on the demand side and not in the wholesale market as a supply resource. This will avoid the double payment issue where a customer may receive wholesale energy revenue and retail cost savings for the same MW of load reduction. The majority of retail markets in the PJM footprint have been deregulated so customers have a choice of how their electricity is priced. If retail customers would like to reduce their energy costs, they may do so through their retail contract or tariff, similar to any other purchase. If the retail market is regulated, a state can ensure that its retail customers have appropriate options through their regulated rates. PJM should

[26] A DR resource with a capacity commitment (Load Management) is not required to offer into the day ahead energy market.

[27] Please see http://www.pjm.com/~/media/markets-ops/dsr/pjm-analysis-of-dr-baseline-methods-full-report.ashx for link to Kema CBL report.

focus on providing LSEs the necessary information and tools so they can properly reflect their load in the wholesale market. LSEs already have the capability to provide price responsive demand bids and make their load's price sensitivity transparent to PJM. Further, PJM should work more closely with LSEs to determine if there are other mechanisms needed to facilitate their customers' DR.

To the extent DR participates directly in the wholesale energy market on the supply side, the compensation structure should be revisited. As discussed through the FERC Order 745 proceedings, any DR compensation based on full LMP distorts market outcomes and will provide subsidies to DR.[28] These subsidies could incent generation to locate behind the meter and operate as DR. From an economic efficiency standpoint, it is more accurate to compensate DR in the energy market based on LMP – less the generation component of the retail price – than to compensate based on full LMP. Since DR in the energy market is also used for energy price formation, PJM should consider whether a default price should be used, unless the DR can support a higher cost-based offer. This puts some additional analysis into the development of DR offer prices, instead of simply putting in the highest price out of convenience.

Ancillary Services

Current State

DR is currently allowed to provide day-ahead schedule reserves (DASR), synchronized reserves (SR) and regulation (Reg). DR may provide up to 25 percent of the overall DASR and Reg amounts and up to 33 percent of the RS requirement. The participation limit on DR was developed by stakeholders based on concerns about performance. When DR participation approaches the limit, stakeholders review and change the limit as appropriate based on comparison of DR and generation performance. DR currently does not participate in the DASR market because of limited revenue opportunities.

Table 5 and Figure 8 summarize DR participation in the SR market. There were 139 locations certified to provide SR, with the capability to provide 457 MW (on average across the year). Monthly revenue for DR SR resources was typically below $500,000 per month and less than 60,000 MWh per month (average of 83 MW per hour). Most of the resources are located in the midatlantic dominion (MAD) portion of PJM.

[28] Please see the following for PJM paper which outlines PJM recommendation on proper energy market compensation http://www.pjm.com/~/media/markets-ops/dsr/analysis-of-load-payments-and-expenditures.ashx

Table 5. DR Synchronized Reserve 2015 Capability

	Zone	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Locations	MAD	138	141	142	143	142	118	121	122	128	132	134	135
	Non-MAD	2	2	3	3	3	8	8	9	10	10	10	10
	RTO	140	143	145	146	145	126	129	131	138	142	144	144
Average number of unique participating locations per month:							139						
MW	MAD	344	345	351	351	351	351	354	354	362	373	375	377
	Non-MAD	14	14	24	24	24	73	73	159	198	198	198	198
	RTO	358	358	374	375	374	424	427	513	560	571	574	574
Average MW per month:							457						

Figure 8. 2015 DR Synchronized Reserve Participation (MWh and $ revenue)

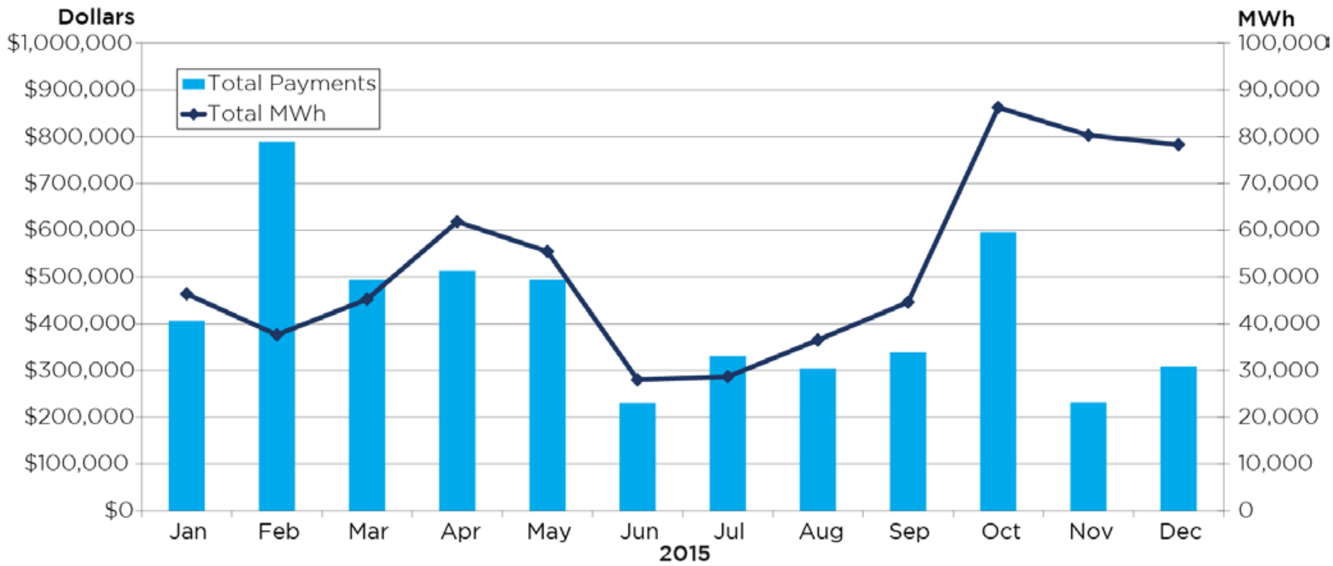
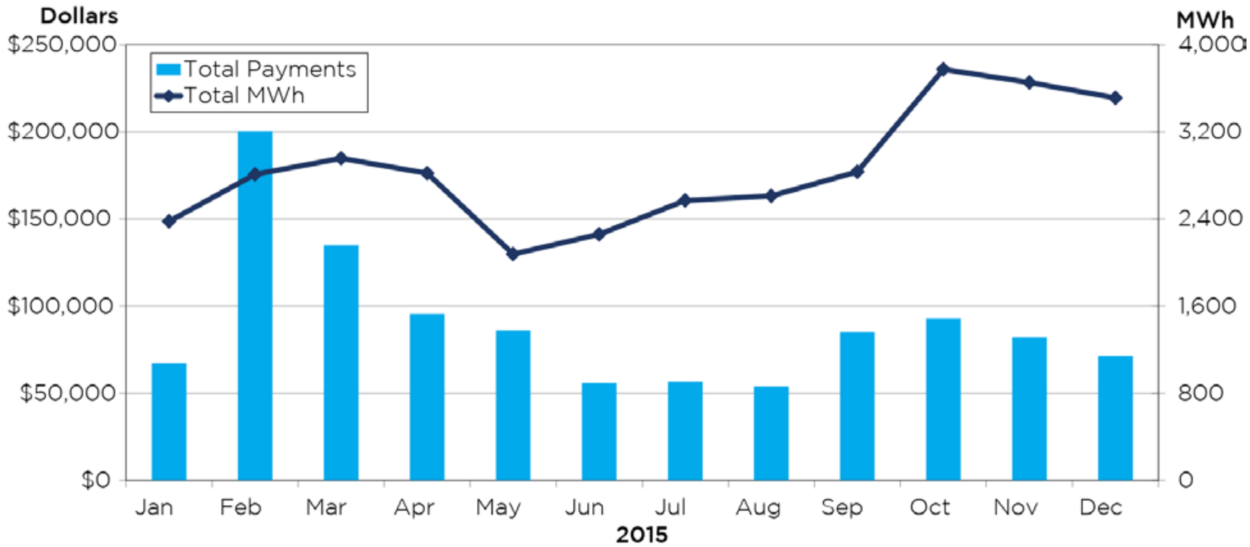


Table 6 and Figure 9 illustrate DR participation in the regulation market. There were 294 locations certified to provide regulation with the capability to provide 16 MW (on average across the year). Monthly revenue for DR regulation resources was typically below $100,000 per month and less than 1,600 MWh per month (average of 2 MW per hour).

Table 6. DR Regulation 2015 Capability

Regulation	Zone	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Locations	RTO	274	274	274	297	298	299	302	304	304	321	286	292
Average number of unique participating locations per month:							294						
MW	RTO	12	12	12	12	13	15	16	18	18	19	21	22
Average MW per month:							16						

Figure 9. 2015 DR Regulation Participation (MWh and $ revenue)



Future State for DR in Ancillary Service Markets

PJM should continue to explore opportunities to enhance rules that would allow more DR to fulfill ancillary service needs and therefore provide more options of quick response to dispatch. This would include the elimination of caps on the amount of DR that may provide these services, similar to DR resources in other U.S. grid operators.[29] Generation typically does not want to provide ancillary services due to the wear and tear on the machines. DR discretionary load is a good source for providing these services. The penetration of technology will continue to reduce the cost to control loads, thus allowing DR to provide these services in the future.

PJM should also explore opportunities to co-optimize DR participation in the energy and ancillary service markets, similar to the way generation participates. In the long run, this is a more efficient mechanism than requiring the CSP to decide how much DR capability should be placed in each market. As DR participation in synchronized reserves has grown, a DR synchronized reserve test and telemetry requirement should be considered, similar to the testing and telemetry requirement for DR that provides regulation. This will help all DR synchronized reserve resources to have the appropriate capability before they enter the market and provide more visibility to performance during synchronized reserve events in case PJM dispatch would like to make additional adjustments.

In 2012, PJM implemented market rule changes to help enable more regulation from DR with a simplified economic regulation-only registration process and a more flexible measurement and verification process. The changes allow PJM to measure regulation performance from the specific end-use device (or DER) that will perform the regulation, instead of the actual load (or net load for DER). Prior to this change, PJM measured performance based on the actual load (or net load for DER) where the regulation performance may not be transparent because the amount of regulation compared to total load is small and normal load changes obfuscate the device-specific regulation response. This led to a significant increase in regulation participation, especially from batteries. Two EDCs have expressed concerns that DR that provides regulation may theoretically create operational issues for the distribution system. To date, no empirical information has been provided to support this claim, but PJM should keep this potential issue on its radar if DR penetration becomes more significant in the future.

[29] The only exceptions to this statement are ERCOT's limitation on DR provision of Responsive Reserve Service – Under Frequency Relay (50 percent) and MISO's limitation on DR provision of spinning reserve (40 percent).

Planning

Current State

The PJM long-term planning process provides several key inputs to RPM capacity auctions, and DR projected in the future is a component in some of these:

1. The reliability requirement for RTO is calculated as RTO forecast peak load multiplied by forecast pool requirement (FPR).

2. The reliability requirement for locational deliverability areas is calculated as the sum of capacity emergency transfer objective (CETO) and the internal resources modeled in the CETO study. The internal resources modeled include DR projected in the future.

3. CETO and Capacity Emergency Transfer Limit (CETL) are calculated for each LDA as a part of load deliverability analysis. The DR projected amount reduces CETO and may increase CETL.

As noted above, the amount of DR projected in the future is used to reduce the load forecast, which is used for CETO/CETL calculations.[30] The forecast for the amount of DR expected in the future is based on the average ratio of committed DR (by DR product) to the past forecasted peak in the last three delivery years, multiplied by the forecasted summer peaks. Additional adjustments are made to recognize the transition from limited, extended summer and annual DR to base capacity and CP DR products (effective delivery year 2018/2019) and the elimination of base capacity DR (effective delivery year 2020/2021). Stakeholders adopted this forecast approach in 2015.

As noted above, the load forecast used to determine the RTO reliability requirement for the RPM auctions is based on the PJM unrestricted load. The unrestricted load represents what load will be in the future if DR with capacity commitment continues to consume electricity at its normal level (i.e., load will not be reduced). All load reductions associated with a DR program that has a wholesale market capacity commitment and is dispatched by PJM are added back to the customers' load before the load forecast is produced. The add-back ensures the load forecast is based on what the load would have been without the load reduction dispatched by PJM and therefore ensures the load forecast will represent an unrestricted value.

What Does "Unrestricted" Load Really Mean?

Under the current rules, unrestricted load is defined as what load would have been if the retail customer did not participate as a PJM wholesale market capacity resource and was not dispatched by PJM. The unrestricted load does not include load reductions performed by retail customers to manage their own electricity costs (as noted previously), which assumes this type of DR activity will continue into the future. If every retail customer that currently manages its load decided to stop doing so in the future, then the load forecast would potentially be too low. Conversely, if more retail customers decided to actively manage their loads than in the past, the load forecast would potentially be too high.

Future State of DR in the Planning Process

Ideally, PJM would have a truly unrestricted peak-load forecast with a complete understanding of explicit (dispatch and/or managed by PJM) versus implicit (managed by LSE, EDC or end-use customer) DR, allowing more visibility to quantify forecast risk. PJM also would be able to accurately quantify price impact (capacity and energy) on the amount of DR and,

30 See Load Forecast Report http://www.pjm.com/~/media/documents/reports/2016-load-report.ashx, page 65 footnote for complete description.

therefore, on the load forecast, which would allow a more accurate long-term forecast with more visibility on the forecast drivers and more information on the sources of forecast error, and would also allow a more accurate DR forecast. To the extent that future DR is not reasonably predictable, PJM should revisit including or excluding DR in the long-term forecast used in the regional transmission expansion plan (RTEP) process.

Wholesale Market Coordination with State DR Initiatives

With the implementation of FERC Order 719A, PJM sends all DR registrations to the applicable EDC to approve or deny. The EDC is responsible for interpreting the relevant electric retail regulatory authority (RERRA) policy based on existing orders, ordinances or resolutions and making the appropriate decisions. This allows each state to determine exactly which retail customers may participate in the wholesale markets, based on its policy. Each state and/or RERRA may have significantly different DR strategies, such as:

- RERRA does not actively promote and allows PJM wholesale market design to determine the level of DR participation.
- RERRA encourages DR participation in the wholesale market (i.e., provides communication/education, incentives, removes retail barriers such as distribution on load data).
- RERRA uses wholesale DR as mechanism to implement specific policy (e.g., another revenue stream to offset costs for smart meter deployment).
- RERRA creates retail DR policy with no consideration for wholesale DR market opportunities.
- RERRA allows limited or no wholesale market participation and implements any DR policy through the normal rate case approach.

Retail/Wholesale Electricity Market Overlap

One of the challenges associated with allowing DR or energy efficiency (EE) to participate in the wholesale market is how to handle DR activity that will already occur because of retail contracts, rates or other incentives. Some retail customers will reduce load or install EE measures to manage retail electricity cost regardless of participation in the wholesale markets. For example, a large sophisticated industrial customer may actively manage its electricity costs through Cogen[31] and retail electricity contracts in which electricity is a significant portion of its overall cost. This type of customer may continue to activity manage electricity costs, especially energy-related costs, whether or not it also participates in the wholesale market. In such instances, PJM believes that it is inappropriate for the customer and/or its CSP to also receive compensation through the wholesale market because such compensation is not actually driving the response or installation of the EE measures.

Many ISOs have concluded that this is not a wholesale-market issue and does not need to be considered. PJM has implemented market-specific measures to mitigate this issue, primarily focused on exactly how to measure and verify load reductions. PJM will need to consider how far to go in this area. PJM believes that DR participation in the wholesale market should be restricted to those end-use customers responding to wholesale market incentives. Ultimately, depending on the specific situation, participation in the retail market versus the wholesale market may be considered a substitute instead of a complement.

[31] Cogen or Combined Heat and Power represent the generation of electricity and other energy jointly, especially the utilization of the steam left over from electricity generation to produce heat.

Distributed Energy Resources

A significant portion (12 percent or 1,156 MW[32]) of DR today comes from DER (where DER is predominately comprised of behind-the-meter generation).[33] If a customer can reduce its load, it can operate as a DR resource. PJM does not differentiate based on how the load will be reduced or shifted to another time period. For example, a customer may reduce its load with behind-the-meter generation, cycle an air conditioner or shut down a factory production line.

Current State

DER includes a wide range of energy source that operates behind the meter such as small back-up diesel engines, batteries, natural gas combustion turbines, large combine heat and power or cogeneration applications. Behind-the-meter generation typically means behind the customer retail electric service meter(s), depending on how a particular location is configured. It also includes a municipality utility or electric cooperatives where the entire municipality or co-op is considered one customer.

DER that participates as DR may only participate to the extent there is load to offset at the customer site. If there is no load at the facility, the customer cannot inject beyond the meter and receive wholesale market compensation. In this scenario, as there is no demand for electricity at that moment, it is no longer considered DR, and thus does not receive wholesale market compensation. For example, a battery may not participate in the wholesale regulation market while solar is injecting onto the distribution system through a retail/state net metering agreement as they would not qualify as DR for that time period. These DER issues are currently under discussion in Special Market Implementation Committee meetings.[34]

Some PJM members are deploying large-scale batteries in municipalities as a DR resource instead of going through the PJM interconnection queues because they view it as a quicker and less expensive way to bring these resources to the market.

Future State

Behind-the-meter DER has unique characteristics, which may be leveraged to optimize market outcomes and grid operation. For example, many DER applications have known costs similar to front-of-the-meter generation that may be used instead of load shifting, for which costs can be very difficult to quantify. Behind-the-meter DER should be on a level playing field with front-of-the-meter generation. There should be no incentives to have generation behind the meter instead of in front of the meter simply to avoid installing physical protection to the distribution system (such as reverse power flow relays that the DER will trip to avoid creating a distribution system issue if load trips).

Ideally, PJM should have a more coordinated approach in which DER with additional capability beyond the host load can provide this surplus power to the market without legal/jurisdictional, safety, transmission/distribution equipment or market equity issues. Stakeholders have spent a significant amount of time discussing this issue.[35]

[32] Based on Load Management registered for 2016/2017 delivery year.

[33] Please see PJM report on DER that participates as DR at http://www.pjm.com/~/media/markets-ops/demand-response/2016-der-annual-report.ashx.

[34] Please see the following for information on the Distributed Energy Resources in PJM Markets issue: http://www.pjm.com/committees-and-groups/issue-tracking/issue-tracking-details.aspx?Issue={FCADF6DC-FA84-4F5E-9B33-DE2428F47A2B}.

[35] A summary of this issue in the stakeholder process is located on the pjm.com “Issue Tracking” webpage: http://www.pjm.com/committees-and-groups/issue-tracking/issue-tracking-details.aspx?Issue={FCADF6DC-FA84-4F5E-9B33-DE2428F47A2B}.

Comparative Analysis

The comparative analysis evaluates the gap between the current state of DR and the proposed future state outlined earlier in the report and has been used to develop a roadmap for the future. Specifically, the gap is a function of regulatory policy (FERC and/or states), expected stakeholder support/opposition and cost (implementation/maintenance cost for members and PJM). The effort put into closing the gap between current state and possible future state should be determined based on the value added to all stakeholders (including PJM). Any initiative that involves changes to the current market rules will be initiated through the normal stakeholder process.

Table 7 provides a summary of current versus future state attributes, by market. The attributes are evaluated for each driver (regulatory, stakeholders, cost) and compared to the expected value to stakeholders. This approach was used to help determine where to focus, based on the expected effort and support for the change relative to the expected value to all stakeholders.

Table 7. Comparative Analysis of Market Attributes

Legend	
Gap (Regulatory)	Indicates how difficult it would be from a regulatory standpoint (state and federal) to implement the future state
Gap (Stakeholders)	Indicates how much support/opposition there would be from PJM stakeholders to implement the future state. Large gap means more than one stakeholder group would oppose
Gap (Cost)	Indicates how much it would cost PJM stakeholders (PJM, members, people/process/system changes) to implement the future state
Value (Benefit)	Reflects value future state would bring to all stakeholders (PJM and members). Value represents increased reliability and lower costs and/or risk
🔴	Large gap between current vs future state (Cost > $5M), Value = Not a significant amount of value or difficult to quantify
🟡	Medium gap between current vs future state (Cost = $1-5M), Value = Significant value for at least one whole member sector or PJM
🟢	Small gap between current vs future state (Cost < $1M), Value = Major perceived value to PJM and most member sectors
Time Frame	Long term = attribute on the radar 5+ years in the future. Medium term = attributes to consider over the next 3–5 years after DR participation in CP is better known. Short term = attributes to consider over next 2 years

Time Frame	Market	Attribute	Current	Future	Regulatory	Stakeholders	Cost	Value
Short	Capacity	Product	DR, PRD (proposed WLR)	Consistent DR mechanism for wholesale market participation	🟡	🟡	🟡	🟡
Short	Capacity	Measurement and verification (performance obligation)	FSL in summer and CBL in non-summer	Continue to align with retail capacity allocation to minimize retail/wholesale issues. Look to develop with more consistent approach year round	🟡	🟡	🟡	🟢
Short	Capacity	Aggregation	Ability to aggregate by registration and by resources (DR or other permitted types)	Optimize aggregation rules in capacity market to enable seasonal DR customers to fulfill CP commitment	🟢	🟡	🟢	🟡
Short	Capacity	Capacity dispatch	Dispatch by variety of parameters through administrative procedures	Develop model that will provide optimal DR dispatch strategy based on current state of system, forecast and prior use of DR	🟢	🟢	🟡	🟢

Time Frame	Market	Attribute	Current	Future	Regulatory	Stakeholders	Cost	Value
Short	Capacity	Forecast	RT forecast primarily by region	Provide RT forecast by TO zone to increase visibility of DR for RT operations	🟢	🟢	🟡	🟢
Short	Capacity	Registration	Registration complete before start of delivery year (DY)	Consider registrations after start of DY to enable more customers to meet RPM/FRR commitment	🟢	🟢	🟡	🟡
Short	Capacity	Training	Training not required	Implement mandatory training to ensure all CSPs are ready when DR is dispatched	🟢	🟡	🟢	🟢
Medium	Capacity	RPM participation	DR/PRD plan; CSP provides officer certification to ensure they plan on physical delivery	CSP can remedy shortfall with Incremental Auction (IA) but not receive financial gain (profit). Eliminate incentive to sell in Base Residual Auction (BRA) and buy out in IA	🔴	🟡	🟢	🟡
Medium	Capacity	Test	DR/PRD – CSP determined, 1 hour only if not dispatched by PJM	PJM-initiated multi-hour test for more than 1 day, or demonstrate that the automated response to price/emergency event is installed/works and cannot be overridden	🟡	🟡	🔴	🟢
Medium	Capacity	Capacity dispatch	See above	Increase PJM flexibility to dispatch load management by volume (MW or %)	🟢	🟡	🟡	🟡
Medium	Capacity	Capacity dispatch	See above	Increase PJM flexibility to administratively dispatch by pNode	🟡	🔴	🔴	🟡
Medium	Capacity	Capacity dispatch	See above	Provide more visibility/operational awareness to dispatch regarding RT DR reductions through telemetry (or status of DR implementation)	🟡	🔴	🔴	🟡
Long	Capacity	Existing vs. planned DR/PRD	DR/PRD plan; existing based on prior registration	CSP to provide more visibility on status of DR capability as DY approaches (similar to PJM interconnection process)	🟢	🟡	🟢	🔴

Time Frame	Market	Attribute	Current	Future	Regulatory	Stakeholders	Cost	Value
Long	Capacity	Forecast	Based on historic DR (ratio of DR to peak load)	Do not include DR in forecast for RTEP, may not be predictable over long term (depends on economic factors)				
Long	Capacity	Nominated DR quantity	UCap = (PLC – (load * losses)) * FPR	Eliminate FPR gross up and consider historic performance on future capacity nomination				
Long	Capacity	Retail capacity allocation methodology	PLC primarily based on average 5 summer CP method	Make wholesale and retail capacity allocation more consistent. This would require more robust retail capacity allocation process				
Long	Capacity	Capacity dispatch	DR - by resource type, lead time and zone/subzone PRD – none, just need to be offline when prices above “willing to pay” amount and PJM loads Max E, reduces voltage or accept emergency energy	Economically dispatch each registration prior to emergency actions based on actual “willingness to pay” offer price				
Long	Capacity	Load data	CSP submits ~ 60 days after the event	Explore how to leverage existing retail meter equipment and associated load data to streamline process for members and speed up access to data to make decisions. Ideally PJM should be able to leverage one set of meter infrastructure for wholesale and retail needs and use one set of standards to exchange load data				

Time Frame	Market	Attribute	Current	Future	Regulatory	Stakeholders	Cost	Value
Long	Capacity	Non-retail behind-the-meter generation	May participate as DR against entire muni/co-op load, under NRBTMG rules or interconnect	Eliminate ability to participate as DR. Modify NRBTMG rules if there is an issue, or have resources interconnect (or modify interconnect process if issue for smaller generators)	🔴	🔴	🟡	🟡
Medium	Energy	Offer requirements	Economic – no requirements, voluntary load management – single point offer up to max price	Explore load management default offer price/shutdown cost unless evidence received to support higher cost	🟡	🟡	🟢	🟢
Long	Energy	Compensation	Economic, voluntary emergency energy and load management paid full LMP and made whole to price	Consider no compensation from energy market (or LMP - G, if necessary). Consider differences for economic and load management. If LM receives energy payment than consider for test as price taker	🔴	🔴	🟡	🟡
Long	Energy	Price formation	Economic DR based on zonal Dfax. Load management DR based on closed loop interface	Economic and load management based on pricing node (minimize time delay with closed loop interface)	🟡	🔴	🔴	🔴
Long	Energy	Dispatch	Dispatch by registration	Dispatch by registration and use pNode to allow dispatch for transmission constraints	🟡	🔴	🔴	🟡
Medium	AS	SR test	SR is not required to test	DR SR resources required to test to ensure capability exists (similar to regulation)	🟢	🟡	🟡	🟡
Medium	AS	SR M&V	Measuring avoided demand	Measure avoided energy over duration of event (similar to CBL)	🟢	🟡	🟡	🟢

Conclusion – Paths to the Future

CSP Model

The CSP model of DR participation in PJM wholesale markets has been successful and likely will continue to foster innovation for customers. PJM believes this approach should be preserved for the foreseeable future.

Capacity and Ancillary Services Markets

PJM should maintain DR as a supply-side resource in future wholesale capacity and ancillary service markets through curtailment service providers because this approach is a more effective way for customers to manage these costs and for the wholesale market to incorporate these load-reduction actions. For customers, managing capacity cost as a supply-side resource in the wholesale market is more effective than through retail cost reduction, based on the challenges described in Table 1.

Energy Market

In the long term, PJM ideally will find the appropriate opportunity to realize DR capability on the demand side of the energy market. If the customer desires to manage its energy cost, an appropriate retail rate/contract should be available to facilitate that capability. Retail customers should not necessarily receive compensation through the wholesale energy market, as it may result in a subsidy when they are already on a dynamic retail rate. Subsidies for a single type of resource lead to inefficient market outcomes, because that resource will be utilized when another type of resource may be more cost effective, which also may lead to distortion of energy price formation. The wholesale energy market should accurately forecast this price sensitively to effectively commit other resources. PJM will look for opportunities to evolve in this direction through collaboration with load-serving entities and the state retail regulatory authorities. PJM recognizes that the transition of energy cost savings from both supply-side payments and demand-side retail cost savings to just demand-side retail cost savings will have several obstacles to overcome but believe this direction should be the long-term goal.

Short-Term Goals: Transition to Capacity Performance and Annual Capability through Aggregation

DR commitment in the capacity market and EDC integrated resource plans typically had been based on load reductions during the summer period for a handful of peak hours. The implementation of CP will require DR resources to be available on an annual basis with the potential to dispatch for several hours during a day. This is a major change in the DR capacity market availability requirements. The capacity market typically accounts for 95 percent or more of DR annual wholesale market revenue. PJM's short-term focus is on the following:

- DR transition to capacity performance requirements. PJM will continue to work with stakeholders on enhancements that add value
- Developing DR dispatch model to optimize dispatch and release of DR
- Reviewing DR and PRD rules and consider integrating into one approach
- Continuing to increase PJM operational visibility of DR
- Implementing broader energy market changes (e.g., five-minute settlements, hourly offers, price caps)
- Identifying any needed enhancement for distributed energy resources (DER) that operate as DR
- Implementing mandatory training to ensure all CSPs are ready when DR is dispatched

Medium-Term Focus: Ensure DR Capabilities Align with Commitments

As we transition further away from customer-specific capabilities to portfolio capabilities (based on the new annual CP requirements), DR commitments must align with DR capabilities. This requirement is especially important because DR has not been dispatched in more than three years. Higher availability requirements combined with low utilization suggest PJM should review existing rules and procedures and make changes where necessary to ensure PJM fully understands the DR capability beyond the simple one-hour self-directed test in place today. In the medium term, PJM will:

- Ensure DR commitments reflect DR capabilities by developing and implementing:
  - More robust and comprehensive capacity testing requirements
  - Synchronized reserve testing with enhanced performance measurement using the CBL approach
- Work with states and other stakeholders on other options to recognize the value of seasonal resource flexibility
- Refine PJM's ability to dispatch DR by quantity and by location

Long-Term Direction: Explore Opportunities to Move DR in the Energy Market to the Demand Side

PJM will focus on working with LSEs to determine what PJM can do to enable more dynamic retail contracts. While PJM understands customers may not want the risk of real-time prices, there may be other things PJM can do to help align wholesale market prices with retail market prices or incentives. This will help to make the transition from wholesale energy market revenue on the supply side to retail energy cost savings on the demand side. PJM will continue to refine participation in the capacity and ancillary service markets based on the value to stakeholders. In the long term, PJM plans to:

- Collaborate with LSEs to support contracts/pricing that foster demand elasticity
- Explore and develop opportunities to move DR in the energy market to demand side (cost savings) by modifying or eliminating energy compensation. This approach will help to avoid existing market distortions created through the payment of full LMP, which leads to uneconomic dispatch and the potential for inaccurate price formation[36]
- Expand participation in ancillary services markets where performance is comparable to generation
- Foster or support investment and implementation of DR automation
- Evaluate transitioning energy efficiency to the demand side (retail electricity cost savings) by eliminating capacity compensation. The PJM load forecast currently reflects the implementation of energy efficiency that has been installed or will be installed irrespective of participation in the wholesale market. In order to pay energy efficiency a capacity payment, PJM must inflate its load forecast to what it would have been for energy efficiency, and this would not be appropriate for energy efficiency improvements that would have been made regardless of wholesale market participation. Based on measurement and verification plans submitted to date, it appears that wholesale capacity market revenue for energy efficiency is not driving the installation of energy efficiency measures; therefore, it would be more efficient to return the economic decision and benefit to the retail consumers

[36] Consider a customer that pays a fixed retail rate with a generation portion of that rate equal to $110/MWh. The customer provides 1 MWh of demand response when the LMP equals $200/MWh. By reducing usage 1 MWh, the customer avoids the $110/MWh generation portion of the retail rate. If the load also receives "Full LMP" as a direct payment from the wholesale market, which is equal to $200/MWh, then the total incentive that accrues to the load that provides 1 MWh of DR is the $110/MWh avoided cost plus the direct payment of $200/MWh, which equals $310/MWh, and exceeds the market value of energy by the generation portion of the retail rate of $110/MWh. In other words, LMP is only at $200MWh but this customer will receive $310/MWh of incentive, while the market may have other lower-cost resources (with offers between $200 and $310 MWh) that could have been dispatched to meet the need. If the demand response is on the margin, this will distort the price for the entire market.

Appendices

Appendix A – PJM's 2014 report: Wholesale Load Response White Paper for Stop-Gap Filing

Below provides the PJM proposed plan to allow DR into the market based on the potential limitations imposed by the Court of Appeals order. This order was ultimately overturned by the Supreme Court and therefore unnecessary but contains ideas on how to combine DR and PRD into one product if PJM could not pay for DR resources in the capacity and energy markets. The Wholesale Load Response White Paper looked to maintain participation in the capacity market through capacity cost reductions and was developed based on attributes from DR or PRD.

Background

In 2011, the FERC issued Order 745, which requires grid operators to compensate electricity end- users for conserving power at peak times. Demand response customers get paid the same rate for conservation as utilities get paid for generating electricity.

The Electric Power Supply Association challenged the FERC's regulatory authority to set compensation for demand response in the wholesale energy market based on Order 745. In May 2014, the U.S. Court of Appeals for the District of Columbia Circuit effectively overturned FERC Order 745.

The case went to the U.S. Supreme Court. On Jan. 25, 2016, the court overturned the Court of Appeals decision, stated that FERC did have the authority to set compensation.

In the interim between the Court of Appeals decision and the Supreme Court's overturning it, PJM published a paper that proposed a viable way to still incorporate demand response in the wholesale market. PJM developed an approach for capacity market participation that included a review of demand response and price responsive demand rules to come up with an approach that would be legally viable.

That paper is reproduced below. PJM included it here as context to demonstrate its commitment to finding solutions that are not just best for its markets but stakeholders and the reliability of the grid.

Introduction

In any market, the participation of consumer response to price is essential to healthy and competitive market outcomes. This axiom holds true for wholesale electric markets as with any other market. The more that demand actively participates in our wholesale electricity markets, the more competitive and robust the market. Additionally, demand response, if visible and dependable, can and has proven to be an operational tool that assists in maintaining reliability, both in regards to real-time security and long-term resource adequacy. For these reasons, PJM Interconnection remains committed to finding ways to preserve the value that demand response provides to both our system and market operations. PJM also notes our market experience has demonstrated the value of competition among service providers, which has fostered demand response innovations. The market would benefit by preserving this competitive dynamic.

Since the May 2014 decision by the D.C. Circuit Court of Appeals (the "*EPSA*" decision), PJM has considered alternate approaches that would permit demand response to continue to participate in our markets in a manner consistent with the division of jurisdictional responsibility between the states and the Federal Energy Regulatory Commission described in the panel decision. This paper presents PJM's thoughts and rationale to support an approach that would meet these objectives and do so without exposing PJM and its members to an intolerable degree of litigation risk and uncertainty as to settled market outcomes.

Different approaches, other than the approach PJM advances in this paper, are conceptually possible under the *EPSA* decision. Moreover, stakeholders hold differing views generally as to (1) the value of demand response to PJM's markets and operations and (2) its lawful participation in wholesale electricity markets. Indeed, at least one group of PJM stakeholders, and perhaps the FERC itself, will request appeal of the *EPSA* decision to the U.S. Supreme Court, leaving open the possibility of a return to the status quo before the *EPSA* decision. PJM offers this paper to illustrate a viable path forward to evolve demand response in light of the *EPSA* decision, should the FERC decide, after considering its options under the *EPSA* decision (including possible further appeal), that such a path is needed. Ultimately, any path forward will be subject to stakeholder comment and critique and acceptance by the FERC and state regulators. PJM is committed to working with state regulators to develop strategies to monetize the benefits of consumer demand response in the wholesale markets.

Where We Have Come from – a Thumbnail Sketch

Demand response has come to mean many things. Therefore, offering some precise definitional terms helps to promote a shared understanding of options. Currently, curtailment participates most commonly in PJM as a "demand resource." By this (and despite what may appear to be a contradiction in terms) we mean demand resources offer into the PJM markets and are paid as "supply-side" resources. As such, demand resources are expected to perform (more or less) comparably to traditional supply-side resources (generation). In this paper, the term "demand *resource*" describes the supply-side participation of demand, and the term "demand *response*" describes demand (as load) making a curtailment commitment and, in so doing, avoiding costs and charges it otherwise would incur. Peak shaving, active load management and PJM's "price responsive demand" rules are examples of "demand response."

While PJM market rules offer both "demand resource" and "demand response" opportunities, most activity in recent years has taken the form of "demand resource" (i.e. supply-side) participation. There are logical and policy arguments on both sides of the "demand resource" paradigm.[37] The path forward advanced in this paper does not reflect a preference on the part of PJM between these competing economic and policy arguments. Rather, the proposal is informed by the law and analysis represented by *EPSA* and by practicalities which favor an approach that would reduce lengthy litigation risk and the potential for disrupting settled transactions – particularly in the context of the three-year "forward" capacity market administered by PJM.

The Law Following the *EPSA* Decision and Practicalities

The reach of the *EPSA* decision is subject to debate. Technically, the decision vacated FERC Order No. 745, which was confined only to the payment of demand resources in the wholesale energy market. However, the jurisdictional analysis applied by the majority to reach the *vacatur* suggests a precedent that could apply, when litigated, to PJM's Reliability Pricing Model capacity market. The FERC will need to confront this question; indeed, it has been put in play by FirstEnergy's May 23, 2014, filing of a complaint with the FERC seeking to remove demand resources from the 2014 Base Residual Auction. PJM will answer this complaint on or about October 22, 2014. Suffice to note here, PJM's answer will oppose FirstEnergy's complaint and its requested relief.

In considering the implications of *EPSA* to PJM's capacity market, we once again face the question of what is capacity. Arguments can be offered that, unlike energy, capacity is a product (albeit abstract in nature) that can be sold for resale. Alternatively, whether a product or service, capacity is a uniquely wholesale market concept, one not subject to state regulation and one over which the FERC exercises expansive jurisdictional authority as evidenced by recent decisions out of the Third and Fourth Circuit Courts of Appeal. While PJM acknowledges arguments of this nature, they are uncertain and untested.

[37] A thorough treatment of these positions can be found in the comments and the FERC decision finalizing Order No. 719.

Moreover, the linkage between the capacity and energy markets is undeniably strong. After all, the theory underlying the purpose of capacity markets is the recognition that energy markets alone are impeded in providing sufficient compensation to supply – due in part to the suppressing effect of offer caps, reserve margins and other features giving rise to a "missing money" problem that capacity markets are designed to solve. PJM's unfolding capacity performance initiative more explicitly defines capacity in reference to a resource's performance in the energy markets, further suggesting that capacity is simply a form of inchoate energy or a call on energy. The derivative and interdependent nature of the capacity market vis-a-vis the energy market raises the question under *EPSA* whether a commitment to curtail in the capacity market (a demand resource) is functionally any different than a commitment to curtail in the energy market.

The *EPSA* decision is more explicit in focusing on curtailment as the action defining a demand resource and further regarding this action as within the jurisdiction of the states and not the FERC. Yet, PJM does not believe the *EPSA* court squarely addressed the notion of "wholesale curtailment." PJM recognizes this notion. Load serving entities, in partnership with their customers (often under state programs), can manage their wholesale consumption, lower their forecast demand requirements and actively manage their consumption of energy at the peaks to lower their capacity obligations. PJM can and does account for these actions in making planning and procurement decisions in the wholesale market. Nothing in the *EPSA* decision prevents PJM from taking such actions to recognize wholesale curtailment actions. In PJM's view, the jurisdictional divide between wholesale and retail under the *EPSA* reasoning allows PJM to account for curtailment only to the extent it reflects the action of a wholesale entity, such as a load-serving entity or competitive retail service provider, and only to the extent such curtailment reflects that entity's own wholesale load.

Finally, PJM will be the first to agree that the *EPSA* decision, both in regards to its scope and its division of state and federal responsibilities, raises numerous unanswered questions and is open to various differing, reasonable interpretations. Accordingly, as noted earlier, one could propose different paths forward and argue such approaches are consistent with or distinguishable from *EPSA*. In arriving at its proposed path forward, PJM sought first to maximize the continuing value of demand in its markets and operations and, second, to do so in a manner compatible with a reasonable interpretation of *EPSA*.

But a third consideration deserves equal weight: risk. Litigation risk can upset market and settlement outcomes as evident from appellate court decisions in recent years remanding transmission cost allocation methodologies and marginal loss surplus allocations. These disruptions, often many years into the future, would upset what were thought to be settled market and billing outcomes and could lead to default and default allocations to members. PJM is particularly mindful of this risk when considering its capacity market. The three-year-forward commitment feature in PJM's capacity market raises a host of complications when it comes to resettling auction outcomes. The amount of money subject to disgorgement can be considerable, and the change in clearing prices given the sensitivity of the supply and demand curves in the auction can be dramatic.

Demand resources participate today in PJM's energy markets under pre-*EPSA* rules. PJM will be clearing capacity auctions in 2015, including the Base Residual Auction in May 2015. The form by which demand is eligible to participate in these auctions ideally would be known before conducting such auctions. Pursuing creative but untested notions of demand as a demand resource in upcoming capacity market auctions and thus facing the prospect of several years of uncertain administrative and judicial litigation serves to undermine intolerably the very purpose of the capacity market – namely, to provide a certain stream of forward revenues to assist capital formation for resource investment.

In considering PJM's market and operational objectives in maximizing demand participation along with the law and practicalities (including risks) associated with the *EPSA* ruling, PJM proposes an approach to integrate DR into PJM's energy and capacity markets under the following broad terms:

1. As demand response (i.e. demand side). PJM's markets would not separately compensate demand as a supply-side resource. The economics and incentives in having demand participate would result from avoided costs and obligations. State programs, of course, could offer added incentives to both wholesale and retail market participants.

2. Through load-serving entities. PJM would account for and base planning and procurement decisions on commitments bid into PJM's markets by wholesale market entities. These entities, by definition, have control over, or an obligation to serve, specified retail load and can commit to reduce their wholesale load based on curtailment commitments or alternate supply (behind the meter) which they arrange with their end-use retail load. We envision that in many states third-party curtailment service providers will serve a continuing and important function by partnering with load-serving entities to provide their customer management expertise.

Demand Response in Specific Markets Going Forward

Capacity Market

Consistent with the foregoing, PJM describes below a modified approach to demand response participation in the capacity market and, in addition, proposes a transition mechanism to address the question of cleared demand resource bids from past base and incremental capacity auctions.

Subject to the state opt-out provisions of FERC Order No. 719, wholesale demand response would bid into the capacity auction as a commitment to curtail by wholesale market entities (load serving entities, including competitive retail providers). This alternative would enable wholesale (load-serving entity-based) load to participate on the demand side of the capacity market as "demand response" and would be modeled as a reduction in capacity obligation. The demand would bid a curtailment commitment into the capacity auction at a price. This curtailment commitment bid would affect the demand curve, could set the capacity price and, if cleared, would avoid paying the capacity clearing price. This cleared curtailment would result in PJM procuring less capacity for that load-serving entity in the same amount as the cleared curtailment bid quantity. Under this approach, PJM would define the eligibility characteristics of a curtailment commitment and would establish measurement, verification, penalty and credit requirements as necessary to ensure performance and compliance. The curtailment commitment is essentially a commitment by the load-serving entity to reduce its wholesale demand at PJM's request during the established compliance period. If the demand response curtailment commitment is called to perform in the energy market, it may receive no additional energy market payment,[38] but would avoid an energy payment for the demand reduced.

PJM believes a transition mechanism can be developed based on this alternate approach to minimize disruption to participation by wholesale demand response that is already committed through a capacity auction for delivery years 2015/16, 2016/17 and 2017/18. The proposed transition mechanism is as follows:

- PJM would review demand resource commitments and would certify which are load-serving-entity-based and can be directly converted to demand response curtailment commitment.

- PJM would develop a mechanism to work with curtailment service providers, state commissions and load-serving entities to explore arrangements to certify demand resources that are not currently load-serving-entity-based through an agency

[38] In implementing *EPSA*, the FERC will decide whether the court decision leaves open any room for the FERC to direct PJM to offer affirmative payments for wholesale curtailment. PJM would have concern with any theory upon which such FERC authority is based, should such a theory be creative and subject to the uncertainty of credible and protracted litigation.

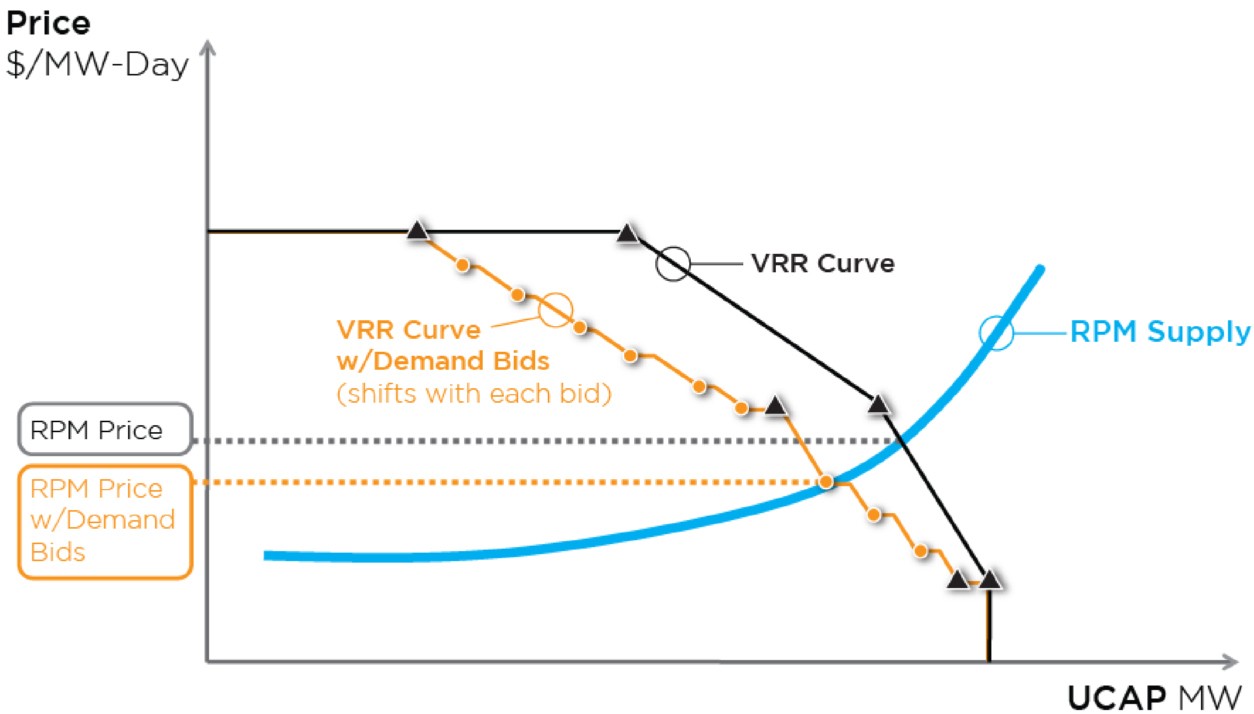
agreement with the load-serving entity in order to convert them to a load-serving entity-based demand response curtailment commitment.

- PJM would establish procedures for demand resources that cannot be converted to release them from their capacity commitment. Such resources would receive no capacity credit for their released commitment and retain no curtailment obligation in the delivery year.

- Similar to the recent rules transitioning demand resources affected by the newly imposed 30-minute notification requirement, PJM would account for the quantity of released demand resources in the remaining incremental auctions for the three transition delivery years and, if necessary, purchase additional capacity to replace the released demand resources. Additional, load serving entity-based demand response would be eligible to bid into the incremental auctions as demand-side participants.

- The terms of the curtailment commitment in the energy market for each type of demand resource (limited, extended summer and annual) would be preserved during the transition.

Figure 10. Integration of Demand Response Bids with RPM Demand Curve



Shown based on existing PJM Variable Resource Requirement Curve.
PJM has proposed an alternative demand curve as part of the triennial review process.

Energy Market

Depending on the FERC's decisions for demand response compensation, demand reduction in the PJM energy markets may not receive direct compensation from the wholesale market. The PJM Day-Ahead Energy Market permits price responsive demand bids in which load-serving entities can specify a price at which they choose not to consume energy rather than pay energy market clearing prices. The PJM Tariff also includes provisions for price-responsive demand in the Real-Time Energy Market. Under these provisions, a load-serving entity can provide a forecast of aggregated price responsive demand which PJM will model in the regional dispatch to avoid dispatch of generating resources in anticipation of price responsive demand reduction.

Ancillary Service Markets

The participation of demand in PJM's ancillary service markets in light of *EPSA* strikes PJM as presenting a different legal argument than participation by demand in capacity and energy markets. While we would regard any legal basis allowing demand to continue to participate in energy and capacity markets as a demand resource as an intolerably uncertain, PJM believes ancillary service markets might be different. Ancillary services are well-defined wholesale products and services closely tied to the FERC's federal authority over interstate transmission service. They were defined as required elements of open access transmission service in FERC Orders Nos. 888 and 889. Ancillary services are not directly bought or sold at retail by, or from, end users. As such, they are not matters historically under state purview. While ancillary services support the consumption and delivery of electric energy, they are discretely recognized and not, by PJM's way of thinking, so closely linked as capacity might be to energy.

At this time, PJM would propose to pay demand that is eligible to provide frequency regulation and synchronized reserve, as a resource in the markets that PJM operates for those services. Under PJM's construct, demand resource offers in the frequency regulation and synchronized reserve markets could continue to be submitted by both load-serving and non-load-serving entities.

Conclusion

PJM sets forth this approach for consideration by regulators and stakeholders and will address these ideas further in responding to the FirstEnergy complaint. PJM believes it appropriate at this critical time to layout this "road map" for continued participation by demand in wholesale markets – one that fits within reasonable interpretation of EPSA. We do so with the hope that it advances our stakeholder and regulator's consideration of options to restore confidence and certainty in the PJM markets. PJM respects and seeks to understand other views and suggested options. Given the day to day continuing operation of our markets and our reliance on these markets to fulfill important aspects of PJM's larger mission (notably, ensuring adequate resources in the face of a changing fuel mix of generation resources), we admittedly will place a premium on policy approaches that can be quickly implemented and that bring certainty, with a minimum risk of protracted litigation or threat of judicial disruption.

Appendix B – High-Level Comparison of Demand Response in Select ISOs/RTOs

Table 8. PJM

Attribute	Capacity/Resource Adequacy	Energy (DA vs RT and Emergency)	Ancillary Services
Market Participant that can fulfill function of the Curtailment Service Provider (CSP)	Electric distribution company (EDC) for its customers and others, Load-serving entity (LSE) for its customers and others, and entities that specialize in demand reduction and load management aka competitive CSPs	EDCs, LSEs, & competitive CSPs	EDCs, LSEs, & competitive CSPs
Dispatch	Called by Operations per emergency procedures	Clear in the day-ahead market or dispatched by real-time SCED or by Operations during an emergency event using minimum dispatch price	Called by Operations to respond to a system contingency
Price formation	Offered into forward auction, price separation possible because of location and caps on quantity of limited resources cleared DR can set price when cleared as the marginal resource No requirement to offer in the DA energy market	Offered into day-ahead market, cleared based on strike price. Offered into real-time market, cleared based on notice requirement and strike price. Emergency energy paid LMP or made whole to the value determined by the Minimum Dispatch Price	Offer as inflexible or flexible resource into synchronized reserve market for transmission constrained portion of market region. Clearing price for an hour is determined by the average of the five-minute clearing prices calculated during the operating hour
Other			

Table 9. ISO New England

Attribute	Capacity/Resource Adequacy	Energy (DA vs RT and Emergency)	Ancillary Services
Market Participant that can fulfill function of the Curtailment Service Provider (CSP)	Electric distribution companies, load-serving entities & competitive demand response providers FCM #9 in February of 2015 cleared 372 MW of DR – 367 MW of the cleared DR came from non-regulated third parties. FCM #10 in February of 2016 cleared 310 MW of DR.	Electric distribution companies, load-serving entities, & competitive demand response providers	Electric distribution companies, load-serving entities, & competitive demand response providers
Dispatch	By Operations when reserves are short per OP4. Purpose is to preserve reserves provided by generators. Currently, there are 295 MW of DR providing capacity in the ISO. DR committed as capacity beginning with the 2018/2019 delivery year must provide an energy offer for the DA and RT energy Market.	Before 6/1/18: DR MW that clear in the day-ahead market must perform but are not dispatched. DR MW that do not clear DA but whose offers exceed the Order 745 threshold LMP will be paid the LMP for load reductions. Today, 40 to 50 MW of DR (primarily industrial DR) are active in the energy market. These DR MW will not be dispatched by the ISO until after 6/1/18. After 6/1/18 (full integration): DR will be added to the bid stack and will provide market operations with parameters applicable to DR. The ISO's market engines will dispatch DR just like other resources and will co-optimize DR offers for the energy and ancillary services markets. Furthermore, DR with a capacity commitment will be required to offer into both the day-ahead and real-time energy markets and will be dispatched like other resources.	Before 6/1/18: no DR dispatched for ancillary services markets. After 6/1/18 (full integration): DR will be able to participate in the ISO's 10- and 30-minute reserve markets and will be cleared and dispatched like other resources. DR participation in the ancillary services markets will not be capped.
Price formation		Before 6/1/18: DR will not set price in the energy market After 6/1/18 (full integration): DR will set price in the energy market when it is on the margin Given the high opportunity costs of DR and the impossibility of monitoring DR offers like generation offers, the ISO is considering other options for monitoring energy offers of DR.	Before 6/1/18: DR will not set the price in the ancillary services markets that are co-optimized with energy. After 6/1/18 (full integration): DR will set price when it is on the margin.
Other	All DR today must be telemetered and able to provide ISO Operations with 5 minute usage information	All DR today must be telemetered and able to provide ISO Operations with 5-minute usage information. This information is not shared with the distribution company, but the customer's retail bill is used to verify the accuracy of the telemetered values at ISO's request.	After 6/1/18 (full integration): DR that participates as 10 reserves must increase the granularity of the telemetered usage to one minute rather than five minutes.

Table 10. NYISO

Attribute	Capacity/Resource Adequacy	Energy (DA vs RT and Emergency)	Ancillary Services
Market Participant that can fulfill function of the Curtailment Service Provider (CSP)	Electric distribution companies, load-serving entities, & competitive demand response providers. Handful of large industrials provide DR as limited direct customers (financial requirements include $200,000 of collateral, but not their own load-serving entities) Currently, 1250 MW of DR have capacity commitment Unregulated DR providers typically provide 90 percent of MW with capacity commitments	Electric distribution companies, load serving entities, & competitive demand response providers. Handful of large industrials provide DR as limited direct customers (financial requirements include $200,000 of collateral, but not their own load-serving entities)	Electric distribution companies, load-serving entities, & competitive demand response providers. Handful of large industrials provide DR as limited direct customers (financial requirements include $200,000 of collateral, but not their own load-serving entities) There is no cap on the percentage of market requirements that DR can provide.
Dispatch	By Operations to address an emergency event. NYISO Operations tests all DR resources by zone 1X in the winter and 1X in summer by sending a signal to DR providers to reduce for one hour. Last event in 2013.	DR offered and cleared like generation = in the bid stack for the day-ahead market and the markets for ancillary services but not in real-time energy market = DR participation is disjointed. Order 745 compliance filing made in 2013 delayed by FERC because of EPSA case. Order anticipated any day. Previous $75/MWH offer price floor prevails until FERC approves a monthly LMP threshold calculation per Order 745.	Currently, 126 MW of DR registered and qualified to be dispatched by NYISO to provide ancillary services. Telemetry required = 6 second data = AGS signal = same as for generation.
Price formation	DR sets the market price if it is marginal	DR sets the LMP in day-ahead if it is marginal (Real-time not applicable, no activity)	DR sets the clearing price if it is marginal
Other	NYISO calls for new capacity market design that is similar to capacity performance in ISO New England in that cleared DR would be required to offer into the day-ahead and real-time energy markets but only for hours when the DR is obligated to reduce. Unlike ISO New England and PJM, there would be for the foreseeable future two capacity products for DR: the new capacity performance and the existing, legacy opportunity (similar to Base Capacity in PJM).	Stakeholder process underway to develop one program for DR (full integration) participation in NYISO markets. Goal is to implement in 2019. Focus will be the supply side. The rules affecting load bids in the day-ahead market (price responsive demand) will not be revised as part of the DR stakeholder process.	Quantity of DR that can provide telemetered data directly to the ISO through a private MPLS network is limited to 200 MW. Balance of DR MW must go through the utility as do generators. This is because NYISO has only one manned control center and thus depends on the utilities to jump in if and when NYISO must switch over to its unmanned control center. Consequently, the utilities can see all but 200 MW of the telemetered DR.

Table 11. CAISO

Attribute	Capacity/Resource Adequacy	Energy (DA vs RT and Emergency)	Ancillary Services
Market Participant that can fulfill function of the Curtailment Service Provider (CSP)	No explicit limitations on who is a demand response provider but must have a capacity procurement contract awarded through the demand response auction mechanism (DRAM) or come through a utility program. DRAM is a California Public Utility Commission requirement that CA utilities have met. For the DRAM pilot, the utilities have contracted for 40 MW of DR. These DR MW have been registered by CAISO but are not included in the bid stack until an emergency event. When the DRAM MW are put into the bid stack their offer price must be 95 percent of the bid cap. Utilities have also registered DR MW for reliability adequacy credits. A total of 1400 MW of DR currently gets resource adequacy credits (1200 MW registered by SCE). The plan is to integrate DR as a reliability adequacy resource in the CAISO market by 2018.	No explicit limitations on who is a demand response provider	No explicit limitations on who is a demand response provider CAISO sponsored and funded frequency response summer pilot to learn about battery including EV resources
Dispatch	Called by Operations per emergency procedures and then added to the bid stack at 95 percent of the bid cap	DR offers in the real-time energy market are included in the bid stack and dispatched based on parameters, the same as other resources	Non-spinning and spinning reserves called by Operations
Price formation	Yes, but subject to special offer rules (see above).	DR can set the RT and DA price	Included in the bid stack (capacity and energy offers required) and cleared day-ahead market. DR can set the price
Other			

Appendix C – Comparative Analysis Notes

- Existing vs. Planned DR/PRD – The value of requiring CSP to track status similar to interconnection queue is not clear. To the extent we can articulate why this would improve reliability or market efficiency is something we can revisit at a later date.

- RPM Participation – PJM has the FERC report dating from regarding our prior filing in November 2016 which would eliminate a CSP's ability to profit from selling short in the base residual auction and buying back at lower price in the incremental auctions. This will be opportunity to push the resolution of this issue with the FERC. If we are not successful then it will not make sense to push this forward; we can revisit at a later time

- DR Forecast for RTEP – This currently has minimal impact on overall RTEP plan and would be a significant uphill battle with regulators to remove from the RTEP process. DR forecast methodology was significantly improved in 2015 and can monitor the accuracy of forecast and impact to RTEP over the medium term to determine when this should be revisited

- Product – With implementation of Capacity Performance several stakeholders (especially EDC residential direct load control programs) expressed interest in PRD because the underlying measurement and verification methodology would allow them to participate as a PRD within Capacity Performance's capacity market. A long stakeholder process (including significant comprises) created PRD when DR was a summer-only product. During the EPSA case, PJM combined concepts from DR and PRD to propose wholesale load reduction. WLR was our attempt to pull together the best aspects from the two products within a regulatory framework that would not allow PJM to make payments for DR. With the finalization of the EPSA case, PJM can continue to make payments to wholesale demand response and participation in the capacity market represent the vast majority of revenue. There may be significant value to explore what to do with existing PRD and DR construct before we have participation in PRD and potentially need to change existing PRD rules to bring up to speed with the Capacity Performance world.

- Nominated DR Quantity – This is being discussed in the SCRSTF. The calculation and maintenance of DR metric such as the equivalent demand forced outage rate has significant issues that would need to be solved to effectively do this. For example: do we do at CSP, registration or location level and how to reconcile with CSP portfolio management (performance aggregation). Also, how to handle location transition from one CSP to another CSP over time where location transition from one member to another is much more frequent than anything that occurs for generators. At this point, the focus is more on the application of the forecast pool requirement factor and implication of Capacity Performance balancing ratio where PJM has taken the position to allow FPR to be applied to DR but not all balancing ratio to be applied.

- Retail Capacity Allocation Methodology – The current EDC capacity allocation process creates cost shifting for retail customers. For example, residential customers that need more capacity in the summer (because of air conditioning) than the winter are charged for same amount of capacity year round. Further, industrial customers that peak shave their five coincident peaks may not be charged for any capacity while the total amount of capacity that is procured remains almost the same (it goes down slightly over long period of time). There is a very large regulatory and stakeholder gap to making any changes in this area and these types of changes are really outside the scope of the FERC's jurisdiction, since they are retail electricity market issues).

- Measurement and Verification (Performance Obligation) – Capacity Performance changed the underlying measurement and verification process which has created a disconnection between capacity cost allocation in retail market and DR capacity obligations in the wholesale market. The gap between future and current state may be reduced in the short term which will help better align retail & wholesale and meet PJM's Capacity Performance objectives.

- Test – DR resources are dispatched infrequently and are managed as a portfolio (because actual capability is not transparent). There is enormous value to increasing the test requirements when infrequently dispatched to ensure resources are ready to reduce load when needed and better understand the DR actual capability. There is a major difference between test performance and event performance which indicates that current test conditions do not mimic the conditions of when/how DR resources will be dispatched.

- Capacity Performance Aggregation – Implementation of Capacity Performance has made registration and RPM resource aggregation critical to viability of significant amount of DR. Since this is primary revenue source, there is significant value in development of more effective way for members to aggregate individual customers or resources to meet Capacity Performance requirements.

- Capacity Dispatch – Gap between current and future state varies based on variety of solutions considered. Ultimately, to have perfect information on willingness to reduce load based on actual cost (such as DER cost to operate behind-the-meter generation or cost to change production time) and therefore be able to dispatch on more economic basis would be ideal over existing administrative approach. To the extent that DR offer prices are very high and similar, economic dispatch will not help the dispatch process (value goes down) and administrative tools will still be required to allow PJM to manage the system.

- Load Data – The gap between current and future state is large and it will take major effort/cost to narrow. Ideally, one set of retail metering and load data management should allow load data to be shared on a frequent basis for all purposes (wholesale market participation, manage load, retail settlements, etc.).

- Non-Retail Behind-the-Meter Generation – Gap between current and future state is large since there will be significant stakeholder (and potentially the FERC) resistance from eliminating non-retail behind-the-meter generation for participation as a DR resource and require them to participate at non-retail behind-the-meter generation or traditional supply resource.