Comparisons of Different ISO/RTO Capacity Market Structures

Capacity markets[1] are designed to provide long-term pricing signals to attract new investments. Capacity markets also maintain existing resources required to ensure resource adequacy and the reliability of an Independent System Operator (ISO)/Regional Transmission Organization (RTO) region. The capacity market's main tasks are to commit capacity resources required to reliably meet forecasted demand, to provide sufficient reserve margins, and to provide fixed-cost recovery (e.g., capital cost, fixed operation and maintenance costs) for existing and new generators.

Overview of RTO and ISO Capacity Markets

In the U.S., four ISOs/RTOs offer a capacity market:

1. PJM's Interconnection, L.L.C. – Reliability Pricing Model (RPM)
2. New York ISO – Installed Capacity (ICAP) market
3. ISO New England – Forward Capacity Market (FCM)
4. Midwest ISO – Voluntary Capacity Auction (VCA)

Reliability Pricing Model (RPM): PJM

The RPM is a three-year forward capacity market model. The RPM was designed to provide long-term pricing signals to attract necessary investments required to ensure the reliability of the PJM region. The RPM is used to commit capacity resources required to reliably meet forecasted demand on an annual basis, to provide sufficient reserve margins, and to help plan transmission upgrades. The RPM uses an annual capacity auction mechanism to clear the market by reconciling an offer-based supply curve with a downward-sloping demand curve.

The supply curve is designed by sequentially aggregating offers submitted by capacity resource owners. In the RPM, the capacity resources consist of:

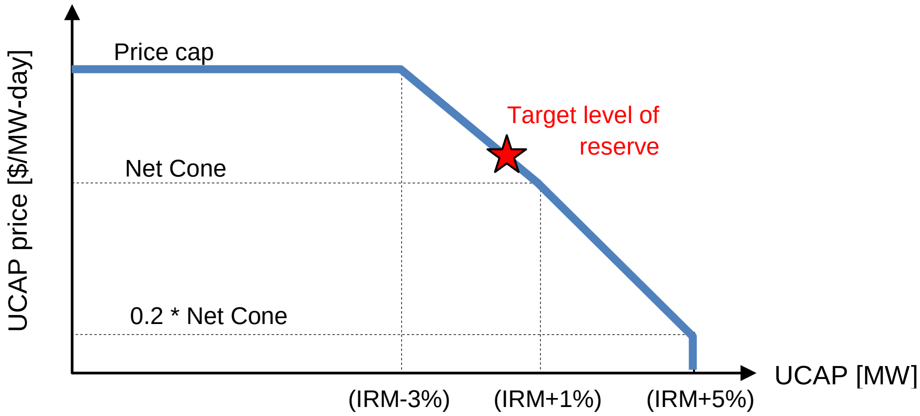
- Generator resources (existing and planned)
- Demand resources
- Energy efficiency resources
- Qualifying transmission upgrades

The demand curve, also known as the variable resource requirement (VRR) curve, is based on the variable resource requirement concept. The purpose of the resource requirement concept is to prevent overbuilding and to provide revenue to a resource when the reliability level is lower than required. The demand curve incorporates the value of the reliability into the price. The demand curve is defined by a family of price/quantity points in which each level of the resources is correlated with a specified price relative to reliability requirements (Exhibit 1). The demand prices are a function of the net cost of new entry (CONE)[2] and the demand quantities are a function of the reliability requirement. The unforced capacity (UCAP) requirement is calculated as a product of the forecasted peak load increased by installed reserve margin (IRM) and the probability that the generating unit will be available. The VRR (demand) price is higher than the net CONE if the level of the resources is less than the reliability requirement.[3] The VRR (demand) price is lower than the net CONE if the level of the resources is larger than the reliability requirement. The demand capacity price is capped at 150 percent of the net CONE. The VRR curves are

[1] Many of the technical terms used in this primer are defined in a companion *Glossary for Power Market Primers.*
[2] PJM defines cost of new entry as "levelized annual cost in installed capacity $/MW-Day of a reference combustion turbine to be built in a specific location." PJM. (2013). *Glossary*. Retrieved on January 15, 2013, from http://pjm.com/Home/Glossary.aspx
[3] The reliability requirement is a function of regional and locational target reserve margin.

defined by PJM for the PJM region and for each of constrained locational deliverability areas. Locational deliverability areas are areas within the PJM footprint that have been identified as constrained because of their limited import capability in the event of an emergency. The limited import capability is caused by transmission system capacity limitations or voltage limitations.

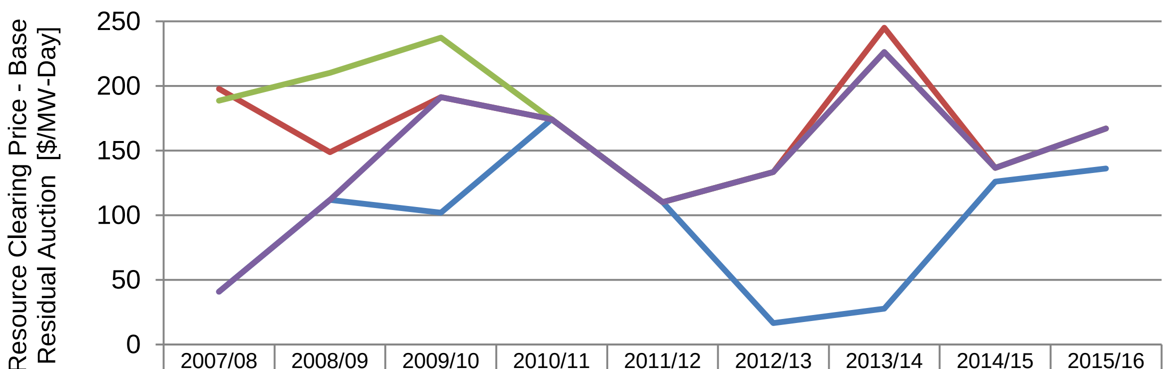
Exhibit 1 Illustrative example of a variable resource requirement curve



(Adapted with permission from PJM.[4])

The intersection of the supply curve and the VRR curve determines the capacity market clearing price. Exhibit 2 illustrates the RPM base residual auction resource clearing price for 2007/2008 – 2015/2016 delivery years.[5]

Exhibit 2 Resource Clearing Price – Base Residual Auction (2007/2008 – 2015/2016)



	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16
RTO	$40.8	$111.9	$102.0	$174.3	$110.0	$16.5	$27.7	$126.0	$136.0
EMAAC	$197.7	$148.8	$191.3	$174.3	$110.0	$133.4	$245.0	$136.5	$167.0
SWMAAC	$188.5	$210.1	$237.3	$174.3	$110.0	$133.4	$226.2	$136.5	$167.0
MAAC	$40.8	$111.9	$191.3	$174.3	$110.0	$133.4	$226.2	$136.5	$167.0
Date held	May-07	Jul-07	Oct-07	Feb-08	May-08	May-09	May-10	May-11	May-12

Data Source: 2015/2016 RPM Base Residual Auction Results [6]

[4] PJM. (2013). *Load Serving Entity 202 – Reliability Pricing Model*. Retrieved on January 15, 2013, from http://pjm.com/training/training-material.aspx

[5] Mid-Atlantic Area Council (MAAC) includes: Pennsylvania Electric, Metropolitan Edison, Jersey Central Power and Light, PPL Electric Utilities Corporation, PECO Energy, Public Service Electric and Gas, Baltimore Gas and Electric, Potomac Electric Power Company, Atlantic City Electric, Delmarva Power and Light, UGI Corporation and Rockland Electric.

Southwestern Mid-Atlantic Area Council (SWMAC) includes: Baltimore Gas and Electric, and Potomac Electric Power Company.

Eastern Mid-Atlantic Area Council (EMAAC) includes: Jersey Central Power and Light, PECO Energy, Public Service Electric and Gas, Atlantic City Electric, Delmarva Power and Light and Rockland Electric.

In the 2008/2009 auction, the increase in RTO's RPM price from $41/MW-day to $112/MW-day was caused by the increase in load growth that was in excess of supply growth. Decreases in EMAAC's RPM price from $198/MW-day to $149/MW-day was caused by the rise in capacity import capability into the EMAAC locational deliverability area (LDA) (multiple transmission upgrades were scheduled to be in service prior to the delivery year). This increase in import capability allowed more capacity to be imported into constrained EMAAC and caused EMAAC's RMP price to be lowered. On the contrary, a decrease in capacity import capability into SWMAAC LDA caused SWMAAC's RMP price to increase.[7]

In the 2009/2010 auction, the RTO's RPM price decrease was result of addition of new capacity and a decrease of export from the PJM system. The growth in supply was in excess of the growth in load and caused a decrease in the RTO's price. Although the RTO's price decreased, a new constrained area MAAC+APS (contains EMAAC, SWMAAC, Pennsylvania Electric, PPL Electric Utilities Corporation, Metropolitan Edison and Allegheny Power System zones), was formed due to transmission limitation. EMAAC was not constrained in the 2009/2010 auction due to an increase in capacity import capability and an increase in available supply. However, since it was a part of MAAC, its RPM price was the same as that of MAAC. SWMAAC was more constrained in the 2008/2009 auction than in the 2007/2008 due to an increase in emergency requirements and a net decrease in capacity.[8]

In the 2010/2011 auction, there were no constrained LDAs and the entire PJM system had a uniform RPM price.[9]

The same situation occurred in the 2011/2012 auction, so there were no constrained LDAs and the entire PJM system had a uniform RPM price. The decrease in the RPM price is caused by an increase in new capacity, demand response resources and power imports. In addition, the Duquesne Light Company zone was not included in the auction causing lower load growth in the PJM area and increased import (Duquesne Light Company capacity was offered as an external resource in the auction).[10]

In the 2012/2013 auction, several changes to the RMP design were accepted. Duquesne Light load was included in the demand curve; the CONE was increased; and criteria for LDA modeling were changed. In addition, interruptible load was eliminated; energy efficiency and planned external generators were permitted; and the avoidable cost rate values were increased. The decrease in the RTO's RPM price is caused by new capacity introduced in this auction and decreases in exports from PJM. MAAC was a constrained area in the 2012/2013 auction due to transmission import limitations and new criteria for the LDA selection.[11]

American Transmission Systems, Inc. (ATSI) transmission zone, which joined the PJM in 2011, participated for the first time in the 2013/2014 capacity auction. Load in the ATSI zone was included in the RTO demand curve and supply resources were included in the RTO supply curve. The MAAC,

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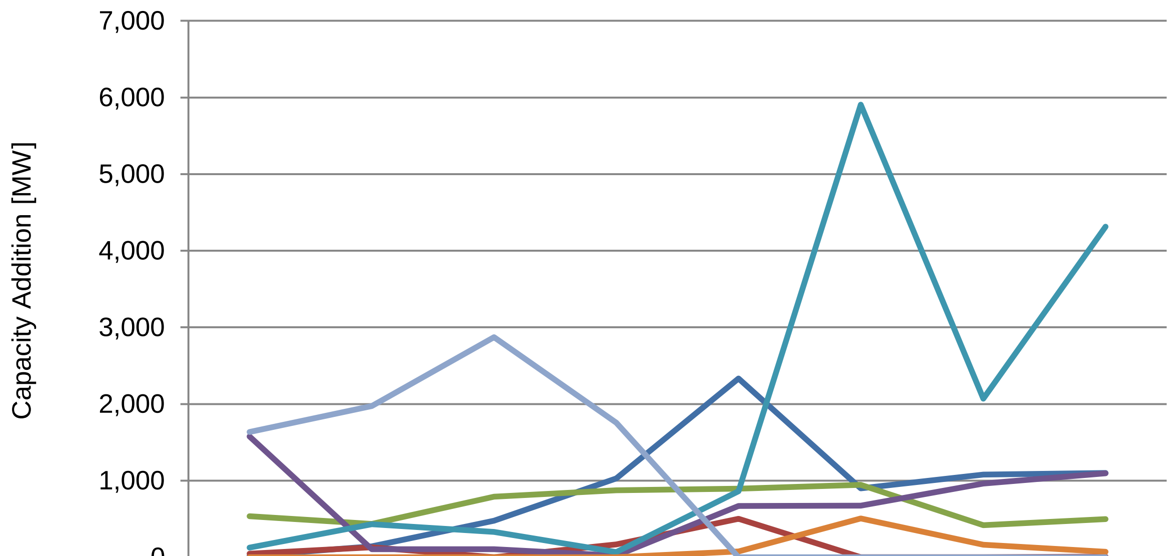
[6] PJM. (2012). *2015/2016 RPM Base Residual Auction Results*. Retrieved on January 15, 2013, from http://pjm.com/markets-and-operations/rpm/rpm-auction-user-info.aspx
[7] PJM. (2007). *2008/2009 RPM Base Residual Auction Results.* Retrieved on January 15, 2013, from http://pjm.com/markets-and-operations/rpm/rpm-auction-user-info.aspx#Item01
[8] PJM. (2007). *2009/2010 RPM Base Residual Auction Results.* Retrieved on January 15, 2013, from http://pjm.com/markets-and-operations/rpm/rpm-auction-user-info.aspx#Item01
[9] PJM. (2008). *2010/2011 RPM Base Residual Auction Results.* Retrieved on January 15, 2013, from http://pjm.com/markets-and-operations/rpm/rpm-auction-user-info.aspx#Item01
[10] PJM. (2008). *2011/2012 RPM Base Residual Auction Results.* Retrieved on January 15, 2013, from http://pjm.com/markets-and-operations/rpm/rpm-auction-user-info.aspx#Item01
[11] PJM. (2009). *2012/2013 RPM Base Residual Auction Results.* Retrieved on January 15, 2013, from http://pjm.com/markets-and-operations/rpm/rpm-auction-user-info.aspx#Item01

SWMAAC and EMAAC price increases were mostly due to reduced transmission transfer limits into the areas and partially due to increase in the net CONE.[12]

The RTO's price of $126/MW-day in 2014/2015 is due to high bids and the excused capacity from coal units related to EPA regulations.[13] For 2014/2015, a large amount of demand response capacity was cleared, replacing the existing generating units.

Since the RPM was established in 2007, about 35,000 MW of the new capacity was added. Since the 2010/2011 auction, the addition of the new generation capacity resources has been decreasing while the demand resources addition has been increasing (Exhibit 3).

Exhibit 3 Capacity additions (2007/2008 – 2015/2016)



	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15
New	19	145	476	1,031	2,332	901	1,080	1,102
Reactivated	47	131	-	170	501	-	-	9
Uprates	536	438	793	876	896	946	418	499
Imports	1,576	107	105	24	672	676	963	1,096
DR	127	432	333	70	864	5,908	2,068	4,316
EE	-	-	-	-	76	509	163	74
ILR	1,636	1,972	2,873	1,755	-	-	-	-

Note: New = New Generation Capacity Resource, Reactivated = Reactivated Generation Capacity Resource, Uprates = Uprates to Existing Generation Capacity Resources, Imports= Net Increase in Capacity Imports, DR = Demand Resources, EE =Energy Efficiency, ILR = Interruptible Load for Reliability

Data Source: 2011 State of the Market Reports [14]

The significant increase in demand response in the 2012/2013 auction is caused by capacity market incentives (the existing demand response offer price is equal to $0/MW-day and they are price takers) and the elimination of the ILR alternative. Since the 2012/2013 auction, EE was permitted as a new type of capacity resource.

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[12] PJM. (2010). *2013/2014 RPM Base Residual Auction Results.* Retrieved on January 15, 2013, from http://pjm.com/markets-and-operations/rpm/rpm-auction-user-info.aspx#Item01

[13] PJM. (2011). *2014/2015 RPM Base Residual Auction Results.* Retrieved on January 15, 2013, from http://pjm.com/markets-and-operations/rpm/rpm-auction-user-info.aspx#Item01

[14] PJM. (2012). *2011 State of the Market Reports*. Retrieved on January 15, 2013, from http://pjm.com/documents/reports/state-of-market-reports/2011-state-of-market-reports.aspx

Exhibit 4 illustrates incremental capacity resource additions from 2007/2008 to 2015/2016.[6] There is a significant increase in the amount of new capacity offered in the 2015/2016 auction. The most recent auction attracted mostly natural gas resources. The largest growth remains in gas turbines and combined cycle plants. The 2011/2012 and 2012/2013 were the last auctions when coal power plants had a significant growth in the new capacity units.

Exhibit 4 Incremental capacity resource additions from 2007/2008 to 2015/2016

	Delivery Year	CT/GT	CC	Diesel	Hydro	Steam	Nuclear	Solar	Wind	Fuel Cell	Total
New Capacity Units (ICAP MW)	2007/08			18.7	0.3						**19**
	2008/09			27.0					66.1		**93**
	2009/10	399.5		23.8		53.0					**476**
	2010/11	283.3	580.0	23.0					141.4		**1.028**
	2011/12	416.4	1,135.0			704.8		1.1	75.2		**2,332**
	2012/13	403.8		7.8		621.3			75.1		**1,108**
	2013/14	329.0	705.0	6.0		25.0		9.5	245.7		**1,320**
	2014/15	108.0	650.0	35.1	132.9			28.0	146.6		**1,101**
	2015/16	1,382.5	5,914.5	19.4	148.4	45.4		13.8	104.9	30.0	**7,659**
Reactivated Units (ICAP MW)	2007/08					47.0					**47**
	2008/09					131.0					**131**
	2009/10										**-**
	2010/11	160.0		10.7							**171**
	2011/12	80.0				101.0					**181**
	2012/13										**-**
	2013/14										**-**
	2014/15			9.0							**9**
	2015/16										**-**
Uprates to Existing Resources (ICAP MW)	2007/08	114.5		13.9	80.0	235.6	92.0				**536**
	2008/09	108.2	34.0	18.0	105.5	196.0	38.4				**500**
	2009/10	152.2	206.0		162.5	61.4	197.4		16.5		**796**
	2010/11	117.3	163.0		48.0	89.2	160.3				**578**
	2011/12	369.2	148.6	57.4		186.8	292.1		8.7		**1,063**
	2012/13	231.2	164.3	14.2		193.0	126.0		56.8		**786**
	2013/14	56.4	59.0	0.3		215.0	47.0		39.6		**417**
	2014/15	104.9		0.5	41.5	138.6	107.0	7.1	73.6		**473**
	2015/16	216.8	72.0	4.7	15.7	63.4	149.2	2.2	24.1		**548**
Total		**5,033**	**9,831**	**289**	**735**	**3,108**	**1,209**	**62**	**1,0743**	**30**	**21,372**

Data Source: 2015/2016 RPM Base Residual Auction Results [6]

The largest growth in new capacity units remains in gas turbines and combined cycle plants. While the largest growth in uprates to existing resources remains in gas turbines and combined cycle plants, a fair amount of uprate capacity in Steam and Nuclear were offered into the recent auctions.

Installed Capacity (ICAP): NYISO

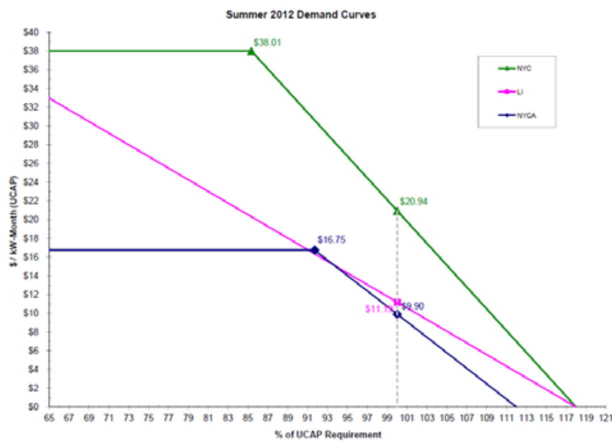
The ICAP consists of voluntary monthly auctions and mandatory spot auctions. The ICAP market should produce efficient long-term economic signals that give incentives to invest in new generation, transmission, and demand response resources and to maintain existing resources. The NYISO uses the spot capacity auction mechanism to clear the market by reconciling the offer-based supply curve with the downward-sloping demand curve.

The supply curve is designed by sequentially aggregating unforced capacity offers submitted by capacity resource owners or load serving entities. In the ICAP, the capacity resources consist of:

- Generator resources (existing and planned)
- Special case resources – end-use loads capable of being interrupted upon demand, and distributed generators

The ICAP demand curve is similar to the PJM curve with three different slopes. The NYISO designs three demand curves. The first curve is for the entire NYISO area (NYCA). The second curve is for the New York City area (NYC), and the last curve is for the Long Island area (LI) (Exhibit 5).

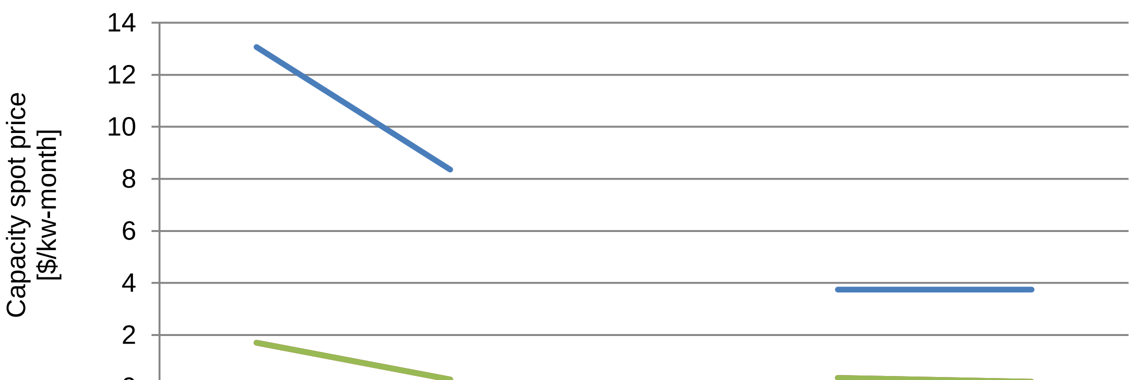
Exhibit 5 Illustrative example of a NY ISO demand curve



(Used with permission from New York ISO.[15]*)*

The intersection of the supply curve and the demand curve determines the capacity market clearing price. Exhibit 6 illustrates ICAP base residual auction resource clearing prices for the last four auctions.

Exhibit 6 ICAP clearing price



	Summer 2010	Summer 2011		Winter 2010-2011	Winter 2011-2012
NYC	$13.1	$8.4		$3.7	$3.7
NYCA	$1.7	$0.3		$0.4	$0.2
LI	$1.7	$0.3		$0.4	$0.2

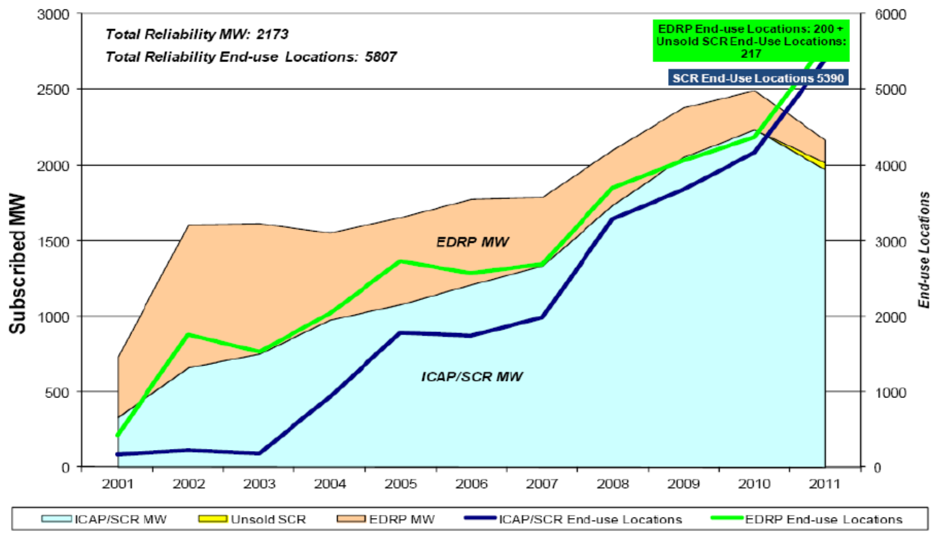
Data Source: 2011 State of the Market Report for the New York ISO Markets [16]

[15] New York ISO. (2012). *ICAP/UCAP Translation of Demand Curve - Summer 2012 Capability Period*. Retrieved on February 25, 2013, from *http://www.nyiso.com/public/webdocs/markets_operations/market_data/icap/ICAP%20Auctions/2012/Summer%202012/Documents/Demand_Curve_Summer_2012_FINAL.pdf)*

The summer capacity market price decrease of 35 percent in New York City and 80 percent in other areas from 2010 is primarily the result of new capacity (~1 GW) and a lower summer peak load forecast. Seasonal variations are the result of additional capability typically available in the winter periods due to lower ambient temperatures, which increase the capability of some resources to produce electricity.

The NYISO offers five different demand response programs. In the Installed Capacity/Special Case Resource Program, the demand resources (Exhibit 7) sell capacity in the ICAP and accept an obligation to respond when called upon within a two-hour notice. These resources are paid the higher of their strike price (any dollar value between $0 and $500)[17] or the real-time clearing price.[18]

Exhibit 7 NYISO demand response reliability programs



(Used with permission from New York ISO.[19])

Forward Capacity Market (FCM): ISO New England

The FCM is a three-year forward capacity market model. The FCM was designed to provide long-term pricing signals to attract needed investments required to ensure the reliability of the ISO New England region. The FCM is used to commit capacity resources required to reliably meet forecasted demand on an annual basis, to provide sufficient reserve margins, and to help plan transmission upgrades. The FCM uses a descending clock auction annual mechanism to clear the market by reconciling an offer-based supply curve with a vertical demand curve and price floor and cap.

The supply curve is designed by sequentially aggregating unforced capacity offers submitted by capacity resource owners or load serving entities. In the FCM, the capacity resources consist of:

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[16] New York ISO. (2012). *2011 State of the Market Report for the New York ISO Markets*. Retrieved on February 25, 2013, from http://www.nyiso.com/public/markets_operations/documents/studies_reports/index.jsp

[17] New York ISO. (2013). *Demand Response Information System Market Participant's Guide.* Retrieved on January 15, 2013, from http://www.nyiso.com/public/webdocs/markets_operations/documents/Manuals_and_Guides/Guides/User_Guides/DRIS_User_Guide.pdf

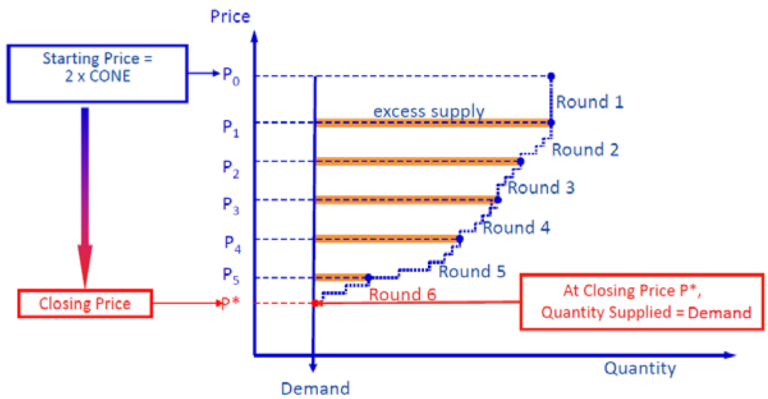
[18] Potomac Economics. (2011). *2011 State of the Market Report for the New York ISO Markets*. Retrieved on December 15, 2012, from http://www.nyiso.com/public/markets_operations/documents/studies_reports/index.jsp

[19] New York ISO. (2012). *2011 State of the Market Report for the New York ISO Markets - Potomac Economics.* Retrieved on February 25, 2013, from *http://www.nyiso.com/public/markets_operations/documents/studies_reports/index.jsp*

- Generator resources (existing and planned)
- Import
- Demand resources (load management, energy efficiency, distributed generation)

The descending clock auction is a multi-round process. The process is based on reducing the capacity market price until the quantity of available capacity resources matches the fixed capacity demand requirements. The basic concept of the descending clock auction is that more than enough capacity resources are offered if the market capacity price is high. Some capacity resources are removed from the auction by the system operator as the capacity market price drops (Exhibit 8).

Exhibit 8 Descending clock auction mechanics

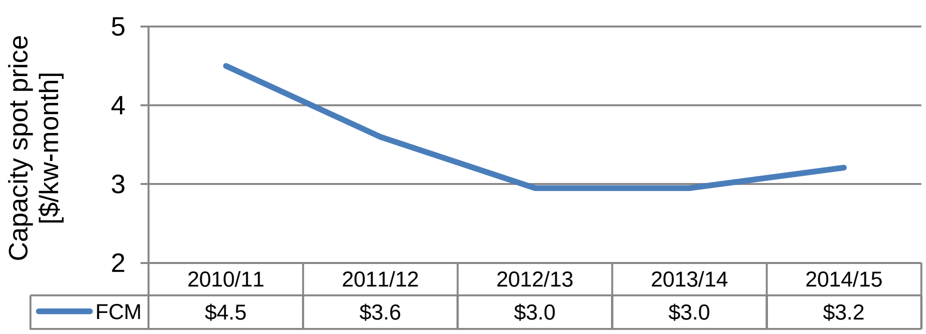


(Adapted with permission from ISO New England.[20])

In each round the auctioneer announces the start and end of the round price and the excess supply at the end of the prior round. The participants respond by submitting offers at prices within the announced price range.

Exhibit 9 illustrates the FCM base residual auction resource clearing price for the last five auctions.

Exhibit 9 FCM clearing price



	2010/11	2011/12	2012/13	2013/14	2014/15
FCM	$4.5	$3.6	$3.0	$3.0	$3.2

Data Source: 2011 Assessment of the ISO New England Electricity Markets [21]

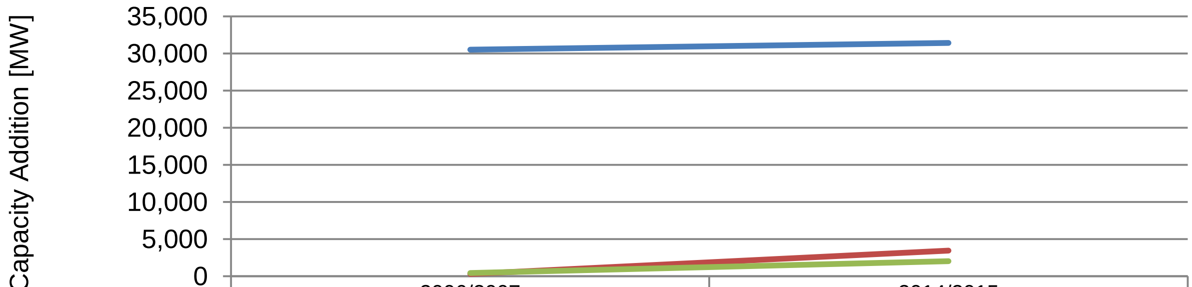
Each auction was cleared at the floor price, illustrating that there is a surplus of capacity.

The FCM, similarly to the RPM, resulted in most of the resources added in the recent years being demand resources or imports (Exhibit 10).

[20] ISO NE. (2013). *Introduction to Wholesale Electricity Market (WEM 101) – Overview of Forward Capacity Market (FCM)*. Retrieved on January 15, 2013, from http://www.iso-ne.com/support/training/courses/wem101/21_overview_of_fcm.pdf

[21] Potomac Economics. (2012). *2011 Assessment of the ISO New England Electricity Markets*. Retrieved on January, 2013, from http://www.potomaceconomics.com/markets_monitored/iso_new_england

Exhibit 10 Cumulative capacity additions



	2006/2007	2014/2015
Generation	30,509	31,439
Demand	314	3,468
Imports	451	2,011

Data Source: 2011 Annual Markets Report-Internal Market Monitor [22]

Voluntary Capacity Auction (VCA): Midwest ISO

The VCA is a voluntary market. This market may be vulnerable to the exercise of strategic withholding due to its voluntary nature. The VCA was designed to provide long-term pricing signals to attract needed investments required to ensure the reliability of the MISO region. The cleared capacity in the VCA averaged only 1.7 GW in 2010-2011 since most load serving entities' obligations were satisfied through owned capacity or bilateral purchases. The VCA market clearing price was around $0 in 2011.

Recognizing the limitations of the existing capacity market, MISO proposed a model for planning resource auctions that should be used for the annual planning resource auction and zonal auction clearing processes. The proposed model is a linear programming model that minimizes the cost of providing capacity service. The constraints include capacity offer constraints, non-negative cleared capacity constraints, system demand constraints, and minimal and maximal zonal clearing constraints.[23]

Advantages and Disadvantages of Different Markets

An advantage of the market with the vertical demand curve is that it is simple to implement. A disadvantage of the vertical demand curve is that the curve values incremental capacity as zero value.

An advantage of the downward-sloping demand curve is its stabilization of the capacity market price in a case of a very steep demand curve. It also recognizes that incremental capacity above the minimum requirement has a non-zero value (i.e., improves reliability).

A disadvantage of the downward-sloping curve is that it does not represent buyers' bids or actual customer demand. These demand curves are based on the net CONE that may lead to inefficient levels of investment or sustained surpluses. Today, most ISO/RTOs select a peak unit for the net CONE.

Does Today's Capacity Market Favor Natural Gas over Other Fuels?

Capacity markets are designed to ensure that investments which may not be recoverable through the energy and ancillary services markets are recovered. PJM's and NYISO's demand curves are established to allow suppliers to recover the net CONE for the investments over a long term. The levelized RPM net CONE was estimated at $320.63/MW-day in PJM, $360/MW-day in ATSI, and $270/MW-day in MACC zones. The levelized ICAP net CONE for a new peaking unit was estimated at $280 per kW-year (or $767/MW-day) in New York City, $250 per kW-year (or $685/MW-day) on Long Island, and $120 per

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[22] ISO NE. (2012). *2011 Annual Markets Report-Internal Market Monitor*. Retrieved on January 15, 2013, from http://iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/index.html

[23] MISO. (2012). *Planning Resource Auction Software Formulation*. Retrieved on December 15, 2012, from https://www.midwestiso.org/Library/Repository/Meeting%20Material/Stakeholder/SAWG/2012/20121101/20121101%20SAWG%20Item%20XX%20PRA%20Auction%20Formulations.pdf

kW-year (or $330/MW-day) in the New York control area for the 2011/12 capability period. The levelized FCM net CONE was estimated at $6.055/kW-month (or $200/MW-day) in ISONE. Comparing these numbers with an estimated daily cost of the cheapest coal power plant ($470/MW-day), nuclear power plant ($974/MW-day), hydro ($460/MW-day), and natural gas ($120/MW-day to $360/MW-day), it is clear that other technologies cannot compete with natural gas power plants in the capacity markets, except in NYISO, unless they get enough revenue from energy and ancillary service markets.

In the PJM market, a coal power plant is a marginal unit about 5 percent of the time in the day-ahead market and 70 percent in the spot market. It means that the coal power plants will not receive adequate revenue to recover both capital and operating costs, and they will face a problem of "missing money" without capacity payments.

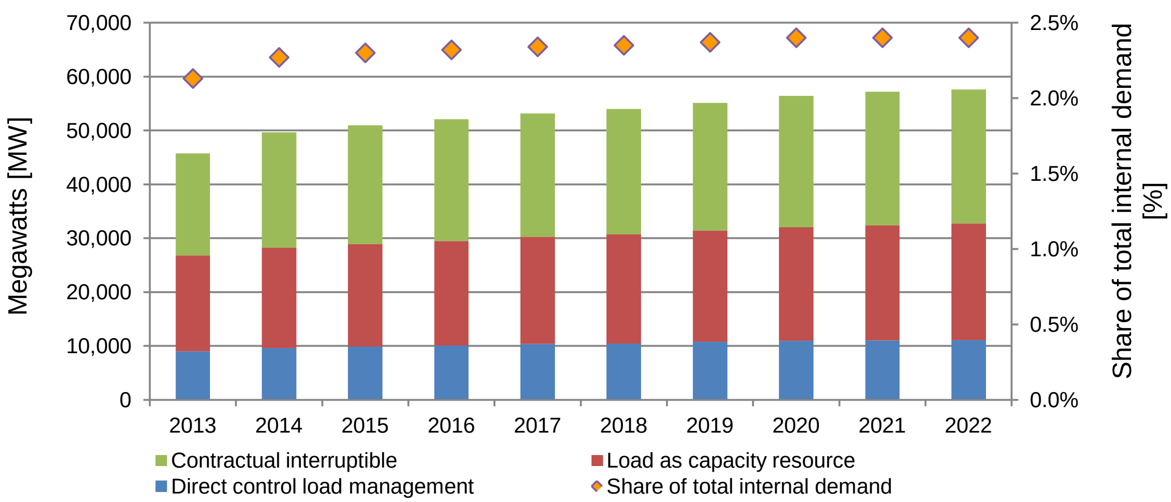
Summary

Today's capacity markets are designed mostly using a peaking plant as a new entry and corresponding net CONE. This approach was acceptable for coal power plants before natural gas prices dropped and the U.S. Environmental Protection Agency regulations were accepted. Now, natural gas power plants are competitive with coal power plants in the energy market. Coal power plants cannot obtain enough revenue from the capacity market to recover fixed and variable costs.

The capacity markets design does not consider the type of power plant (base, intermediate, and peaking). This will very likely lead to replacing retired coal power plants with demand resources and natural gas power plants.

In the last few years, generation capacity has been replaced with demand resources and that trend will probably continue to exist in the future, but may slow down. According to North American Electric Reliability Corporation total expected demand resource increases steadily over the next ten years.

Exhibit 11 Demand resource (dispatchable and controllable) expected capacity



Data Source: NERC - 2012 Long-Term Reliability Assessment [24]

More details about the different markets can be found in the primers *Energy Market*, *Ancillary Services* and *Capacity Market*. More details about the different ISOs/RTOs can be found in the ISO/RTO primers *California Independent System Operator*, *ERCOT Independent System Operator*, *MISO Regional Transmission Organization*, *ISO New England Regional Transmission Organization*, *New York ISO Regional Transmission Organization*, *PJM Regional Transmission Organization* and *Southwest Power Pool, Inc*.

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[24] North American Electric Reliability Corporation. (2012). *2012 Long-Term Reliability Assessment*. Retrieved on February 15, 2013, from http://www.nerc.com/files/2012_LTRA_FINAL.pdf